APPENDIX 10.2.5

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

PSD REPORT

AIR CONSTRUCTION PERMIT APPLICATION FOR THE FLORIDA POWER & LIGHT COMPANY OKEECHOBEE CLEAN ENERGY CENTER OKEECHOBEE COUNTY, FLORIDA

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List of Acronyms

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

HFCs	hydrofluorocarbons
HHV	higher heating value
hp	horsepower
hr/yr	hours per year
HRSG	heat recovery steam generator
HSH	highest, second highest
Hz	hertz
I	Interstate highway
km	kilometer
kW	kilowatt
lb/hr	pound per hour
lb/MMBtu	pound per million British thermal units
lb/MW-hr	pound per megawatt-hour
LHV	lower heating value
m	meter
MACT	Maximum Available Control Technology
MMBtu/hr	million British thermal units per hour
MMcf/hr	million cubic feet per hour
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum 83
NESHAP	National Emission Standards for Hazardous Air Pollutants
N_2O	nitrous oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NP	National Park
NSPS	New Source Performance Standards
NSR	New Source Review
NWA	National Wilderness Area
NWS	National Weather Service
O_2	oxygen
O_3	ozone
OCEC	Okeechobee Clean Energy Center
PFCs	perfluorocarbons
PM	particulate matter
$PM_{2.5}$	particulate matter less than 2.5 microns
PM_{10}	particulate matter less than 10 microns
ppb	parts per billion
ppbvd	parts per billion by volume dry
ppm	parts per million
ppmvd	parts per million by volume dry

PSD	Prevention of Significant Deterioration
psia	pound per square inch absolute
psig	pound per square inch gauge
QA/QC	quality assurance/quality control
RICE	reciprocating internal combustion engines
SAM	sulfuric acid mist
scf/yr	standard cubic foot per year
SCR	selective catalytic reduction
SCRAM	Support Center for Regulatory Air Models
SER	significant emissions rate
SIL	significant impact level
SIP	State Implementation Plan
Site	OCEC Certified Site
SF_6	sulfur hexafluoride
SO_2	sulfur dioxide
S.R.	State Road
ST or STG	Steam Turbine or Steam Turbine Generator
TPY	tons per year
TSP	total suspended particulate
TTN	Technology Transfer Network
ULSD	ultra low sulfur distillate
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compound

1.0 INTRODUCTION

Florida Power & Light Company (FPL) proposes to construct a new combined cycle natural gas fired generating unit located in northeast Okeechobee County that provides approximately 1,600 megawatts (MW) nominal-net of electric generation. The Project is called the Okeechobee Clean Energy Center (OCEC) and consists of a 3-on-1 natural gas fired combined cycle unit (OCEC Unit 1), supporting facilities, and potential future solar. OCEC Unit 1 has a planned commercial operation date in 2019. The Site is located approximately 24 miles west of Vero Beach and 27 miles northeast of Okeechobee (Figure 1-1).

The combined cycle unit will consist of three combustion turbines (CTs) connected to heat recovery steam generators (HRSGs) and an associated steam turbine-generator. The CTs will use natural gas as the primary fuel with ultra-low sulfur distillate (ULSD) oil used as the backup fuel. When firing natural gas, emissions of nitrogen oxides (NO_x) will be controlled using dry low NO_x (DLN) combustion technology and selective catalytic reduction (SCR). When firing ULSD oil, emissions of NO_x will be controlled using water injection and SCR. The combined cycle unit is referred to as OCEC Unit 1. Other sources of air emissions will include an auxiliary boiler, emergency generators, natural gas heater, fire pump engine, hurricane shelter engines and mechanical draft cooling tower.

The U.S. Environmental Protection Agency's (EPA's) Prevention of Significant Deterioration (PSD) regulations are promulgated under Title 40, Parts 51 and 52 of the Code of Federal Regulations (40 CFR 51.166 and 40 CFR 52.21). Florida adopted these regulations by reference in Rule 62-204.800(2) and (3) Florida Administrative Code (F.A.C.) and Florida's PSD regulations are codified in FDEP Rule 62-212.400 F.A.C. These FDEP rules have been approved by EPA as part of the State Implementation Plan (SIP). Under these requirements, the Project is classified as a new major stationary source because OCEC Unit 1 is one of the 28 listed sources and has potential emissions of a PSD pollutant that exceeds 100 tons per year [FDEP Rule 62-210.200(174) F.A.C.]. The procedures for determining applicability of the PSD permitting program to the Project are defined in FDEP Rule 62-212.400(2)(a)1. F.A.C. PSD review is required for all PSD pollutants that exceed the "significant emissions rates" (SERs) as defined in FDEP Rule 62-210.200(258) F.A.C.

On June 3, 2010, EPA promulgated regulations related to PSD and Title V GHG Tailoring Rule [75 Federal Register (FR) 31514-31608]. This change in EPA's PSD regulations requires PSD review and approval for new major projects and modifications exceeding the PSD thresholds for review. This application includes information to address PSD review of GHGs under EPA's rules. This application includes information to address PSD review of GHGs under EPA's rules and the Supreme Court Decision [*Utility Air Regulatory Group (UARG) v. Environmental Protection Agency* (EPA) (Case No. 12-1146)].

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).

Using the required regulatory comparison there will be an increase in several PSD pollutants above the SERs for the Project including GHGs. Therefore, pursuant to FDEP Rule 62-212.400, F.A.C., PSD review is applicable for the Project.

This Application is being filed for the purpose of obtaining an air construction/PSD permit for the Project in accordance with FDEP's federally approved major source air construction permit program under Florida's federally required State Implementation Plan. This Air Construction Permit Application Report is divided into seven major sections.

- Section 1.0 presents an introduction to the Project
- Section 2.0 presents a description of the Project, including air emissions and stack parameters
- Section 3.0 provides a review of the regulatory analysis conducted, including PSD and nonattainment requirements, applicable to the Project
- Section 4.0 includes the control technology review including a Best Available Control Technology (BACT) analysis including GHG
- Section 5.0 discusses the ambient air monitoring analysis
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the Project with NAAQS and PSD Increments.
- Section 7.0 presents the additional impact analysis required for PSD review.
- Appendices which include emission calculations, BACT determinations and FDEP Form No. 62-210.900(1): Application for Air Permit – Long Form.

2.0 PROJECT DESCRIPTION

2.1 Facility Description

The OCEC Site is comprised of approximately 2,341 acres of FPL's 2,842-acre property located adjacent to FPL's existing 500-kilovolt (kV) transmission system. The Site includes sufficient property for the potential for approximately 200 MW of photovoltaic (PV) solar generation. Figure 2-1 presents the conceptual site plan for the Project.

2.2 New Combustion Turbines

The CTs for the Project will be the General Electric (GE) 7HA.02. The GE "H" CT has a gross capacity of approximately 350 MW at an inlet temperature of 75°F. The HRSGs will not have duct firing. Each CT will utilize inlet air cooling that will consist of evaporative cooling and wet compression.

The generating capacity of a combined cycle plant is affected by ambient temperature, machine specific performance and features, unless wet compression is in operation. Generally, greater overall fuel consumption will occur at lower ambient temperatures when ULSD oil is fired. Machine wet compression feature available for natural gas operation allows nearly level fuel consumption over the ambient range. For the purpose of calculating hourly fuel use quantities representative of the nominal 1,600 MW (net) combined cycle unit, the following specific operating conditions for the CTs were used (see SCA Appendix 10.2.5, Air Construction Permit):

- 35°F dry bulb ambient temperature;
- 60 percent relative humidity;
- Approximately 20,566 Btu/lb and 918 British thermal units per standard cubic foot (Btu/scf), LHV, of natural gas (approximately 22,828 Btu/lb and 1,019 Btu/scf, HHV); and
- Approximately 18,300 Btu/lb and 129,900 Btu/ gallon, LHV, for ULSD oil (approximately 19,398 Btu/lb and 137,700 Btu/gallon, HHV).

The heat input for CTs being used for OCEC Unit 1 is 3,028 MMBtu/hr (LHV) (3,361 MMBtu/hr, HHV) when firing natural gas at 100 percent capacity and an ambient temperature of 35°F. When using wet compression, the heat input is 3,095.7 MMBtu/hr (LHV) (3,436.2 MMBtu/hr, HHV) at an ambient temperature of 75 ^{o}F. The corresponding fuel usage is approximately 3.37 million cubic feet per hour (MMcf/hr) at an ambient temperature of 75 ^{o}F for each CT. The potential fuel usage at 75°F ambient temperature with wet compression is approximately 8.86×10^{10} cf/yr of natural gas for OCEC Unit 1 operating 8,760 hours per year (hr/yr) on gas.

ULSD oil use will be based on the equivalent of 500 hr/yr per CT at full load. The fuel use is approximately 23,500 gallons per hour per CT at 35°F ambient temperature with an annual usage rate of approximately 33.6 MG for 3 CTs each operating for 500 hours and ambient temperature of 75°F and evaporative cooling.

2.3 Source Emission Units and Stack Parameters

The Project's air emission units are:

- 3 GE 7HA.02 CTs
- One approximately 7 million gallon ULSD oil storage tank
- Auxiliary boiler
- Three emergency generators
- Natural gas heaters (2, one is a spare)
- Fire water pump diesel engine
- Hurricane shelter propane fired engines (2)
- 30-cell mechanical draft cooling tower
- Circuit breakers containing sulfur hexafluoride (SF_6)

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

Estimated emissions for the GE 7HA.02 CTs of non-GHG pollutants are presented in Tables 2-1 and 2-2, respectively, for natural gas and ULSD oil firing. Potential annual emissions for the CTs are calculated for regulated air pollutants at an ambient temperature of 59°F with evaporative cooling and wet compression in service. 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 near the compressor inlet resulting in increased power through compressed air cooling and increased mass flow. The CT performance using evaporative cooling and wet compression is relatively constant from 59^{o} F to 95^{o} F. An ambient temperature of 75°F with wet compression is used to determine potential emissions in tons/year, since the annual average temperature is about 75°F. To produce the potential annual emissions, it is assumed that each CT would operate for 8,760 hours with 8,260 hr/yr firing natural gas and 500 hr/yr firing ULSD oil. Table 2-3 presents a summary of potential emissions for various operating conditions such as ambient temperature of the CTs.

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

During combustion, two primary types of NO_x are formed: fuel NO_x and thermal NO_x. Fuel NO_x emissions are formed through the oxidation of a portion of the nitrogen contained in the fuel. Thermal NO_x emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. NO_x formation can be limited by lowering combustion temperatures (through water or steam injection) and/or staging combustion (a reducing atmosphere followed by an oxidizing atmosphere, known as DLN control). The proposed NO_x stack emissions rates for the CTs associated with OCEC Unit 1 are 2 parts per million by volume dry (ppmvd), corrected to 15-percent oxygen (O_2) or less when firing natural gas, and 8 ppmvd corrected to 15-percent O_2 or less when firing ULSD oil.

Carbon monoxide (CO) is formed by incomplete combustion of fuel. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize CO formation. CO formation is limited by ensuring complete efficient combustion of the fuel in the turbines. Recent improvements in CT combustor technology allow for both reduced NO_x emissions and low CO emissions. The proposed CO stack emission rates for the CTs when firing natural gas and ULSD oil at full load are 4.3 ppmvd corrected to 15-percent O_2 and 10 ppmvd corrected to 15-percent O_2, respectively.

Similarly, volatile organic compound (VOC) emissions are formed by incomplete combustion of fuel. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize VOC formation. VOC formation is limited by ensuring complete efficient combustion of the fuel in the CTs. Recent improvements in CT combustor technology allow for both reduced NO_x emissions and low VOC emissions. The VOC stack emission rates for the CTs when firing natural gas and ULSD oil at full load are 1.0 ppmvd corrected to 15-percent O_2 and 2 ppmvd corrected to 15-percent O_2, respectively.

PM, sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4) emissions are controlled and minimized by the use of clean fuels that include natural gas with a sulfur content of no greater than 2 gr/100 scf of sulfur and ULSD oil with a sulfur content of no greater than 0.0015-percent sulfur by weight.

GHG emissions are minimized through the use of highly efficient combined cycle technology and the primary use of natural gas, the lowest GHG emitting fossil fuel.

A new approximately 7 million gallons (MG) fuel oil storage tank will be used to store the ULSD oil at the Site. Appendix A provides emissions information for the ULSD oil storage tank.

The auxiliary boiler will be used as necessary for startup. The limited use auxiliary boiler will have a maximum heat input of 99.8 MMBtu/hr higher heat value (HHV) firing natural gas. Table 2-4 contains performance and emissions information for the auxiliary boiler.

For construction, temporary boilers will be required for steam blows and cleaning. In addition, temporary diesel powered electric generators may be used for construction power to support various types of electric powered construction equipment. Information that includes operation and emissions for the construction boilers and diesel generators is contained as temporary emission units in the application form (Appendix C).

The 3-on-1 combined cycle unit may also include one natural gas-fired fuel heater and a spare. These heaters will have a heat input of 10 MMBtu/hr (HHV) or less and will be used as necessary to heat natural gas above the dew point. Only one fuel heater may be necessary for the operation of CTs associated with OCEC Unit 1. Table 2-5 contains performance and emissions information for the fuel heaters.

OCEC will be equipped with three large emergency generators to support the power plant and transmission system. Two, 3,298 kilowatt (kW-brake) emergency generators will be installed to support the power plant. One emergency generator, not to exceed 3,298 kW, will be installed to support transmission and other emergency power needs, such as the gas yard, that are outside the main power block area. These emergency generators will be used when electric power is not available. This would primarily occur during catastrophic events such as hurricanes. In addition to the larger emergency generators, there are small 25 kW propane fired emergency generators associated with the OCEC hurricane shelter. OCEC will be equipped with a 422-horsepower (hp) fire pump engine. This engine will be used when necessary during catastrophic events such as fires. Tables 2-6, 2-7, and 2-8 contain emissions and manufacturer's information for the emergency generators, hurricane shelter engines and fire pump engine, respectively. Normally, the engines are operated 1 to 2 hours per month for maintenance and reliability testing.

OCEC Unit 1 will have a mechanical draft cooling tower for steam cycle cooling. PM will be emitted from the mechanical draft cooling tower in the form of drift. Cooling tower drift will be controlled through the use of mist eliminators that will be designed to limit drift to 0.0005 percent of the circulating water rate of the cooling tower. Table 2-9 presents information on the cooling tower and potential PM, PM_{10} and $PM_{2.5}$ from drift. The information presented in Table 2-9 is based on a 30-cell design.

2.4 Annual Emissions for the Project

The potential annual emissions from OCEC Unit 1 include air emissions from the CTs, fuel heater, emergency generators, auxiliary boiler, fire pump engine, hurricane shelter engines, cooling tower and fuel oil tank. Table 2-10 presents the annual potential emissions for the OCEC Unit 1 Project. Annual potential emissions were based on baseload operation, ambient air temperatures of 75°F, 8,260 hr/yr firing natural gas, and 500 hr/yr firing ULSD. This ambient temperature is appropriate, since the annual average temperatures are approximately 75°F.

Table 2-10 presents the potential emissions resulting from the Project and the PSD SERs, which are thresholds for PSD review for all PSD pollutants from new major PSD sources. PSD review is required for emissions of a pollutant greater than the listed PSD SER. As shown in this table, the potential emissions for OCEC are greater than the PSD SERs for all regulated air pollutants except lead.

In addition, maximum annual potential hazardous air pollutants (HAPs) emissions are presented in Table 2-11. Additional detail on the HAP emission calculations is also presented in Appendices A, Tables A-13 through A-16. The OCEC project will be a minor (or area) source of hazardous air pollutant (HAP) emissions due to the combined potential emissions from the Project being less than the major source thresholds for HAPs [10 tons per year (TPY) of a single HAP, or 25 TPY for all HAPs].

2.5 Annual Emissions for GHGs

On June 3, 2010, the U.S. Environmental Protection Agency (EPA) promulgated regulations related to PSD and Title V Greenhouse Gas (GHG) Tailoring Rule (75 Federal Register 31514-31608). In EPA's promulgation, GHGs are defined to include an aggregate group of six classes of compounds that have been determined to have GHG properties: CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Each of these GHGs has a specific Global Warming Potential (GWP) that is calculated as "CO_2 equivalent emissions" or CO_2e that is equivalent to the GHG properties of one ton of CO_2. In 2014 the Supreme Court issued a decision that indicated that GHG alone could not trigger PSD review. Rather, PSD for GHGs could only be triggered if PSD were required for other air pollutants (Case No. 12-1146).

For the OCEC Unit 1, 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. Table 2-10 presents the potential GHG emission from the OCEC Unit 1 Project. Tables A-17 and A-18 in Appendix A present the potential GHG emissions resulting from the CTs and other combustion sources, respectively. The GHG emissions for the circuit breakers are also included and discussed in the following paragraphs.

In addition to combustion sources, the Project will have circuit breakers containing sulfur hexafluoride (SF_6). 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 are required for connection of the electric power generated by OCEC Unit 1 to FPL's 500 kV transmission system located adjacent to the site. The switchyard will require ten 500 kV circuit breakers and the collector year will require four 500 kV circuit breakers. Within the power block there will be three circuit breakers. The 17 circuit breakers associated with the OCEC Project are estimated to contain approximately 18,290 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:

- 18,290 lb SF_6 x 0.005 leakage/year = 91.45 lb SF_6/year
- 91.45 lb SF_6/year x 22,800 lb CO_2e/lb SF_6 (Table A-1, 40 CFR Part 98) x ton/2,000 lb = 1,042.53 tons CO_2e

Since PSD review is triggered for the Project for several regulated air pollutants, PSD review is required for GHG emissions if they are greater than 75,000 TPY CO_2e. As shown in Table 2-10, the potential annual CO_2e emissions of the Project will exceed the PSD threshold for GHGs.

2.6 Layout, Structures, and Stack Sampling Facilities

A conceptual site plan of the Project is presented in Figure 2-1. The arrangement of the power block may be adjusted based on final design. Figure 2-3 shows alternative arrangements of the CT/HRSG and steam turbine generator (STG). Typical dimensions of the structures associated with the CTs are presented in Section 6.0. Stack sampling facilities will be constructed in accordance with FDEP Rule 62-297.310(6), F.A.C.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

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

3.1 National, State, and Local AAQS

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

3.2 PSD Requirements

3.2.1 General Requirements

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

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

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of SO_2, PM_{10}, $PM_{2.5}$ and NO_2 concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, $PM_{2.5}$ and NO_2.

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

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

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

3.2.2 Greenhouse Gases

EPA issued a "Tailoring Rule" on June 3, 2010 that "tailors" the applicability provisions of the PSD and Title V programs to enable EPA and state agencies to phase in permitting requirements for GHGs. The first phase of the Tailoring Rule began on January 2, 2011, and continued through June 30, 2011. During this period GHG sources became subject to PSD if the increase in GHG emissions from a project exceeded 75,000 TPY of CO_2e or more and the project was required to undergo PSD review for other air regulated pollutants. The second phase of the Tailoring Rule began on July 1, 2011, and continues thereafter for new major GHG emitting facilities and major modifications. New major sources with the potential to emit 100,000 TPY CO_2e or more of GHG will be considered major sources for PSD permitting purposes and are required to undergo PSD review. Additionally, any physical change or change in the method of operation at a major source resulting in a net GHG emissions increase of 75,000 TPY CO_2e or more will be subject to PSD review. The Supreme Court issued a decision that indicated that GHG alone could not trigger PSD review (Case No. 12-1146). Rather, PSD for GHGs could only be triggered if PSD were required for other air pollutants. PSD review is required for GHG emissions greater than the listed PSD SER of 75,000 tons CO_2e if PSD is required for other PSD pollutants.

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

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

3.2.3 Control Technology Review

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

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

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted, which the Department, on a case-by-case basis, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant taking into account:

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

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

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

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

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

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

The BACT requirements are intended to ensure that the control systems incorporated in the design of a new facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the new facility. BACT must, at a minimum, demonstrate compliance with 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).

For GHG emissions, control technology review is conducted by FDEP pursuant to its regulations in Rule 62-212.400, F.A.C. EPA approved FDEP's PSD permitting program for GHGs on May 9, 2014. EPA issued guidance on the determination of BACT for GHGs ("*PSD and Title V Permitting Guidance for Greenhouse Gases*", March 2011). This EPA guidance supplements previous EPA guidance on the determination of BACT that is specific to BACT determinations for GHG emissions.

3.2.4 Source Impact Analysis

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

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

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

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

3.2.5 Air Quality Monitoring Requirements

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

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

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

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

3.2.6 Source Information/GEP Stack Height

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

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

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

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

where:

Hg = GEP stack height,

H = Height of the structure or nearby structure, and

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

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

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

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

3.2.7 Additional Impact Analysis

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

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

3.2.8 Air Quality Related Values

An Air Quality Related Value (AQRV) analysis is required for projects for those pollutants undergoing PSD review to assess the potential impact on AQRVs in PSD Class I areas. The nearest Class I areas to the Project are the Everglades National Park (ENP), located about 203 km (127 miles) from the Project, and the Chassahowitzka National Wilderness Area (NWA), located more than 211 km (132 miles) from the Project. The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

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

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

3.3 Nonattainment Rules

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

3.4 Emission Standards

3.4.1 New Source Performance Standards

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

The Project will be subject to one or more NSPS. EPA promulgated new NSPS for Stationary Combustion Turbines that will commence construction after February 18, 2005. Subpart KKKK replaces Subpart GG for CTs. On October 15, 2003, EPA promulgated changes to 40 CFR 60, Subpart Kb that would exempt ULSD oil tanks containing No. 2 ULSD oil by virtue of its vapor pressure (FR Vol. 68, No. 199, Pages 59328-59333).

Combustion Turbine

NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired, are limited per 40 CFR 60 Subpart KKKK. NO_x emissions for these new CTs (i.e., >850 MMBtu/hr) are limited by Subpart KKKK to 15-ppmvd corrected to 15-percent O_2 and 42 ppmvd corrected to 15-percent O_2 for natural gas and oil firing, respectively. SO_2 emissions are limited to using a fuel with a sulfur content of no greater than 0.05 percent and 20 gr/10 scf of sulfur for oil and natural gas firing, respectively. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR 60 Subpart KKKK.

EPA recently approved NSPS for GHG emissions from new, modified, and reconstructed electric utility generating units (40 CFR Part 60, Subpart TTTT; Signed 8/3/15). The NSPS applies to new stationary CTs that commence construction after January 8, 2014 and have a heat input rating of over 250 MMBtu/hr and serve a generator capably selling more than 25 MW of electricity to a utility distribution system. New baseload CTs that combust more than 90 percent natural gas are required to meet a CO_2

emissions rate of 1,000 lb/MW (gross) or 1,030 lb/MWh (net) on a 12-month rolling average basis. The monitoring requirements for natural gas fired units are based on 40 CFR Part 75 requirements.

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

40 CFR 60.7 Notification and Record Keeping

- *(a)(1) Notification of the date of construction - 30 days after such date.*
- *(a)(3) Notification of actual date of initial startup - within 15-days after such date.*
- *(a)(5) Notification of date which demonstrates CEM - not less than 30 days prior to date*

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

- *(c) Excess emissions reports – semi-annually by the 30th day following 6-month period (required even if no excess emissions occur).*
- *(d) Maintain file of all measurements for 2 years.*

60.8 Performance Tests

- *(a) Must be performed within 60 days after achieving maximum production rate, but no later than 180 days after initial startup.*
- *(d) Notification of Performance tests at least 30 days prior to them occurring.*

Other Emission Units

NSPS are also applicable to the auxiliary boiler, natural gas heater, emergency generators and fire pump engine. The EPA NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to the auxiliary boiler. There are no emission standards for natural gas firing under Subpart Dc. The diesel engines associated with the emergency generators and fire pump engines meet the definition of “emergency stationary internal combustion engine” in NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. This NSPS is applicable and the diesel engines would be operated for according to Section 60.4211(f) and required to meet the emission standards for the size and date of manufacturer of the engine.

3.4.2 National Emission Standards for Hazardous Air Pollutants

EPA has promulgated maximum achievable control technology (MACT) standards under the National Emissions Standards for Hazardous Air Pollutants (NESHAPs) regulations. Maximum annual potential HAPs emissions were presented in Table 2-11. Additional detail on the HAP emission calculations is also presented in Appendices A.

The Project will be a minor (area) source of HAPs since the potential HAP emissions from the Project will be less than the major source HAP thresholds of 25 TPY for total HAPs and 10 TPY for a single HAP. Under the NESHAPs of 40 CFR Part 63, Subpart YYYY applies to the CTs located at a major source of

HAPs. Since the Project's potential HAP emission are less than the major source thresholds this NESHAP does not apply. Subpart JJJJJJ that applies to industrial, commercial and institutional boilers and process heaters applies to areas (minor) sources of HAPs. This NESHAP does not apply to boilers and process heaters that fire only natural gas. Therefore, this NESHAP does not apply to the Project's auxiliary boiler or natural gas heater. Subpart ZZZZ applies to the reciprocating internal combustion engines (RICE) located at major and area (minor) sources of HAPs. Meeting the requirements of NSPS Subpart IIII meets the requirements of NESHAP Subpart ZZZZ.

3.4.3 Florida Rules

FDEP has adopted the EPA NSPS by reference in FDEP Rule 62-204.800(8): Subsection (b)82., F.A.C., for stationary gas turbines; Subsection (b)4., F.A.C., for the auxiliary boiler; and Subsection (b)80., F.A.C., for the emergency generators and fire pump engine. Therefore, the facility is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping as those described in Section 3.4.1. FDEP has authority for implementing NSPS requirements in Florida.

3.4.4 Florida Air Permitting Requirements

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

3.4.5 Local Air Regulations

There is no local air pollution control program in Okeechobee County. Ordinance 1.06.02. Z. that states: "Ambient air quality shall not be degraded below minimum EPA standards." is an objective of the Okeechobee County comprehensive plan. The FDEP air quality regulations, which adopt EPA ambient air quality standards by reference, require demonstration that all applicable air quality standards are met prior to approval of new facilities such as OCEC.

3.5 Source Applicability

3.5.1 Area Classification

The Project is located in Okeechobee County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Okeechobee County and surrounding counties are designated as PSD Class II areas for SO_2, PM [total suspended particulate (TSP)], and NO_2. The Class I areas nearest to the Project are the ENP, located approximately 203 km (127 miles) from the Project, and Chassahowitzka NWA, located 211 km (132 miles) from the Project.

3.5.2 PSD Review

Pollutant Applicability

The Project is considered to be a major facility under FDEP PSD rules because the potential emissions of several regulated pollutants will exceed 100 TPY and the emissions units are one of the 28 listed major source categories under the PSD rules. PSD review for a new major facility is required for any PSD-regulated air emissions that exceed the PSD SERs. As shown in Table 3-3, potential emissions from the proposed Project will trigger PSD review for SO_2, PM (TSP), PM_{10}, $PM_{2.5}$, NO_x, CO, VOC, sulfuric acid mist, and GHGs. (Note: EPA no longer requires PSD review for HAPs from PSD review. The pollutants vinyl chloride, asbestos, and beryllium are no longer evaluated in PSD review because they are addressed through the NESHAP program.)

Emission Standards

NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired, are limited per 40 CFR 60 Subpart KKKK adopted by reference by FDEP in Rule 62-204.800(8)(b)82., F.A.C. NO_x emissions for these new CTs (i.e., >850 MMBtu/hr) are limited by Subpart KKKK to 15-15-ppmvd corrected to 15-percent O_2 and 42 ppmvd corrected to 15-percent O_2 for natural gas and oil firing, respectively. These emission standards are based on 30-day rolling average and must be met at all times, including start, shutdown and malfunctions. SO_2 emissions are limited to using a fuel with a sulfur content of no greater than 0.05 percent and 20 gr/100 scf of sulfur for oil and natural gas firing, respectively. These requirements are summarized in Section 4.2. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR 60 Subpart KKKK. There are also applicable notification, reporting, and recordkeeping requirements in the general provisions of 40 CFR 60 Subpart A. The proposed emissions rates for the Project will be well below the Subpart KKKK emission limit (see Section 4.0).

GHG emissions as CO_2 from OCEC Unit 1 are limited to 1,000 lb/MW (gross) or 1,030 lb/MWh (net) by 40 CFR Part 60, Subpart TTTT. This emission limit is applicable to OCEC Unit 1 since the amount of electric output over a 3-year rolling average will exceed the threshold for this standard (estimated to be a capacity factor of approximately 42 percent for each CT associated with OCEC Unit 1). Although the limit is applicable to each CT, the amount of generation produced by the steam electric turbine generator is used in calculating the lb/MWh for each CT/HRSG train. The proposed emissions for CTs being used for OCEC Unit 1 will be well below the Subpart TTTT CO_2 limit (see Section 4.0).

EPA has promulgated MACT standards under the NESHAP regulations and applicability is based on whether a source is major or minor for HAPs. A facility is classified as a major source of HAPs when the maximum potential emissions for all emission units located at the facility exceed 10 TPY of a single HAP and 25 TPY for all HAPs. The Project will not be a major source of HAPs since the combined potential emissions of the Project are less than the major HAP thresholds.

The NESHAP Subpart YYYY does not apply to the Project. If it were applicable, this NESHAP would only apply to the CTs if the aggregate use of oil by existing and new turbines exceeds 1,000 hours during any calendar year. Information available from the equipment vendors indicate that the CTs being proposed for the Project will meet the MACT of 91 parts per billion by volume dry (ppbvd) corrected to 15-percent O_2 for formaldehyde. FDEP adopted this EPA rule by reference in Rule 62-204.800(11)(b)81, F.A.C.

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

Ambient Monitoring

For the Project, the impacts will be more than the PSD *de minimis* monitoring concentrations for certain pollutants (see Section 5.0). As a result, an air quality monitoring impact analysis for these pollutants is required by NSR under FDEP air regulations. Air quality monitoring data from FDEP for the closest air quality monitoring locations to the Project were used to fulfill the ambient air quality monitoring requirements. These data are presented in Section 5.0 of this application.

GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 meters (213 ft) high. The HRSG stacks will be 149 ft. These stack heights do not exceed the GEP stack height. However, as discussed in Section 6.0, Air Quality Modeling Approach, since the stack height is less than GEP, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the CT/HRSGs stack emissions caused by nearby structures is included in the modeling analysis.

3.5.3 Local Air Regulations

As specified in Subsection 3.4.5, Okeechobee County does not have air quality program for the review, process, or approval of sources of air pollution; therefore, FDEP permitting requirements are applicable to the Project.

3.5.4 Other Clean Air Act Requirements

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

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

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

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

EPA in 2011 finalized the Cross-State Air Pollution Rule (CSAPR) that required 27 state in the eastern half of the U.S. to reduce annual emissions from electric utility units that cross state lines and contribute to ozone (NO_x emissions) and fine particle concentrations (SO_2 and NO_x). Florida was included as one of the 27 states for contributing to ozone. A number of court actions delayed the implementation of CSAPR, leaving CAIR in place. On April 29, 2014, the Supreme Court upheld CSAPR, remanded the rule to the D.C. Circuit, and it became effective in Florida on January 1, 2015.

4.0 CONTROL TECHNOLOGY DESCRIPTION

4.1 Introduction

The 1977 CAA Amendments established requirements for the approval of pre-construction permit applications under the PSD program. As discussed in Subsection 3.2.2, one of these requirements is that BACT be applied to all applicable pollutants. This section presents the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a "top-down" approach. A BACT determination requires a site-specific analysis of the technical, economic, environmental, and energy impacts of the proposed and alternative control technologies [see Rule 62-212.400 of the Florida Administrative Code (F.A.C.)].

The "top-down" approach consists of the following five steps, as described in the New Source Review Workshop Manual-Draft (EPA, 1990):

1) Identification of all available control technologies
2) Elimination of technically infeasible control options
3) Ranking of the technically feasible control technologies based on their effectiveness
4) Evaluation of the economic, environmental, and energy impacts of the feasible control options
5) Selection of BACT based on consideration of the above factors

The PSD regulations require that new major stationary sources and major modifications to existing major sources undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. In the case of the proposed Project, $PM/PM_{10}/PM_{2.5}$, NO_x, CO, VOC, SO_2 (including sulfuric acid mist) and GHG emissions require a BACT analysis utilizing the top-down approach. In each case, BACT is an emission limitation that meets the maximum degree of emission reduction after taking into account the proposed Project's specific economic, environmental, and energy impacts, as well as consideration of the application of the technologies proposed. If it is impractical to impose an emission limit, a work practice standard may be specified.

As indicated previously, new facilities with potential emissions of non-GHG pollutants that are required to undergo PSD review are required to conduct a BACT analysis for GHG emissions if emissions are greater than 75,000 TPY.

An overview of the BACT analysis is presented in Section 4.2, and the following sections provide the required BACT analysis.

4.2 Overview of Proposed BACT

FDEP has issued many PSD permits with BACT determinations for projects involving natural gas and/or fuel oil-fired combined cycle CTs. These decisions for CT/HRSGs have included the use of advanced DLN combustors and a SCR system for limiting emissions of NO_x, good combustion practices for minimizing CO and VOC emissions, and the use of clean fuels such as pipeline-quality natural gas or ULSD oil for control of other emissions including PM_{10}, $PM_{2.5}$ and SO_2. The stack exhaust NO_x concentration levels have ranged from 2.0 to 2.5 ppmvd corrected to 15-percent O_2 in these determinations.

The BACT limits proposed for the Project are consistent with the DEP-issued PSD Permits for other combined cycle projects and other emission units. The proposed BACT limits for this Project are presented in Table 4-1.

The proposed limits contained in Table 4-1 are for normal operation and exclude startup, shutdown, malfunctions, fuel switching, and DLN tuning. During startup and shutdown of the CTs and STG, conditions exist where the CTs are operating at low loads where the DLN systems are ineffective and the SCR cannot function. Non-normal operation results in emissions higher than of those proposed as a BACT for normal operation. The durations of these non-normal operation periods depend upon the specific startup, shutdown, malfunctions, fuel switching and DLN tuning condition. Presented below are suggested permit conditions for these periods. For NO_x and GHG, there are NSPS that have to be met at all times and are proposed as secondary BACT. In addition, work practice standards are proposed as secondary BACT for all pollutants.

Suggested Conditions for Primary and Secondary BACT Limits, including Periods of Startup, Shutdown, Malfunctions, Fuel Switching, and DLN Tuning

1. Compliance with BACT Emission Limits: The Primary BACT numeric emission limits are listed in Table 4-1, and apply at all times, except during startup, shutdown, fuel switching, DLN tuning and malfunctions. As specified in this condition, emissions during startup, shutdown, DLN tuning, fuel switching, and documented malfunctions are not required to meet the Primary BACT numeric emission limits provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents and comply with the applicable Secondary BACT limits. As specified below, for each gas turbine/HRSG System, emissions resulting from startup, shutdown, or malfunction shall be excluded from CEMS or other continuous data in any 24-hour period ("any 24-hour period" means a calendar day, midnight to midnight) for the following conditions (these conditions are considered separate events and each event may occur independently within any 24-hour period).

CEMs or other continuous monitoring data shall be used to demonstrate compliance with the Secondary NO_x and GHG BACT numeric emission limits described in Condition 2. The Secondary BACT Work Practice Standards in Condition 3 shall apply to all operating conditions described below. All valid emissions data (including data collected during startup, shutdown, malfunction, DLN tuning, and fuel switching) shall be used to report emissions for the Annual Operating Report.

a. Steam Turbine Cold Startup: During a cold startup of the steam turbine, any emissions in determining compliance with a Primary BACT numeric emission limit from any CT/HRSG system can be excluded for a period not to exceed eight (8) hours in any 24-hour period. A cold “startup of the steam turbine” is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

{Permitting note: During a cold startup of the steam turbine, each CT/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam turbine and prevent thermal metal fatigue or equipment materials differential expansion damage. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

b. CT/HRSG System Cold Startup. During a cold startup of a CT/HRSG system, any emissions in determining compliance with a Primary BACT numeric emission limit from any CT/HRSG system can be excluded for a period not to exceed four (4) hours in any 24-hour period. “Cold startup of a CT/HRSG system” is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 pounds per square inch gauge (psig) for at least a one-hour period.

c. CT/HRSG System Warm Startup. During a warm startup of a CT/HRSG system, any emissions in determining compliance with a Primary BACT numeric emission limit from any CT/HRSG system can be excluded for a period not to exceed two (2) hours in any 24-hour period. “Warm startup of a CT/HRSG system” is defined as a startup after the pressure in the HP steam drum is above 450 psig.

d. Shutdown Combined Cycle Operation: During the shutdown of combined-cycle operation, any emissions in determining compliance with a Primary BACT numeric emission limit from any CT/HRSG system can be excluded for a period not to exceed three (3) hours in any 24-hour period.

e. CT/HRSG System Shutdown. During the shutdown of any CT/HRSG system, any emissions in determining compliance with a Primary BACT numeric emission limit can be excluded for a period not to exceed two (2) hours in any 24-hour period.

f. Fuel Switching: During a fuel switch, any emissions in determining compliance with a Primary BACT numeric emission limit from any CT/HRSG system can be excluded for a period not to exceed two (2) hours and no more than four (4) hours in any 24-hour period for any CT/HRSG system.

g. DLN Tuning: During a DLN tuning session and manufacturer required Full Speed No Load Tests (FSNL) trip tests, any emissions may be excluded from the compliance demonstrations provided the tuning session is performed in accordance with the manufacturer's specifications or determined best practices. Prior to performing any tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

h. Documented Malfunction: During a documented malfunction, any emissions in determining compliance with a Primary BACT numeric emission limit from any CT/HRSG system may be excluded for a period not to exceed two (2) hours in any 24-hour period. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic email. The permittee shall report to the Department the nature, extent, and duration of the malfunction; the cause of the malfunction; and the actions taken to correct the problem.

2. Secondary NO_x and GHG BACT Numeric Emission Limits: During the operating conditions listed in Specific Condition 1, the permittee shall comply with the Secondary NO_x and GHG BACT limits (40 CFR 60, Subpart KKKK and Subpart TTTT). Demonstrating compliance with the NSPS Subpart KKKK limit for NOX shall be sufficient for demonstrating compliance with the Secondary NO_x BACT limit. Demonstrating compliance with the NSPS Subpart TTTT limit for CO2 shall be sufficient for demonstrating compliance with the Secondary GHG BACT limit. [Rule 62-210.200(BACT) and 40 CFR 60, Subpart KKKK and Subpart TTTT]

3. Secondary BACT Work Practice Standards for Startup, Shutdown, Fuel Switching and DLN Tuning:

a. Startup on Gas: The permittee shall fire only natural gas during all periods of startup, up to a load of no less than 40%, except for periods of gas curtailment or periods during which gas is not reasonably available, or for purposes of testing and maintenance. For all startups on ULSD oil, the permittee shall document the necessity of firing ULSD oil at startup. The permittee shall maintain documentation of all startups on ULSD oil for a period of five years and shall make this documentation available to the Department upon request. [Rule 62-210.200 (BACT)]

b. Manufacturer-Recommended Procedures: The permittee shall follow the manufacturer's recommended operating procedures for startup and shutdown, fuel switching, and DLN tuning. All personnel responsible for startup or shutdown of equipment, fuel switching and DLN tuning shall be familiar with these procedures. For each operator responsible for startup or shutdown and fuel switching, the permittee shall document that the operator has been trained in the manufacturer's recommended procedures. The permittee shall make this documentation available to the Department upon request. [Rule 62-210.200 (BACT)]

4.3 Combined Cycle CT/HRSGs

This section contains the BACT analysis for the NO_x, CO, VOC, $PM/PM_{10}/PM_{2.5}$, SO_2 (including sulfuric acid mist) and GHG emissions from combined cycle CT/HRSGs.

4.3.1 Nitrogen Oxides

4.3.1.1 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous BACT determinations issued within the last 12 years (i.e., since 2003) for NO_x emissions from combined cycle CTs listed in the RACT/BACT/LAER Clearinghouse (RBLC) on EPA's web page. A summary of the BACT determinations for natural gas- and fuel oil-fired CTs are presented in Appendix B, Tables B-1 and B-2, respectively. Only large CTs with more than 100 MW electricity output or more than 1,000 MMBtu/hr heat input were included in the tables. These tables also include determinations from major source permits available on the FDEP website and in other recent relevant BACT analysis reports.

As shown in Appendix B, Table B-1, it is evident that the overwhelming majority of BACT emissions limits over the last 10 years for natural gas firing combined cycle CT/HRSGs are typically 2 and 2.5 ppmvd corrected at 15-percent O_2. Almost all determinations are based on DLN and SCR. Appendix B Table B-2 shows that for oil-firing CT/HRSGs, all BACT determinations are based on water injection and SCR with emissions limits for new combined cycle units typically at 8 ppmvd at 15-percent O_2.

FDEP has issued several permits for natural gas-fired CTs and have established BACT for NO_x emissions from these CT/HRSGs as DLN and/or SCR with a stack NO_x concentration of 2.0 ppmvd or higher. The most recent gas- and oil-fired combined cycle unit in Florida that met NO_x levels equivalent to BACT was the FPL Port Everglades Energy Center (PEEC) in 2012. The emission limits established by FDEP were based on DLN when firing gas and water injection when firing oil along with SCR to meet emission limit of 2 ppmvd corrected to 15-percent O_2 for natural gas firing and 8 ppmvd corrected to 15-percent O_2 for oil firing.

4.3.1.2 Identification of Potentially Applicable Control Technologies

A list of potential control technologies for controlling NO_x emissions from the CT/HRSGs are identified below.

Water Injection

The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of possible NO_x emissions reduction depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion result (i.e., CO and VOC emissions). With the advent of DLN or equivalent combustion technology when firing natural gas, water injection is used only when units fire fuel oil.

DLN Combustors

DLN combustors or equivalent technology, which are offered for conventional CTs manufactured by GE, Siemens, Mitsubishi Heavy Industries (MHI), and ABB, can achieve NO_x emissions concentrations as low as 9 ppmvd or less when firing natural gas. All these vendors have offered DLN combustors on advanced heavy-duty industrial units. Formation of thermal NO_x, which is a product of combustion, is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the GE 7HA.02 CTs being planned for the Project, the standard combustion chamber design includes the use of the latest GE DLN combustor technology.

Selective Catalytic Reduction

SCR is a process for controlling emissions of NO_x from stationary sources. The basic principle of SCR is the reduction of NO_x to nitrogen (N_2) and water (H_2O) by the reaction of NO_x and ammonia (NH_3) within a catalyst bed. The primary reactions are temperature dependent typically occurring in the range of 600 and 750 ^oF, although reaction also can occur at lower and higher temperatures. The SCR reaction requires O_2, and performs effectively at O_2 levels above 2 to 3 percent that are easily achieved in the exhaust gas of a CT.

Several different catalysts are available for use at different exhaust gas temperatures. The longest and most common catalysts in use are base metal catalysts, which typically contain titanium and vanadium oxides and which may also contain molybdenum, tungsten, and other elements. Base metal catalysts are useful between 450 and 800°F. For high temperature operation (700 to over 1,100°F), zeolite catalysts may be used. In clean, low-temperature (350 to 550°F) applications, catalysts containing precious metals such as platinum and palladium can be used.

SCR system consists of a reactor chamber with a catalyst bed, composed of catalyst modules and an NH_3 handling, storage and injection system, with the NH_3 injected into the flue gas upstream of the catalyst. In a combined cycle unit the SCR catalyst and ammonia injection grid are located in the HRSG. A typical combined cycle SCR design places the reactor chamber after the super heater within a cavity of the HRSG system. The flue gas temperature in this area is within the operating range for base metal-type catalysts. For combined cycle CT/HRSGs, SCR is considered an available, demonstrated technology. Other than spent catalyst, the SCR process produces no waste products.

In principle, SCR can provide reductions in NO_x emissions approaching 100 percent. (Simple thermodynamic calculations indicate that a reduction of well over 99 percent is possible at 650°F.) In practice, commercial SCR systems have met control targets of over 90 percent in many cases.

SCONOx Process

Goal Line Environmental Technologies developed the SCONOx, a relatively new multi-pollutant post-combustion technology, which utilizes a coated oxidation catalyst to oxidize and remove NO_x and CO without a reagent such as NH_3. Now offered by EmeraChem (formerly Goal Line), the technology is marketed under the name EMx™.

The SCONOx system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize CO to CO_2 and NO to NO_x. CO_2 generated in the catalyst bed is exhausted to the atmosphere with the flue gas, while NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Periodically, dilute hydrogen gas is passed across the catalyst to regenerate the potassium carbonate coating. The regeneration step converts KNO_2 and KNO_3 into K_2CO_3, water, and nitrogen gas. In order to maintain continuous operation during catalyst regeneration, the system is furnished in arrays of five-module catalyst sections. During operation, four of the five modules are online and treating flue gas, while one module is isolated from the flue gas for regeneration. NO_x reduction in the system occurs in an operating temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG.

A regeneration cycle is typically set to last for 3 to 5 minutes. Regeneration gas is produced by reacting natural gas with O_2 present in ambient air. The SCONOx system uses a gas generator to produce hydrogen and CO_2. For SCONOx systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the SCONOx catalyst that reforms the natural gas.

The SCONOx system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system (SCOSOx) to remove sulfur compounds is installed upstream of the SCONOx catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the SCOSOx catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The SCOSOx catalyst is regenerated along with the SCONOx catalyst.

The SCONOx catalyst must be recoated, or “washed” every 6 months to 1 year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the SCOSOx catalyst. The “washing” consists of removing the catalyst modules from the unit and placing each module in a K_2CO_3 reagent tank, which is the active ingredient of the catalyst. The SCOSOx catalyst also requires washing.

EmeraChem states that their EMx™ technology (the second-generation of the SCONOx NO_x absorber technology) is capable of reducing gas-fired NO_x emissions to less than 1.0 ppm, release undetectable levels of CO, reduce VOC emissions by >90-percent, reduce fine PM by 30 percent, and reduce sulfur emissions by 95 percent.

Commercial experience with the SCONOx control system is extremely limited. The NO_x reduction system was commercially demonstrated first at the 32-MW (GE LM2500 turbine) Sunlaw Federal Cogeneration Facility located in Vernon, California. NO_x emissions from the process were <2 parts per million (ppm) during 100-percent operation, and <1 ppm for 90-percent operation. Other installations of the technology include a 15-MW (Solar Titan 130 turbines) installation at the University of California, San Diego, and a 45-MW (Alstom GTX100 turbine) installation at the City of Redding Municipal Electric Plant. A number of smaller installations are also operating: two 5-MW installations at the Wyeth BioPharma cogeneration facility, Andover, Massachusetts, and a 5-MW installation at the Montefiore Medical Center, Bronx, New York. Actual NO_x emissions from these smaller installations are typically below 1.5 ppm, with substantial periods below 1.0 ppm. Alstom Power, one of the EMx™ licensees, engineered and installed the technology on one of their GTX100 (43-MW class) gas turbines.

The application of this technology has not advanced in over a decade and this technology is not commercially available at the size of modern combined cycle units.

XONON™ Catalytic Combustor

The XONON™ Combustion System is a catalytic combustion system developed by Catalytica Energy Systems, Inc., that is designed to avoid high temperatures created in conventional combustors. The XONON™ combustor utilizes a catalyst integrated into the gas turbine combustor to limit temperature below the temperature where NO_x is formed. It also lowers CO and VOC emissions.

The XONON™ technology is installed as an integral part of the combustor. Conventional combustion fuel and air are supplied to combustor; however, rather than combusting the fuel in a flame, the XONON™ system combusts the fuel using a catalyst at lower temperatures. Fuel and air are thoroughly mixed prior to entering a catalyst region that acts to combust the fuel, releasing its energy. The XONON™ catalyst module consists of a channel structure whereby the fuel-air mixture readily passes through the channels coated with the catalyst. As fuel and O_2 molecules contact the channel walls, the molecules and catalyst interact and are rearranged at temperatures well below those of flame combustion. Energy is extracted from the fuel in this manner, producing CO_2 and water byproducts. Nitrogen molecules are not involved in the XONON™ chemistry and pass through the channels unchanged, thereby preventing the formation of NO_x.

The XONON™ technology was first designed into the combustor of a 1.4-MW Kawasaki Model M1A-13A gas turbine at Silicon Valley Power in Santa Clara, California, in 1999. Since its installation, the turbine has operated as a demonstration of XONON™'s performance. The California EPA's Air Resources Board (CA EPA, 2004) evaluated NO_x and CO CEM system data and concluded that XONON™ achieved a NO_x level of 2.5 ppmvd at 15-percent O_2 and a CO level of 6.0 ppmvd at 15-percent O_2

Other commercial installations of the XONON™ technology include a 1.5-MW Kawasaki MIA-13X installation at Sonoma Development Center in Eldridge, California, and a 1.4-MW Kawasaki GPB15X installation at Plains Exploration & Production Company in San Luis Obispo, California. The Eldridge installation's expected performance was 3 ppmvd NO_x and 10 ppmvd CO. According to the manufacturer, the unit has consistently achieved continuous NO_x emission levels below the emission target, and on the average, NO_x emissions are under 2.0 ppmvd at 15-percent O_2. Based on the manufacturer's report, the unit at the Plains Exploration & Production Co. has achieved NO_x emissions around 0.8 ppmvd at 15-percent O_2 on the average.

Kawasaki Gas Turbines-Americas started selling GPB 15X generators including a 1.4-MW M1A-13X gas turbine equipped with XONON™ in December 2000. Furthermore, Catalytica Energy Systems is working with GE to incorporate XONON™ into their GE10 gas turbines (11.3 MW) and Solar Turbines for use in their Solar Taurus 70 gas turbines.

In September 2006, the XONON™ Combustion System (referred to as the XONON™ Cool Combustion® technology) was sold to Kawasaki Heavy Industries, Ltd. (KHI). Kawasaki is currently making the technology available to the gas turbine generators in the 1- to 1.4-MW range (KHI, 2008).

Similar to $SCONO_x$, XONON™ technology has not advanced in a decade and is not commercially available for the size of modern combined cycle units. Moreover, advances in CT combustion technology such as DLN or equivalent result very low NO_x, CO and VOC emissions that the manufacturers are willing to guarantee.

NOxOUT Process

The NOxOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NOxOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600 to 1,900°F. In the presence of O_2, the following reaction results:

$$CO(NH_2)_2 + 2NO + \frac{1}{2} O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NOx. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600 and 1,950°F. Advantages of the system are as follows:

- Low capital and operating costs as a result of use of urea injection
- The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems

Disadvantages of the system are as follows:

- Formation of NH_3 from excess urea treatment rates and/or improper use of reagent catalysts

- Sulfur trioxide (SO_3), if present, will react with NH_3 created from the urea to form ammonium bisulfate, potentially plugging the cold-end equipment downstream

Commercial application of the NOxOUT system has been limited to oil- and coal-fired boilers and municipal solid waste combustors and has not been demonstrated on any combined cycle gas turbines.

Thermal DeNOx

Thermal DeNOx is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high-temperature selective noncatalytic reduction (SNCR) of NO_x using NH_3 as the reducing agent. Thermal DeNOx requires the exhaust gas temperature to be above 1,800°F. However, use of NH_3 plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, the high temperature must be achieved by additional firing in the exhaust stream before NH_3 injection.

The only known commercial applications of Thermal DeNOx are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with combined cycle units. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NOxOUT process, high capital, operating, and maintenance costs are expected because of material requirements, an additional natural gas-fired exhaust heater system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Selective Non-Catalytic Reduction

SNCR is a post-combustion NO_x emission control technology that reduces NO_x into nitrogen gas and water vapor by reacting the flue gas with a reagent. SNCR systems can either use NH_3 or urea as reagents. The chemical reaction for this technology is driven by high temperatures normally found in combustion sources, typically from 1,600 to 2,100°F. SNCR is "selective" in that the reagent reacts primarily with NO_x.

SNCR is a proven and reliable technology. SNCR was first applied commercially in 1974 and has been installed on approximately 400 applications worldwide. Applications include utility boilers and a broad range of industrial applications including wood-fired boilers, coal-fired boilers, co-generation boilers, pulp and paper boilers, steel industry furnaces, refinery process units, process heaters, cement kilns, municipal waste combustors, glass-melting furnaces, hazardous waste incinerators, and other combustion-type sources. Urea-based SNCR has been applied commercially to sources ranging in size from a 60-MMBtu/hr (gross heat input) paper mill sludge incinerator to a 640-MW pulverized coal-fueled, wall-fired electric utility boiler [Institute of Clean Air Companies (ICAC), 2006].

Non-Selective Catalytic Reduction

Stationary non-selective catalytic reduction (NSCR), as with the automobile sector, involves the use of a three-way catalyst technology to promote the reduction of NO_x to nitrogen and water and simultaneous oxidation of CO and hydrocarbons (HC) to CO_2 and water. NO_x is reduced by the CO and hydrogen (H_2) over the catalyst under slightly rich or stoichiometric conditions to produce CO_2 and water with typical conversion efficiencies in the range 80- to 99-percent achievable together with corresponding decreases in HC and CO.

NSCR can be applied to various spark ignited internal combustion engines that are rich-burn, including natural gas-fueled engines. These types of engines are commonly found in the following applications: gas gathering and storage, gas transmission, power generation, combined heat and power, cogeneration/trigeneration, irrigation, inert gas production, and non-road mobile machinery. NSCR has been used routinely in the automotive industry to reduce vehicular carbon monoxide, hydrocarbons, and NO_x emissions with over a billion catalyst units equipped to automobiles since the mid-1970s. The application of NSCR to stationary gas engines for the control of NO_x and CO first became commercially available in North America in the late 1980s, and more than 5,000 stationary engine installations are in service today (ICAC, 2006).

4.3.1.3 Identification of Technically Feasible Control Alternatives

In this section, the technical feasibility of each potentially applicable control technology is assessed. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.

Water Injection

Water injection is a demonstrated technology and considered technically feasible.

DLN Combustors

DLN combustors are available, demonstrated, and technically feasible for units in either simple cycle or combined cycle configurations. The DLN combustion technology alone can achieve NO_x emission rates as low as 9 ppm (corrected to 15-percent O_2 dry conditions) when firing natural gas in some CT models.

SCR

SCR has been demonstrated successfully in numerous applications and is considered technically feasible for CT/HRSGs associated with OCEC Unit 1.

NOxOUT

As discussed previously, commercial application of the NOxOUT system is limited mainly to boilers, and the NOxOUT ULTRA system has not been commercially operated on any large combined cycle gas turbine unit; therefore, these technologies are not considered available or technically feasible. Even if the NOxOUT process were technically feasible for the proposed Project, the operating temperature range of the combined cycle exhaust is below the NOxOUT application temperature of 1,600 to 1,950°F. The maximum exhaust gas temperature of the CTs associated with the Project is well below 1,600°F and not in the range of the NOxOUT process reaction. Raising the exhaust temperature to the required level would require installation of a natural gas fired heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions including NO_x.

Thermal DeNOx

As discussed previously, there are no known applications of the Thermal DeNOx technology to combined cycle units. Since this technology has not been demonstrated for combined cycle units, it is not considered available or technically feasible. Additionally, even if this technology were technically feasible, the operating temperatures for the Thermal DeNOx technology (approximately 1,800°F) would require higher temperature alloy materials constructed with very large piping and components since the exhaust gas volume would be increased significantly. As with the NOxOUT process, high capital, operating, and maintenance costs would be expected because of material requirements, a natural gas-fired exhaust heating system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

SNCR

Because the exhaust temperatures from the proposed CTs will not approach the operating temperature window for SNCR, this technology is not technically feasible for this application. The CT exhaust temperature is typically around 1,225°F; the temperature at the exhaust stack downstream of the HRSG is expected to range between approximately 160 and 220°F, which is far below the range of SNCR application. Further, a review of EPA’s RBLC database and discussions with control technology vendors do not indicate that SNCR systems have been successfully installed for combined cycle gas turbines. Based on the above limitations (i.e., operating temperature range and lack of actual application to combined cycle units), SNCR is considered technically infeasible.

NSCR

As discussed previously, the NSCR process requires low O_2 content in the exhaust gas stream to be effective. Combined cycle unit exhaust streams have high O_2 levels (greater than 12 percent); and therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for combined cycle units.

SCONOx

The SCONOx control technology is not considered available (and therefore is considered technically infeasible) since it has not been commercially demonstrated on large combined cycle CTs. The proposed CTs are GE 7HA.02 turbines with a nominal generating capacity of 350 MW, approximately seven times larger than the 45-MW (Alstom GTX100 turbine) installation at the City of Redding Municipal Electric Plant. Technical problems associated with scale-up of the SCONOx technology are unknown given the large differences in machine flow rates. Additional concerns with the SCONOx control technology include process complexity (multiple catalytic oxidation / absorption / regeneration systems), brief operating history and no commercial availability.

XONON

While the XONON™ catalytic combustion system is applied directly to the CT, application on large CTs has not been demonstrated. The XONON™ technology is not considered available or technically feasible.

Summary

Based on the preceding discussion, the following technologies are considered to be technically feasible:

- Water injection
- DLN Combustors
- SCR

4.3.1.4 Ranking of Technically Feasible Control Alternatives

Water injection, DLN combustors, and SCR are compatible technologies and can be applied together. Water injection and DLN combustors are pre-combustion technologies and SCR is a post-combustion technology. Considered together, this would be the best control strategy for the control of NO_x. Therefore, a ranking is not required to establish the top technology.

4.3.1.5 Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

Economic Impacts

The water injection system and DLN combustors are part of the standard design of modern CTs reducing substantially NO_x emissions. The total capital cost of SCR is estimated to be about $3.3 million per CT. The total annualized cost of applying SCR is estimated to be approximately $1.6 million. The incremental cost effectiveness of adding SCR to the low- NO_X combustors and water injection (for oil firing) is estimated to be $1,268-per ton of NO_X removed, based on 8,760 hours of operation with 8,260 hours firing natural gas and 500 hours firing ULSD oil. Detailed calculations are provided in Tables 4-2 and 4-3.

Environmental Impacts

Water injection or properly tuned DLN combustors do not create negative environmental impacts since these systems are designed and operated to achieve the optimum balance between CO and NO_x emissions. SCR requires storage and use of NH_3, which can cause environmental consequences if not handled and stored properly. NH_3 for the SCR can be either in anhydrous or aqueous liquid form. Storage of anhydrous and aqueous (19% or greater) will trigger requirements as specified by OSHA and the Community Right-to-Know Act. NH_3 slip (i.e., unreacted NH_3 emitted from the stack) is typically 9 ppm or less but has the potential to increase with increasing NH_3 feed rates. Additionally, during the life of the Project, the catalyst would require periodic regeneration or replacement. The used catalyst would be returned to the catalyst supplier for regeneration or would be disposed of in accordance with all applicable regulations.

The installation of SCR would reduce potential NO_X emissions by about 1,300 TPY per CT while causing direct emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate (see Table 4-4). Ammonia emissions associated with SCR are expected to be up to 10 ppm based on reported experience; previous permit conditions have specified this level. Indeed, ammonia emissions could be as high as 113 TPY per unit at the end of the catalyst's life. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10} and $PM_{2.5}$; up to 14.77 TPY per unit could be emitted.

Energy Impacts

Water injection and DLN combustors are inherent to the combustion process and do not create any energy impacts. With SCR, the output of the CT will be reduced by about 0.2 percent more than with advanced low-NOx combustors. This penalty in CT output would result in about 6,537,413 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 2,890,800 kWh per year. Taken together, the total lost generation and energy requirements of SCR of 9,428,213 kWh per year could supply the monthly electrical needs of about 786 residential customers. To replace this lost energy, an additional 91,246 million British thermal units per year (Btu/yr) or about 91 million cubic feet per year (ft^3/yr) of natural gas would be required.

4.3.1.6 Selection of BACT and Rationale

DLN combustors, water injection, and SCR are proposed as the technologies to establish BACT emission limits for combined cycle CT/HRSGs. These technologies are the only feasible control technologies and together, they represent the best and most cost effective NO_x control option. These technologies are the only feasible control technologies and together they represent the best and most cost-effective NOx control option, All NO_x BACT determinations for large natural gas and fuel oil-fired CT/HRSGs are based on these control technologies. The proposed BACT emissions limits are 2 ppmvd, corrected to 15-percent O_2 for natural gas firing and 8 ppmvd, corrected to 15-percent O_2 for fuel oil firing, both based on a 24-hour block averaging period excluding startup and shutdown periods. The emission limits required by NSPS Subpart KKKK are required to be met at all times and is proposed as the secondary BACT limit for NO_x emissions. There will also be limited hours of fuel oil firing. Fuel oil will be limited to 500 hr/yr per CT.

The most recent NO_x emission limit representative of BACT in Florida for a large natural gas-fired combined cycle CT/HRSGs is for the FPL PEEC Project (Permit No. 0110036-010-AC, issued May 9, 2012) based on an emissions limit of 2 ppmvd at 15-percent O_2. The most recent BACT determination in Florida for an oil-fired CT/HRSG is also for the PEEC Project based on an emissions limit of 8 ppmvd at 15-percent O_2.

The proposed Secondary BACT limits that will include emissions during periods of startup, shutdown and malfunctions are the NSPS limits of are 15-ppmvd, corrected to 15-percent O_2 for natural gas firing and 42 ppmvd, corrected to 15-percent O_2 for fuel oil firing based on 30-day rolling average pursuant to 40 CFR 60, Subpart KKKK.

4.3.2 Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

4.3.2.1 Previous BACT Determinations

CO and VOC BACT determinations are presented together in this section since the same emission control technologies are used for both. As part of the BACT analysis, a review was performed of previous CO and VOC BACT determinations for large CTs similar in size to the proposed CTs in EPA's RBLC database. BACT determinations issued within the last 12 years (i.e., since 2003) were identified. A summary of these BACT determinations are presented in Appendix B Tables B-3 through B-6. Tables B-3 and B-4 summarize CO BACT determinations for natural gas and oil firing, respectively. Tables B-5 and B-6 summarize VOC BACT determinations for natural gas and oil firing, respectively.

From the review of previous BACT determinations, it is evident that all CO and VOC BACT determinations for both natural gas and fuel oil-fired CTs have been based on good combustion practices (GCP). The use of clean fuel has been named as BACT along with GCP for most determinations for fuel oil-fired CTs. Based on RBLC data for natural gas-fired CTs, there have been ten BACT determinations for CO and ten for VOC in Florida since 2003. These determinations in Florida are based on emissions limits in the range of 4.1 to 35.0 ppmvd at 15-percent O_2 for CO and

1.2 to 10 ppmvd at 15-percent O_2 for VOC. Based on RBLC data, there have been only six CO and six VOC BACT determinations in Florida for fuel oil-fired CTs.

The CO and VOC emission limits representative of large combined cycle CT/HRSGs in Florida are for the FPL PEEC Project with the permit issued in May 2012 and the Duke Energy Florida, Inc. Citrus Combined Cycle Project (CCCP) with the permit issued in December 2014. The 250 MW CT/HRSGs for PEEC are natural gas fired with up to 3,000 aggregated hours of fuel oil firing for the three CT/HRSGs per year. The CO emissions limits are 9.0 ppmvd at 15-percent O_2 firing natural gas and 35 ppmvd firing fuel oil. The VOC emissions limit is 1.2 ppmvd at 15-percent O_2 firing natural gas and 10.0 ppmvd firing fuel oil. CCCP involved two 2-on-1 combined cycle units using Mitsubishi Power Systems 501 GAC CTs with a nominal rating of 270 MWs each. Only natural gas is used as fuel for CCCP. The emission rates for CCCP at baseload conditions are 4.0 ppmvd at 15-percent O_2 for CO and 0.8 ppmvd at 15-percent O_2 for VOCs. Good combustion practice was used for the CO and VOC for the emission limits established for PEEC and CCCP.

4.3.2.2 Identification of Potentially Applicable Control Technologies

Combustion is a thermal oxidation process in which carbon and hydrogen contained in a fuel combine with oxygen in the combustion zone to form CO_2 and H_2O. Incomplete combustion occurs when there is not enough oxygen to allow the fuel to react completely to produce CO_2 and water. CO and VOC are a result of incomplete or partial combustion of fossil fuel. Carbon in the fuel that does not experience the required temperature or residence time will form CO or other organic compounds instead of being fully oxidized to CO_2. The important parameters in CO formation are combustion temperatures, fuel residence time, and local stoichiometric ratio of fuel and air (i.e., mixing of fuel and air). Properly designed and operated combustion units typically emit low levels of CO and VOC.

The following control options are evaluated in the BACT analysis. These control options were selected based on recent CO and VOC BACT analysis for large CTs and recent BACT determinations from the RBLC database.

Combustion Controls

CO and VOC emissions are generated from the incomplete combustion of carbon in the fuel and organic compounds. Optimization of the combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering CO and VOC emissions. This process is often referred to as combustion controls. The combustion system design in modern CTs provides all of the factors required to facilitate complete combustion. These factors include continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber. As a result, CO and VOC emissions from CTs are inherently low.

GCPs are typically employed to ensure that the CTs are operated as designed.

Oxidation Catalyst

Catalytic oxidation technology is primarily designed to reduce CO emissions (VOC emissions are also reduced to a lesser extent). Oxidation catalysts operate at elevated temperatures. In the presence of an oxidation catalyst, excess O_2 in the exhaust reacts with CO to form CO_2. No chemical reagent is necessary. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components is considered toxic.

Oxidation catalysts are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst. Catalyst poisoning reduces catalyst activity and pollutant removal efficiencies. The most effective oxidation of CO and VOC emissions is achieved if the catalyst bed is located prior to the HRSG in the high-temperature region.

SCONOx Process

The SCONOx system previously described in Subsection 4.3.1 also controls CO. The SCONOx system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. The SCONOx operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG.

4.3.2.3 Evaluation of Technically Feasible Control Alternatives

In this section, the technical feasibility of each potentially applicable control technology is assessed. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.

Combustion Controls

Combustion controls have been applied successfully on combined cycle units similar to those proposed for the Project and are considered technically feasible.

Oxidation Catalyst

Oxidation catalyst technology has been applied successfully on combined cycle units in states other than Florida similar to those proposed for the Project and is considered technically feasible.

SCONOx

As described in the BACT evaluation for NO_x in Subsection 4.3.1, the application of the SCONOx system is limited to a few small turbines with no systems installed on large gas turbines similar to the ones proposed for the Project. Therefore, SCONOx is considered to be not technically feasible or commercially available for the Project.

4.3.2.4 Ranking of Technically Feasible Control Alternatives

Combustion controls and oxidation catalyst are compatible technologies and are considered together in combination as the top control option for CO and VOC; thus, a ranking is not required to establish the top technology.

4.3.2.5 Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

Economic Impacts

The DLN combustors and GCP are part of the standard design of modern CTs reducing substantially CO and VOC emissions. The total capital cost of an oxidation catalyst is estimated to be about $1.75 million per CT/HRSG. The total annualized cost of applying an oxidation catalyst is estimated to be approximately $862,000. The incremental cost effectiveness of adding an oxidation catalyst is estimated to be over $8,200 per ton of CO removed, based on 8760 hours of operation with 8,260 hours of natural gas firing and 500 hours of ULSD oil firing. For VOC emissions, the addition of an oxidation catalyst will not appreciably lower VOC emissions since the emissions are already extremely low. Assuming 40 percent removal of VOC that is a typical vendor guarantee for VOC removal for an oxidation catalyst, the total cost effectiveness for CO and VOC emissions is $7,550 per ton of pollutant removed. Detail calculations are provided in Tables 4-5 and 4-6.

Environmental Impacts

DLN combustors and GCP do not create negative environmental impacts since these systems are designed and operated to achieve the optimum balance between CO and NO_x emissions. The installation of an oxidation catalyst would theoretically reduce potential CO emissions by about 105 TPY per CT while causing direct emissions of sulfuric acid mist due to oxidation of SO_2 (see Table 4-7). Emissions of sulfuric acid mist could increase by up to 2 TPY with secondary emissions of 7.68 TPY.

Energy Impacts

DLN combustors and GCP are inherent to the combustion process and do not create any energy impacts. With an oxidation catalyst, the output of the CT would be reduced by the additional backpressure. This penalty could amount to about 6,537,413 kWh per year in potential lost generation. This potential lost in generation could supply the monthly electrical needs of about 545 residential customers. To replace this lost energy, an additional 67,204 British thermal units per year (Btu/yr) or about 67 million cubic feet per year (ft^3/yr) of natural gas would be required.

4.3.2.6 Selection of BACT and Rationale

The evaluation of the energy, environmental, and economic impacts demonstrates that an oxidation catalyst system will not be cost effective for the proposed CTs. Therefore, GCP is proposed as the technology to meet BACT emission limits for CO and VOC with the following emissions limits for CO and VOC that are:

CO – Natural Gas Firing

4.3 ppmvd at 15-percent O_2 (base load)
7.1 ppmvd at 15-percent O_2 (non-base load)

CO – ULSD Oil Firing

10.0 ppmvd at 15-percent O_2 (base load)
13.6 ppmvd at 15-percent O_2 (non-base load)

VOC – Natural Gas Firing
1.0 ppmvd at 15-percent O_2

VOC – ULSD Oil Firing

2.0 ppmvd at 15-percent O_2

Moreover, the air quality impacts at the proposed uncontrolled GCP CT emission rate are predicted to be much less than the PSD significant impact levels. The maximum predicted CO impacts are less than 5 percent of the applicable ambient air quality standards (see Section 6.0). Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

4.3.3 Particulate Matter ($PM/PM_{10}/PM_{2.5}$)

4.3.3.1 Previous BACT Determinations

A small amount of $PM/PM_{10}/PM_{2.5}$ emissions, collectively referred to as "PM" will result from the combustion of pipeline quality natural gas and ULSD oil in the CTs, which are generally low emitters of PM. NSPS Subpart KKKK, which specifies performance standards for stationary CTs, does not set any PM emissions limits for CTs.

As part of the BACT analysis, a review was performed for previous BACT determinations within the last 10 years for PM emissions from natural gas and fuel oil-fired large CTs in EPA's RBLC web page. A summary of these BACT determinations are presented in Appendix B Tables B-7 and B-8 for natural gas and fuel oil firing, respectively.

From the review of previous BACT determinations, it is evident that all PM BACT determinations are based on GCP and the use of natural gas or low-sulfur fuel. Add-on PM control technologies were not selected as BACT for any of the determinations. FDEP has issued ten PM BACT determinations for natural gas-fired CTs and five for fuel oil-fired CTs since 2003 and all determinations are based on GCP or clean fuel.

4.3.3.2 Identification of Potentially Applicable Control Technologies

PM is the general term for a mixture of solid particles and liquid droplets present in the emissions stream. PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions can be classified as "filterable" or "condensable" PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micron in aerodynamic diameter. EPA's Compilation of Air Pollution Emission Factors (AP-42) states in Section 3.1 (Stationary Gas Turbines) – "PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content."

PM emissions that are less than 10 microns in diameter are referred to as PM_{10}. $PM_{2.5}$ is PM emissions that are less than 2.5 microns in diameter. All PM_{10} emissions from CTs are considered to be $PM_{2.5}$. The following control options are evaluated in the PM BACT analysis:

Good Combustion Practices (GCP)

PM emissions from natural gas combustion are inherently low, and combustion controls can further minimize the amount of PM emissions generated due to incomplete combustion in the combined cycle CTs. Optimization of the combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering PM emissions. This process is often referred to as "good combustion practices." Good combustion chamber design is inherent to modern CTs.

Clean Fuel

One mechanism for the formation of particulate is the oxidation of sulfur compounds, which can precipitate as PM in the exhaust stream. The proposed CTs will burn pipeline-quality natural gas and ULSD oil. Both fuels contain very low levels of sulfur; thus, emissions of sulfur and the resulting PM are minimized through the use of these clean-burning fuels.

Fabric Filter Baghouse

A fabric filter baghouse removes particles and condensed metals from a flue gas stream by drawing dust-laden flue gas and condensables through a bank of filter tubes suspended in a housing. A filter cake, composed of the removed particulate, builds up on the "dirty" side of the bag. Periodically, the cake is removed through physical mechanisms (i.e., blast of compressed air from the clean side of the bag, mechanical shaking of the bags, etc.), which causes the cake to fall. The dust is then collected in a hopper and removed.

Electrostatic Precipitator

An electrostatic precipitator (ESP) removes dust or other fine particles from a flue gas stream by charging the particles inductively with an electric field and then attracting the particles to highly charged collector plates, from which they are removed. An ESP consists of a hopper-bottomed box containing rows of plates forming passages through which the flue gas flows. Centrally located in each passage are emitting electrodes energized with a high-voltage, negative polarity direct current. The voltage applied is high enough to ionize the gas molecules close to the electrodes, resulting in a corona current of gas ions from the emitting electrodes across the gas passages to the grounded collecting plates. When passing through the flue gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The electric field forces the charged particles out of the gas stream towards the grounded plates, and there they collect in a layer. The plates are periodically cleaned by a rapping system to release the ash layer into ash hoppers as an agglomerated mass.

Wet Electrostatic Precipitator

A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP: charging, collection, and removal. Unlike with a dry ESP; however, with a WESP, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid, rather than mechanically rapping the collector plates. WESPs are more widely used in applications where the gas stream has a high moisture content, is below the dew point, or includes “sticky” particulate.

Wet Scrubber

Wet scrubbers trap suspended particles by direct contact with a spray of water or other liquid. In effect, a scrubber washes the particulates out of the dirty airstream as they collide with and are entrained by the tiny droplets in the spray. Several configurations of wet scrubbers are in use. In a spray-tower scrubber, an upward-flowing airstream is washed by water sprayed downward from a series of nozzles. The water is re-circulated after it is sufficiently cleaned to prevent clogging of the nozzles. In orifice scrubbers and wet-impingement scrubbers, the air and droplet mixture collides with a solid surface. Collision with a surface atomizes the droplets, reducing droplet size and thereby increasing total surface contact area. These devices have the advantage of lower water-recirculation rates.

Scrubber efficiency depends on the relative velocity between the droplets and the particulates. Venturi scrubbers achieve high relative velocities by injecting water into the throat of a venturi channel-a constriction in the flow path through which particulate-laden air is passing at high speed. As a result, Venturi scrubbers are the most efficient of the wet collectors.

4.3.3.3 Evaluation of Technically Feasible Control Alternatives

Technical feasibility of the potential control options is evaluated below. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.

Good Combustion Practices

Good combustion chamber design to minimize incomplete combustion is inherent to modern CTs. GCP is typically employed to operate the CTs at optimum design conditions. GCP is considered technically feasible.

Clean Fuel

Both pipeline quality natural gas and ULSD oil are available and feasible for use in the Project.

Add-On Controls

Add-on control devices [including fabric filtration, ESP, wet ESP (WESP), and wet scrubbers] are not technically feasible for the combined cycle CTs because of high volumes of airflow, fine particulate distribution, and inherently low uncontrolled PM emission rates. Consistent with this position and based on the information in EPA's RBLC database, no natural gas- or fuel oil-fired CT has been equipped with an add-on control device.

4.3.3.4 Ranking of Technically Feasible Control Alternatives

GCP and the use of clean fuels such as pipeline-quality natural gas and ULSD are the only feasible PM control technologies for CTs. These technologies are compatible control strategies and, considered together, they present the best control option for PM from CTs. A ranking is therefore, not required to establish the top technology.

4.3.3.5 Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

The use of GCP and clean fuels are recognized to result is the lowest economic, environmental and energy impacts in reducing emissions of PM.

4.3.3.6 Selection of BACT and Rationale

Based on the identification and technical evaluation of the available control technologies, the proposed BACT for PM emissions from the combined cycle CTs is the work practice standard of using GCP and clean fuels (natural gas and ULSD oil). The proposed BACT emissions limits are consistent with most BACT emissions limits in Florida (see Tables B-7 and B-8).

4.3.4 Sulfur Oxides

4.3.4.1 Identification of SO_2 and SAM Control Technologies

SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. While the SO_2 generally remains in a gaseous phase throughout the flue gas flow path, a small portion of the SO_2 may be oxidized to SO_3. Technologies employed to control SO_2 emissions from combustion sources consist of fuel treatment and post-combustion add-on controls that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas [also referred to as flue gas desulfurization (FGD) systems].

EPA's RBLC database was queried and a summary of SO_2 BACT determinations for natural gas-fired combined-cycle units is presented in Appendix B, Table B-9.

Clean Fuels (Natural Gas and ULSD Oil)

Natural gas and ULSD oil contain very low levels of sulfur; thus, emissions of sulfur compounds are minimized through the use of this clean-burning fuel.

Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to the end user. Desulfurization of natural gas is performed by the fuel supplier prior to distribution by pipeline. ULSD oil is produced from higher grades of oil and desulfurized to 0.0015% sulfur.

Flue Gas Desulfurization

FGD systems are post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. The chemical reaction with an alkaline chemical, which can be performed in a wet or dry contact system, converts the SO_2 to sulfite or sulfate salts. FGD systems also removed a portion of the SO_3 emissions depending on the type of scrubber and reagent. The following FGD systems are discussed.

Wet Scrubber

The wet scrubber is a once-through wet technology. In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport/disposal.

The wet scrubber can be further classified on the basis of the reagents used and the by-products generated. The typical reagents are lime and limestone. Additives, such as magnesium, may be added to the lime or limestone to increase the reactivity of the reagent. Seawater has also been used as a reagent since it has a high concentration of dissolved limestone. The reaction by-products are calcium sulfite and/or calcium sulfate. The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced depending on the desired by-product. The most common wet scrubber application utilizes limestone as the reagent and forced oxidation of the reaction by-products to form calcium sulfate.

Spray Dryer Absorber (Dry Scrubber)

The dry scrubber is a once-through dry technology. In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a dry form upon leaving the system and are subsequently captured in a downstream particulate collection device, typically a baghouse.

4.3.4.2 Technical Feasibility Analysis

The only feasible technology for SO_2 emission from combined cycle unit is the use of natural gas and ULSD oil. The SO_2 emission levels of these fuels are extremely low. Fuel treatment and FGD are not technically or economically feasible for combined cycle units.

4.3.4.3 Rank Control Technologies by Control Effectiveness

The third step in the BACT analysis is to evaluate the effectiveness of the remaining control technologies. Natural gas and ULSD oil do not have associated with negative energy, environmental, or economic impacts.

4.3.4.4 Evaluate the Most Effective Controls

There are no potential energy, environmental, or economic impacts that would preclude the use of natural gas and ULSD oil.

4.3.4.5 Select BACT

The use of natural gas and ULSD oil as the BACT work practice standards for SO_2 and SAM.

4.4 Auxiliary Boiler

This section contains the BACT analysis for the proposed auxiliary boiler. The auxiliary boiler has a maximum design heat input rating of 99.77 MMBtu/hr and will be exclusively fueled by pipeline quality natural gas. A boiler can be used during the startup and shutdown sequences of the CTs to provide steam to the steam cycle. OCEC proposes to limit the hours of operation of the auxiliary boiler to 2,000 hr/yr. Based on emissions calculation presented in Table 2-4, the auxiliary boiler will potentially emit 0.56 TPY SO_2, 4.99 TPY of NO_x, 7.98 TPY CO, 0.54 TPY of VOC, and 0.74 TPY of PM emissions.

A search of EPA's RBLC database was conducted for previous BACT determinations for auxiliary boiler and a summary of previous 5 years of determination is presented in Appendix B, Table B-10. It is evident that most of the BACT determinations are based on GCP and LNBs. FGR has been used as BACT in addition to LNB for NO_x control in some of the permits. LNBs are designed to limit NO_x formation by controlling the stoichiometric temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air, resulting in one or more of the following conditions: (a) reduced O_2 in the primary flame zone; (b) reduced flame temperature; or (c) reduced residence time at peak temperature. LNB systems are also designed to minimize CO and VOC emissions through staging the combustion process that balances the combustion temperatures to minimize NO_x formation at high combustion temperatures while maintaining adequate combustion temperatures to combust CO and VOCs. The proposed auxiliary boiler will be equipped with LNB to minimize emissions of NO_x while maintaining low CO and VOC emissions through good combustion practices.

The use of LNB with a NO_x emission limit of 0.05 lb/MMBtu is proposed as BACT. This is consistent with the BACT limits found in the EPA's RBLC database and meet the requirements of the NSPS for industrial-commercial-institutional steam generators as set forth in 40 CFR 60 Subpart Dc.

The auxiliary boiler will exclusively use natural gas that minimize emissions of $PM/PM_{10}/PM_{2.5}$ and SO_2.

4.5 Fuel Gas Heater

This section contains the BACT analysis for the proposed fuel heaters rated at 9.9 MMBtu/hr. The heaters will be fired by pipeline quality natural gas with maximum sulfur content limited to 2 gr/100 scf. Based on the emissions calculation for the fuel heater presented in Table 2-5 with one fuel heater operating, the fuel heater has the potential to emit 0.24 TPY SO_2, 4.25 TPY of NO_x, 3.57 TPY of CO, 0.23 TPY of VOC, and 0.32 TPY of PM/PM_{10}/$PM_{2.5}$ emissions.

Based on EPA's RBLC database search, a summary of previous BACT determinations for fuel heaters are presented in Appendix B, Table B-11. As shown, add-on controls have never been applied to a fuel heater. Based on low emissions potential and RBLC research, add-on controls are considered infeasible.

The proposed BACT emissions limit is the work practice standards of using only natural gas with a NOx design value of less than 0.1 lb/MMBtu. This is consistent with the BACT limits found in the EPA's RBLC database.

4.6 Cooling Tower

This section contains the BACT analysis for the PM/PM_{10}/$PM_{2.5}$ emissions, collectively referred as "PM" emissions from the mechanical draft cooling tower for the Project that is anticipated to be a 30-cell tower design. Cooling towers use a fan to move air through a re-circulated water system. This allows a considerable amount of water vapor and sometimes droplets to be introduced into the surroundings. The use of high-efficiency drift eliminating media to de entrain droplets from the air flow exiting the cooling tower is a commercially proven technique to reduce PM emissions. The drift eliminators used in cooling towers rely on inertial separation caused by direction changes while passing through the eliminators. Types of drift eliminator configurations include herringbone (blade-type), wave form, and cellular (or honeycomb) designs. The cellular units generally are the most efficient.

Based on the review of EPA's RBLC database, which is presented in Appendix B, Table B-11, the most stringent BACT limit for cooling towers is drift eliminators with drift rate 0.0005 to 0.001 percent. There are no energy or environmental impacts associated with drift eliminators. Drift eliminators with a drift rate of 0.001-percent is most common and demonstrated in practice.

The use high-efficiency drift eliminators with a design drift rate of 0.0005-percent is proposed as BACT work practice standard for PM emissions from the proposed cooling tower.

4.7 Emergency Generators, Fire Pump Engine, Hurricane Shelter Engines and Fuel Oil Storage Tank

The emergency generators, fire pump engine and hurricane shelter engines will normally be operated 1 to 2 hours per month for maintenance and testing. The amount of operation outside of an emergency condition will be 100 hr/yr. This low amount of operation coupled with good combustion practices and meeting the applicable requirements of EPA NSPS (Part 60, Subpart IIII), NESHAP

(Part 63, Subpart ZZZZ) and non-road engine standards (Part 89) is proposed as BACT for control of NO_x, CO and VOC emissions. The installation of controls would not be cost effective given the amount of operation. The emergency generators and the fire pump engine will utilize ULSD oil and the hurricane shelter engines will use propane. The use of these clean fuels that will minimize the emissions of PM, PM_{10} and $PM_{2.5}$ and SO_2 are proposed as BACT. The use of good combustion practices and use of clean fuels has consistently been determined as BACT for similar minor sources.

A 7,000,000-gallon fixed-roof tank will be installed for storage of ULSD oil. The tank will be equipped with conservation vent valves. These include both pressure relief valves (to keep fuel vapors in the tank up to a safe pressure) and vacuum relief valves (to allow outside air to enter the tank to avoid a significant vacuum). Such valves are needed to accommodate pressure variations occurring with changes in ambient temperature and fuel level changes associated with filling and dispensing.

Based on the low emissions potential and the high cost of add-on controls, fixed-roof tanks with conservation vent valves is proposed as BACT for the fuel storage tank.

4.8 CO_2 BACT Evaluation

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). This is supported by EPA's recent final rule approval of NSPS for GHGs from new, modified, and reconstructed electric utility units. In this rule EPA determined that the best system of emission reduction (BSER) was 1,000 lb CO_2/MWh that is readily achievable in natural gas-fired combined cycle units. This CO_2 emission standard represents the BSER in establishing NSPS and is the highest emission limit that can be determined as BACT (i.e., BACT cannot be less stringent than this NSPS).

The following subsections provide the BACT analysis for the Project.

4.8.1 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.

4.8.1.1 Identification of 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.

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).

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 combined cycle generation 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 1.84 million short tons from each of the Project's CTs, the annual cost for separation alone would be over $380 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_2e for each CT were estimated to about 1.84 million TPY including distillate oil firing (Table A-18). Assuming 90 percent CO_2 removal, the annualized cost for CO_2 would be calculated at $70 per ton of CO_2 removed and sequestered. This cost represents full application of CCS. However, EPA found in its recent approval of GHG NSPS for electric utility units (40 CFR Part 60 Subpart TTTT) that full application of CCS for controlling CO_2 emissions for coal-fired units was not cost-effective when compared to nuclear and other technologies. EPA concluded in its final rule that NSPS emission standards for partial CCS at approximately 16 to 32 percent are reasonable. In contrast, EPA found the use of NGCC units to be the most cost effective.

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. This clearly demonstrates the infeasibility of an oxidation catalyst to control CH_4 emissions.

4.8.1.2 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.

Based on these considerations and EPA determinations in the recent final NSPS for GHG emissions from electric utility units, it can be reasonably concluded that CCS is not applicable to the Project, and consequently not technically or economically 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.

4.8.1.3 Ranking of 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.

4.8.1.4 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 combined cycle mode and are among the largest and most efficient available. The CTs will use natural gas as the primary fuel and ULSD oil as a backup fuel limited to 500 hr/yr. Natural gas has the lowest GHG emissions of any fossil fuel.

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 proposed combined cycle units' heat rate and energy efficiency were compared to data obtained from the U.S. Energy Information Administration (EIA). Based on data provided in the Annual Energy Review 2012, the approximate heat rate for electricity for fossil fueled power plants in the U.S. in 2011 was 9,756 Btu/kWh net (HHV) (35.0 percent efficiency) (http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb1206)

Based on US EIA's 2014 annual review of the electrical power industry, the reported average net heat rate (HHV) for natural gas firing was 8,185 Btu/kWh net (HHV) (41.7 percent efficiency) including all types of generation (http://www.eia.gov/electricity/annual/html/epa_08_02.html). Of the generation types, the average tested heat rates when firing natural gas are:

- Steam turbine generator – 10,354 Btu/kWh net (HHV) (33.0 percent efficiency),
- Natural gas turbine – 11,371 Btu/kWh net (HHV) (30.0 percent efficiency),
- Internal combustion – 9,573 Btu/kWh net (HHV) (35.7 percent efficiency), and
- Combined cycle – 7,667 Btu/kWh net (HHV) (44.5 percent efficiency).

The average base heat rate of OCEC Unit 1 when firing gas is 6,304 Btu/kWh net (HHV) based on average ambient air temperature of 75ºF. For the same amount of generation, the efficiency of OCEC will result in almost one million less tons of GHGs than existing combined cycle plants in the U.S.

OCEC Unit 1 will be more efficient than other existing combined cycle plants in FPL's system. This is a result of utilizing the latest CT technology that results in greater efficiency in the CT generated power and increased exhaust energy through the HRSG to produce more steam electric generation. Together this significantly improves the efficiency over earlier generation combined cycle plants.

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 for units, plants, power control areas (system), states, National Electric Reliability Council (NERC) regions and subregions, and the U.S. 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 (accessed 8/25/15: http://www.epa.gov/cleanenergy/energy-resources/egrid/; gross heat rate as HHV):

- Florida Reliability Coordination Council – 1,196.7 lb CO_2/MWh gross (HHV) for all generation (including nuclear); 1,342.0 lb CO_2/MWh for total combustion generation.
- FPL – 787.1 lb CO_2/MWh for all generation (including nuclear); 1,030.8 lb CO_2/MWh gross (HHV) for total combustion generation.

When firing natural gas, the GHG emissions for OCEC Unit 1 at baseload, and new and clean condition is expected to be less than 750 lb CO_2/MWh (gross, HHV) based on an average an average base heat rate of 6,304 Btu/kWh net (HHV) and ambient air temperature of 75ºF. When compared to the existing generation facilities in FPL's system for fossil combustion, the GHG emissions on a generation basis will be lower than the existing generation and when operated displaces less efficient generation resulting in overall GHG reduction in FPL's system.

4.8.1.5 Selection of 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 as supported by EPA's recent GHG NSPS for electric utility units. 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 or economically feasible control technology based on the current status of this technology.

The proposed GHG BACT limits for OCEC Unit 1 are based on operation and startup. Since NSPS for GHG are applicable pursuant to 40 CFR Part 60, Subpart TTTT, FPL proposes as a Secondary BACT the NSPS emission limit of 1,000 lb CO_2e/MWh 12-month rolling average that would also include startup, shutdown, malfunctions, fuel switching and DLN testing (see Section 4.2). FPL proposes a Primary BACT composite emission limit of 870 lb CO_2e/MWh when firing natural gas and 1,210 lb CO_2e/MWh for ULSD oil on a 3-year rolling average. The Primary BACT is based on an analysis of actual operation of FPL's existing 3-on-1 combined cycle units that reflect the actual operating profiles of five 3-on-1 combined cycle units. The units evaluated were West County Energy Center (WCEC) Units 1, 2 and 3, Cape Canaveral Energy Center (CCEC) Unit 3, and Riviera Beach

Energy Center (RBEC) Unit 5. The actual hours of operation at each were used with design information for OCEC Unit 1 operating at 75ºF ambient temperature. The actual operating hours over the period 8-1-2014 through 8-1-2015 for three operational configurations (3-on-1, 2-on-1 and 1-on-1) and load (baseload and part load) were determined.

To account for operation over the life of OCEC Unit 1, an operating profile consisting of the three unit configurations and operating loads was developed. The unit configurations and load operation were based on 80th percentile of actual 2-on-1 and 1-on-1 operation of the five units evaluated. The 3-on-1 operation was based on the 20th percentile. The operating profile used with the OCEC Unit 1 design basis is presented below.

OCEC Unit 1 Natural Gas Operating Profile Used as the Basis of the Proposed BACT Limit

Load	Configuration			Total
	3x1	2x1	1x1	
Part Load	30.0%	33.0%	10.0%	73.0%
Baseload	12.0%	9.0%	6.0%	27.0%
Total	42%	42%	16%	100%
Load	Configuration			Total
	3x1	2x1	1x1	
Part Load	2,412	2,653	804	5,869
Baseload	965	724	482	2,171
Total	3,377	3,377	1,286	8,040

For part load operation, the hours in the above table were equally split between 75 percent and 50 percent load in the evaluation. In addition, OCEC Unit 1 is designed to accommodate operation of the combustion turbines without the operation of the steam turbine (steam bypass). This operation has occurred in FPL's system for considerable durations to support electric demand. A portion of operation was assumed to include this operation. The table below presents the basis of the proposed primary BACT:

Natural Gas Operating Mode Basis and Composite Gross Generation and GHG Emissions for Proposed OCEC Unit 1 BACT Limit

Operating Condition	Hours	Comments
3x1 Operation	3376.8	Based on Load Distribution
2x1 Operation	3377	Based on Load Distribution
1x1 Operation	1286.4	Based on Load Distribution
Bypass CT Only	720	3x1 at 100%
Total	8760	
Parameter	Data	Comments
Gross Output (MWh)	7,634,310	New and Clean (75 oF ambient)
CO2e tons	3,085,970	New and Clean (75 ^{0}F ambient)
lb CO2e/MWh	824.6	New and Clean w/2 % Commercial Margin
lb CO2e/MWh	866	5% Degradation

All the OCEC Unit 1 design values are for new and clean condition and a 5 percent margin that has been previously considered appropriate in determining GHG BACT was included to account for unit degradation. The calculated value is rounded up to 870 lb CO_2e/MWh.

For ULSD oil firing, extended operating profiles are not available from FPL's existing 3-on-1 combined cycle units. As a result, an average of the GHG emissions of 100 percent, 75 percent and 50 percent load was used. These are shown in the following table.

ULSD Oil Operating Modes & Summary Data for Proposed BACT Limit:

Operating Condition	Hours	Comments
100% Load	165	33% Operation at 100% Load
75% Load	165	33% Operation at 75% Load
50% Load	170	34% Operation at 50% Load
Total	500	
Parameter	Data	Comments
Gross Output (MWh)	546,535	New and Clean (75 ^{o}F ambient)
CO2e tons	308,172	New and Clean (75 ^{0}F ambient)
lb CO2e/MWh	1150.3	New and Clean w/2 % Commercial Margin
lb CO2e/MWh	1,208	5% Degradation

A Primary BACT emission limit for ULSD oil is proposed as 1,210 lb CO_2e/MWh.

FPL proposes an output based 3-year monthly rolling average aggregate CO_2e emission limit for gas and oil firing based on gross generation as the Primary BACT standard that excludes startup, shutdown, fuel switches, DLN tuning and malfunctions. As described previously, FPL proposes the emission limits required by 40 CFR Part 60, Subpart TTTT [1,000 lb CO_2e/MWh (gross)] as the Secondary BACT GHG emission limit. The composite Primary GHG BACT standard consists of a weighted average of the natural gas and ULSD oil standards, weighted by the generation from each fuel over a 3-year period and would be as follows:

$$Composite\ Standard = \frac{MWh_{gas}}{Total\ MWh} \times Limit_{gas} + \frac{MWh_{ULSD}}{Total\ MWh} \times Limit_{ULSD}$$

where: MWh_{gas} = Gross output from gas firing for 3-year compliance period,

MWh_{ULSD} = Gross output from ULSD oil firing for 3-year compliance period,

Total MWh = Total gross output for three-year compliance period = MWh_{gas} + MWh_{ULSD}

$Limit_{gas}$ = GHG BACT limit for natural gas operation = 870 lb CO_2 / MWh, and

$Limit_{ULSD}$ = GHG BACT limit for ULSD oil operation = 1,210 lb CO_2 / MWh.

This is among the lowest GHG emission limits with GHG BACT limits as shown in the EPA BACT clearinghouse and summarized in Appendix Table B-13. Moreover, this proposed BACT emission limit is 130 lb CO_2/MWh lower than the recently promulgated Subpart TTTT NSPS limit of 1,000 lb CO_2/MWh.

For the rolling proposed GHG limits, FPL is proposing a continuous monitoring based on 40 CFR Part 60 Subpart TTTT, Section 60.5535.

4.8.2 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 18,290 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:

- 18,290 lb SF_6 x 0.005 leakage/year = 91.45 lb SF_6/year
- 91.45 lb SF_6/year x 22,800 lb CO_2e/lb SF_6 (Table A-1, 40 CFR Part 98) x ton/2,000 lb = 1,042.53. tons CO_2e

4.8.2.1 Identification of 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. Circuit breakers have indicators 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 and the 500 kV transmission systems.

4.8.2.2 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)].

4.8.2.3 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.

4.8.2.4 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.

4.8.2.5 Selection of 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.

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 and potential CO_2e emissions by 99.5 percent.

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.

4.8.3 BACT Analysis for Auxiliary Boiler, Emergency Generators, Natural Gas Heater, Diesel Fire Pump Engine, and Hurricane Shelter Generators

The auxiliary boiler, emergency generators, natural gas heaters, and diesel fire pump engine are all necessary support facilities for the operation of OCEC Unit 1. GHG emissions potential for these sources are less than 0.5 percent of the combined cycle system. The actual GHG emissions from these sources are expected to be considerably lower than that requested due to their function. The emergency generators, diesel fire pump, and hurricane shelter generators that will have operational limits of no more than 100 hr/yr will normally only be operated a few hours per month for maintenance checks. The auxiliary boiler is used for startup and shutdowns that are not expected to be frequent for the advanced combined cycle unit. The natural gas fuel heater maintains the temperature of natural gas as needed, but is not required to operate continuously at full load to serve this purpose. Taken together the actual GHG emissions of these sources are expected to be much less than 0.5 percent of the combined cycle unit. Due to the negligible amount of GHG emissions from these sources compared to the combined cycle system, even 100 percent control of GHG emissions from these units will not make any meaningful reduction in total GHG emissions. As a result, any reduction of GHG emissions from these minor units will therefore not be practicable given that GHG emissions from these units only support OCEC Unit 1 and are not by themselves an individual unit GHG issue. Rather, the GHG emissions of an entire project like OCEC Unit 1 are the most relevant factor in reviewing these sources. As demonstrated in Section 4.3.1, OCEC Unit 1 will be one of the most energy efficient combined cycle plants in the U.S.

In the BACT analysis, GHGs 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 low temperature combustion. CO_2, N_2O, and CH_4 are the principal GHGs that will be emitted from the auxiliary boiler, emergency generators, natural gas heaters, diesel fire pump engine and hurricane shelter generators. Emissions of CH_4 and N_2O are negligible compared to CO_2 and specific control options for these pollutants are not practicable.

A brief discussion of the BACT steps with respect to GHG emissions from auxiliary boiler, emergency generators, natural gas heaters, diesel fire pump engine, and hurricane shelter generators is presented below.

4.8.3.1 Identification of 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 definition of BACT in Title 40, Part 52.21(b)(12) of the Code of Federal Regulations [40 CFR 52.21(b)(12)] includes use of clean fuels as a pollution control technique. The proposed auxiliary boiler and natural gas heater will be fired with only natural gas, which is the cleanest GHG emitting fuel compared to other fossil fuels due to its low GHG emissions potential when combusted. The emergency generators and diesel fire pump require fuel located onsite in order to provide to service during emergency situations.

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 on two mitigation approaches for CO_2 – energy efficiency and carbon capture and storage (CCS). CCS is not practical for CO_2 emissions from the auxiliary boiler, emergency generators, natural gas heaters, and diesel fire pump engine due to the small amount of CO_2 emissions potential from this equipment compared to the combined cycle system. Moreover, these units are not operated continuously or at their rated capacities making the addition of control equipment problematic.

Energy Efficiency

In the GHG BACT guidance, EPA has stressed importance of energy efficiency for combustion sources. The auxiliary boiler will be used to provide steam to the steam cycle during the startup sequences. A boiler's efficiency is measured by its annual fuel utilization efficiency (AFUE). AFUE is the ratio of heat output of the boiler compared to the total energy consumed by the boiler. An AFUE of 90 percent means that 90 percent of the energy in the fuel becomes heat and the other 10 percent is lost in the system. In general, fossil fuel fired boilers have high AFUE rating around 90 percent. For example, based on data from Cleaver Brooks fire tube boilers, the fuel to steam efficiencies for boilers are in the 90 percent range for natural gas.

The natural gas heater may be used to warm up the natural gas flowing through the pipeline before feeding into the CTs. The heater supplies heat based on the natural gas conditions. Therefore, the amount of fuel used in the heater is regulated to that necessary for the natural gas delivered to the CT.

The emergency generators and diesel fire pump are designed to meet the applicable NSPS and NESHAP for non-road engines. These units maximize efficiency while meeting the required emissions standards.

4.8.3.2 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. The energy efficiency through the regulation of the amount of fuel used is considered to be the only technically feasible CO_2 control option for the auxiliary boiler, emergency generators, natural gas heaters, and diesel fire pump engine.

4.8.3.3 Ranking 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, 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 New Source Review (NSR) pollutant under review. Based on the discussion in Steps 1 and 2, the only technically feasible control option for CO_2 from the auxiliary boiler, emergency generators, natural gas heater, and diesel fire pump engine is energy efficiency through the operation of these emissions units to meet the OCEC Unit 1 requirements.

4.8.3.4 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.

In the top down BACT analysis, the “top” control option 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.

The auxiliary boiler and natural gas heaters will use natural gas. GHG emissions for natural gas firing is 116.9 lb CO_2e/MMBtu compared to 163.6 lb CO_2/MMBtu for distillate fuel oil firing based on Subpart C of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting. The hurricane shelter generators will use propane with a CO_2 emission rate of 159.7 lb/MMBtu that is less than ULSD oil. The emission factors include N_2O and CH_4 at the equivalent rates. Therefore, firing natural gas and propane will generate less GHGs than firing ULSD oil.

4.8.3.5 Selection of 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.

Energy efficiency through the regulation of fuel use to meet the function is the only remaining and feasible control technology is selected as BACT for the GHG emissions from the auxiliary boiler, emergency generators, natural gas heaters, diesel fire pump engine, and hurricane shelter generators. Additionally, the use of natural gas in the auxiliary boiler, and natural gas heater results in the lowest GHG emission practicable.

As mentioned in Step 1, an important measure of the efficiency for a boiler is the units' AFUE natural gas boilers have an AFUE rating around 90 percent in general, which is higher than other fossil fuel fired boilers. In addition, all units are operated only to meet the requirements of OCEC Unit 1 requirements. Thus, fuel use is optimized resulting in lower GHG emissions than if these units operate continuously.

The auxiliary boiler, emergency generators, natural gas heater, and diesel fire pump engine together accounts for less than 0.5 percent of the total GHG emissions potential of the OCEC Project with expected emissions to be much less than 0.1 percent. Moreover, these minor GHG emission units support the overall Project and, as discussed above, OCEC Unit 1 will be one of the most efficient combined cycle units in the U.S. GHG emissions on a lb/MW-hr basis from OCEC Unit 1 will be one of the lowest in the country. The operation of these minor units will be limited: the auxiliary boiler will be based on 2,000 hr/yr; emergency generators, fire pump engine, and hurricane shelter generators are limited to 100 hours or less; and the natural gas heaters are operated as necessary. Together, the negligible amount of GHG emissions potential, limitation in operating hours, and use of the natural gas and ULSD oil, represents the best available option in controlling GHG emissions from these emission units. This is consistent with the definition of BACT, which allows "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." Due to the negligible amount of GHG emissions potential, operational limits the auxiliary boiler, natural gas heaters, emergency generators, and fire pump engine is proposed as BACT rather than a numerical GHG emission limit.

5.0 AMBIENT MONITORING ANALYSIS

Based on the potential emissions from the proposed Project (see Table 3-3), pre-construction ambient monitoring analyses for PM_{10}, $PM_{2.5}$, NO_2, SO_2 and CO, and O_3 (based on NO_X or VOC emissions) may be required as part of the PSD application. Ambient monitoring analyses are not required if it can be demonstrated that the Project's maximum air quality impacts will not exceed the PSD significant monitoring concentrations (SMC) and, for O_3, the Project's potential emissions will not exceed 100 TPY of NO_X or VOC emissions.

Maximum impacts due to the Project only are predicted to be below the SMC for CO, NO_2 (annual average) and SO_2 (see Tables 3-2 and 6-6). As a result, a pre-construction ambient monitoring analysis is not required for these pollutants as part of the application pursuant to Rule 62-212.400(3)e F.A.C. It should be noted that EPA has not proposed SMC for the 1-hour average NO_2 concentration.

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

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

In addition, ambient O_3, PM_{10} and $PM_{2.5}$ monitoring data collected by FDEP at monitoring stations near the Project, are considered to be representative of air quality in the Project's vicinity. These data are being used to satisfy the pre-construction monitoring requirement for O_3, PM_{10} and $PM_{2.5}$.

Air quality monitoring data collected in Brevard County, Indian River County, Orange County, Palm Beach County and Lake County from 2012 through 2014 for O_3, PM_{10} and $PM_{2.5}$ are presented in Tables 5-1, 5-2, and 5-3, respectively. These monitoring locations are the closest to OCEC Unit 1 and located in areas much more urbanized than the rural setting of the Project. As a result, the monitoring is likely higher compared to the ambient air quality in northeast Okeechobee County. These data indicate that the maximum air quality concentrations measured in the region are well below applicable standards.

Since the Project's maximum 1-hour average NO_2 and 24-hour PM_{10} and $PM_{2.5}$ impacts are predicted to be greater than the significant impact levels for these pollutants (see Table 6-6, Section 6), more detail analyses are required to demonstrate compliance with the NAAQS for these compounds. For the pollutants and averaging times that are greater than the SIL, total air quality impacts are predicted for all modeled sources plus an added non-modeled background concentration. The non-modeled background concentrations are estimated from representative ambient air quality monitoring data obtained from air monitoring stations. Monitoring data for 1-hour NO_2 are summarized in Table 5-4. The data presented in Table 5-4 are from two monitoring sites: ID 012-095-2002 in Winter Park which is the closest station to the Project site and also ID 012-099-0020 in Lantana which is a little further from the Project site. These data will provide a conservatively high background concentration due to the urbanized influence of this monitoring data.

6.0 AIR QUALITY IMPACT ANALYSIS

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

As described in Section 1.0, the Project involves the construction and operation of a 3-on-1 combined-cycle unit that will consist of three nominal 350-MW General Electric (GE) 7HA.02 CTs with three associated HRSGs, which will utilize the waste heat from the CTs to produce steam to be utilized in a single steam turbine generator. The units will be fired with natural gas as the primary fuel with the potential for up to 500 hr/yr of ULSD oil as the backup fuel. The Project will be located in northeastern Okeechobee County. The Project will also include a 30-cell mechanical draft cooling tower. As described in Section 1.0, the Project will also include the following ancillary equipment: an auxiliary boiler that will be used for construction and possibly for unit startup, three emergency generators, a fire pump engine, and hurricane shelter generators. Due to the highly intermittent operation, the emissions from the ancillary equipment were not included in the assessment.

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

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

Model Selection

The selection of air quality models to calculate air quality impacts for the proposed Project must be based on the models' ability to simulate impacts in the vicinity of the facility. The American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was used to evaluate the pollutant impacts due to the proposed Project. AERMOD (Version 14134) is available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technology Transfer Network (TTN). The EPA and FDEP recommend that AERMOD be used to predict pollutant concentrations at receptors located within 50 km of a source. AERMOD calculates hourly concentrations based on hourly meteorological data. AERMOD is applicable for the type of Project sources and area in which the Project is located since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain.

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

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

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

The EPA regulatory default options were used to address maximum impacts

Project Sources

Air quality analyses were performed to assess the maximum impacts of the new 3-on-1 combined-cycle unit and the cooling tower. 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. Air impacts were not conducted for the intermittent sources that include the emergency generators, fire pump engine, hurricane shelter generators, and auxiliary boiler. The nature of actual emissions associated with intermittent sources such as emergency generators, fire pump engines, and hurricane shelter generators when coupled with the probabilistic form of the 1-hour NO_2 ambient air quality standard [based on the 5-year average of 98th percentile (i.e., 8^{th}-highest) of daily maximum 1-hour concentrations], can result in modeled impacts being significantly higher than would be realistically expected from such sources. To address this issue, the EPA promulgated specific guidance on the modeling of such sources in their memorandum entitled "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" (EPA, March 1, 2011). The emergency sources are permitted to conservatively operate up to 100 hours per year and in reality will operate much less. As such, it is highly improbable that these sources will be able to operate the required frequency (i.e., eight days per year) to impact the 1-hour NO_2 standard. For this reason, emissions for the intermittent sources are not included in the impact assessment. The auxiliary boiler was also not modeled since the auxiliary boiler would only be used during initial startup and not operated when OCEC Unit 1 is operating. The auxiliary boiler would only be operated for short durations and would exclusively use natural gas.

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

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

The new HRSGs will have stack heights of 149 feet and inner diameters of 25.6 ft. Building downwash effects were included in the modeling analysis to account for all newly constructed nearby structures. The new cooling tower cell stack heights will be 51.5 ft. with inner diameters of 30 ft. The tower deck height will be 37.8 ft. and was included as a one of the proposed structures in the building downwash analysis.

Building Downwash Effects

The primary structures for each CT are the HRSG structures and the dimensions for each HRSG structure are provided in the table below. The dimensions for the cooling tower are also included. There 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)
HRSG Structure	103	42	96.5
Cooling Tower	37.8	102	815

Meteorological Data

Meteorological data used in AERMOD to estimate air quality impacts was obtained from FDEP and 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 St. Lucie County International Airport located in Fort Pierce (FPR) 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 13134. 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 44 km (27.5 miles) east-southeast of the Project site. All areas between FPR and the proposed Okeechobee Plant are flat with very similar land characteristics. As such, the meteorological parameters collected at FPR 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 (FPR)	0.15	0.44	0.061
Project Site	0.15	0.31	0.160

The results indicate that the Project site's land use parameters are similar to those for the NWS station including the critical surface roughness parameter which is very low at both sites. As such, the meteorological record is considered reflective of the climatological frequencies and land use surrounding the proposed Project and was selected for use in 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 from the facility. 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, and
- From 5 km to 10 km – 500 meters

Overall, more than 3,500 receptors were used to estimate the maximum concentrations predicted for the proposed Project impacts. Based on the results of the Project only impacts, additional receptor grids were developed for cumulative source analysis. The extent of those grids were determined either by the maximum distance of the Project's significant impact or, in the case of NO_2, set by current regulatory guidance.

Significant Impact Analysis

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

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

- NO_2: 1-hour and annual averages
- SO_2: 1-hour, 24-hour, 3-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 the 24-hour and 3-hour SO_2, 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 each CT/HRSG operating 8,760 hr/yr with 8,260 hr/yr natural gas firing and 500 hr/yr for ULSD oil-firing. For pollutants with higher predicted impacts occurring during ULSD oil-firing, the predicted annual impact is based on the maximum of 500 hr/yr of ULSD oil-firing and natural gas firing during the remaining 8,260 hr/yr. For pollutants with higher predicted impacts occurring when firing natural gas, the predicted annual impacts are based on 8,760 hr/yr of natural gas-firing.

Once the highest impacts were identified for the combination of ambient temperature and operating load condition (i.e., worst-case operating condition), all subsequent modeling analyses were performed using HRSG emission rates and exit gas operating data for the worse-case conditions identified 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 analyses, only 1-hour NO_2, 24-hour $PM_{2.5}$ and 24-hour PM_{10} concentrations were predicted to exceed the SIL. The maximum predicted impacts for annual $PM_{2.5}$, annual PM_{10}, 1- and 8-hour CO, 1-, 3-, 24-hour and annual SO_2 and annual NO_2 were less than the SIL and additional detailed modeling analyses are not required for these pollutants and averaging times.

NO_2 Modeling Analysis

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

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

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

Cumulative Air Quality Analyses

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

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

When addressing the NAAQS for 1-hour NO_2, the 5-year averaged 98^{th} (8^{th} highest) percentile daily maximum 1-hour average concentration at each receptor was determined and the highest of these values is used to estimate compliance. For 24-hour $PM_{2.5}$, the 5-year averaged 98^{th} percentile 24-hour average concentration at each receptor is determined and the highest of these values is used to estimate compliance. For 24-hour PM_{10}, the sixth-highest 24-hour concentration over the 5-year period is determined for each receptor and the highest of these values is used to estimate compliance.

When addressing the allowable 24-hour PM_{10} and 24-hour $PM_{2.5}$ PSD Class II increments, the second-highest concentration at each receptor is determine for each year and the highest of these values is used to estimate compliance.

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 analyses, an inventory of background NO_2 emission sources was requested and obtained from FDEP. Facilities were sorted by increasing distance from the proposed Project and a summary of the emissions, distances and directions of these sources from the proposed Project are summarized in Table 6-1. The significant impact distance of the proposed Project is 8.6 km and nearest background facility with emissions greater than 5 TPY is located over 30 km from the proposed Project. As such, no additional background sources were included in the NAAQS analysis.

Background $PM_{2.5}$ and PM_{10} Emission Sources

The significant impact areas (SIA) for 24-hour $PM_{2.5}$ and 24-hour PM_{10} were determined to be 14.7 and 4.7 km, respectively, which are the maximum distances to which the Project had a predicted significant impact when firing fuel oil. These distances were used as the basis for determining the inventory of background $PM_{2.5}$ and PM_{10} sources, respectively, to be considered for inclusion in the air impact analyses for these pollutants.

EPA and FDEP modeling guidance require that the background source inventory include sources located within and 50 km beyond the SIA. 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. $PM_{2.5}$ and PM_{10} background facilities located within the SIA plus 50 km are summarized in Tables 6-2 and 6-3, respectively. Based on the results of the facility screening, no additional background sources were identified for inclusion in the NAAQS and PSD Class II increment analyses.

Non-Modeled Background Concentrations

Summaries of measured ambient concentrations, for use in determining background concentrations, are presented in Section 5.0. The background concentrations are based on averages of monitor measurements taken from 2012 to 2014. The background concentration used for the 1-hour NO_2 NAAQS analysis (see Table 5-4) is 72.7 micrograms per cubic meter (µg/m^3) and is based on continuous measurements taken at the Lantana monitoring site located in Palm Beach County. Of the two NO_2 monitoring sites considered, the Lantana monitor was selected for background because the concentration was the most conservative.

The 24-hour PM_{10} and $PM_{2.5}$ background concentrations are based on measurements from the Melbourne monitoring station and are 55.0 and 15.7 µg/m^3, respectively (see Tables 5-2 and 5-3).

Model Results

Significant Impact/CT Load Analysis

The results of the CT load analysis for one CT/HRSG firing natural gas are presented in Table 6-4 and the results for one CT/HRSG firing ULSD oil are presented in Table 6-5. The predicted maximum impacts due to the 3 CT/HRSGs only and 3 CTs/HRSGs with the operation of the cooling tower (for PM_{10} only, as the cooling tower's $PM_{2.5}$ emissions are negligible) are compared to the significant impact levels in Table 6-6. The results in Table 6-6 are based on either the CT/HRSGs firing either natural gas for an entire year (8,760 hr/yr) or firing natural gas for 8,260 hr/yr and firing ULSD oil for 500 hr/yr.

A CT load analysis and a significant impact analysis was also performed for the alternative arrangement of the CT/HRSGs and STG as shown in Figure 2-3. These arrangements group the CT/HRSG trains together rather than having a STG separating some CT/HRSG trains. Tables 6-4A and 6-5A present the CT load analyses for natural gas and ULSD oil firing, respectively. Table 6-6A presents the results of the significant impact analysis. There are only very minor differences the impacts of the power block arrangements and no change in the impacts relative to the SILs.

Based on the results presented in Table 6-6, the proposed Project's maximum impacts are predicted to be less than the SIL except for the 1-hour NO_2, 24-hour PM_{10} and 24-hour $PM_{2.5}$ concentrations. As such, cumulative source modeling analyses are required for these pollutants and averaging times to determine compliance with the NAAQS and allowable PSD increments. Due to the very minor changes in the significant impacts of the power block arrangements, the modeling was conducted for the primary arrangement (Figure 2-1).

1-hour NO_2 NAAQS Results

The NAAQS modeling results are summarized in Table 6-7. The maximum predicted 1-hour NO_2 concentration due to all sources plus a background concentration of 72.7 µg/m^3 is 84.7 µg/m^3, which is less than the NAAQS of 188.1 µg/m^3.

24-Hour PM_{10} NAAQS Results

The NAAQS modeling results for 24-hour PM_{10} are also summarized in Table 6-7. The maximum predicted 24-hour $PM_{2.5}$ concentration due to all sources plus a background concentration is 61.6 µg/m^3 which is less than the NAAQS of 150 µg/m^3.

24-Hour $PM_{2.5}$ NAAQS Results

The NAAQS modeling results for 24-hour $PM_{2.5}$ are also summarized in Table 6-7. When firing ULSD oil, the maximum predicted 24-hour $PM_{2.5}$ concentration due to all sources plus a background concentration is 20.2 µg/m^3 which is less than the NAAQS of 35 µg/m^3. When firing natural gas, the maximum predicted 24-hour $PM_{2.5}$ concentration due to all sources plus a background concentration is 16.6 µg/m^3 which is less than the NAAQS of 35 µg/m^3.

24-Hour PM_{10} Increment Analysis Results

The PSD increment modeling results for 24-hour PM_{10} are also summarized in Table 6-8. The maximum predicted 24-hour PM_{10} increment is 8.0 µg/m^3 which is less than the allowable increment of 30 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 6-8. When firing ULSD oil, the maximum predicted 24-hour $PM_{2.5}$ increment is 7.6 µg/m^3 which is less than the allowable increment of 9 µg/m^3. When firing natural gas, the maximum predicted 24-hour $PM_{2.5}$ increment is 1.4 µg/m^3 which is less than the allowable increment of 9 µg/m^3.

Secondary $PM_{2.5}$ Formation

Because the proposed Project will result in emission increases of SO_2 or NO_X greater the EPA Significant Emission Rates, an analysis of the proposed Project's potential for secondary $PM_{2.5}$ formation is required. To address this issue, this qualitative evaluation is provided in a manner that is consistent with the EPA's "Guidance for $PM_{2.5}$ Permit Modeling" (May, 2014).

The proposed OCEC Project will result in the following increases of $PM_{2.5}$ precursor pollutants: 254 TPY (SO_2); 396 TPY (NO_X); and 71 TPY (VOC). Because secondary $PM_{2.5}$ is formed over a longer timeframe from chemical conversions occurring in the atmosphere, peak secondary formation is more diffuse than emitted primary $PM_{2.5}$ and the peak secondary $PM_{2.5}$ concentrations occur much further downwind than do primary $PM_{2.5}$ peak concentrations.

From the Project's primary $PM_{2.5}$ emissions, the maximum predicted total air quality 24-hour $PM_{2.5}$ impact in the vicinity of the proposed Project is 20.2 µg/m^3 based on an individual impact of 4.5 µg/m^3 for the Project when firing ULSD oil, which is limited to 500 hours/year, and a non-modeled background concentration of 15.7 µg/m^3 derived from monitoring data. When firing natural gas, the primary fuel, the maximum total impact is 16.6 µg/m^3 which is less than 50 percent of the $PM_{2.5}$ NAAQS of 35 µg/m^3 (see Table 6-7). As presented in Table 5-3, the $PM_{2.5}$ monitoring data at the closest FDEP station to the Project (Site No. 012-009-0007) measured 24-hour average $PM_{2.5}$ concentrations from 2012 to 2014 that were well below the respective NAAQS. The 98th percentile of 24-hour average $PM_{2.5}$ concentrations ranged from 12.9 to 20.6 µg/m^3 with a 3-year average of 15.7 µg/m^3 which are less than 50 percent of the NAAQS of 35 µg/m^3. These measured values, which include $PM_{2.5}$ concentrations from primary $PM_{2.5}$ emissions and from secondary formation of $PM_{2.5}$ from precursors, such as NO_x and SO_2, indicate that the $PM_{2.5}$ emissions and secondary formation of $PM_{2.5}$ from existing sources in the vicinity of the monitoring station comply with the NAAQS and provide sufficient margin for additional growth in the area.

Finally, it is noted that significant emission reductions of NO_x and SO_2 have also occurred in southern Florida due to various modernization projects by FPL. Several of these include:

- Riviera Beach Energy Center Project (Palm Beach County)
  - NO_x reduction – 3,305 TPY
  - SO_2 reduction – 10, 787 TPY
- Port Everglades Energy Center Project (Broward County)
  - NO_x reduction – 3,878 TPY
  - SO_2 reduction – 9, 283 TPY
- Cape Canaveral Energy Center Project (Brevard County)
  - NO_x reduction – 7,228 TPY
  - SO_2 reduction – 10,930 TPY
- Fort Myers CT Project (Lee County)
  - NO_x reduction – 5,250TPY
  - SO_2 reduction – 20,424 TPY

These projects will result in significant NO_x and SO_2 emission reductions in southern Florida which are significantly greater than the potential emissions from the Project and will continue to maintain the $PM_{2.5}$ air quality levels that comply with NAAQS.

Based on the available information, secondary formation of $PM_{2.5}$ in the vicinity of the OCEC Project is not expected to significantly contribute to total air quality $PM_{2.5}$ concentrations for comparison to the NAAQS or Class II $PM_{2.5}$ increment consumption for several reasons.

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

Model Selection and General Assumptions

The CALPUFF air modeling system (Version 5.8.4) was used to predict the Project's maximum air quality concentrations at locations beyond 50 km from the Project. CALPUFF is a non-steady state Lagrangian puff long-range transport model that includes algorithms for chemical transformations (important for visibility controlling pollutants) and wet/dry deposition. CALPUFF was used in a manner that is consistent with methodologies recommended in the following document and in subsequent discussions with the FLM.

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

Parameter settings to be used in CALPUFF were based on the latest regulatory guidance. Where the modeling guidance recommends regulatory model defaults, those defaults 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. For predicting 24-hour visibility impairment, the FLAG guidance recommends using CALPOST Version 6.221 Method 8 (MVISBK = 8) and submode 5 (M8_MODE = 5). For this analysis, the background hygroscopic and non-hygroscopic aerosol levels were derived from the 20 percent best natural background days. In addition, parameters will be set to calculate wet and dry (i.e., total) fluxes and concentrations at each evaluated PSD Class I area.

Project Modeled Emissions

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

PM emissions for the Project's stack emissions were speciated into filterable and condensable components and into six particle size categories. The effect that each species has on visibility impairment is related to a parameter called the extinction coefficient. The higher the extinction coefficient, the greater is that species' effect on visibility. Filterable PM is speciated into coarse (PMC), fine (PMF), and elemental carbon (EC). The default extinction efficiencies for these species are 0.6, 1.0, and 10.0, respectively. PMC is PM with aerodynamic diameters greater than 2.5 microns. Both EC and PMF have aerodynamic diameters equal to or less than 2.5 microns. Condensable PM is comprised of sulfate (SO_4) and secondary organic aerosols (SOA). The extinction efficiencies for these species are 3 x f(RH) and 4, respectively, where f(RH) is the relative humidity factor.

The PM group was speciated into filterable and condensable species using the POSTUTIL utility program. Note that emissions for condensable inorganic PM are input directly to CALPUFF as SO_4.

PM speciation (PM_{10} versus $PM_{2.5}$) was developed based on the best available vendor information for the Project's stack sources.

Building Downwash Considerations

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

Meteorological Data

The far-field air modeling analyses were conducted using meteorological and geophysical databases which have been developed for use with the most recent versions of CALPUFF. These datasets were developed using CALMET Version 5.8 and were originally developed by VISTAS and recompiled for Version 5.8.4 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 the Everglades National Park (ENP) and the Chassahowitzka National Wilderness Areas (CNWA). The minimum distances to these areas from the location of OCEC Unit 1 are 203 km and 211 km, respectively, while the next closest PSD Class I area is greater than 450 km from the location of OCEC Unit 1.

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 proposed Project were compared to EPA's proposed PSD Class I significant impact levels. If the proposed Project's maximum predicted impacts exceed a proposed EPA PSD Class I significant impact level for any pollutant and averaging time then a more detailed PSD Class I increment analysis must be performed for that pollutant and averaging time. In the PSD Class I incremental analysis, PSD-increment affecting sources will be modeled for comparison to the allowable PSD Class I increments.

The proposed PSD Class I significant impact levels are:

- NO_2: annual average – 0.1 µg/m^3
- 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

As the maximum predicted 24-hour $PM_{2.5}$ concentration due to the proposed Project exceeded the SIL at both the ENP and the CNWA, detailed analysis to address compliance with the allowable PSD Class I increment are required at both areas. The following section discusses the methodology for conducting the increment analyses.

$PM_{2.5}$ PSD Class I Increment Analyses

The amount of increment consumed is determined by the increase or decrease in actual emissions from two baseline dates. For $PM_{2.5}$, the major baseline date is October 20, 2010; the minor source baseline date is October 20, 2011. The major source baseline date is set by federal PSD rules and establishes the date after which actual emission increases associated with new or modified major stationary sources consume increment if construction has begun. The minor source baseline date establishes the date after which increment consumption and expansion must be evaluated for changes that occur at all sources (including minor, area and mobile sources).

A listing of permitted facilities located within 200 km of the ENP and CNWA that emit SO_2, NO_x, and/or PM_{10}/$PM_{2.5}$ was requested and obtained from FDEP. For each Class I area, source were initially sorted by increasing distance from the respectively Class I areas. The lists of background facilities were updated based on Golder’s prior application experience in southern and central Florida as well as other recent submittals made by these facilities to the FDEP, such as air operating permits (e.g., Title V permits) or annual operating reports (AORs). The background source lists were then updated, as necessary, to identify any new sources that were not included in the initial list of background facilities.

The following general assumptions were made in the preparation of the background source inventories for $PM_{2.5}$:

- $PM_{2.5}$ emissions were assumed to be equal to PM_{10} emissions unless $PM_{2.5}$ emissions were available (either permitted or based on particle size distribution for that source).
- Increment consuming major and minor sources were modeled at the maximum permitted rate; if permitted rates were not available, potential emissions rates calculated based on maximum permitted throughput and readily-available emissions factors (such as AP-42) were used.
- Increment expanding major sources were modeled using actual emissions (based on available annual emissions from the AORs and actual annual operating hours).
- Baseline major and minor sources still operating since the minor source baseline date were assumed to have no changes in emissions and not modeled.
- Condensable $PM_{2.5}$ emissions were calculated, when available, and added to the filterable emissions for increment consuming sources.
- SO_2 and NO_X emissions were included for each source to estimate the amount of secondary $PM_{2.5}$ created due the conversion of these pollutants to nitrates and sulfates. Where available, SAM emissions were entered as primary sulfate. Where SAM emissions were not available, they were typically assumed to be 10 percent of the emitted SO_2.
- The amount of total $PM_{2.5}$ increment consumed was assumed to be the sum of primary $PM_{2.5}$ increment + secondary PM2.5 increment consumed. To be conservative, the PSD expansion of secondary $PM_{2.5}$, due to reductions of NO_X and SO_2 emissions, were not included in the Class I increment analysis.

It should be noted that there are numerous emissions sources located within 200 km of both the ENP and CNWA. However, most of these sources were not included in the $PM_{2.5}$ increment analyses for one of the following reasons:

- They were in operation before the major or minor source baseline date and have not changed in emissions. These sources do not affect the PSD increment.
- They have minimal $PM_{2.5}$ emissions of 1 lb/hr of less or have low-level releases such as from cooling towers located more than 25 km from a PSD Class I area.
- They emit less than 500 TPY and located more than 25 km from the PSD Class I area.

These sources were not considered to result in significant impacts and were excluded for the modeling analysis. Sources with emissions that consumed the PSD increment and sources that expanded the PSD increment were modeled separately using CALPUFF Version 5.8.4. The outputs for the consuming and expanding source analyses were then combined using the CALSUM postprocessor to obtain the total increment change. The CALPOST postprocessor was then used to estimate the amount of primary $PM_{2.5}$ and secondary $PM_{2.5}$ (i.e., the concentration sum of sulfates and nitrates) consumed at each Class I area. The primary and secondary components were then summed to obtain the total $PM_{2.5}$ increment, based on the predicted highest, second-highest concentration.

Model Results

Significant Impact Analysis Results

The results of the PSD Class I significant impact analysis at the ENP is presented in Table 6-9. All predicted concentrations are less than the SIL except for the 24-hour $PM_{2.5}$. The results of the PSD Class I significant impact analysis at the CNWA is presented in Table 6-10. At each PSD Class I area, all predicted concentrations are less than the SIL except for the 24-hour $PM_{2.5}$. As such, cumulative source analyses to address compliance with the allowable 24-hour $PM_{2.5}$ PSD Class I increment were conducted for both the ENP and CNWA.

24-Hour PM_{25} Increment Analysis

ENP $PM_{2.5}$ Increment-Affecting Sources

The following southern Florida facilities were determined to incur significant $PM_{2.5}$ emission changes (consuming and/or expanding increment) during the past 5 years due to recently completed or current projects:

- FPL Lauderdale Plant: replace 22 of the 24 GTs at Lauderdale Plant and 12 GTs at the Port Everglades Plant with 5 simple-cycle CTs (Lauderdale CT Project) (PSD application originally submitted in July, 2013 and revised application submitted in March, 2015).
- FPL Port Everglades Plant: replace fossil-fuel fired steam Units 1 through 4 with a 3-on-1 combined cycle unit (Port Everglades Energy Center Project).
- FPL Fort Myers Plant: replaced 10 of 12 No. 2 oil fired GTs with 2 simple-cycle CTs (Fort Myers CT Project) (PSD application submitted in July, 2013 and revised PSD application submitted in May 2015).

One additional facility (South Florida Water Management District, Pump Station S-332B) was added to the modeling analyses since it was approximately 1 km from the Class I area.

Direct $PM_{2.5}$ emissions for several sources (i.e., Lauderdale CT Project, Fort Myers CT Project, Waste Management Medley Landfill PSD Project) were speciated into individual particle size categories from those projects based on the type of source (boilers, turbines, etc.) using AP-42 information. The $PM_{2.5}$ emissions were split equally among the typical particle size categories as follows:

- 1.25 to 2.5 µm
- to less than 1.25 µm
- 0.63 to less than 1.0 µm
- Less than 0.63 µm

A summary of the background facilities considered for the ENP 24-hour $PM_{2.5}$ Class I analysis is presented in Table 6-11. As shown, information for each facility is provided which includes the facility's ID number, location in UTM coordinates, distance from the ENP, and maximum annual emissions (based on the short-term emission rates considered in the modeling prorated to annual emission rates) that consumed or expanded the PSD increment.

A detailed summary of the emission units and source parameters at each facility that were included in the modeling analysis is presented in Table 6-12. Table 6-12 includes the source parameters (stack height, stack diameter, exhaust velocity, and exhaust temperature); short-term emission rates; classification of the source as consuming, expanding, or baseline for $PM_{2.5}$.

CNWA $PM_{2.5}$ Increment-Affecting Sources

A summary of the background facilities considered for the CNWA 24-hour $PM_{2.5}$ Class I analysis is presented in Table 6-13. The $PM_{2.5}$ increment at CNWA was affected mostly by the following projects:

- Shady Hills Generating Station Expansion
- Duke Energy Florida Crystal River repowering
- Tampa Electric Company Polk Power Station Modification
- Florida Power and Light Manatee Power Plant Installation of Electrostatic Precipitators

A detailed summary of the emission units and source parameters at each facility that were included in the modeling analysis is presented in Table 6-14.

24 Hour PM Modeling ENP and CNWA Results

A summary of the 24 hour $PM_{2.5}$ PSD Class I increment analysis at both the ENP and the CNWA is presented in Table 6-15. Table 6-15-presents the amount of primary, secondary and total $PM_{2.5}$ increment consumed at each Class I area. The total increment consumed at the ENP and at the CNWA is 0.29 and 0.41 µg/m^3, respectively. These concentrations are well below the allowable PSD Class I increment of 2 µg/m^3.

7.0 ADDITIONAL IMPACT ANALYSIS

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

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

7.1 Potential Impacts Due to Associated Growth

7.1.1 Impacts of Associated Growth

Construction of the proposed Project will occur over approximately 18 to 24 months and will require an average of 290 workers during that time. It is anticipated that many of these construction personnel will commute to the Site. There will be about 30 permanent personnel associated with the operation of OCEC Unit 1. The workforce needed to construct and operate the facility represents a small fraction of the population already present in the region that includes Okeechobee, Indian River, and St. Lucie counties. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

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

As demonstrated in Section 6.0, the maximum air quality impacts resulting from the proposed OCEC are predicted to be low and for some pollutants and averaging times, below the significant impact levels for the majority of air pollutant and averaging times. The predicted cumulative source 24-hour PM_{10}, 24-hour $PM_{2.5}$, and 1-hour average impacts demonstrate that the OCEC and all nearby background source emissions will comply with the PSD increments and NAAQS.

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

7.2.1 Soils

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

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

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

7.2.2 Vegetation

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

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

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

Nitrogen Dioxide

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

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

Particulate Matter

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

Carbon Monoxide

Information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of adenosine triphosphate (ATP), the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok, et al. (1989) reported that exposure to a

$CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85×10^6 µg/m^3) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik, et al. (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10^5 µg/m^3). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

Ozone

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

7.2.3 Wildlife

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

7.2.4 Impact Analysis Methodology

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

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

7.3.1 Impacts on Vegetation and Soils

Vegetative communities in the vicinity of the OCEC Unit 1 include agricultural activities such as improved pasture and citrus groves, mixed hardwood wetlands and shrub and brushland. The forested wetlands are surrounded by drainage ditches connecting to the network of citrus irrigation ditches. The canopy is dominated by red maple, with occasional subdominant species including cabbage palm, American elm (*Ulmus americana*), blackgum (*Nyssa sylvatica*), and laurel oak (*Quercus laurifolia*). Brazilian pepper typically forms a dense shrub layer along the perimeter of these mixed hardwood wetlands, with additional shrub species present including wax myrtle and groundsel tree. The groundcover within the interior of the wetlands includes a variety of species such as swamp fern (*Blechnum serrulatum*), cinnamon fern (*Cinnamomea camphora*), royal fern (*Osmunda regalis*), sawgrass (*Cladium jamaicense*), arrowhead, Virginia chain fern, marsh pennywort, leather fern, and the exotic old world climbing fern (*Lygodium microphyllum*). The shrub and brushland is dominated by low growth of saw palmetto and gallberry (*Ilex glabra*) over sandy soils, with additional subdominant species including bahia grass, broomsedge bluestem, blackberry, bracken fern (*Pteridium aquilinum*), wiregrass (*Aristida stricta*), and wax myrtle.

Soils in the area are primarily Myakka or Basinger fine sand (>80 percent) with 0 to 2 percent slopes.

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

Since the Project's impacts on the local air quality are predicted to be less than the NAAQS and less than the effect levels on soils and vegetation, the Project's impacts on soils, vegetation, and wildlife in the vicinity of the Site are expected to be negligible. With regard to O_3 concentrations, the Project's VOC and NO_x emissions (precursors to O_3 formation) represent an insignificant increase in VOC and NO_x emissions for the region that includes Okeechobee, Indian River, and St. Lucie counties.

7.3.2 Impacts on Wildlife

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

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. It is highly unlikely that emissions from the OCEC facility will cause adverse effects to wildlife due to the proposed Project's low impacts, which are predicted to be below the NAAQS based on worst-case operation. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the Project's impacts is extremely unlikely.

7.4 Impacts to the ENP and CNWA PSD Class I Areas

7.4.1 Identification of AQRVs and Methodology

An AQRV analysis was conducted to assess the potential risk to AQRVs both at the ENP and the CNWA due to the emissions from the proposed Project. The ENP is located 203 km to the southwest of the OCEC and the CNWA is 211 km to the northwest of the OCEC.

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

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

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

7.4.2 AQRVs Other Than Visibility and Sulfur/Nitrogen Deposition at the ENP

7.4.2.1 Impacts to Soils

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

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

7.4.2.2 Impacts to Vegetation

General

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, PM, CO, and O_3. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term injury, as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

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

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

Sulfur Dioxide

The maximum annual average SO_2 concentration resulting from the Project is 0.0007 µg/m^3, less than 0.01% of the concentration that damaged the most sensitive lichen species (8 µg/m^3). The maximum 3 -, and 24-hour average SO_2 concentrations for the Project are predicted to be 0.03, and 0.067 µg/m^3, respectively, at the ENP. The maximum 3-hour average SO_2 concentration predicted for the project at the ENP is less than 0.01 percent of the acute exposure that caused damage to sensitive species of vegetation (i.e., 790 µg/m^3). The modeled annual incremental increase in SO_2 adds only slightly to background levels of this gas and poses no threat to vegetation within the ENP.

Nitrogen Dioxide

The maximum 1-, 3-, and 8-hour average NO_2 concentrations due to the proposed Project are predicted to be 0.245, 0.188, and 0.155 µg/m^3, respectively, at the ENP. These concentrations are less than 0.01 percent of the levels that could potentially injure 5 percent of vascular plant foliage (i.e., 3,800 to 15,000 µg/m^3; see previous subsections), and less than 0.05 percent of the concentration that caused adverse effects in lichen species in acute exposure scenarios (564 µg/m^3; see previous subsections). For a chronic exposure, the maximum annual NO_2 concentration due to the Project is predicted to be 0.0003 µg/m^3 at the ENP, which is less than 0.0005 percent of the levels that caused minimal yield loss and chlorosis in plant tissue (i.e., 2,000 µg/m^3; see previous subsections).

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

Particulate Matter

The maximum 8-hour PM_{10} concentration due to the Project is predicted to be 0.243 µg/m^3 at the ENP. This impact is less than 0.12 percent of the values that affected plant foliage (i.e., 210 µg/m^3, see previous subsections). As a result, no significant effects to vegetative AQRVs within the ENP are expected as a result of the Project's PM emissions.

Carbon Monoxide

The maximum 1-hour average concentration due to the Project is 0.41 µg/m^3 at the, which is less than 0.00002 percent of the minimum value that caused inhibition in laboratory studies (i.e., 6.85×10^6 µg/m^3, see previous subsections). The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum predicted annual concentrations of 0.001 µg/m^3 at the ENP reflect a more realistic, yet conservative, CO impact level for the Class I areas. The maximum concentrations are predicted to be less than 1×10^{-7} percent of the value that caused cytochrome *c* oxidase inhibition (6.85×10^5 µg/m^3).

VOC and NOx Emissions and Impacts to Ozone

VOC and NO_x emissions are precursors to O_3 formation. Natural (i.e., without man-made sources) ambient concentrations of O_3 are normally in the range of 20 to 39 µg/m^3 (0.01 to 0.02 ppm) (Heath, 1975). O_3 can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis and markings on the upper surface leaves know as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. O_3 can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.

Ozone formation is often a local issue since NO_x will be converted to stable nitrate compounds during the dispersion, which inhibits the accumulation of ozone formation from the reaction of O_2 and the atomic oxygen produced from NO_2 photolysis. Since the distance of the ENP is over 200 km away from the OCEC Site, the impact of the ozone formation from the VOC and NO_X emissions from the Project will be minimal.

Summary

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

7.4.2.3 Impacts to Wildlife

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

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary AAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards. For impacts on wildlife, the lowest threshold values of NO_2 and particulates, which are reported to cause physiological changes, are shown in Table 7-1. These values are up to orders of magnitude larger than maximum predicted concentrations for the ENP. No effects on wildlife AQRVs from NO_2 and particulates are expected. The Project's contribution to cumulative impacts is negligible.

7.4.3 AQRVs Other Than Visibility and Sulfur/Nitrogen Deposition at the CNWA

7.4.3.1 Impacts to Soils

According to the USDA Soil Surveys of Citrus and Hernando Counties, nine soil complexes are found in the CNWA. These include Aripeka fine sand, Aripeka-Okeelanta-Lauderhill, Hallendale- Rock outcrop, Homosassa mucky fine sandy loam, Lacoochee, Okeelanta mucks, Okeelanta-Lauderdale-Terra Ceia mucks, Rock outcrop-Homosassa-Lacoochee, and Weekiwachee-Durbin mucks (Porter,1996). The majority of the soil complexes found in the NWA are inundated by tidal waters, contain a relatively high organic matter content, and have high buffering capacities based on their CEC, base saturation, and bulk density. The regular flooding of these soils by the Gulf of Mexico regulates the pH and any change in acidity in the soil would be buffered by this activity. Therefore, they would be relatively insensitive to atmospheric inputs. However, Terra Ceia, Okeelanta, and Lauderdale freshwater mucks are present along the eastern border of the NWA, and may be more sensitive to atmospheric sulfur deposition (Porter, 1996). Although not tidally influenced, these freshwater mucks are highly organic and therefore have a relatively high intrinsic buffering capacity.
The relatively low sensitivity of the soils to atmospheric inputs coupled with the extremely low ground-level concentrations of contaminants projected for the CNWA from the proposed plant emissions precludes any significant impact on soils.

7.4.3.2 Vegetation

General

The analytical methodology is the same as the one in Section 7.4.2.2.

Sulfur Dioxide

The maximum annual average SO_2 concentration resulting from the Project is 0.0014 µg/m^3, less than 0.02% of the concentration that damaged the most sensitive lichen species (8 µg/m^3). The maximum 3 -, and 24-hour average SO_2 concentrations for the Project are predicted to be 0.079, and 0.024 µg/m^3, respectively, at the CNWA. The maximum 3-hour average SO_2 concentration predicted for the project at the CNWA is less than 0.001 percent of the acute exposure that caused damage to sensitive species of vegetation (i.e., 790 µg/m^3). The modeled annual incremental increase in SO_2 adds only slightly to background levels of this gas and poses no threat to vegetation within the CNWA.

Nitrogen Dioxide

The maximum one, three, and eight hour average NO_2 concentrations due to the Project are predicted to be 0.291, 0.222, and 0.143 µg/m^3, respectively, at the CNWA PSD Class I area. These maximum concentrations are well below the levels that could potentially injure five percent of vascular plant foliage (i.e., 3,800 to 15,000 µg/m^3), and less than 0.01 percent of the concentration that caused acute adverse effects in sensitive lichen species. For a chronic exposure, the maximum annual NO_2 concentration due to the project is predicted to be 0.001 µg/m^3 at the CNWA, which is over six orders of magnitude lower than the level that caused minimal yield loss and chlorosis in plant tissue (i.e., 2,000 µg/m^3).

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

Particulate Matter

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

By comparison of these published toxicity values for particulate matter exposure (i.e., concentration for an 8-hour averaging time), the possibility of plant damage in the CNWA can be determined. The maximum predicted 8-hour PM_{10} concentration in the CNWA due to the project only is 0.193 mg/m^3 when firing fuel oil (see Table 6-10). Since this concentration is much less than the minimum concentration that can potentially affect vegetation, no effects to vegetative AQRVs are expected from the project.

Carbon Monoxide

The maximum 1-hour average concentration due to the project is 0.45 µg/m^3 at the, which is less than 0.00001 percent of the minimum value that caused inhibition in laboratory studies (i.e., 6.85×10^6 µg/m^3, see previous subsections). The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum predicted annual concentrations of 0.0014 µg/m^3 at the CNWA reflect a more realistic, yet conservative, CO impact level for the Class I areas. The maximum concentrations are predicted to be less than 2×10^{-8} percent of the value that caused cytochrome *c* oxidase inhibition (6.85×10^5 µg/m^3).

VOC and NOx Emissions and Impacts to Ozone

Ozone sensitive vegetation is present within the Chassahowitzka NWA, including elderberry (Sambucus canadensis), smooth cordgrass (Spartina alterniflora), and Virginia creeper (Parthenocissus quinquefolia) (NPS, 2003).

Elderberry is considered a bioindicator for describing ozone impact thresholds. However, the low levels of ozone exposure at the Class I Area make the risk of foliar ozone injury to plants low (NPS, 2004). Exposure indices, including the Sum06 and W126 indices, utilize maximum hourly concentrations to identify risk assessment thresholds. Due to the long distance, the Project's influence on O_3 concentrations is negligible and will not result in any foliar damage resulting from increases in O_3 concentrations.

Summary

In summary, the phytotoxic effects from the proposed plant emissions are minimal. It is important to note that the elements were conservatively modeled with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.4.3.3 Wildlife

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

7.4.4 Impacts Upon Visibility at the ENP and the CNWA

Introduction

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

Visibility is an AQRV for both the ENP and CNWA. Visibility can take the form of plume blight for nearby areas or regional haze for long distances (e.g., distances beyond 50 km). Because the closest approach of the two PSD Class I areas is much greater than 50 km from the proposed OCEC Site, the change in visibility will be analyzed as regional haze and the following methodology was used to address AQRVs.

Methodology

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

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

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

b_{extb} = the background extinction coefficient

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

Processing of visibility impairment for this study was performed with the California Puff (CALPUFF, Version 5.8.4) model and the CALPUFF post-processing program CALPOST Version 6.221. The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. For predicting visibility impairment, the FLAG guidance recommends using Method 8 (MVISBK = 8) and submode 5 (M8_MODE = 5). For this analysis, the background hygroscopic and non-hygroscopic aerosol levels were derived from the 20 percent best natural background days.

Emissions input to CALPUFF include the maximum rates for SO_2, NO_2, PM, and sulfuric acid mist. Results are provided for both natural gas and ULSD oil firing.

Results

The results of the visibility analysis at the ENP are presented in Table 7-2. When firing natural gas, the maximum predicted visibility impairment is 0.051 dv which is well below the FLM's criteria of 0.5 dv. This value is also below the FLM's recommended screening criterion of 5 percent change. For ULSD oil, the predicted impact is 0.118 dv, based on a conservative 24 hours per day for 365 days per year. As a result, the Project is not expected to have an adverse impact on the existing visibility at the PSD Class I area of the ENP. The same conclusion can be drawn from the visibility analysis results at the CNWA also presented in Table 7-2. When firing natural gas, the maximum predicted visibility impairment is 0.069 dv and for ULSD oil, the predicted impact is 0.126 dv.

7.4.5 Sulfur and Nitrogen Deposition at the ENP and the CNWA

General Methods

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

For N deposition, the species include:

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

For S deposition, the species include:

- SO_2, wet and dry deposition; and
- SO_4, wet and dry deposition

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

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

Results

The predicted total annual nitrogen and sulfur deposition due to the proposed Project at the ENP and CNWA are summarized in Table 7-3. At the ENP, the maximum annual total nitrogen deposition rate predicted for the project is 0.0005 kg/ha/yr and that for total sulfur deposition rate is 0.0009 kg/ha/yr, both of which are well below the FLM's criteria of 0.01 kg/ha/yr. At the CNWA, the maximum annual average total nitrogen deposition rate predicted for the project is 0.0011 kg/ha/yr and the total sulfur deposition rate is 0.0019 kg/ha/yr.

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TABLES

TABLE 2-1
STACK, OPERATING, AND EMISSION DATA
FOR THE COMBUSTION TURBINES/HRSGS -
NATURAL GAS COMBUSTION

		Operating and Emission Data [a] for Ambient Temperature			
		Combustion Turbine/ HRSG			
Parameter	**Units**	**35 °F**	**59 °F**	**75 °F**	**95 °F**
CT/HRSG Stack Data					
Height	ft	149	149	149	149
Diameter	ft	25.6	25.6	25.6	25.6
100 Percent Load					
Temperature	°F	177	180	182	184
Velocity	ft/sec	49.9	50.8	50.3	50.1
Maximum Hourly Emissions per CT					
SO_2	lb/hr	18.8	19.1	19.3	19.3
$PM/PM_{10}/PM_{2.5}$	lb/hr	15.4	15.5	15.5	15.6
NO_x	lb/hr	24.4	24.7	24.9	25.0
CO	lb/hr	36.0	37.4	37.8	38.2
VOC (as methane)	lb/hr	4.8	5.0	5.0	5.1
Sulfuric Acid Mist	lb/hr	3.7	3.7	3.7	3.8
75 Percent Load					
Temperature	°F	171	171	176	182
Velocity	ft/sec	39.9	39.4	39.4	39.1
Maximum Hourly Emissions per CT					
SO_2	lb/hr	14.8	14.3	14.0	13.4
$PM/PM_{10}/PM_{2.5}$	lb/hr	14.4	14.2	14.2	14.0
NO_x	lb/hr	19.2	18.5	18.1	17.4
CO	lb/hr	41.5	40.0	39.1	37.5
VOC (as methane)	lb/hr	3.3	3.2	3.1	3.0
Sulfuric Acid Mist	lb/hr	2.89	2.78	2.72	2.61
50 Percent Load					
Temperature	°F	168	169	172	178
Velocity	ft/sec	32.8	32.3	32.2	31.9
Maximum Hourly Emissions per CT					
SO_2	lb/hr	11.3	10.9	10.7	10.3
$PM/PM_{10}/PM_{2.5}$	lb/hr	13.5	13.4	13.3	13.2
NO_x	lb/hr	14.6	14.1	13.8	13.3
CO	lb/hr	31.7	30.5	29.8	28.7
VOC (as methane)	lb/hr	2.5	2.5	2.4	2.3
Sulfuric Acid Mist	lb/hr	2.20	2.12	2.07	1.99

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Sources: GE, 2015; Golder, 2015.

TABLE 2-2
STACK, OPERATING, AND EMISSION DATA
FOR THE COMBUSTION TURBINES/HRSGS -
ULTRA LOW-SULFUR DISTILLATE OIL COMBUSTION

		Operating and Emission Data [a] for Ambient Temperature Combustion Turbine/ HRSG			
Parameter	**Units**	**35 °F**	**59 °F**	**75 °F**	**95 °F**
CT/HRSG Stack Data					
Height	ft	149	149	149	149
Diameter	ft	25.6	25.6	25.6	25.6
100 Percent Load					
Temperature	°F	205.4	203.8	208	213.1
Velocity	ft/sec	55.3	53.8	53.9	54.6
Maximum Hourly Emissions per CT					
SO_2	lb/hr	5.0	4.8	4.8	4.7
$PM/PM_{10}/PM_{2.5}$	lb/hr	70.0	70.0	70.0	69.9
NO_x	lb/hr	101.5	98.0	96.8	95.8
CO	lb/hr	77.2	74.6	73.6	72.9
VOC (as methane)	lb/hr	8.8	8.5	8.4	8.3
Lead	lb/hr	0.973	0.940	0.929	0.920
Sulfuric Acid Mist	lb/hr	0.05	0.04	0.04	0.04
75 Percent Load					
Temperature	°F	191	188	193	194
Velocity	ft/sec	42.3	40.8	41.6	39.1
Maximum Hourly Emissions per CT					
SO_2	lb/hr	3.9	3.8	3.8	3.5
$PM/PM_{10}/PM_{2.5}$	lb/hr	69.3	69.3	69.3	69.2
NO_x	lb/hr	79.9	76.7	76.8	71.4
CO	lb/hr	82.7	79.3	79.5	73.9
VOC (as methane)	lb/hr	7.0	6.7	6.7	6.2
Lead	lb/hr	0.767	0.736	0.737	0.686
Sulfuric Acid Mist	lb/hr	0.04	0.03	0.03	0.03
60 Percent Load					
Temperature	°F	175	174	177	180
Velocity	ft/sec	32.3	31.0	31.2	29.6
Maximum Hourly Emissions per CT					
SO_2	lb/hr	3.1	2.9	2.9	2.7
$PM/PM_{10}/PM_{2.5}$	lb/hr	69.1	69.1	69.1	69.0
NO_x	lb/hr	62.5	59.6	59.3	55.5
CO	lb/hr	64.6	61.7	61.4	57.5
VOC (as methane)	lb/hr	5.4	5.2	5.2	4.8
Lead	lb/hr	0.599	0.572	0.569	0.532
Sulfuric Acid Mist	lb/hr	0.03	0.03	0.03	0.02

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Sources: GE, 2015; Golder, 2015.

TABLE 2-3
SUMMARY OF POTENTIAL ANNUAL EMISSIONS FOR THE CTS/HRSGs

	Hourly Emissions (lb/hr) - Fuel for Ambient Temperature & Load						Emissions (tons/year) for Operating Scenario						
							Operating Scenario	Operating Hours					
							Nat Gas 100 % Load	8,760	8,260	0	3,380	0	4,380
							Fuel Oil 100 % Load	0	500	0	500	0	500
							Nat Gas 75 % Load	0	0	8,760	3,880	0	0
							Fuel Oil 75 % Load	0	0	0	0	0	0
							Nat Gas 50 % Load	0	0	0	1,000	8,760	3,880
							Fuel Oil 50 % Load	0	0	0	0	0	0
Pollutant	**Nat Gas 75 °F 100%**	**ULSD Oil 75 °F 100%**	**Nat Gas 75 °F 75%**	**ULSD Oil 75 °F 75%**	**Nat Gas 75 °F 50%**	**ULSD Oil 75 °F 50%**	**TOTAL**	**8,760**	**8,760**	**8,760**	**8,760**	**8,760**	**8,760**
<u>One CT/HRSG</u>													
SO_2	19.3	4.8	14.0	3.8	10.7	2.9		84.4	80.8	61.2	66.2	46.7	64.1
$PM/PM_{10}/PM_{2.5}$	15.5	70.0	14.2	69.3	13.3	69.1		68.1	81.7	62.0	77.9	58.2	77.3
NO_x	24.9	96.8	18.1	76.8	13.8	59.3		109.3	127.2	79.3	108.4	60.3	105.6
CO	37.8	73.6	39.1	79.5	29.8	61.4		165.8	174.7	171.3	173.1	130.4	159.0
VOC (as methane)	5.0	8.4	3.1	6.7	2.4	5.2		22.0	22.9	13.8	17.9	10.5	17.8
Sulfuric Acid Mist	3.7	0.9	2.7	0.7	2.1	0.6		16.4	15.7	11.9	12.9	9.1	12.5
Lead	0.0	0.043	0.0	0.034	0.0	0.026		0.0	0.0	0.0	0.0	0.0	0.0
HAPs	1.49	3.84	1.08	3.05	0.82	2.35		6.5	7.1	4.7	6.0	3.6	5.8
<u>Three CT/HRSGs</u>													
SO_2	57.8	14	41.9	11	32.0	9		253	242	184	199	140	192
$PM/PM_{10}/PM_{2.5}$	46.6	210	42.5	208	39.9	207		204.3	245.1	186.1	234	175	232
NO_x	74.8	290	54.3	230	41.3	178		328	382	238	325	181	317
CO	113.5	221	117.3	238	89.3	184		497	524	514	519	391	477
VOC (as methane)	15.1	25.2	9.4	20.0	7.2	15.5		66.1	68.6	41.4	53.7	31.5	53.3
Sulfuric Acid Mist	11.2	2.8	8.2	2.2	6.2	1.7		49.2	47.1	35.7	38.6	27.2	37.4
Lead	0.00	0.13	0.00	0.10	0.00	0.08		0.00	0.032	0.00	0.032	0.00	0.032
HAPs	4.47	11.52	3.24	9.14	2.47	7.06		19.6	21.3	14.2	18.0	10.8	17.5

Sources: GE, 2015; Golder, 2015.

TABLE 2-4
PERFORMANCE, STACK PARAMETERS, AND EMISSIONS
FOR THE AUXILIARY BOILER

Parameter	**Units**	**Values**
Performance		
Number of Units		1
Fuel		Natural gas
Heat Input (HHV) [a]	MMBtu/hr	99.77
Heat Content (HHV-Btu/scf)	Btu/scf	1,020
Fuel Usage	scf/hr	97,814
Rating [a]	lb steam/hr	85,000
Maximum operation/yr	hours	2,000
Maximum Fuel Usage	scf/yr	195,627,451
Exhaust Flow [a]		
Mass Flow	lb/hr	88,066
Molecular Weight		27.62
Moisture	%	18.17
Stack Parameters [a]		
Diameter	ft	2.75
Height	ft	60
Temperature	^oF	296
Velocity	ft/sec	82
Flow	acfm	29,325
Emissions		
SO_2 -Basis [b]	grains S/100 scf	2
Emissions	lb/hr	0.56
	TPY	0.56
NO_x - Basis [a]	lb/MMBtu	0.050
Emissions	lb/hr	4.99
	TPY	4.99
CO - Basis [a]	lb/MMBtu	0.080
Emissions	lb/hr	7.98
	TPY	7.98
VOC - Basis [c]	lb/MMscf	5.5
Emissions	lb/MMBtu	0.0054
	lb/hr	0.54
	TPY	0.54
$PM/PM_{10}/PM_{2.5}$ - Basis [c,d]	lb/MMscf	7.6
Emissions	lb/MMBtu	0.0075
	lb/hr	0.74
	TPY	0.74

[a] Nebraska Boiler (2005); Golder Associates, (2015); Values are typical.
[b] Typical maximum sulfur content for natural gas
[c] EPA, AP-42, Natural Gas Combustion (March 1998).
[d] For PM, emissions include filterable and condensables.

TABLE 2-5

PERFORMANCE, STACK PARAMETERS, AND EMISSIONS FOR THE NATURAL GAS FUEL HEATERS

Parameter	Units	Values
Performance[a]		
Number of Units		1
Fuel		Natural gas
Heat Input (HHV)	MMBtu/hr	9.90
Heat Content (HHV-Btu/scf)	Btu/scf	1,020
Fuel Usage	scf/hr	9,706
Maximum operation/yr	hours	8,760
Maximum Fuel Usage	MMscf/yr	85.0
Stack Parameters (typical)		
Diameter	ft	1.4
Height	ft	30
Temperature	^{o}F	500
Velocity	ft/sec	53.6
Flow	acfm	4,950
Emissions		
SO_2 -Basis [b]	grains S/100 scf	2
Emissions	lb/MMBtu	0.0056
	lb/hr	0.055
	TPY	0.24
NO_x - Basis [c]	lb/MMscf	100
Emission rate	lb/MMBtu	0.098
	lb/hr	0.97
	TPY	4.25
CO - Basis [c]	lb/MMscf	84
Emission rate	lb/MMBtu	0.082
	lb/hr	0.82
	TPY	3.57
VOC - Basis [c]	lb/MMscf	5.5
Emission rate	lb/MMBtu	0.0054
	lb/hr	0.053
	TPY	0.23
$PM/PM_{10}/PM_{2.5}$ - Basis [c,d]	lb/MMscf	7.6
Emission rate	lb/MMBtu	0.0075
	lb/hr	0.074
	TPY	0.32

Note: Project will also have spare heater.

[a] Based on 10 MMBtu/hr (HHV) indirect gas heaters from Hanover Compression Company or equivalent.

[b] Typical maximum for natural gas.

[c] EPA, AP-42, Natural Gas Combustion (March 1998): small boilers < 100 MMBtu/hr.

[d] For PM, emissions include filterable and condensables.

TABLE 2-6

PERFORMANCE AND EMISSION DATA FOR THE EMERGENCY GENERATORS

Parameter		Units	Values	
Performance [a]				
Number of Units			1	3
Rating (brake)		kW	3,298	9,894
Rating (brake)		hp	4,423	13,268
Fuel			ULSD Oil	ULSD Oil
Fuel Heat content (HHV)		Btu/lb	19,500	19,500
Fuel density		lb/gal	7.06	7.06
Heat input (HHV)		MMBtu/hr	29.49	88
Fuel usage		gal/hr	214.2	643
Maximum operation/yr		hours	100	300
Maximum fuel usage		gal/yr	21,420	64,260
Stack Parameters (typical) [a]				
Diameter		ft	1.2	1.2
Height		ft	30	30
Temperature		^oF	891.9	891.9
Flow		acfm	25,624	25,624
Emissions [b]				
SO_2 -	Basis	%S	0.0015%	
	Conversion of S to SO_2	%	100	
	Molecular weight SO_2/ S (64/32)		2	
	Emission rate	lb/hr	0.045	0.136
		TPY	0.0023	0.0068
NO_x -	Basis	g/kW-hr	6.4	
	Emission rate	lb/hr	46.5	139.6
		TPY	2.3	7.0
CO -	Basis	g/kW-hr	3.5	
	Emission rate	lb/hr	25.4	76
		TPY	1.3	3.8
VOC -	Basis	g/kW-hr	0.2	
	Emission rate	lb/hr	1.5	4.4
		TPY	0.07	0.22
$PM/PM_{10}/PM_{2.5}$ -	Basis	g/kW-hr	0.2	
	Emission rate	lb/hr	1.5	4.4
		TPY	0.07	0.22

Source: FPL, 2015; Golder; 2015.

[a] Performance based on Caterpillar C175 kW 60 Hz Emergency Diesel Generator (RBEC)

[b] Emission based on 40 CFR Part 60 Subpart IIII and Part 89 Requirements.

TABLE 2-7

ESTIMATED PERFORMANCE AND EMISSION DATA FOR THE FIRE PUMP ENGINE

Parameter		Units	Values
Performance			
Number			1
Rating [a]		hp	422
Rating [a]		kW	315
Fuel			ULSD Oil
Fuel Heat content (HHV)		MMBtu/lb	19,500
Fuel density		lb/gal	7.06
Heat input (HHV)		MMBtu/hr	2.75
Fuel usage [a]		gal/hr	20.0
Maximum operation/yr		hours	100
Maximum fuel usage		gal/yr	2,000
Stack Parameters [a]			
Exhaust Flow		cfm	2,048
Stack Velocity		ft/sec	120
Exhaust Temperature		^oF	891
Stack Height		ft	17
Stack Diameter		ft	0.60
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	0.0042
		TPY	0.00021
NO_x -	Basis [b]	g/kW-hr	3.8
	Emission rate	lb/hr	2.64
		TPY	0.132
CO -	Basis [b]	g/kW-hr	0.9
	Emission rate	lb/hr	0.63
		TPY	0.031
VOC -	Basis [b]	g/kW-hr	0.1
	Emission rate	lb/hr	0.07
		TPY	0.003
$PM/PM_{10}/PM_{2.5}$ - Basis [b]		g/kW-hr	0.13
	Emission rate	lb/hr	0.09
		TPY	0.005

[a] Vendor not selected; based on actual data from FPL's PEEC using 422 hp John Deere engine.
[b] Emissions based on Certified Data that will meet 40 CFR Part 89 Tier III engines.

TABLE 2-8
EMISSIONS FROM THE HURRICANE SHELTER EMERGENCY GENERATOR
FORD 3.0 L V-6 OHV ENGINE

Pollutants	Emission Factor		Ref.	Activity Factor[a]					Potential Emissions (per engine)	
				Engine Power (kW)	Engine Power (bhp)	Fuel Consumption (gal/hr)	Maximum Heat Input (MMBtu/hr)	Operating Hours	(lb/hr)	(TPY)
Carbon Monoxide (CO)	28.23	g/hp-hr	b	3.7 liter propane engine	40.0	4.41	0.40	100	2.49	0.124
Nitrogen Oxides (NOx)	11.99	g/hp-hr	b	3.7 liter propane engine	40.0	4.41	0.40	100	1.06	0.053
Particulate Matter (PM)	0.05	g/hp-hr	b	3.7 liter propane engine	40.0	4.41	0.40	100	0.004	0.0002
Particulate Matter (PM_{10})	0.05	g/hp-hr	d	3.7 liter propane engine	40.0	4.41	0.40	100	0.004	0.0002
Particulate Matter ($PM_{2.5}$)	0.05	g/hp-hr	d	3.7 liter propane engine	40.0	4.41	0.40	100	0.004	0.0002
Sulfur Dioxide (SO_2)	0.20	$lb/10^3$ gal	c	3.7 liter propane engine	40.0	4.41	0.40	100	0.0009	0.00004
Volatile Organic Compounds (VOC)	24.64	g/hp-hr	b	3.7 liter propane engine	40.0	4.41	0.40	100	2.17	0.109
Greenhouse Gases (CO_2e)	139.1	lb/MMBtu	e				0.40	100	56.09	2.805

Note: Two generators will be installed for the hurricane shelter. Information for one generator provided.

[a] Engine power and fuel consumption based on manufacturer data. Heat input calculated based on propane fuel heat content of 2,520 Btu/scf.

[b] EPA 2010 Non-Road Engine Emission Factors for uncontrolled engines. Note: Engine likely has lower emissions that stated.

[c] AP-42 Table 1.5-1 and 2 gr/100 scf the same as natural gas.

[d] Assumed equal to PM emissions.

[e] 40 CFR Part 98, Tables C-1 and C-2 for propane.

TABLE 2-9

PHYSICAL, PERFORMANCE, AND EMISSIONS DATA FOR THE MECHANICAL DRAFT COOLING TOWER

Parameter	3 x 1
Physical Data	
Number of Cells	30
Deck Dimensions, ft	
Length	815
Width	102
Height	37.8
Stack Dimensions	
Height, ft	51.5
Stack Top Effective Inner Diameter, per cell, ft	30
Effective Diameter, all cells, ft	164.3
Performance Data	
Discharge Velocity, ft/min	1,337
Circulating Water Flow Rate (CWFR), gal/min	465,815
Design hot water temperature, °F	90.8
Design cold water temperature, °F	78.9
Heat Rejected, million Btu/hr	2,771
Design Air Flow Rate per cell, acfm	945,069
Liquid/ Gas (Air Flow) (L/G) Ratio	1.13
Hours of operation	8,760
Temperature of Exit Air, °F	86.0
Emission Data	
Drift Rate[a] (DR), percent	0.0005
Total Dissolved Solids (TDS) Concentration [b], maximum ppm	35,000
Solution Drift [c] (SD), lb/hr	1,165.5
PM Drift [d], lb/hr	40.8
tons/year	178.7
PM_{10} Drift[e]	
PM_{10} Emissions, lb/hr	1.79
tons/year	7.84
$PM_{2.5}$ Emissions, lb/hr	0.01
tons/year	0.05

[a] Drift rate is the percent of circulating water.

[b] A TDS of 35,000 results in maximum PM emissions.

[c] Includes water and based on circulating water flow rate and drift rate (CWFR x DR x 8.34 lb/gal x 60 min/hr).

[d] PM calculated based on total dissolved solids and solution drift (TDS x SD).

[e] PM_{10} based on Calculating Realistic PM_{10} Emissions from Cooling Towers, Joel Reisman and Gordon Frisbie.

Sources: FPL, 2015; Golder; 2015.

TABLE 2-10
SUMMARY OF POTENTIAL ANNUAL EMISSIONS FOR THE OCEC UNIT 1 PROJECT

	OCEC Project Potential Annual Emissions (TPY)									PSD
Pollutant	3 CTs/HRSGs Circuit Breakers [a]	1 Auxiliary Boiler [b]	1 Natural Gas Heater	3 Emergency Generators	1 Fire Pump Engine	2 Hurricane Shelter Generators	1 Cooling Tower	Fuel Oil Storage Tank	TOTAL	Significant Emission Rate (TPY)
SO_2	253	0.56	0.24	0.007	0.00021	8.81E-05	--	NA	254	40
PM	245	0.74	0.32	0.22	0.005	4.41E-04	178.67	NA	425	25
PM_{10}	245	0.74	0.32	0.22	0.005	4.41E-04	7.84	NA	254	15
$PM_{2.5}$	245	0.74	0.32	0.22	0.00	4.41E-04	0.011	NA	254	10
NO_x	382	4.99	4.25	6.98	0.13	0.11	--	NA	398	40
CO	524	7.98	3.57	3.82	0.031	0.249	--	NA	540	100
VOC (as methane)	68.6	0.54	0.23	0.22	0.003	0.217	--	1.55	71.4	40
Sulfuric Acid Mist	49.2	Neg.	Neg.	Neg.	Neg.	Neg.	--	NA	49.2	7
Lead	0.032	Neg.	Neg.	Neg.	Neg.	Neg.	--	NA	0.032	0.6
Greenhouse Gases (CO_2e)	5,443,568	11,671	5,072	724	22.5	5.6	--	NA	5,461,062	75,000

[a] Based on oil-firing for: 500 hours (maximum).; includes 14-500 kV breakers and 3-generator breakers with SF_6: 1,042.53 tons CO_2e/year

[b] An auxiliary boiler is only required to supply steam during startup.

Note: Neg.= negligible; NA= not applicable

Source: Golder, 2015.

TABLE 2-11
SUMMARY OF POTENTIAL ANNUAL HAP EMISSIONS FOR OCEC THE UNIT 1 PROJECT

	Potential Annual Emissions (TPY)						
Pollutant	3 CTs/HRSGs	1 Auxiliary Boiler [b]	2 Emergency Generators	1 Natural Gas Heater	1 Fire Pump Engine	TOTAL	HAP Major Source Threshold (TPY)
GE 7HA.02 CTs							
Total HAPs	23.1	0.0088	0.007	0.004	0.0002	23.1	25
Single HAP [a]	9.6	0.0073	0.0003	0.003	0.00001	9.6	10

[a] Based on formaldehyde emissions

[b] An auxiliary boiler is only required to supply steam during startup.

Note: Hurricane shelter generators and fuel oil tank have negligible HAP emissions; SF_6 emitted from the circuit breakers is not a HAP.

Source: Golder, 2015.

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

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

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

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

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

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

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

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

Sources: FR, Vol. 43, No. 118, June 19, 1978; 40 CFR 50; 40 CFR 52.21; Florida Chapter 62.204, F.A.C.
Golder, 2015.

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

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

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

NA = not applicable

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

mg/m^3 = micrograms per cubic meter

MWC = municipal waste combustor

MSW = municipal solid waste

NMOC = non-methane organic compounds

[a] Short-term concentration threshold for monitoring requirement applicability.

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

[c] Any emission rate of these pollutants.

Source: 40 CFR 52.21.

Rule 62-210.200 F.A.C. and Rule 62-212.400, F.A.C.

Table 3-3: Potential Emissions Due to the OCEC Project Compared to the PSD Significant Emission Rates

Pollutant	Pollutant Emissions: Emission Increase* (TPY)	Significant Emission Rate (TPY)	PSD Review
Sulfur Dioxide	254	40	Yes
Particulate Matter [PM (TSP)]	425	25	Yes
Particulate Matter (PM_{10})	254	15	Yes
Particulate Matter ($PM_{2.5}$)	254	15	Yes
Nitrogen Dioxide	398	40	Yes
Carbon Monoxide	540	100	Yes
Volatile Organic Compounds	71	40	Yes
Lead	0.03	0.6	No
Sulfuric Acid Mist	49	7	Yes
Total Fluorides	NEG	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	NEG	0.1	No
Greenhouse Gases	5,461,062	75,000	Yes

Note: NEG = Negligible.

* See Table 2-10.

TABLE 4-1
PROPOSED BACT EMISSION LIMITS AND COMPLIANCE METHODS FOR OCEC UNIT 1

Pollutant	Fuel	Operating Mode	Proposed BACT Emission Limits	Type of BACT Limit	Compliance Methods
NO_x	Natural Gas	Normal [a]	2 ppmvd at 15% O_2	Primary	Initial: EPA Methods- 7E or 20, Continuous: CEM 24-hour block average excluding startup shutdown and malfunction
	Natural Gas	All	15 ppmvd at 15% O_2	Secondary	Subpart KKKK; 30-day rolling, includes startup, shutdown and malfunctions
	ULSD	Normal [a]	8 ppmvd at 15% O_2	Primary	Initial: EPA Methods- 7E or 20, Continuous: CEM 24-hour block average excluding startup shutdown and malfunction
	ULSD	All	42 ppmvd at 15% O_2	Secondary	Subpart KKKK; 30-day rolling, includes startup, shutdown and malfunctions
CO	Natural Gas	Baseload	4.3 ppmvd at 15% O_2	Primary	Initial: EPA Method 10; 90 -100% of Baseload
	ULSD	Baseload	10 ppmvd at 15% O_2	Primary	Initial: EPA Method 10; 90 -100% of Baseload
	All	All	Work Practice	Secondary	Documentation of work practice standards.
VOC	Natural Gas	Baseload	1 ppmvd at 15% O_2	Primary	Initial Only: EPA Methods 18 or 25a
	ULSD	Baseload	2 ppmvd at 15% O_2	Primary	Initial Only: EPA Methods 18 or 25a
	All	All	Work Practice	Secondary	Documentation of work practice standards.
PM/PM_{10}	Natural Gas	Normal [a]	10% Opacity	Primary	Initial/Annual: EPA Method 9
	ULSD	Normal [a]	10% Opacity	Primary	Initial/Annual: EPA Method 9
	All	Other [a]	20% Opacity	Secondary	Ten, 6-minute averaging periods during a calendar day; work practice.
SO_2 and SAM	Natural Gas	All	2 grains S/100 scf	P & S [c]	Initial/Annual: 40 CFR Part 75 Fuel Sampling
	ULSD	All	0.0015% S	P & S [c]	Initial/Annual: 40 CFR Part 75 Fuel Sampling
GHG	Natural Gas	All	870 lb CO_{2e} /MW-hr	Primary	3-year monthly rolling combined fuel composite average; MW-hr based on gross generation; CO_{2e} based on 40 CFR Parts 75 and 98
	ULSD	All	1,210 lb CO_{2e} /MW-hr	Primary	3-year monthly rolling combined fuel composite average; MW-hr based on gross generation; CO_{2e} based on 40 CFR Parts 75 and 98
	All	All	1,000 lb CO_{2e} /MW-hr	Secondary	12-month rolling average, combined fuel composite average, based on gross generation; work practice.

Note: CT = combustion turbine; HRSG = heat recovery steam generator; ULSD = ultra low sulfur distillate oil; S = sulfur; CO_2e = CO_2 equivalent; MW = megawatt..

[a] Excluding periods of startup, shutdown, fuel switches and DLN tuning and malfunction.

[b] Work practices include using best operational practices to minimize the amount and duration of emissions during specified events, following manufacturer-recommeded procedures, and starting up on gas (absent the necessity to use ULSD oil)

[c] P = Primary; S = Secondary.

Table 4-2: Capital Cost for Selective Catalytic Reduction for General Electric 7HA.02 Combustion Turbine/HRSG

Cost Component	Costs		Basis of Cost Component
Direct Capital Costs			
SCR Associated Equipment	1,594,744		FPL CCEC Actual SCR Costs, 2015
Ammonia Storage Tank	included		
Flue Gas Ductwork	included		
Instrumentation and Auxiliary Systems	$145,527	9%	of SCR Cost; FPL CCEC SCR Costs, 2015
Emission Monitoring	$79,737	5%	of SCR Associated Equipment
Freight	$79,737	5%	of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	1,899,745		
Direct Installation Costs			
Foundation and supports	$151,980	8%	of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$265,964	14%	of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$75,990	4%	of TDCC and RCC;OAQPS Cost Control Manual
Piping (Ammonia Injection Grid)	$37,995	2%	of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$18,997	1%	of TDCC and RCC;OAQPS Cost Control Manual
Painting	$18,997	1%	of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation (General Facilities)	$94,987	5%	of TDCC and RCC;OAQPS Cost Control Manual
Project Contingencies	$189,974	10%	of TDCC and RCC;OAQPS Cost Control Manual
Total Direct Installation Costs (TDIC)	$854,885		
Total Capital Costs (TCC)	$2,754,630		Sum of TDCC and TDIC
Indirect Costs			
Engineering	included		
PSM/RMP Plan	$50,000		Engineering Estimate
Construction and Field Expense	$137,731	5%	of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$275,463	10%	of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$55,093	2%	of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$27,546	1%	of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$545,833		
Total Direct, Indirect and Capital Costs (TDICC)	$3,300,463		Sum of TCC and TInCC

Table 4-3: Annualized Cost for Selective Catalytic Reduction for General Electric 7HA.02 Combustion Turbine/HRSG

Cost Component	**Costs**	**Basis of Cost Component**
Direct Annual Costs		
Operating Personnel	$21,840	28 hours/week at $15/hr
Supervision	$3,276	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$288,916	$556 per ton for anhydrous NH_3, 8,760 hr/year
PSM/RMP Update	$25,000	Engineering Estimate
Inventory Cost	$1,746	Capital Recovery (9.44%) for 1/3 catalyst for SCR
Catalyst Replacement	$55,500	4 years catalyst life; CCEC costs
Contingency	$11,888	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$408,167	
Energy Costs		
Electrical (SCR)	$115,632	330kW/hr (SCR system) @ $0.04/kWh,
MW Loss and Heat Rate Penalty	$440,505	0.2% of MW output; and $3/mmBtu fuel costs
Total Energy Costs (TEC)	$556,137	
Indirect Annual Costs		
Overhead	$188,419	60% of Operating/Supervision Labor and Ammonia
Property Taxes (exempt)	$0	0% of Total Capital Costs
Insurance	$33,005	1% of Total Capital Costs
Administration	$66,009	2% of Total Capital Costs
Annualized Total Direct Capital	$369,639	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$657,072	
Total Annualized Costs	$1,621,376	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness (25 to 2 ppmvd gas and 42 to 8 oil)	$1,268	NO_x Reduction Only
	$1,424	Net Emission Reduction

Table 4-4: Potential Incremental Emission Changes (TPY) with Selective Catalytic Reduction

Pollutants		Incremental Emissions (tons/year) of SCR		
		Primary	Secondary	Total
Particulate		14.77	0.22	14.99
Sulfur Dioxide			0.16	0.16
Nitrogen Oxides		-1,278.24	11.10	-1,267.14
Carbon Monoxide			0.33	0.33
Volatile Organic Compounds			0.06	0.06
Ammonia		112.87		112.87
	Total:	-1,150.60	11.86	-1,138.74
Carbon Dioxide (additonal from gas firing)			5,424.59	5,424.59

Table 4-5: Capital Costs for Oxidation Catalyst for General Electric 7HA.02 Combustion Turbine/HRSG

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$823,926	Esitmated based on actual catalyst costs.
Instrumentation and Auxiliary Systems	$82,393	10% of Oxidation Catalyst Associated Equipment
Freight	$41,196	5% of Oxidation Catalyst Associated Equipment
Total Direct Capital Costs (TDCC)	$947,515	
Direct Installation Costs		
Foundation and supports	$75,801	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$132,652	14% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$9,475	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$9,475	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$47,376	5% Engineering Estimate
Total Direct Installation Costs (TDIC)	$274,779	
Total Capital Costs	$1,222,295	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$122,229	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$61,115	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$122,229	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$24,446	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$12,223	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$342,243	
Contingencies	$183,344	15% of Total Capital Costs
Total Direct, Indirect and Capital Costs (TDICC)	$1,747,882	Sum of TCC and TInCC

Table 4-6: Annualized Cost for Oxidation Catalyst for General Electric 7HA.02 Combsution Turbine/HRSG

Cost Component	Cost		Basis of Cost Estimate
Direct Annual Costs			
Operating Personnel	$16,425		1/2 hr/shift, $30/hr, 8760 yr
Supervision	$2,464		15% of Operating Personnel;OAQPS Cost Control Manual
Maintenance (labor and materials)	$26,218		1.5% of TDICC, OAQPS Seciton 4
Catalyst Replacement	$60,321	7	year catalyst life, 50% catalyst replaced
Inventory Cost	$37,200		Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,131	5%	of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$149,759		
Energy Costs			
Heat Rate Penalty	$440,505		0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$440,505		
Indirect Annual Costs			
Overhead	$27,064	60%	of Operating/Supervision Labor
Property Taxes (exempt)	$0	0%	of Total Capital Costs
Insurance	$17,479	1%	of Total Capital Costs
Administration	$34,958	2%	of Total Capital Costs
Annualized Total Direct Capital	$191,917	10.98%	Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$271,418		
Total Annualized Costs	$861,683		Sum of TDAC, TEC and TIAC
	105.02		Net CO Emission Reduciton
Cost Effectiveness	$8,205		per ton of CO Removed
	$9,049		Net Emission Reduction

Table 4-7: Potential Incremental Emission Changes (TPY) with Oxidation Catalyst
`

Pollutants		Incremental Emissions (TPY) of SCR Primary	Incremental Emissions (TPY) of SCR Secondary	Total
Particulate		2.12	0.24	2.36
Sulfur Dioxide			0.09	0.09
Nitrogen Oxides			4.48	4.48
Carbon Monoxide		-105.02	2.69	-102.33
Volatile Organic Compounds			0.18	0.18
	Total:	-102.90	7.68	-95.22
Carbon Dioxide (additonal from gas firing)			4,256.25	4,256.25

Basis:

Lost Energy (mmBtu/year)	67,204

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NO_x controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Footnote: Based on Siemens CT which has more reduction in total pollutants than GE CT after the installation of Hot SCR equipment.

Table 5-1: Summary of Maximum Measured O_3 Concentrations at Monitoring Locations Closest to OCEC Unit 1, 2012-2014

		Measurement Period		Concentration (µg/m^3) 1-Hour		
Site No.	**Location**	**Year**	**Months**	**Highest**	**2nd Highest**	**4th Highest[a]**
Ozone AAQS				**NA**	**NA**	**157**
012-069-0002	Sebastian Inlet State Recreation Area	2014	Jan-Dec	159.0	147.2	141.3
	Vero Beah, FL	2013	Jan-Dec	157.0	149.2	131.5
	(82 miles away)	2012	Jan-Dec	155.1	145.3	139.4
		3-Yr Average				137.4
012-061-9991	1901 Johns Lake Rd Clermont, FL (26 miles away, data for one year)	2014	Jan-Dec	145.3	145.3	137.4

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

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

Source: FDEP Quicklook Reports, 2012-2014.

Table 5-2: Summary of Maximum Measured PM_{10} Concentrations at Monitoring Locations Closest to OCEC Unit 1, 2012 - 2014

		Measurement Period		Concentration (µg/m³) 24-Hour	
Site No.	**Location**	**Year**	**Months**	**Highest [a]**	**2nd Highest**
PM_{10} AAQS				**NA**	**150**
012-009-0007	401 Florida Ave	2014	Jan-Dec	59.0	44.0
	Melbourne, FL	2013	Jan-Dec	76.0	54.0
	(30 miles away)	2012	Jan-Dec	65.0	55.0
		highest			**55.0**

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

[a] The 24-hour PM_{10} standard is met when the number of days per calendar year with a 24-hour concentration above 150µg/m³ is equal to or less than one.

Source: FDEP Quicklook Reports, 2012-2014.

Table 5-3: Summary of Maximum Measured $PM_{2.5}$ Concentrations at Monitoring Locations Closest to OCEC Unit 1, 2012 - 2014

				Concentration (µg/m³)			
		Measurement Period		24-Hour			Annual [b]
Site No.	**Location**	**Year**	**Months**	**Highest**	**2nd Highest**	**98th Percentile [a]**	**Mean**
$PM_{2.5}$ AAQS				**NA**	**NA**	**35**	**12**
012-009-0007	401 Florida Ave	2014	Jan-Dec	14.7	13.8	12.9	8.0
	Melbourne, FL	2013	Jan-Dec	25.8	22.8	20.6	5.8
	(30 miles away)	2012	Jan-Dec	17.0	16.2	13.6	6.0
		3-Yr Average				**15.7**	**6.6**

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, 2012-2014.

Table 5-4: Summary of Maximum Measured NO_2 Concentrations at Monitoring Locations Closest to OCEC Unit 1, 2012 - 2014

		Measurement Period		Concentration (μg/m³)			
				1-Hour			Annual
Site No.	Location	Year	Months	Highest	2nd Highest	98th Percentile [a]	Average
Nitrogen Dioxide AAQS				**NA**	**NA**	**188.1**	**100**
012-095-2002	Morris Blvd	2014	Jan-Dec	79.0	79.0	67.7	9.3
	Winter Park, FL	2013	Jan-Dec	79.0	75.2	64.0	8.5
	(75 miles away)	2012	Jan-Dec	82.8	79.0	65.8	10.1
		3-Yr Average				65.8	9.3
012-099-0020							
	1199 Lantana Rd	2014	Jan-Dec	75.2	73.4	67.7	8.3
	Lantana, FL	2013	Jan-Dec	88.4	84.6	71.5	6.9
	(85 miles away)	2012	Jan-Dec	90.3	90.3	79.0	7.9
		3-Yr Average				72.7	7.7

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

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

Source: FDEP Quicklook Reports, 2012-2014.

TABLE 6-1
SUMMARY OF THE NOx FACILITIES CONSIDERED FOR INCLUSION IN THE 1-HOUR NAAQS AIR MODELING ANALYSiS

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to FPL [a] X (km)	Relative to FPL [a] Y (km)	Relative to FPL [a] Distance (km)	Relative to FPL [a] Direction (deg)	Maximum NOx Emissions (TPY)	Q, (TPY) Emission Threshold [b,c] (Dist - SID) x 20	Include in Modeling Analysis ?
Modeling Area [d]											
	No Facilities are located within the modeling area										
Screening Area [d]											
0930108	TWIN OAKS PET CEMETARY & CREMATORIUM INC-OKEECHOBEE FACILITY	Okeechobee	517.5	3043.9	-3.1	-12.8	13.2	194	0.0	92.6	NO
0610099	LANE CONSTRUCTION CORP-INDIAN RIVER ASPHALT PLANT	Indian River	544.0	3071.6	23.4	14.9	27.8	58	4.1	383.4	NO
0610096	INEOS NEW PLANET BIOENERGY-INPB IRC FACILITY	Indian River	550.7	3051.3	30.1	-5.4	30.6	100	181.6	439.6	NO
0610015	INDIAN RIVER COUNTY, SWDD-INDIAN RIVER CO LANDFILL	Indian River	551.2	3050.7	30.6	-6.0	31.2	101	2.4	452.7	NO
1110107	TREASURE COAST LAND CLEARING-TREASURE COAST LAND CLEARING	St. Lucie	545.6	3035.4	25.0	-21.3	32.8	130	6.0	484.3	NO
0930104	OKEECHOBEE LANDFILL, INC.-OKEECHOBEE LANDFILL	Okeechobee	530.9	3024.3	10.3	-32.4	34.0	162	34.5	508.1	NO

Note: NA = Not applicable, ND = No data, SID = Significant impact distance for the project

[a] FPL OCEC Unit 1 East and North Coordinates (km) are: 520.6 3056.70 km

[b] The significant impact distance for the project is estimated to be: 8.6 km

[c] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is beyond the modeling area and its emission rate is greater than the product of (Distance-SID) x 20.

[d] "Modeling Area" is the area in which the project is predicted to have a significant impact (8.6 km). EPA recommends that all sources within this area be modeled.
"Screening Area" is the significant impact distance for the 35 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area.

TABLE 6-2
SUMMARY OF THE PM_{10} FACILITIES CONSIDERED FOR INCLUSION IN THE NAAQS AND PSD CLASS II AIR MODELING ANALYSES

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to FPL [a] X (km)	Relative to FPL [a] Y (km)	Relative to FPL [a] Distance (km)	Relative to FPL [a] Direction (deg)	Maximum PM_{10} Emissions (TPY)	Q, (TPY) Emission Threshold [b,c] (Dist - SID) x 20	Include in Modeling Analysis ?
Modeling Area [d]											
	No Facilities are located within the modeling area										
Screening Area [d]											
0610099	LANE CONSTRUCTION CORP-INDIAN RIVER ASPHALT PLANT	Indian River	544.0	3071.6	23.4	14.9	27.77	58	1.7	461.4	NO
0610096	INEOS NEW PLANET BIOENERGY-INPB IRC FACILITY	Indian River	550.7	3051.3	30.1	-5.4	30.58	100	11.6	517.6	NO
0930104	OKEECHOBEE LANDFILL, INC.-OKEECHOBEE LANDFILL	Okeechobee	530.9	3024.3	10.3	-32.4	34.00	162	7.0	586.1	NO
7775057	CRUSHER CONTRACTORS CO.-CRUSHER CONTRACTORS, CO.	Indian River	557.7	3062.6	37.1	5.9	37.58	81	3.8	657.7	NO
0610002	S & B INDUSTRIAL MINERALS NORTH AMERICA-VERO BEACH FACILITY	Indian River	557.0	3065.1	36.4	8.4	37.36	77	24.2	653.3	NO
0610029	CITY OF VERO BEACH-CITY OF VERO BEACH MUNICIPAL UTILITIES	Indian River	561.4	3056.7	40.8	0.0	40.82	90	557.1	722.4	NO
1110060	FLORIDA GAS TRANSMISSION COMPANY-FGTC COMPRESSOR STATION 20	St. Lucie	557.8	3035.9	37.2	-20.8	42.61	119	8.0	758.3	NO
0930001	OKEECHOBEE ASPHALT & READY-MIX CONCRETE,-OKEECHOBEE ASPHALT/ASPHALT PLANT	Okeechobee	516.2	3014.4	-4.4	-42.3	42.55	186	4.8	757.0	NO
0090106	FLORIDA GAS TRANSMISSION COMPANY-COMPRESSOR STATION NO. 19	Brevard	529.0	3102.9	8.4	46.2	46.95	10	11.7	845.0	NO
0090047	HARRIS CORPORATION-HARRIS GOVT COMMUNICATIONS SYSTEMS DIV	Brevard	538.9	3100.6	18.3	43.9	47.59	23	1.8	857.8	NO
1110004	TROPICANA MANFACTURING COMPANY, INC-FORT PIERCE CITRUS PROCESSING FACILITY	St. Lucie	559.6	3028.3	39.0	-28.4	48.24	126	129.1	870.8	NO
1110051	CEMEX CONSTRUCTION MATERIALS FLORIDA LLC-CEMEX-WEST FT PIERCE READY MIX & BLOCK	St. Lucie	560.0	3028.1	39.4	-28.6	48.74	126	5.5	880.8	NO
1110001	CENTRAL CONCRETE SUPERMIX-SUPERMIX-FT PIERCE	St. Lucie	562.1	3030.2	41.5	-26.5	49.25	123	2.2	891.0	NO
1110121	FLORIDA MUNICIPAL POWER AGENCY-TREASURE COAST ENERGY CENTER	St. Lucie	561.5	3029.2	40.9	-27.5	49.31	124	340.7	892.1	NO
1110040	RANGER CONSTRUCTION INDUSTRIES, INC.-RANGER / FT. PIERCE	St. Lucie	561.7	3030.2	41.1	-26.5	48.89	123	5.8	883.9	NO
1110002	TARMAC AMERICA LLC-FT PIERCE RMC & BLOCK PLANT	St. Lucie	561.9	3029.8	41.3	-26.9	49.33	123	31.0	892.5	NO
0550046	HIGHLANDS COUNTY DEPT.OF SOLID WASTE-HIGHLANDS COUNTY DEPT.OF SOLID WASTE	Highlands	469.3	3042.9	-51.3	-13.8	53.11	255	7.9	968.2	NO
0090112	R. A. CONNOR PAVING, INC.-R. A. CONNOR PAVING, INC.	Brevard	528.2	3110.6	7.5	53.9	54.39	8	9.7	993.7	NO
0970079	OMNI WASTE OF OSCEOLA COUNTY, LLC-JED SOLID WASTE MANAGEMENT FACILTY	Osceola	491.0	3103.0	-29.6	46.3	54.93	327	6.6	1004.5	NO
0550032	TURF CARE SUPPLY CORP.-TCSC SEBRING PLANT	Highlands	469.5	3038.4	-51.1	-18.3	54.28	250	30.5	991.6	NO

Note: NA = Not applicable, ND = No data, SID = Significant impact distance for the project

[a] FPL OCEC Unit 1 East and North Coordinates (km) are: 520.6 3056.70 km

[b] The significant impact distance for the project is estimated to be: 4.7 km

[c] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is beyond the modeling area and its emission rate is greater than the product of (Distance-SID) x 20.

[d] "Modeling Area" is the area in which the project is predicted to have a significant impact (4.7 km). EPA recommends that all sources within this area be modeled.
"Screening Area" is the significant impact distance for the FPL Facility of 4.7 km, plus 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area.

TABLE 6-3
SUMMARY OF THE $PM_{2.5}$ FACILITIES CONSIDERED FOR INCLUSION IN THE NAAQS AND PSD CLASS II AIR MODELING ANALYSES

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to FPL [a] X (km)	Relative to FPL [a] Y (km)	Relative to FPL [a] Distance (km)	Relative to FPL [a] Direction (deg)	Maximum $PM_{2.5}$ Emissions (TPY)	Q, (TPY) Emission Threshold [b,c] (Dist - SID) x 20	Include in Modeling Analysis ?
Modeling Area [d]											
	No Facilities are located within the modeling area										
Screening Area [d]											
0610099	LANE CONSTRUCTION CORP-INDIAN RIVER ASPHALT PLANT	Indian River	544.0	3071.6	23.4	14.9	27.77	58	1.7	261.4	NO
0610096	INEOS NEW PLANET BIOENERGY-INPB IRC FACILITY	Indian River	550.7	3051.3	30.1	-5.4	30.58	100	11.6	317.6	NO
0930104	OKEECHOBEE LANDFILL, INC.-OKEECHOBEE LANDFILL	Okeechobee	530.9	3024.3	10.3	-32.4	34.00	162	7.0	386.1	NO
7775057	CRUSHER CONTRACTORS CO.-CRUSHER CONTRACTORS, CO.	Indian River	557.7	3062.6	37.1	5.9	37.58	81	3.8	457.7	NO
0610002	S & B INDUSTRIAL MINERALS NORTH AMERICA-VERO BEACH FACILITY	Indian River	557.0	3065.1	36.4	8.4	37.36	77	24.2	453.3	NO
0930001	OKEECHOBEE ASPHALT & READY-MIX CONCRETE,-OKEECHOBEE ASPHALT/ASPHALT PLANT	Okeechobee	516.2	3014.4	-4.4	-42.3	42.55	186	4.8	557.0	NO
0090106	FLORIDA GAS TRANSMISSION COMPANY-COMPRESSOR STATION NO. 19	Brevard	529.0	3102.9	8.4	46.2	46.96	10	11.7	645.2	NO
0090047	HARRIS CORPORATION-HARRIS GOVT COMMUNICATIONS SYSTEMS DIV	Brevard	538.9	3100.6	18.3	43.9	47.59	23	1.8	657.8	NO
1110004	TROPICANA MANFACTURING COMPANY, INC-FORT PIERCE CITRUS PROCESSING FACILITY	St. Lucie	559.6	3028.3	39.0	-28.4	48.24	126	14.2	670.8	NO
1110051	CEMEX CONSTRUCTION MATERIALS FLORIDA LLC-CEMEX-WEST FT PIERCE READY MIX & BLOCK	St. Lucie	560.0	3028.1	39.4	-28.6	48.74	126	5.5	680.8	NO
1110001	CENTRAL CONCRETE SUPERMIX-SUPERMIX-FT PIERCE	St. Lucie	562.1	3030.2	41.5	-26.5	49.25	123	2.2	691.0	NO
1110121	FLORIDA MUNICIPAL POWER AGENCY-TREASURE COAST ENERGY CENTER	St. Lucie	561.5	3029.2	40.9	-27.5	49.31	124	42.0	692.2	NO
1110040	RANGER CONSTRUCTION INDUSTRIES, INC.-RANGER / FT. PIERCE	St. Lucie	561.7	3030.2	41.1	-26.5	48.89	123	5.8	683.9	NO
1110002	TARMAC AMERICA LLC-FT PIERCE RMC & BLOCK PLANT	St. Lucie	561.9	3029.8	41.3	-26.9	49.33	123	31.0	692.5	NO
0550046	HIGHLANDS COUNTY DEPT.OF SOLID WASTE-HIGHLANDS COUNTY DEPT.OF SOLID WASTE	Highlands	469.3	3042.9	-51.3	-13.8	53.11	255	7.9	768.2	NO
0090112	R. A. CONNOR PAVING, INC.-R. A. CONNOR PAVING, INC.	Brevard	528.2	3110.6	7.5	53.9	54.39	8	9.7	793.7	NO
0970079	OMNI WASTE OF OSCEOLA COUNTY, LLC-JED SOLID WASTE MANAGEMENT FACILTY	Osceola	491.0	3103.0	-29.6	46.3	54.93	327	6.6	804.5	NO
0550032	TURF CARE SUPPLY CORP.-TCSC SEBRING PLANT	Highlands	469.5	3038.4	-51.1	-18.3	54.28	250	30.5	791.6	NO
0550049	E-STONE USA CORPORATION-E-STONE USA CORPORATION	Highlands	465.2	3037.2	-55.4	-19.5	58.78	251	1.5	881.6	NO

Note: NA = Not applicable, ND = No data, SID = Significant impact distance for the project

[a] FPL OCEC Unit 1 East and North Coordinates (km) are: 520.6 3056.70 km

[b] The significant impact distance for the project is estimated to be: 14.7 km

[c] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is beyond the modeling area and its emission rate is greater than the product of (Distance-SID) x 20.

[d] "Modeling Area" is the area in which the project is predicted to have a significant impact (14.7 km). EPA recommends that all sources within this area be modeled.
"Screening Area" is the significant impact distance for the FPL Facility of 14.7 km, plus 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area.

Table 6-4: Predicted Concentrations for Emissions of One CT Firing Natural Gas in Combined-Cycle Operation, OCEC Unit 1

Natural Gas

	Emission Rates for CT (lb/hr) by Operating Load and Air Temperature									Averaging	Predicted Concentrations ($\mu g/m^3$) for CT by Operating Load and Air Temperature [a]								
	Base Load			75% Load			50% Load				Base Load			75% Load			50% Load		
	35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°	Time	35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°
Generic [b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.25	0.24	0.24	0.29	0.29	0.28	0.33	0.33	0.33
(10 g/s = 3.333 g/s/CT)										Annual [d]	0.23	0.23	0.22	0.27	0.27	0.26	0.30	0.30	0.30
										24-Hour [c]	2.90	2.83	2.80	4.25	4.14	3.98	5.50	5.50	5.32
										24-Hour [d]	1.83	1.80	0.29	2.42	2.37	2.30	3.04	3.04	2.95
										8-Hour [c]	5.01	4.89	4.85	6.06	5.99	5.89	7.00	7.01	6.91
										3-Hour [c]	6.20	6.10	6.08	8.11	7.95	7.72	9.75	9.75	9.55
										1-Hour [c]	8.09	7.82	7.71	10.28	10.10	9.84	11.34	11.32	11.12
										1-Hour [e]	6.06	5.82	5.76	7.93	7.78	7.57	9.56	9.54	9.31
Emissions for 1 CT																			
SO_2	18.85	19.27	19.31	14.85	13.98	13.41	11.32	10.65	10.26	Annual [c]	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04
										24-Hour [c]	0.69	0.69	0.68	0.79	0.73	0.67	0.79	0.74	0.69
										3-Hour [c]	1.47	1.48	1.48	1.52	1.40	1.30	1.39	1.31	1.23
										1-Hour [e]	1.44	1.41	1.40	1.48	1.37	1.28	1.36	1.28	1.20
PM_{10}	15.44	15.55	15.56	14.39	14.16	14.01	13.47	13.29	13.19	Annual [c]	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.05
										24-Hour [c]	0.56	0.55	0.55	0.77	0.74	0.70	0.934	0.920	0.885
$PM_{2.5}$	15.44	15.55	15.56	14.39	14.16	14.01	13.47	13.29	13.19	Annual [d]	0.05	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
										24-Hour [d]	0.36	0.35	0.06	0.44	0.42	0.41	0.52	0.51	0.49
NO_x	24.39	24.95	25.02	19.22	18.10	17.35	14.65	13.78	13.26	Annual [c]	0.08	0.08	0.08	0.07	0.07	0.06	0.06	0.06	0.05
										1-Hour [e]	1.86	1.83	1.82	1.92	1.77	1.65	1.76	1.66	1.55
CO	36.05	37.85	38.20	41.54	39.11	37.50	31.66	29.77	28.66	8-Hour [c]	2.28	2.33	2.33	3.17	2.95	2.78	2.79	2.63	2.50
										1-Hour [c]	3.68	3.73	3.71	5.38	4.98	4.65	4.52	4.25	4.02

[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 St. Lucie County 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 3 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (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 6-4A: Predicted Concentrations for Emissions of One CT Firing Natural Gas in Combined-Cycle Operation, OCEC Unit 1 - Alternate Power Block Arrangement

Natural Gas

	Emission Rates for CT (lb/hr) by Operating Load and Air Temperature									Averaging	Predicted Concentrations (μg/m³) for CT by Operating Load and Air Temperature [a]								
	Base Load			75% Load			50% Load				Base Load			75% Load			50% Load		
	35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°	Time	35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°
Generic [b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.25	0.25	0.24	0.30	0.29	0.29	0.34	0.34	0.33
(10 g/s = 3.333 g/s/CT)										Annual [d]	0.24	0.23	0.23	0.27	0.27	0.27	0.31	0.31	0.30
										24-Hour [c]	2.93	2.81	2.79	4.30	4.18	4.03	5.58	5.57	5.39
										24-Hour [d]	1.86	1.82	0.30	2.45	2.40	2.33	3.08	3.08	3.00
										8-Hour [c]	5.19	5.07	5.03	6.26	6.19	6.09	7.26	7.27	7.16
										3-Hour [c]	6.15	6.06	6.03	8.15	7.98	7.75	9.83	9.82	9.62
										1-Hour [c]	8.12	7.84	7.73	10.61	10.43	10.17	11.63	11.62	11.42
										1-Hour [e]	6.11	5.88	5.82	8.02	7.86	7.64	9.64	9.62	9.38
Emissions for 1 CT																			
SO_2	18.85	19.27	19.31	14.85	13.98	13.41	11.32	10.65	10.26	Annual [c]	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.04
										24-Hour [c]	0.70	0.68	0.68	0.80	0.74	0.68	0.80	0.75	0.70
										3-Hour [c]	1.46	1.47	1.47	1.53	1.41	1.31	1.40	1.32	1.24
										1-Hour [e]	1.45	1.43	1.42	1.50	1.38	1.29	1.38	1.29	1.21
PM_{10}	15.44	15.55	15.56	14.39	14.16	14.01	13.47	13.29	13.19	Annual [c]	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
										24-Hour [c]	0.57	0.55	0.55	0.78	0.75	0.71	0.946	0.932	0.896
$PM_{2.5}$	15.44	15.55	15.56	14.39	14.16	14.01	13.47	13.29	13.19	Annual [d]	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.05	0.05
										24-Hour [d]	0.36	0.36	0.06	0.45	0.43	0.41	0.52	0.52	0.50
NO_x	24.39	24.95	25.02	19.22	18.10	17.35	14.65	13.78	13.26	Annual [c]	0.08	0.08	0.08	0.07	0.07	0.06	0.06	0.06	0.06
										1-Hour [e]	1.88	1.85	1.83	1.94	1.79	1.67	1.78	1.67	1.57
CO	36.05	37.85	38.20	41.54	39.11	37.50	31.66	29.77	28.66	8-Hour [c]	2.36	2.42	2.42	3.27	3.05	2.88	2.89	2.73	2.59
										1-Hour [c]	3.69	3.74	3.72	5.55	5.14	4.80	4.64	4.36	4.12

[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 St. Lucie County 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 3 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (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 6-5: Predicted Concentrations for Emissions of One CT Firing ULSD Oil in Combined-Cycle Operation, OCEC Unit 1

Ultra Low-Sulfur Fuel Oil

	Emission Rates for CT (lb/hr) by Operating Load and Air Temperature										Predicted Concentrations (µg/m³) for CT by Operating Load and Air Temperature[a]								
	Base Load			75% Load			50% Load			Averaging	Base Load			75% Load			50% Load		
	35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°	Time	35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.21	0.21	0.20	0.26	0.26	0.27	0.33	0.33	0.34
(10 g/s = 3.333 g/s/CT)										Annual [d]	0.20	0.20	0.19	0.24	0.24	0.25	0.30	0.30	0.31
										24-Hour [c]	2.34	2.38	2.30	3.31	3.36	3.62	5.35	5.48	5.67
										24-Hour [d]	1.57	1.59	1.55	2.00	2.02	2.13	2.96	3.03	3.13
										8-Hour [c]	4.17	4.21	4.11	5.32	5.37	5.62	6.92	7.02	7.18
										3-Hour [c]	5.38	5.43	5.31	6.59	6.68	7.14	9.57	9.74	9.98
										1-Hour [c]	6.92	6.99	6.87	8.53	8.62	9.16	11.14	11.29	11.59
										1-Hour [e]	4.83	4.88	4.78	6.64	6.70	7.07	9.34	9.50	9.75
Emissions for 1 CT																			
SO_2	5.01	4.77	4.73	3.95	3.79	3.53	3.08	2.93	2.74	Annual [c]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
										24-Hour [c]	0.15	0.14	0.14	0.16	0.16	0.16	0.21	0.20	0.20
										3-Hour [c]	0.34	0.33	0.32	0.33	0.32	0.32	0.37	0.36	0.34
										1-Hour [e]	0.30	0.29	0.28	0.33	0.32	0.31	0.36	0.35	0.34
PM_{10}	70.0	70.0	69.9	69.3	69.3	69.2	69.1	69.1	69.0	Annual [c]	0.18	0.18	0.18	0.23	0.23	0.23	0.28	0.29	0.29
										24-Hour [c]	2.07	2.10	2.03	2.89	2.93	3.16	4.65	4.76	4.93
$PM_{2.5}$	70.0	70.0	69.9	69.3	69.3	69.2	69.1	69.1	69.0	Annual [d]	0.17	0.17	0.17	0.21	0.21	0.22	0.26	0.26	0.27
										24-Hour [d]	1.39	1.40	1.37	1.75	1.76	1.86	2.58	2.64	2.72
NO_x	101.5	96.8	95.8	79.9	76.8	71.4	62.5	59.3	55.5	Annual [c]	0.27	0.25	0.25	0.26	0.25	0.24	0.26	0.25	0.24
										1-Hour [e]	6.18	5.94	5.77	6.69	6.49	6.36	7.35	7.11	6.82
CO	77.2	73.6	72.9	82.7	79.5	73.9	64.6	61.4	57.5	8-Hour [c]	4.06	3.91	3.78	5.55	5.38	5.24	5.63	5.43	5.20
										1-Hour [c]	6.73	6.49	6.31	8.89	8.63	8.54	9.08	8.74	8.39

[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 St. Lucie County 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 3 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (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 6-5A: Predicted Concentrations for Emissions of One CT Firing ULSD Oil in Combined-Cycle Operation, OCEC Unit 1 - Alternate Power Block Arrangement

<u>Ultra Low-Sulfur Fuel Oil</u>

	Emission Rates for CT (lb/hr) by Operating Load and Air Temperature											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	75°F	95°	35°F	75°F	95°	35°F	75°F	95°	Time		35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	c	0.21	0.21	0.21	0.26	0.26	0.27	0.33	0.34	0.34
(10 g/s - 3.333 g/s/CT)										Annual	d	0.20	0.20	0.19	0.25	0.25	0.25	0.30	0.31	0.31
										24-Hour	c	2.33	2.37	2.29	3.35	3.40	3.67	5.41	5.55	5.75
										24-Hour	d	1.60	1.61	1.58	2.03	2.05	2.16	3.01	3.08	3.18
										8-Hour	c	4.32	4.36	4.24	5.52	5.57	5.83	7.16	7.27	7.44
										3-Hour	c	5.34	5.40	5.27	6.61	6.71	7.15	9.64	9.81	10.06
										1-Hour	c	6.89	6.96	6.84	8.78	8.89	9.49	11.44	11.58	11.88
										1-Hour	e	5.04	5.09	4.98	6.70	6.77	7.13	9.41	9.58	9.84
<u>Emissions for 1 CT</u>																				
SO_2	5.01	4.77	4.73	3.95	3.79	3.53	3.08	2.93	2.74	Annual	c	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
										24-Hour	c	0.15	0.14	0.14	0.17	0.16	0.16	0.21	0.20	0.20
										3-Hour	c	0.34	0.32	0.31	0.33	0.32	0.32	0.37	0.36	0.35
										1-Hour	e	0.32	0.31	0.30	0.33	0.32	0.32	0.37	0.35	0.34
PM_{10}	70.0	70.0	69.9	69.3	69.3	69.2	69.1	69.1	69.0	Annual	c	0.19	0.19	0.18	0.23	0.23	0.24	0.29	0.29	0.30
										24-Hour	c	2.05	2.08	2.02	2.92	2.96	3.20	4.71	4.83	5.00
$PM_{2.5}$	70.0	70.0	69.9	69.3	69.3	69.2	69.1	69.1	69.0	Annual	d	0.18	0.18	0.17	0.21	0.22	0.22	0.27	0.27	0.27
										24-Hour	d	1.41	1.42	1.39	1.77	1.79	1.89	2.62	2.68	2.76
NO_x	101.5	96.8	95.8	79.9	76.8	71.4	62.5	59.3	55.5	Annual	c	0.27	0.26	0.25	0.26	0.26	0.25	0.26	0.25	0.24
										1-Hour	e	6.44	6.20	6.02	6.75	6.55	6.42	7.41	7.17	6.88
CO	77.2	73.6	72.9	82.7	79.5	73.9	64.6	61.4	57.5	8-Hour	c	4.20	4.05	3.90	5.75	5.58	5.43	5.84	5.63	5.38
										1-Hour	c	6.70	6.46	6.29	9.15	8.91	8.84	9.32	8.96	8.60

[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 St. Lucie County 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 3 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (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 6-6: Summary of Predicted Concentrations for Natural Gas and ULSD Oil Firing, 3-CTs OCEC Unit 1

Pollutant	Averaging Time	Concentrations ($\mu g/m^3$) Natural Gas for Full Year	ULSD Oil for Full Year	8,260 Hrs Natural Gas and 500 Hrs ULSD Oil	Maximum Impact for SIL	EPA Class II Significant Impact Levels ($\mu g/m^3$)
CT/HRSGs Only						
SO_2	Annual	0.18	0.04	0.17	0.18	1
	24-Hour	2.4	0.6	-	2.4	5
	3-Hour	4.6	1.1	-	4.6	25
	1-Hour	4.4	1.1	-	4.4	7.86
PM_{10}	Annual	0.17	0.88	0.21	0.21	1
	24-Hour	2.8	14.8	-	14.8	5
$PM_{2.5}$	Annual	0.15	0.80	0.19	0.19	0.3
	24-Hour	1.5	8.2	-	8.17	1.2
Tier 1						
NO_2	Annual	0.23	0.80	0.26	0.26	1
	1-Hour	5.76	22.1	-	22.1	7.52
Tier 2[a]						
NO_2	Annual	0.17	0.60	0.20	0.20	1
	1-Hour	4.61	17.6	-	17.6	7.52
CO	8-Hour	9.5	16.9	-	16.9	500
	1-Hour	16.1	27.2	-	27.2	2,000
CT/HRSGs With Cooling Tower						
PM_{10}	Annual	-	-	0.29	0.29	1
	24-Hour	-	15.1		15.1	5

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

Table 6-6A: Summary of Predicted Concentrations for Natural Gas and ULSD Oil Firing, OCEC Unit 1 Alternate Power Block Arrangement

Pollutant	Averaging Time	Concentrations ($\mu g/m^3$) Natural Gas for Full Year	ULSD Oil for Full Year	8,260 Hrs Natural Gas and 500 Hrs ULSD Oil	Maximum Impact for SIL	EPA Class II Significant Impact Levels ($\mu g/m^3$)
<u>CT/HRSGs Only</u>						
SO_2	Annual	0.18	0.04	0.17	0.18	1
	24-Hour	2.4	0.6	-	2.4	5
	3-Hour	4.6	1.1	-	4.6	25
	1-Hour	4.5	1.1	-	4.5	7.86
PM_{10}	Annual	0.17	0.89	0.21	0.21	1
	24-Hour	2.8	15.0	-	15.0	5
$PM_{2.5}$	Annual	0.16	0.82	0.20	0.20	0.3
	24-Hour	1.6	8.3	-	8.29	1.2
<u>Tier 1</u>						
NO_2	Annual	0.23	0.81	0.26	0.26	1
	1-Hour	5.83	22.2	-	22.2	7.52
<u>Tier 2</u>[a]						
NO_2	Annual	0.17	0.61	0.20	0.20	1
	1-Hour	4.66	17.8	-	17.8	7.52
CO	8-Hour	9.8	17.5	-	17.5	500
	1-Hour	16.7	28.0	-	28.0	2,000
<u>CT/HRSGs With Cooling Tower</u>						
PM_{10}	Annual	-	-	0.29	0.29	1
	24-Hour	-	15.3		15.3	5

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

Table 6-7: Predicted 1-hour NO_2 and 24-hour PM_{10} and $PM_{2.5}$ Impacts Compared to the NAAQS
OCEC Unit 1

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 [a]						
1-Hour, 98th Percentile	84.7	12.0	72.7	519,851	3,057,698	188
PM_{10} (Oil)						
24-Hour, H6H	61.6	6.6	55.0	519,056	3,057,146	150
$PM_{2.5}$ (Oil)						
24-Hour, 98th Percentile	20.2	4.5	15.7	578,990	2,883,570	35
$PM_{2.5}$ (Gas)						
24-Hour, 98th Percentile	16.6	0.9	15.7	519,701	3,057,697	35

H6H = highest sixth-highest

Concentrations are based on concentrations predicted using 5 years of meteorological data from 2009 to 2013 consisting of surface and upper air data from the weather stations at St. Lucie International Airport and FIU, Miami, 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.

Table 6-8: Predicted 24-hour PM_{10} and $PM_{2.5}$ Impacts from all PSD Sources Compared to the Allowable PSD Class II Increments, OCEC Unit 1

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)
PM_{10} (Oil)				
24-HR, H2H	8.0	519,056	3,057,146	30
$PM_{2.5}$ (Oil)				
24-HR, H2H	7.6	519,056	3,057,146	9
$PM_{2.5}$ (Gas)				
24-HR, H2H	1.4	519,056	3,057,146	9

H2H = Highest, Second Highest -

[a] Concentrations are based on concentrations predicted using 5 years of meteorological data from 2009 to 2013 consisting of surface and upper air data from the weather stations at St. Lucie County International Airport and FIU, Miami respectively.

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Table 6-9: Maximum Predicted Concentrations at the ENP PSD Class I Area Compared to the PSD Class Significant Impact Levels

Pollutant	Averaging Time	Maximum Concentrations[a] ($\mu g/m^3$)				PSD Class I SIL ($\mu g/m^3$)
		8,760 Hrs on Nat.Gas	8,760 Hrs on Fuel Oil	8,260 Hrs Nat Gas & 500 Hrs Oil		
NO_2	Annual	0.000	0.001	0.0003	b	0.1
	24-Hour	0.015	0.062	0.062		--
	8-Hour	0.038	0.155	0.155		--
	3-Hour	0.046	0.188	0.188		--
	1-Hour	0.063	0.245	0.245		--
PM_{10}	Annual	0.001	0.0036	0.0010	b	0.2
	24-Hour	0.036	0.146	0.146		0.3
	8-Hour	0.056	0.243	0.243		--
	3-Hour	0.076	0.320	0.32		--
	1-Hour	0.091	0.367	0.37		--
$PM_{2.5}$	Annual	0.001	0.004	0.0010	b	0.06
	24-Hour	0.036	0.146	0.146		0.07
	8-Hour	0.056	0.243	0.24		--
	3-Hour	0.076	0.320	0.32		
	1-Hour	0.091	0.367	0.37		
CO	Annual	0.003	0.005	0.001	b	--
	24-Hour	0.094	0.172	0.13	c	--
	8-Hour	0.140	0.274	0.27		--
	3-Hour	0.188	0.361	0.36		
	1-Hour	0.229	0.414	0.41		
SO_2	Annual	0.001	0.0002	0.0007	c	0.1
	24-Hour	0.030	0.007	0.030		0.2
	3-Hour	0.067	0.015	0.067		1
	1-Hour	0.077	0.020	0.02		--

SIL = EPA PSD Class I Significant Impact Level

ENP = Everglades National Park

[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 are based on 500 hours of fuel oil and 8,260 hours of natural gas firing

[c] Annual concentrations are based on 8,760 hours of natural gas firing

Table 6-10: Maximum Predicted Concentrations at the CNWA PSD Class I Area Compared to the PSD Class Significant Impact Levels

Pollutant	Averaging Time	Maximum Concentrations[a] (μg/m³) 8,760 Hrs on Nat.Gas	8,760 Hrs on Fuel Oil	8,260 Hrs Nat Gas & 500 Hrs Oil		PSD Class I SIL (μg/m³)
NO_2	Annual	0.001	0.003	0.0010	b	0.1
	24-Hour	0.016	0.061	0.061		--
	8-Hour	0.037	0.143	0.143		--
	3-Hour	0.058	0.222	0.222		--
	1-Hour	0.071	0.291	0.291		--
PM_{10}	Annual	0.001	0.0062	0.0018	b	0.2
	24-Hour	0.024	0.099	0.099		0.3
	8-Hour	0.061	0.193	0.193		--
	3-Hour	0.085	0.312	0.31		--
	1-Hour	0.096	0.404	0.40		--
$PM_{2.5}$	Annual	0.001	0.006	0.0018	b	0.06
	24-Hour	0.024	0.099	0.099		0.07
	8-Hour	0.061	0.193	0.19		--
	3-Hour	0.085	0.312	0.31		
	1-Hour	0.096	0.404	0.40		
CO	Annual	0.005	0.010	0.002	b	--
	24-Hour	0.061	0.116	0.08	c	--
	8-Hour	0.155	0.214	0.21		--
	3-Hour	0.218	0.347	0.35		-
	1-Hour	0.246	0.450	0.45		-
SO_2	Annual	0.001	0.0004	0.0014	c	0.1
	24-Hour	0.024	0.006	0.024		0.2
	8-Hour	0.049	0.012	0.012		--
	3-Hour	0.079	0.019	0.079		1
	1-Hour	0.101	0.025	0.02		--

SIL = EPA PSD Class I Significant Impact Level
CNWA = Chassahowitzka National Wilderness Area
[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 are based on 500 hours of fuel oil and 8,260 hours of natural gas firing

TABLE 6-11
BACKGROUND $PM_{2.5}$ SOURCES CONSIDERED IN THE ENP PSD CLASS I SCREENING MODELING ANALYSIS

Facility ID	Facility Description	UTM Coordinates East (km)	UTM Coordinates North (km)	Distance from Class I (km)	Modeled Maximum $PM_{2.5}$ Emissions (TPY) [a] Consuming	Expanding	Net Change
Sources 0-25 km from Class I Area:							
0250615	Waste Management Inc. Of Florida Medley Landfill	565.04	2860.02	20.6	31	0	31
0250003	Florida Power & Light (PTF) Turkey Point Power Plant	567.20	2813.20	20.8	0.026	0	0.026
Sources 25-50 km from Class I Area:							
0110037	Florida Power & Light (PFL) Ft. Lauderdale Power Plant	580.24	2883.61	47.7	1,095	-539	556
Sources 50-100 km from Class I Area:							
0110036	Florida Power & Light (PPE) Port Everglades Power Plant	587.40	2885.30	54.0	576	-1,176	-601
0990332	New Hope Power Company Okeelanta Cogeneration Plant	524.90	2940.10	91.8	27	0	27
0710002	Florida Power & Light (PFM) Fort Myers Power Plant	422.30	2952.00	95.7	438	-283	155
Sources 100-200 km from Class I Area:							
0550061	Highlands Ethanol, LLC (SE Renewable)	493.20	3013.20	155.0	28	0	28
	TOTAL EMISSIONS				2,221	-1,997	224

[a] For sources that consume PSD increment, the annual PM emissions, in tons per year (TPY), are based on short-term emission rates prorated to annual emission rates. These emissions are conservative since they represent the maximum short-term rates based on the highest rate permitted for the source.

TABLE 6-12
SUMMARY OF DETAILED MODELING INFORMATION FOR $PM_{2.5}$ SOURCES INCLUDED IN THE ENP PSD Class I INCREMENT ANALYSIS

Facility	Facility Name		CALPUFF	UTM Location		Stack Parameters								Stack Parameter	$PM_{2.5}$ Emission Rate		$PM_{2.5}$ PSD Category		Emissions Data
				X	Y	Height		Diameter		Temperature		Velocity			24-Hour				
ID	Emission Unit Description	EU ID	ID Name	(m)	(m)	ft	m	ft	m	°F	K	ft/s	m/s	Data Source [a]	(lb/hr)	(g/sec)	EXP, CON, OR BASE	Modeled?	Data Source [a]
0250615	**Waste Management Inc. Of Florida Medley Landfill**																		
	6 Lean Burn RICE/Generator Set		MEDLEY	565,890	2,859,870	50.00	15.24	1.18	0.36	910.2	760.9	188.1	57.32	Golder (093-87674)	7.10	0.89	CON	Yes	Golder (093-87674)
0250003	**Florida Power & Light (PTF) Turkey Point Power Plant**																		
	Units 6 & 7 Cooling Towers		TURKCOOL	567,200	2,813,200	66.50	20.27	33.70	10.27	104.6	313.3	33.0	10.0584	Golder (0838-8705)	0.0257	0.0032	CON	Yes	Golder (0838-8705)
0110037	**Florida Power & Light (PFL) Ft. Lauderdale Power Plant**																		
	GT 1-22 (22 of the existing 24 GTs are to be retired)		LDGTS1_24	579,390	2,883,360	45.00	13.72	15.60	4.75	860.0	733.2	93.3	28.44	Golder (073-87652)	-122.98	-15.50	EXP	Yes	1979 AOR & AP-42 factors.
	5 New GE F7A.5 SC CTs		LDSCCTS	579,390	2,883,360	79.99	24.38	23.00	7.01	1215.3	930.4	75.2	22.93	Golder (15-20938)	250.00	31.50	CON	Yes	Golder (15-20938)
0110036	**Florida Power & Light (PPE) Port Everglades Power Plant**																		
	Units 1&2 at 2.5%s fuel oil		PTEVU12	587,400	2,885,300	342.85	104.50	14.01	4.27	289.0	415.9	87.7	26.72	Golder (073-87652)	-47.82	-6.03	EXP	Yes	1979 AOR & AP-42 factors.
	Units 3&4 at 2.5%s fuel oil		PTEVU34	587,400	2,885,300	342.85	104.50	18.11	5.52	287.0	414.8	78.3	23.88	Golder (073-87652)	-153.02	-19.28	EXP	Yes	AOR & AP-42 factors.
	GT 1-12 (0.5% fuel oil)		PTEVGTS	587,400	2,885,300	43.96	13.40	15.58	4.75	860.1	733.2	93.3	28.43	Golder (073-87652)	-67.68	-8.53	EXP	Yes	1979 AOR & AP-42 factors.
	3 New CC CTs		PTEVCTS	587,400	2,885,300	148.95	45.40	22.01	6.71	359.2	454.8	79.4	24.20	Golder (133-87588)	131.40	16.56	CON	Yes	Golder (133-87588)
0990332	**New Hope Power Company Okeelanta Cogeneration Plant**																		
	Boiler D		NHPBLRD	524,920	2,939,440	199.02	60.66	11.09	3.38	326.3	436.5	62.0	18.9	Golder (073-87652)	6.11	0.77	CON	Yes	Golder (073-87652)
0710002	**Florida Power & Light (PFM) Fort Myers Power Plant**																		
	Gas Turbines 1 -10 (10 of the existing 12 GTs are to be retired)		FMYGTS	422,300	2,952,000	31.99	9.75	11.42	3.48	975.2	797.0	189.4	57.73	Golder (033-37600)	-64.50	-8.13	EXP	Yes	1979 AOR & AP-42 factors.
	2 new GE 7fFA.5 SC CTs		FMYSCCTS	422,300	2,952,000	100.49	30.63	23.00	7.01	1215.3	930.4	78.7	23.98	Golder (133-87590001)	100.00	12.60	CON	Yes	Golder (133-87590001)
0550061	**Highlands Ethanol, LLC (SE Renewable)**																		
	Biomass Boiler	--	BIOMBLR	493,200	3,013,200	150.00	45.72	8.01	2.44	361.1	456.0	20.1	6.12	Golder (093-87660)	6.30	0.79	CON	Yes	Golder (093-87660)
	Truck Load Flare	--	TRKFLR	493,200	3,013,200	30.87	9.41	1.02	0.31	1831.7	1273.0	5.2	1.58	Golder (093-87660)	0.034	0.004	CON	Yes	Golder (093-87660)

Note: EXP = PSD expanding source.
CON = PSD consuming source.
BASE = Baseline Source, emissions are part of baseline and not included in modeling analysis.

[a] Data sources are from the following projects submitted by Golder to FDEP:
Golder (03337600): Florida Power & Light Company, Site Certification Application, Turkey Point Expansion Project; November 2003
Golder (073-87652): Florida Power & Light Company, Site Certification Application, West County Energy Center Unit 3, SCA Vol. III of III; March 2008
Golder (093-87660): Southeast Renewable Fuels, LLC, Prevention of Significant Deterioration Application for Aspring Sweet Sorghum-To-Ethanol Advanced Bio refinery; March 2010
Golder (093-87674): Waste Management, Inc. of Florida, Prevention of Significant Deterioration Application for Landfill Gas-To-Energy Plant at Medley Landfill; August 2010
Golder (133-87588): Florida Power & Light Company, Air Construction Permit Application for the Florida Power & Light Company Lauderdale Combustion Turbine Project, Broward County, Florida; July 2013
Golder (133-87590): Florida Power & Light Company, Air Construction Permit Application for Florida Power & Light Company Fort Myers Combustion Turbine Project, Lee County, Florida; July 2013

Table 6-13: Background PM2.5 Sources Considered in the CNWA PSD Class I Screening Analysis

Facility ID	Facility Description	UTM Coordinates East (km)	UTM Coordinates North (km)	Distance from Class I (km)	Modeled Maximum $PM_{2.5}$ Emissions (TPY) [a] Consuming	Expanding	Net Change
Sources 0-25 km from Class I Area:							
0530380	FLORIDA POWER DEVELOPMENT, LLC-BROOKSVILLE POWER PLANT	360.00	3,162.50	22.2	33.3	0.0	33
Sources 25-50 km from Class I Area:							
0170004	DUKE ENERGY FLORIDA, INC. (DEF)-CRYSTAL RIVER POWER FOSSIL PLANT	334.30	3,204.50	29.9	184.0	-1,915.4	-1,731
1010373	SHADY HILLS GENERATING STATION	347.00	3,139.00	37.7	297.8	0.0	298
Sources 50-200 km from Class I Area:							
0951340	HARVEST POWER ORLANDO, LLC-HARVEST ENERGY GARDEN-ORLANDO FACILITY	447.25	3,139.41	110.9	4.2	0.0	4
0010131	GAINESVILLE RENEWABLE ENERGY CENTER, LLC-GAINESVILLE RENEWABLE ENERGY C	365.01	3,293.83	120.2	58.3	0.0	58
1050233	TAMPA ELECTRIC COMPANY-POLK POWER STATION	402.45	3,067.36	124.3	332.9	-134.6	198
0810010	FLORIDA POWER & LIGHT (PMT)-MANATEE POWER PLANT	367.15	3,054.23	124.5	0.0	-5,304.2	-5,304
1050444	U.S. ECOGEN POLK, LLC-WOODY BIOMASS POWER PLANT	424.01	3,069.93	134.1	97.2	0.0	97
1150089	SAR. CNTY CENTRAL CNTY SW DISPOSAL CMPLX	361.63	3,008.57	169.2	20.8	0.0	21
0310358	CITY OF JACKSONVILLE-TRAIL RIDGE LANDFILL	399.51	3,344.04	178.3	20.7	0.0	21
1210003	DUKE ENERGY FLORIDA, INC.-SUWANNEE RIVER PLANT	290.66	3,362.12	194.1	332.0	0.0	332
	TOTAL EMISSIONS				1,381	-7,354	-5,973

[a] For sources that consume PSD increment, the annual PM emissions, in tons per year (TPY), are based on short-term emission rates prorated to annual emission rates. These emissions are conservative since they represent the maximum short-term rates based on the highest rate permitted for the source.

Table 6-14: Summary of Detailed Modeling Information for $PM_{2.5}$ Sources Included in CNWA PSD Increment Analysis

Facility ID	Facility Name / Emission Unit Description	EU ID	CALPUFF ID Name	UTM Location X (m)	UTM Location Y (m)	Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	Stack Parameter Data Source [a]	$PM_{2.5}$ Emission Rate 24-Hour (lb/hr)	$PM_{2.5}$ 24-Hour (g/sec)	SO_2 Emission Rate 24-Hour (lb/hr)	SO_2 24-Hour (g/sec)	NO_2 Emission Rate 24-Hour (lb/hr)	NO_2 24-Hour (g/sec)	SAM Emission Rate [a] 24-Hour (lb/hr)	SAM 24-Hour (g/sec)	PSD Category EXP, CON, OR BASE	Modeled?	Emissions Data Data Source
0530380	**FLORIDA POWER DEVELOPMENT, LLC-BROOKSVILLE POWER PLANT**																								
	Hybrid Suspension Grate Boiler	002	FPDBRL	360,000	3,162,500	165.0	50.29	12.0	3.66	340.0	444.3	57.5	17.53	FDEP Data 5/28/15	7.6	0.96	135.0	17.01	135.0	17.01	13.50	1.70	CON	Yes	FDEP Data 5/28/15
0170004	**DUKE ENERGY FLORIDA, INC. (DEF)-CRYSTAL RIVER POWER PLANT FOSSIL PLANT**																								
	Fossil Fuel Steam Generator Unit 1 (Phase II Acid Rain Unit)	001	--	334,300	3,204,500	499.0	152.10	15.0	4.57	291.0	417.0	132.8	40.48	FDEP Data 5/28/15	194.6	24.52	--	--	--	--	--	--	EXP		2010 AOR
	Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit)	002	--	334,300	3,204,500	502.0	153.01	16.0	4.88	300.0	422.0	160.1	48.80	FDEP Data 5/28/15	242.7	30.58	--	--	--	--	--	--	EXP		2010 AOR
	Fossil Fuel Steam Generator Units 1 and 2		FFSG1&2	334,300	3,204,500	500.5	152.55	15.5	4.72	295.5	419.5	146.5	44.64		437.3	55.10	--	--	--	--	--	--	EXP	Yes	
	Combined Cycle Unit 2A - One 270 MW CT with duct-fired HRSG	042	--	336,820	3,205,630	180.0	54.86	22.0	6.71	185.0	358.2	59.4	18.11	FDEP Data 5/28/15 - 0170004-047-AC application	10.5	1.32	17.7	2.23	175.3	22.09	2.6	0.33	CON		FDEP Data 5/28/15 - 0170004-047-AC application
	Combined Cycle Unit 2B - One 270 MW CT with duct-fired HRSG	043	--	336,820	3,205,630	180.0	54.86	22.0	6.71	185.0	358.2	59.4	18.11	FDEP Data 5/28/15 - 0170004-047-AC application	10.5	1.32	17.7	2.23	175.3	22.09	2.6	0.33	CON		FDEP Data 5/28/15 - 0170004-047-AC application
	Combined Cycle Unit 1A - One 270 MW CT with duct-fired HRSG	040	--	336,820	3,205,630	180.0	54.86	22.0	6.71	185.0	358.2	59.4	18.11	FDEP Data 5/28/15 - 0170004-047-AC application	10.5	1.32	17.7	2.23	175.3	22.09	2.6	0.33	CON		FDEP Data 5/28/15 - 0170004-047-AC application
	Combined Cycle Unit 1B - One 270 MW CT with duct-fired HRSG	041	--	336,820	3,205,630	180.0	54.86	22.0	6.71	185.0	358.2	59.4	18.11	FDEP Data 5/28/15 - 0170004-047-AC application	10.5	1.32	17.7	2.23	175.3	22.09	2.6	0.33	CON		FDEP Data 5/28/15 - 0170004-047-AC application
	Citrus Combined Cycle Project Units 1 and 2		CCCP1&2	336,820	3,205,630	180.0	54.86	22.0	6.71	185.0	358.2	59.4	18.11		42.0	2.65	70.8	4.46	701.2	44.18	10.4	0.66	CON	Yes	
1010373	**SHADY HILLS GENERATING STATION**																								
	Simple Cycle GE 7FA combustion turbines	005	--	347,000	3,139,000	75.0	22.86	18.0	5.49	1,099.0	865.9	182.0	55.47	FDEP Data 5/28/15	34.0	4.28	3.5	0.44	370.9	46.73	0.35	0.04	CON		Permit Application (Golder 103-89556)
	Simple Cycle GE 7FA combustion turbines	006	--	347,000	3,139,000	75.0	22.86	18.0	5.49	1,099.0	865.9	182.0	55.47	FDEP Data 5/28/15	34.0	4.28	3.5	0.44	370.9	46.73	0.35	0.04	CON		Permit Application (Golder 103-89556)
	Simple Cycle Units 4 and 5		SHSC4&5	347,000	3,139,000	75.0	22.86	18.0	5.49	1,099.0	865.9	182.0	55.47		68.0	8.57	7.0	0.88	741.8	93.47	0.70	0.09	CON	Yes	
0951340	**HARVEST POWER ORLANDO, LLC-HARVEST ENERGY GARDEN-ORLANDO FACILITY**																								
	1.6 MW Caterpillar Model G3520C engine/generator set	001	--	447,250	3,139,410	18.0	5.49	1.3	0.41	915.0	763.7	147.7	45.02	FDEP Data 5/28/15	0.24	0.030	1.04	0.131	9.89	1.246	0.10	0.013	CON		0951340-001-AC application
	1.6 MW Caterpillar Model G3520C engine/generator set	002	--	447,250	3,139,410	18.0	5.49	1.3	0.41	915.0	763.7	147.7	45.02	FDEP Data 5/28/15	0.24	0.030	1.04	0.131	9.89	1.246	0.10	0.013	CON		0951340-001-AC application
	backup flare to burn biogass when RICE not available	004	--	447,250	3,139,410	24.0	7.32	0.7	0.20	1,100.0	866.5	163.3	49.77	FDEP Data 5/28/15	0.47	0.059	0.11	0.014	2.85	0.359	0.01	0.001	CON		0951340-001-AC application
	All Activities		HPWALL	447,250	3,139,410	20.0	6.1	1.1	0.3	976.7	798.0	152.9	46.6		1.0	0.12	2.2	0.28	22.6	2.85	0.2	0.03	CON	Yes	
0010131	**GAINESVILLE RENEWABLE ENERGY CENTER, LLC-GAINESVILLE RENEWABLE ENERGY CENTER**																								
	Bubbling Fluidized Bed woody biomass 1358 mmBtu/hr boiler	002	GRECBRL	365,010	3,293,830	230.0	70.10	12.0	3.66	310.0	427.6	76.7	23.38	FDEP Data 5/28/15	13.3	1.68	39.4	4.96	9.5	1.20	1.4	0.18	CON	Yes	0010131-003-AC
1050233	**TAMPA ELECTRIC COMPANY-POLK POWER STATION**																								
	Nominal 165 MW Simple Cycle Turbine No. 2	009	--	402,450	3,067,350	114.0	34.75	29.0	8.84	1,117.0	875.9	60.2	18.35	FDEP Data 5/28/15	7.22	0.91	--	--	--	--	--	--	EXP		2010 AOR
	Nominal 165 MW Simple Cycle Turbine No. 3	010	--	402,450	3,067,350	114.0	34.75	29.0	8.84	1,117.0	875.9	60.2	18.35	FDEP Data 5/28/15	8.35	1.05	--	--	--	--	--	--	EXP		2010 AOR
	Nominal 165 MW Simple Cycle Turbine No. 4	013	--	402,440	3,067,360	114.0	34.75	18.0	5.49	1,117.0	875.9	156.8	47.79	FDEP Data 5/28/15	7.54	0.95	--	--	--	--	--	--	EXP		2010 AOR
	Nominal 165 MW Simple Cycle Turbine No. 5	014	--	402,440	3,067,360	114.0	34.75	18.0	5.49	1,117.0	875.9	156.8	47.79	FDEP Data 5/28/15	7.61	0.96	--	--	--	--	--	--	EXP		2010 AOR
	Simple Cycle Turbine Nos. 2~5		TECOSCT	402,445	3,067,355	114.0	34.7	23.5	7.16	1,117.0	875.9	108.5	33.1		30.72	3.87	--	--	--	--	--	--	EXP	Yes	
	Unit 2A Nominal 165 MW Combustion Turbine and Duct-fired Heat Recovery Steam Generator	020	--	402,450	3,067,350	130	39.62	19.0	5.79	210	372.04	60.42	18.42	1050233-034-AC application	19.0	2.39	2.9	0.37	70.5	8.88	0.3	0.04	CON		1050233-034-AC application
	Unit 2B Nominal 165 MW Combustion Turbine and Duct-fired Heat Recovery Steam Generator	021	--	402,450	3,067,350	130	39.62	19.0	5.79	210	372.04	60.42	18.42	1050233-034-AC application	19.0	2.39	2.9	0.37	70.5	8.88	0.3	0.04	CON		1050233-034-AC application
	Unit 2C Nominal 165 MW Combustion Turbine and Duct-fired Heat Recovery Steam Generator	022	--	402,440	3,067,360	130	39.62	19.0	5.79	210	372.04	60.42	18.42	1050233-034-AC application	19.0	2.39	2.9	0.37	70.5	8.88	0.3	0.04	CON		1050233-034-AC application
	Unit 2D Nominal 165 MW Combustion Turbine and Duct-fired Heat Recovery Steam Generator	023	--	402,440	3,067,360	130	39.62	19.0	5.79	210	372.04	60.42	18.42	1050233-034-AC application	19.0	2.39	2.9	0.37	70.5	8.88	0.3	0.04	CON		1050233-034-AC application
	Combined Cycle Turbine Nos. 2~5		TECOCCT	402,445	3,067,355	130.0	39.6	19.0	5.8	210.0	372.0	60.4	18.4		76.0	9.58	11.6	1.46	282.0	35.53	1.2	0.15	CON	Yes	
0810010	**FLORIDA POWER & LIGHT (PMT)-MANATEE POWER PLANT**																								
	Fossil Fuel Steam Generator, Unit 1-Phase II Acid Rain Unit	001		367,150	3,054,230	499.0	152.10	27.3	8.32	344.0	446.5	78.0	23.77	FDEP Data 5/28/15	605.5	76.29	--	--	--	--	--	--	EXP		0810010-016-AC, during normal operation
	Fossil Fuel Steam Generator, Unit 2-Phase II Acid Rain Unit	002		367,150	3,054,230	499.0	152.10	26.2	7.99	325.0	435.9	82.5	25.15	FDEP Data 5/28/15	605.5	76.29	--	--	--	--	--	--	EXP		0810010-016-AC, during normal operation
	Fossil Fuel Steam Generator, Units 1 and 2		FPLMSG1&2	367,150	3,054,230	499.0	152.10	26.8	8.15	334.5	441.2	80.3	24.46		1211.0	152.59	--	--	--	--	--	--	EXP	Yes	
1050444	**U.S. ECOGEN POLK, LLC-WOODY BIOMASS POWER PLANT**																								
	Power Island	002	USEPPI	424,010	3,069,930	180.0	54.86	11.0	3.35	295.0	419.3	58.8	17.91	FDEP Data 5/28/15	22.2	2.80	51.8	6.53	222.0	27.97	5.2	0.65	CON	Yes	1050444-001-AC
1150089	**SAR. CNTY CENTRAL CNTY SW DISPOSAL CMPLX**																								
	Lean-Burn, Spark-Ignited RICE/Generator Set	010~013	SCCENG1-4	361,630	3,008,570	10.0	3.05	1.5	0.46	900.0	755.4	129.2	39.38	FDEP Data 5/28/15	4.8	0.60	8.2	1.03	11.9	1.49	0.8	0.10	CON	Yes	1150089-008-AC application
0310358	**CITY OF JACKSONVILLE-TRAIL RIDGE LANDFILL**																								
	LFG fueled Engines (4)	012~015	COJTRLENG	399,510	3,344,040	23.0	7.01	1.5	0.46	900.0	755.4	129.2	39.38	FDEP Data 5/28/15	4.7	0.59	3.8	0.48	11.8	1.49	0.4	0.05	CON	Yes	0310358-012-AC application
1210003	**DUKE ENERGY FLORIDA, INC.-SUWANNEE RIVER PLANT**																								
	Boiler No. 3 (Phase II Acid Rain Unit)	003	SRBRL3	290,460	3,362,510	135.0	41.15	7.7	2.35	300.0	422.0	109.0	33.22	FDEP Data 5/28/15	7.3	0.92	--	--	--	--	--	--	EXP	Yes	2010 AOR
	Simple Cycle Combustion Turbine-Electrical Generator Unit P4	011	--	290,659	3,362,145	115.0	35.05	20.0	6.10	1084.0	857.6	133.3	40.61	1210003-AC-008 application, temperature and velocity based on ULSD firing	37.9	4.78	9.1	1.15	359.1	45.25	1.6	0.20	CON		1210003-AC-008 Permit
	Simple Cycle Combustion Turbine-Electrical Generator Unit P5	012	--	290,659	3,362,099	115.0	35.05	20.0	6.10	1084.0	857.6	133.3	40.61	1210003-AC-008 application, temperature and velocity based on ULSD firing	37.9	4.78	9.1	1.15	359.1	45.25	1.6	0.20	CON		1210003-AC-008 Permit
	Simple Cycle Combustion Trubine-Electrical Generator Unit P4/P5		SRSCCT4&5	290,659	3,362,122	115	35.05	20.0	6.10	1,084.0	857.6	133.3	40.61		75.8	9.55	18.2	2.29	718.2	90.49	3.2	0.40	CON	Yes	

Note: EXP = PSD expanding source.

CON = PSD consuming source.

Rows that are highlighted indicate one source to represent multiple sources combined into that one source.

[a] When sulfuric acid mist emissions not available, 10% conversion factor from SO_2 is assumed.

Table 6-15: Predicted 24-Hour PM2.5 Impacts for All Increment Consuming Sources as Compared to the Allowable PSD Class I Increments

PSD AREA	Maximum Predicted Primary $PM_{2.5}$ Concentrations ($\mu g/m^3$) [a] for PSD-Affecting Sources			Maximum Predicted Secondary $PM_{2.5}$ Concentrations ($\mu g/m^3$) [b] for PSD-Affecting Sources			Maximum Predicted Total $PM_{2.5}$ Concentrations ($\mu g/m^3$) [c] for PSD-Affecting Sources			Allowable PSD Class I Increment ($\mu g/m^3$)
	2001	2002	2003	2001	2002	2003	2001	2002	2003	
ENP	0.11	0.08	0.08	0.11	0.15	0.21	0.22	0.23	0.29	2.0
CNWA	0.14	0.16	0.11	0.23	0.25	0.19	0.37	0.41	0.30	2.0

[a] Based on the highest, second-highest $PM_{2.5}$ concentration.

[b] Based on the sum of of the highest, second-highest concentrations of sulfate and nitrate. Secondary organic aerosol is not counted.

[c] Based on the sum of primary $PM_{2.5}$ and secondary $PM_{2.5}$. Secondary organic aerosol is not counted.

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

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

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

Table 7-2: Predicted 24-Hour Visibility Impairment for OCEC Unit 1 at the ENP and CNWA PSD Class I Areas

CT / Fuel Type	Visibility Impairment (%) [a]			Visibility Impairment Criteria (deciview)
	2001	2002	2003	
CNWA				
24-Hours/Day on Natural Gas (Primary)	0.059	0.069	0.058	0.5
24-Hour/Day on ULSD Oil (Backup)	0.118	0.126	0.120	0.5
ENP				
24-Hours/Day on Natural Gas (Primary)	0.045	0.051	0.046	0.5
24-Hour/Day on ULSD Oil (Backup)	0.086	0.118	0.109	0.5

CC CTs = Combined Cycle Combustion Turbines

[a] Values presented are 98th-percentile deciviews using CALPUFF v5.8.4 and CALPOST v6.221, MVISBK=8, M8_MODE=5. Background extinctions are based on FLAG 2008 and 20th best natural background values.

Table 7-3: Predicted Annual Total Nitrogen and Sulfur Deposition for OCEC Unit 1 at the CNWA PSD Class I Area and ENP PSD Class I Area

Deposition	Total Deposition (Wet & Dry) ($g/m^2/s$)	Total Deposition (Wet & Dry) (kg/ha/yr)[a,c]	Year	Deposition Analysis Threshold [b] (kg/ha/yr)
CNWA				
Total Sulfur	4.04E-12	0.0013	2001	0.01
	6.11E-12	0.0019	2002	0.01
	5.04E-12	0.0016	2003	0.01
Total Nitrogen	2.38E-12	0.0008	2001	0.01
	3.48E-12	0.0011	2002	0.01
	3.13E-12	0.0010	2003	0.01
ENP				
Total Sulfur	1.89E-12	0.0006	2001	0.01
	2.74E-12	0.0009	2002	0.01
	1.96E-12	0.0006	2003	0.01
Total Nitrogen	7.75E-13	0.0002	2001	0.01
	1.63E-12	0.0005	2002	0.01
	1.13E-12	0.0004	2003	0.01

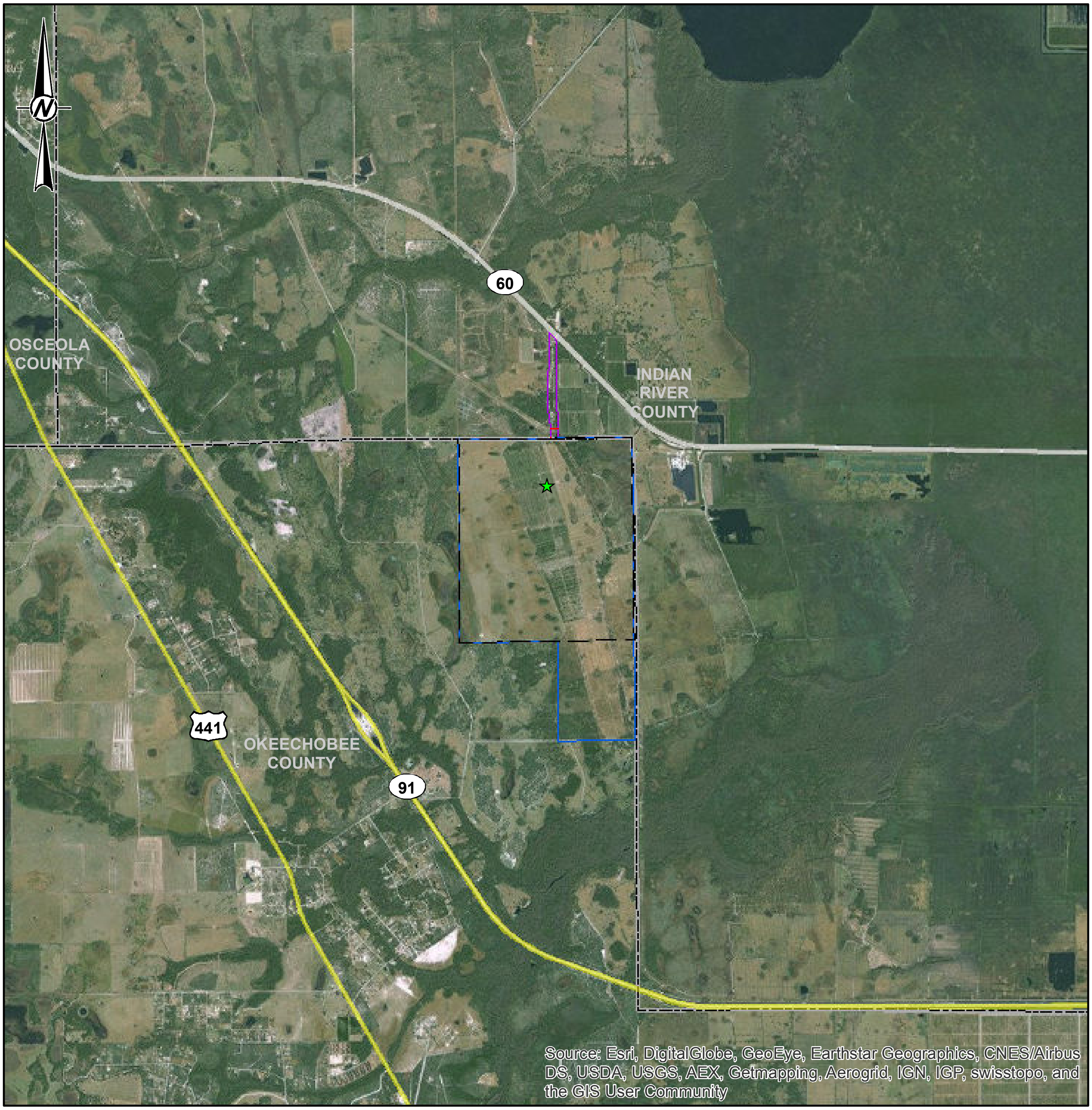
[a] Conversion factor is used to convert $g/m^2/s$ to kg/hectare (ha)/yr with the following units:

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

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

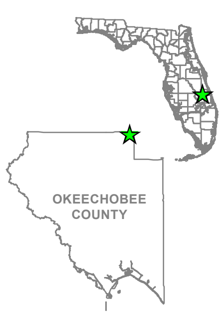
[c] Total nitrogen and sulfur deposition is based on CTs operating 8,260 hours/year on natural gas and 500 hours/year on ultra low sulfur fuel oil.

FIGURES



LEGEND

- Project Location
- FPL Owned Property
- Linear Facility Corridor
- Transmission Interconnection Corridor
- Certified Site Boundary
- County Boundary



0 1.5 3

1:95,056 Miles

REFERENCE(S)
PROPERTY, LINEAR FACILITY CORRIDOR, CERTIFIED BOUNDARY, FPL & GOLDER ASSOCIATES INC., 2015

CLIENT
FPL

PROJECT
OKEECHOBEE CLEAN ENERGY CENTER

TITLE
LOCATION OF THE FPL PROJECT

CONSULTANT
Golder Associates

YYYY-MM-DD	2015-09-22
DESIGNED	NRL
PREPARED	NRL
REVIEWED	KAB
APPROVED	KFK

PROJECT NO.	CONTROL	REV.	FIGURE
1414979	B074	0	**1-1**

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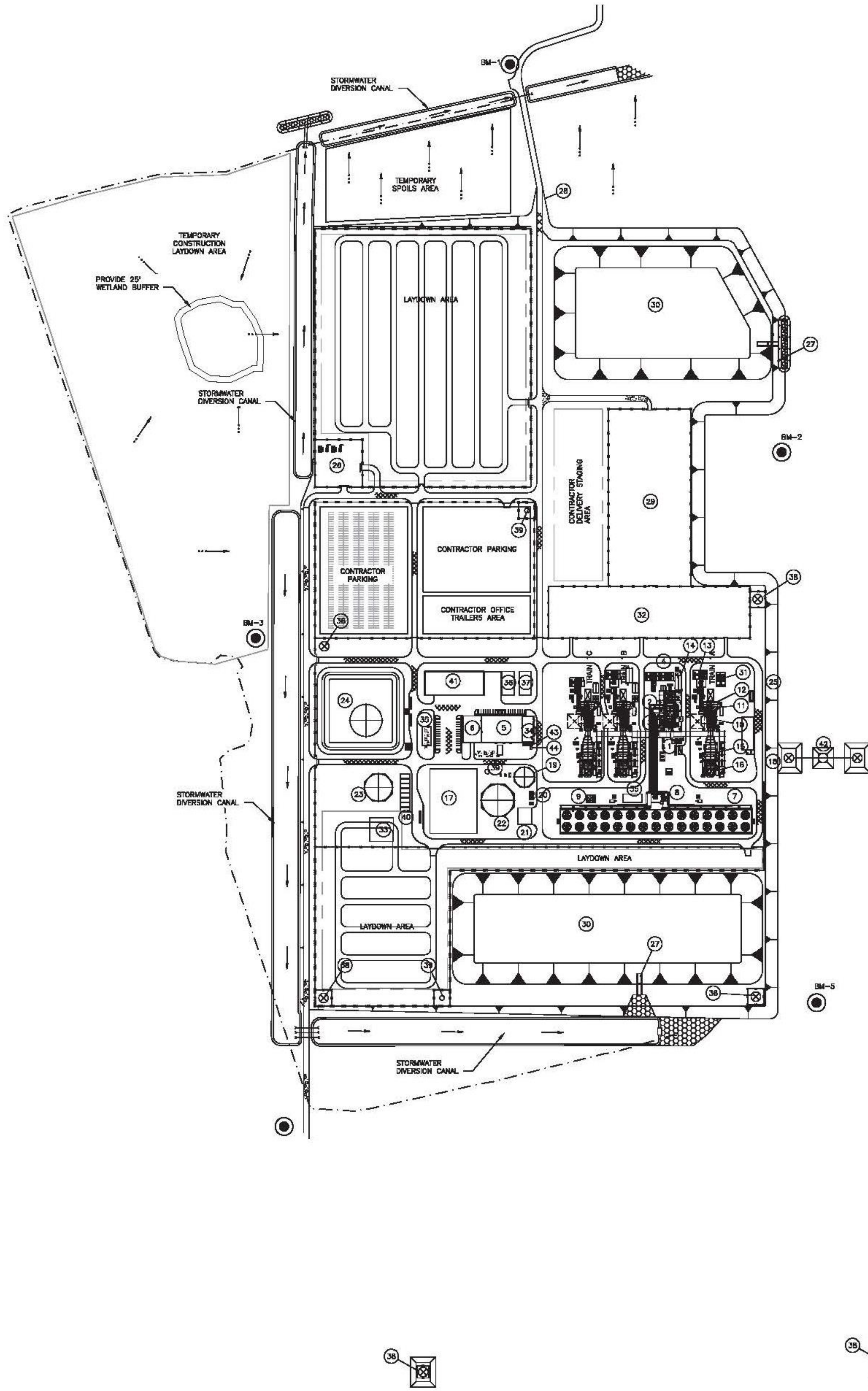


FACILITIES LEGEND

ID	FACILITY	FOUNDATION	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST
1	STEAM TURBINE	–	–	–
2	STEAM TURBINE GENERATOR	–	–	–
3	SURFACE CONDENSER (BELOW)	–	–	–
4	ST GENERATOR STEP–UP TRANSFORMER	–	–	–
5	ADMINISTRATION BUILDING	–	–	–
6	WAREHOUSE	–	–	–
7	COOLING TOWER	–	–	–
8	CIRCULATING WATER PUMP STRUCTURE	–	–	–
9	COOLING TOWER CHEMICAL FEED	–	–	–
10	COMBUSTION TURBINE	–	–	–
11	COMBUSTION TURBINE GENERATOR	–	–	–
12	INLET AIR FILTER (ABOVE)	–	–	–
13	CT GENERATOR STEP–UP TRANSFORMER	–	–	–
14	POWER CONTROL MODULE	–	–	–
15	HEAT RECOVERY STEAM GENERATOR	–	–	–
16	HRSG EXHAUST STACK	–	–	–
17	WATER TREATMENT AREA	–	–	–
18	AMMONIA STORAGE AREA	–	–	–
19	FIRE/SERVICE WATER STORAGE TANK	–	–	–
20	FIRE PUMP ENCLOSURE	–	–	–
21	DEMINERALIZATION AREA	–	–	–
22	DEMINERALIZED WATER STORAGE TANK	–	–	–
23	RAW WATER SORAGE TANK	–	–	–
24	FUEL OIL STORAGE TANK	–	–	–
25	HYDROGEN STORAGE AREA	–	–	–
26	FUEL GAS REGULATING AREA	–	–	–
27	POND OUTFALL STRUCTURE	–	–	–
28	MAIN ENTRANCE ROAD	–	–	–
29	500kV SWITCHYARD	–	–	–
30	STORMWATER DETENTION POND	–	–	–
31	SPARE STG GSU TRANSFORMER	–	–	–
32	COLLECTOR YARD	–	–	–
33	LEACH FIELD	–	–	–
34	CONTROL AREA	–	–	–
35	OIL/WATER SEPARATOR	–	–	–
36	AUXILIARY BOILER	–	–	–
37	EMERGENCY DIESEL GENERATORS	–	–	–
38	MAKE–UP WATER WELL (FLORIDIAN)	–	–	–
39	POTABLE WATER WELL (SURFICIAL)	–	–	–
40	ROLL–OFF AREA AND MISC STORAGE FACILITY	–	–	–
41	FABRICATION/STORAGE BUILDING	–	–	–
42	UIC/DZMW WELLS	–	–	–
43	HURRICANE SHELTER	–	–	–
44	HURRICANE SHELTER GENERATORS	–	–	–

LEGEND

ASPHALT ROAD

AGGREGATE ROAD

PLANT FENCING

CONTRACTOR FENCING

REFERENCES

FACILITY LAYOUT TAKEN FROM BLACK & VEATCH SITE ARRANGEMENT, DRAWING No. 185922-DS-G1001, REV. 1, DATED 09-08-2015

CLIENT
FPL

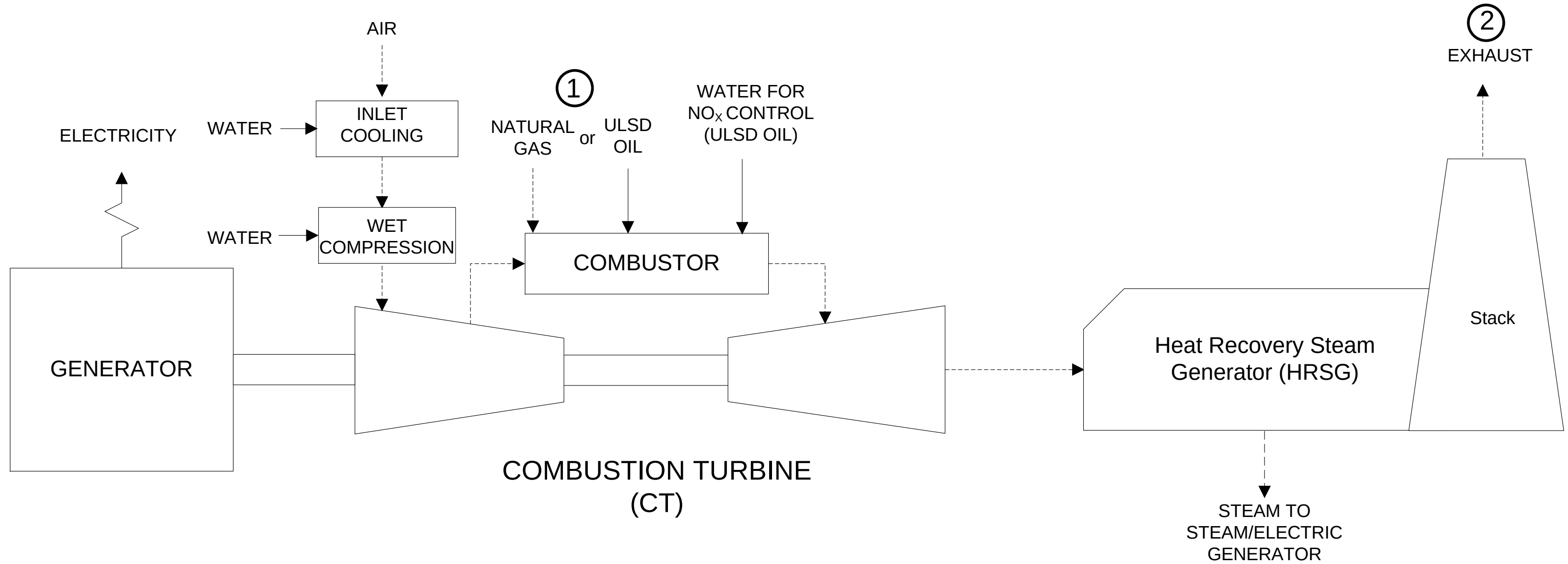
PROJECT
OKEECHOBEE CLEAN ENERGY CENTER

CONSULTANT
Golder Associates

YYYY-MM-DD	2015-09-17
PREPARED	NRL
DESIGN	NRL
REVIEW	KAB
APPROVED	KFK

TITLE
CONCEPTUAL SITE PLAN

PROJECT No.	CONTROL	Rev.	FIGURE
1414979	B039	0	2-1



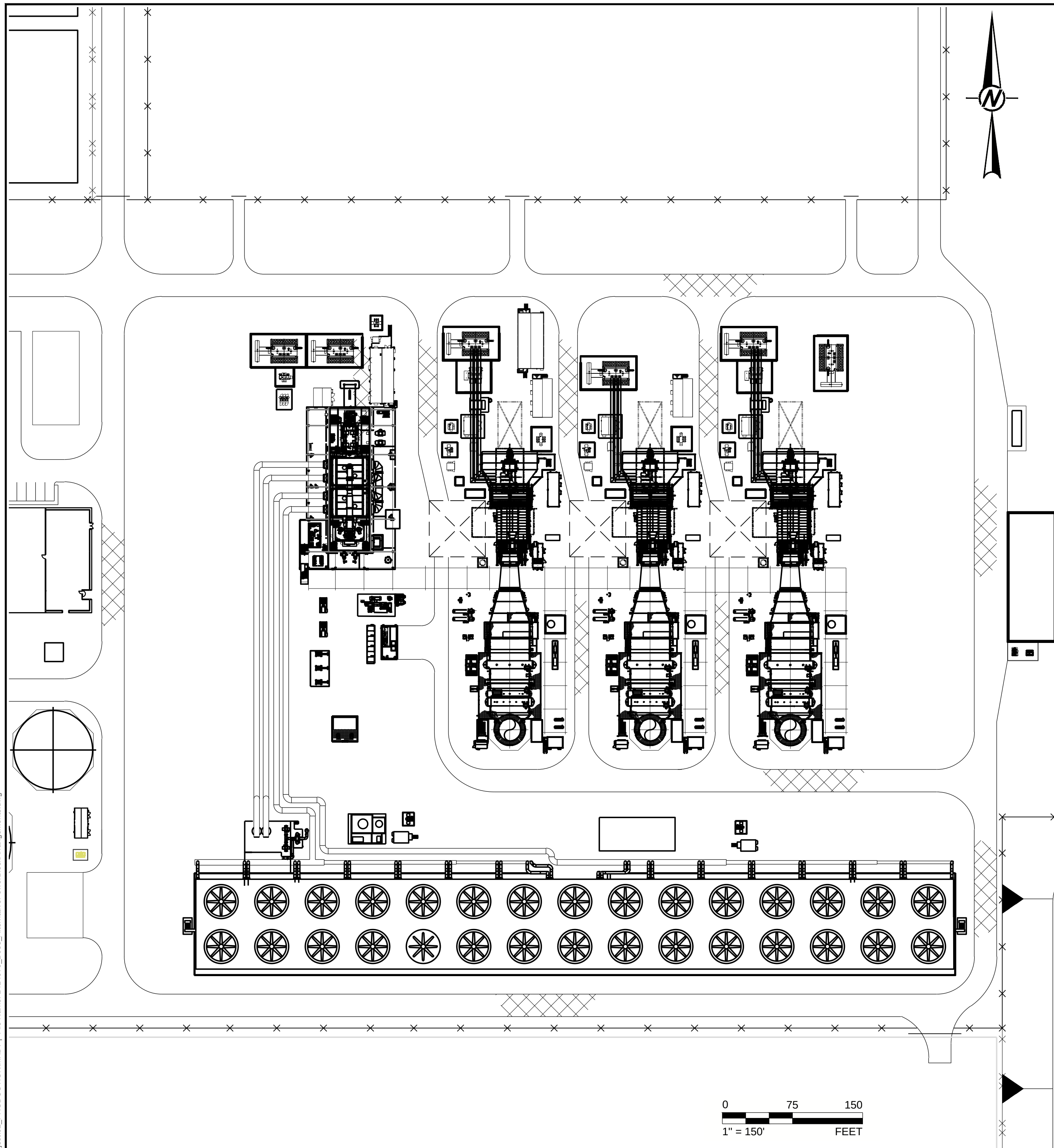
	Parameters	Units	Fuel	GE 7HA.02
1	CT Heat Input (at 75 °F with inlet cooling)	MMBtu/hr (HHV)	Gas	3,436.2
		MMBtu/hr (HHV)	Oil	3,087.3
2	Mass Flow (at 75 °F with inlet cooling)	lb/hr	Gas	5,566,000
		lb/hr	Oil	5,753,000
2	Stack Velocity	ft/sec	Gas	50.3
		ft/sec	Oil	53.9
2	Stack Temperature	°F	Gas	182
		°F	Oil	208
2	Stack Height	feet	Gas/Oil	149
2	Stack Diameter	feet	Gas/Oil	25.6

Figure 2-2. Process Flow Diagram for Each CT
Baseload Operation, Ambient Temperature of 75°F
FPL OCEC Unit 1, Okeechobee County, Florida

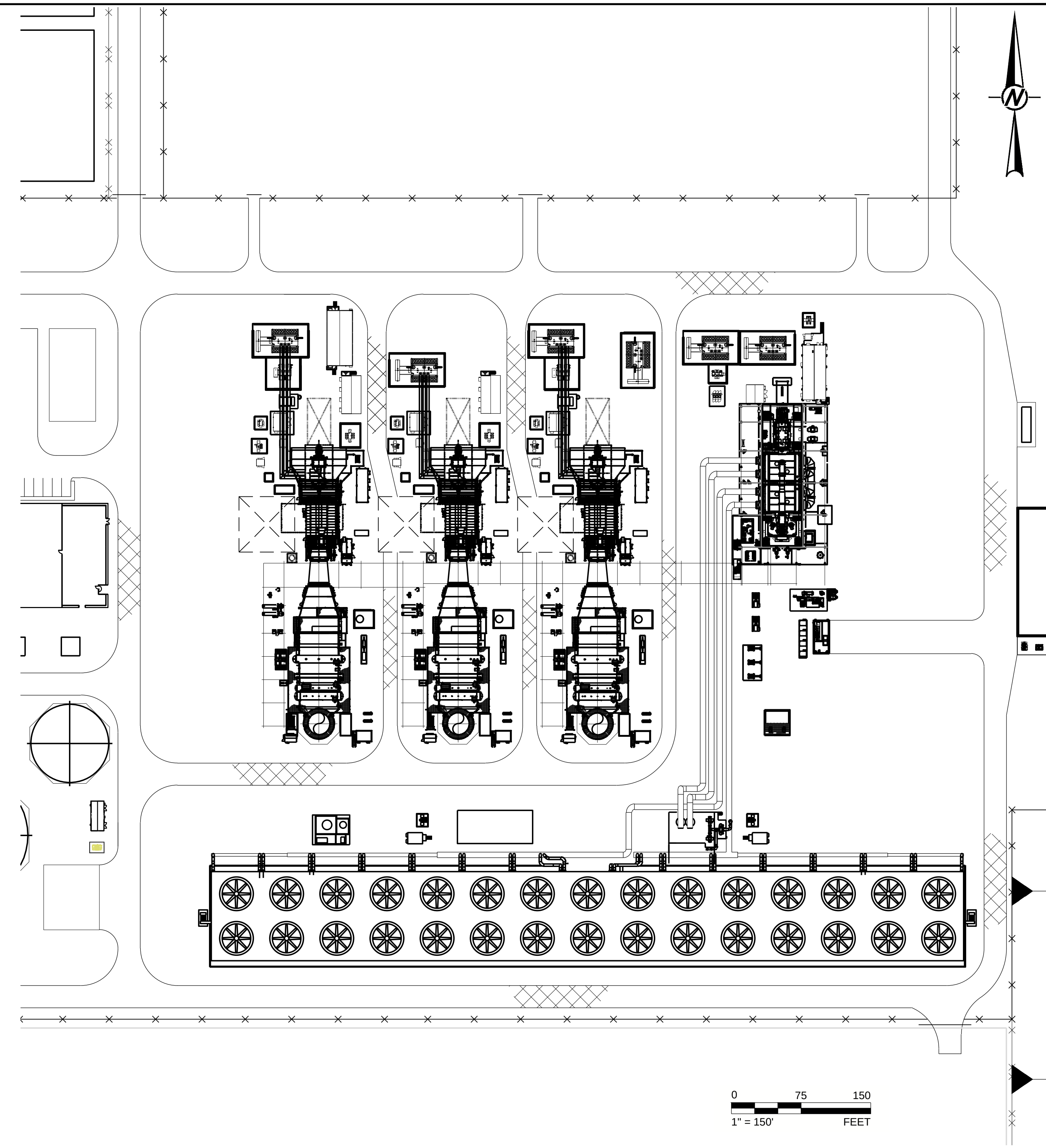
Source: GE, 2015; FPL, 2015; Golder, 2015.

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates



STG LOCATED WEST OF CT/HRSG TRAINS



STG LOCATED EAST OF CT/HRSG TRAINS

NOTE(S)
- STG = STEAM TURBINE GENERATOR
- CT = COMBUSTION TURBINE
- HRSG = HEAT RECOVERY STEAM GENERATOR

CLIENT FPL		PROJECT OKEECHOBEE CLEAN ENERGY CENTER	
CONSULTANT Golder Associates	YYYY-MM-DD: 2015-08-25 DESIGNED: NRL PREPARED: NRL REVIEWED: KAB APPROVED: KFK	TITLE **ALTERNATIVE POWER BLOCK ARRANGEMENTS**	
		PROJECT NO.: 1414979 CONTROL: B058	REV.: 0 FIGURE: 2-3

APPENDIX A

EXPECTED PERFORMANCE, STACK AND EMISSION INFORMATION FOR GE 7HA.02 COMBUSTION TURBINE/HRSG

TABLE A-1
DESIGN INFORMATION AND STACK PARAMETERS FOR OCEC UNIT 1
GE 7HA.02 CT, NATURAL GAS, BASE LOAD

	CT Ambient Temperature			
Parameter	**35 °F**	**59 °F**	**75 °F**	**95 °F**
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	3,028.0	3,068.3	3,095.7	3,102.3
(MMBtu/hr, HHV)	3,361.1	3,405.8	3,436.2	3,443.6
Wet Compression/Evap Cooling	Off	On	On	On
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	20,566	20,566.0	20,566.0	20,566.0
(Btu/lb, HHV)	22,828	22,828	22,828	22,828
(HHV/LHV)	1.110	1.110	1.110	1.110
Steam Flow (lb/hr)	NA	NA	NA	NA
CT/DB Exhaust Flow				
Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (^{o}F + 460 K)] / [2112.5 x 60 min/hr x MW]				
Mass Flow (lb/hr)	5,635,000	5,650,000	5,566,000	5,487,000
Temperature (°F)	1,211	1,186	1,223	1,252
Moisture (% Vol.)	9.16	11.60	12.53	13.76
Oxygen (% Vol.)	11.11	10.59	10.23	9.87
Molecular Weight	28.37	28.10	28.01	27.88
Volume flow (acfm)	4,041,180	4,029,667	4,072,034	4,102,448
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)	3,028	3,068	3,096	3,102
Heat content (Btu/lb, LHV)	20,566	20,566	20,566	20,566
Fuel usage (lb/hr)	147,233	149,193	150,525	150,846
Heat content (Btu/cf, LHV)	918	918	918	918
Fuel density (lb/ft^3)	0.0446	0.0446	0.0446	0.0446
Fuel usage (cf/hr)	3,298,475	3,342,375	3,372,222	3,379,412
HRSG Stack				
HRSG - Stack Height (feet)	149	149	149	149
Diameter (feet)	25.6	25.6	25.6	25.6
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	5,635,000	5,650,000	5,566,000	5,487,000
HRSG Stack Temperature (^{o}F)	177	180	182	184
Molecular weight	28.37	28.10	28.01	27.88
Volume flow (acfm)	1,540,292	1,567,065	1,552,115	1,544,169
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)- calculated	49.9	50.8	50.3	50.1

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia).
Source: GE, 2015; Golder, 2015.

TABLE A-2
EMISSIONS FOR CRITERIA POLLUTANTS FOR OCEC UNIT 1
GE 7HA.02, CT NATURAL GAS, BASE LOAD

	CT Ambient Temperature				
Parameter	**35 °F**	**59 °F**	**75 °F**	**95 °F**	
Particulate (including $PM_{2.5}$) from CT and SCR					
Total PM_{10} = PM_{10} (CT Front Half + Back Half) + PM_{10} [$(NH_4)_2SO_4$] in HRSG					
a. PM_{10} (CT front half + back half) (lb/hr)					
Total emission rate (lb/hr)	10.5	10.5	10.5	10.5	
b. PM_{10} [$(NH_4)_2SO_4$] from HRSG only (back half) = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})					
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 in CT and in SCR x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$ / lb SO_3					
CT SO_2 emission rate (lb/hr)	18.8	19.1	19.3	19.3	
Conversion (%) from SO_2 to SO_3 in CT	10.0	10.0	10.0	10.0	
DB SO_2 emission rate (lb/hr)	--	--	--	--	
Conversion (%) from SO_2 to SO_3 in DB	--	--	--	--	
Remaining SO_2 (lb/hr) after conversion	17.0	17.2	17.3	17.4	
Conversion (%) from SO_2 to SO_3 in SCR	3.0	3.0	3.0	3.0	
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3	
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100	
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7	
HRSG Particulate as $(NH_4)_2(SO_4)$ (lb/hr)	4.94	5.00	5.05	5.06	
Total HRSG stack emission rate (lb/hr) [a + b]	15.4	15.5	15.5	15.6	#
Sulfur Dioxide					
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 (cf/hr)	3,298,475	3,342,375	3,372,222	3,379,412	
Sulfur content (grains/ 100 cf)	2	2	2	2	
lb SO_2 /lb S (64/32)	2	2	2	2	
HRSG stack emission rate (lb/hr)	18.8	19.1	19.3	19.3	
Nitrogen Oxides					
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]					
NO_x (ppmv actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]					
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr					
Basis, ppm actual	33.4	33.4	34.1	44.2	
Basis, ppmvd @15% O_2	25	25	25	32	
Moisture (%)	9.16	11.60	12.53	13.76	
Oxygen (%)	11.11	10.59	10.23	9.87	
Oxygen (%) dry	12.23	11.98	11.70	11.44	
Turbine Flow (acfm)	4,041,180	4,029,667	4,072,034	4,102,448	
Turbine Flow (acfm), dry	3,671,008	3,562,225	3,561,808	3,537,951	
Turbine Exhaust Temperature (°F)	1,211	1,186	1,223	1,252	
CT/DB emission rate (lb/hr)	304.9	309.0	311.8	400.4	
HRSG Stack emission rate, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	
HRSG stack emission rate (lb/hr)	24.4	24.7	24.9	25.0	#
Carbon Monoxide					
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]					
CO (ppmv wet or actual) = CO (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]					
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr					
Basis, ppm actual	6.48	6.64	6.80	6.93	
Basis, ppmvd @15% O_2	4.30	4.30	4.30	4.30	
Moisture (%)	9.16	11.60	12.53	13.76	
Oxygen (%)	11.11	10.59	10.23	9.87	
Oxygen (%) dry	12.23	11.98	11.70	11.44	
Turbine Flow (acfm)	4,041,180	4,029,667	4,072,034	4,102,448	
Turbine Flow (acfm), dry	3,671,008	3,562,225	3,561,808	3,537,951	
Turbine Exhaust Temperature (°F)	1,211	1,186	1,223	1,252	
CT/DB emission rate (lb/hr)	36.0	37.4	37.8	38.2	
HRSG Stack emission rate, ppmvd @ 15% O_2	4.3	4.3	4.3	4.3	
Volatile Organic Compounds					
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]					
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]					
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr					
Basis, ppm actual	1.51	1.54	1.58	1.61	
Basis, ppmvd @15% O_2	1.00	1.00	1.00	1.00	
Moisture (%)	9.16	11.60	12.53	13.76	
Turbine Flow (acfm)	4,041,180	4,029,667	4,072,034	4,102,448	
Turbine Flow (acfm), dry	3,671,008	3,562,225	3,561,808	3,537,951	
Turbine Exhaust Temperature (°F)	1,211	1,186	1,223	1,252	
CT/DB emission rate (lb/hr)	4.79	4.97	5.03	5.08	
HRSG Stack emission rate (lb/hr)	4.8	5.0	5.0	5.1	
Sulfuric Acid Mist					
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100					
CT SO_2 emission rate (lb/hr)	18.8	19.1	19.3	19.3	
CT Conversion to H_2SO_4 (% by weight)	10	10	10	10	
DB SO_2 emission rate (lb/hr)	0	0	0	0	
DB Conversion to H_2SO_4 (%)	20	20	20	20	
SCR SO_2 (lb/hr)(remaining SO_2 after conversion)	17.0	17.2	17.3	17.4	
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3	
HRSG Stack emission rate (lb/hr)	3.67	3.71	3.75	3.76	
Lead					
Lead (lb/hr) = NA					
Emission Rate Basis	NA	NA	NA	NA	
Emission rate (lb/hr)	NA	NA	NA	NA	

Note: ppmvd= parts per million, volume dry; O_2= oxygen.
Source: GE, 2015; Golder, 2015.

TABLE A-3
DESIGN INFORMATION AND STACK PARAMETERS
FOR OCEC UNIT 1
GE 7HA.02 CT, NATURAL GAS, 75% LOAD

Parameter	**Ambient Temperature** 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	2,385.6	2,299.1	2,245.3	2,154.7
(MMBtu/hr, HHV)	2,648.0	2,552.0	2,492.3	2,391.7
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	20,566.0	20,566.0	20,566.0	20,566.0
(Btu/lb, HHV)	22,828	22,828	22,828	22,828
(HHV/LHV)	1.110	1.110	1.110	1.110
CT/DB Exhaust Flow				
Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (^{o}F + 460 K)] / [2112.5 x 60 min/hr x MW]				
Mass flow (lb/hr)	4,545,000	4,482,000	4,439,000	4,351,000
Temperature (°F)	1,223	1,223	1,223	1,223
Moisture (% Vol.)	8.96	9.33	9.91	10.69
Oxygen (% Vol.)	11.33	11.44	11.44	11.46
Molecular Weight	28.38	28.33	28.26	28.17
Volume flow (acfm)	3,281,729	3,241,952	3,218,802	3,165,071
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)	2,386	2,299	2,245	2,155
Heat content (Btu/lb, LHV)	20,566	20,566	20,566	20,566
Fuel usage (lb/hr)	115,997	111,791	109,175	104,770
Heat content (Btu/cf, LHV)	918	918	918	918
Fuel density (lb/ft^3)	0.0446	0.0446	0.0446	0.0446
Fuel usage (cf/hr)	2,598,693	2,504,466	2,445,861	2,347,168
HRSG Stack				
HRSG - Stack Height (feet)	149	149	149	149
Diameter (feet)	25.6	25.6	25.6	25.6
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	4,545,000	4,482,000	4,439,000	4,351,000
HRSG Stack Temperature (^{o}F)	171	171	176	182
Molecular weight	28.38	28.33	28.26	28.17
Volume flow (acfm)	1,230,210	1,215,299	1,216,183	1,206,977
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)	39.9	39.4	39.4	39.1

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft^2 (@14.69 psia).
Source: GE, 2015; Golder, 2015.

TABLE A-4
EMISSIONS FOR CRITERIA POLLUTANTS FOR OCEC UNIT 1
GE 7HA.02 CT, NATURAL GAS, 75% LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Particulate (including $PM_{2.5}$) from CT and SCR				
Total PM_{10} = PM_{10} (CT front half + back half) + PM_{10} [$(NH_4)_2SO_4$] in HRSG only (back-half)				
a. PM_{10} (front half) (lb/hr)				
Emission (lb/hr)	10.50	10.50	10.50	10.50
b. PM_{10} [$(NH_4)_2SO_4$] from HRSG only (back half) = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 in CT and in SCR x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$ / lb SO_3				
CT SO_2 emission rate (lb/hr)	14.8	14.3	14.0	13.4
Conversion (%) from SO_2 to SO_3 in CT	10.0	10.0	10.0	10.0
Remaining SO_2 (lb/hr) in CT after conversion	13.4	12.9	12.6	12.1
Conversion (%) from SO_2 to SO_3 in SCR	3.0	3.0	3.0	3.0
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
HRSG Particulate as $(NH_4)_2(SO_4)$ (lb/hr)	3.89	3.75	3.66	3.51
Total HRSG stack emission rate (lb/hr) [a + b]	14.4	14.2	14.2	14.0
(lb/mmBtu, HHV)	NA	NA	NA	NA
Sulfur Dioxide				
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 (cf/hr)	2,598,693	2,504,466	2,445,861	2,347,168
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2
HRSG Stack emission rate (lb/hr)	14.8	14.3	14.0	13.4
Nitrogen Oxides				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
NO_x (ppm actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	32.6	31.8	31.3	39.1
Basis, ppmvd @15% O_2	25	25	25	32
Moisture (%)	8.96	9.33	9.91	10.69
Oxygen (%)	11.33	11.44	11.44	11.46
Oxygen (%) dry	12.45	12.62	12.70	12.83
Turbine Flow (acfm)	3,281,729	3,241,952	3,218,802	3,165,071
Turbine Flow (acfm), dry	2,987,686	2,939,478	2,899,819	2,826,725
Turbine Exhaust Temperature (°F)	1,223	1,223	1,223	1,223
CT Emission rate (lb/hr)	240.3	231.6	226.2	277.7
HRSG Stack emission rate, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0
HRSG Stack emission rate (lb/hr)	19.2	18.5	18.1	17.4
Carbon Monoxide				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
CO (ppmv wet or actual) = CO (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	9.3	9.0	8.9	8.7
Basis, ppmvd @15% O_2	7.1	7.1	7.1	7.1
Moisture (%)	8.96	9.33	9.91	10.69
Oxygen (%)	11.33	11.44	11.44	11.46
Oxygen (%) dry	12.45	12.62	12.70	12.83
Turbine Flow (acfm)	3,281,729	3,241,952	3,218,802	3,165,071
Turbine Flow (acfm), dry	2,987,686	2,939,478	2,899,819	2,826,725
Turbine Exhaust Temperature (°F)	1,223	1,223	1,223	1,223
CT Emission rate (lb/hr)	41.5	40.0	39.1	37.5
HRSG Stack emission rate, ppmvd @ 15% O_2	7.1	7.1	7.1	7.1
HRSG Stack emission rate (lb/hr)	41.5	40.0	39.1	37.5
Volatile Organic Compounds				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	1.3	1.3	1.3	1.2
Basis, ppmvd @15% O_2	1.00	1.00	1.00	1.00
Moisture (%)	8.96	9.33	9.91	10.69
Oxygen (%)	11.33	11.44	11.44	11.46
Oxygen (%) dry	12.45	12.62	12.70	12.83
Turbine Flow (acfm)	3,281,729	3,241,952	3,218,802	3,165,071
Turbine Flow (acfm), dry	2,987,686	2,939,478	2,899,819	2,826,725
Turbine Exhaust Temperature (°F)	1,223	1,223	1,223	1,223
CT Emission rate (lb/hr)	3.34	3.22	3.15	3.02
HRSG Stack emission rate (lb/hr)	3.3	3.2	3.1	3.0
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr)	14.8	14.3	14.0	13.4
CT Conversion to H_2SO_4 (% by weight)	10	10	10	10
DB SO_2 emission rate (lb/hr)	0	0	0	0
DB Conversion to H_2SO_4 (%)	20	20	20	20
SCR SO_2 emission rate (lb/hr) - calculated (remaining SO_2 after conversion)	13.4	12.9	12.6	12.1
HRSG Stack emission rate (lb/hr)	2.89	2.78	2.72	2.61
Lead				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
HRSG Stack emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O2= oxygen
Source: GE, 2015; Golder, 2015.

TABLE A-5
DESIGN INFORMATION AND STACK PARAMETERS
FOR OCEC UNIT 1
GE 7HA.02 CT, NATURAL GAS, 50% LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	1,819.1	1,749.9	1,711.2	1,648
(MMBtu/hr, HHV)	2,019.2	1,942.4	1,899.4	1,829.1
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	20,566.0	20,566.0	20,566.0	20,566
(Btu/lb, HHV)	22,828	22,828	22,828	22,828
(HHV/LHV)	1.110	1.110	1.110	1.110
CT/DB 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]				
Mass flow (lb/hr)	3,763,000	3,694,000	3,653,000	3,575,000
Temperature (°F)	1,223	1,223	1,226	1,231
Moisture (% Vol.)	8.30	8.70	9.31	10.15
Oxygen (% Vol.)	12.07	12.14	12.11	12.07
Molecular Weight	28.42	28.37	28.30	28.20
Volume flow (acfm)	2,713,260	2,668,203	2,649,830	2,610,163
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)	1,819	1,750	1,711	1,648
Heat content (Btu/lb, LHV)	20,566	20,566	20,566	20,566
Fuel usage (lb/hr)	88,452	85,087	83,205	80,123
Heat content (Btu/cf, LHV)	918	918	918	918
Fuel density (lb/ft^3)	0.0446	0.0446	0.0446	0.0446
Fuel usage (cf/hr)	1,981,590	1,906,209	1,864,052	1,794,989
HRSG Stack				
HRSG - Stack Height (feet)	149	149	149	149
Diameter (feet)	25.6	25.6	25.6	25.6
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,763,000	3,694,000	3,653,000	3,575,000
HRSG Stack Temperature (°F)	168	169	172	178
Molecular weight	28.42	28.37	28.30	28.20
Volume flow (acfm)	1,012,918	997,049	992,665	984,021
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)	32.8	32.3	32.2	31.9

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia).
Source: GE, 2015; Golder, 2015.

TABLE A-6
EMISSIONS FOR CRITERIA POLLUTANTS FOR OCEC UNIT 1
GE 7HA.02 CT, NATURAL GAS, 50% LOAD

	Ambient Temperature			
Parameter	**35 °F**	**59 °F**	**75 °F**	**95 °F**
Particulate from CT and HRSG				
Particulate (including $PM_{2.5}$) from CT and SCR				
a. PM_{10} (CT front half + back half) (lb/hr)				
Emission (lb/hr)	10.50	10.50	10.50	10.50
b. PM_{10} [$(NH_4)_2SO_4$] from HRSG only (back half) = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 in CT and in SCR x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
CT SO_2 emission rate (lb/hr)	11.3	10.9	10.7	10.3
Conversion (%) from SO_2 to SO_3 in CT	10.0	10.0	10.0	10.0
Remaining SO_2 (lb/hr) in CT after conversion	10.2	9.8	9.6	9.2
Conversion (%) from SO_2 to SO_3 in SCR	3.0	3.0	3.0	3.0
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
HRSG Particulate as $(NH_4)_2(SO_4)$ (lb/hr)	2.97	2.85	2.79	2.69
Total HRSG stack emission rate (lb/hr) [a + b]	13.5	13.4	13.3	13.2
Sulfur Dioxide				
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 (cf/hr)	1,981,590	1,906,209	1,864,052	1,794,989
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2
HRSG Stack emission rate (lb/hr)	11.3	10.9	10.7	10.3
Nitrogen Oxides				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
NO_x (ppm actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	30.1	29.4	29.0	36.4
Basis, ppmvd @15% O_2	25	25	25	32
Moisture (%)	8.30	8.70	9.31	10.15
Oxygen (%)	12.07	12.14	12.11	12.07
Oxygen (%) dry	13.16	13.30	13.35	13.43
Turbine Flow (acfm)	2,713,260	2,668,203	2,649,830	2,610,163
Turbine Flow (acfm), dry	2,488,059	2,436,069	2,403,131	2,345,232
Turbine Exhaust Temperature (°F)	1,223	1,223	1,226	1,231
CT Emission rate (lb/hr)	183.1	176.2	172.2	212.2
HRSG Stack emission rate, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0
HRSG Stack emission rate (lb/hr)	14.6	14.1	13.8	13.3
Carbon Monoxide				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
CO (ppmv wet or actual) = CO (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	8.5	8.4	8.2	8.1
Basis, ppmvd @15% O_2	7.1	7.1	7.1	7.1
Moisture (%)	8.30	8.70	9.31	10.15
Oxygen (%)	12.07	12.14	12.11	12.07
Oxygen (%) dry	13.16	13.30	13.35	13.43
Turbine Flow (acfm)	2,713,260	2,668,203	2,649,830	2,610,163
Turbine Flow (acfm), dry	2,488,059	2,436,069	2,403,131	2,345,232
Turbine Exhaust Temperature (°F)	1,223	1,223	1,226	1,231
CT Emission rate (lb/hr)	31.7	30.5	29.8	28.7
HRSG Stack emission rate, ppmvd	7.1	7.1	7.1	7.1
HRSG Stack emission rate (lb/hr)	31.7	30.5	29.8	28.7
Volatile Organic Compounds				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	1.2	1.2	1.2	1.1
Basis, ppmvd @15% O_2	1.00	1.00	1.00	1.00
Moisture (%)	8.30	8.70	9.31	10.15
Oxygen (%)	12.07	12.14	12.11	12.07
Oxygen (%) dry	13.16	13.30	13.35	13.43
Turbine Flow (acfm)	2,713,260	2,668,203	2,649,830	2,610,163
Turbine Flow (acfm), dry	2,488,059	2,436,069	2,403,131	2,345,232
Turbine Exhaust Temperature (°F)	1,223	1,223	1,226	1,231
CT Emission rate (lb/hr)	2.55	2.45	2.40	2.31
HRSG Stack emission rate (lb/hr)	2.5	2.5	2.4	2.3
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr)	11.3	10.9	10.7	10.3
CT Conversion to H_2SO_4 (% by weight)	10	10	10	10
DB SO_2 emission rate (lb/hr)	0	0	0	0
DB Conversion to H_2SO_4 (%)	20	20	20	20
SCR SO_2 emission rate (lb/hr) - calculated (remaining SO_2 after conv	10.2	9.8	9.6	9.2
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3
HRSG Stack emission rate (lb/hr)	2.20	2.12	2.07	1.99
Lead				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
HRSG Stack emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O2= oxygen.
Source: GE, 2015; Golder, 2015.

TABLE A-7
DESIGN INFORMATION AND STACK PARAMETERS
FOR OCEC UNIT 1
GE 7HA.02 CT, ULSD OIL, BASE LOAD

Parameter	**Ambient Temperature** 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	3,053.6	2,949.5	2,912.5	2,885.0
(MMBtu/hr, HHV)	3,236.8	3,126.5	3,087.3	3,058.1
Evaporative Cooling	Off	On	On	On
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	18,300.0	18,300.0	18,300.0	18,300.0
(Btu/lb, HHV)	19,398	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060	1.060
CT/DB 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]				
Mass Flow (lb/hr)	5,953,000	5,788,000	5,753,000	5,759,000
Temperature (°F)	1,046	1,058	1,065	1,072
Moisture (% Vol.)	11.82	12.39	12.97	13.82
Oxygen (% Vol.)	10.70	10.65	10.60	10.53
Molecular Weight	28.28	28.21	28.14	28.04
Volume flow (acfm)	3,859,923	3,792,227	3,796,097	3,831,113
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)	3,054	2,950	2,913	2,885
Heat content (Btu/lb, LHV)	18,300	18,300	18,300	18,300
Fuel usage (lb/hr)	166,863	161,175	159,153	157,650
HRSG Stack				
HRSG - Stack Height (feet)	149	149	149	149
Diameter (feet)	25.6	25.6	25.6	25.6
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	5,953,000	5,788,000	5,753,000	5,759,000
HRSG Stack Temperature (°F)	205	204	208	213
Molecular weight	28.28	28.21	28.14	28.04
Volume flow (acfm)	1,705,440	1,658,288	1,662,815	1,683,239
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)	55.3	53.8	53.9	54.6

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia).
Source: GE, 2015; Golder, 2015.

TABLE A-8
EMISSIONS FOR CRITERIA POLLUTANTS FOR OCEC UNIT 1
GE 7HA.02 CT, ULSD OIL, BASE LOAD

Parameter	**Ambient Temperature** 35 °F	59 °F	75 °F	95 °F
Particulate (including $PM_{2.5}$) from CT and SCR				
Total PM_{10} = PM_{10} (CT front half + back half) + PM_{10} [$(NH_4)_2SO_4$] in HRSG only (back-half)				
a. PM_{10} (CT front half + back half) (lb/hr)				
Emission (lb/hr)	68.70	68.70	68.70	68.70
b. PM_{10} ($(NH_4)_2SO_4$) from HRSG only (back half) = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 in CT and in SCR x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)	5.0	4.8	4.8	4.7
Conversion (%) from SO_2 to SO_3	10.0	10.0	10.0	10.0
Remaining SO_2 (lb/hr) in CT after conversion	4.5	4.4	4.3	4.3
Conversion (%) from SO_2 to SO_3 in SCR	3.0	3.0	3.0	3.0
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
HRSG Particulate as $(NH_4)_2(SO_4)$ (lb/hr)	1.31	1.27	1.25	1.24
Total HRSG stack emission rate (lb/hr) [a + b]	70.0	70.0	70.0	69.9
(lb/mmBtu, HHV)	NA	NA	NA	NA
Sulfur Dioxide				
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%
Fuel oil use (lb/hr)	166,863	161,175	159,153	157,650
lb SO_2 / lb S (64/32)	2	2	2	2
HRSG Stack emission rate (lb/hr)	5.0	4.8	4.8	4.7
Nitrogen Oxides				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisture (%)]				
NO_x (ppm actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	55.0	54.5	54.0	53.3
Basis, ppmvd @15% O_2	42	42	42	42
Moisture (%)	11.82	12.39	12.97	13.82
Oxygen (%)	10.70	10.65	10.60	10.53
Oxygen (%) dry	12.13	12.16	12.18	12.22
Turbine Flow (acfm)	3,859,923	3,792,227	3,796,097	3,831,113
Turbine Flow (acfm), dry	3,403,680	3,322,370	3,303,743	3,301,653
Turbine Exhaust Temperature (°F)	1,046	1,058	1,065	1,072
CT Emission rate (lb/hr) - calculated	532.8	514.7	508.1	503.2
HRSG Stack emission rate, ppmvd @ 15% O_2	8.0	8.0	8.0	8.0
HRSG Stack emission rate (lb/hr)	101.5	98.0	96.8	95.8
Carbon Monoxide				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisture (%)]				
CO (ppmv wet or actual) = CO (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	13.1	13.0	12.9	12.7
Basis, ppmvd @15% O_2	10	10	10	10
Moisture (%)	11.82	12.39	12.97	13.82
Oxygen (%)	10.70	10.65	10.60	10.53
Oxygen (%) dry	12.13	12.16	12.18	12.22
Turbine Flow (acfm)	3,859,923	3,792,227	3,796,097	3,831,113
Turbine Flow (acfm), dry	3,403,680	3,322,370	3,303,743	3,301,653
Turbine Exhaust Temperature (°F)	1,046	1,058	1,065	1,072
CT Emission rate (lb/hr)	77.2	74.6	73.6	72.9
HRSG Stack emission rate (lb/hr)	77.2	74.6	73.6	72.9
Volatile Organic Compounds				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisture (%)]				
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	2.6	2.6	2.6	2.5
Basis, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0
Moisture (%)	11.82	12.39	12.97	13.82
Oxygen (%)	10.70	10.65	10.60	10.53
Oxygen (%-dry)	12.13	12.16	12.18	12.22
Turbine Flow (acfm)	3,859,923	3,792,227	3,796,097	3,831,113
Turbine Flow (acfm), dry	3,403,680	3,322,370	3,303,743	3,301,653
Turbine Exhaust Temperature (°F)	1,046	1,058	1,065	1,072
CT Emission rate (lb/hr)	8.8	8.5	8.4	8.3
HRSG Stack emission rate (lb/hr)	8.8	8.5	8.4	8.3
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr)	5.0	4.8	4.8	4.7
CT Conversion to H_2SO_4 (% by weight)	10	10	10	10
DB SO_2 emission rate (lb/hr)	0	0	0	0
DB Conversion to H_2SO_4 (%)	20	20	20	20
SCR SO_2 emission rate (lb/hr) - calculated (remaining SO_2 after conversion)	4.5	4.4	4.3	4.3
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3
HRSG Stack emission rate (lb/hr)	0.97	0.94	0.93	0.92
Lead				
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14
HRSG Stack emission rate (lb/hr)- calculated	0.0453	0.0438	0.0432	0.0428

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia)
Source: GE, 2015; Golder, 2015.

TABLE A-9
DESIGN INFORMATION AND STACK PARAMETERS
FOR OCEC UNIT 1
GE 7HA.02 CT, ULSD OIL, 75% LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	2,406.7	2,307.5	2,312.5	2,150.3
(MMBtu/hr, HHV)	2,551.1	2,446.0	2,451.3	2,279.3
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	18,300.0	18,300.0	18,300.0	18,300.0
(Btu/lb, HHV)	19,398	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060	1.060
CT/DB Exhaust Flow				
Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (^{o}F + 460 K)] / [2112.5 x 60 min/hr x MW]				
Mass Flow (lb/hr)	4,662,000	4,513,000	4,552,000	4,262,000
Temperature (°F)	1,103	1,120	1,123	1,154
Moisture (% Vol.)	11.27	11.70	12.27	12.89
Oxygen (% Vol.)	10.75	10.75	10.70	10.64
Molecular Weight	28.35	28.29	28.22	28.15
Volume flow (acfm)	3,129,503	3,068,928	3,109,019	2,975,334
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)	2,407	2,308	2,313	2,150
Heat content (Btu/lb, LHV)	18,300	18,300	18,300	18,300
Fuel usage (lb/hr)	131,514	126,093	126,366	117,503
HRSG Stack				
HRSG - Stack Height (feet)	149	149	149	149
Diameter (feet)	25.6	25.6	25.6	25.6
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	4,662,000	4,513,000	4,552,000	4,262,000
HRSG Stack Temperature (^{o}F)	191	188	193	194
Molecular weight	28.35	28.29	28.22	28.15
Volume flow (acfm)	1,304,060	1,259,037	1,282,298	1,206,356
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)	42.3	40.8	41.6	39.1

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia)
Source: GE, 2015; Golder, 2015.

TABLE A-10
EMISSIONS FOR CRITERIA POLLUTANTS FOR OCEC UNIT 1
GE 7HA.02 CT, ULSD OIL, 75% LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Particulate (including $PM_{2.5}$) from CT and SCR				
Total PM_{10} = PM_{10} (CT front half + back half) + PM_{10} [$(NH_4)_2SO_4$] in HRSG only (back-half)				
a. PM_{10} (CT front half + back half) (lb/hr)				
Emission (lb/hr)	68.30	68.30	68.30	68.30
b. PM_{10} ($(NH_4)_2SO_4$) from HRSG only (back half) = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 in CT and in SCR x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$ / lb SO_3				
SO_2 emission rate (lb/hr)	3.9	3.8	3.8	3.5
Conversion (%) from SO_2 to SO_3	10.0	10.0	10.0	10.0
Remaining SO_2 (lb/hr) in CT after conversion	3.6	3.4	3.4	3.2
Conversion (%) from SO_2 to SO_3 in SCR	3.0	3.0	3.0	3.0
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
HRSG Particulate as $(NH_4)_2(SO_4)$ (lb/hr)	1.03	0.99	0.99	0.92
Total HRSG stack emission rate (lb/hr) [a + b]	69.3	69.3	69.3	69.2
Sulfur Dioxide				
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%
Fuel oil use (lb/hr)	131,514	126,093	126,366	117,503
lb SO_2 / lb S (64/32)	2	2	2	2
HRSG Stack emission rate (lb/hr)	3.9	3.8	3.8	3.5
Nitrogen Oxides				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
NO_x (ppm actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60				
Basis, ppm actual	55.5	54.8	54.4	53.9
Basis, ppmvd @15% O_2	42	42	42	42
Moisture (%)	11.27	11.70	12.27	12.89
Oxygen (%)	10.75	10.75	10.70	10.64
Oxygen (%) dry	12.12	12.17	12.20	12.21
Turbine Flow (acfm)	3,129,503	3,068,928	3,109,019	2,975,334
Turbine Flow (acfm), dry	2,776,808	2,709,863	2,727,542	2,591,814
Turbine Exhaust Temperature (°F)	1,103	1,120	1,123	1,154
CT Emission rate (lb/hr)	419.7	402.5	403.3	375.1
HRSG Stack emission rate, ppmvd @ 15% O_2	8.0	8.0	8.0	8.0
HRSG Stack emission rate (lb/hr)	79.9	76.7	76.8	71.4
Carbon Monoxide				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
CO (ppmv wet or actual) = CO (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	18.0	17.8	17.6	17.4
Basis, ppmvd @15% O_2	13.6	13.6	13.6	13.6
Moisture (%)	11.27	11.70	12.27	12.89
Oxygen (%)	10.75	10.75	10.70	10.64
Oxygen (%) dry	12.12	12.17	12.20	12.21
Turbine Flow (acfm)	3,129,503	3,068,928	3,109,019	2,975,334
Turbine Flow (acfm), dry	2,776,808	2,709,863	2,727,542	2,591,814
Turbine Exhaust Temperature (°F)	1,103	1,120	1,123	1,154
CT Emission rate (lb/hr)	82.7	79.3	79.5	73.9
HRSG Stack emission rate (lb/hr)	82.7	79.3	79.5	73.9
Volatile Organic Compounds				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	2.6	2.6	2.6	2.6
Basis, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0
Moisture (%)	11.27	11.70	12.27	12.89
Oxygen (%)	10.75	10.75	10.70	10.64
Oxygen (%-dry)	12.12	12.17	12.20	12.21
Turbine Flow (acfm)	3,129,503	3,068,928	3,109,019	2,975,334
Turbine Flow (acfm), dry	2,776,808	2,709,863	2,727,542	2,591,814
Turbine Exhaust Temperature (°F)	1,103	1,120	1,123	1,154
CT Emission rate (lb/hr)	7.0	6.7	6.7	6.2
HRSG Stack emission rate (lb/hr)	7.0	6.7	6.7	6.2
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr)	3.9	3.8	3.8	3.5
CT Conversion to H_2SO_4 (% by weight)	10	10	10	10
DB SO_2 emission rate (lb/hr)	0	0	0	0
DB Conversion to H_2SO_4 (%)	20	20	20	20
SCR SO_2 emission rate (lb/hr) - calculated (remaining SO_2 after conversion)	3.6	3.4	3.4	3.2
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3
HRSG Stack emission rate (lb/hr)	0.77	0.74	0.74	0.69
Lead				
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14
HRSG Stack emission rate (lb/hr)	0.0357	0.0342	0.0343	0.0319

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia)
Source: GE, 2015; Golder, 2015.

TABLE A-11
DESIGN INFORMATION AND STACK PARAMETERS
FOR OCEC UNIT 1
GE 7HA.02 CT, ULSD OIL, 50% LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	1,879.4	1,792.7	1,785.0	1,670.3
(MMBtu/hr, HHV)	1,992.2	1,900.3	1,892.1	1,770.5
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	18,300.0	18,300.0	18,300.0	18,300.0
(Btu/lb, HHV)	19,398	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060	1.060
CT/DB Exhaust Flow				
Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (^{o}F + 460 K)] / [2112.5 x 60 min/hr x MW]				
Mass Flow (lb/hr)	3,656,000	3,511,000	3,511,000	3,309,000
Temperature (°F)	1,205	1,223	1,226	1,254
Moisture (% Vol.)	10.81	11.16	11.69	12.34
Oxygen (% Vol.)	10.86	10.85	10.79	10.73
Molecular Weight	28.40	28.35	28.29	28.21
Volume flow (acfm)	2,609,752	2,537,810	2,547,725	2,447,945
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)	1,879	1,793	1,785	1,670
Heat content (Btu/lb, LHV)	18,300	18,300	18,300	18,300
Fuel usage (lb/hr)	102,699	97,962	97,541	91,273
HRSG Stack				
HRSG - Stack Height (feet)	149	149	149	149
Diameter (feet)	25.6	25.6	25.6	25.6
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,656,000	3,511,000	3,511,000	3,309,000
HRSG Stack Temperature (^{o}F)	175	174	177	180
Molecular weight	28.40	28.35	28.29	28.21
Volume flow (acfm)	995,311	956,014	962,575	914,052
Diameter (feet)	25.58333333	25.58333333	25.58333333	25.58333333
Velocity (ft/sec)	32.3	31.0	31.2	29.6

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft^2 (@14.69 psia).
Source: GE, 2015; Golder, 2015.

TABLE A-12
EMISSIONS FOR CRITERIA POLLUTANTS FOR OCEC UNIT 1
7HA.02 CT, ULSD OIL, 50% LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Particulate (including $PM_{2.5}$) from CT and SCR				
Total PM_{10} = PM_{10} (CT front half + back half) + PM_{10} [$(NH_4)_2SO_4$] in HRSG only (back-half)				
a. PM_{10} (CT front half + back half) (lb/hr)				
Emission (lb/hr)	68.30	68.30	68.30	68.30
b. PM_{10} ($(NH_4)_2SO_4$) from HRSG only (back half) = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 in CT and in SCR x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)	3.1	2.9	2.9	2.7
Conversion (%) from SO_2 to SO_3	10.0	10.0	10.0	10.0
Remaining SO_2 (lb/hr) in CT after conversion	2.8	2.6	2.6	2.5
Conversion (%) from SO_2 to SO_3 in SCR	3.0	3.0	3.0	3.0
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
HRSG Particulate as $(NH_4)_2(SO_4)$ (lb/hr)	0.81	0.77	0.77	0.72
Total HRSG stack emission rate (lb/hr) [a + b]	69.1	69.1	69.1	69.0
(lb/mmBtu, HHV)	NA	NA	NA	NA
Sulfur Dioxide				
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%
Fuel oil use (lb/hr)	102,699	97,962	97,541	91,273
lb SO_2 / lb S (64/32)	2	2	2	2
HRSG Stack emission rate (lb/hr)	3.1	2.9	2.9	2.7
Nitrogen Oxides				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisture (%)]				
NO_x (ppm actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	55.4	54.9	54.6	54.0
Basis, ppmvd @15% O_2	42	42	42	42
Moisture (%)	10.81	11.16	11.69	12.34
Oxygen (%)	10.86	10.85	10.79	10.73
Oxygen (%) dry	12.18	12.21	12.22	12.24
Turbine Flow (acfm)	2,609,752	2,537,810	2,547,725	2,447,945
Turbine Flow (acfm), dry	2,327,638	2,254,590	2,249,896	2,145,869
Turbine Exhaust Temperature (°F)	1,205	1,223	1,226	1,254
CT Emission rate (lb/hr) - calculated	328.0	313.0	311.6	291.6
HRSG Stack emission rate, ppmvd @ 15% O_2	8.0	8.0	8.0	8.0
HRSG Stack emission rate (lb/hr)	62.5	59.6	59.3	55.5
Carbon Monoxide				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisture (%)]				
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	17.9	17.8	17.7	17.5
Basis, ppmvd @15% O_2	13.6	13.6	13.6	13.6
Moisture (%)	10.81	11.16	11.69	12.34
Oxygen (%)	10.86	10.85	10.79	10.73
Oxygen (%) dry	12.18	12.21	12.22	12.24
Turbine Flow (acfm)	2,609,752	2,537,810	2,547,725	2,447,945
Turbine Flow (acfm), dry	2,327,638	2,254,590	2,249,896	2,145,869
Turbine Exhaust Temperature (°F)	1,205	1,223	1,226	1,254
CT Emission rate (lb/hr)	64.6	61.7	61.4	57.5
HRSG Stack emission rate (lb/hr)	64.6	61.7	61.4	57.5
Volatile Organic Compounds				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisture (%)]				
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	2.6	2.6	2.6	2.6
Basis, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0
Moisture (%)	10.81	11.16	11.69	12.34
Oxygen (%)	10.86	10.85	10.79	10.73
Oxygen (%-dry)	12.18	12.21	12.22	12.24
Turbine Flow (acfm)	2,609,752	2,537,810	2,547,725	2,447,945
Turbine Flow (acfm), dry	2,327,638	2,254,590	2,249,896	2,145,869
Turbine Exhaust Temperature (°F)	1,205	1,223	1,226	1,254
CT Emission rate (lb/hr)	5.4	5.2	5.2	4.8
HRSG Stack emission rate (lb/hr)	5.4	5.2	5.2	4.8
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr)	3.1	2.9	2.9	2.7
CT Conversion to H_2SO_4 (% by weight)	10	10	10	10
DB SO_2 emission rate (lb/hr)	0	0	0	0
DB Conversion to H_2SO_4 (%)	20	20	20	20
SCR SO_2 emission rate (lb/hr) - calculated (remaining SO_2 after conversion)	2.8	2.6	2.6	2.5
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3
HRSG Stack emission rate (lb/hr)	0.60	0.57	0.57	0.53
Lead				
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14
HRSG Stack emission rate (lb/hr)- calculated	0.0279	0.0266	0.0265	0.0248

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia)
Source: GE, 2015; Golder, 2015.

TABLE A-13
HAZARDOUS AIR POLLUTANT (HAP) EMISSION FACTORS AND EMISSIONS
FOR THE OCEC UNIT 1
WHEN FIRING NATURAL GAS

Parameter	Emission Rate (lb/hr) firing Natural Gas Base Load [a]	Potential Emissions (TPY) [b]	
Ambient Temperature (^oF) and Wet Compression:	75 °F	1	3
HIR (MMBtu/hr):	3,436	CT/HRSG	CTs/HRSGs
HAPs [Section 112(b) of Clean Air Act]			
1,3-Butadiene	0.001478	0.006	0.019
Acetaldehyde	0.1374	0.60	1.81
Acrolein	0.0220	0.10	0.29
Benzene	0.0412	0.18	0.54
Ethylbenzene	0.1100	0.48	1.44
Formaldehyde	0.734	3.21	9.64
Naphthalene	0.00447	0.02	0.06
Polycyclic Aromatic Hydrocarbons (PAH) [c]	0.00756	0.03	0.10
Propylene Oxide	0.0997	0.44	1.31
Toluene	0.1134	0.50	1.49
Xylene	0.220	0.96	2.89
Antimony	0.0	0.0	0.0
Arsenic	0.0	0.0	0.0
Beryllium	0.0	0.0	0.0
Cadmium	0.0	0.0	0.0
Chromium	0.0	0.0	0.0
Lead	0.0	0.0	0.0
Manganese	0.0	0.0	0.0
Mercury	0.0000034	0.0	0.000045
Nickel	0.0	0.0	0.0
Selenium	0.0	0.0	0.0
HAPs (Total)	1.491	6.53	19.6

[a] Emissions based on the following emission factors and conversion factors for firing natural gas

Emission Factors		Value	Reference
Sulfuric acid mist		10	%; Conversion of SO_2 to SO_3 in gas turbine
1,3-Butadiene	(a)	0.43	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Acetaldehyde		40	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Acrolein		6.4	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Benzene		12	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Ethylbenzene		32	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Formaldehyde		0.091	ppmvd @15% O_2 (see Table 9a)
Naphthalene		1.3	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		2.2	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Propylene Oxide	(a)	29	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Toluene		33	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000. Database
Xylene		64	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Antimony		0.00E+00	
Arsenic		0.00E+00	
Beryllium		0.00E+00	
Cadmium		0.00E+00	
Chromium		0.00E+00	
Lead		0.00E+00	
Manganese		0.00E+00	
Mercury		1.00E-03	
Nickel		0.00E+00	
Selenium		0.00E+00	

(a) Based on 1/2 the detection limit; expected emissions are lower.

[b] Annual emissions based on firing natural gas for : 8760 hours.

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

TABLE A-13a
FORMALDEHYDE EMISSIONS
FOR THE OCEC UNIT 1
WHEN FIRING NATURAL GAS

Parameter	**CT Only at Baseload Ambient Temperature** 35 °F	59 °F	75 °F	95 °F
Formaldehyde (CH_2O) MW = 30				
CH_2O (lb/hr) = CH_2O (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2116.8 lb/ft^2 (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
CH_2O (ppm actual) = CH_2O (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x (1- Moisture(%)/100)				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
Basis, ppm actual- calculated	0.121	0.122	0.122	0.126
CT, ppmvd @15% O_2	0.091	0.091	0.091	0.091
Moisture (%)	9.16	11.6	11.60	13.76
Oxygen (%)	11.11	10.59	10.59	9.87
Oxygen (%) dry	12.23	11.98	11.98	11.44
Exhaust Flow (acfm)	1,540,292	1,567,065	1,579,061	1,544,169
Exhaust Temperature (°F)	177	180	185	184
CT Emission rate (lb/hr)	0.724	0.734	0.734	0.743
CT Emission rate (lb/10^{12} Btu) (HHV)	215.4	215.4	215.4	215.6

Note: ppmvd= parts per million, volume dry; O_2= oxygen.
Source: GE, 2014; Golder, 2015.

TABLE A-14
HAZARDOUS AIR POLLUTANT (HAP) EMISSION FACTORS AND EMISSIONS FOR THE OCEC UNIT 1 WHEN FIRING NATURAL GAS AND ULSD OIL

Parameter	Emission Rate (lb/hr) Distillate Fuel Oil [a] 1 CT/HRSG - Base Load	Emission Rate (lb/hr) Natural Gas [b] 1 CT/HRSG - Base Load	Potential Emissons (TPY) 3 CTs/HRSGs	3 CTs/HRSGs Natural Gas and
Ambient Temperature (°F) with Wet Compression:	75 °F	75 °F	Hours on ULSD Oil	Hours on ULSD Oil
Heat Input Rate (MMBtu/hr):	3,087	3,436	500	500
HAPs [Section 112(b) of Clean Air Act]				
1,3-Butadiene	0.0494	0.0015	0.037	0.06
Acetaldehyde	0.00	0.137	0.00	1.70
Acrolein	0.00	0.022	0.00	0.27
Benzene	0.170	0.041	0.13	0.64
Ethylbenzene	0.00	0.110	0.00	1.36
Formaldehyde	0.727	0.734	0.55	9.64
Naphthalene	0.1081	0.004	0.08	0.14
Polycyclic Aromatic Hydrocarbons (PAH) c	0.1235	0.008	0.09	0.19
Propylene Oxide	0.00	0.100	0.00	1.23
Toluene	0.00	0.113	0.00	1.40
Xylene	0.00	0.220	0.00	2.72
Antimony	0.00	0.00	0.00	0.00
Arsenic	0.0340	0.00	0.025	0.03
Beryllium	0.000957	0.00	0.00	0.00
Cadmium	0.01482	0.00	0.011	0.01
Chromium	0.0340	0.00	0.025	0.03
Lead	0.0432	0.00	0.032	0.03
Manganese	2.44	0.00	1.83	1.83
Mercury	0.00370	0.00	0.003	0.00
Nickel	0.01420	0.00	0.011	0.01
Selenium	0.0772	0.00	0.06	0.06
HAPs (Total)	3.84	1.5	2.88	21.3

[a] Emissions based on the following emission factors and conversion factors for firing distillate fuel oi

Emission Factors		Value	Reference
Sulfuric acid mist		5	%; Conversion of SO_2 to SO_3 in gas turbine
1,3-Butadiene	(a)	16	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Acetaldehyde		0.0	
Acrolein		0.0	
Benzene		55	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Ethylbenzene		0.0	
Formaldehyde		0.091	ppmvd @15% O2 (see Table 10a)
Naphthalene		35	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		40	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Propylene Oxide		0.0	
Toluene		0.0	
Xylene		0.0	
Antimony		0.0	
Arsenic	(a)	11	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Beryllium	(a)	0.31	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Cadmium		4.8	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Chromium		11	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Lead		14	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Manganese		790	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Mercury		1.2	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Nickel	(a)	4.6	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Selenium	(a)	25	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000

(a) Based on 1/2 the detection limit; expected emissions are lower

[b] Natural gas firing emission rates based on Table A-13

[c] Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HA

TABLE A-14a
MAXIMUM FORMALDEHYDE EMISSIONS
FOR THE OCEC UNIT 1
GE 7HA.02, ULSD OIL, BASE LOAD

Parameter	**CT Only Turbine Inlet Temperature 35 °F**	**59 °F**	**75 °F**	**95 °F**
Formaldehyde (CH_2O) MW = 30				
CH_2O (lb/hr) = CH_2O (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2116.8 lb/ft^2 (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
CH_2O (ppm actual) = CH_2O (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
Basis, ppmvw - calculated	0.119	0.118	0.117	0.115
CT, ppmvd @15% O_2	0.091	0.091	0.091	0.091
Moisture (%)	11.82	12.39	12.97	13.82
Oxygen (%)	10.70	10.65	10.60	10.53
Oxygen (%) dry	12.13	12.16	12.18	12.22
Exhaust Flow (acfm)	1,705,440	1,658,288	1,662,815	1,683,239
Exhaust Temperature (°F)	205	204	208	213
CT Emission rate (lb/hr)	0.753	0.727	0.718	0.711
CT Emission rate (lb/10^{12} Btu) (HHV)	232.6	232.6	232.5	232.5

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

Source: GE, 2014; Golder, 2015.

TABLE A-15
HAZARDOUS AIR POLLUTANT (HAP) EMISSIONS
FOR FIRE PUMP ENGINE AND EMERGENCY GENERATORS - ULSD OIL

			Annual Emission Basis	
Parameter	**Units**	**Value**	**Fire Pump Engine**	**Emergency Generators**
Number			1	3
Heat Input Rate	MMBtu/hr	per unit	2.75	29.5
Maximum operation/yr	hours	per unit	100	100
Heat Input Rate/annual	MMBtu/yr	all units	275.3	8,846.7
HAPs [Section 112(b) of Clean Air Act]	Emission Factor [a, b]		Emissions (TPY)	
Acrolein	lb/MMBtu	7.88E-06	1.08E-06	3.49E-05
Acetaldehyde	lb/MMBtu	2.52E-05	3.47E-06	1.11E-04
Benzene	lb/MMBtu	7.76E-04	1.07E-04	3.43E-03
Formaldehyde	lb/MMBtu	7.89E-05	1.09E-05	3.49E-04
Naphthalene	lb/MMBtu	1.30E-04	1.79E-05	5.75E-04
Toluene	lb/MMBtu	2.81E-04	3.87E-05	1.24E-03
Xylene	lb/MMBtu	1.93E-04	2.66E-05	8.54E-04
Acenaphthene	lb/MMBtu	4.68E-06	6.44E-07	2.07E-05
Acenaphthylene	lb/MMBtu	9.23E-06	1.27E-06	4.08E-05
Anthracene	lb/MMBtu	1.23E-06	1.69E-07	5.44E-06
Benzo(a)anthracene	lb/MMBtu	6.22E-07	8.56E-08	2.75E-06
Benzo(b)fluoranthene	lb/MMBtu	1.11E-06	1.53E-07	4.91E-06
Benzo(k)fluoranthene	lb/MMBtu	2.18E-07	3.00E-08	9.64E-07
Benzo(g,h,i)perylene	lb/MMBtu	5.56E-07	7.65E-08	2.46E-06
Benzo(a)pyrene	lb/MMBtu	2.57E-07	3.54E-08	1.14E-06
Chrysene	lb/MMBtu	1.53E-06	2.11E-07	6.77E-06
Dibenzo(a,h)anthracene	lb/MMBtu	3.46E-07	4.76E-08	1.53E-06
Fluoanthene	lb/MMBtu	4.03E-06	5.55E-07	1.78E-05
Fluorene	lb/MMBtu	4.47E-06	6.15E-07	1.98E-05
Indo(1,2,3-cd)pyrene	lb/MMBtu	4.14E-07	5.70E-08	1.83E-06
Phenanthrene	lb/MMBtu	1.05E-06	1.45E-07	4.64E-06
Pyrene	lb/MMBtu	3.71E-06	5.11E-07	1.64E-05
Arsenic	$lb/10^{12}$ Btu	4.0	5.51E-07	1.77E-05
Beryllium	$lb/10^{12}$ Btu	3.0	4.13E-07	1.33E-05
Cadmium	$lb/10^{12}$ Btu	3.0	4.13E-07	1.33E-05
Chromium	$lb/10^{12}$ Btu	3.0	4.13E-07	1.33E-05
Lead	$lb/10^{12}$ Btu	9.0	1.24E-06	3.98E-05
Mercury	$lb/10^{12}$ Btu	3.0	4.13E-07	1.33E-05
Manganese	$lb/10^{12}$ Btu	6.0	8.26E-07	2.65E-05
Nickel	$lb/10^{12}$ Btu	3.0	4.13E-07	1.33E-05
Selenium	$lb/10^{12}$ Btu	15.0	2.07E-06	6.64E-05
HAPs (Total)			2.17E-04	6.96E-03

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

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

TABLE A-16
HAZARDOUS AIR POLLUTANT (HAP) EMISSIONS
FOR FUEL HEATERS AND AUXILIARY BOILER - NATURAL GAS-FIRING

	Fuel Heater			Auxillary Boiler		
Parameter/Pollutant	**Units**	**Value**	**Annual Emission Basis**	**Units**	**Value**	**Annual Emission Basis**
Number			1			1
Heat Input Rate	MMBtu/hr	per unit	9.90	MMBtu/hr	per unit	99.77
Fuel use	scf/hr	per unit	9,706	scf/hr	per unit	97,814
Maximum operation/yr	hours	per unit	8,760	hours	per unit	2,000
Heat Input Rate/annual	MMBtu/yr	all units	NA	MMBtu/yr	all units	NA
Fuel use/annual	MMscf/yr	all units	85.02	MMscf/yr	all units	195.63
HAPs [Section 112(b) of Clean Air Act]	Emission Factor [a]		Emissions (TPY)	Emission Factor [a]		Emissions (TPY)
Benzene	$lb/10^6$ scf	2.10E-03	8.93E-05	$lb/10^6$ scf	2.10E-03	2.05E-04
Formaldehyde	$lb/10^6$ scf	7.50E-02	3.19E-03	$lb/10^6$ scf	7.50E-02	7.34E-03
Naphthalene	$lb/10^6$ scf	6.10E-04	2.59E-05	$lb/10^6$ scf	6.10E-04	5.97E-05
Toluene	$lb/10^6$ scf	3.40E-03	1.45E-04	$lb/10^6$ scf	3.40E-03	3.33E-04
Dichlorobenzene	$lb/10^6$ scf	1.20E-03	5.10E-05	$lb/10^6$ scf	1.20E-03	1.17E-04
Acenaphthene	$lb/10^6$ scf	1.80E-06	7.65E-08	$lb/10^6$ scf	1.80E-06	1.76E-07
Acenaphthylene	$lb/10^6$ scf	1.80E-06	7.65E-08	$lb/10^6$ scf	1.80E-06	1.76E-07
Acetaldehyde	--	NA	NA	--	NA	NA
Acrolein	--	NA	NA	--	NA	NA
Anthracene	$lb/10^6$ scf	2.40E-06	1.02E-07	$lb/10^6$ scf	2.40E-06	2.35E-07
Benzo(a)anthracene	$lb/10^6$ scf	1.80E-06	7.65E-08	$lb/10^6$ scf	1.80E-06	1.76E-07
Benzene	$lb/10^6$ scf	2.10E-03	8.93E-05	$lb/10^6$ scf	2.10E-03	2.05E-04
Benzo(g,h,i)perylene	$lb/10^6$ scf	1.20E-06	5.10E-08	$lb/10^6$ scf	1.20E-06	1.17E-07
Chrysene	$lb/10^6$ scf	1.80E-06	7.65E-08	$lb/10^6$ scf	1.80E-06	1.76E-07
Dibenzo(a,h)anthracene	$lb/10^6$ scf	1.20E-06	5.10E-08	$lb/10^6$ scf	1.20E-06	1.17E-07
Ethylbenzene	--	NA	NA	--	NA	NA
Fluoanthene	$lb/10^6$ scf	3.00E-06	1.28E-07	$lb/10^6$ scf	3.00E-06	2.93E-07
Fluorene	$lb/10^6$ scf	2.80E-06	1.19E-07	$lb/10^6$ scf	2.80E-06	2.74E-07
Indeno(1,2,3-cd)pyrene	$lb/10^6$ scf	1.80E-06	7.65E-08	$lb/10^6$ scf	1.80E-06	1.76E-07
Phenanthrene	$lb/10^6$ scf	1.70E-05	7.23E-07	$lb/10^6$ scf	1.70E-05	1.66E-06
Phenol	--	NA	NA	--	NA	NA
Pyrene	$lb/10^6$ scf	5.00E-06	2.13E-07	$lb/10^6$ scf	5.00E-06	4.89E-07
Xylene	--	NA	NA	--	NA	NA
1,3-Butadiene	--	NA	NA	--	NA	NA
Polycyclic Aromatic Hydrocarbons (PAH)	--	NA	NA	--	NA	NA
Propylene Oxide	--	NA	NA	--	NA	NA
Arsenic	$lb/10^6$ scf	2.00E-04	8.50E-06	$lb/10^6$ scf	2.00E-04	1.96E-05
Beryllium	$lb/10^6$ scf	1.20E-05	5.10E-07	$lb/10^6$ scf	1.20E-05	1.17E-06
Cadmium	$lb/10^6$ scf	1.10E-03	4.68E-05	$lb/10^6$ scf	1.10E-03	1.08E-04
Chromium	$lb/10^6$ scf	1.40E-03	5.95E-05	$lb/10^6$ scf	1.40E-03	1.37E-04
Cobalt	$lb/10^6$ scf	8.40E-05	3.57E-06	$lb/10^6$ scf	8.40E-05	8.22E-06
Mercury	$lb/10^6$ scf	2.60E-04	1.11E-05	$lb/10^6$ scf	2.60E-04	2.54E-05
Manganese	$lb/10^6$ scf	3.80E-04	1.62E-05	$lb/10^6$ scf	3.80E-04	3.72E-05
Nickel	$lb/10^6$ scf	2.10E-03	8.93E-05	$lb/10^6$ scf	2.10E-03	2.05E-04
Selenium	$lb/10^6$ scf	2.40E-05	1.02E-06	$lb/10^6$ scf	2.40E-05	2.35E-06
HAPs (Total)			3.83E-03			8.80E-03

Note: Only one fuel heater is operated; one fuel heater is a spare.

[a] EPA AP-42, Section 1.4, Natural Gas Combustion (March 1998).

[b] EPA AP-42, Section 3.2, Stationary Gas Turbines (April 2000).

TABLE A-17
GREENHOUSE GAS (GHG) EMISSIONS
GE 7H.02 CT, BASE LOAD

Pollutant	Maximum Heat Input at 75 ^{0}F Ambient with Wet Compression (MMBtu/hr)		Emission Factor [a] (lb/MMBtu)		Hourly GHG Emissions (lb/hr)		Operating Hours		Annual GHG Emissions (TPY)		CO_2e Emission Rate [b] (TPY)		
	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Total
Natural Gas Only													
CO_2	3,436.2	0.0	118.9	162.3	408,420.1	0.0	8760	0	1,788,880.1	0	1,788,880.1	0	1,788,880.1
CH_4	3,436.2	0.0	0.002204	0.006612	7.6	0.0	8760	0	33.2	0	829.3	0	829.3
N_2O	3,436.2	0.0	0.0002204	0.001322	0.8	0.0	8760	0	3.3	0	988.5	0	988.5
										Total	1,790,697.9	0.0	1,790,697.9
Natural Gas & Distillate Fuel Oil													
CO_2	3,436.2	3,087.3	118.9	162.3	408,420.1	501,016.6	8260	500	1,686,775.1	125,254.1	1,686,775.1	125,254.1	1,812,029.3
CH_4	3,436.2	3,087.3	0.002204	0.006612	7.5734	20.4129	8260	500	31.3	5.1	781.96	127.58	909.5
N_2O	3,436.2	3,087.3	0.0002204	0.001322	0.7573	4.0826	8260	500	3.1	1.0	932.09	304	1236.2
										Total	1,688,489.2	125,685.9	1,814,175.0
										Maximum Total	1,790,697.9	125,685.9	1,814,175.0

[a] CO_2 in lb/MMBtu, based on 40 CFR Part 75 Appendix G, Section 2.3 Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu for CH_2 and N_2O.

Pollutant	Natural Gas	ULSD Oil
CO_2	118.9	162.3

Pollutant	Natural Gas	ULSD 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 based on 40 CFR Part 98.

Pollutant	CO_{2e} Factor
CH_4	25
N_2O	298

TABLE A-18
GREENHOUSE GAS (GHG) EMISSIONS
FOR AUXILIARY BOILER, EMERGENCY GENERATORS, FUEL HEATER AND 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)	CO2e Emissions Rate [b] (TPY)
Auxilliary Boiler (Natural Gas)						
CO_2	99.77	116.9	11,658.7	2,000	11,658.7	11,658.7
CH_4	99.77	0.002204	0.220	2,000	0.220	5.497
N_2O	99.77	0.0002204	0.0220	2,000	0.022	6.553
						11,670.8
Emergency Generator (Fuel Oil) [c]						
CO_2	29.49	163.0	4,806.9	100	240.3	240.3
CH_4	29.49	0.006612	0.195	100	0.010	0.24
N_2O	29.49	0.001322	0.039	100	0.0019	0.58
						241.2
Natural Gas Heater (Natural Gas)						
CO_2	9.90	116.9	1,156.9	8,760	5,067.1	5067.1
CH_4	9.90	0.002204	0.022	8,760	0.096	2.39
N_2O	9.90	0.0002204	0.0022	8,760	0.0096	2.85
						5,072.4
Fire Pump Engine (Fuel Oil)						
CO_2	2.75	163.0	448.8	100	22.4	22.4
CH_4	2.75	0.006612	0.0182	100	0.00091	0.02
N_2O	2.75	0.001322	0.0036	100	0.00018	0.05
						22.5

[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

[c] GHG emissions for one emergency generator shown.

TABLE A-19
ULTRA LOW SULFUR DISTILLATE OIL
STORAGE TANK VOC EMISSIONS - EPA TANKS PROGRAM

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

Identification

User Identification:	OCEC Tank
City:	Okeechobbe
State:	florida
Company:	FPL
Type of Tank:	Horizontal Tank
Description:	Okeechobee tank

Tank Dimensions

Shell Length (ft):		65.00
Diameter (ft):		141.00
Volume (gallons):		7,000,000.00
Turnovers:		4.80
Net Throughput(gal/yr):		33,600,000.00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	N	

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good

Breather Vent Settings

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

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

TABLE A-19
ULTRA LOW SULFUR DISTILLATE OIL
STORAGE TANK VOC EMISSIONS - EPA TANKS PROGRAM

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

OCEC Tank - Horizontal Tank
Okeechobbe, florida

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jan	71.05	66.05	76.05	74.37	0.0093	0.0080	0.0108	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Feb	71.85	66.53	77.16	74.37	0.0096	0.0081	0.0111	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Mar	74.21	68.52	79.90	74.37	0.0103	0.0086	0.0120	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Apr	76.37	70.10	82.64	74.37	0.0109	0.0090	0.0131	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	May	78.78	72.66	84.90	74.37	0.0116	0.0098	0.0140	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Jun	80.07	74.78	85.37	74.37	0.0120	0.0104	0.0141	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Jul	80.43	75.36	85.50	74.37	0.0122	0.0106	0.0142	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Aug	80.38	75.43	85.34	74.37	0.0122	0.0106	0.0141	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Sep	79.73	75.15	84.31	74.37	0.0119	0.0105	0.0137	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Oct	77.42	72.72	82.12	74.37	0.0112	0.0098	0.0128	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Nov	74.28	69.40	79.16	74.37	0.0103	0.0089	0.0117	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012
Distillate fuel oil no. 2	Dec	71.74	66.87	76.62	74.37	0.0095	0.0082	0.0110	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TABLE A-19
ULTRA LOW SULFUR DISTILLATE OIL
STORAGE TANK VOC EMISSIONS - EPA TANKS PROGRAM

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

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

OCEC Tank - Horizontal Tank
Okeechobbe, florida

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	1,135.21	1,965.77	3,100.98

APPENDIX B

BACT DETERMINATIONS FROM EPA RBL CLEARINGHOUSE

TABLE B-1
SUMMARY OF NOx BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	NO_x Limit	Basis
Florida							
FPL Port Everglades Power Plant	FL	5/9/2012	(3) Combined Cycle CT with HRSG	250 MW	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG	265 MW	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG	265 MW	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
OUC Curtis H. Stanton Energy Center	FL	5/12/2008	300 MW Combined Cycle CT	1765 MMBtu/hr	LNB and SCR	8.0 ppmvd @ 15% O_2	BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Progress Bartow Power Plant	FL	1/29/2007	Combined Cycle CT (4-On-1)	1,972 MMBtu/hr	DLN	15.0 ppmvd uncorrected	BACT-PSD
FPL West County Energy Center Units 1 & 2	FL	1/10/2007	Combined Cycle CTs - 6 Units	2,333 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Progess Energy Hines Power Block 4	FL	6/8/2005	Combined Cycle Turbine	530 MW	SCR	2.5 ppm	BACT-PSD
FPL Turkey Point Power Plant	FL	2/8/2005	(4) Combustion Turbines	170 MW	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Hines Energy Complex, Power Block 3	FL	9/8/2003	(2) Combined Cycle CTs	1,830 MMBtu/hr	DLN and SCR	2.5 ppmvd @ 15% O_2	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbine, Combined Cyle	170 MW	DLN, SCR	2.5 ppmvd @ 15% O_2	BACT-PSD
FPL Martin Plant	FL	4/16/2003	Combined Cycle CT With Duct Burner	170 MW	DLN, SCR	2.5 ppm @ 15% O_2	BACT-PSD
FPL Manatee Plant - Unit 3	FL	4/15/2003	(4) Turbine, Combined Cycle	170 MW	DLN, SCR	2.5 ppmvd @ 15% O_2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
Effingham County Power (current project)	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG	180 MW	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/ DB	600 MW	DLN and SCR	2.5 ppmvd @ 15% O_2	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	(3) Turbine, Combined Cycle	1,844 MMBtu/hr	DLN and SCR	2.5 ppm @ 15% O_2	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	3 CTs (GE 7FB), 2,126 MMBtu/hr each	230 MW	DLN and SCR	3.5 ppmvd @ 15% O_2	BACT-PSD
Peace Vally Generation Company, LLC	GA	6/1/2003	(3) Combined Cycle CTs (GE 7FA) w/DB	1,550 Net MW	DLN and SCR	2.5 ppmvd @ 15% O_2	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)/HRSG	140 MW	DLN and SCR	2.5 ppmvd @ 15% O_2	BACT-PSD
Wansley Combined Cycle Energy Facility	GA	1/15/2002	(2) CTs (Siemens V84.3a2)/HRSG	521 Net MW	DLN and SCR	3.0 ppmvd @ 15% O_2	BACT-PSD
Effingham County Power	GA	12/27/2001	(2) Combined Cycle CT (GE 7FA)/HRSG	185 MW	SCR	3.0 ppmvd @ 15% O_2	BACT-PSD
Other States							
Colorado Bend Energy Center	TX	4/1/2015	COMBINED CYCLE CT	1,100 MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
S R Bertron Electric Generating Station	TX	12/19/2014	(2) combined cycle turbines	240 MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Victoria Power Station	TX	12/1/2014	combined cycle turbine	197 MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Trinidad Generating Facility	TX	11/20/2014	combined cycle turbine	497 MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Cedar Bayou Electric Generation Station	TX	8/29/2014	Combined cycle natural gas turbines	225 MW	DLN, SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Tenaska Brownsville Generating Station	TX	4/29/2014	(2) combined cycle turbines	274 MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #1 - combined cycle	2,258 mmBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #2 -combined cycle	2,258 mmBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Fge Texas Power I And Fge Texas Power Ii	TX	3/24/2014	Alstom Turbine	231 MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Combined Cycle CT w/ DB	2,988 MMBtu/hr	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	COMBINED CYCLE CT	2,267 MMBtu/hr	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	COMBINED CYCLE CT	700 MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Sand Hill Energy Center	TX	9/13/2013	COMBINED CYCLE CT	174 MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	COMBINED CYCLE CT	2,237 MMBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	COMBINED CYCLE CT w/DB	2,486 MMBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3,000 MMBtu/hr	SCR	2.0 ppmvd @ 15% O_2	CASE-BY-CASE
Sunbury Generation Lp/Sunbury Ses	PA	4/1/2013	COMBINED CYCLE CTs w/DB (3)	2,538 MMBtu/hr	SCR	2.0 ppmvd @ 15% O_2	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	COMBINED CYCLE CTs (3)	3,442 MMBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
La Paloma Energy Center	TX	2/7/2013	COMBINED CYCLE CTs (2)	650 MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Channel Energy Center Llc	TX	10/15/2012	Combined Cycle CT	180 MW	SCR	2.0 ppmvd	LAER
Deer Park Energy Center	TX	9/26/2012	Combined Cycle CT	180 MW	SCR	2.0 ppmvd	LAER
Es Joslin Power Plant	TX	9/12/2012	Combined Cycle Gas Turbine	195 MW	SCR	2.0 ppmvd	BACT-PSD
Palmdale Hybrid Power Project	CA	10/18/2011	Combustion Turbines (Normal Operation)	154 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Thomas C. Ferguson Power Plant	TX	9/1/2011	Natural Gas-Fired Turbines	390 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #2 w/DB	180 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Carty Plant	OR	12/29/2010	Combined Cycle Natural Gas-Fired Electric Ge	2,866 MMBTU/H	SCR	2.0 PPM@15%O2	BACT-PSD
Warren County Power Plant - Dominion	VA	12/17/2010	Combined Cycle Turbine & Duct Burner, 3	2,996 MMBTU/H	DLN and SCR	2.0 ppmvd@15%O2	BACT-PSD
King Power Station	TX	8/5/2010	Turbine	1,350 MW	DLN and SCR	2.0 ppmvd AT 15% O2	LAER
Langley Gulch Power Plant	ID	6/25/2010	Combined Cycle CT W/ DB	2,375 MMBTU/H	DLN, SCR, GCP	2.0 ppmvd	BACT-PSD
Colusa Generating Station	CA	3/11/2010	Combustion Turbines	172 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #2 w/DB	154 MW	SCR	2.0 ppmvd	BACT-PSD
High Desert Power Project	CA	3/11/2010	Combustion Turbine Generators	190 MW	DLN and SCR	2.5 ppmvd	BACT-PSD
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	DLN	9.0 ppmvd @ 15% O_2	BACT-PSD

TABLE B-1
SUMMARY OF NOx BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	NO_x Limit	Basis
CPV St. Charles	MD	11/12/2008	(2) Combustion Turbines		DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2,169 MMBtu/hr	DLN	9.0 ppm	BACT-PSD
Gateway Generating Station	CA	7/1/2008	(2) Combined Cycle CT (GE 7FA)/HRSG	530 Net MW	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Colusa Generating Station	CA	5/1/2008	(2) Combined Cycle CT/HRSG	172 MW	DLN and SCR	2.0 ppmvd @ 15% O_2	
Arsenal Hill Power Plant	LA	3/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	Low Nox Turbines, SCR	30.15 lb/hr	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	DLN and SCR	30.15 lb/hr	BACT-PSD
CPV Warren, LLC	VA	1/14/2008	Electric Generation - Scenario 1	1,717 MMBtu/hr	DLN, GCP and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Russell City Enery Center	CA	6/19/2007	(2) CTs (Westinghouse 501F)/HRSG	600 Net MW	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Faribault Energy Park	MN	6/5/2007	Combined Cycle CT W/Duct Burner	1,758 MMBtu/hr	DLN and SCR	3.0 ppmvd @ 15% O_2	BACT-PSD
Blythe Energy Project II, LLC	CA	4/25/2007	(2) Combustion Turbines	170 MW	SCR	2.0 ppmvd	BACT-PSD
PSO Southwestern Power Plt	OK	2/9/2007	Gas-Fired Turbines		DLN	9.0 ppm	BACT-PSD
Lawton Energy Cogen Facility	OK	12/12/2006	Combustion Turbine And Duct Burner		DLN and SCR	3.5 ppmvd	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	Combustion Turbine	2,221 MMBtu/hr	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Rocky Mountain Energy Center, LLC	CO	5/2/2006	Combined-Cycle Turbine	300 MW	DLN and SCR	3.0 ppm @ 15% O_2	BACT-PSD
City Public Service Jk Spruce Electrice Generating	TX	12/28/2005	Spruce Power Generator Unit No 2			1,600 lb/hr	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Combined Cycle CT/HRSG and DB	306 MW	SCR	2.0 ppm @ 15% O_2	BACT-PSD
Wanapa Energy Center	OR	8/8/2005	(4) CT/HRSG and DB	2,384 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Crescent City Power	LA	6/6/2005	(2) Gas Turbines - 187 MW	2,006 MMBtu/hr	DLN and SCR	21.8 lb/hr	BACT-PSD
Duke Energy Washington County, LLC	OH	5/9/2005	(2) Turbines (Model GE7FA), w/ DB	170 MW	DLN and SCR	3.5 ppmvd @ 15% O_2	BACT-PSD
Duke Energy Washington County, LLC	OH	5/9/2005	(2) Turbines (Model GE7FA), w/o DB	170 MW	DLN and SCR	3.5 ppmvd @ 15% O_2	BACT-PSD
Berrien Energy, LLC	MI	4/13/2005	(3) CT w/ Duct Burners	1,584 MMBtu/hr	DLN and SCR	2.5 ppmvd @ 15% O_2	BACT-PSD
BP Cherry Point Cogeneration Project	WA	1/11/2005	CT (Model GE 7FA)/HRSG	174 MW	DLN and SCR	2.5 ppmvd	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (Model GE7FA), w/ DB	172 MW	DLN and SCR	3.0 ppmvd @ 15% O_2	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (Model GE7FA), w/o DB	172 MW	DLN and SCR	3.0 ppmvd @ 15% O_2	BACT-PSD
Pastoria Energy Facility	CA	12/23/2004	(3) Combustion Turbines	168 MW	XONON or DLN with SCR	2.5 ppmvd	BACT-PSD
Sabine Pass Lng Import Terminal	LA	11/24/2004	(4) 30 MW Gas Turbine Generators	290 MMBtu/hr	DLN	29 lb/hr	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	(3) GE 7FB CTs (230 MW, ea.)	2,126 MMBtu/hr	DLN and SCR	3.5 ppmvd @ 15% O_2	BACT-PSD
El Dorado Energy, LLC	NV	8/19/2004	(2) Combined Cycle CT & Cogen	475 MW	DLN and SCR	3.5 ppm @ 15% O_2	BACT-PSD
Sutter Power Plant	CA	8/16/2004	(2) Combustion Turbines	170 MW	DLN and SCR	2.5 ppmvd	BACT-PSD
Currant Creek	UT	5/17/2004	(2) Natural Gas Fired Turbines And HRSGs		SCR	2.25 ppmvd	BACT-PSD
Copper Mountain Power	NV	5/14/2004	Large CTs, Combined Cycle & Cogeneration	600 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	Combined Cycle CT w/o DB	170 MW	SCR and DLN, GCP	2.5 ppmvd	BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	Combined Cycle CT w/ DB	170 MW	SCR and DLN, GCP	2.5 ppmvd	BACT-PSD
COB Energy Facility, LLC	OR	12/30/2003	(4) Combined Cycle CT w/ DB	1,150 MW	DLN and SCR	2.5 ppmvd @ 15% O_2	BACT-PSD
Ivanpah Energy Center, L.P.	NV	12/29/2003	Large CTs, Combined Cycle & Cogeneration	500 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Mankato Energy Center	MN	12/4/2003	(2) Large CT	1,916 MMBtu/hr	Lean Pre-Mix Combustion & SCR	3.0 ppmvd @ 15% O_2	BACT-PSD
Mankato Energy Center	MN	12/4/2003	(2) Large CT	1,827 MMBtu/hr	WI and SCR	5.5 ppmvd @ 15% O_2	BACT-PSD
James City Energy Park	VA	12/1/2003	Combined Cycle CT	1,973 MMBtu/hr	DLN and SCR	2.5 ppm	BACT-PSD
James City Energy Park	VA	12/1/2003	Combined Cycle CT w/ DB	1,973 MMBtu/hr	DLN and SCR	2.5 ppm	BACT-PSD
Duke Energy Arlington Valley (AVEFII)	AZ	11/12/2003	Combined Cycle CT w/ DB	325 MW	SCR	2.0 ppm @ 15% O_2	BACT-PSD
Duke Energy Arlington Valley (AVEFII)	AZ	11/12/2003	Combined Cycle CT w/o DB	325 MW	SCR	2.0 ppm @ 15% O_2	BACT-PSD
Redbud Power Plant	OK	6/3/2003	Combustion Turbine And Duct Burners	1,832 MMBtu/hr	DLN and SCR	3.5 ppmvd @ 15% O_2	BACT-PSD
Magnolia Power Project, Scppa	CA	5/27/2003	Gas Turbine	181 Net MW	SCR	2.0 ppmvd @ 15% O_2	BACT-PSD
Mirant Sugar Creek, LLC	IN	4/23/2003	(4) Combined Cycle, Startup & Shut Down	1,491 MMBtu/hr	DLN Burners, GCP	64.9 TPY	BACT-PSD
Sumas Energy 2 Generation Facility	WA	4/17/2003	(2) Turbines, Combined Cycle	660 MW	DLN, SCR	2.0 ppmvd	BACT-PSD
Duke Energy Stephens, Llc Stephens Energy	OK	3/21/2003	(2) Turbines, Combined Cycle	1,701 MMBtu/hr	DLN, SCR	3.5 ppm @ 15% O_2	BACT-PSD
Kalkaska Generating, Inc	MI	2/4/2003	(2) Turbine, Combined Cycle	605 MW	DLN and SCR	3.0 ppmvd @ 15% O_2	BACT-PSD
South Shore Power, LLC	MI	1/30/2003	(2) Turbine, Combined Cycle	172 MW	DLN & SCR	3.0 ppmvd @ 15% O_2	BACT-PSD
Mirant Wyandotte, LLC	MI	1/28/2003	(2) Turbine, Combined Cycle	2,200 MMBtu/hr	DLN and SCR	3.5 ppm	BACT-PSD
Bluewater Energy Center, LLC	MI	1/7/2003	(3) Turbine, Combined Cycle	180 MW	DLN and SCR	4.5 ppmvd	BACT-PSD

Source: EPA 2015 (RBLC database); Golder, 2015

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

TABLE B-2
SUMMARY OF NOx BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	NO_x Limit	Basis
Florida								
FPL Port Everglades Power Plant	FL	5/9/2012	(3) Combined Cycle CT with HRSG	250 MW	Fuel Oil	DLN and SCR	8.0 ppmvd @ 15% O_2	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG	265 MW	Fuel Oil	DLN and SCR	8.0 ppmvd @ 15% O_2	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG	265 MW	Fuel Oil	DLN and SCR	8.0 ppmvd @ 15% O_2	BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	Fuel Oil	DLN and SCR	8.0 ppmvd @ 15% O_2	BACT-PSD
Progress Bartow Power Plant	FL	1/29/2007	Combined Cycle CT (4-On-1)	1,972 MMBtu/hr	Fuel Oil	WI	42.0 ppmvd uncorrected	BACT-PSD
FPL - Turkey Point Power Plant	FL	2/8/2005	(4) Combined Cycle CTs and HRSGs	170 MW (EACH)	Fuel Oil	DLN and SCR	8.0 ppmvd @ 15% O_2	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbines, Combined Cycle,	170 MW	Fuel Oil	SCR and WI	10.0 ppmvd @ 15% O_2	
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Effingham County Power	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG	180 MW	Fuel Oil	SCR and WI	10 ppmvd @ 15% O_2	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)/HRSG	140 MW	Fuel Oil	SCR and WI	6.0 ppmvd @ 15% O_2	BACT-PSD
Other States								
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	General Electric Combustion Turbines		Fuel Oil		42.0 ppm @ 15% O_2	BACT-PSD
Fairbault Energy Park	MN	7/15/2004	(1) CT, CC	1801 MMBtu/hr	Fuel Oil	SCR and WI	6.0 ppmvd @ 15% O_2	BACT-PSD
SCE&G - Jasper County Generating Facility	SC	5/23/2002	Turbines (3 each)	170 MW (EACH)	Fuel Oil	SCR and WI	7.5 ppm @ 15% O_2	BACT-PSD
Fayetteville Generation, LLC.	NC	1/10/2002	(2) CT, CC	1940 MMBtu/hr	Fuel Oil	SCR and WI	18.0 ppmvd	BACT-PSD
Broad River Investors - Gaffney	SC	12/21/2000	(2) CTs	193 MW (EACH)	Fuel Oil	DLN, SI, Proper Op. and Maint.	12.0 ppmvd @ 15% O_2	BACT-PSD
Rainey Generating Station	SC	4/3/2000	(2) CTs, CC	170 MW (EACH)	Fuel Oil	DLN, WI	341 lb/hr	BACT-PSD
Santee Cooper Rainey Generation Station	SC	4/3/2000	(2) CT, CC	170 MW	Fuel Oil	WI	341 lb/hr	BACT-PSD
Tenaska Bear Garden Station	VA	4/30/2002	GE 7 FA Dual Fired CTs	2029 MMBtu	Fuel Oil	SCR and CEMs	2.5 ppm	BACT-PSD
Middleton Facility	ID	10/19/2001	(2) Gas Turbines w/o Duct Burners	1699 MMBtu/hr	Fuel Oil	SCR, Catalytic Oxidation	26 lb/hr	BACT-PSD
Gray's Ferry Cogen Partnership	PA	3/21/2001	CT, CC	1515 MMBtu/hr	Fuel Oil	SCR	0.17 lb/MMBtu	BACT-PSD
San Juan Repowering Project	PR	3/2/2000	(2) CTs, HRSGs	232 MW (EACH)	Fuel Oil	SI System	219 lb/hr	BACT-PSD
LSP Nelson Energy, LLC.	IL	1/28/2000	CT, CC w/o Duct Burner	2166 MMBtu/hr	Fuel Oil	SCR and WI	0.065 lb/MMBtu	BACT-PSD
LSP Nelson Energy, LLC.	IL	1/28/2000	CT, CC w/ Duct Burner	2166 MMBtu/hr	Fuel Oil	SCR and WI	0.056 lb/MMBtu	BACT-PSD

Source: EPA 2015 (RBLC database); Golder, 2015

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

TABLE B-3
SUMMARY OF CO BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	CO Limit	Basis
Florida							
FPL Port Everglades Power Plant	FL	5/9/2012	(3) Combined Cycle CT with HRSG	250 MW	GCP	9.0 ppmvd @ 15% O_2	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG w/o DB	265 MW	GCP	5.0 ppmvd @ 15% O_2	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG w/ DB	265 MW	GCP	7.6 ppmvd @ 15% O_2	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG w/ DB	265 MW	GCP	7.6 ppmvd @ 15% O_2	BACT-PSD
OUC Curtis H. Stanton Energy Center	FL	05/12/2008	300 MW Combined Cycle CT	1765 MMBtu/hr	GCP	8.0 ppmvd @15% O_2	BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	GCP	4.1 ppmvd @ 15% O_2	BACT-PSD
Progress Bartow Power Plant	FL	1/29/2007	Combined Cycle CT (4-On-1)	1,972 MMBtu/hr	GCP	8.0 ppmvd	BACT-PSD
FPL West County Energy Center Units 1 & 2	FL	01/10/2007	Combined Cycle CT - 6 Units	2,333 MMBtu/hr	GCP	8.0 ppmvd @ 15% O_2	BACT-PSD
Hines Power Block 4	FL	06/08/2005	Combined Cycle Turbine	530 MW	GCP	8.0 ppm	BACT-PSD
FPL Martin Plant	FL	04/16/2003	(4) Turbine, Combined Cyle, Natural Gas	170 MW	GCP	10.0 ppmvd @ 15% O_2	BACT-PSD
FPL Manatee Plant - Unit 3	FL	04/15/2003	(4) Turbine, Combined Cycle, Natural Gas	170 MW	GCP	10.0 ppmvd @ 15% O_2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
Effingham County Power (current project)	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG	180 MW	GCP, Catalytic Oxidation	2.0 ppmvd @ 15% O_2	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/o DB	600 MW	Oxidation Catalyst	2.0 ppmvd @ 15% O_2	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/ DB	600 MW	Oxidation Catalyst	3.2 ppmvd @ 15% O_2	BACT-PSD
McDonough Combined Cycle Plant	GA	1/7/2008	(6) CTs (Mitsubishi M501G) w/ DB	254 MW	Oxidation Catalyst	1.8 ppm @ 15% O_2	BACT-PSD
Forsyth Energy Plant	NC	09/29/2005	(3) Turbine, Combined Cycle, Natural Gas	1,844 MMBtu/hr	GCP And Efficient Process Design.	11.6 ppm @ 15% O_2	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	3 CTs (GE 7FB), 2,126 MMBtu/hr each	230 MW		18.4 ppmvd @ 15% O_2	BACT-PSD
Peace Vally Generation Company, LLC	GA	6/1/2003	(3) Combined Cycle CTs (GE 7FA) w/ DB	1550 Net MW	Oxidation Catalyst	2.0 ppmvd @ 15% O_2	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Turbine, Combined Cycle, Natural Gas	140 MW	Catalytic Oxidation	2.0 ppmvd @ 15% O_2	BACT-PSD
GenPower Rincon, LLC	GA	3/24/2003	(2) Combined Cycle CT (GE 7FA)/HRSG	171.7 MW	Catalytic Oxidation	2.0 ppmvd @ 15% O_2	BACT-PSD
Wansley Combined Cycle Energy Facility	GA	1/15/2002	(2) CTs (Siemens V84.3a2)/HRSG	521 Net MW	GCP	2.0 ppmvd @15% O_2	BACT-PSD
Effingham County Power	GA	12/27/2001	(2) Combined Cycle CT (GE 7FA)/HRSG	185 MW	GCP	9.0 ppmvd @15% O_2	BACT-PSD
Other States							
Colorado Bend Energy Center	TX	4/1/2015	Combined Cycle Turbine	1100 MW	Oxidation Catalyst	4.0 ppmvd @ 15% O2	BACT-PSD
Cedar Bayou Electric Generating Station	TX	3/31/2015	Combined Cycle Turbine	187 MW each	Oxidation catalyst	15.0 ppmvd	BACT-PSD
S R Bertron Electric Generating Station	TX	12/19/2014	(2) Combined Cycle Turbine	240 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Victoria Power Station	TX	12/1/2014	Combined Cycle Turbine	197 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Trinidad Generating Facility	TX	11/20/2014	Combined Cycle Turbine	497 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Cedar Bayou Electric Generation Station	TX	8/29/2014	Combined Cycle Turbine	225 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Freeport Lng Pretreatment Facility	TX	7/16/2014	Combustion Turbine	87 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Tenaska Brownsville Generating Station	TX	4/29/2014	(2) Combined Cycle Turbine	274 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258 MMBtu/hr	catalytic oxidizer	2.0 ppmvd	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258 MMBtu/hr	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Fge Texas Power I And Fge Texas Power Ii	TX	3/24/2014	Alstom Turbine	230.7 MW	Oxidation catalyst	2.0 ppmvd	BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Combined Cycle Turbine w/ DB	2988 MMBtu/hr	Oxidation catalyst	3.3 ppmvd AT 15% O2	BACT-PSD
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267 MMBtu/hr	Oxidation Catalyst	3.0 ppmvd	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Combined Cycle Turbine w/ DB	647 MMBtu/hr each	Oxidation Catalyst, GCP	4.0 ppmvd	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Combined Cycle Turbine	700 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Sand Hill Energy Center	TX	9/13/2013	Combined Cycle Turbine	173.9 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Bayport Complex	TX	9/5/2013	(4) cogeneration turbines	90 MW	Closed Loop Emissions Controls (CLEC)	15.0 ppmvd	BACT-PSD
Thetford Generating Station	MI	7/25/2013	Combined Cycle Turbine w/ DB	2,587 MMBtu/hr each	Oxidation catalyst	4.0 ppmvd	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	Combined Cycle Turbine w/o DB	2,237 MMBtu/hr	GCP	9.0 ppmvd	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	Combined Cycle Turbine w/ DB	2,486 MMBtu/hr	GCP	10.5 ppmvd	BACT-PSD
Sunbury Generation Lp/Sunbury Ses	PA	4/1/2013	Combined Cycle Turbine w/ DB (3)	2,538 MMBtu/hr	Oxidation Catalyst	2.0 ppmvd	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3,442 MMBtu/hr	Oxidation Catalyst	1.5 ppmvd	BACT-PSD
La Paloma Energy Center	TX	2/7/2013	(2) Combined Cycle Turbine	650 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Moxie Energy Llc/Patriot Generation Plt	PA	1/31/2013	Combined Cycle Power Blocks (2)	472 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Channel Energy Center Llc	TX	10/15/2012	Combined Cycle Turbine	180 MW	GCP	4.0 ppmvd	BACT-PSD
Deer Park Energy Center	TX	9/26/2012	Combined Cycle Turbine	180 MW	GCP	4.0 ppmvd	BACT-PSD
Es Joslin Power Plant	TX	9/12/2012	Combined Cycle Gas Turbine	195 MW	GCP	4.0 ppmvd	BACT-PSD
Palmdale Hybrid Power Project	CA	10/18/2011	Combustion Turbines (Normal Operation)	154 MW	Oxidation Catalyst	1.5 ppmvd	BACT-PSD
Thomas C. Ferguson Power Plant	TX	9/1/2011	Natural Gas-Fired Turbines	390 MW	Oxidation Catalyst, GCP	4.0 ppmvd	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #1 and #2 (w/o DB)	180 MW	Oxidation Catalyst	1.5 ppmvd	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #1 and #2 (w/ DB)	180 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Colusa Generating Station	CA	3/11/2011	Combustion Turbines (Normal Operation)	172 MW	Oxidation Catalyst	3.0 ppmvd	BACT-PSD
Nelson Energy Center	IL	12/28/2010	Electric Generation Facility	220 MWe each		5.0 ppmvd @ 15% O2	BACT-PSD
Warren County Power Plant - Dominion	VA	12/17/2010	Combined Cycle Turbine & Duct Burner, 3	2996 MMBTU/H	Oxidation Catalyst, GCP	1.5 ppmvd	BACT-PSD
King Power Station	TX	8/5/2010	Turbine	1350 MW	Oxidation Catalyst, GCP	2.0 ppmvd @ 15% O2	BACT-PSD
Langley Gulch Power Plant	ID	6/25/2010	Combustion Turbine, Combined Cycle W/ Duct Burner	2375.28 MMBTU/H	Oxidation Catalyst, GCP	2.0 ppmvd	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #1 and #2 (w/o DB)	154 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #1 and #2 (w/ DB)	154 MW	Oxidation Catalyst	3.0 ppmvd	BACT-PSD
High Desert Power Project	CA	3/11/2010	Combustion Turbine Generators (Normal Operation)	190 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD

TABLE B-3
SUMMARY OF CO BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	CO Limit	Basis
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	GCP	9.0 ppmvd	BACT-PSD
CPV St. Charles	MD	11/12/2008	(2) Combustion Turbines		Oxidation Catalyst	2.0 ppmvd @15% O_2	BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2169 MMBtu/hr	GCP	4.0 ppm	BACT-PSD
Gateway Generating Station	CA	7/1/2008	(2) Combined Cycle CT (GE 7FA)/HRSG	530 Net MW	Oxidaion Catalyst	4.0 ppmvd @ 15% O_2	BACT-PSD
Colusa Generating Station	CA	5/1/2008	(2) Combined Cycle CT/HRSG	172 MW	Oxidation Catalyst	3.0 ppmvd @ 15% O_2	BACT-PSD
Arsenal Hill Power Plant	LA	03/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	Proper Operating Practices	143.3 lb/hr	BACT-PSD
Kleen Energy Systems, LLC	CT	02/25/2008	(2) CT (Siemens SGT6-5000f) w/ DB	2,136 MMBtu/hr	Oxidation Catalyst	0.9 ppmvd @ 15% O_2	BACT-PSD
Kleen Energy Systems, LLC	CT	02/25/2008	(2) CT (Siemens SGT6-5000f), DB	2,581 MMBtu/hr	Oxidation Catalyst	1.7 ppmvd @ 15% O_2	BACT-PSD
CPV Warren, LLC.	VA	01/14/2008	Electric Generation - Secnario 3	2,204 MMBtu/hr	GCP and Oxidation Catalyst.	1.8 ppmvd	BACT-PSD
Russell City Enery Center	CA	6/19/2007	(2) CTs (Westinghouse 501F)/HRSG	600 Net MW	Oxidation Catalyst	4.0 ppmvd @ 15% O_2	BACT-PSD
Fairbault Energy Park	MN	06/05/2007	Combined Cycle CT W/ DB	1,758 MMBtu/hr	GCP	9.0 ppmvd	BACT-PSD
Blythe Energy Project II, LLC	CA	04/25/2007	(2) Combustion Turbines	170 MW		4.0 ppmvd	BACT-PSD
Pso Southwestern Power Plt	OK	02/09/2007	Gas-Fired Turbines		Combustion Control	25.0 ppmvd	BACT-PSD
Lawton Energy Cogen Facility	OK	12/12/2006	Combustion Turbine And Duct Burner		GCP	16.4 ppmvd	BACT-PSD
Caithnes Bellport Energy Center	NY	05/10/2006	Combustion Turbine	2,221 MMBtu/hr	Oxidation Catalyst	2.0 ppmvd @ 15% O_2	BACT-PSD
Rocky Mountain Energy Center, LLC	CO	05/02/2006	Natural-Gas Fired, Combined-Cycle Turbine	300 MW	GCP and Oxidation Catalyst.	3.0 ppm @ 15% O_2	BACT-PSD
JK Spruce Electrice Generating Unit 2	TX	12/28/2005	Spruce Power Generator Unit No 2			4480.0 lb/hr	BACT-PSD
Tracy Substation Expansion Project	NV	08/16/2005	Combined Cycle CT/HRSG w/ DB	306 MW	Oxidation Catalyst	3.5 ppm @ 15% O_2	BACT-PSD
Wanapa Energy Center	OR	08/08/2005	CT/HRSG	2,384 MMBtu/hr	Oxidation Catalyst.	2.0 ppmvd @ 15% O_2	BACT-PSD
Crescent City Power	LA	06/06/2005	(2) Gas Turbines - 187 MW	2,006 MMBtu/hr	GCP and Oxidation Catalyst.	17.7 lb/hr	BACT-PSD
Duke Energy Washington County, LLC	OH	05/09/2005	(4) Turbines (Model GE7FA), w/ DB	170 MW		14.0 ppmvd @ 15% O2	BACT-PSD
Duke Energy Washington County, LLC	OH	05/09/2005	(4) Turbines (Model GE7FA), w/o DB	170 MW		10.0 ppmvd @ 15% O2	BACT-PSD
Berrien Energy, LLC	MI	04/13/2005	(3) Combustion Turbines And DB	1,584 MMBtu/hr	Catalytic Oxidation.	2.0 ppmvd @ 15% O_2	BACT-PSD
BP Cherry Point Cogeneration Project	WA	01/11/2005	GE7FA CT&HRSG	174 MW	Lean Pre-Mix Ct Burner & Ox Catalyst	2.0 ppmvd	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (Model GE7FA), w/ DB	172 MW		9.0 ppmvd @ 15% O_2	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (Model GE7FA), w/o DB	172 MW		6.0 ppmvd @ 15% O_2	BACT-PSD
Pastoria Energy Facility	CA	12/23/2004	(3) Combustion Turbines	168 MW	DLN	6.0 ppmvd	BACT-PSD
Sabine Pass Lng Import Terminal	LA	11/24/2004	(4) 30 MW Gas Turbine Generators	290 MMBtu/hr ea.	GCP	17.8 lb/hr	BACT-PSD
Sutter Power Plant	CA	08/16/2004	(2) Combustion Turbines	170 MW	Oxidation Catalyst Sysem	4.0 ppmvd	BACT-PSD
Currant Creek	UT	05/17/2004	(2) Natural Gas Fired Turbines And HRSGs		Oxidatino Catalyst	3.0 ppmvd	BACT-PSD
Duke Energy Wythe, LLC	VA	02/05/2004	Combined Cycle CT w/ DB	170 MW	GCP	9.0 ppmvd	BACT-PSD
Duke Energy Wythe, LLC	VA	02/05/2004	Combined Cycle CT w/o DB	170 MW	GCP	14.6 ppmvd	BACT-PSD
COB Energy Facility, LLC	OR	12/30/2003	(4) Combined Cycle CT w/ DB	1,150 MW	Catalytic Oxidation	2.0 ppmvd @ 15% O_2	BACT-PSD
Mankato Energy Center	MN	12/04/2003	(2) Combustion Turbine, Large, 2 Each	1,916 MMBtu/hr	GCP and Oxidation Catalyst.	4.0 ppmvd @ 15% O_2	BACT-PSD
Mankato Energy Center	MN	12/04/2003	Combustion Turbine, Large 2 Each	1,827 MMBtu/hr	GCP and Oxidation Catalyst.	4.8 ppmvd @ 15% O_2	BACT-PSD
James City Energy Park	VA	12/01/2003	Turbine, Combined Cycle, Natural Gas	1,973 MMBtu/hr	GCP	9.0 ppm	BACT-PSD
James City Energy Park	VA	12/01/2003	Combined Cycle CT w/ Duct Burner	1,973 MMBtu/hr	GCP	12.0 ppm	BACT-PSD
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	Combined Cycle CT w/ Duct Burner	325 MW	Catalytic Oxidizer	3.0 ppm @ 15% O_2	BACT-PSD
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	Turbine, Combined Cycle	325 MW	Catalytic Oxidizer	2.0 ppm @ 15% O_2	BACT-PSD
Hines Energy Complex, Power Block 3	FL	09/08/2003	(2) Combined Cycle CTs	1,830 MMBtu/hr	GCP and Oxidation Catalyst.	10.0 ppmvd @ 15% O_2	BACT-PSD
Redbud Power Plant	OK	06/03/2003	Combustion Turbine And Duct Burners	1,832 MMBtu/hr	GCP	17.2 ppmvd	BACT-PSD
Magnolia Power Project, Scppa	CA	05/27/2003	Gas Turbine	181 NET MW	Oxidation Catalyst	2.0 ppmvd @ 15% O_2	BACT-PSD
Mirant Sugar Creek, LLC	IN	04/23/2003	(4) Combined Cycle, Startup & Shut Down	1,491 MMBtu/hr	GCP, NG As Fuel.	82.5 tpy	BACT-PSD
Midland Cogeneration (Mcv)	MI	04/21/2003	(1) Turbine, Combined Cycle	984 MMBtu/hr	GCP	26.0 lb/hr	BACT-PSD
Sumas Energy 2 Generation Facility	WA	04/17/2003	(2) Turbines, Combined Cycle	660 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Duke Energy Stephens, Llc Stephens Energy	OK	03/21/2003	(2) Turbines, Combined Cycle	1,701 MMBtu/hr	Combustion Control	10.0 ppm @ 15% O_2	BACT-PSD
Kalkaska Generating, Inc	MI	02/04/2003	(2)Turbine, Combined Cycle,	605 MW	Oxidation Catalyst.	5.0 ppmvd @ 15% O_2	BACT-PSD
Source: EPA 2015 (RBLC database); Golder, 2015	MI	01/30/2003	(2) Turbine, Combined Cycle	172 MW	Catalytic Oxidation And Use Of GCP	4.0 ppmvd @ 15% O_2	BACT-PSD
Mirant Wyandotte, LLC	MI	01/28/2003	(2) Turbine, Combined Cycle	2,200 MMBtu/hr	Catalytic Oxidation System.	3.8 ppm	BACT-PSD
Bluewater Energy Center, LLC	MI	01/07/2003	(3) Turbine, Combined Cycle	180 MW	Catalytic Afterburner	41.7 lb/hr	BACT-PSD

Source: EPA 2015 (RBLC database); Golder, 2015

Note: DB = duct burner; DLN= dry low NOx; GCP= good combustion practices

TABLE B-4
SUMMARY OF CO BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	CO Limit	Basis
Florida								
FPL Port Everglades Power Plant	FL	5/9/2012	(3) Combined Cycle CT with HRSG	250 MW	Fuel Oil	GCP	35 ppmvd @ 15% O_2	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG w/o DB	265 MW	Fuel Oil	GCP	10 ppmvd @ 15% O_2	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG w/o DB	265 MW	Fuel Oil	GCP	10 ppmvd @ 15% O_2	BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	Fuel Oil	GCP	8.0 ppmvd @ 15% O_2	BACT-PSD
FPL - Turkey Point Power Plant	FL	2/8/2005	(4) Combined Cycle CTs and HRSGs	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	8.0 ppmvd @ 15% O_2	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbines, Combined Cycle,	170 MW	Distillate Fuel Oil	GCP	15 ppmvd @ 15% O_2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Effingham County Power (current project)	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG	180 MW	Fuel Oil	GCP, Catalytic Oxidation	2 ppmvd @ 15% O_2	BACT-PSD
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	General Electric Combustion Turbines		Fuel Oil		20 ppm @ 15% O_2	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Turbine, Combined Cycle	140 MW	Fuel Oil	Catalytic Oxidation	2 ppmvd @ 15% O_2	BACT-PSD
SCE&G - Jasper County Generating Facility	SC	5/23/2002	Turbines (3 each)	170 MW (Each)	Fuel Oil	GCP	22 ppmvd	BACT-PSD
Fayetteville Generation, LLC	NC	1/10/2002	(2) CT, CC	1940 MMBtu/hr	Fuel Oil	Combustion Control	20 ppmvd	BACT-PSD
Broad River Investors - Gaffney	SC	12/21/2000	(2) CTs	193 MW (Each)	Fuel Oil	GCP, Clean Burning Fuels	15 ppmvd @ 15% O_2	BACT-PSD
Rainey Generating Station	SC	4/3/2000	(2) CTs, CC	170 MW (Each)	Fuel Oil	GCP, Clean Burning Fuels	114 lb/hr	BACT-PSD
Santee Cooper Rainey Generation Station	SC	4/3/2000	(2) CT, CC	170 MW	Fuel Oil	GCP, Clean Burning Fuels	114 lb/hr	
Other States								
Fairbault Energy Park	MN	7/15/2004	(1) CT, CC	1801 MMBtu/hr	Fuel Oil	GCP	10 ppmvd @ 15% O_2	BACT-PSD
Tenaska Bear Garden Station	VA	4/30/2002	GE 7 FA Dual Fired CTs	2029 MMBtu/hr	Fuel Oil	GCP	222 TPY	BACT-PSD
Middleton Facility	ID	10/19/2001	(2) Gas Turbines w/o Duct Burners	1699 MMBtu/hr	Fuel Oil	None Indicated	30.6 lb/hr	BACT-PSD
Gray's Ferry Cogen Partnership	PA	3/21/2001	CT, CC	1515 MMBtu/hr	Fuel Oil	Oxidation Catalyst	0.0182 lb/MMBtu	BACT-PSD
San Juan Repowering Project	PR	3/2/2000	(2) CTs, HRSGs	232 MW (Each)	Fuel Oil	GCP, Oxydation Catalyst	100 lb/hr	BACT-PSD
LSP Nelson Energy, LLC	IL	1/28/2000	CT, CC w/o Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP and Combustion Controls	0.0986 lb/MMBtu	BACT-PSD
LSP Nelson Energy, LLC	IL	1/28/2000	CT, CC w/ Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP and Combustion Controls	0.1024 lb/MMBtu	BACT-PSD

Source: EPA 2015 (RBLC database); Golder, 2015

Note: GCP= good combustion practices

TABLE B-5

SUMMARY OF VOC BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	VOC Limit	Basis
Florida							
FPL Port Everglades Power Plant	FL	5/9/2012	(3) Combined Cycle CT with HRSG	250 MW	GCP	1.2 ppmvd @ 15% O_2	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG w/ DB	265 MW	GCP	1.9 ppmvd @ 15% O_2	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG w/o DB	265 MW	GCP	1.5 ppmvd @ 15% O_2	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG w/ DB	265 MW	GCP	1.9 ppmvd @ 15% O_2	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG w/o DB	265 MW	GCP	1.5 ppmvd @ 15% O_2	BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	GCP	1.2 ppmvd @ 15% O_2	BACT-PSD
Progress Bartow Power Plant	FL	1/29/2007	Combined Cycle CT and DB (4-On-1)	1,972 MMBtu/hr	GCP	1.5 ppmvd	BACT-PSD
Progress Bartow Power Plant	FL	1/29/2007	Combined Cycle CT (4-On-1)	1,972 MMBtu/hr	GCP	1.2 ppmvd	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Combined Cycle CT - 6 Units	2,333 MMBtu/hr	GCP	1.2 ppmvd @ 15 % O_2	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Combined Cycle CT and DB - 6 Units	2,761 MMBtu/hr	GCP	1.6 ppmvd @ 15 % O_2	BACT-PSD
FPL Turkey Point Power Plant	FL	2/8/2005	170 Mw Combustion Turbine, 4 Units	170 MW	GCP	1.3 ppmvd @ 15 % O_2	
Hines Energy Complex, Power Block 3	FL	9/8/2003	2 Combined Cycle CTs	1,830 MMBtu/hr	Combustion Design, GCP	2.0 ppmvd @ 15 % O_2	BACT-PSD
FPL Martin Plant	FL	4/16/2003	4 Combined Cycle CTs w/o DB	170 MW	GCP	1.3 ppmvd @ 15 % O_2	BACT-PSD
FPL Martin Plant	FL	4/16/2003	Combined Cycle CT w/ DB	170 MW	GCP	4.0 ppmvd @ 15 % O_2	BACT-PSD
FPL Manatee Plant - Unit 3	FL	4/15/2003	4 Combined Cycle CTs w/o DB	170 MW	GCP	1.3 ppmvd @ 15 % O_2	BACT-PSD
FPL Manatee Plant - Unit 3	FL	4/15/2003	Combined Cycle CT w/ DB	170 MW	GCP	4.0 ppmvd @ 15 % O_2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
Effingham County Power	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG	180 MW	GCP, Catalytic Oxidation	2.0 ppmvd @ 15% O_2	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w or w/o DB	600 MW	Oxidation Catalyst	2.0 ppmvd @ 15% O_2	BACT-PSD
McDonough Combined-Cycle Generating Units	GA	1/7/2008	(6) CTs (Mitsubishi M501G) w/ DB	250 MW	Oxidation Catalyst	1.8 ppmvd @ 15 % O_2	LAER
Forsyth Energy Plant	NC	9/29/2005	Turbine, Combined Cycle, Natural Gas, (3)	1844.3 MMBtu/hr	GCP and Efficient Process Design	5.7 ppm @ 15% O_2	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	3 GE 7FB Turbines (230 MW, ea.)	2126 MMBtu/hr	GCP	3.6 ppmvd @ 15 % O_2	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)/HRSG	140 MW	Catalytic Oxidation	2.0 ppm @ 15% O_2	BACT-PSD
Other States							
Colorado Bend Energy Center	TX	4/1/2015	Combined cycle turbine	1,100 MW	Oxidation Catalyst	4.0 ppmvd @ 15% O2	BACT-PSD
S R Bertron Electric Generating Station	TX	12/19/2014	(2) combined cycle turbines	240 MW	Oxidation Catalyst	1.0 ppmvd	BACT-PSD
Victoria Power Station	TX	12/1/2014	Combined cycle turbine	197 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Trinidad Generating Facility	TX	11/20/2014	Combined cycle turbine	497 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Freeport Lng Pretreatment Facility	TX	7/16/2014	Combined cycle turbine	87 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Tenaska Brownsville Generating Station	TX	4/29/2014	(2) combined cycle turbines	274 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #1 - combined cycle	2,258 mmBtu/hr	Oxidation Catalyst	1.0 ppmvd	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #2 -combined cycle	2,258 mmBtu/hr	Oxidation Catalyst	1.0 ppmvd	BACT-PSD
Fge Texas Power I And Fge Texas Power Ii	TX	3/24/2014	Alstom Turbine	231 MW	Oxidation catalyst, GCP	2.0 ppmvd	BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Combined cycle turbine w/ DB	2,988 MMBtu/hr	Oxidation Catalyst	2.0 ppmvd @ 15% O2	BACT-PSD
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2,267 MMBtu/hr	CO Catalyst	2.0 ppmvd	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Combined cycle turbine w/ DB (2)	647 MMBtu/hr each	Oxidation catalyst technology and good cor	4.0 ppmvd	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Combined cycle turbine	700 MW	oxidation catalyst	2.0 ppmvd	BACT-PSD
Sand Hill Energy Center	TX	9/13/2013	Combined cycle turbine	174 MW		2.0 ppmvd	BACT-PSD
Sunbury Generation Lp/Sunbury Ses	PA	4/1/2013	Combined cycle turbine w/ DB (3)	2,538 MMBtu/hr	Oxidation Catalyst	1.0 ppmvd	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	Combined cycle turbines (3)	3,442 MMBtu/hr	Oxidation catalyst; good combustion practic	0.7 ppmvd	BACT-PSD
La Paloma Energy Center	TX	2/7/2013	Combined cycle turbines (2)	650 MW	oxidation catalyst	2.0 ppmvd	BACT-PSD
Channel Energy Center Llc	TX	10/15/2012	Combined Cycle Turbine	180 MW	GCP	2.0 ppmvd	BACT-PSD
Deer Park Energy Center	TX	9/26/2012	Combined Cycle Turbine	180 MW	GCP, Clean Fuels	2.0 ppmvd	BACT-PSD
Es Joslin Power Plant	TX	9/12/2012	Combined Cycle Gas Turbine	195 MW	GCP, Clean Fuels	2.0 ppmvd	BACT-PSD
Colusa Generating Station	CA	3/11/2011	Combustion Turbines (Normal Operation)	172 MW		2.0 ppmvd	BACT-PSD

TABLE B-5
SUMMARY OF VOC BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	VOC Limit	Basis
Nelson Energy Center	IL	12/28/2010	Electric Generation Facility	220 MWe each		4.0 ppmvd @ 15% O2	BACT-PSD
Warren County Power Plant - Dominion	VA	12/17/2010	Combined Cycle Turbine & Duct Burner, 3	2996 MMBTU/H	Combustion Design, GCP	2.6 LB/H	BACT-PSD
King Power Station	TX	8/5/2010	Turbine	1350 MW	Oxidation Catalyst, DLN, and GCP	1.8 ppmvd AT 15% O2	LAER
Langley Gulch Power Plant	ID	6/25/2010	Combustion Turbine, Combined Cycle W/ Duct Burner	2375.28 MMBTU/H	Oxidation Catalyst, DLN, and GCP	2.0 ppmvd	BACT-PSD
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	GCP	4.0 ppmvd	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	Two Combined Cycle CTs	2110 MMBtu/hr	Proper Operating Practices	12.1 lb/hr	BACT-PSD
Kleen Energy Systems, LLC	CT	2/25/2008	Siemens SGT6-5000f CT #1 and #2	2136 MMBtu/hr	Oxidation Catalyst	5.0 ppmvd @ 15 % O_2	BACT-PSD
CPV Warren LLC	VA	1/14/2008	Electric Generation - Scenario 2	1944 MMBtu/hr	GCP and Oxidation Catalyst	0.7 ppmvd	BACT-PSD
Faribault Energy Park	MN	6/5/2007	Combined Cycle CT w/ DB	1758 MMBtu/hr	GCP	1.5 ppmvd	BACT-PSD
Rocky Mountain Energy Center, Llc	CO	5/2/2006	Combined Cycle CT	300 MW	NG only, GCP and Oxidation Catalyst.	0.0 lb/MMBtu	BACT-PSD
City Public Service Jk Spruce Electrice Generating	TX	12/28/2005	Spruce Power Generator Unit No 2			29.0 lb/hr	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Combined Cycle CT/HRSG w/ DB	306 MW	Oxidation Catalyst	4.0 ppm @ 15% O_2	BACT-PSD
Xcel Energy High Bridge Generating Plant	MN	8/12/2005	CT/HRSG and DB - 2 Units	2384.1 MMBtu/hr	NG Fuel	2.0 ppmvd @ 15 % O_2	BACT-PSD
Wanapa Energy Center	OR	8/8/2005	CT/HRSG and DB - 4 Units	2384.1 MMBtu/hr	NG Fuel, Oxidation Catalyst	19.7 lb/hr	BACT-PSD
Crescent City Power	LA	6/6/2005	Gas Turbines - 187 Mw (2)	2006 MMBtu/hr	GCP and Oxidation Catalyst	2.8 lb/hr	BACT-PSD
Berrien Energy, Llc	MI	4/13/2005	3 Combustion Turbines And Duct Burners	1584 MMBtu/hr	Catalytic Oxidizer	3.2 lb/hr	BACT-PSD
Bp Cherry Point Cogeneration Project	WA	1/11/2005	GE7FA CT/HRSG	174 MW	Lean Pre-Mix CT Burner & Ox Catalyst		BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	Turbines (4) (Model GE7FA) w/ DB	172 MW	GCP	20.4 lb/hr	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	Turbines (4) (Model GE7FA), w/ DB	172 MW	GCP	3.2 lb/hr	BACT-PSD
El Dorado Energy, LLC	NV	8/19/2004	Combined Cycle CT & Cogen(2)	475 MW	NG Only and GCP	5.2 lb/hr	BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	Combined Cycle CT w/DB	170 MW	GCP	3.0 lb/hr	BACT-PSD
Cob Energy Facility, LLC	OR	12/30/2003	Combined Cycle CT w/ DB	1150 MW	GCP and Oxidation Catalyst	7.1 lb/hr	BACT-PSD
Ivanpah Energy Center, L.P.	NV	12/29/2003	Combined Cycle CT	500 MW	GCP and Oxidation Catalyst	2.3 ppmvd	BACT-PSD
Mankato Energy Center	MN	12/4/2003	Combustion Turbine, Large (2)	1827 MMBtu/hr	GCP and Oxidation Catalyst	7.1 ppmvd @ 15 % O_2	BACT-PSD
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	Turbine, Combined Cycle w/ DB	325 MW		4.0 ppm	BACT-PSD
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	Turbine, Combined Cycle	325 MW		1.0 ppm	BACT-PSD
Duke Energy Washington County LLC	OH	8/14/2003	Turbines (2) (Model GE 7FA), w/DB	170 MW	GCP	19.6 lb/hr	BACT-PSD
Duke Energy Washington County LLC	OH	8/14/2003	Turbines (2) (Model GE 7FA), w/o DB	170 MW	GCP	3.0 lb/hr	BACT-PSD
Magnolia Power Project, Scppa	CA	5/27/2003	Gas Turbine	181 NET MW	Oxidation Catalyst	2.0 ppmvd @ 15 % O_2	BACT-PSD
Sumas Energy 2 Generation Facility	WA	4/17/2003	2 Combined Cycle CTs	660 MW	GCP	420.0 lb/d	BACT-PSD
Duke Energy Stephens, LLC Stephens Energy	OK	3/21/2003	Turbines, Combined Cycle (2)	1701 MMBtu/hr	Good Combustion and DLN	45.6 lb/hr	BACT-PSD
Kalkaska Generating, Inc	MI	2/4/2003	Turbine, Combined Cycle, (2)	605 MW	Oxidation Catalyst	3.5 ppm	BACT-PSD
South Shore Power Llc	MI	1/30/2003	Turbine, Combined Cycle, (2)	172 MW	Oxidation Catalyst	7.3 lb/hr	Other Case-by-Case
Mirant Wyandotte Llc	MI	1/28/2003	Turbine, Combined Cycle, (2)	2200 MMBtu/hr	GCP and Oxidation Catalyst	10.0 ppm	Other Case-by-Case
Bluewater Energy Center LLC	MI	1/7/2003	3 Combined Cycle CTs	180 MW	Catalytic Afterburner.	28.0 lb/hr	BACT-PSD

Source: EPA 2015 (RBLC database); Golder, 2015

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

Golder Associates

TABLE B-6
SUMMARY OF VOC BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	VOC Limit	Basis
Florida								
FPL Port Everglades Power Plant	FL	5/9/2012	(3) Combined Cycle CT with HRSG	250 MW	Fuel Oil	GCP, Clean Fuels	10.0 ppmvd @ 15% O_2	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG w/ DB	265 MW	Fuel Oil	GCP, Clean Fuels	6.0 ppmvd @ 15% O_2	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG w/ DB	265 MW	Fuel Oil	GCP, Clean Fuels	6.0 ppmvd @ 15% O_2	BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	Fuel Oil	GCP, Clean Fuels	6.0 ppmvd @ 15% O_2	
FPL - Turkey Point Power Plant	FL	2/8/2005	(4) Combined Cycle CTs and HRSGs	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	2.8 ppmvd @ 15% O_2	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbines, Combined Cycle,	170 MW ea.	Fuel Oil	GCP	2.5 ppmvd @ 15% O_2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Effingham County Power (current project)	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG	180 MW	Fuel Oil	GCP, Catalytic Oxidation	2.0 ppmvd @ 15% O_2	BACT-PSD
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	General Electric Combustion Turbines		Fuel Oil		70.0 lb/hr	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)/HRSG	140 MW	Fuel Oil	Catalytic Oxidation	2.0 ppmvd @ 15% O_2	BACT-PSD
Fayetteville Generation, LLC.	NC	1/10/2002	(2) CT, CC	1940 MMBtu/hr	Fuel Oil	GCP	7.0 ppmvd	BACT-PSD
Rainey Generating Station	SC	4/3/2000	(2) CTs, CC	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	8.0 lb/hr	BACT-PSD
Santee Cooper Rainey Generation Station	SC	4/3/2000	(2) CT, CC	170 MW	Fuel Oil	GCP, Clean Fuels	8.0 lb/hr	
Other States								
Fairbault Energy Park	MN	7/15/2004	(1) CT, CC	1801 MMBtu/hr	Fuel Oil	GCP	5.0 ppmvd @ 15% O_2	BACT-PSD
Gray's Ferry Cogen Partnership	PA	3/21/2001	CT, CC	1515 MMBtu/hr	Fuel Oil	GCP	0.026 lb/MMBtu	BACT-PSD
San Juan Repowering Project	PR	3/2/2000	(2) CTs, HRSGs	232 MW (EACH)	Fuel Oil	GCP, Catalytic Oxidation	15.0 lb/hr	BACT-PSD
LSP Nelson Energy, LLC.	IL	1/28/2000	CT, CC w/o Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP	0.0157 lb/MMBtu	BACT-PSD
LSP Nelson Energy, LLC.	IL	1/28/2000	CT, CC w/ Duct Burner	2166 MMBtu/hr	Fuel Oil	GCP	0.023 lb/MMBtu	BACT-PSD

Source: EPA 2015 (RBLC database); Golder, 2015

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

TABLE B-7

SUMMARY OF PM BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	$PM/PM_{10}/PM_{2.5}$ Limit	Equivalent $PM/PM_{10}/PM_{2.5}$ Emissions Rate	Basis
Florida								
FPL Port Everglades Power Plant	FL	5/9/2012	(3) Combined Cycle CT with HRSG	250 MW	NG Fuel and GCP	2 gr S/100 scf		BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG	265 MW	NG Fuel and GCP	2 gr S/100 scf		BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG	265 MW	NG Fuel and GCP	2 gr S/100 scf		BACT-PSD
OUC Curtis H. Stanton Energy Center	FL	5/12/2008	300 MW Combined Cycle CT	1765 MMBtu/hr	NG Fuel			BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	NG Fuel	2 gr S/100 scf	0.0015 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	CC CTs - 6 Units	2,333 MMBtu/hr	NG only, GCP	2 gr S/100 scf	0.0015 lb/MMBtu	BACT-PSD
Hines Power Block 4	FL	6/8/2005	CC Turbine	1,915 MMBtu/hr	Clean Fuels	10 % Opacity	0.0053 lb/MMBtu	BACT-PSD
FPL Turkey Point Power Plant	FL	2/8/2005	(4) 170 MW CT	1,776 MMBtu/hr	GCP		0.0051 lb/MMBtu	BACT-PSD
Hines Energy Complex, Power Block 3	FL	9/8/2003	(2) CC CTs	1,830 MMBtu/hr	GCP and Clean Fuel			BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbine, CC, NG	2,095 MMBtu/hr	Use of NG			BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Effingham County Power (current project)	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG w/ DB	180 MW	Low Sulfur Fuel	0.5 gr S/100 scf		BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/o DB	200 MW	Low Sulfur Fuel	0.5 gr S/100 scf	0.0064 lb/MMBtu	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/ DB	200 MW	Low Sulfur Fuel	0.5 gr S/100 scf	0.0054 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	(3) Turbine w/o DB	1,844 MMBtu/hr	LSF and GCP	0.019 lb/MMBtu	0.0190 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	(3) Turbine w/ DB	1,844 MMBtu/hr	LSF and GCP	0.021 lb/MMBtu	0.0210 lb/MMBtu	BACT-PSD
Reliant Energy Choctaw County, LLC	MS	11/23/2004	Combined Cycle GE CT (Aa-003)	230 MW each		20.59 lb/hr		BACT-PSD
Peace Vally Generation Company, LLC	GA	6/1/2003	(3) CTs (GE 7FA)/Duct Burners	1,550 MW	NG Fuel	0.011 lb/MMBtu	0.011 lb/MMBtu	BACT-PSD
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Combined Cycle CT (GE 7FA)	140 MW	Clean Fuel, GCP	0.009 lb/MMBtu	0.009 lb/MMBtu	BACT-PSD
GenPower Rincon, LLC	GA	3/24/2003	(2) Combined Cycle CT (GE 7FA)/HRSG	172 MW	Firing NG	0.011 lb/MMBtu	0.011 lb/MMBtu	BACT-PSD
Wansley Combined Cycle Energy Facility	GA	1/15/2002	(2) CTs (Siemens V84.3a2)/HRSG	521 MW	GCP, Low Sulfur Fuel	0.011 lb/MMBtu	0.011 lb/MMBtu	BACT-PSD
Effingham County Power	GA	12/27/2001	(2) Combined Cycle CT (GE 7FA)/HRSG	185 MW	Clean Fuel, GCP	21.6 lb/hr		BACT-PSD
Other States								BACT-PSD
Colorado Bend Energy Center	TX	4/1/2015	Combined-Cycle Gas Turbine	1,100 MW	GCP, Clean Fuels	43 lb/hr		BACT-PSD
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Combined Cycle Turbine w/ DB	2,159 MMBtu/hr	GCP, Clean Fuels	7.6 lb/hr	0.0035 lb/MMBtu	BACT-PSD
Freeport Lng Pretreatment Facility	TX	7/16/2014	Combustion Turbine	87 MW		15.22 lb/hr		BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion Turbine #1 - Combined Cycle	2,258 MMBtu/hr		0.01 lb/MMBtu	0.0100 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion Turbine #2 -Combined Cycle	2,258 MMBtu/hr		0.01 lb/MMBtu	0.0100 lb/MMBtu	BACT-PSD
Fge Texas Power I And Fge Texas Power Ii	TX	3/24/2014	Alstom Turbine	231 MW	GCP, Clean Fuels	2 PPMVD		BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Combined Cycle Turbine w/ DB	2,988 MMBtu/hr	GCP, Clean Fuels	23.6 LB/HR TOTAL PM		BACT-PSD
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	Turbine, Combined Cycle Unit (Siemens 5000)	2,267 MMBtu/hr		10.4 lb/hr	0.0046 lb/MMBtu	BACT-PSD
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	Turbine, Combined Cycle Unit (Siemens 5000)	2,267 MMBtu/hr		15.6 lb/hr	0.0069 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc LLC/Ontelaunee	PA	12/17/2013	Turbine, Combined Cycle, #1 And #2	3,046 MMBtu/hr		48.56 TPY		BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Combined Cycle Turbine w/ DB	647 MMBtu/hr each	GCP, Clean Fuels	0.014 lb/MMBtu	0.0140 lb/MMBtu	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Combined Cycle Turbine	700 MW	GCP, Clean Fuels	26.2 lb/hr		BACT-PSD
Thetford Generating Station	MI	7/25/2013	Combined Cycle Turbine w/ DB	2,587 MMBtu/hr each	GCP, Clean Fuels	0.0066 lb/MMBtu	0.0066 lb/MMBtu	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	Combined Cycle Turbine w/o DB	2,237 MMBtu/hr	GCP, Clean Fuels	0.006 lb/MMBtu	0.0060 lb/MMBtu	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	Combined Cycle Turbine w/ DB	2,486 MMBtu/hr	GCP, Clean Fuels	0.008 lb/MMBtu	0.0080 lb/MMBtu	BACT-PSD
Sunbury Generation Lp/Sunbury Ses	PA	4/1/2013	Combined Cycle Turbine w/ DB (3)	2,538 MMBtu/hr		0.0088 lb/MMBtu	0.0088 lb/MMBtu	OTHER CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	Combustion Turbine Generators, (3)	3,442 MMBtu/hr	GCP, Clean Fuels	0.0033 lb/MMBtu	0.0033 lb/MMBtu	BACT-PSD
Channel Energy Center Llc	TX	10/15/2012	Combined Cycle Turbine	180 MW	GCP, Clean Fuels	27 lb/hr		BACT-PSD
Es Joslin Power Plant	TX	9/12/2012	Combined Cycle Gas Turbine	195 MW	GCP, Clean Fuels	18 lb/hr	lb/MMBtu	OTHER CASE-BY-CASE
Sumpter Power Plant	MI	11/17/2011	Combined Cycle Combustion Turbine W/ Hrsg	130 MW electrical output		0.0066 lb/MMBtu	0.0066 lb/MMBtu	BACT-PSD
Palmdale Hybrid Power Project	CA	10/18/2011	Combustion Turbines (Normal Operation)	154 MW	Use of NG	0.0048 lb/MMBtu	0.0048	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #1 and #2 w/o DB	180 MW	Use of NG	8.91 lb/hr		BACT-PSD
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #1 and #2 w/ DB	180 MW	Use of NG	11.78 lb/hr		BACT-PSD
Colusa Generating Station	CA	3/11/2011	Combustion Turbines (Normal Operation)	172 MW	Use of NG	13.5 lb/hr	lb/MMBtu	BACT-PSD
Nelson Energy Center	IL	12/28/2010	Electric Generation Facility	220 MWe each		0.012 lb/MMBtu	0.012 lb/MMBtu	BACT-PSD
Warren County Power Plant - Dominion	VA	12/17/2010	Combined Cycle Turbine & Duct Burner, 3	2,996 MMBtu/hr	Natural Gas only, fuel has maxin	8 lb/hr	0.0027	BACT-PSD
King Power Station	TX	8/5/2010	Turbine	1,350 MW	use low ash fuel (natural gas or l	11.1 lb/hr		BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #1 and #2 w/ DB	154 MW	PUC QUALITY NATURAL GAS	12 lb/hr		BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #1 and #2 w/ DB	154 MW	PUC QUALITY NATURAL GAS	18 lb/hr	lb/MMBtu	BACT-PSD
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	GCP, NG as Fuel	0.01 lb/MMBtu	0.01 lb/MMBtu	BACT-PSD

TABLE B-7

SUMMARY OF PM BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	$PM/PM_{10}/PM_{2.5}$ Limit	Equivalent $PM/PM_{10}/PM_{2.5}$ Emissions Rate	Basis
CPV St. Charles	MD	11/12/2008	(2) Combustion Turbines			0.012 lb/MMBtu	0.012	BACT-PSD
Gateway Generating Station	CA	7/1/2008	(2) Combined Cycle CT (GE 7FA)/HRSG	530 Net MW	NG with 0.75 gr/100 scf S			BACT-PSD
Colusa Generating Station	CA	5/1/2008	(2) Combined Cycle CT/HRSG	172 MW		20 lb/hr	lb/hr	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	GCP, NG as Fuel	24.23 lb/hr	24.23 lb/MMBtu	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	Two CC Gas Turbines	2,110 MMBtu/hr	GCP, NG as Fuel	24.23 lb/hr	0.0000 lb/MMBtu	BACT-PSD
Kleen Energy Systems, LLC	CT	2/25/2008	(2) CT (Siemens SGT6-5000f) w/o DB	2,136 MMBtu/hr	NG Fuel	11 lb/hr	0.0051 lb/MMBtu	BACT-PSD
Kleen Energy Systems, LLC	CT	2/25/2008	(2) CT (Siemens SGT6-5000f) w/ DB	2,581 MMBtu/hr	NG Fuel	15.2 lb/hr	0.0059 lb/MMBtu	N/A
CPV Warren	VA	1/14/2008	Electric Generation - Scenario 1	1,717 MMBtu/hr	GCP	0.013 lb/MMBtu	0.0130 lb/MMBtu	N/A
Russell City Enery Center	CA	6/19/2007	(2) CTs (Westinghouse 501F)/HRSG	600 Net MW	NG with 0.25 gr/100 scf S		lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/5/2007	CC CT w/DB	1,758 MMBtu/hr		0.01 lb/MMBtu	0.0100 lb/MMBtu	BACT-PSD
Blythe Energy Project II, LLC	CA	4/25/2007	2 CTs	1,776 MMBtu/hr ea.	NG with 0.5 gr S/100 SCF	6 lb/hr	0.0034 lb/MMBtu	BACT-PSD
PSO Southwestern Power Plant	OK	2/9/2007	Gas-Fired Turbines		NG and Efficient Combustion	0.0093 lb/MMBtu	0.0093 lb/MMBtu	BACT-PSD
Lawton Energy Cogen Facility	OK	12/12/2006	CT w/ DB		GCP	0.0067 lb/MMBtu	0.0067 lb/MMBtu	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	CT/HRSG w/o DB	2,221 MMBtu/hr	LSF	0.0055 lb/MMBtu	0.0055 lb/MMBtu	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	CT/HRSG w/ DB	2,715 MMBtu/hr	LSF	0.0066 lb/MMBtu	0.0066 lb/MMBtu	BACT-PSD
Rocky Mountain Energy Center, LLC	CO	5/2/2006	NG Fired, CC Turbine	300 MW	NG only and GCP	0.0074 lb/MMBtu	0.0074 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	CC CT/HRSG and DB	306 MW	Best Combustion Practices.	0.011 lb/MMBtu	0.0110 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Combined Cycle CT/HRSG w/ DB	306 MW	Best Combustion Practices.	0.011 lb/MMBtu	0.0110	BACT-PSD
Wanapa Energy Center	OR	8/8/2005	CT/HRSG	2,384 MMBtu/hr				
Crescent City Power	LA	6/6/2005	(2) Gas Turbines - 187 Mw	2,006 MMBtu/hr	GCP and Clean Fuel	29.4 lb/hr	0.0000 lb/MMBtu	BACT-PSD
Duke Energy Washington County, LLC	OH	5/9/2005	(2) Turbines (GE 7FA), w/ DB	170 MW		28 lb/hr		BACT-PSD
Duke Energy Washington County, LLC	OH	5/9/2005	(2) Turbines (GE 7FA), w/o DB	170 MW		19 lb/hr		BACT-PSD
Berrien Energy, LLC	MI	4/13/2005	(3) CTs w/ DB	1,584 MMBtu/hr	GCP, use of NG	19 lb/hr	0.0120 lb/MMBtu	BACT-PSD
Bp Cherry Point Cogeneration Project	WA	1/11/2005	(3) GE7FA CT/HRSG	1,614 MMBtu/hr ea.	Only NG	20.6 lb/hr		BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (GE7FA), w/ DB	172 MW		23.3 lb/hr		BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	(4) Turbines (GE7FA), w/o DB	172 MW		15 lb/hr		BACT-PSD
Sutter Power Plant	CA	8/16/2004	(2) CT	170 MW		11.5 lb/hr		BACT-PSD
Currant Creek	UT	5/17/2004	NG Fired Turbines And HRSGs			0.066 lb/MMBtu	0.0660 lb/MMBtu	BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	CC CT w/o DB	170 MW	GCP	17.5 lb/hr		BACT-PSD
Duke Energy Wythe, LLC	VA	2/5/2004	CC CT w/ DB	170 MW	GCP	23.7 lb/hr		BACT-PSD
COB Energy Facility, LLC	OR	12/30/2003	CC CT w/ DB	1,150 MW	GCP, use of NG	14 lb/hr		BACT-PSD
Mankato Energy Center	MN	12/4/2003	Large CT, 2 Each	1,827 MMBtu/hr	GCP and Clean Fuel	0.057 lb/MMBtu	0.0570 lb/MMBtu	BACT-PSD
James City Energy Park	VA	12/1/2003	Turbine, Combined Cycle, Natural Gas	1,973 MMBtu/hr	GCP and Clean Fuel	18 lb/hr	0.0091 lb/MMBtu	
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	CC CT w/ DB	325 MW		25 lb/hr	25 lb/MMBtu	
Duke Energy Arlington Valley (Avefii)	AZ	11/12/2003	CC CT w/o DB	325 MW		18 lb/hr	18 lb/hr	BACT-PSD
Redbud Power Plant	OK	6/3/2003	CT And DBs	1,832 MMBtu/hr	Efficient Combustion	0.012 lb/MMBtu	0.0120 lb/MMBtu	BACT-PSD
Magnolia Power Project, Scppa	CA	5/27/2003	Gas Turbine: Combined Cycle	181 NET MW		0.01 gr/scf		BACT-PSD
Sumas Energy 2 Generation Facility	WA	4/17/2003	(2) Turbines, CC	660 MW	GCP & LSF	194 lb/d (filterable)		BACT-PSD
Sumas Energy 2 Generation Facility	WA	4/17/2003	(2) Turbines, CC	660 MW	GCP & LSF	377 lb/d (condensible)		BACT-PSD
Duke Energy Stephens, LLC	OK	3/21/2003	(2) Turbines, CC	1,701 MMBtu/hr	GCP and Clean Fuel	0.015 lb/MMBtu	0.0150 lb/MMBtu	Other Case-by-Case
Kalkaska Generating, Inc	MI	2/4/2003	(2) Turbine, CC	605 MW	GCP and Clean Fuel	38 lb/hr		BACT-PSD
South Shore Power, LLC	MI	1/30/2003	(2) Turbine, CC	172 MW	GCP	24 lb/hr		BACT-PSD
Mirant Wyandotte, LLC	MI	1/28/2003	(2) Turbine, CC	2,200 MMBtu/hr	GCP and Firing NG	16.8 lb/hr	0.0076 lb/MMBtu	BACT-PSD
Bluewater Energy Center, LLC	MI	1/7/2003	(3) Turbine, CC	180 MW	Only NG	19.6 lb/hr		BACT-PSD

Source: EPA 2015 (RBLC database); Golder, 2015

Note: GCP= good combustion practices; LSF= low sulfur fuel; NG = natural gas; CC = combined cycle; CT = combustion turbine; DB = duct burner; HRSG = heat recovery steam generator.

TABLE B-8
SUMMARY OF PM BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input		Fuel	Control Method	$PM/PM_{10}/PM_{2.5}$ Limit		Basis
Florida										
FPL Port Everglades Power Plant	FL	5/9/2012	(3) Combined Cycle CT with HRSG	250	MW	Fuel Oil	Clean Fuel, GCP	0.0015	% S in Fuel Oil	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG	265	MW	Fuel Oil	Clean Fuel, GCP	0.0015	% S in Fuel Oil	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG	265	MW	Fuel Oil	Clean Fuel, GCP	0.0015	% S in Fuel Oil	BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333	MMBtu/hr	Fuel Oil	LSF, GCP	0.0015	% S in Fuel Oil	BACT-PSD
FPL Martin Plant	FL	4/16/2003	(4) Turbines, Combined Cycle,	170	MW	Fuel Oil	Ultra LSF			BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)										
Effingham County Power (current project)	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG w/ DB	180	MW	Fuel Oil		0.0103	lb/MMBtu	
Effingham County Power (current project)	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG w/o DB	180	MW	Fuel Oil		0.0153	lb/MMBtu	
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	General Electric CTs			Fuel Oil		54.4	TPY	BACT-PSD
Fairbault Energy Park	MN	7/15/2004	(1) CT, CC	1,801	MMBtu/hr	Fuel Oil	Clean Fuel and GCP			Other Case-by-Case
Mcintosh Combined Cycle Facility	GA	4/17/2003	(4) Turbine, Combined Cycle	140	MW	Fuel Oil	Clean Fuel, GCP	0.0160	lb/MMBtu	
SCE&G - Jasper County Generating Facility	SC	5/23/2002	Turbines (3 each)	170	MW (Each)	Fuel Oil	LSF, GCP	100.8	TPY	BACT-PSD
Fayetteville Generation, LLC	NC	1/10/2002	(2) CT, CC	1,940	MMBtu/hr	Fuel Oil	Combustion Control			BACT-PSD
Other States										
Middleton Facility	ID	10/19/2001	(2) Gas Turbines w/o DB	1,699	MMBtu/hr	Fuel Oil	Pollution Prevention Precautions			BACT-PSD
Gray's Ferry Cogen Partnership	PA	3/21/2001	CT, CC	1,515	MMBtu/hr	Fuel Oil	GCP	32.5	lb/hr	BACT-PSD
San Juan Repowering Project	PR	3/2/2000	(2) CTs, HRSGs	232	MW	Fuel Oil	GCP, LSF	0.0413	lb/MMBtu	BACT-PSD
LSP Nelson Energy, LLC	IL	1/28/2000	CT, CC w/o Duct Burner	2,166	MMBtu/hr	Fuel Oil	GCP, LSF	77.9	lb/hr	BACT-PSD
LSP Nelson Energy, LLC	IL	1/28/2000	CT, CC w/ Duct Burner	2,166	MMBtu/hr	Fuel Oil	GCP, LSF	85	lb/hr	BACT-PSD

Source: EPA 2015 (RBLC database); Golder, 2015
Note: GCP= good combustion practices; LSF= low sulfur fuel; NG = natural gas; CC = combined cycle; CT = combustion turbine; DB = duct burner; HRSG = heat recovery steam generator.

TABLE B-9
SUMMARY OF SO_2 BACT DETERMINATIONS FOR CTS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input		Fuel	Control Method	VOC Limit		Basis
Colorado Bend Energy Center	TX	4/1/2015	Combined-cycle gas turbine	1100	MW	Natural Gas	LSF, GCP	2	GR/100 SCF	BACT-PSD
West Deptford Energy Station	NJ	7/18/2014	Combined Cycle Combustion Turbine w/o DB	2,308	MMBtu/hr	Natural Gas	LSF	0.00214	lb/MMbtu	BACT-PSD
Freeport Lng Pretreatment Facility	TX	7/16/2014	Combustion Turbine	87	MW	Natural Gas		3.68	lb/hr	BACT-PSD
FGE Texas Power I And Fge Texas Power II	TX	3/24/2014	Alstom Turbine	231	MW	Natural Gas	LSF, GCP	1	GR S / 100 DSCF	BACT-PSD
PSEG Fossil LLC Sewaren Generating Station	NJ	3/7/2014	Combined Cycle Combustion Turbine w/ DB	3846.005	MMBtu/hr	Natural Gas	LSF	0.0013	lb/MMbtu	CASE-BY-CASE
PSEG Fossil LLC Sewaren Generating Station	NJ	3/7/2014	Combined Cycle Combustion Turbine w/ DB	3,846	MMBtu/hr	Natural Gas	LSF	0.0013	lb/MMbtu	CASE-BY-CASE
PSEG Fossil LLC Sewaren Generating Station	NJ	3/7/2014	Combined-cycle gas turbine w/ DB	3846.005	MMBtu/hr	Natural Gas	LSF	0.0014	lb/MMbtu	CASE-BY-CASE
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	Combined-cycle gas turbine	2,267	MMBtu/hr	Natural Gas		0.0023	lb/MMbtu	BACT-PSD
Berks Hollow Energy Assoc LLC/Ontelaunee	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBtu/hr	Natural Gas		0.0015	lb/MMbtu	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Combined Cycle Combustion Turbine w/o DB	5,886	MMBtu/hr	Natural Gas	LSF	0.0014	lb/MMbtu	N/A
Oregon Clean Energy Center	OH	6/18/2013	Combined Cycle Combustion Turbine w/ DB	5,886	MMBtu/hr	Natural Gas		0.0014	lb/MMbtu	N/A
Oregon Clean Energy Center	OH	6/18/2013	Combined Cycle Combustion Turbine w/o DB	5,470	MMBtu/hr	Natural Gas	LSF	0.0014	lb/MMbtu	N/A
Oregon Clean Energy Center	OH	6/18/2013	Combined Cycle Combustion Turbine w/ DB	5,470	MMBtu/hr	Natural Gas	LSF	0.0014	lb/MMbtu	N/A
Sunbury Generation LP/Sunbury SES	PA	4/1/2013	Combined Cycle Combustion Turbine w/ DB	2,538	MMBtu/hr	Natural Gas		0.0024	lb/MMbtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	Combustion Turbine	3442	MMBtu/hr	Natural Gas	LSF	0.0011	lb/MMbtu	BACT-PSD
Woodbridge Energy Center	NJ	7/25/2012	Combined Cycle Combustion Turbine w/ DB	4600	MMBtu/hr	Natural Gas	LSF, GCP	0.0011	lb/MMbtu	CASE-BY-CASE
Woodbridge Energy Center	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o DB	4600	MMBtu/hr	Natural Gas	LSF	0.0009	lb/MMbtu	CASE-BY-CASE
Thomas C. Ferguson Power Plant	TX	9/1/2011	Natural Gas-Fired Turbines	390	MW	Natural Gas	LSF	27.07	lb/r	BACT-PSD
Warren County Power Plant - Dominion	VA	12/17/2010	Combined Cycle Turbine & Duct Burner, 3	2996	MMBtu/hr	Natural Gas	LSF, GCP	0.0003	lb/MMbtu	CASE-BY-CASE

Source: EPA 2015 (RBLC database); Golder, 2015

Note: LSF=low sulfur fuel, GCP= good combustion practices.

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TABLE B-10
SUMMARY OF NOx, CO, VOC, PM, AND SO2 BACT DETERMINATIONS FOR AUXILIARY BOILERS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Nitrogen Oxides (NO_x)								
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Auxiliary Boile	NG	100 MMBtu/hr	LNB and FGR	0.020 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	auxiliary boiler	NG	60.1 MMBtu/hr		0.013 lb/MMBtu	BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Auxiliary boile	NG	39.8 MMBtu/hr	LNB and FGR	0.035 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boile	NG	40 MMBtu/hr		0.006 lb/MMBtu	CASE-BY-CASE
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB	NG	95 MMBtu/hr	LNB and FGR	0.050 lb/MMBtu	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILERA	NG	55 MMBtu/hr	LNB and GCP	0.050 lb/MMBtu	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Auxiliary boile	NG	150 MMBtu/hr	LNB	16 PPMVD	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Auxillary Boile	NG	99 MMBtu/hr	LNB and FGR	0.020 lb/hr	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	AUXILIARY BOILER	NG	40 MMBtu/hr		0.011 lb/MMBtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	AUXILIARY BOILER	NG	66.7 MMBtu/hr	LNB	9 PPMVD	BACT-PSD
Effingham County Power (current project	GA	5/30/2012	Auxilliary Boiler	NG	17 MMBtu/hr	LNB and Clean Fuel	0.098 lb/MMBtu	BACT-PSD
Suwannee Mill	FL	9/5/2012	Natural Gas Boilers (4)	NG	46 MMBtu/hr	LNB and FGR	0.036 lb/MMBtu	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Auxilliary Boiler	NG	37.4 MMBtu/hr	LNB and Clean Fuel	9 ppmvd	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0323 - Boiler 401F	NG	99 MMBtu/hr	LNB and/or CSR	0.040 lb/MMBtu	BACT-PSD
Carty Plant	OR	12/29/2010	NATURAL GAS-FIRED BOILER	Diesel	91 MMBtu/hr	LNB	0.049 lb/hr	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	AUXILIARY BOILER	NG	35 MMBtu/hr	Restricted hours	9 ppmvd	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS	NG	41.64 MMBtu/hr	LNB and FGR	0.011 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT FL01	Diesel Oil	14.34 MMBtu/hr	LNB and FGR	0.035 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA01	NG	16.8 MMBtu/hr	LNB and FGR	0.030 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA03	NG	31.38 MMBtu/hr	LNB	0.031 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP01	NG	35.4 MMBtu/hr	LNB	0.035 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP03	NG	33.48 MMBtu/hr	LNB	0.037 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT PA15	Diesel Oil	21 MMBtu/hr	LNB	0.037 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT IP04	Diesel Oil	16.7 MMBtu/hr	LNB	0.049 lb/MMBtu	LAER
FPL Cape Canaveral Energy Center	FL	7/23/2009	Auxiliary Boiler	NG	99.8 MMBtu/hr	Oxidation Catalyst	0.050 lb/MMBtu	BACT-PSD
FPL Riveria Beach Energy Center	FL	6/10/2009	Auxiliary Boiler	NG	99.8 MMBtu/hr	Oxidation Catalyst	0.050 lb/MMBtu	BACT-PSD
Concord Steam Corporation	NH	2/27/2009	BOILER 2 and 3 (AUXILIARY)	NG	76.8 MMBtu/hr	LNB and FGR	0.049 lb/MMBtu	BACT-PSD
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr	LNB with FGR	0.011 lb/MMBtu	N/A
Fairbault Energy Park	MN	6/5/2007	Boiler	NG	40 MMBtu/hr	LNB, FGR	0.040 lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/6/2007	Boiler	Diesel Oil	40 MMBtu/hr	LNB, FGR	0.058 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Aux Boilers (2)	NG	99.8 MMBtu/hr	GCP	0.050 lb/MMBtu	BACT-PSD
Lawton Energy Cogen Facility	OK	12/12/2006	Auxiliary Boiler	NG		LNB	0.036 lb/MMBtu	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	Auxiliary Boiler	NG	29.4 MMBtu/hr	LNB & FGR	0.011 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Auxilliary Boiler	NG	110.2 MMBtu/hr	LNB, GCP, Low-Sulfur NG	0.137 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Auxilliary Boiler	NG	37.7 MMBtu/hr	GCP	0.037 lb/MMBtu	
Volatile Organic Compounds (VOC)								
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Auxiliary Boiler	NG	100 MMBtu/hr	GCP	0.0060 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Auxiliary Boiler	NG	60.1 MMBtu/hr	GCP	0.0050 lb/MMBtu	BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Auxiliary boiler	NG	39.8 MMBtu/hr	GCP	0.0050 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boiler	NG	40 MMBtu/hr	GCP	0.0008 lb/MMBtu	
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	NG	95 MMBtu/hr	GCP	0.0080 lb/MMBtu	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILERA)	NG	55 MMBtu/hr	GCP	0.0080 lb/MMBtu	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Auxiliary boiler	NG	150 MMBtu/hr	GCP	0.0060 lb/MMBtu	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Auxillary Boiler	NG	99 MMBtu/hr	GCP	0.0060 lb/MMBtu	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	AUXILIARY BOILER	NG	40 MMBtu/hr	GCP	0.0015 lb/MMBtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	AUXILIARY BOILER	NG	66.7 MMBtu/hr	GCP	0.0050 lb/MMBtu	BACT-PSD
Suwannee Mill	FL	9/5/2012	Natural Gas Boilers (4)	Diesel	46 MMBtu/hr	GCP	0.0030 lb/MMBtu	BACT-PSD
Republic Steel	OH	7/18/2012	Steam Boiler	NG	65 MMBtu/hr	Proper burner design and good	0.0054 lb/MMBtu	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0323 - Boiler 401F	N/A	99 MMBtu/hr	Proper design and operation, gc	0.0054 lb/MMBtu	BACT-PSD
Archer Daniels Midland-Mexico	MO	10/5/2010	DUAL-FIRED 85.6 MMBTU/HR WATER-TUBE BOILER	NG	85.6 MMBtu/hr	GCP	0.0055 lb/MMBtu	LAER
Flopam Inc.	LA	6/14/2010	Boilers	NG	25.1 MMBtu/hr	GCP	0.0030 lb/MMBtu	BACT-PSD
Flakeboard America Limited - Bennettsville Mdf	SC	12/22/2009	SANDERDUST BOILER	Diesel	99 MMBtu/hr	GCP	0.1000 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC001, CC002, AND CC003 AT CITY CENTER	N/A	41.64 MMBtu/hr	GCP	0.0024 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC004, CC005, AND CC006 AT CITY CENTER	NG	4.2 MMBtu/hr	GCP	0.0048 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILER - UNIT MB090 AT MANDALAY BAY	NG	4.3 MMBtu/hr	GCP and FGR	0.0054 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS BE102 THRU BE105 AT BELLAGIO		2 MMBtu/hr	GCP, Low-Sulfur NG	0.0054 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILER - UNIT BE111 AT BELLAGIO	Low Sulfur Diese	2.1 MMBtu/hr	GCP, Low-Sulfur NG	0.0048 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC026, CC027 AND CC028 AT CITY CENTER	NG	44 MMBtu/hr	GCP, Low-Sulfur NG	0.0055 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS NY42, NY43, AND NY44 AT NEW YORK - NEW YORK	NG	2 MMBtu/hr	GCP	0.0050 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT HA08	Diesel Oil	8.37 MMBtu/hr	GCP	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT FL01	Diesel Oil	14.34 MMBtu/hr	FGR	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA01	NG	16.8 MMBtu/hr	FGR	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA03	NG	31.38 MMBtu/hr	OPERATING IN ACCORDANCI	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP01	NG	35.4 MMBtu/hr	GCP	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP03	N/A	33.48 MMBtu/hr	GCP	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP26	Diesel Oil	24 MMBtu/hr	GCP	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT IP04	Diesel Oil	16.7 MMBtu/hr	GCP	0.0053 lb/MMBtu	LAER
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr		0.0020 lb/MMBtu	CASE-BY-CASE
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		GCP	0.0094 lb/MMBtu	N/A
Cpv Warren	VA	1/14/2008	Auxiliary Boiler - Scenario 2	NG	97 MMBtu/hr	CEM System	0.0060 lb/MMBtu	N/A
Cpv Warren	VA	1/14/2008	Auxiliary Boiler - Scenario 3	NG	62 MMBtu/hr	CEM System	0.0060 lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/5/2007	Boiler, Natural Gas (1)	NG	40 MMBtu/hr	GCP	0.0060 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Auxilliary Boiler	NG	110.2 MMBtu/hr	LNB, GCP, Low-Sulfur NG	0.0054 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Boiler, Auxiliary	NG	37.7 MMBtu/hr	GCP	0.0050 lb/MMBtu	BACT-PSD
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)								
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Auxiliary Boiler	NG	100 MMBtu/hr	GCP	0.005 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Auxiliary Boiler	NG	60.1 MMBtu/hr		0.008 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boiler	NG	40 MMBtu/hr		0.46 TPY	CASE-BY-CASE
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	NG	95 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILERA)	NG	55 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD

TABLE B-10
SUMMARY OF NOx, CO, VOC, PM, AND SO2 BACT DETERMINATIONS FOR AUXILIARY BOILERS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Pinecrest Energy Center	TX	11/12/2013	Auxiliary boiler	NG	150 MMBtu/hr	GCP	0.0076 lb/MMBtu	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Auxillary Boiler	NG	99 MMBtu/hr	GCP	0.0080 lb/MMBtu	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	AUXILIARY BOILER	NG	40 MMBtu/hr		0.005 lb/MMBtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	AUXILIARY BOILER	NG	66.7 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
Suwannee Mill	FL	9/5/2012	Natural Gas Boilers (4)	Diesel	46 MMBtu/hr	GCP	2 GR OF S/100 SCF	RACT
Suwannee Mill	FL	9/5/2012	Biomass-Fuel Boilers (2)		120 MMBtu/hr	ESP - Electrostatic Procipitator	0.015 lb/MMBtu	BACT-PSD
Avenal Energy Project	CA	6/21/2011	AUXILIARY BOILER	Natural Gas	37.4 MMBtu/hr	USE PUC QUALITY NATURAL	0.0034 GR/DSCF	BACT-PSD
Flopam Inc.	LA	6/14/2010	Boilers	N/A	25.1 MMBtu/hr	Good equipment design and prc	0.0052 lb/MMBtu	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	AUXILIARY BOILER	Natural Gas	35 MMBtu/hr	OPERATIONAL RESTRICTION	0.2 GRAINS PER 100	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	BOILERS #1 AND #2	Natural Gas	80 MMBtu/hr		0.0075 lb/MMBtu	BACT-PSD
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr		0.005 lb/MMBtu	CASE-BY-CASE
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		GCP	0.019 lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/5/2007	Boiler, Natural Gas (1)	NG	40 MMBtu/hr	Clean Fuel and GCP	0.008 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	Aux Boilers (2)	NG	99.8 MMBtu/hr	Use of NG	2 gr S/100 SCF	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	Auxiliary Boiler	NG	29.4 MMBtu/hr	Low-Sulfur Fuel	0.0033 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Auxilliary Boiler	NG	110.2 MMBtu/hr	LNB, GCP, Low-Sulfur NG	0.0074 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Boiler, Auxiliary	NG	37.7 MMBtu/hr	Best Combustion Practices	0.004 lb/MMBtu	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	Boilers (2)	NG	30.6 MMBtu/hr		0.01 lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/5/2007	Boiler	NG	40 MMBtu/hr	GCP	0.008 lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/6/2007	Boiler	Diesel Oil	40 MMBtu/hr	GCP	0.024 lb/MMBtu	
Carbon Monoxide (CO)								
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Auxiliary Boiler	NG	100 MMBtu/hr	GCP	0.04 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Auxiliary Boiler	NG	60.1 MMBtu/hr	CO catalytic oxidizer	0.02 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boiler	NG	40 MMBtu/hr		0.04 lb/MMBtu	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	NG	95 MMBtu/hr		0.01 lb/MMBtu	CASE-BY-CASE
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILERA)	NG	55 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Auxiliary boiler	NG	150 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Auxillary Boiler	NG	99 MMBtu/hr	GCP	75.00 PPMVD	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	AUXILIARY BOILER	NG	40 MMBtu/hr	GCP	0.14 lb/MMBtu	BACT-PSD
Brunswick County Power Station	VA	3/12/2013	AUXILIARY BOILER	NG	66.7 MMBtu/hr		0.04 lb/MMBtu	CASE-BY-CASE
Effingham County Power (current project)	GA	5/30/2012	Auxiliary Boiler	NG	17 MMBtu/hr	GCP	50.00 PPMVD	BACT-PSD
Suwannee Mill	FL	9/5/2012	Natural Gas Boilers (4)	NG	46 MMBtu/hr	GCP	0.04 lb/MMBtu	BACT-PSD
Suwannee Mill	FL	9/5/2012	Biomass-Fuel Boilers (2)		120 MMBtu/hr	GCP	0.40 lb/MMBtu	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0323 - Boiler 401F	N/A	99 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Flopam Inc.	LA	6/14/2010	Boilers	N/A	25.1 MMBtu/hr	GCP	0.04 lb/MMBtu	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	AUXILIARY BOILER	Natural Gas	35 MMBtu/hr	OPERATIONAL RESTRICTION	50.00 ppmvd	BACT-PSD
Flakeboard America Limited - Bennettsville Mdf	SC	12/22/2009	SANDERDUST BOILER	Diesel	99 MMBtu/hr	GCP	0.30 lb/MMBtu	BACT-PSD
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC001, CC002, AND CC003 AT CITY CENTER	NG	41.64 MMBtu/hr	GCP	0.02 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC004, CC005, AND CC006 AT CITY CENTER	NG	4.2 MMBtu/hr	GCP	0.02 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILER - UNIT MB090 AT MANDALAY BAY		4.3 MMBtu/hr	FGR and GCP	0.04 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS BE102 THRU BE105 AT BELLAGIO		2 MMBtu/hr	GCP	0.04 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILER - UNIT BE111 AT BELLAGIO	Low Sulfur Diese	2.1 MMBtu/hr	GCP, Low-Sulfur NG	0.04 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC026, CC027 AND CC028 AT CITY CENTER		44 MMBtu/hr	GCP	0.01 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS NY42, NY43, AND NY44 AT NEW YORK - NEW YORK	NG	2 MMBtu/hr	GCP	0.04 lb/MMBtu	LAER
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT HA08	Diesel Oil	8.37 MMBtu/hr	GCP	0.04 lb/MMBtu	CASE-BY-CASE
Source: EPA 2015 (RBLC database); Golder, 2015	NV	8/20/2009	BOILER - UNIT FL01	Diesel Oil	14.34 MMBtu/hr	FGR and GCP	0.07 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA01	NG	16.8 MMBtu/hr	FGR and GCP	0.02 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA03	NG	31.38 MMBtu/hr	GCP	0.02 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP01	NG	35.4 MMBtu/hr	GCP	0.01 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP03	NG	33.48 MMBtu/hr	GCP	0.01 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP26	Diesel Oil	24 MMBtu/hr	GCP	0.04 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT PA15	Diesel Oil	21 MMBtu/hr	GCP	0.85 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT IP04	NG	16.7 MMBtu/hr	GCP	0.01 lb/MMBtu	CASE-BY-CASE
FPL Cape Canaveral Energy Center	FL	7/23/2009	Auxiliary Boiler	NG	99.8 MMBtu/hr	Oxidation Catalyst	0.08 lb/MMBtu	BACT-PSD
FPL Riveria Beach Energy Center	FL	6/10/2009	Auxiliary Boiler	NG	99.8 MMBtu/hr	Oxidation Catalyst	0.08 lb/MMBtu	BACT-PSD
Medicine Bow Igl Plant	WY	3/4/2009	AUXILIARY BOILER	NG	66 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	BOILERS #1 AND #2	NG	80 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Ponca City Refinery	OK	2/9/2009	TB-1 Leased Boiler No. 1	NG	95 MMBtu/hr	LNB, GCP, Low-Sulfur NG	0.04 lb/MMBtu	BACT-PSD
Chouteau Power Plant	OK	1/23/2009	AUXILIARY BOILER		33.5 MMBtu/hr	GCP	0.15 lb/MMBtu	N/A
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr		0.02 lb/MMBtu	BACT-PSD
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		GCP	0.04 lb/MMBtu	CASE-BY-CASE
CPV Warren, LLC.	VA	1/14/2008	Auxiliary Boiler - Scenario 2	NG	97 MMBtu/hr	GCP	0.04 lb/MMBtu	N/A
CPV Warren, LLC.	VA	1/14/2008	Auxiliary Boiler - Scenario 3	NG	62 MMBtu/hr	GCP	0.04 lb/MMBtu	N/A
Fairbault Energy Park	MN	6/5/2007	Auxiliary Boiler	NG	40 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Progress Bartow Power Plant	FL	1/26/2007	One 99 MMBtu/Hr Auxiliary Boiler	NG	99 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Fpl West County Energy Center	FL	1/10/2007	(2) Auxiliary Boilers	NG	99.8 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	Auxiliary Boiler	NG	29.4 MMBtu/hr	GCP	0.04 lb/MMBtu	BACT-PSD
Forsyth Energy Plant	NC	9/29/2005	Auxilliary Boiler	NG	110.2 MMBtu/hr	LNB, GCP	0.08 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Boiler, Auxiliary	NG	37.7 MMBtu/hr	GCP	0.04 lb/MMBtu	BACT-PSD
Sulfur Dioxide (SO_2)								
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boiler	NG	40 MMBtu/hr	Low sulfur fuel	0.0011 lb/MMBtu	
Hickory Run Energy Station	PA	4/23/2013	Auxiliary Boiler	NG	40 MMBtu/hr	Low sulfur fuel	0.0021 lb/MMBtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	Auxiliary Boiler	NG	66.7 MMBtu/hr	Low sulfur fuel	0.0011 lb/MMBtu	BACT-PSD
Lake Charles Gasification Facility	LA	6/22/2009	Auxiliary Boiler	NG	938.3 MMBtu/hr	Low sulfur fuel	0.0003 lb/MMBtu	BACT-PSD
Chouteau Power Plant	OK	1/23/2009	Auxiliary Boiler	NG	33.5 MMBtu/hr	Low sulfur fuel	0.0009 lb/MMBtu	N/A

Source: EPA 2015 (RBLC database); Golder, 2015
Note: LNB= dry low NOx; GCP= good combustion practices; LNB= low NOx burner; FGR= flue gas recirculation

TABLE B-11
SUMMARY OF BACT DETERMINATIONS FOR FUEL HEATERS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Nitrogen Oxides (NOx)								
Marshalltown Generating Station	IA	4/14/2014	Dew point heater	NG	13.32 MMBtu/hr		0.013 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc LLC/Ontelaunee	PA	12/17/2013	Fuel Preheater	NG	8.5 MMBtu/hr		0.035 lb/MMBtu	CASE-BY-CASE
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	NG	3.7 MMBtu/hr	GCP	0.149 lb/MMBtu	BACT-PSD
Thetford Generating Station	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	NG	12 MMBtu/hr	LNB	0.060 lb/MMBtu	BACT-PSD
Sunbury Generation LP/Sunbury SES	PA	4/1/2013	DEW POINT HEATER	NG	15 MMBtu/hr		0.085 lb/MMBtu	CASE-BY-CASE
Cheyenne Prairie Generating Station	WY	8/28/2012	Inlet Air Heater (EP06-11)	Diesel	16.1 MMBtu/hr	LNB and GCP	0.012 lb/MMBtu	BACT-PSD
International Station Power Plant	AK	12/20/2010	Sigma Thermal Auxiliary Heater (1)	NG	12.5 MMBtu/hr	LNB and FGR	0.030 lb/MMBtu	BACT-PSD
Lake Charles Chemical Complex - Lab Unit	LA	11/29/2010	EQT0028 - PACOL STARTUP HEATER H-202	NG	21 MMBtu/hr	LNB	0.129 lb/MMBtu	BACT-PSD
Mgm Mirage	NV	11/30/2009	WATER HEATERS - UNITS NY037 AND NY038		2 MMBtu/hr	LNB and GCP	0.025 lb/MMBtu	
Medicine Bow Igl Plant	WY	3/4/2009	Gasification Preheaters (4)	Natural Gas	21 MMBtu/hr	LNB and GCP	0.050 lb/MMBtu	BACT-PSD
Gp Clarendon Lp	SC	2/10/2009	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	Diesel	75 MMBtu/hr	LNB and GCP	0.048 lb/MMBtu	BACT-PSD
Ponca City Refinery	OK	2/9/2009	NH-3 NEW NO. 4 CTU VACUUM HEATER	NG	45 MMBtu/hr	LNB and GCP	0.031 lb/MMBtu	BACT-PSD
Chouteau Power Plant	OK	1/23/2009	FUEL GAS HEATER (H2O BATH)		18.8 MMBtu/hr		0.144 lb/MMBtu	BACT-PSD
CPV St. Charles	MD	11/12/2008	Heater	NG	1.7 MMBtu/hr		0.100 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) Process Heaters	NG	10 MMBtu/hr	GCP	0.095 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #2	NG	4 MMBtu/hr	GCP	0.140 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #1	NG	4 MMBtu/hr	GCP	0.140 lb/MMBtu	BACT-PSD
Crescent City Power	LA	6/6/2005	(3) Fuel Gas Heaters	NG	19 MMBtu/hr	LNB and GCP	0.095 lb/MMBtu	BACT-PSD
Volatile Organic Compounds (VOC)								
Freeport Lng Pretreatment Facility	TX	7/16/2014	Heating Medium Heaters	NG	130 MMBtu/hr	GCP	0.002 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Fuel Preheater	NG	9 MMBtu/hr		0.050 lb/MMBtu	CASE-BY-CASE
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	NG	4 MMBtu/hr	GCP	0.0081 lb/MMBtu	BACT-PSD
Thetford Generating Station	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters	NG	12 MMBtu/hr	GCP	0.008 lb/MMBtu	BACT-PSD
Sunbury Generation LP/Sunbury SES	PA	4/1/2013	DEW POINT HEATER	NG	15 MMBtu/hr		0.006 lb/MMBtu	CASE-BY-CASE
International Station Power Plant	AK	12/20/2010	Sigma Thermal Auxiliary Heater (1)	NG	12.5 MMBtu/hr	GCP	0.0072 lb/MMBtu	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	AUXILIARY HEATER	NG	40 MMBtu/hr	GCP	2 gr S/100 scf gas	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	NITRIC ACID PREHEATERS #1, #3, AND #4	NG	20 MMBtu/hr		0.008 lb/MMBtu	BACT-PSD
Gp Clarendon Lp	SC	2/10/2009	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	Diesel	75 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
CPV St. Charles	MD	11/12/2008	Heater	NG	1.7 MMBtu/hr		0.005 lb/MMBtu	BACT-PSD
Progress Bartow Power Plant	FL	1/26/2007	(5) 3 Mmbtu/Hr Process Heaters	NG	3 MMBtu/hr		2 gr S/100 scf gas	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) CT (Siemens SGT6-5000f) w/ DB	NG	10 MMBtu/hr	GCP	2 gr S/100 scf gas	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #2	NG	4 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #1	NG	4 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Crecent City Power	LA	6/6/2005	(3) Fuel Gas Heaters	NG	19 MMBtu/hr	GCP	0.005 lb/MMBtu	BACT-PSD
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)								
Freeport Lng Pretreatment Facility	TX	7/16/2014	Heating Medium Heaters	NG	130 MMBtu/hr		0.007 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	dew point heater	NG	13.32 MMBtu/hr		0.008 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Fuel Preheater	NG	8.5 MMBtu/hr		0.007 lb/MMBtu	CASE-BY-CASE
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	NG	3.7 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
Thetford Generating Station	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	NG	12 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
Sunbury Generation LP/Sunbury SES	PA	4/1/2013	DEW POINT HEATER	NG	15 MMBtu/hr		0.008 lb/MMBtu	CASE-BY-CASE
CFIndustries Nitrogen, LLC - Port Neal Nitrogen Compl	IA	7/12/2013	Startup Heater	NG	58.8 MMBtu/hr	GCP	0.002 lb/MMBtu	BACT-PSD
International Station Power Plant	AK	12/20/2010	Sigma Thermal Auxiliary Heater (1)	NG	12.5 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	AUXILIARY HEATER	NG	40 MMBtu/hr	GCP	2 gr S/100 scf gas	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	NITRIC ACID PREHEATERS #1, #3, AND #4	NG	20 MMBtu/hr		0.008 lb/MMBtu	BACT-PSD
GP Clarendon LP	SC	2/10/2009	BACKUP THERMAL OIL HEATER	Diesel	75 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
CPV St. Charles	MD	11/12/2008	Heater	NG	1.7 MMBtu/hr		0.007 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) 10 MMBtu/hr Process Heaters	NG	10 MMBtu/hr	GCP	2 gr S/100 scf gas	BACT-PSD

TABLE B-11
SUMMARY OF BACT DETERMINATIONS FOR FUEL HEATERS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #2	NG	4 MMBtu/hr	GCP	0.02 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #1	NG	4 MMBtu/hr	GCP	0.02 lb/MMBtu	BACT-PSD
Crecent City Power	LA	6/6/2005	(3) Fuel Gas Heaters	NG	19 MMBtu/hr	Use of NG and GCP	0.007 lb/MMBtu	BACT-PSD
Carbon Monoxide (CO)								
Freeport LNG Pretreatment Facility	TX	7/16/2014	Heating Medium Heaters	NG	130 MMBtu/hr	GCP	25 PPMVD	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	dew point heater	NG	13 MMBtu/hr		0.04 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc LLC/Ontelaunee	PA	12/17/2013	Fuel Preheater	NG	9 MMBtu/hr		0.05 lb/MMBtu	
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	NG	4 MMBtu/hr	GCP	0.11 lb/MMBtu	BACT-PSD
Thetford Generating Station	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	NG	12 MMBtu/hr	Efficient combustion	0.11 lb/MMBtu	BACT-PSD
Sunbury Generation LP/Sunbury SES	PA	4/1/2013	DEW POINT HEATER	NG	15 MMBtu/hr		0.04 lb/MMBtu	CASE-BY-CASE
Cheyenne Prairie Generating Station	WY	8/28/2012	Inlet Air Heater (EP06-11)		16.1 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Mgm Mirage	NV	11/30/2009	WATER HEATERS		2 MMBtu/hr	Use of NG and GCP	0.04 lb/MMBtu	BACT-PSD
Lake Charles Gasification Facility	LA	6/22/2009	SHIFT REACTOR STARTUP HEATER	NG	34.2 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Lake Charles Gasification Facility	LA	6/22/2009	STEAM SUPERHEATERS (A & B)	NG	415 MMBtu/hr	GCP	0.04 lb/MMBtu	BACT-PSD
Lake Charles Gasification Facility	LA	6/22/2009	METHANATION STARTUP HEATERS	NG	56.9 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Echo Springs Gas Plant	WY	4/1/2009	HOT OIL HEATER S38	Diesel	84 MMBtu/hr	GCP	0.02 lb/MMBtu	BACT-PSD
Medicine Bow Igl Plant	WY	3/4/2009	Gasification Preheaters (4)	NG	21 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Chouteau Power Plant	OK	1/23/2009	FUEL GAS HEATER (H2O BATH)	NG	18.8 MMBtu/hr		0.02 lb/MMBtu	N/A
CPV St. Charles	MD	11/12/2008	Heater	NG	1.7 MMBtu/hr		0.08 lb/MMBtu	BACT-PSD
Progress Bartow Power Plan	FL	1/26/2007	(5) 3 MMBtu/hr Process Heaters	NG	3 MMBtu/hr		0.08 lb/MMBtu	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) 10 MMBtu/hr Process Heaters	NG	10 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #2	NG	4 MMBtu/hr	GCP	0.03 lb/MMBtu	BACT-PSD
Tracy Substation Expansion Project	NV	8/16/2005	Fuel Preheater #1	NG	4 MMBtu/hr	GCP	0.03 lb/MMBtu	BACT-PSD
Crecent City Power	LA	6/6/2005	(3) Fuel Gas Heaters	NG	19 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Sulfur Dioxide (SO_2)								
Freeport Lng Pretreatment Facility	TX	7/16/2014	Heating Medium Heaters	NG	130 MMBtu/hr		7.692E-05 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Fuel Preheater	NG	8.5 MMBtu/hr		2.000E-03 lb/MMBtu	CASE-BY-CASE
Lake Charles Gasification Facility	LA	6/22/2009	Shift Reactor Startup Heater	NG	34 MMBtu/hr	LOW SULFUR FUEL	5.848E-04 lb/MMBtu	BACT-PSD
Lake Charles Gasification Facility	LA	6/22/2009	Methanation Startup Heaters	NG	57 MMBtu/hr	LOW SULFUR FUEL	3.515E-04 lb/MMBtu	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	Nitric Acid Preheaters #1, #3, And #4	NG	20 MMBtu/hr	LOW SULFUR FUEL	1.000E-03 lb/MMBtu	BACT-PSD
Chouteau Power Plant	OK	1/23/2009	Fuel Gas Heater (H2O Bath)	NG	19 MMBtu/hr	LOW SULFUR FUEL	1.064E-03 lb/MMBtu	N/A

Source: EPA 2015 (RBLC database); Golder, 2015

Note: DLN= dry low NOx; SCR= selective catalytic reduction; WI= water injection; GCP= good combustion practices; LSF= low sulfur fuel; LNB= low NOx burner; FGR= flue gas recirculation

TABLE B-12
SUMMARY OF BACT DETERMINATIONS FOR COOLING TOWERS (2003-2015) AS OF 6/2015

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	Pollutant Limit	Basis
S R Bertron Electric Generating Station	TX	12/19/2014	Cooling Tower		Drift Eliminators 0.0005% DR		BACT-PSD
Victoria Power Station	TX	12/1/2014	Cooling Tower		Drift Eliminators 0.001% DR		BACT-PSD
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Cooling Tower	159,000 gal/min		0.50 lb/hr	BACT-PSD
Trinidad Generating Facility	TX	11/20/2014	Cooling Tower		Drift Eliminators 0.001% DR		BACT-PSD
Tenaska Brownsville Generating Station	TX	4/29/2014	Cooling Tower		Drift Eliminators 0.0005% DR		BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Cooling Tower	160,000 gal/min	Mist/drift eliminators.	1.20 lb/hr	BACT-PSD
Pseg Fossil Llc Sewaren Generating Station	NJ	3/7/2014	3 Cell Wet Mechanical Cooling Tower	13,000 gal/min		0.16 lb/hr	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Cooling Tower -- Wet Mechanical Draft		Mist/drift eliminators.	0.54 lb/hr	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Mechanical draft wet cooling tower, 16 cell	322,000 gal/min		1.03 lb/hr	BACT-PSD
Cf Industries Nitrogen, Llc - Port Neal Nitrogen Complex	IA	7/12/2013	Cooling Towers		Drift Eliminators 0.0005% DR		BACT-PSD
Effingham County Power	GA	5/30/2012	Cooling Towers		Drift Eliminators 0.0005% DR		BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0010 - Cooling Tower 403	61,250 gal/min	Drift eliminators	1.20 lb/hr	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0035 - Cooling Tower CT-600	45,000 gal/min	Drift eliminators	0.09 lb/hr	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0243 - HCU Cooling Tower	50,000 gal/min	Drift eliminators	0.10 lb/hr	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0244 - New West Cooling Tower	40,000 gal/min	drift eliminators	0.08 lb/hr	BACT-PSD
Sabina Petrochemicals Llc	TX	8/20/2010	COOLING TOWER	73,000 gal/min	Monitoring VOC concentration in cooling water	3.07 lb/hr	BACT-PSD
Lake Charles Gasification Facility	LA	6/22/2009	COOLING TOWERS	436,000 gal/min	DRIFT ELIMINATORS	1.64 lb/hr	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	COOLING TOWER #2	40,000 gal/min	MIST ELIMINATORS	1.92 lb/hr	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	COOLING TOWER #1	24,500 gal/min	MIST ELIMINATORS	1.18 lb/hr	BACT-PSD
CPV St. Charles	MD	11/12/2008	Cooling Tower		Drift Eliminators, Max 0.0005% DR		BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Mechanical Draft Cooling Tower (26 Cell)	304,000 gal/min	Drift Eliminators, Max 0.0005% DR	1.20 lb/hr	
Arsenal Hill Power Plant	LA	3/20/2008	Cooling Tower	140,000 gal/min	Use Of Mist Eliminators	1.40 lb/hr	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) Cooling Tower (26 Cell Mechanical Draft)	306,000 gal/min	Drift Eliminators, Max 0.0005% DR	1.20 lb/hr	
Wanapa Energy Center	OR	8/8/2005	Cooling Tower	2,783 gal/min	Drift Eliminators, Max 0.0005% DR	3,532 ppmw	BACT-PSD
Public Serices Company of Colorado	CO	7/5/2005	Cooling Tower	140,650 gal/min	Drift Eliminators, Max 0.0005% DR		BACT-PSD
Crescent City Power	LA	6/6/2005	Main Cooling Tower	290,200 gal/min	Drift Eliminators	2.61 lb/hr	BACT-PSD
Auburn Nugget	IA	5/31/2005	Cooling Tower	290,200 gal/min	PM - 0.0050% of throughput	20 % (opacity)	BACT-PSD
Newmant Nevada Energy Investment, LLC	NV	5/5/2005	Cooling Tower		Drift Eliminators, PM_{10} - 0.0005% drift		BACT-PSD
Ingen-Nassau Energy Corporation	NY	3/31/2005	Cooling Tower		PM_{10} - 0.0005% drift		BACT-PSD
Omaha Public Power District	NE	3/9/2005	Cooling Tower			0.001 lb/hr (PM_{10})	BACT-PSD
BP Cherry Point Cogeneration Project	WA	1/11/2005	Cooling Tower		Drift Eliminators, Max 0.001% DR	1.64 lb/hr	BACT-PSD
Duke Energy Washington County LLC	OH	5/9/2005	Cooling Tower			2.08 lb/hr	BACT-PSD
Duke Energy Hanging Rock Energy Facility	OH	12/28/2004	Cooling Tower (2)		Drift Eliminators, Max 0.001% DR	2.60 lb/hr	BACT-PSD
Chocolate Bayou Plant	TX	3/24/2003	Cooling Water Tower (2 Cells)		None Indicated	0.54 lb/hr	Other Case-by-Case
Duke Energy Stephens, LLC Stephens Energy	OK	3/21/2003	Cooling Tower		Drift Eliminators	1.20 lb/hr	BACT-PSD
Wallula Power Plant	WA	1/3/2003	Cooling Tower		Water Treatment, 0.0005% DR	3.70 lb/hr	LAER

Source: EPA 2015 (RBLC database); Golder, 2015
Note: DR = Drift rate

Golder Associates

TABLE B-13

SUMMARY OF GREENHOUSE GAS BACT DETERMINATIONS FOR NATURAL GAS COMBINED-CYCLE CTs (AS OF 8/2015)

Facility Name	State	Permit Issued	CO_2e Limit	CO_2e Limit (lb/MWH)	Heat Rate (Btu/kWH)	Note
West Deptford Energy Station	NJ	7/18/2014	1,237,923 TPY	947	NA	2-on-1; lb/MWh is 1-month rolling
Mounds Power, LLC	WV	11/21/2014	254,315 lb/hr	793	NA	2-on-1; GE 7F.04
CPV Maryland, LLC	MD	4/23/2014	NA	NA	7,605	2-on-1; GE 7F 57% Efficiency (ISO)
Old Dominion Wildcat Point Facility	MD	6/9/2014	NA	946	7,500	2-on-1; MPS G, heat rate at all times, excludes SU/SD
FGE Power LLC	TX	4/28/2014	NA	889	7,625	2-on-1; 4-Alstom GT24, heat rate is net; SU/SD 48 t/h
Marshalltown Generating Station	IA	4/14/2014	1,318,647	951	NA	2-on-1; Siemens SGT6-5000F; Limit 12-month rolling
Troutdale Energy Center, LLC	OR	3/5/2014	NA	1,000	NA	2-on-1; MPS M501-GAC; 365 day rolling average
Holland Board of Public Works	MI	12/4/2013	339,125 TPY	NA	8,361	2-on-1 (115 MW); 12-month rolling average; heat rate is gross; SU/SD 635 hrs/yr
Thetford generating Station	MI	7/25/2013	1,386,268 TPY	NA	NA	2-on-1; 4 F-Class CTs, 12-month rolling average
Orgeon Clean Energy Center	OH	6/18/2013	318,404 lb/hr; 1,394,611 TPY	840	NA	2-on-1; MPS or Siemens F-Class; 12-month rolling average
Hickory Run Energy Center, LLC	PA	4/23/2013	3,665,974 TPY	NA	NA	2-on-1; F-Class CTs; 12-month rolling
Calpine Garrison Energy Center	DE	1/30/2013	1,006,304	NA	NA	2-on-1; GE F-Class CTs; 12-month rolling average
Calpine Deer Park	TX	11/29/2012	1,063,650	920	7,730	2-on-1; Siemens F-Class CTs; 12-month rolling average
Calpine Channel	TX	11/29/2012	1,063,650	920	7,730	2-on-1; Siemens F-Class CTs; 12-month rolling average
Hess Newark	NJ	10/13/2012	2,000,268	887	7,522	without Duct Burner
Criket Valley	NY	9/27/2012	3,576,943	913	7,605	without Duct Burner
Gibson County	TN	9/4/2012	1,679,459	NA	NA	2-on-1; GE F-Class
Woodbridge	NJ	8/24/2012	312,885	925	7,605	2-on-1; GE F-Class
CPV Valley	NY	7/11/2012	NA	925	NA	

Source: EPA RBLC, 2015.

Note: NA = not applicable.

APPENDIX C

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: **Okeechobee Clean Energy Center**	
3. Facility Identification Number: **New Facility**	
4. Facility Location... Street Address or Other Locator: **State Road 60 approximately 24 miles west of Vero Beach, south on 226th Court to Okeechobee County line** City: County: **Okeechobee** Zip Code:	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: **Matthew J. Raffenberg, Director of Environmental Licensing and Permitting**
2. Application Contact Mailing Address... Organization/Firm: **Florida Power & Light Company** Street Address: **700 Universe Blvd. JES/JB** City: **Juno Beach** State: **Florida** Zip Code: **33408**
3. Application Contact Telephone Numbers... Telephone: **(561) 691-2808** ext. Fax: **(561) 691-7070**
4. Application 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

Application is for an air construction/PSD permit for a new approximately 1,600 MW (net-nominal) electric generating facility consisting of a 3-on-1 combined cycle unit using General Electric 7HA.02 combustion turbines (CTs) connected to heat recovery steam generators (HRSGs). The combined cycle unit is referred to as Okeechobee Clean Energy Center (OCEC) Unit 1.

The Project will be subject to PSD review for CO, SO_2, NOx, PM, PM_{10}, $PM_{2.5}$, volatile organic compounds (VOC), sulfuric acid mist (SAM) and Greenhouse Gases.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
1A - 1C	**Three GE 7HA.02 CTs/HRSGs**	**AC1A**	
2	**Auxiliary Boiler**	**AC1A**	
3	**Fuel Gas Heaters**	**AC1A**	
4	**Emergency Diesel Generators**	**AC1A**	
5	**Fire Pump Engine**	**AC1A**	
6	**Hurricane Shelter Emergency Propane Generators**	**AC1A**	
7	**Mechanical Draft Cooling Tower**	**AC1A**	
8	**Construction Boilers (2)**	**AC1C**	
9	**Construction Generators (3: 1-450 kW, 2-1,800 kW)**	**AC1D**	

Application Processing Fee

Check one: ☒ Attached - Amount: $ **7,500** ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : **Randall R. LaBauve, Vice President**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Florida Power & Light Company** Street Address: **700 Universe Blvd. 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: Date: Sept 23, 2015

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. **516** Fax: **(352) 336-6603**	
4. Professional Engineer E-mail Address: **kkosky@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.

Kennard F. Kosky
Signature

9/22/15
Date

(seal) No. 14996

* **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) **520.6** North (km) **3056.7**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27/38/03** Longitude (DD/MM/SS) **80/47/28**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Agnes Ramsey, Sr. Environmental Specialist**
2. Facility Contact Mailing Address... Organization/Firm: **Florida Power & Light Company** Street Address: **700 Universe Blvd.** City: **Juno Beach** State: **FL** Zip Code: **33408**
3. Facility Contact Telephone Numbers: Telephone: **(561) 691-2820** ext. Fax: **(561) 691-7070**
4. Facility Contact E-mail Address: **Agnes.Ramsey@fpl.com**

Facility Primary Responsible Official

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

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) ext. Fax: ( )
4. Facility Primary Responsible Official 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: **See PSD Report Section 3.0 for applicable facility classifications.**	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	**A**	**N**
PM10	**A**	**N**
PM2.5	**A**	**N**
VOC	**A**	**N**
SO2	**A**	**N**
NOx	**A**	**N**
CO	**A**	**N**
CO2e	**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 PSD 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 PSD 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 PSD Report** ☐ Previously Submitted, Date:_________

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **See PSD Report**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **See PSD 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 PSD Report** ☐ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: **See PSD 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 PSD 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: **See Comment** ☐ Previously Submitted, Date:______ ☐ Not Applicable (not an Acid Rain source) Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.): ☐ Attached, Document ID:______ ☐ Previously Submitted, Date:______ ☒ Not Applicable New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.): ☐ Attached, Document ID:______ ☐ Previously Submitted, Date:______ ☒ Not Applicable
2.	CAIR Part (DEP Form No. 62-210.900(1)(b)): ☒ Attached, Document ID: **See Comment** ☐ Previously Submitted, Date:______ ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

FPL will provide the appropriate Acid Rain and CAIR forms for the new 3-on-1 combined cycle unit pursuant to 40 CFR Parts 72 and 96 and FDEP rules.

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   Three General Electric (GE) H Class CTs

3. Emissions Unit Identification Number: **1A, 1B, 1C**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2016**	**2019**	**49**

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

   ☒ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **7HA.02**

10. Generator Nameplate Rating: **375** MW

11. Emissions Unit Comment:
    Combined cycle unit will have a nominal capacity of 1,600 MW (net) consisting of 3 CT/HRSG trains. Generator nameplate based on gross generation at maximum output provided by GE for operating range.

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

1. Control Equipment/Method Description: **Natural Gas: Combined Cycle - SCR**
2. Control Device or Method Code: **139**

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

1. Control Equipment/Method Description: **Distillate Fuel Oil:** **Water Injection** **Combined Cycle - SCR**
2. Control Device or Method Code: **25, 28**

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 **8,760** hours/year
6. Operating Capacity/Schedule Comment: **See Tables A-1 for maximum heat input when firing natural gas; and Tables A-7 for maximum heat input when firing ultra low sulfur distillate 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: **Exhausts through the HRSG stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **149** feet	7. Exit Diameter: **25.6** feet
8. Exit Temperature: **See Air Report**°F	9. Actual Volumetric Flow Rate: **See Air Report** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: Feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **See Tables 2-1 and 2-2 for the stack parameters associated with each CT when firing natural gas and ultra low sulfur distillate oil.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **2**

1. Segment Description (Process/Fuel Type): **Distillate (No. 2) Fuel Oil [Ultra Low Sulfur (0.0015%) distillate oil]**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 Gallons Used**	
4. Maximum Hourly Rate: **23.5**	5. Maximum Annual Rate: **11,208**	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 = 130.5 (rounded to 131). Based on 7.1 pounds per gallon (lb/gal); LHV = 18,300 Btu/lb ISO conditions. Max hourly rate based on 35°F, max annual rate based on 75°F with evaporative cooling and 500 hours per year (hr/yr) operation. Based on one GE "H" CT.**		

Segment Description and Rate: Segment **2** of **2**

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million cubic feet**	
4. Maximum Hourly Rate: **3.39**	5. Maximum Annual Rate: **29,541**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **918**
10. Segment Comment: **Based on 20,566 Btu/lb (LHV). Max hourly rate based on 85 °F and wet compression. Max annual rate based on 75 °F wet compression and 8,760 hr/yr operation. Based on one GE "H" CT. Maximum sulfur content 2 grains/100 scf. See Air Permit Application Report.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM/PM10/PM2.5			EL
SO2			EL
NOX	25, 28, 139		EL
CO			EL
VOC			EL
CO2e			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: **Particulate Matter Total - PM/PM10/PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Air Report** Reference:	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-1, 2-2, and 2-3 and Appendice A in Air Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

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

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

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

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

1. Pollutant Emitted: **Carbon Dioxide Equivalent- CO2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Air Report** Reference:	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table 2-10 and Appendice A in Air Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation **1** of **2**

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

Visible Emissions Limitation: Visible Emissions Limitation **2** of **2**

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Proposed as emission limit for PM/PM_{10}/$PM_{2.5}$.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor **1** of **1**

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75. NO_x monitoring includes diluent monitor (O_2 or CO_2).**	

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 PSD 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 PSD 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 PSD 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 PSD 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: **See PSD Report**	☐ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Report**	☐ 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:
   Auxiliary Boiler

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2016**	**2019**	**49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **Nebraska Boiler or equivalent** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

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

1. Control Equipment/Method Description: **Low NOX burners**
2. Control Device or Method Code: **205**

Emissions Unit Control Equipment/Method: Control _____ of _____

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **99.77** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **7** days/week **52** weeks/year **2,000** hours/year	
6. Operating Capacity/Schedule Comment:	

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

Emission Point Description and Type

<table>
<tr><td colspan="2">1. Identification of Point on Plot Plan or Flow Diagram:</td><td colspan="2">2. Emission Point Type Code:</td></tr>
<tr><td colspan="4">3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:</td></tr>
<tr><td colspan="4">4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:</td></tr>
<tr><td>5. Discharge Type Code:</td><td colspan="2">6. Stack Height:
60 feet</td><td>7. Exit Diameter:
2.75 Feet</td></tr>
<tr><td>8. Exit Temperature:
296°F</td><td colspan="2">9. Actual Volumetric Flow Rate:
29,325 acfm</td><td>10. Water Vapor:
%</td></tr>
<tr><td colspan="2">11. Maximum Dry Standard Flow Rate:
dscfm</td><td colspan="2">12. Nonstack Emission Point Height:
Feet</td></tr>
<tr><td colspan="2">13. Emission Point UTM Coordinates...
Zone: East (km):
North (km):</td><td colspan="2">14. Emission Point Latitude/Longitude…
Latitude (DD/MM/SS)
Longitude (DD/MM/SS)</td></tr>
<tr><td colspan="4">15. Emission Point Comment:
See Table 2-4 in Air Permit Application Report.</td></tr>
</table>

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **Natural gas**		
2. Source Classification Code (SCC):	3. SCC Units: **MMscf**	
4. Maximum Hourly Rate: **0.098**	5. Maximum Annual Rate: **195.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum annual rate based on 2,000 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
PM	Fuel Quality		EL
SO2	Fuel Quality		EL
NOX	205		EL
CO	Good Combustion		EL
VOC	Good Combustion		EL
CO2e			WP

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Particulate Matter Total - PM/PM10/PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.74** lb/hour **0.74** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0075 lb/MMBtu** Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.0075 lb/MMBtu x 99.77 MMBtu/hr = 0.74 lb/hr** **0.74 lb/hr x 2,000 hr x ton/2,000 lb = 0.74 TPY**	
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: **10% Opacity**	4. Equivalent Allowable Emissions: **0.74** lb/hour **0.74** tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.56** lb/hour **0.56** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 grains S/100 scf gas** Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
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:
2 grains S/100 scf x 64/32 (MW SO2/S) x 1 lb/7,000 gr x 97,814 scf/hr x 1/100 scf = 0.56 lb/hr
0.56 lb/hr x 2,000 hr/2,000 lb = 0.56 TPY

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: **2 grains S/100 scf gas**	4. Equivalent Allowable Emissions: **0.56** lb/hour **0.56** tons/year
5. Method of Compliance: **Fuel Sampling and Analysis**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Nitrogen Oxides - NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.99** lb/hour **4.99** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.050 lb/MMBtu** Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.050 lb/MMBtu x 99.77 MMBtu/hr = 4.99 lb/hr** **4.99 lb/hr x 2,000 hr x ton/2,000 lb = 4.99 TPY**	
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: **LNB**	4. Equivalent Allowable Emissions: **4.99** lb/hour **4.99** tons/year
5. Method of Compliance: **Manufacturer Certification**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Carbon Monoxide - CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **7.98** lb/hour **7.98** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.080 lb/MMBtu** Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.08 lb/MMBtu x 99.77 MMBtu/hr = 7.98 lb/hr** **7.98 lb/hr x 2,000 hr x ton/2,000 lb = 7.98 TPY**	
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: **LNB**	4. Equivalent Allowable Emissions: **7.98** lb/hour **7.98** tons/year
5. Method of Compliance: **Work Practice – Good Combustion Practices**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.54** lb/hour **0.54** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0054 lb/MMBtu** Reference: **Emissions based on AP-42**	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.0054 lb/MMBtu x 99.77 MMBtu/hr = 0.54 lb/hr** **0.54 lb/hr x 2,000 hr x ton/2,000 lb = 0.54 TPY**	
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: **LNB**	4. Equivalent Allowable Emissions: **0.54** lb/hour **0.54** tons/year
5. Method of Compliance: **Work Practice – Good Combustion Practices**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Carbon Dioxide Equivalent - CO2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11,670.8** lb/hour **11670.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **116.9 lb/MMBtu for CO2, 0.002204 lb/MMBtu for CH4 and 0.0002204 lb/MMBtu for N2O** Reference: **Table C-2, Subpart C, 40 CFR 98.**	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table A-18.**	
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 _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2,000 hours and natural gas**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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% opacity. Excess emissions provided by Rule 62-210.700(1), F.A.C.**	

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

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 PSD 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 PSD 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 PSD 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 PSD 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 PSD 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: **See PSD Report** ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Report** ☐ 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:
   Natural Gas Fuel Heater (two with one a spare)

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

4. Emissions Unit Status Code: **C**	5. Commence Construction Date: **2016**	6. Initial Startup Date: **2019**	7. Emissions Unit Major Group SIC Code: **49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **Hanover Compression Company or equivalent** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    Two natural gas heaters will be installed with one as a spare. See Air Permit application report.

Emissions Unit Control Equipment/Method: Control _____ of _____

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

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

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **9.9** 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 **8,760** 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: **V**	6. Stack Height: **30** feet	7. Exit Diameter: **1.4** Feet
8. Exit Temperature: **500**°F	9. Actual Volumetric Flow Rate: **4,950** 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 2-5 in Air Permit Application Report.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **Natural gas**		
2. Source Classification Code (SCC):	3. SCC Units: **1,000,000 SCF**	
4. Maximum Hourly Rate: **0.01**	5. Maximum Annual Rate: **85.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum annual rate based on 8,760 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			EL
PM/PM10/PM2.5	Fuel Quality		EL
NOX			EL
SO2	Fuel Quality		EL
VOC			EL
CO2e			WP

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Carbon Monoxide - CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.82** lb/hour **3.57** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.082 lb/MMBtu** Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.082 lb/MMBtu x 9.9 MMBtu/hr = 0.82 lb/hr** **0.82 lb/hr x 8,760 hr x ton/2,000 lb = 3.57 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-5**	

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: **0.082 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.82** lb/hour **3.57** tons/year
5. Method of Compliance: **Manufacturer Certification**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, 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: **Nitrogen Oxides - NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.97** lb/hour **4.25** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.098 lb/MMBtu** Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.098 lb/MMBtu x 9.9 MMBtu/hr = 0.97 lb/hr** **0.97 lb/hr x 8,760 hr x ton/2,000 lb = 4.25 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-5**	

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: **0.098 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.97** lb/hour **4.25** tons/year
5. Method of Compliance: **Manufacturer Certification**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, 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: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.055** lb/hour **0.24** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 grains S/100 scf gas** Reference: **Emissions based on AP-42**	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: **2 grains S/100 scf x 64/32 (MW SO2/S) x 1 lb/7,000 gr x 9,706 scf/hr x 1/100 scf = 0.055 lb/hr** **0.055 lb/hr x 8,760 hr x ton/2,000 lb = 0.24 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-5**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 grains S/100 scf**	4. Equivalent Allowable Emissions: **0.055** lb/hour **0.24** tons/year
5. Method of Compliance: **Fuel vendor information**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Particulate Matter - PM/PM10/PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.074** lb/hour **0.32** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0075 lb/MMBtu** Reference: **Emissions based on AP-42**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
0.0075 lb/MMBtu x 9.9 MMBtu/hr = 0.074 lb/hr
0.074 lb/hr x 8,760 hr x ton/2,000 lb = 0.32 TPY

11. Potential, Fugitive, and Actual Emissions Comment:
See Table 2-5

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **0.074** lb/hour **0.32** tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.053** lb/hour **0.23** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0054 lb/MMBtu** Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.0054 lb/MMBtu x 9.9 MMBtu/hr = 0.053 lb/hr** **0.053 lb/hr x 8,760 hr x ton/2,000 lb = 0.23 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-5**	

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: **0.0054 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.053** lb/hour **0.23** tons/year
5. Method of Compliance: **Natural gas**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Carbon Dioxide Equivalent - CO2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1,156.9** lb/hour **5,072.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **116.9 lb/MMBtu for CO2, 0.002204 lb/MMBtu for CH4 and 0.0002204 lb/MMBtu for N2O** Reference: **Table C-2, Subpart C, 40 CFR 98.**	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table A-18.**	
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 _ of _

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **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 PSD 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 PSD 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 PSD 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 PSD 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 PSD 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:

   Emergency generators (3) to supply power in the event power is not available.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2016**	**2019**	**49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **Caterpillar or equivalent** Model Number: **C175 or equivalent**

10. Generator Nameplate Rating: **3.298** MW

11. Emissions Unit Comment:
    Two 3,298-kW emergency generators to support the power plant, each with rating of 4,423 hp will be installed. One emergency generator not to exceed 3,298-kW will be installed to support the transmission system and other emergency power needs outside the power plant. Information based on Caterpillar, 3,000 ekW 3,750 kVA Diesel Generator Set.

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: **Good combustion practices - ultra low sulfur distillate oil**	
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.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **29.49** 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 emergency generators will each normally be operated 1 to 2 hours per month for testing and maintenance. The emergency generators 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: **30** feet	7. Exit Diameter: **1.2** Feet
8. Exit Temperature: **891.9**°F	9. Actual Volumetric Flow Rate: **25,624** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: Feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack information for each generator. See Table 2-6 in Air Permit Application Report.**		

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: **0.214**	5. Maximum Annual Rate: **21.42**	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 for each emergency generator.**		

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			**EL**
PM/PM10/PM2.5			**EL**
NOX			**EL**
SO2	**Fuel Quality**		**EL**
VOC			**EL**
CO2			**WP**

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: **Carbon Monoxide - CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **25.4** lb/hour **1.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.5 grams per kilowatt-hour (g/kW-hr)** Reference: **Manufacturer certification**	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: **3.5 g/kW-hr x 3,298 kW x 1 lb/453.6 g = 25.4 lb/hr** **24.5 lb/hr x 100 hr x ton/2,000 lb = 1.3 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator. See Table 2-6**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3.5 g/kW-hr**	4. Equivalent Allowable Emissions: **25.4** lb/hour **1.3** tons/year
5. Method of Compliance: **Manufacturer certification of Subpart IIII standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Nitrogen Oxides - NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **46.5** lb/hour **2.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **6.4 g/kW-hr** Reference: **Manufacturer certification**	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: **6.4 g/kW-hr x 3,298 kW x 1 lb/453.6 g = 46.5 lb/hr** **46.5 lb/hr x 100 hr x ton/2,000 lb = 2.3 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator. See Table 2-6.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **6.4 g/kW-hr**	4. Equivalent Allowable Emissions: **46.5** lb/hour **2.3** tons/year
5. Method of Compliance: **Manufacturer certification of Subpart IIII standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.045** lb/hour **0.0023** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0015% S fuel oil** Reference: **Fuel vendor information**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.0015% S x 64/32 (MW SO2/S) x 7.06 lb/gal x 214.2 gal/hr = 0.045 lb/hr** **0.045 lb/hr x 100 hr x ton/2,000 lb = 0.0023 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator. See Table 2-6**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0015% S fuel oil**	4. Equivalent Allowable Emissions: **0.045** lb/hour **0.0023** tons/year
5. Method of Compliance: **Fuel vendor information**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Particulate Matter - PM/PM10/PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.5** lb/hour **0.07** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.2 g/kW-hr** Reference: **Manufacturer certification**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.2 g/kW-hr x 3,298 kW x 1 lb/453.6 g = 1.5 lb/hr** **1.5 lb/hr x 100 hr x ton/2,000 lb = 0.07 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator. See Table 2-6**	

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: **0.2 g/kW-hr**	4. Equivalent Allowable Emissions: **1.5** lb/hour **0.07** tons/year
5. Method of Compliance: **Manufacturer certification of Subpart IIII Standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.5** lb/hour **0.07** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.2 g/kW-hr** Reference: **Manufacturer certification**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.2 g/kW-hr x 3,298 kW x 1 lb/453.6 g = 1.5 lb/hr** **1.5 lb/hr x 100 hr x ton/2,000 lb = 0.07 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator. See Table 2-6**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.2 g/kW-hr**	4. Equivalent Allowable Emissions: **1.5** lb/hour **0.07** tons/year
5. Method of Compliance: **Manufacturer certification of Subpart IIII Standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Carbon Dioxide Equivalent - CO2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **9,613.8** lb/hour **482.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **116.9 lb/MMBtu for CO2, 0.002204 lb/MMBtu for CH4 and 0.0002204 lb/MMBtu for N2O** Reference: **Table C-2, Subpart C, 40 CFR 98.**	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table A-18.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for two generators.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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 PSD 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 PSD 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 PSD 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 PSD 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 PSD 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:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2016**	**2019**	**49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **John Deere or equivalent** Model Number: **JU6H-UFAD80**

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    One diesel fire pump engine rated at 422 hp.

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.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **2.75** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **7** days/week **52** weeks/year **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: **0.6** Feet
8. Exit Temperature: **891**°F	9. Actual Volumetric Flow Rate: **2,048** 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 2-7 in Air Permit Application Report.**		

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: **0.02**	5. Maximum Annual Rate: **2.0**	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			EL
PM/PM10/PM2.5			EL
NOX			EL
SO2	Fuel Quality		EL
VOC			EL
CO2e			WP

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: **Carbon Monoxide - CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.6** lb/hour **0.03** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.9 grams per kilowatt-hour (g/kW-hr)** Reference: **Manufacturer certification**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.9 g/kW-hr x 315 kW x 1 lb/453.6 g = 0.6 lb/hr** **0.6 lb/hr x 100 hr/2,000 lb = 0.03 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-7**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.9 g/kW-hr**	4. Equivalent Allowable Emissions: **0.6** lb/hour **0.03** tons/year
5. Method of Compliance: **Manufacturer certification of Subpart IIII standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Nitrogen Oxides - NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.64** lb/hour **0.132** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.8 g/kW-hr** Reference: **Manufacturer certification**	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: **3.8 g/kW-hr x 315 kW x 1 lb/453.6 g = 2.64 lb/hr** **2.64 lb/hr x 100 hr x ton/2,000 lb = 0.132 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-7**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3.8 g/kW-hr**	4. Equivalent Allowable Emissions: **2.64** lb/hour **0.132** tons/year
5. Method of Compliance: **Manufacturer certification of Subpart IIII standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0042** lb/hour **0.00021** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0015% S fuel oil** Reference: **Fuel vendor information**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.0015% S x 64/32 (MW SO2/S) x 7.06 lb/gal x 20 gal/hr = 0.0042 lb/hr** **0.0042 lb/hr x 100 hr x ton/2,000 lb = 0.00021 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-7**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0015% S fuel oil**	4. Equivalent Allowable Emissions: **0.0042** lb/hour **0.00021** tons/year
5. Method of Compliance: **Fuel vendor information**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

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

1. Pollutant Emitted: **Particulate Matter - PM/PM10/PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.09** lb/hour **0.005** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.13 g/kW-hr** Reference: **Manufacturer certification**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.13 g/kW-hr x 315 kW x 1 lb/453.6 g = 0.09 lb/hr** **0.09 lb/hr x 100 hr/2,000 lb = 0.005 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-7**	

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: **0.13 g/kW-hr**	4. Equivalent Allowable Emissions: **0.09** lb/hour **0.005** tons/year
5. Method of Compliance: **Manufacturer certification of Subpart IIII Standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.07** lb/hour **0.003** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.1 g/kW-hr** Reference: **Manufacturer certification**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.1 g/kW-hr x 315 kW x 1 lb/453.6 g = 0.07 lb/hr** **0.07 lb/hr x 100 hr/2,000 lb = 0.003 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-7**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 g/kW-hr**	4. Equivalent Allowable Emissions: **0.07** lb/hour **0.003** tons/year
5. Method of Compliance: **Manufacturer certification of Subpart IIII Standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Carbon Dioxide Equivalent - CO2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **448.8** lb/hour **22.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **116.9 lb/MMBtu for CO2, 0.002204 lb/MMBtu for CH4 and 0.0002204 lb/MMBtu for N2O** Reference: **Table C-2, Subpart C, 40 CFR 98.**	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table A-18.**	
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 _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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 PSD 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 PSD 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 PSD 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: **<u>See PSD Report</u>** ☐ 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 PSD 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:

   Hurricane shelter generators for emergency usage with propane-fired engine.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code: **C**	5. Commence Construction Date: **2016**	6. Initial Startup Date: **2019**	7. Emissions Unit Major Group SIC Code: **49**

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

   ☐ Acid Rain Unit
   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **Ford** Model Number: **3.0 L V-6 OHV**

10. Generator Nameplate Rating: **0.027** MW

11. Emissions Unit Comment:
   Two generators are installed with the hurricane shelter. Note that these generators are designed as insignificant activities in the FPL OCEC and RBEC Title V permits.

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: **Good combustion practices - Propane 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.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **0.4** 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: **Heat input for each engine.**	

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: 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): **Propane fuel combustion**		
2. Source Classification Code (SCC):	3. SCC Units: **MMscf**	
4. Maximum Hourly Rate: **0.00016**	5. Maximum Annual Rate: **0.016**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2 gr/100scf**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **2,520**
10. Segment Comment: **Maximum annual rate based on 100 hr/yr operation fuel use for each engine.**		

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			EL
PM/PM10/PM2.5			EL
NOX			EL
SO2	Fuel Quality		EL
VOC			EL
CO2e			WP

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Carbon Monoxide - CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.49** lb/hour **0.124** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **28.23 grams per horsepower-hour (g/hp-hr)** Reference: **EPA 2010 Non-Road Engine Emission Factors for uncontrolled engines**	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: **28.23 g/hp-hr x 40 hp x 1 lb/453.6 g = 2.49 lb/hr** **2.49 lb/hr x 100 hr/2,000 lb = 0.124 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions for each engine. See Table 2-8.**	

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: **28.23 g/hp-hr**	4. Equivalent Allowable Emissions: **2.49** lb/hour **0.124** tons/year
5. Method of Compliance: **EPA 2010 Non-Road Engine Emission Factors for uncontrolled engines**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions for each engine.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Nitrogen Oxides - NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.06** lb/hour **0.053** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **11.99 g/hp-hr** Reference: **EPA 2010 Non-Road Engine Emission Factors for uncontrolled engines**	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:

11.99 g/hp-hr x 40 hp x 1 lb/453.6 g = 1.06 lb/hr
1.06 lb/hr x 100 hr x ton/2,000 lb = 0.053 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions for each engine. See Table 2-8.

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: **11.99 g/hp-hr**	4. Equivalent Allowable Emissions: **1.06** lb/hour **0.053** tons/year
5. Method of Compliance: **EPA 2010 Non-Road Engine Emission Factors for uncontrolled engines**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions for each engine.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.00088** lb/hour **0.000044** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.2 lb/10^3 gal** Reference: **assuming 2 gr/100 scf, the same as natural gas**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.2 lb S/10^3 gal x 4.41 gal/hr = 0.00088 lb/hr** **0.00088 lb/hr x 100 hr x ton/2,000 lb = 0.000044 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions for each engine. See Table 2-8**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0015% S fuel oil**	4. Equivalent Allowable Emissions: **0.00088** lb/hour **0.000044** tons/year
5. Method of Compliance: **Fuel vendor information**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions for each engine.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Particulate Matter - PM/PM10/PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0044** lb/hour **0.00022** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.05 g/hp-hr** Reference: **EPA 2010 Non-Road Engine Emission Factors for uncontrolled engines**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.05 g/hp-hr x 40 hp x 1 lb/453.6 g = 0.0044 lb/hr** **0.0044 lb/hr x 100 hr/2,000 lb = 0.00022 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions for each engine. See Table 2-8.**	

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: **0.05 g/hp-hr**	4. Equivalent Allowable Emissions: **0.0044** lb/hour **0.00022** tons/year
5. Method of Compliance: **EPA 2010 Non-Road Engine Emission Factors for uncontrolled engines**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions for each engine.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.17** lb/hour **0.109** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **24.64 g/hp-hr** Reference: **EPA 2010 Non-Road Engine Emission Factors for uncontrolled engines**	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: **24.64 g/hp-hr x 40 hp x 1 lb/453.6 g = 2.17 lb/hr** **2.17 lb/hr x 100 hr/2,000 lb = 0.109 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions for each engine. See Table 2-8.**	

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: **24.67 g/hp-hr**	4. Equivalent Allowable Emissions: **2.17** lb/hour **0.109** tons/year
5. Method of Compliance: **EPA 2010 Non-Road Engine Emission Factors for uncontrolled engines**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions for each engine.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

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

1. Pollutant Emitted: **Carbon Dioxide Equivalent - CO2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **56.0** lb/hour **2.805** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **116.9 lb/MMBtu for CO2, 0.002204 lb/MMBtu for CH4 and 0.0002204 lb/MMBtu for N2O** Reference: **Table C-2, Subpart C, 40 CFR 98.**	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table 2-8.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions for each 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 _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   Mechanical Draft Cooling Tower

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2016**	**2019**	**49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment: **30 cell wet mechanical draft cooling tower. Any differences in the information contained in the form and the emission calculations contained in the PSD Report are due to round-off. The values in the PSD Report govern.**

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: **Mist Eliminators.**	
2. Control Device or Method Code: **014**	

Emissions Unit Control Equipment/Method: Control _____ of _____

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate:	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 **8,760** 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: **See PSD Report**		2. Emission Point Type Code:
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **30 Cooling Tower Cells**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **51.5** feet	7. Exit Diameter: **30** feet
8. Exit Temperature: **86**°F	9. Actual Volumetric Flow Rate: **945,069** 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): **520.65** North (km): **3056.63**		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack dimensions per cell.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

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:			

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
PM	**014**		**WP**
PM10	**014**		**WP**

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **40.8**lb/hour **178.7**tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0005% Drift Rate** Reference: **FPL, 2015; Golder, 2015**	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 2-9 in PSD Report.**	
11. Potential Fugitive and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.0005 percent of CW**	4. Equivalent Allowable Emissions: **40.8** lb/hour **178.7**tons/year
5. Method of Compliance: **Design certification from manufacturer.**	
6. Allowable Emissions Comment (Description of Operating Method): **CW = circulating water.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.79**lb/hour **7.84**tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0005 percent Drift Rate** Reference: **FPL, 2015; Golder, 2015**	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 2-9 in PSD Report.**	
11. Potential Fugitive and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.0005 percent of CW**	4. Equivalent Allowable Emissions: **1.79** lb/hour **7.84**tons/year
5. Method of Compliance: **Design certification from manufacturer.**	
6. Allowable Emissions Comment (Description of Operating Method): **CW = circulating water.**	

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

<u>Visible Emissions Limitation:</u> 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:	

<u>Visible Emissions Limitation:</u> 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 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: **N.A.** ☐ 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 PSD 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 PSD 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 PSD 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 PSD 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:

   Temporary Construction Boilers (to be used during construction period only).

3. Emissions Unit Identification Number: **7**

4. Emissions Unit Status Code: **C**	5. Commence Construction Date:	6. Initial Startup Date: **2018**	7. Emissions Unit Major Group SIC Code: **49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **Nebraska Boiler or equivalent** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    These temporary emission units will only be used during the project construction period. Once the OCEC commences commercial operation, these units will no longer be operated.

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

1. Control Equipment/Method Description: **Low NOX burners**	
2. Control Device or Method Code: **205**	

Emissions Unit Control Equipment/Method: Control _____ of _____

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **150** million Btu/hr **(up to)**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	**7** days/week **1,500** hours/year
6. Operating Capacity/Schedule Comment: **These temporary emission units will only be used during the project construction period. Once the OCEC commences commercial operation, these units will no longer be operated.**	

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:	
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:	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: **Stack parameter may vary based on availability from vendors.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **2**

1. Segment Description (Process/Fuel Type): **Natural gas**		
2. Source Classification Code (SCC):	3. SCC Units: **MMscf**	
4. Maximum Hourly Rate: **0.147**	5. Maximum Annual Rate: **220.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2 grains/100 scf**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum hourly and annual rates for each boiler.** **Maximum annual rate based on 1,500 hr/yr operation.**		

Segment Description and Rate: Segment **2** of **2**

1. Segment Description (Process/Fuel Type): **Ultra low sulfur**		
2. Source Classification Code (SCC):	3. SCC Units: **1,000 gallons**	
4. Maximum Hourly Rate: **1.110**	5. Maximum Annual Rate: **1,665.4**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Maximum hourly and annual rates for each boiler.** **Maximum annual rate based on 1,500 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
PM	Fuel Quality		NS
PM10	Fuel Quality		NS
SO2	Fuel Quality		EL
NOX	205		EL
CO	Good Combustion		NS
VOC	Good Combustion		NS

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: **Particulate Matter Total - PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **7.3** lb/hour **5.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
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 Attachment EU8 F1- Construction Boilers for calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **For both boilers.**	

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: **10% Opacity**	4. Equivalent Allowable Emissions: **7.3** lb/hour **3.3** tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

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

1. Pollutant Emitted: **Particulate Matter - PM10/PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **7.3** lb/hour **3.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
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 Attachment EU-8 F1-Construction Boilers for calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **For both boilers.**	

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: **10% Opacity**	4. Equivalent Allowable Emissions: **7.3** lb/hour **3.3** tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

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

1. Pollutant Emitted: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.7** lb/hour **1.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
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 Attachment EU-8 F1-Construction Boilers for calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **For both boilers.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 grains S/100 scf gas 0.0015% S ULSD oil**	4. Equivalent Allowable Emissions: **1.7** lb/hour **1.3** tons/year
5. Method of Compliance: **Maintain fuel 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):	

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: **Nitrogen Oxides - NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22.2** lb/hour **16.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
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 Attachment EU-8 F1-Construction Boilers for calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **For both boilers.**	

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:	4. Equivalent Allowable Emissions: **22.2** lb/hour **16.7** tons/year
5. Method of Compliance: **Use of natural gas or ULSD**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Carbon Monoxide - CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **24.7** lb/hour **18.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Emissions based on AP-42**	7. Emissions Method Code: **3**
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 Attachment EU-8 F1-Construction Boilers for calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **For both boilers.**	

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:	4. Equivalent Allowable Emissions: **24.7** lb/hour **18.5** 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):	

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.6** lb/hour **1.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Emissions based on AP-42**	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Attachment EU-8 F1-Construction Boilers for calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **For both boilers.**	

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:	4. Equivalent Allowable Emissions: **1.6** lb/hour **1.2** 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 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% opacity. Excess emissions provided by Rule 62-210.700(1), F.A.C.**	

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: ____________ ☒ 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

See Air Report

ATTACHMENT EU8-F1

CONSTRUCTION BOILERS
EMISSION CALCULATIONS FOR CONSTRUCTION BOILERS

ATTACHMENT EU8-F1 - CONSTRUCTION BOILERS
EMISSION CALCULATIONS FOR CONSTRUCTION BOILERS

Pollutant	No. of Units	Maximum Heat Input Rate/Unit (MMBtu/hr)	Hourly Fuel Usage [a] (10^6 scf/hr) (10^3gal/hr)	Annual Operating Hours Per Boiler (hrs/yr)	Annual Fuel Usage [a] (10^6 scf/hr) (10^3gal/hr)	AP-42 Emissions Factor [b]		Emission Rate Hourly (lb/hr) (both boilers)	Emission Rate Annual (TPY) (both boilers)
Natural Gas Combustion									
$PM/PM_{10}/PM_{2.5}$	2	150.0	0.294	1,500	441.2	7.6	lb/10^6scf	2.2	1.7
SO_2	2	150.0	0.294	1,500	441.2	2	S gr/100 scf [c]	1.7	1.3
NO_x	2	150.0	0.294	1,500	441.2	50.0	lb/10^6scf	14.7	11.0
CO	2	150.0	0.294	1,500	441.2	84	lb/10^6scf	24.7	18.5
VOC [d]	2	150.0	0.294	1,500	441.2	5.5	lb/10^6scf	1.6	1.2
Ultra Low-Sulfur Diesel Combustion									
$PM/PM_{10}/PM_{2.5}$	2	150.0	2.221	1,500	3330.9	3.3	lb/10^3gal	7.3	5.5
SO_2	2	150.0	2.221	1,500	3330.9	157	*S lb/10^3gal [e]	0.5	0.4
NO_x	2	150.0	2.221	1,500	3330.9	10.0	lb/10^3gal	22.2	16.7
CO	2	150.0	2.221	1,500	3330.9	5.0	lb/10^3gal	11.1	8.3
VOC [d]	2	150.0	2.221	1,500	3330.9	0.2	lb/10^3gal	0.4	0.3

Footnotes:

[a] Based on both boilers operating. Based on natural gas heat content of 1,020 Btu/scf and ultra low-sulfur diesel heat content of 131,500 Btu/gal, respectively.

[b] Natural gas combustion emission factors are based on Tables 1.4-1 and 1.4-2, AP-42, Section 1.4, (2015). Ultra Low-Sulfur diesel combustion emission factors are based on Tables 1.3-1, 1.3-2, and 1.3-3, AP-42, Section 1.3, (2015).

[c] "S" is sulfur content in natural gas. A sulfur content of 0.2 gr/100 ft^3 is used in the calculation.

[d] Non-methane total organic compounds.

[e] "S" is weight percent of sulfur in oil. A sulfur content of 0.0015% by weight used in the calculation.

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:

   Temporary construction generators (2) to supply construction power.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2016**	**2017**	**49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **Caterpillar or equivalent** Model Number:

10. Generator Nameplate Rating: **4.05** MW

11. Emissions Unit Comment:
    Three temporary construction generators; 1 at 450 kW and 2 at 1,800 kW.

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.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:
2. Maximum Production Rate:
3. Maximum Heat Input Rate: **37.9** million Btu/hr
4. Maximum Incineration Rate: pounds/hr
   tons/day
5. Requested Maximum Operating Schedule:
   12 hours/day **6** days/week
   50 weeks/year **3,600** hours/year
6. Operating Capacity/Schedule Comment:
   The temporary construction generators will be operated as necessary to generate construction power during the construction of OCEC. Maximum heat input for all generators provided. The typical operation will be 12 hours/day and 6 days/week. The duration of weeks per year will vary by year but 50 weeks per year is the expected maximum operation during peak construction periods. The expected distribution during operation is in the following table.

Year:	2017	2018	2019
450 kW	3,600	3,600	1,440
1,800 kW	3,024	3,600	1,440
1,800 kW	2,736	3,600	0

The generators are expected meet the requirements of 40 CFR 89 for non-road engines.

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: 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: **See Attachment EU-9 F1-Construction Generators.**		

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: **0.275**	5. Maximum Annual Rate: **991.7**	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 all generators operating at capacity for 3,600 hours in one year. Actual operation will vary depending upong construciton power needs.**		

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			EL
PM/PM10/PM2.5			EL
NOX			EL
SO2	Fuel Quality		EL
VOC			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: **Carbon Monoxide - CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **56.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.5 grams per horsepower-hour (g/kW-hr)** Reference: **EPA 40 CFR 89.112**	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 Attachment EU-9 F1-Construction Generators**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for maximum operation in any year with all generators operating.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3.5 g/kW-hr**	4. Equivalent Allowable Emissions: lb/hour **56.3** tons/year
5. Method of Compliance: **EPA 40 CFR 89.111 non-road engine standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

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

1. Pollutant Emitted: **Nitrogen Oxides - NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **98.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **6.4 g/kW-hr** Reference: **EPA 40 CFR 89.112 non-road engines**	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 Attachment EU-9 F1-Construction Generators.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for maximum operation in any year with all generators operating.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **6.4 g/kW-hr**	4. Equivalent Allowable Emissions: lb/hour **98.6** tons/year
5. Method of Compliance: **EPA 40 CFR 89.112 non-road engines standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **0.105** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0015% S fuel oil** Reference: **ULSD Oil**	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 Attachment EU-9 F1-Construction Generators.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for maximum operation in any year with all generators operating.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0015% S fuel oil**	4. Equivalent Allowable Emissions: lb/hour **0.105** tons/year
5. Method of Compliance: **ULSD Oil**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Particulate Matter - PM/PM10/PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **3.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.2 g/kW-hr** Reference: **EPA 40 CFR 89.112 non-road engines**	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 Attachment EU-9 F1-Construction Generators.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for maximum operation in any year with all generators operating.**	

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: **0.2 g/kW-hr**	4. Equivalent Allowable Emissions: lb/hour **3.2** tons/year
5. Method of Compliance: **EPA 40 CFR 89.112 non-road engine standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **3.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.2 g/kW-hr** Reference: **EPA 40 CFR 89.112 non-road engines**	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 Attachment EU-9 F1-Construction Generators**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for maximum operation in any year with all generators operating.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.2 g/kW-hr**	4. Equivalent Allowable Emissions: lb/hour **3.2** tons/year
5. Method of Compliance: **EPA 40 CFR 89.112 non-road engine standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation **1** of **1**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **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 PSD 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 PSD 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 PSD 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 PSD 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: ____________ ☒ 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

ATTACHMENT EU9-F1

CONSTRUCTION GENERATORS
PERFORMANCE AND EMISSION DATA FOR THE CONSTRUCTION GENERATORS

ATTACHMENT EU9-F1 - CONSTRUCTION GENERATORS

PERFORMANCE AND EMISSION DATA FOR THE CONSTRUCTION GENERATORS

Parameter		Units	Values	
Performance				
Number of Units			1	2
Rating		kW	450	1,800
Rating		hp	584	2,336
Fuel			Diesel	Diesel
Fuel Heat content (HHV)		Btu/lb	19,500	19,500
Fuel density		lb/gal	7.06	7.06
Heat input (HHV) (per generator)		MMBtu/hr	4.21	17
Fuel usage (per generator)		gal/hr	30.6	122.4
Maximum operation/yr (2018)		hours	3,600	3,600
Maximum fuel usage (total for number of units)		gal/yr	110,119	880,951
Stack Parameters (typical per unit)				
Diameter		ft	0.8	1.6
Height		ft	20	30
Temperature		^oF	916	916
Flow		acfm	3,525	14,100
Emissions				
SO_2 -	Basis	%S	0.0015%	0.0015%
	Conversion of S to SO_2	%	100	100
	Molecular weight SO_2/ S (64/32)		2	2
	Emission rate	lb/hr/unit	0.006	0.026
		TPY (total)	0.0117	0.0933
NO_x -	Basis	g/kW-hr	4.0	6.4
	Emission rate	lb/hr/unit	4.0	25.4
		TPY (total)	7.1	91.4
CO -	Basis	g/kW-hr	3.5	3.5
	Emission rate	lb/hr/unit	3.5	13.9
		TPY (total)	6.3	50.0
VOC -	Basis	g/kW-hr	0.2	0.2
	Emission rate	lb/hr/unit	0.2	0.8
		TPY (total)	0.36	2.9
$PM/PM_{10}/PM_{2.5}$ -	Basis	g/kW-hr	0.2	0.2
	Emission rate	lb/hr/unit	0.2	0.8
		TPY (total)	0.36	2.9

Source: FPL, 2015; Golder; 2015.
Performance based on typical diesel generator (e.g., Caterpillar C175 kW 60 Hz)
Emissions based on 40 CFR Part 60 Subpart IIII Requirements