Dania Beach Energy Center

SITE CERTIFICATION APPLICATION

Volume II of III

FPL

July 2017

SITE CERTIFICATION APPLICATION
DANIA BEACH ENERGY CENTER

VOLUME II OF III

Submitted by:

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

July 2017

17-73823

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APPENDIX 10.2.5

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

PSD REPORT

AIR CONSTRUCTION PERMIT APPLICATION FOR THE FLORIDA POWER & LIGHT COMPANY DANIA BEACH ENERGY CENTER BROWARD 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
AFUE	annualized fuel utilization efficiency
AOR	Annual Operating Report
AQRV	air quality related value
ASOS	automatic surface observing system
BACT	Best Available Control Technology
BSER	best system of emission reduction
BPIP	Building Profile Impact Program
Btu/lb	British thermal unit per pound
Btu/yr	British thermal unit per year
Btu/kWh	British thermal unit per kilowatt hour
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCR	carbon capture and storage
CEC	cation exchange capacity
CEM	continuous emissions monitoring
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CSAPR	Cross-State Air Pollution Rule
CT or CTG	combustion turbine or combustion turbine generator
DATs	Deposition analysis threshold
DBEC	Dania Beach Energy Center
DLN	dry-low NO_X
EC	elemental carbon
EIA	U.S. Energy Information Administration
ENP	Everglades National Park
EPA	U.S. Environmental Protection Agency
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FIU	Florida International University
FPL	Florida Power & Light Company
ft	foot

ft^3/yr	cubic feet per year
FR	Federal Register
GCP	good combustion practices
GEP	Good Engineering Practice
gr/100 scf	grains per 100 standard cubic feet
GT	gas turbines
GHG	greenhouse gas
H_2SO_4	sulfuric acid mist
HAP	hazardous air pollutant
HFCs	hydrofluorocarbons
HHV	higher heat value
hp	horsepower
hr/yr	hours per year
HRSG	heat recovery steam generator
IEC	International Electrotechnical Commission
kg/ha/yr	kilogram per hectare per year
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
MECL	Minimum Emission Compliance Load
MMBtu/hr	million British thermal units per hour
MMcf/hr	million cubic feet per hour
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
N_2O	nitrous oxide
N	nitrogen
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
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
PPRAQD	Pollution Prevention, Remediation and Air Quality Division of Broward County
PSD	Prevention of Significant Deterioration
psi	pound per square inch
psia	pound per square inch absolute
psig	pound per square inch gauge
QA/QC	quality assurance/quality control
RACT	reasonably available control technology
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	DBEC Certified Site
SF_6	sulfur hexafluoride
SMC	significant monitoring concentrations
SO_2	sulfur dioxide
SO_4	sulfate
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
UTM	Universal Transverse Mercator
VOC	volatile organic compound

1.0 INTRODUCTION

Florida Power & Light Company's (FPL's) existing Lauderdale Plant is located in Broward County, Florida (see Figure 1-1) and includes Units 4 and 5, consisting of four 1990's vintage combustion turbines (CTs), four heat recovery steam generators (HRSGs), and two 1950s vintage steam turbines, Unit 6, consisting of five new combustion turbines and two 1970's vintage gas turbines. Unit 6 (Units 6A through 6E), which began commercial operation in 2016, replaced 22 gas turbines at the Lauderdale Plant and 12 gas turbines at the nearby Port Everglades Plant. FPL proposes to modernize Units 4 and 5 with a modern, highly efficient, lower-emission next generation clean energy center using the latest combined cycle technology. The modernized unit will be located wholly within the existing Lauderdale Site, and will be known as the "Dania Beach Energy Center" (DBEC).

DBEC will be a net 1,200 megawatt (MW) nominal 2-on-1 combined cycle electrical generating unit that will consist of two new advanced-technology combustion turbine/electric generators, two HRSGs, and one steam turbine/electric generator, along with adjacent supporting facilities. Natural gas will be the primary fuel for DBEC. Ultra low-sulfur distillate (ULSD) "light oil" will be used as a backup fuel for the combustion turbines. The natural gas will be provided by an existing pipeline connection and ULSD will be delivered by truck. The combined cycle unit is referred to as Unit 7. Other sources of air emissions will include an auxiliary boiler, emergency diesel generators, natural gas heater, emergency diesel fire pump engine and mechanical draft auxiliary cooling system.

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 EPA's PSD regulations by reference in Rule 62-204.800(3), Florida Administrative Code (F.A.C.) and Florida's PSD regulations are codified in Florida Department of Environmental Protection (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 major modification of a "major stationary source" because the existing FPL Lauderdale Plant 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(172), 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(256), 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 existing FPL Lauderdale Plant is located within the Cities of Dania Beach and Hollywood in Broward County, Florida. The existing Site is situated within 392 acres of property owned by FPL. The existing Lauderdale Site has been used for power generation since 1927 and currently includes two nominal 440 MW combined cycle units (Units 4 and 5), five nominal 200 MW combustion turbines (Units 6a through 6E) and two 1970's vintage nominal 35 MW gas turbines. Units 4 and 5 began operation in May 1993 and June 1993, respectively (Title V Air Permit No. 0110037-010). Units 6A through 6E that began commercial operation in 2016 and replaced 22 gas turbines at the Lauderdale Plant and 12 gas turbines at the nearby Port Everglades Plant (Air Permit No. 0110037-013-AC). The Site also includes 138 kV and 230 kV transmission facilities (system substation). Figure 2-1 presents the conceptual site plan for the Project.

2.2 New Combustion Turbines

The CTs for the Project will be the latest model of General Electric's (GE) Frame 7HA. These CTs have a gross capacity of over 400 MW at an inlet air temperature of 75°F. The HRSGs will not have duct firing.

Each CT will utilize inlet air cooling that will consist of evaporative cooling. Evaporative cooling systems achieve adiabatic cooling using water evaporated from a treated media. The evaporated water extracts the latent heat of vaporization from the inlet air stream when the water droplet is converted to water vapor. The result is a cooler, denser air stream. This allows additional power to be produced. Enhanced power modes can be operated using wet compression which introduces water into the CT compressor inlet to enhance the CT capability during warm ambient conditions or other CT improvements.

The CTs will use natural gas as the primary fuel, with ULSD oil used as the backup fuel. Natural gas for DBEC will be transported to the Site by the existing pipeline connection to the Lauderdale Plant. DBEC will be connected to the existing natural gas yard. The ULSD oil will be delivered to the Site by truck and will be stored in existing fuel oil tanks. 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 generating capacity of a combined cycle plant is affected by ambient temperature, machine specific performance and features unless wet compression is in operation when firing natural gas. Generally, greater overall fuel consumption will occur at lower ambient temperatures when ULSD oil is used. Wet compressions when firing natural gas allows nearly level fuel consumption over the ambient range. Appendix A contains the heat input and fuel use over an ambient range of 35 ^{o}F to 95 ^{o}F for natural gas and ULSD.

2.3 Source Emission Units and Stack Parameters

The Project's air emission units are:

- 2 GE 7HA CTs
- Auxiliary boiler
- Two emergency diesel generators
- Natural gas heaters (2, one is a spare)
- Fire water pump diesel engine
- 14-cell auxiliary cooling system
- Circuit breakers containing sulfur hexafluoride (SF_6) and located in Unit 7 power block

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

Tables 2-1 presents the CT performance and regulated air pollutant emission rates for GE's latest 7HA CTs when firing natural gas. Tables 2-2 presents the CT performance and estimated emission rates of regulated air pollutants when firing ULSD oil. The maximum estimated emission rates for the conditions stated when firing natural gas and ULSD oil were determined using the manufacturer's information for the equipment proposed for DBEC. The design parameters are provided for the range of operating loads and ambient temperatures. For natural gas firing, the lowest operating load where compliance with emission levels are achieved are shown in Table 2-1. This is referred to as minimum emission compliance load (MECL) which is approximately 30 percent for the GE 7H CT but varies with ambient temperature. Appendix A contains the GE provided performance and emissions for three loads (100 percent, 75 percent and MECL) and four ambient temperatures (35 ^{o}F, 59 ^{o}F, 75 ^{o}F and 95 ^{o}F) used for Table 2-1 and 2-2.

Potential annual emissions for the CTs are calculated for regulated air pollutants at an ambient temperature of 75°F with evaporative cooling and manufacturer's 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. An ambient temperature of 75°F is used to determine potential emissions in tons/year, since the annual average temperature in Fort Lauderdale is about 75°F. To produce the potential annual emissions, it is assumed that each CT would operate for 8,760 hours with 7,760 hours per year (hr/yr) firing natural gas and 1,000 hr/yr firing ULSD oil. Tables 2-3 presents a summary of potential emissions for various operating conditions (loads and fuel used).

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 DBEC will be further controlled using SCR to reduce emissions of NO_x to 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. There will be a 95 percent reduction in the NO_x emission rate when firing natural gas compared to existing Units 4 and 5 that have a NO_x emission rate of 42 ppmvd corrected to 15 percent O_2 when firing natural gas.

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.

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.

PM, sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4) emissions are controlled and minimized by the use of clean fuels, which 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.

The auxiliary boiler will be used as necessary for startup. The limited use auxiliary boiler will have a maximum heat input of 99.8 Million British thermal units per hour (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 E).

The 2-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. Table 2-5 contains performance and emissions information for the fuel heaters.

Two, 3,300 kilowatt (kW-brake) emergency diesel generators will be installed to support the power plant. These emergency diesel generators will be used when electric power is not available. This would primarily occur during catastrophic events such as hurricanes.

DBEC will be equipped with a 425-horsepower (hp) fire pump engine. This engine will be used when necessary during catastrophic events such as fires. Tables 2-6 and 2-7 contain estimated emissions for the emergency diesel generators and fire pump engine, respectively. Normally, the engines are operated 1 to 2 hours per month for maintenance and reliability testing.

DBEC will have a mechanical draft auxiliary cooling system. PM will be emitted in the form of drift and controlled through the use of high efficiency mist eliminators that will be designed to limit drift to 0.0005 percent of the once-through water rate. Table 2-8 presents information on the auxiliary cooling system and potential PM, PM_{10} and $PM_{2.5}$ from drift. The information presented in Table 2-8 is based on a 14-cell design.

2.4 Annual Emissions for the Project

The total annual emissions from DBEC are presented in Table 2-9 and include air emissions from the CTs, fuel heater, emergency diesel generators, auxiliary boiler, fire pump engine, and auxiliary cooling system. Annual potential emissions were based on maximum emissions for baseload operation and ambient temperatures of 75°F at enhanced power output and evaporative cooling when firing natural gas and evaporative cooling when firing ULSD oil. The maximum CT emissions are based on 8,760 hr/yr with 7,760 hr/yr firing natural gas and 1,000 hr/yr firing ULSD oil. The potential emissions are based on the 75°F ambient temperature at 100 percent load condition.

Maximum annual potential hazardous air pollutants (HAPs) emissions are presented in Table 2-10. Additional detail on the HAP emission calculations is also presented in Appendices A, Tables A-13 through

A-16. The Lauderdale Plant will remain a “major source” of HAP emissions due to the combined potential emissions from the DBEC Project, Unit 6 and the two gas turbines being greater than the major source thresholds for HAPs [10 tons per year (TPY) of a single HAP, or 25 TPY for all HAPs located on a single facility location].

Because the Project involves a physical change to an existing major stationary source that will result in an increase in actual emissions for certain pollutants, review is required to determine whether the Project constitutes a Major Modification triggering PSD requirements under Rule 62-212.400, F.A.C. PSD applicability is determined on a pollutant-by-pollutant basis and, as defined in Rule 62-210.200(169), a Major Modification occurs where there is a “significant emission increase” of a PSD pollutant and a “significant *net* emissions increase” of that pollutant that exceeds the PSD significant emission rates (SERs). Because this project involves the construction of new emission units and changes to existing units (the retirement of Units 4 and 5), the Hybrid Test for Multiple Types of Emission Units in Rule 62-212.400(2)(a)3., F.A.C., is used to determine if there is a significant emissions increase. As defined in Rule 62.210.200(187), F.A.C., a significant *net* emissions increase is determined by accounting for all other “contemporaneous” and creditable increases or decreases in actual emissions. Emission increases or decreases for a particular modification are contemporaneous if they occur five years before the construction of that change and the date the increase from the change occurs. Since Units 6A through 6E are contemporaneous with the DBEC Project, their potential to emit must be included in determining PSD applicability.

For an existing emission unit like Units 4 and 5, the emission decreases are determined based on “baseline actual emissions” as defined in Rule 62.210.200(28), F.A.C. The “baseline actual emissions” are the emissions over a consecutive 24-month period within the 5 years immediately preceding the date that a complete application is submitted. The use of different consecutive 24-month periods for each pollutant is allowed. Table 2-11 presents the annual emissions for Units 4 and 5 for the period 2012 through 2016 along with the two consecutive year averages. Appendix B contains the FDEP Annual Operating Report (AOR) information used to develop Table 2-11.

The net emission increase/decrease of a project located at a major stationary source is determined from the sum of all the contemporaneous creditable increases and decreases. For new units, emission increases are based on “potential to emit” as defined in Rule 62.210.200(223), F.A.C. Tables 2-12 presents the potential emissions resulting from the Project, the contemporaneous emissions increases for Unit 6, the contemporaneous emission decreases associated with the retirement of Units 4 and 5, and the net emission increases/decreases. The PSD SERs are thresholds for PSD review for specific pollutants and new major stationary sources or major modifications. PSD review is required for emissions of any PSD pollutant greater than the listed PSD SER. As shown in this table, the potential emissions for DBEC are less than the PSD SER for NO_x; for all other PSD air pollutants, except lead, PSD is required.

2.5 Annual Emissions for GHGs

On June 3, 2010, the 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: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Each of these GHGs has a specific Global Warming Potential (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 (*Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427(2014)).

For the DBEC, 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. Tables 2-12 also shows the potential GHG emissions resulting from the Project, contemporaneous GHG emissions increases/decreases, net GHG emission increases/decreases and the PSD significant emission rate for CO_2e, which is a threshold for PSD review.

In addition to combustion sources, Unit 7 will have circuit breakers in the power block 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 Unit 7 to FPL's transmission and distribution system through the facilities located on the property. Unit 7 will require two circuit breakers associated with the Unit 7 located in the power block area. The 2 circuit breakers associated with the Unit 7 are estimated to contain approximately 100 lbs of SF_6. Based on a design leak rate, less than 1.0 percent/year, the estimated GHG emissions from the circuit breakers are as follows:

- 100 lb SF_6 x >0.01 leakage/year = >1.0 lb SF_6/year
- >1.0 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 = 11.4 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 Tables 2-12 the net emission increases of CO_2e emissions for the combustion sources and Unit 7 circuit breakers will exceed the PSD significant emission rate for GHGs.

Potential emissions from the Project less net emission decreases will trigger PSD review for SO_2, PM [(total suspended particulate (TSP)], PM_{10}, $PM_{2.5}$, CO, VOC, sulfuric acid mist and GHGs.

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 Unit 7 circuit breakers are also included and discussed in the following paragraphs.

2.6 Layout, Structures, and Stack Sampling Facilities

A conceptual site plan of the Project is presented in Figure 2-1. Typical dimensions of the structures associated with the CTs are presented in Section 6.0. Stack sampling facilities will be constructed in accordance with FDEP Rule 62-297.310(7), 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 (NAAQS/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:

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 (*Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014)). Rather, PSD review for GHGs could only be triggered if PSD review 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 AAQS 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 stationary source" 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 PSD 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(32), 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 stationary source" or "major modification" 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.

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(7), F.A.C., PSD review for a new "major stationary source" 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 stationary source" 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, 1987).

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)(e), 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 stationary source" or "major modification" subject to PSD review [FDEP Rule 62-212.400(8), F.A.C.]. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (see Table 3-2).

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

3.2.8 Air Quality Related Values

An Air Quality Related Value (AQRV) analysis is required for projects for those pollutants undergoing PSD review to assess the potential impact on AQRVs in PSD Class I areas. The nearest Class I areas to the Project are the Everglades National Park (ENP), located about 48 km (~30 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 sources" or modifications to major sources located in a nonattainment area and above certain nonattainment thresholds. 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 Broward County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment New Source Review (NSR) requirements are not applicable.

Broward County along with Dade and Palm Beach Counties are designated as an Air Quality Maintenance Area for ozone 62-204.340(4) F.A.C. Emission limiting standards determined to be Reasonably Available Control Technology (RACT) for this area are contained in Rule 62-296.570 F.A.C. and apply to certain sources of NO_x and VOC emissions. Although these standards are not applicable to the DBEC project, the emissions rates for the sources associated with DBEC Project are substantially lower than the emission rates established as RACT in this FDEP rule.

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 (LHV) 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. At less than 75 percent load, the emission limit is 96 ppmvd at 15% O_2 for gas turbines greater than 30 MW at peak load. 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 of 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/MWh (gross) or 1,030 lb/MWh (net) on a 12-month rolling average basis. EPA determined that these emission limits represent the Best System of Emission Reduction (BSER) required under

Section 111(b) of the Clean Air Act. The monitoring requirements for natural gas fired units are based on 40 CFR Part 75 requirements. EPA announced on April 4, 2017 that these NSPS are being reviewed and if appropriate, will initiate proceedings to suspend, revise or rescind these NSPS (82 Fed. Reg. 16330). FDEP adopted these NSPS by reference in Rule 62-204.800(8)(b)87, F.A.C. 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 diesel 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 diesel 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 according to Section 60.4211(f) and required to meet the emission standards for the size and date of manufacturer of the engine (based on purchasing a certified engine from the manufacturer).

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.

The entire Lauderdale Site will include the DBEC, Unit 6 and two gas turbines. The Site is a major source of HAPs since the potential HAP emissions from all emission units will be greater than the major source HAP thresholds of 25 TPY for total HAPs and 10 TPY for any single HAP. Under the NESHAPs of 40 CFR Part 63, Subpart YYYY potentially applies to the CTs located at a major source of HAPs. Since the potential HAP emissions of the Lauderdale Plant are greater than the major source thresholds, this NESHAP is potentially applicable if all new, reconstructed, and existing stationary combustion turbines at the site fire oil more than an aggregate total of 1,000 hours during any calendar year (Sections 63.6095(a)(2) and 63.6175 diffusion flame oil-fired gas turbine). Subpart JJJJJJ applies to industrial, commercial and institutional boilers located at areas (minor) sources of HAPs. This NESHAP does not apply to boilers 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)83., F.A.C., for stationary gas turbines (Subpart KKKK); Subsection (b)4., F.A.C., for the auxiliary boiler (NSPS Subpart Dc) and Subsection (b)81 for the emergency diesel generators and fire pump engine (Subpart IIII). FDEP has adopted EPA NESHAP by reference in Rule 62-204.800(11), Subsection (b)81 for the combustion turbines (Subpart YYYY) and Subsection (b)82., F.A.C., for the emergency diesel generators and fire pump engine (Subpart ZZZZ). 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 stationary 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

The Pollution Prevention, Remediation and Air Quality Division (PPRAQD) of Broward County is the air compliance authority for the County, implementing FDEP regulations (Article IV Air Quality, Broward County Code of Ordinances). PPRAQD has been delegated authority to review, process, and take appropriate action (i.e., exempt, issue, or deny) on most FDEP District-Level permits within the County. However, PSD and Title V permits for electrical power plants are issued by FDEP. PPRAQD provides a review of the application during FDEP's review period.

3.5 Source Applicability

3.5.1 Area Classification

The Project is located in Broward County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Broward County and surrounding counties are designated as PSD Class II areas for SO_2, PM (TSP), and NO_2. The Class I area nearest to the Project is the ENP, located approximately 48 km (~30 miles) from the Project.

3.5.2 PSD Review

Pollutant Applicability

The Project is considered to be a major modification under FDEP PSD rules because the net emissions of several regulated pollutants will exceed the PSD significant emission rates. As shown in Table 2-12 potential emissions from the proposed Project will trigger PSD review for SO_2, PM (TSP), PM_{10}, $PM_{2.5}$, CO, VOC, sulfuric acid mist, and GHGs. (Note: EPA no longer requires PSD review for HAPs. 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)83., F.A.C. NO_x emissions for these new CTs (i.e., >850 MMBtu/hr) are limited by Subpart KKKK to 15-ppmvd corrected to 15-percent O_2 and 42 ppmvd corrected to 15-percent O_2 for natural gas and oil firing, respectively. At less than 75 percent load, the emission limit is 96 ppmvd at 15% O_2 for gas turbines greater than 30 MW at peak load. These emission standards are based on 30-day rolling average and must be met at all times, including startup, 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 grains per 100 standard cubic feet (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 DBEC are limited to 1,000 lb/MWh (gross) or 1,030 lb/MWh (net) by 40 CFR Part 60, Subpart TTTT if not revised or eliminated based on EPA's current review of these NSPS. This emission limit is applicable to DBEC 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 DBEC). 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 DBEC 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 Site will be a major source of HAPs since the combined potential emissions of DBEC, Unit 6 and the two gas turbines are greater than the major HAP thresholds.

The NESHAP Subpart YYYY potentially applies to the Site including DBEC once operational. However, this NESHAP would only apply to the CTs if the aggregate use of oil by existing and new turbines at the Site exceeds 1,000 hours during any calendar year. FDEP adopted this EPA rule by reference in Rule 62-204.800(10)(b)82, 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(10)(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 diesel 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, Broward County has an air quality permitting program for the review, processing, or approval of minor sources of air pollution and Title V permits with the exception of those for electrical power plants. FDEP processes all PSD permitting and Title V permitting for electric power plants.

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 promulgated 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), an allowance tracking 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. (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 (i.e., 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 nation-wide. FPL's allocation of SO_2 allowances from EPA for Units 4 & 5 is more than sufficient for operation of Unit 7.

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 states 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 originally included as one of the 27 states for contributing to ozone. A number of court actions delayed the implementation of CSAPR, leaving the former Clean Air Interstate Rule (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. In EPA's September 7, 2016 update to the CSAPR rule the Agency concluded that Florida no longer significantly contributes to downwind nonattainment and removed Florida from compliance with the rule.

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, 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 stationary 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 (TSP)/PM_{10}/$PM_{2.5}$, 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.

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. Although BACT review is not required for NO_x, SCR is being installed to meet a concentration of 2.0 ppmvd corrected to 15-percent O_2 and is consistent with recent FDEP BACT determinations.

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-steady state operation results in emissions higher than of those proposed as a BACT for normal operation. The durations of these non-steady state 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. The suggested permit language is the same as the conditions contained in the Air Construction/PSD Permit for the FPL Okeechobee Clean Energy Center (OCEC); Permit No. 0930117-001-AC/PSD-FL-434:

> **22. Demonstration of Compliance with Primary NOX and GHG BACT**: The Primary NO_X and GHG BACT limits apply at all times, except during the following operating conditions:
>
> a. *Steam Turbine Cold Startup:* During a cold startup of the steam turbine, the Primary NO_X and GHG BACT emission limits do not apply to any CT/HRSG system, for no more than 8 hours during any 24-hour period. A cold startup of the steam turbine is defined as startup of the 2-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, the Primary NOX and GHG BACT emission limits do not apply, for no more than 4 hours during any 24-hour period. A cold startup of the CT/HRSG system is defined as a startup after the pressure in the high-pressure steam drum falls below 450 psig (pounds per square inch, gauge pressure) for at least a one-hour period.
>
> c. *CT/HRSG System Warm Startup:* During a warm startup of a CT/HRSG system, the Primary NO_X and GHG BACT emission limits do not apply, for no more than 2 hours during any 24-hour

period. A warm startup of the CT/HRSG system is defined as a startup after the pressure in the high-pressure steam drum is above 450 psig.

d. *Shutdown of Combined-Cycle Operation:* During the shutdown of combined cycle operation, the Primary NO_X and GHG BACT emission limits do not apply to any CT/HRSG system, for no more than 3 hours during any 24-hour period.

e. *CT/HRSG System Shutdown:* During the shutdown of a CT/HRSG system, the Primary NO_X and GHG BACT emissions limits do not apply to that CT/HRSG system, for no more than 2 hours during any 24-hour period.

f. *Fuel Switching:* During a fuel switch, the Primary NOX and GHG BACT emission limits do not apply, for no more than 2 hours per fuel switch, up to 4 hours during any 24-hour period, for any CT/HRSG system.

g. *DLN Tuning:* The Primary NO_X and GHG BACT emission limits do not apply during a DLN tuning session and manufacturer required Full-Speed No-Load Tests (FSNL) trip tests, 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.

h. *Documented Malfunction:* The Primary NOX and GHG BACT emission limits do not apply during a documented malfunction, for no more than 2 hours in any 24-hour period. To qualify as a "documented malfunction," the malfunction must be documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. The permittee shall report to the Department the nature, extent, and duration of the malfunction, and the actions taken to correct the problem.

Emissions during the startup, shutdown, fuel switching, DLN tuning and documented malfunction events listed above are not subject to the Primary BACT standards for NO_X or GHGs. These are considered separate events, and each event may occur independently within any 24-hour period ("any 24-hour period" means a calendar day, midnight to midnight). Data from the NO_X and CO_2 CEMS (or fuel use monitor) collected during the events described above will not be used to demonstrate compliance with the Primary BACT emission limits for NOX and GHGs.

Data from the NO_X and CO2 CEMS (or fuel use monitor if a CO2 CEMS is not used) collected during the operating conditions described above, during which the Primary NO_X and GHG BACT limits do not apply, will be used to demonstrate compliance with the Secondary NO_X and GHG BACT emission limits at all times, as described in **Specific Conditions 11 and 23**. All valid emissions data (including data collected during startups, shutdowns, malfunction, DLN tuning, and fuel switching) shall be used to report emissions for the Annual Operating Report.

23. Secondary NO_X and GHG BACT Emission Limits: During the operating conditions listed in **Specific Condition 22**, the permittee shall comply with the Secondary NOX and GHG BACT limits specified in **Specific Condition 11**. Demonstrating compliance with the NO_X limit in NSPS Subpart KKKK at all times shall be sufficient for demonstrating compliance with the Secondary NO_X BACT limit. Demonstrating compliance with the GHG limit in NSPS Subpart TTTT at all times shall be sufficient for demonstrating compliance with the Secondary GHG BACT limit. [Rule 62-210.200(BACT), F.A.C., and 40 CFR 60, Subparts KKKK and TTTT]

{Permitting Note: Compliance with the Secondary NO_X and GHG BACT Emission Limits ensures continuous compliance with an applicable SIP emission limit.}

Since the potential HAP emissions for the Lauderdale Plant including DBEC are greater than the major source thresholds, 40 CFR Part 63, Subpart YYYY is potentially applicable. This NESHAP becomes applicable is all the stationary combustion turbines at the Site fires oil more than an aggregate total of 1,000 hours during any calendar year (Sections 63.6095(a)(2) and 63.6175 diffusion flame oil-fired gas turbine). If this NESHAP becomes applicable to the Site, testing will be performed within 180 days after the compliance date as provided in Section 63.6110. As a result, FPL requests that the following permitting note be added to the permit.

{Permitting Note: The requirements of NESHAP 40 CFR 63 Subpart YYYY emission limitations for oil-fired Stationary Combustion Turbines shall apply if the applicable stationary combustion turbines of the facility exceed 1,000 turbine oil-fired hours in aggregate during a calendar year. Should the Dania Beach Energy Center combustion turbines become applicable units under Subpart YYYY, FPL will evaluate the need for air pollution control(s), such as oxidation catalysts, and demonstrate compliance with the standard within 180 calendar days after the applicable compliance date (40 CFR §63.6110)]

4.3 Combined Cycle CT/HRSGs

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

4.3.1 Carbon Monoxide and VOCs

4.3.1.1 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. A summary of recent BACT determinations are presented in Appendix C, Tables C-1 through C-4 for CO and VOCs. Tables C-1 and C-2 summarize CO BACT determinations for natural gas and oil firing, respectively. Tables C-3 and C-4 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 Port Everglades Energy Project (PEEC) Project with the permit issued in May 2012, the Duke Energy Florida, Inc. Citrus Combined Cycle Project (CCCP) with the permit issued in December 2014, and the FPL OCEC Project with a permit issued in 2015. 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.

Most recently, for the 350 MW GE 7HA.02 CTs associated with OCEC, the CO emissions limits when firing natural gas are 4.3 ppmvd at 15-percent O_2 firing for loads equal to or greater than 90 percent and 7.1 ppmvd at 15-percent O_2 for loads less than 90 percent. The CO emissions limits for oil firing are 10 ppmvd at 15-percent O_2 firing for loads equal to or greater than 90 percent and 13.6 ppmvd at 15-percent O_2 for loads less than 90 percent. The VOC emissions limit are 1.0 ppmvd at 15-percent O_2 firing natural gas and 2.0 ppmvd at 15-percent O_2 firing fuel oil.

For comparison to the latest FDEP BACT determination for OCEC, DBEC will utilize the latest GE 7HA offering that is larger and more efficient and larger GE 7HA.02. This latest 7HA will have CO emission rates when firing natural gas will range between 5.4 ppmvd corrected to 15% O_2 at baseload and 6.9 ppmvd corrected to 15% O_2 at MECL. CO emission rates when firing ULSD oil will range between 12.7 ppmvd corrected to 15% O_2 at baseload and 14.3 ppmvd corrected to 15% O_2 at MECL. The proposed BACT emission rates for CO are within those determined to be BACT for CO. Similarly for VOCs, the emission rates for the GE 7H.03 CT will range between 1.0 ppmvd corrected to 15% O_2 at baseload and 1.2 ppmvd corrected to 15% O_2 at MECL. For ULSD oil firing, the VOC emission rates will range between 2.6 ppmvd corrected to 15% O_2 at baseload and 2.8 ppmvd corrected to 15% O_2 at MECL.

4.3.1.2 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 of the CT exhaust.

SCONOx Process

The SCONOx system, an alternate technology for control of NO_x also controls CO and 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.

4.3.1.3 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

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 not be technically feasible or commercially available for the Project.

4.3.1.4 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.

4.3.1.5 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 $956,000. The incremental cost effectiveness of adding an oxidation catalyst is estimated to be $11,061 per ton of CO removed, based on 8,760 hours of operation with 7,760 hours of natural gas firing and 1,000 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 $9,904 per ton of pollutant removed. Detail calculations are provided in Tables 4-2 and 4-3.

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 4-4). Emissions of sulfuric acid mist could increase by up to 2 TPY with secondary emissions of 9.53 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 8,113,500 kWh per year in potential lost generation. This potential lost in generation could supply the monthly electrical needs of about 676 residential customers. To replace this lost energy, an additional 83,410 British thermal units per year (Btu/yr) or about 83 million cubic feet per year (ft^3/yr) of natural gas would be required.

4.3.1.6 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. The proposed BACT emissions limits for natural gas are 9 ppmvd for CO and 1.4 ppmvw for VOC. For ULSD firing, the proposed BACT emission limits are 20 ppmvd for CO and 2.0 ppmvw for VOC. As discussed previously, the proposed BACT emission limits for CO and VOC when corrected to 15 percent oxygen dry conditions is comparable to those established for OCEC using the GE 7HA.02 CT. The latest GE 7HA is in the design phase. As a result, the expected emission rates that can be achieved given the uncertainty are proposed as BACT.

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 AAQS (see Section 6.0). Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

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

4.3.2.1 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 C, Tables C-5 and C-6 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.

4.3.2.2 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 all considered to be 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.

4.3.2.3 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.

4.3.2.4 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.

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

The use of GCP and clean fuels are recognized to result in the lowest economic, environmental and energy impacts in reducing emissions of PM. Add-on controls are not technically feasible in reducing PM emission due to the high exhaust flow and low PM loading. For the latter, the PM exhaust concentration of the CTs is less than 0.01 grains/standard cubic feet (gr/scf) that is the typical design outlet condition for add-on controls used on fossil fuel steam generators that fire coal and oil.

4.3.2.6 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 Appendix C, Tables C-5 and C-6).

4.3.3 Sulfur Oxides

4.3.3.1 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 C, Table C-7.

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 these clean-burning fuels.

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 are potential FGD systems.

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.

4.3.3.2 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.

4.3.3.3 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 are employed together and do not require ranking.

4.3.3.4 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.

4.3.3.5 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. DBEC 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 C, Table C-8. 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 addition of SCR for further NO_x control would not be cost effective since operation of the auxiliary boiler would be limited to startup conditions.

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 C, Table C-9. As shown, add-on controls have never been applied to a fuel heater. Based on low emissions potential and confirmed by 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 Auxiliary Cooling System

This section contains the BACT analysis for the PM/PM_{10}/$PM_{2.5}$ emissions, collectively referred as "PM" emissions from the mechanical draft auxiliary cooling system for the Project that is anticipated to be a 14-cell tower design. The cooling system uses 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 C, Table C-10, the most stringent BACT limit for auxiliary cooling system is high efficiency 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 or less 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 auxiliary cooling system.

4.7 Emergency Diesel Generators and Fire Pump Engine

The emergency diesel generators and fire pump engine 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 diesel generators and the fire pump engine will utilize ULSD oil. 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.

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 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 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.

Golder Associates

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.

EPA's RBLC database of CO_2e BACT determinations for natural gas-fired combined-cycle units is presented in Appendix C, Table C-11. All the BACT determinations have been based on the efficiency.

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 Sec. 169(3), 42 U.S.C. §7479(3)(2013).

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 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 2.27 million short tons from each of the Project’s CTs, the annual cost for separation alone would be about $160 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 2.27 million TPY including distillate oil firing (Table A-17). 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 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_4 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 0.05 percent of total CO_2e emissions and is about 970 tons CO_2e/CT. The secondary emission caused by the backpressure was estimated to be over 5,000 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), 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 1,000 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 HHV. A heat rate of 3,413 British thermal unit per kilowatt hour (Btu/kWh) reflects an efficiency of 100 percent from thermal energy to electrical energy.

The proposed combined cycle units’ net heat rate and energy efficiency were compared to data obtained from the U.S. Energy Information Administration (EIA). Based on data provided in the Electric Power Annual summary for 2015, the approximate heat rate for electricity for fossil fueled power plants in the U.S. in 2015 was 9,211 Btu/kWh net (HHV) (37.1 percent efficiency) (EIA, 2016 Tables 3.1a and Table 8.1).

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 7,878 Btu/kWh net (HHV) (43.3 percent efficiency) including all types of generation (EIA 2016 Table 8.1). Of the generation types, the average tested heat rates when firing natural gas are (EIA 2016, Table 8.2):

- Steam turbine generator – 10,059 Btu/kWh net (HHV) (33.9 percent efficiency),
- Natural gas turbine – 10,197 Btu/kWh net (HHV) (33.5 percent efficiency),
- Internal combustion – 9,923 Btu/kWh net (HHV) (34.4 percent efficiency), and
- Combined cycle – 7,603 Btu/kWh net (HHV) (44.9 percent efficiency).

The average base heat rate of DBEC when firing natural gas is anticipated to be 6,119 Btu/kWh net (HHV) (55.8 percent efficiency) based on an average ambient temperature of 75° F. For the same amount of generation at a 90 percent capacity factor, the efficiency of DBEC will result in approximately a half a million fewer tons of GHGs when compared to the combined cycle units efficiencies provided by EIA for 2014.

DBEC will be among the most efficient 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 (2/27/17 data: https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid; gross heat rate as HHV):

- State of Florida – 1,099.4 lb CO_2/MWh gross (HHV) for all generation (including nuclear); 1,275.9 lb CO_2/MWh for total combustion generation.
- FPL – 675.7 lb CO_2/MWh gross (HHV) for all generation (including nuclear); 881.9 lb CO_2/MWh gross (HHV) for total combustion generation.

The existing average GHG emission for Units 4 and 5 were 956 lb CO_2/MWh for the period 2012 through 2016. DBEC will emit more than 500,000 tons per year less of CO_2 emissions than Units 4 and 5 for the same amount of generation. In addition, when compared to the existing generation facilities in FPL's system for fossil combustion, the DBEC GHG emissions on a generation basis are lower and, when operated, will displace 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 DBEC 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 850 lb CO_2e/MWh when firing natural gas and 1,210 lb CO_2e/MWh for ULSD oil on a 12-month rolling average.

The proposed BACT emission limits are based on those approved by FDEP for OCEC that uses GE 7HA.02 CTs with a 3-on-1 design. These GHG emission limits are appropriate for three reasons.

First, OCEC is currently under construction and not yet operational using the GE 7HA.02 CTs. As shown in Appendix C. Table C-11, the GHG limit established for GE 7HA.02 CTs was for the Colorado Bend Energy Center. The GHG BACT limit for this project was equivalent to 880 lb CO_2e/MWh and it is just becoming operational. The latest GE 7HA CTs to be used for DBEC is in the design stage but based on the smaller 7HA.02 CT. The 7HA CT that will be used for DBEC has a nominal generating capacity of 400 MW while the smaller 7HA.02 CT has a nominal generating capacity of 330 MW. It is appropriate and reasonable to use the most stringent GHG limits for a similar combined cycle unit.

Second, FPL's combined cycle plants are not run as base load units but rather cycled at different loads and configurations. This was demonstrated in the Air Construction/PSD application for OCEC. FPL's newest 3-on-1 combined cycle units such as 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 demonstrated significant unit cycling with significant amounts of part load (60 percent) and different unit operation (i.e. 2-on-1 and 1-on-1). This operation occurred even though these units are relatively new to FPL's fleet.

Third, FPL is rapidly developing solar projects that can change unit dispatching since the generation profile of solar is only during the daytime with an average capacity factor of 27 percent. FPL will increase solar generation by ten-fold over that installed in 2016 and has projected to have 2,420 MW capacity of cost-effective solar by 2023 (FPL, 2017). Over the life of Unit 7, the operating profile will vary with more cycling expected as solar generating capacity increases.

Taken together the similarity of OCEC and DBEC, demonstrated load cycling of FPL's combined cycle plants, increasing solar power and the early development of the latest CTs that will be used for DBEC, the proposed BACT limits are appropriate and reasonable. The proposed BACT emission limits for GHG of 850 lb CO e/MWh for natural gas firing, and 1,210 lb CO e/MWh for ULSD oil firing should accommodate the changes in operating conditions over the 30-year life of Unit 7.

FPL proposes an output based 12-month 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 = 850 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 C, Table C-11. Moreover, this proposed BACT emission limit is 150 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 100 lbs of SF_6. Based on a leak rate, of less than 1.0 percent/year, the estimated GHG emissions from the circuit breakers are as follows:

- 100 lb SF_6 x 0.01 leakage/year = 1.0 lb SF_6/year
- 1.0 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 = 11.4. 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. Average leak rate estimates range from an upper bound of 2.5 percent to a lower bound of 0.2 percent (Blackman, J, et. al., 2016). Over the life of a circuit breaker the National Electrical Manufacturers Association (NEMA) SF_6 management guidelines specify a total equipment leakage of 5 percent or 0.1 percent per year (NEMA, 1998). 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.

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, 2014; (SF_6 Emission Reduction Partnership for Electric Power Systems, 2013 Annual Report, April 2014)].

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 no more than 1 percent that are thoroughly tested, equipped with leak detection systems (density indication) and performing periodic inspections. Together these controls will minimize SF_6 fugitive emissions and potential CO_2e emissions by 99 percent.

SF_6 breakers will be monitored to confirm that SF_6 integrity is maintained. In the event of an indication, 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.

4.8.3 BACT Analysis for Auxiliary Boiler, Emergency Diesel Generators, Natural Gas Heater, and Emergency diesel fire Pump Engine

The auxiliary boiler, emergency diesel generators, natural gas heaters, and emergency diesel fire pump engine are all necessary support facilities for the operation of DBEC. 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 amount due to their function. The emergency diesel generators and emergency diesel fire pump 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, and these events 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 DBEC and are not by themselves an individual unit GHG issue. Rather, the GHG emissions of an entire project like DBEC are the most relevant factor in reviewing these sources. As demonstrated in Section 4.3.1, DBEC will be among 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 diesel generators, natural gas heaters and emergency diesel fire pump engine. 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 diesel generators, natural gas heaters and emergency diesel fire pump engine 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 diesel generators and emergency 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 CCS. CCS is not practical for CO_2 emissions from the auxiliary boiler, emergency diesel generators, natural gas heaters, and emergency 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 diesel generators and emergency 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 diesel generators, natural gas heaters, and emergency 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 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 diesel generators, natural gas heater, and emergency diesel fire pump engine is energy efficiency through the operation of these emissions units to meet the DBEC 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 emission factors include N_2O and CH_4 at the equivalent rates. Therefore, firing natural gas 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 and is selected as BACT for the GHG emissions from the auxiliary boiler, emergency diesel generators, natural gas heaters, and emergency diesel fire pump engine. 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 DBEC requirements. Thus, fuel use is optimized resulting in lower GHG emissions than if these units operate continuously.

The auxiliary boiler, emergency diesel generators, natural gas heater, and emergency diesel fire pump engine together accounts for less than 0.5 percent of the total GHG emissions potential of the DBEC 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, DBEC will be among the most efficient combined cycle units in the U.S. GHG emissions on a lb/MW-hr basis from DBEC will be among 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 diesel generators and fire pump engine are limited to 100 hours or less during non-emergency situations (unlimited in true emergency events); 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, and operational limits the auxiliary boiler, natural gas heaters, emergency diesel generators, and fire pump engine is proposed as BACT rather than a numerical GHG emission limit. This is consistent with the FDEP BACT determinations of GHG emissions from these sources that have limited use, use low-emitting GHG fuels and function efficiently (FDEP Technical Evaluation and Preliminary Determination for OCEC, Draft Permit No. PSD-FL-434, Project No. 0930117-001-AC, January 12, 2016).

5.0 AMBIENT MONITORING ANALYSIS

Pre-construction ambient monitoring analyses may be required for PM_{10}, $PM_{2.5}$, SO_2, SO_2 .and CO, and ozone (O_3) (based on VOC emissions) because PSD review is applicable to these air pollutants. 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 and SO_2 (Table 5-1). 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.

For O_3, the Project's VOC emissions are less than 100 TPY while NO_X emissions are reduced by more than 600 TPY. Although pre-construction ambient monitoring analysis is generally required for O_3, the NO_x emissions reduction more than offsets the increase in VOC emissions.

The maximum predicted 24-hour PM_{10} concentration is predicted to be greater than the SMC only for the scenario of proposed GE CTs firing USLD fuel oil, the backup fuel.

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.

FDEP has provided the following reference concentrations based on 2016 monitoring data to be used as non-modeled background concentrations for the proposed Project:

- PM_{10} from monitor 011-0010 [in micrograms per cubic meter ($\mu g/m^3$)]: Annual – 12.4; highest 24-hr - 43; 2nd highest 24-hr – 41
- $PM_{2.5}$ from monitor 011-2003 (in $\mu g/m^3$): Annual design value – 15; 24-hr design value – 6.5

An exemption from the pre-construction monitoring requirement is applicable pursuant to Rule 62-212.400(3)(e), F.A.C. In addition, ambient 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. The above data are being used to satisfy the pre-construction monitoring requirements for PM_{10} and $PM_{2.5}$ and indicate that the design air quality concentrations measured in the area are below the applicable PM_{10} and $PM_{2.5}$ AAQS.

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 2-on-1 combined-cycle unit. FPL will utilize GE's latest offering of the 7HA CTs. The CTs will have HRSGs, which will utilize the waste heat from each CT to produce steam to be utilized in a single steam turbine generator. The unit will be fired with natural gas as the primary fuel with the potential for up to 1,000 hr/yr of ULSD fuel oil as the backup fuel. The unit will also have a 14-cell mechanical draft auxiliary cooling system. As described in Section 1.0, the project will also include the following ancillary equipment: an auxiliary boiler that will only be used for construction and possibly for unit startup, two emergency diesel generators and a fire pump engine. Due to the highly intermittent operation of the ancillary equipment, the emissions from the ancillary equipment were not included in the assessment.

The proposed Project will be located in the general area currently occupied by Units 4 and 5 that will be removed prior to the construction and operation of the new CC unit.

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

6.1.1 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 16216r) 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

6.1.2 Project Sources

Air quality analyses were performed to assess the maximum impacts of the new 2-on-1 combined cycle unit and the auxiliary cooling system. 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. 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 system cell stack heights will be 60.6 ft with inner diameters of 31.625 ft. The cooling system deck height will be 46.8 ft and the cooling system is included as a one of the proposed structures in the building downwash analysis.

6.1.3 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 system 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
Auxiliary Cooling System	46.8	84	336

6.1.4 Meteorological Data

Meteorological data used in AERMOD to estimate air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and upper air sounding data collected from the National Weather Service (NWS) stations located at Ft. Lauderdale-Hollywood International Airport (FLL) and Florida International University (FIU) in Miami, respectively. The 5-year period of the meteorological data was from 2012 through 2016 and was prepared by the FDEP using AERMET Version 16216. 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 FLL is located approximately 5 km (3 miles) east of the Project site. All areas between FLL and the proposed Project site are flat with very similar land characteristics. As such, the meteorological parameters collected at FLL are considered to be representative of those that exist at the Project site.

6.1.5 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 by the maximum distance of the Project's pollutant-specific significant impact.

6.1.6 CT Load Analysis/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 requiring PSD review and averaging times:

- 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 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 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 SO_2 and PM_{10} concentrations are based on maximum predicted concentrations for any year over the 5-year period.

The predicted annual average impacts for the significant impact analysis are based on the CT/HRSGs operating 8,760 hr/yr with ULSD oil-firing for each CT/HRSG limited to 1000 hr/yr. For pollutants with higher predicted impacts occurring during ULSD oil-firing, the predicted annual impact is based on the maximum of 1,000 hr/yr of ULSD oil-firing and natural gas firing during the remaining 7,760 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 impacts identified for each pollutant.

It should be noted that In January 2013, the U.S. Court of Appeals for the D.C. Circuit vacated and remanded to EPA the $PM_{2.5}$ SIL under 40 CFR 51.166(k)(2) and 40 CFR 52.21(k)(2) portions of EPA's rule exempting 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, the maximum predicted impacts for annual PM_{10}, 1- and 8-hour CO and 1-, 3-, 24-hour and annual SO_2 were less than the SIL. As such, no further modeling analyses are required for these pollutants and averaging times. The maximum annual and 24-hour $PM_{2.5}$ and 24-hour PM_{10} concentrations were predicted to exceed the SIL and will, therefore, require additional modeling to demonstrate compliance with the NAAQS and allowable PSD Class II increments.

6.1.7 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.

When addressing the NAAQS for 24-hour $PM_{2.5}$, the 5-year averaged 98th percentile 24-hour average concentration at each receptor is determined and the highest of these values is used to estimate compliance. For annual averaged $PM_{2.5}$, the highest 5-year 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. When addressing the allowable annual average $PM_{2.5}$ increment, the highest predicted concentration in any year is used to estimate compliance.

6.1.8 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 9.0 and 3.2 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, these facilities 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 6-1 and 6-2, respectively. Based on the results of the facility screening, additional background sources at FPL’s Port Everglades Plant and at Wheelabrator South-Broward, as well as existing sources at FPL Lauderdale, were identified for inclusion in the NAAQS and PSD Class II increment analyses. $PM_{2.5}$ increment-expanding sources include Lauderdale Units 4 and 5, to be retired by the proposed Project as well as the Gas Turbines that were retired at the Lauderdale and Port Everglades plants in 2016.

6.1.9 Non-Modeled Background Concentrations

Summaries of measured ambient concentrations were provided by FDEP for use as non-modeled background concentrations. The background concentrations are based on averages of monitor measurements in the vicinity of the Project site from 2014 to 2016. The annual and 24-hour $PM_{2.5}$ concentrations are based on measurements taken at monitoring station 011-2003 in Pompano Beach Highlands and indicate design concentrations of 6.5 and 15.0 μg/m^3, respectively. The annual and 24-hour PM_{10} concentrations are based on measurements taken at monitoring station 011-0010 in Fort Lauderdale and indicate design concentrations of 12.4 and 41 μg/m^3, respectively.

6.1.10 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 Project involves the construction and operation of new Unit 7 that will replace existing Units 4 and 5. The emissions increases from Unit 7 and actual emission decreases from Units 4 and 5 will result in increases of $PM_{2.5}$ precursor pollutants SO_2 and VOC of up to 196 TPY and 134 TPY, respectively. However, there will be a 1,655 TPY decrease in NOx emissions relative to the actual emissions from Units 4 and 5. The large decrease in NO_X emissions will result in an overall decrease in the formation of secondary $PM_{2.5}$ pollutants for this Project. In contrast to primary $PM_{2.5}$, 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. Due to a significant reduction in NO_X emissions from the Project alone, the proposed Project is expected to result in decreased secondary formation of $PM_{2.5}$ in the vicinity of the plant.

Finally, the significant NO_X emission reductions from this Project also must be considered along with other NO_x and SO_2 reductions in southern Florida that resulted from several FPL modernization projects at existing power plants. The recent PEEC Project located approximately 5 miles east northeast of the DBEC location had NO_x and SO_2 reduction of 3,878 TPY and 9,238 TPY, respectively. Other modernization project in southern Florida and the NO_x and SO_2 reductions were:

- Riviera Beach Energy Center Project
  - NO_x reduction – 3,305 TPY
  - SO_2 reduction – 10, 787 TPY

- Fort Myers CT Project
  - NO_x reduction – 5,250 TPY
  - SO_2 reduction – 20,424 TPY

6.1.11 Model Results

6.1.11.1 Significant Impact/CT Load Analysis

The results of the modeling analysis to determine the maximum impacts for the 9 possible CT/HRSG load and compressor inlet temperatures are presented in Appendix D, Table D-1 for natural gas firing and Table D-2 for ULSD firing. The predicted maximum project-only impacts due to the 2 CT/HRSGs only and also 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 6-3. The results in Table 6-3 are based on either the CT/HRSGs firing either natural gas for an entire year (8,760 hr/yr) or firing natural gas for 7,760 hr/yr and firing ULSD oil for 1,000 hr/yr. Based on the results presented in Table 6-3, the proposed project's maximum impacts are predicted to be greater than the SIL for 24-hour PM_{10} and 24-hour and annual $PM_{2.5}$ concentrations. As such, cumulative source modeling analyses are required for these pollutants and averaging times to determine compliance with the NAAQS and allowable PSD Class II increments.

6.1.11.2 NAAQS Analysis Results

The NAAQS modeling results are summarized in Table 6-4. When firing ULSD oil, the backup fuel, the maximum predicted 24-hour $PM_{2.5}$ concentration due to all modeled sources plus a background concentration is 28.4 μg/m^3 which is less than the NAAQS of 35 μg/m^3. The maximum predicted concentration is located in the vicinity of a background source. When firing 7,760 hr/yr of natural gas and 1,000 hours of ULSD oil, the maximum predicted annual average $PM_{2.5}$ concentration due to all modeled sources plus a background concentration is 8.9 µg/m^3 which is less than the NAAQS of 12 µg/m^3.

The NAAQS modeling results for 24-hour PM_{10} are also summarized in Table 6-4. The maximum predicted 24-hour $PM_{2.5}$ concentration due to all sources plus a background concentration is 61.1 µg/m^3 which is less than the NAAQS of 150 µg/m^3.

6.1.12 PSD Increment Analysis Results

The PSD increment modeling results for 24-hour $PM_{2.5}$ are summarized in Table 6-5. When firing ULSD oil, the maximum predicted 24-hour $PM_{2.5}$ increment is 8.7 µg/m^3 which is less than the allowable increment of 9 µg/m^3. When firing ULSD oil for 1,000 hr/yr, the maximum predicted annual average $PM_{2.5}$ increment is 0.3 µg/m^3 which is less than the allowable increment of 4 µg/m^3.

The PSD increment modeling results for 24-hour PM_{10} are also summarized in Table 6-5. The maximum predicted 24-hour PM_{10} increment is 9.7 µg/m^3 which is less than the allowable increment of 30 µg/m^3.

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

6.2.1 Model Selection and General Assumptions

For PSD Class I Areas, current FDEP modeling guidance indicates that AERMOD initially be used with a ring of 360 receptors spaced at 1-degree intervals to perform an initial assessment of impacts. For this analysis, a receptor ring with a radius distance of 47.7 km was used to represent the closest ENP approach to the proposed Project site. For this analysis, the elevations for all receptors were set to the highest receptor elevation in the ENP (i.e., 1 m).

If the highest concentrations are predicted to be less than the significant impact levels, no additional modeling is required to address Class I impacts. If the maximum predicted concentrations from the AERMOD analyses are greater than one or more PSD Class I SILs, a more refined Class I analysis can be performed using the California Puff (CALPUFF, Version 5.8.5 modeling system.

CALPUFF is a non-steady state Lagrangian puff long-range transport model that includes algorithms for chemical transformations (important for visibility pollutants) and wet/dry deposition. CALPUFF was used in a manner that is consistent with methodologies recommended in FLMs' AQRV Workgroup (FLAG) guidance document, revised in October 2010 and referred to as the FLAG Phase I Report and in subsequent discussions with the FLM.

Parameter settings to be used in CALPUFF were based on the latest regulatory guidance. Where the modeling guidance recommends regulatory model defaults, those defaults were used. For ozone background concentrations, observed hourly ozone data for 2001 to 2003 from CASTNET and AIRS stations were 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 were set to calculate wet and dry (i.e., total) fluxes and concentrations at each evaluated PSD Class I area.

6.2.2 Project Modeled Emissions

A CT load analysis was performed using AERMOD similar to that conducted for PSD Class II areas. The Project's emission, stack, and operating data as well as building dimensions were modeled for the emission sources as previously described in Subsections 6.1.2 and 6.1.6.

For CALPUFF modeling, 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.

6.2.3 Building Downwash Considerations

The same methods used in the PSD Class II analyses (Subsection 6.1.3) to assess building downwash were used in these analyses.

6.2.4 Meteorological Data

The AERMOD analysis used the same 5-year meteorological data base from FLL for the years 2012 to 2016 that was used for the site vicinity modeling.

For CALPUFF modeling meteorological and geophysical dataset were developed using CALMET Version 5.8 that 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 CALPUFF modeling analyses.

6.2.5 Receptor Locations

For predicting air quality impacts with AERMOD at the ENP, a ring of 360 receptors, spaced at 1-degree intervals and at a distance of 47.7 km from the proposed project was used. For predicting impacts with CALPUFF, 901 receptors developed by the Federal Land Managers for the ENP were used.

6.2.6 Significant Impact Analysis

Significant impact analyses were performed to assess the Project's impacts at the ENP PSD Class I area. The maximum predicted SO_2, PM_{10}, and $PM_{2.5}$ concentrations due to the proposed Project were compared to EPA's proposed PSD Class I SILs. If the proposed Project's maximum predicted impacts exceed a proposed EPA PSD Class I SIL 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 were modeled for comparison to the allowable PSD Class I increments.

The proposed PSD Class I significant impact levels that are applicable to the proposed Project are:

- SO_2: 3-hour – 1.0 µg/m^3, 24-hour – 0.2 µg/m^3, and annual average – 0.1 µg/m^3
- PM_{10}: 24-hour – 0.3 µg/m^3, and annual average – 0.2 µg/m^3
- PM_{10}: 24-hour – 0.27 µg/m^3, and annual average – 0.05 µg/m^3

6.2.7 Model Results

6.2.7.1 Significant Impact Analysis/CT Load Results

The results of the modeling analysis to determine the maximum impacts for the 9 possible CT/HRSG load and ambient temperatures in the PSD Class I Area are presented in Appendix D, Table D-3 for natural gas firing and Table D-4 for ULSD firing. The results of the analysis are presented in Table 6-6 and indicate that only the maximum predicted 24-hour PM_{10} and 24-hour $PM_{2.5}$ concentrations were greater than the SIL.

Based on the CT load analysis results, CALPUFF was used to refine the 24-hour PM_{10} and 24-hour $PM_{2.5}$ concentrations. The CALPUFF analysis results are summarized in Table 6-7 and indicate that the maximum predicted 24-hour PM_{10} and 24-hour $PM_{2.5}$ concentrations are less than the SIL. Based on the presented significant impact analysis results, the maximum predicted concentrations for all pollutants are less than the SIL. As such, additional modeling to determine compliance with the allowable Class I increment is not required.

7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts that the Project and general commercial, residential, industrial and other growth associated with the Project will have on vegetation, soils, and visibility in the vicinity of the site and impacts at the PSD Class I 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. However, no additional permanent workers will be employed for the operation of the facility as a result of the project. The workforce needed to construct and operate the facility represents a small fraction of the population already present in the region that includes Broward, Miami-Dade and Palm Beach 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 DBEC 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 DBEC 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.

Sulfur Dioxide

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When SO_2 in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury is usually evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis. Background levels of SO_2 range from 2.5 to 25 µg/m^3.

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak that are injured by exposure to 3-hour SO_2 concentrations of 790 to 1,570 µg/m^3. Intermediate plants, including locust and sweetgum are injured by exposure to 3-hour SO_2 concentrations of 1,570 to 2,100 µg/m^3. Resistant species (injured at concentrations above 2,100 µg/m^3 for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 µg/m^3 SO_2 for 8 hours were not visibly damaged. This finding supports the levels cited by other researchers on the effects of SO_2 on vegetation. Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 µg/m^3 for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 µg/m^3 SO_2 for 24 hours a day for 1 week demonstrated a 48-percent reduction in photosynthesis (Carlson, 1979).

SO_2 is considered to be the primary factor causing the death of lichens in most urban and industrial areas. Sensitive species are damaged or killed by annual average levels of SO_2 ranging from 8 to

30 µg/m^3, and very few lichens can tolerate levels exceeding 125 µg/m^3 (Johnson, 1979; DeWit, 1976; Hawsworth and Rose, 1970; LeBlanc et al., 1972). In another study, two lichen species exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 µg/m^3 for 6 hours/week for 10 weeks (Hart et al., 1988).

Nitrogen Dioxide

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

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the NAAQS. 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). Although physiological and behavioral effects have been observed in experimental animals at or below secondary NAAQS, the most severe of these effects have been observed at concentrations above the secondary NAAQS.

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 Project include upland shrub and brushland, mixed wetland hardwood/exotic wetland hardwoods and mangrove swamp. Common vegetative species within the upland shrub and brushland include Brazilian pepper (*Schinus terebinthifolius*), Virginia creeper (*Parthenocissus quiquefolia*), camphorweed (*Heterotheca subaxillaris*), nettletree (*Trema micrantha*), castor bean (*Ricinus communis*), muscadine (*Vitis rotundifolia*), climbing hempvine (*Mikania scandens*), bermudagrass (*Cynodon dactylon*), and bushy broomsedge (*Andropogon glomeratus*).

The mixed wetland hardwoods/exotic wetland hardwoods is comprised of a mixture of exotic and native species, including the exotics Australian pine, Brazilian pepper, and melaleuca (*Melaleuca quinquenervia*), as well as native species pond apple, swamp bay (*Persea palustris*), red maple (*Acer rubrum*), myrsine, and dahoon holly (*Ilex cassine*). A variety of understory species are present, including wild coffee tree (*Psychotria nervosa*), Carolina willow (*Salix caroliniana*), cocoplum, leather fern (*Acrostichum danaefolium*), Peruvian primrosewillow (*Ludwigia peruviana*) , royal palm (*Roystonea regia*), sawgrass (*Cladium jamaicense*), lance-leafed arrowhead (*Sagittaria lancifolia*), and pickerelweed (*Pontederia cordata*).

The mangrove swamp is dominated by native white mangrove and pond apple, with red mangrove (*Rhizophora mangle*) and black mangrove (*Avicennia germinan*s) also present, as well as scattered Australian pine. The shrub and groundcover layer includes the exotic species Brazilian pepper, shoebutton ardisia (*Ardisia elliptica*), and napiergrass, as well as native species cocoplum (*Chrysobalanus icaco*), saltwater falsewillow (*Baccharis angustifolia*), salt grass (*Distichlis spicata*), and hurricane grass (*Fimbristylis spathacea*).

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 decrease in NO_x emissions for Broward County.

7.3.2 Impacts on Wildlife

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the 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 Unit 7 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.

7.4 Impacts to the ENP PSD Class I Areas

7.4.1 Identification of AQRVs and Methodology

An AQRV analysis was conducted to assess the potential risk to AQRVs at the ENP due to the emissions from the proposed Project. The U.S. Department of the Interior in 1978 defined AQRVs to be:

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

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

7.4.2 Impacts to Soils

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

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

7.4.3 Impacts to Vegetation

7.4.3.1 Sulfur Dioxide

The maximum 3-hour SO_2 concentration due to the Project is predicted to be 0.4 µg/m^3 at the ENP. This is several orders of magnitude lower than the reported injury level discussed in Section 7.2.2. As a result, no significant effects to vegetative AQRVs within the ENP are expected as a result of the Project's SO_2 emissions.

7.4.3.2 Particulate Matter

The maximum 24-hour PM_{10} concentration due to the Project is predicted to be 0.3 µg/m^3 at the ENP. This impact is 0.14 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.

7.4.3.3 Carbon Monoxide

The maximum 1-hour average concentration due to the project is 0.39 µg/m^3 in the Class I area, which is less than 0.000006 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 concentration of 0.008 µg/m^3 reflects a more realistic, yet conservative, CO impact level for the Class I area. This maximum concentration is 0.00006 percent of the value that caused cytochrome *c* oxidase inhibition (6.85×10^5 µg/m^3).

7.4.3.4 VOC and NO_X Emissions and Impacts to Ozone

VOC and NO_x emissions are precursors to O_3 formation. Since the proposed Project includes the retirement of Units 4 and 5 emissions will actually decrease in the vicinity of Broward County.

7.4.3.5 Summary

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

7.4.4 Impacts to Wildlife

The maximum predicted impacts of the project in the Class I area are several orders of magnitude lower than values of potential impacts to wildlife (refer to Section 7.2.3). No effects on wildlife AQRVs from SO_2 and particulates are expected. The Project's contribution to cumulative impacts is negligible.

7.4.5 Impacts Upon Visibility

7.4.5.1 Introduction

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

Visibility is an AQRV for the ENP. Visibility can take the form of plume blight for nearby areas or regional haze for long distances (e.g., distances beyond 50 km). Because the closest approach of the ENP from the Project site is just under 50 km (approximately 48 km) the change in visibility was analyzed as regional haze and the following methodology was used to address AQRVs.

7.4.5.2 Methodology

Based on the FLAG Phase I Report(June 27, 2008), 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). The purpose of the visibility analysis is to calculate the extinction (explained below) at each receptor for each day 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 98th-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 was used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. For predicting visibility impairment, the FLAG guidance recommends using Method 8 (MVISBK = 8) and submode 5 (M8_MODE = 5). For this analysis, the background hygroscopic and non-hygroscopic aerosol levels were derived from the 20 percent best natural background days.

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

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

Results are provided for the proposed CTs firing natural gas (the primary fuel) and also ULSD fuel oil.

7.4.5.3 Results

The results of the visibility analysis at the ENP are presented in Table 7-1. When firing natural gas, the maximum predicted visibility impairment is 0.145 dv. For ULSD oil, the maximum predicted impact is 0.263 dv. These predicted visibility impairment values are well below the FLM's criteria of a 0.5 change in dv. As a result, the Project is not expected to have an adverse impact on the existing regional haze at the PSD Class I area of the ENP.

7.4.6 Sulfur and Nitrogen Deposition at the ENP and the CNWA

7.4.6.1 General Methods

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

For sulfur 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 2011). 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 DAT or significant impact levels.

7.4.6.2 Results

The maximum predicted total annual S depositions due to the proposed project at the ENP are summarized in Table 7-2. The maximum annual deposition rate is 0.0033 kg/ha/yr predicted for the Project which is well below the FLM's criteria of 0.01 kg/ha/yr.

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TABLES

TABLE 2-1 (GE)
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	^oF	177	180	182	184
Velocity	ft/sec	54.8	55.6	55.2	55.4
Maximum Hourly Emissions per CT					
SO_2	lb/hr	23.4	23.9	23.8	23.7
$PM/PM_{10}/PM_{2.5}$	lb/hr	17.6	17.8	17.6	17.6
NO_x	lb/hr	28.7	29.4	29.2	29.1
CO	lb/hr	49.6	50.7	50.4	50.2
VOC (as methane)	lb/hr	4.9	4.9	4.9	4.9
Sulfuric Acid Mist	lb/hr	4.5	4.6	4.6	4.6
75 Percent Load					
Temperature	^oF	171	171	176	182
Velocity	ft/sec	43.5	42.9	37.8	42.8
Maximum Hourly Emissions per CT					
SO_2	lb/hr	18.6	18.1	14.9	17.1
$PM/PM_{10}/PM_{2.5}$	lb/hr	16.0	15.9	14.8	15.9
NO_x	lb/hr	22.8	22.2	18.3	21.0
CO	lb/hr	39.7	39.0	34.0	37.6
VOC (as methane)	lb/hr	3.9	3.9	3.4	3.8
Sulfuric Acid Mist	lb/hr	3.62	3.51	2.90	3.32
Minimum Emission Compliance Load (MECL)					
Temperature	^oF	168	169	172	178
Velocity	ft/sec	28.8	28.5	29.3	31.0
Maximum Hourly Emissions per CT					
SO_2	lb/hr	10.3	10.0	10.4	11.0
$PM/PM_{10}/PM_{2.5}$	lb/hr	13.3	13.3	13.4	13.6
NO_x	lb/hr	12.6	12.3	12.7	13.5
CO	lb/hr	26.9	26.4	26.8	27.8
VOC (as methane)	lb/hr	2.6	2.6	2.6	2.8
Sulfuric Acid Mist	lb/hr	2.00	1.95	2.02	2.14

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

Source: GE, 2017; Golder Associates, 2017.

TABLE 2-2 (GE)
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	61.7	60.7	59.2	57.4
Maximum Hourly Emissions per CT					
SO_2	lb/hr	5.9	5.8	5.5	5.2
$PM/PM_{10}/PM_{2.5}$	lb/hr	61.6	61.6	61.5	61.5
NO_x	lb/hr	120.0	116.8	112.0	106.4
CO	lb/hr	114.8	112.6	108.7	103.8
VOC (as methane)	lb/hr	13.2	13.0	12.6	12.1
Sulfuric Acid Mist	lb/hr	1.150	1.120	1.074	1.020
Lead	lb/hr	0.05	0.05	0.05	0.05
75 Percent Load					
Temperature	°F	191	188	193	194
Velocity	ft/sec	48.2	45.9	44.4	42.5
Maximum Hourly Emissions per CT					
SO_2	lb/hr	4.6	4.5	4.3	4.0
$PM/PM_{10}/PM_{2.5}$	lb/hr	61.3	61.3	61.2	61.2
NO_x	lb/hr	93.9	90.5	86.6	81.6
CO	lb/hr	92.6	88.2	84.3	80.0
VOC (as methane)	lb/hr	10.5	10.1	9.7	9.2
Sulfuric Acid Mist	lb/hr	0.901	0.867	0.830	0.782
Lead	lb/hr	0.04	0.04	0.04	0.04
50 Percent Load					
Temperature	°F	175	174	177	180
Velocity	ft/sec	37.6	36.0	34.7	32.9
Maximum Hourly Emissions per CT					
SO_2	lb/hr	3.4	3.3	3.2	3.0
$PM/PM_{10}/PM_{2.5}$	lb/hr	61.0	61.0	60.9	60.9
NO_x	lb/hr	69.5	67.0	64.4	61.2
CO	lb/hr	77.1	73.5	69.8	65.3
VOC (as methane)	lb/hr	8.4	8.1	7.7	7.3
Sulfuric Acid Mist	lb/hr	0.667	0.643	0.618	0.587
Lead	lb/hr	0.03	0.03	0.03	0.03

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

Source: GE, 2017; Golder Associates, 2017.

TABLE 2-3 (GE)
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	7,760	0	2,880	0	3,880
							Fuel Oil 100 % Load	0	1,000	0	1,000	0	1,000
							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 MECL**	**ULSD Oil 75 °F 50%**	**TOTAL**	**8,760**	**8,760**	**8,760**	**8,760**	**8,760**	**8,760**
One CT/HRSG													
SO_2	23.8	5.5	14.9	4.3	10.4	3.2		104.2	95.0	65.2	71.1	45.5	69.0
$PM/PM_{10}/PM_{2.5}$	17.6	61.5	14.8	61.2	13.4	60.9		77.3	99.2	65.0	91.7	58.9	91.1
NO_x	29.2	112.0	18.3	86.6	12.7	64.4		127.9	169.3	80.0	139.9	55.8	137.4
CO	50.4	108.7	34.0	84.3	26.8	69.8		220.8	249.9	148.8	206.3	117.5	204.2
VOC (as methane)	4.9	12.6	3.4	9.7	2.6	7.7		21.4	25.3	14.8	21.2	11.5	20.9
Sulfuric Acid Mist	4.6	1.1	2.9	0.8	2.0	0.6		20.3	18.5	12.7	13.8	8.8	13.4
Lead	0.0	0.050	0.0	0.039	0.0	0.029		0.0	0.0	0.0	0.0	0.0	0.0
HAPs	3.55	4.64	2.66	3.48	1.42	2.32		15.5	16.1	11.7	13.3	6.2	12.0
Two CT/HRSGs													
SO_2	47.6	11	29.8	9	20.8	6		208	190	130	142	91	138
$PM/PM_{10}/PM_{2.5}$	35.3	123	29.7	122	26.9	122		154.5	198.4	129.9	183	118	182
NO_x	58.4	224	36.5	173	25.5	129		256	339	160	280	112	275
CO	100.8	217	68.0	169	53.7	140		442	500	298	413	235	408
VOC (as methane)	9.8	25.2	6.7	19.3	5.3	15.4		42.8	50.5	29.5	42.4	23.1	41.8
Sulfuric Acid Mist	9.3	2.1	5.8	1.7	4.0	1.2		40.5	37.0	25.4	27.6	17.7	26.9
Lead	0.00	0.10	0.00	0.08	0.00	0.06		0.00	0.050	0.00	0.050	0.00	0.050
HAPs	7.10	9.27	5.33	6.95	2.84	4.64		31.1	32.2	23.3	26.6	12.4	23.9

Source: GE, 2017; Golder Associates, 2017.

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

Sources: FPL, 2017; Golder; 2017.
[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	^oF	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.
Sources: FPL, 2017; Golder; 2017.

TABLE 2-6

PERFORMANCE AND EMISSION DATA FOR THE EMERGENCY DIESEL GENERATORS

Parameter		Units	Values	
Performance [a]				
Number of Units			1	2
Rating (brake)		kW	3,298	6,596
Rating (brake)		hp	4,423	8,845
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	59
Fuel usage		gal/hr	214.2	428
Maximum operation/yr		hours	100	200
Maximum fuel usage		gal/yr	21,420	42,840
Stack Parameters (typical) [a]				
Diameter		ft	1.2	1.2
Height		ft	30	30
Temperature		^{o}F	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	0.091
		TPY	0.0023	0.0045
NO_x -	Basis	g/kW-hr	6.4	
	Emission rate	lb/hr	46.5	93.1
		TPY	2.3	4.7
CO -	Basis	g/kW-hr	3.5	
	Emission rate	lb/hr	25.4	51
		TPY	1.3	2.5
VOC -	Basis	g/kW-hr	0.2	
	Emission rate	lb/hr	1.5	2.9
		TPY	0.07	0.15
$PM/PM_{10}/PM_{2.5}$ -	Basis	g/kW-hr	0.2	
	Emission rate	lb/hr	1.5	2.9
		TPY	0.07	0.15

Sources: FPL, 2017; Golder; 2017.

[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 DIESEL 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

PHYSICAL, PERFORMANCE, AND EMISSIONS DATA FOR THE MECHANICAL DRAFT AUXILIARY COOLING SYSTEM

Parameter	2 x 1 (Maximum)	2 x 1 (Annual)
Physical Data		
Number of Cells	14	14
Deck Dimensions, ft		
Length	336	336
Width	84	84
Height	46.8	46.8
Stack Dimensions		
Height, ft	60.6	60.6
Stack Top Effective Inner Diameter, per cell, ft	32	32
Effective Diameter, all cells, ft	118.3	118.3
Performance Data		
Discharge Velocity, ft/min	1,734	1,734
Water Flow Rate (CWFR), gal/min	232,908	114,964
Design Air Flow Rate per cell, acfm	1,362,000	1,362,000
Hours of operation	8,760	8,760
Temperature of Exit Air, °F	85.3	85.3
Emission Data		
Drift Rate[a] (DR), percent	0.0005	0.0005
Total Dissolved Solids (TDS) Concentration [b], maximum ppm	35,000	35,000
Solution Drift [c] (SD), lb/hr	582.7	287.6
PM Drift [d], lb/hr	20.4	10.1
tons/year	NA	44.1
PM_{10} Drift[e]		
PM_{10} Emissions, lb/hr	0.89	0.44
tons/year	NA	1.93
$PM_{2.5}$ Emissions, lb/hr	0.01	0.003
tons/year	NA	0.01

[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, 2017; Golder; 2017.

TABLE 2-9 (GE)
SUMMARY OF POTENTIAL ANNUAL EMISSIONS FOR THE DBEC PROJECT

	DBEC Project Potential Annual Emissions (TPY)							PSD Significant Emission Rate
Pollutant	2 CTs/HRSGs Circuit Breakers [a]	1 Auxiliary Boiler [b]	1 Natural Gas Heater	2 Emergency Generators	1 Fire Pump Engine	1 Cooling Tower	TOTAL	(TPY)
SO_2	208	0.56	0.24	0.005	0.00021	--	209	40
PM	198	0.74	0.32	0.15	0.005	44.10	244	25
PM_{10}	198	0.74	0.32	0.15	0.005	1.93	202	15
$PM_{2.5}$	198	0.74	0.32	0.15	0.00	0.003	202	10
NO_x	339	4.99	4.25	4.65	0.13	--	353	40
CO	500	7.98	3.57	2.54	0.031	--	514	100
VOC (as methane)	50.5	0.54	0.23	0.15	0.003	--	51.4	40
Sulfuric Acid Mist	40.5	Neg.	Neg.	Neg.	Neg.	--	40.5	7
Lead	0.050	Neg.	Neg.	Neg.	Neg.	--	0.050	0.6
Greenhouse Gases (CO_2e)	4,532,985	11,671	5,072	482	22.5	--	4,550,233	75,000

[a] Based on oil-firing for: 1,000 hours (maximum).; includes 7 circuit breakers with SF_6: 11.40 tons CO_2e/year
[b] An auxiliary boiler is only required to supply steam during startup.
Note: Neg.= negligible; NA= not applicable
Source: Golder, 2017.

TABLE 2-10 (GE)
SUMMARY OF POTENTIAL ANNUAL HAP EMISSIONS FOR THE DBEC PROJECT

Pollutant	Potential Annual Emissions (TPY)						HAP Major Source Threshold (TPY)
	2 CTs/HRSGs	1 Auxiliary Boiler [b]	2 Emergency Generators	1 Natural Gas Heater	1 Fire Pump Engine	TOTAL	
GE 7HA CTs							
Total HAPs	18.1	0.0088	0.005	0.004	0.0002	18.1	25
Single HAP [a]	7.5	0.0073	0.0002	0.003	0.00001	7.5	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 emitted from the circuit breakers is not a HAP.

Source: Golder, 2017.

TABLE 2-11
ANNUAL AVERAGE AND CONSECUTIVE TWO-YEAR AVERAGE EMISSIONS FOR FORT LAUDERDALE UNITS 4 AND 5, 2012-2016

	Annual Emissions for Units 4&5					Two-Year Average Emissions			
Pollutant	2016	2015	2014	2013	2012	2016-2015 (tons)	2015-2014 (tons)	2014-2013 (tons)	2013-2012 (tons)
NO_x	1,303.4	1,920.8	1,966.3	2,020.8	1,830.0	1,612.1	1,943.5	1,993.5	1,925.4
CO	33.4	35.6	27.4	181.1	168.6	34.5	31.5	104.3	174.9
SO_2	12.8	11.5	11.8	13.3	11.0	12.2	11.6	12.5	12.1
VOC	3.7	5.3	4.7	0.1	0.0	4.5	5.0	2.4	0.1
PM	23.7	34.9	122.9	126.3	117.6	29.3	78.9	124.6	122.0
PM_{10}	23.7	34.9	122.9	126.3	117.6	29.3	78.9	124.6	122.0
$PM_{2.5}$ [a]	23.7	34.9	122.9	126.3	117.6	29.3	78.9	124.6	122.0
SAM [b]	2.0	1.8	1.8	2.0	1.7	1.9	1.8	1.9	1.9
CO_2	1,478,722.3	2,182,101.3	2,212,354.1	2,320,681.1	2,150,069.3	1,830,411.8	2,197,227.7	2,266,517.6	2,235,375.2
N_2O [c] (CO_2e)	831.4	1,207.2	1,223.9	1,283.9	1,170.6	1,019.3	1,215.5	1,253.9	1,227.3
CH_4 [c] (CO_2e)	689.6	1,012.0	1,026.0	1,076.4	981.8	850.8	1,019.0	1,051.2	1,029.1

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

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

[c] Calculated based on actual annual heat input - see Table 3.

Source: Annual Operating Report (AOR) for Fort Lauderdale Power Plant, 2012 - 2016; EPA's Acid Rain database.

TABLE 2-12 (GE)
SUMMARY OF POTENTIAL ANNUAL EMISSIONS FOR DBEC AND NET EMISSION INCREASES/DECREASES

Pollutant	DBEC Project Potential Emissions (TPY)			Emission Increases (TPY) (Lauderdale Units 6A - 6E)	Emission Decreases (TPY) (Lauderdale Units 4 & 5)	Net Emissions Increases and Decreased (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Required?
	2 CTs/HRSGs and Circuit Breakers	Auxiliary Emission Sources	TOTAL PROJECT	"Potential Emissions"	"Baseline Actual Emissions"			
SO_2	208	0.8	209	110.2	13	307	40	Yes
PM	198	45.3	244	139.1	125	258	25	Yes
PM_{10}	198	3.1	202	139.1	125	216	15	Yes
$PM_{2.5}$	198	1.2	200	139.1	125	214	10	Yes
NO_x	339	14.0	353	1,009.1	1,994	-632	40	No
CO	500	14.1	514	216.7	175	556	100	Yes
VOC (as methane)	50.5	0.9	51	36.2	5.0	83	40	Yes
Sulfuric Acid Mist	40.5	Neg.	41	16.9	1.9	56	7	Yes
Lead	0.050	Neg.	0	Neg.	Neg.	0.050	0.6	No
Greenhouse Gases (CO_2e) [a]	4,532,985	17,248	4,550,233	2,472,792	2,268,823	4,754,202	75,000	Yes

[a] Includes SF_6 Circuit Breakers: 11.40 tons CO_2e/year

Note: Neg.= negligible; NA= not applicable
Source: Golder, 2017.

TABLE 3-1
NATIONAL AND FLORIDA AAQS, ALLOWABLE PSD INCREMENTS AND SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	National and Florida AAQS (µg/m³) Primary Standard	National and Florida AAQS (µg/m³) Secondary Standard	PSD Increments (µg/m³) Class I	PSD Increments (µg/m³) Class II	Significant Impact Levels (µg/m³) Class I	Significant Impact Levels (µg/m³) 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	0.05	0.3
	24-Hour Maximum	35	35	2	9	0.27	1.2
Sulfur Dioxide [b]	Annual Arithmetic Mean	80	NA	2	20	0.1	1
	24-Hour Maximum	365	NA	5	91	0.2	5
	3-Hour Maximum	NA	1,300	25	512	1	25
	1-Hour Maximum	197	NA	NA	NA	NA	7.9 [e]
Carbon Monoxide	8-Hour Maximum	10,000	10,000	NA	NA	NA	500
	1-Hour Maximum	40,000	40,000	NA	NA	NA	2,000
Nitrogen Dioxide [c]	Annual Arithmetic Mean	100	100	2.5	25	0.1	1
	1-Hour Maximum	188	NA	NA	NA	NA	7.6 [e]
Ozone [d]	1-Hour Maximum	NA	NA	NA	NA	NA	NA
	8-Hour Maximum	147	147	NA	NA	NA	NA
Lead	Rolling 3-Month Average	0.15	0.15	NA	NA	NA	NA

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

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

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

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

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

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 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 4-1
PROPOSED BACT EMISSION LIMITS AND COMPLIANCE METHODS FOR DBEC

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	9 ppmvd (e.g., 5.4 to 6.9 ppmvd at 15% O_2 @ 75 ^oF)	Primary	Initial: EPA Method 10; 90 -100% of Baseload
	ULSD	Baseload	20 ppmvd (e.g.,12.7 to 14.3 ppmvd at 15% O_2 @ 75 ^oF)	Primary	Initial: EPA Method 10; 90 -100% of Baseload
	All	All	Work Practice	Secondary	Documentation of work practice standards.
VOC	Natural Gas	Baseload	1.4 ppmvw (e.g.,1.0 to 1.2 ppmvd at 15% O_2 @ 75 ^oF)	Primary	Initial Only: EPA Methods 18 or 25a
	ULSD	Baseload	3.5 ppmvw (e.g., 2.6 to 2.8 ppmvd at 15% O_2 @ 75 ^oF)	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
	NG/ULSD	Other [a]	20% Opacity	Secondary	Ten, 6-minute averaging periods during a calendar day; work practice.
	ULSD	Startup	40% 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	850 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.

Golder Associates

TABLE 4-2
CAPITAL COSTS FOR OXIDATION CATALYST FOR GE 7HA 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 4-3
ANNUALIZED COST FOR OXIDATION CATALYST FOR GE 7HA COMBUSTIONE 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	$535,569		0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$535,569		
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	$956,746		Sum of TDAC, TEC and TIAC
	86.50		Net CO Emission Reduciton to meet previous BACT Limits with oxidation catalyst
Cost Effectiveness	$11,061		per ton of CO Removed
	$12,782		Net Emission Reduction

TABLE 4-4
POTENTIAL INCREMENTAL EMISSION CHANGES (TPY) WITH OXIDATION CATALYST

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Pollutants		Incremental Emissions (TPY) Primary	Secondary	Total
Particulate		2.12	0.30	2.42
Sulfur Dioxide			0.11	0.11
Nitrogen Oxides			5.56	5.56
Carbon Monoxide		-86.50	3.34	-83.16
Volatile Organic Compounds			0.22	0.22
	Total:	-84.38	9.53	-74.85
Carbon Dioxide (additonal from gas firing)			5,282.38	5,282.38

TABLE 6-1
SUMMARY OF THE PM FACILITIES CONSIDERED FOR INCLUSION IN THE AIR MODELING ANALYSES

Facility ID	Facility Description	Site	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Dania Beach Facility [a] X (km)	Y (km)	Distance (km)	Direction (deg)	Potential Annual PM Emissions (TPY)	Q, (TPY) Emission Threshold [b,c] (Dist - SID) x 20	Include in Modeling Analysis ? [b]
Significant Impact Area [a]											
0110037	FLORIDA POWER & LIGHT COMPANY	FPL LAUDERDALE POWER PLANT (PFL)	579.7	2883.5	-0.6	-0.7	0.97	220	138.2	SIA	YES
0112119	WHEELABRATOR SOUTH BROWARD, INC	WHEELABRATOR SOUTH BROWARD	579.5	2883.3	-0.8	-0.9	1.15	221	98.4	SIA	YES
0112736	G & K SERVICES	G & K SERVICES	581.4	2883.6	1.1	-0.6	1.24	120	4.0	SIA	YES
0110036	FLORIDA POWER & LIGHT (PPE)	PORT EVERGLADES POWER PLANT	587.4	2885.3	7.1	1.1	7.18	81	81.0	SIA	YES
Modeling Area [a]											
0250407	DERBY BUILDING PRODUCTS, LLC	DERBY BUILDING PRODUCTS, LLC	577.5	2867.5	-2.8	-16.7	16.95	190	1.3	159.1	NO
0251334	TAURUS INTERNATIONAL MANUFACTURING, INC.	TAURUS INTERNATIONAL	572.1	2867.0	-8.2	-17.2	19.04	206	3.4	200.7	NO
0112633	NRNH PROPERTIES, INC.	N & N INVESTMENT CORPORATION DBA BARON M	585.2	2905.6	4.9	21.4	21.99	13	0.0	259.8	NO
0250020	TITAN FLORIDA LLC	TITAN-PENNSUCO COMPLEX	562.3	2861.7	-18.0	-22.5	28.83	219	354.3	396.7	NO
0251201	AEROSERVICIOS USA INC.	AEROSERVICIOS USA INC.	573.7	2855.7	-6.6	-28.5	29.28	193	0.0	405.6	NO
0250659	CEMEX CONSTRUCTION MATERIALS FLORIDA LLC	CEMEX FEC QUARRY (PREVIOUS.0250632)	558.5	2864.6	-21.8	-19.6	29.36	228	4.5	407.2	NO
0251313	HYDRO CONDUIT CORPORATION	MIAMI PIPE PLANT	560.8	2861.3	-19.6	-22.9	30.15	220	0.0	423.0	NO
0250348	MIAMI-DADE CO. DEPT. OF SOLID WASTE MGMT	MIAMI-DADE COUNTY RRF/COVANTA	564.5	2857.8	-15.8	-26.4	30.80	211	125.9	436.0	NO
0250945	TALLOWMASTERS L.L.C.	TALLOWMASTERS	558.7	2852.3	-21.7	-31.9	38.52	214	0.0	590.4	NO
0250014	CEMEX CONSTRUCTION MATERIALS FL. LLC.	MIAMI CEMENT PLANT	557.5	2852.1	-22.8	-32.1	39.42	215	130.0	608.4	NO
0250577	CAMILO OFFICE FURNITURE	CAMILO MUEBLES	568.5	2845.8	-11.8	-38.4	40.22	197	0.5	624.4	NO
0250314	MIAMI-DADE WATER AND SEWER DEPARTMENT	ALEXANDER ORR WATER TREATMENT PLANT	566.6	2843.3	-13.7	-40.9	43.12	199	12.9	682.4	NO
0250257	CEMEX CONSTRUCTION MATERIALS FLORIDA LLC	KROME QUARRY	550.2	2842.4	-30.1	-41.8	51.53	216	0.6	850.5	NO

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

Dania Beach Energy Center Facility East and North Coordinates (km) are: 580.30 km (E) 2884.2 km (N)
The significant impact distance for the project is estimated to be: 9 km

[a] "Significant Impact Area" is the area in which the project is predicted to have a significant impact (9.0 km). All sources within the significant impact area with emissions > 1 TPY were included in the analysis.

[b] Modeling area = SIA + 50 km. Sources for which potential annual emission rate in TPY > Q where Q = Distance x (20-SIA), were included in the cumulative modeling analysis.

TABLE 6-2
SUMMARY OF $PM_{2.5}$ SOURCES INCLUDED IN THE NAAQS MODELING ANALYSES

Facility ID	Facility Name / Emission Unit Description	EU ID	Modeling ID Name	UTM Location X (m)	UTM Location Y (m)	Stack Parameters Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	Stack Parameter Data Source	$PM_{2.5}$ Emission Rate 1-Hour (lb/hr)	1-Hour (g/sec)	Emissions Data Source
0110037	FLORIDA POWER & LIGHT (PFL)-FT. LAUDERDALE POWER PLANT																
	Simple cycle combustion turbine-electrical generator (Unit 6A)	053	CT6A	579,390	2,883,360	87.0	26.52	23.0	7.01	1086.0	858.7	114.6	34.9		50.00	6.30	
	Simple cycle combustion turbine-electrical generator (Unit 6B)	046	CT6B	579,390	2,883,360	87.0	26.52	23.0	7.01	1086.0	858.7	114.6	34.9		50.00	6.30	2017 FDEP PM2.5 Data Inventory
	Simple cycle combustion turbine-electrical generator (Unit 6C)	047	CT6C	579,390	2,883,360	87.0	26.52	23.0	7.01	1086.0	858.7	114.6	34.9	2017 FDEP PM2.5 Data Inventory	50.00	6.30	
	Simple cycle combustion turbine-electrical generator (Unit 6D)	048	CT6D	579,390	2,883,360	87.0	26.52	23.0	7.01	1086.0	858.7	114.6	34.9		50.00	6.30	
	Simple cycle combustion turbine-electrical generator (Unit 6E)	049	CT6E	579,390	2,883,360	87.0	26.52	23.0	7.01	1086.0	858.7	114.6	34.9		50.00	6.30	
	Gas Turbine 1		GT1	580,243	2,883,661	45.0	13.72	15.6	4.75	860.0	733.2	93.3	28.43		8.42	1.06	AP-42, Table 3.1-2a
	Gas Turbine 2		GT2	580,245	2,883,606	45.0	13.72	15.6	4.75	860.0	733.2	93.3	28.43		8.42	1.06	AP-42, Table 3.1-2a
0112119	WHEELABRATOR SOUTH BROWARD, INC																
	863 TPD MSW Combustor & Auxiliary Burners- Units 1 - 3	001-003	WHEEL	579,540	2,883,340	195.0	59.44	7.5	2.29	300.0	422.0	63.8	19.4	2017 FDEP PM2.5 Data Inventory	22.47	2.83	0112119-020-AV Permit Renewal Application
0112736	G & K SERVICES																
	Five Industrial Boilers	003	G&K	581,370	2,883,570	26.0	7.92	2.0	0.61	180.0	355.4	51.4	15.7	2017 FDEP PM2.5 Data Inventory	2.50	0.32	2017 FDEP PM2.5 Data Inventory
0110036	FLORIDA POWER & LIGHT (PPE)-PORT EVERGLADES POWER PLANT																
	Unit 5A nominal 250 MW CTG and HRSG	020	CT1A	587,400	2,885,300	149.0	45.42	22.0	6.71	355.0	452.6	72.8	22.2		55.0	6.93	
	Unit 5B nominal 250 MW CTG and HRSG	021	CT1B	587,400	2,885,300	149.0	45.42	22.0	6.71	355.0	452.6	72.8	22.2	Application No. 0110036010AC (fuel oil)	55.0	6.93	Application No. 0110036010AC (PSD avoidance)
	Unit 5C nominal 250 MW CTG and HRSG	022	CT1C	587,400	2,885,300	149.0	45.42	22.0	6.71	355.0	452.6	72.8	22.2		55.0	6.93	

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

TABLE 6-3
SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR NATURAL GAS AND ULSD OIL FIRING, DBEC

Pollutant	Averaging Time	Concentrations (µg/m^3) Natural Gas Modeled as 8760 Hrs/Yr	ULSD Oil Modeled as 8760 Hrs/Yr	Max. 7760 hrs/yr Natural Gas & Max. 1000 Hrs/Yr ULSD Oil	Max. Impact for SIL	EPA Class II Significant Impact Levels (µg/m3)
SO_2	Annual	0.29	0.06	0.26	0.29	1
	24-Hour	2.30	0.50	2.3	2.3	5
	3-Hour	6.26	1.34	6.3	6.3	25
	1-Hour	4.97	0.98	5.0	5.0	7.86
PM_{10}	Annual	0.31	1.17	0.41	0.41	1
	24-Hour	2.97	10.12	10.1	10.1	5
$PM_{2.5}$	Annual	0.28	1.06	0.37	0.37	0.3
	24-Hour	2.17	7.64	7.6	7.64	1.2
CO	8-Hour	10.1	21.3	21.3	21.3	500
	1-Hour	20.1	37.3	37.3	37.3	2,000
With Cooling Tower						
PM_{10}	Annual	0.5	1.3	0.59	0.59	1
	24-Hour	3.4	10.5	10.5	10.5	5

Maximum Hours of Fuel Usage

Natural Gas	8,760
Fuel Oil	1000

TABLE 6-4
MAXIMUM PREDICTED 24-HOUR PM_{10} AND $PM_{2.5}$ IMPACTS COMPARED TO NAAQS

Pollutant Averaging Time and Rank	Maximum Concentration ($\mu g/m^3$)			Receptor Location		NAAQS ($\mu g/m^3$)
	Total	Modeled Sources[a]	Background	UTM- East (m)	UTM- North (m)	
PM_{10} (Oil)						
24-Hour, H6H	61.1	18.1	43.0	581,290	2,883,570	150
$PM_{2.5}$ (Oil)						
24-Hour, 98th Percentile	28.4	13.4	15.0	581,190	2,883,570	35
Annual, highest	8.9	2.4	6.5	581,190	2,883,570	12

H6H = highest sixth-highest

[a] Concentrations are based on concentrations predicted using 5 years of meteorological data from 2012 to 2016 consisting of surface and upper air data from the weather stations at Fort Lauderdale-Hollywood International Airport and FIU, Miami respectively.

TABLE 6-5
MAXIMUM PREDICTED 24-HOUR PM_{10} AND $PM_{2.5}$ IMPACTS FROM ALL PSD-AFFECTING SOURCES COMPARED TO THE ALLOWABLE PSD CLASS II INCREMENTS

Averaging Time and Rank	Maximum Concentration [a] ($\mu g/m^3$)	Receptor Location UTM- East (m)	Receptor Location UTM- North (m)	Allowable PSD Class II Increment ($\mu g/m^3$)
PM_{10} (Oil)				
24-HR, H2H	9.7	579,690	2,883,270	30
$PM_{2.5}$ (Oil)				
24-HR, H2H	8.7	579,690	2,883,270	9
Annual, highest	0.3	579,790	2,883,970	4

H2H = Highest, Second Highest

[a] Concentrations are based on concentrations predicted using 5 years of meteorological data from 2012 to 2016 consisting of surface and upper air data from the weather stations at Fort Lauderdale-Hollywood International Airport and FIU, Miami respectively.

Table 6-6: Summary of Maximum Class I (ENP) Concentrations Predicted for Natural Gas and ULSD Oil Firing, DBEC

Pollutant	Averaging Time	Concentrations (µg/m³)[a] Natural Gas Modeled as 8760 Hrs/Yr	ULSD Oil Modeled as 8760 Hrs/Yr	Max. 7760 hrs/yr Natural Gas & Max. 1000 Hrs/Yr ULSD Oil	Max. for Comparison to SIL	EPA Class I Significant Impact Levels (µg/m3)
SO_2	Annual	0.01	0.00	0.01	0.01	0.1
	24-Hour	0.11	0.02	0.1	0.1	0.2
	3-Hour	0.40	0.08	0.4	0.4	1.0
PM_{10}	Annual	0.01	0.03	0.01	0.01	0.2
	24-Hour	0.09	0.36	0.36	0.36	0.3
$PM_{2.5}$	Annual	0.01	0.02	0.01	0.01	0.05
	24-Hour	0.07	0.29	0.29	0.29	0.27

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data and ring of 360 receptors at 47.7 km from the Project site.

Maximum Hours of Fuel Usage

Natural Gas	8,760
Fuel Oil	1,000

Golder Associates

TABLE 6-7
MAXIMUM 24-HOUR PM_{10} AND 24-HOUR $PM_{2.5}$ CENTRATIONS AT THE ENP - GE CTS ON ULSD OIL COMPARED TO THE PSD CLASS I SIL

Pollutant	Averaging Time	Concentration (µg/m³) for Year			PSD Class I SIL (µg/m³)
		2001	2002	2003	
$PM_{2.5}$	24-Hour	0.231	0.227	0.258	0.27
PM_{10}	24-Hour	0.233	0.228	0.260	0.3

SIL = Class I Significant Impact Level
[a] Concentrations are based on highest predicted concentrations from CALPUFF V5.8.5 and 3 years of meteorological data for 2001 to 2003.

TABLE 7-1
MAXIMUM 24-HOUR VISIBILITY IMPAIRMENT PREDICTED FOR DBEC
AT THE ENP PSD CLASS I AREA

CT Type / Fuel Type	Visibility Impairment (delta-dv) [a]			Visibility Impairment Criteria (deciview)
	2001	2002	2003	
GE				
24-Hours/Day on Natural Gas (Primary)	0.135	0.145	0.149	0.5
24-Hour/Day on ULSD Oil (Backup)	0.217	0.243	0.264	0.5

[a] Values presented are 98th-percentile deciviews using CALPUFF v5.8.5 and CALPOST v6.221, MVISBK=8, M8_MODE=5.

TABLE 7-2
MAXIMUM ANNUAL TOTAL SULFUR DEPOSITION PREDICTED FOR DBEC
AT THE ENP PSD CLASS I AREA

CT Type	Total Deposition (Wet & Dry) ($g/m^2/s$)	($kg/ha/yr$)[a,c]	Year	Deposition Analysis Threshold [b] ($kg/ha/yr$)
GE	8.82E-12	0.0028	2001	0.01
	9.23E-12	0.0029	2002	0.01
	1.06E-11	0.0033	2003	0.01

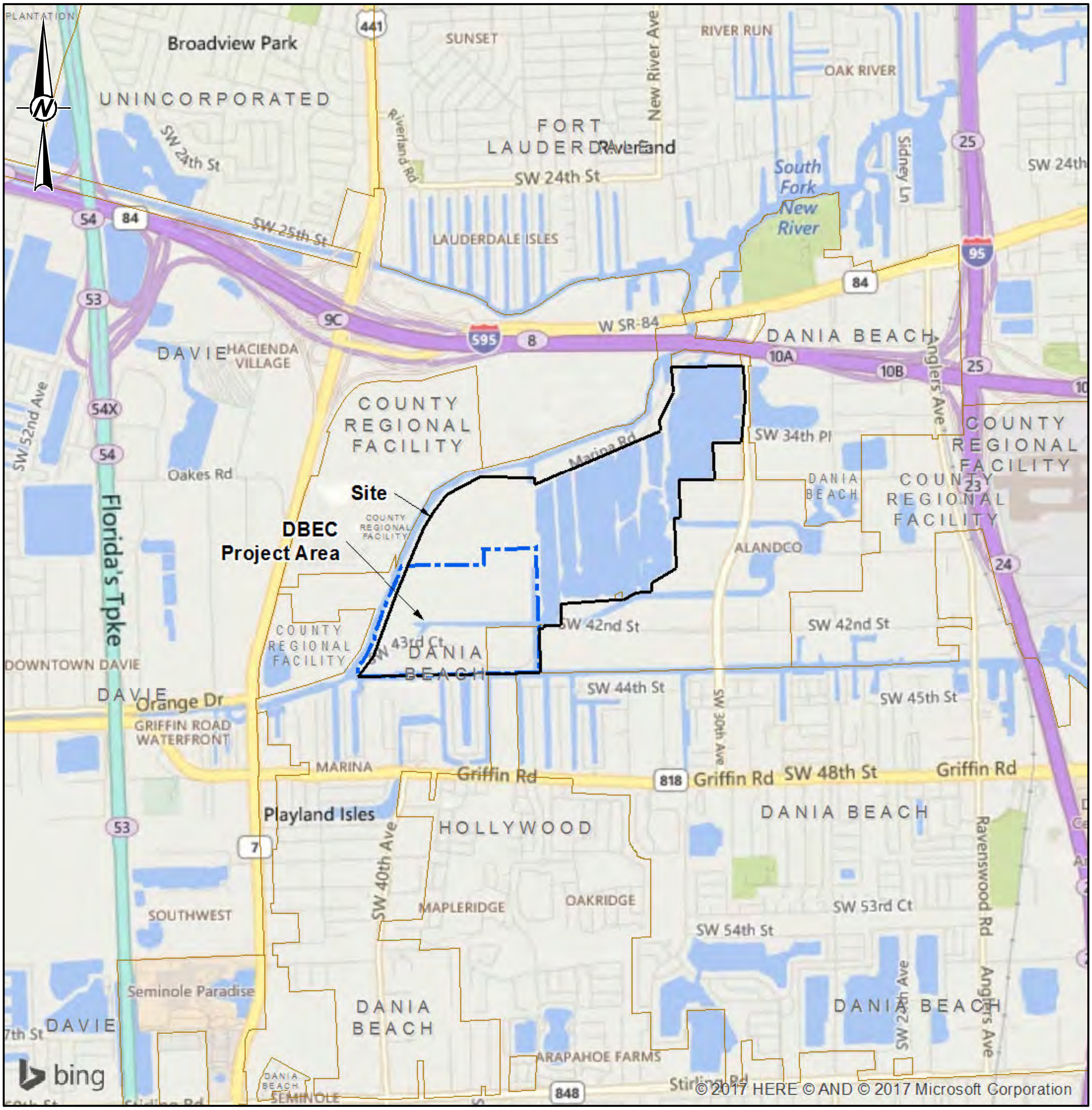
[a] Conversion factor is used to convert $g/m^2/s$ to kg/hectare (ha)/yr with the following units:

$g/m^2/s$ 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 sulfur deposition is based on CTs operating 8,260 hours/year on natural gas and 500 hours/year on ultra low sulfur fuel oil.

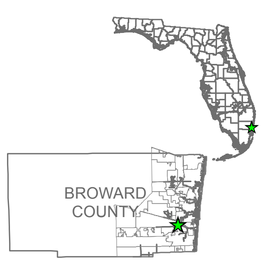
FIGURES



LEGEND

— Site

DBEC Project Area



0 2,640 5,280

Feet

REFERENCE(S)

SITE, A.R. TOUSSAINT & ASSOCIATES, INC., 1989

DBEC PROJECT AREA, GOLDER ASSOCIATES INC., 2017

CLIENT

FPL

PROJECT

DANIA BEACH ENERGY CENTER

TITLE

LOCATION OF THE FPL PROJECT

FPL

YYYY-MM-DD	2017-05-15
DESIGNED	NRL
PREPARED	NRL
REVIEWED	KAB
APPROVED	KFK

PROJECT NO.	CONTROL	REV.	FIGURE
1773823	F005	0	1-1

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

1 inch

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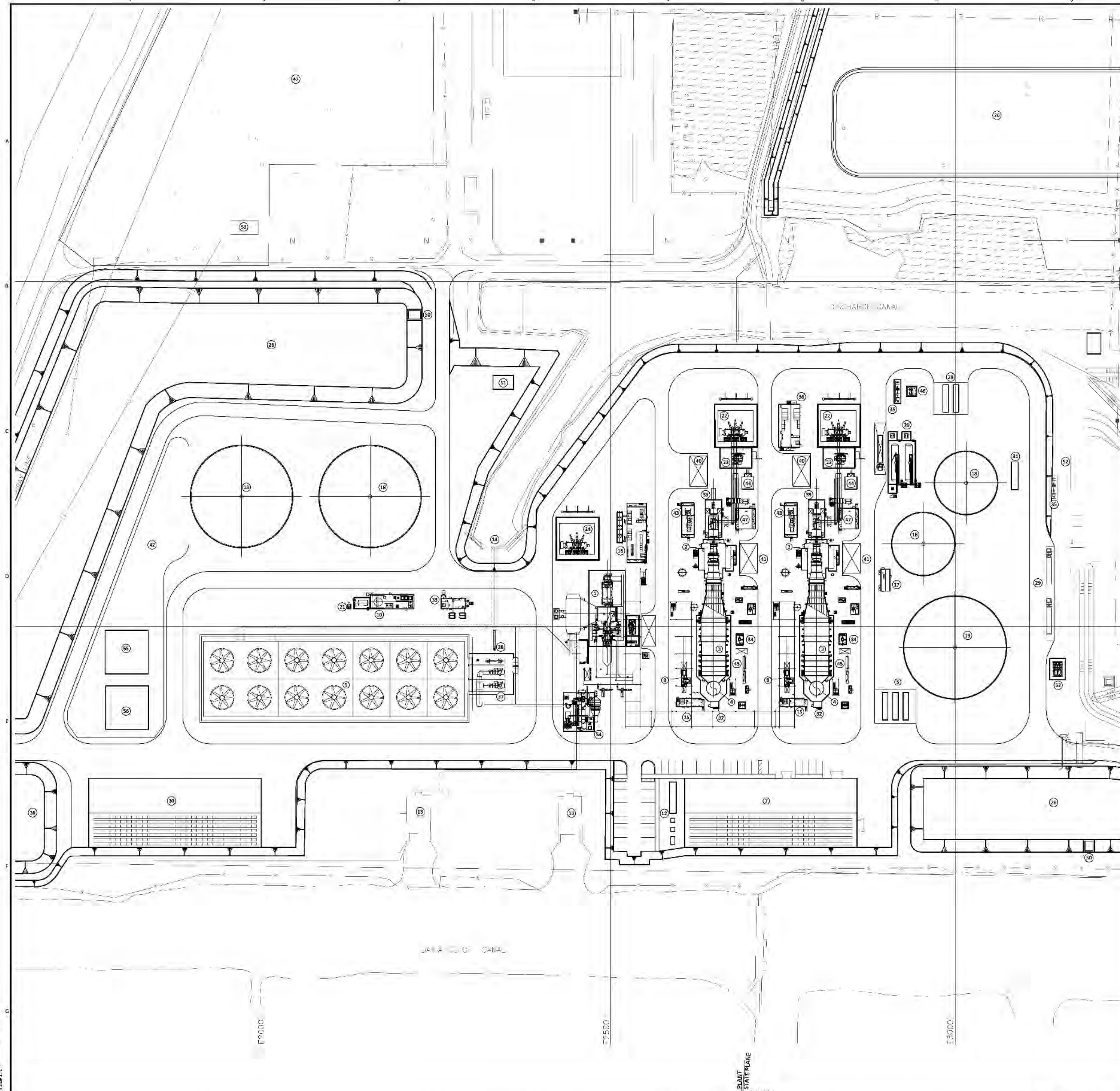
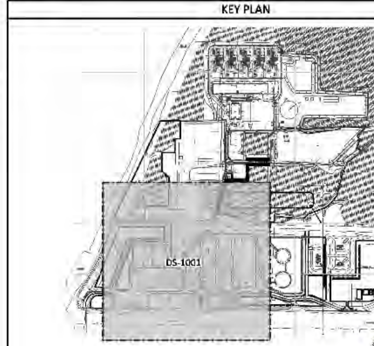


FACILITY ID	
ID	DESCRIPTION
1	STEAM TURBINE
2	COMBUSTION TURBINE
3	HEAT RECOVERY STEAM GENERATOR (HRSG)
4	HEAT RECOVERY STEAM GENERATOR STACK
5	DEMIN WATER TREATMENT
6	EXISTING FUEL STORAGE AREA
7	ADMIN/CONTROL/WAREHOUSE/MAINT BUILDING
8	BOILER FEED PUMPS
9	AUXILIARY COOLER
10	CIRCULATING WATER CHEMICAL FEED
11	ADMIN/CONTROL WAREHOUSE/MAINTENANCE BUILDING PARKING
12	HURRICANE SHELTER
13	CIRCULATING WATER INTAKE STRUCTURE (EXISTING)
14	CIRCULATING WATER DISCHARGE STRUCTURE (EXISTING)
15	POWER DISTRIBUTION CENTER
16	STEAM TURBINE ELECTRICAL EQUIPMENT ENCLOSURE
17	FIRE PUMP ENCLOSURE
18	SERVICE FIRE WATER STORAGE TANK
19	DEMIN WATER STORAGE TANK
20	AMMONIA UNLOADING/STORAGE TANK AREA
21	ACID STORAGE TANK
22	COMBUSTION TURBINE STEP-UP TRANSFORMER
23	COMBUSTION TURBINE AUX TRANSFORMER
24	STEAM TURBINE STEP-UP TRANSFORMER
25	FUEL GAS METERING SKID
26	STORM WATER POND
27	SWITCH YARD
28	BULK HYDROGEN SYSTEM AND TUBE TRAILERS
29	FUEL OIL UNLOADING
30	WAREHOUSE / MAINTENANCE
31	EMERGENCY SHUTDOWN GENERATOR
32	CONTINUOUS EMISSIONS MONITORING SYSTEM
33	AUXILIARY COOLING SYSTEM MCC ENCLOSURE
34	AMMONIA VAPORIZATION SKID
35	OIL/WATER SEPARATOR
36	MEDIUM VOLTAGE SWITCHGEAR
37	CIRCULATING WATER PUMPS
38	AUXILIARY COOLING WATER PUMPS
39	GENERATOR REMOVAL AREA
40	GENERATOR REMOVAL CRANE PAD
41	TURBINE MAINTENANCE CRANE PAD
42	CONSTRUCTION AND MAINTENANCE USE
43	CT ELECTRICAL PACKAGE
44	CT BATTERY COMPARTMENT
45	CT PERFORMANCE GAS HEATERS
46	WASTE WATER COLLECTION SUMP
47	COMBUSTION TURBINE START PACKAGE
48	NOT USED
49	POTABLE WATER STORAGE TANK AND SKID
50	STORM WATER POND CONTROL STRUCTURE
51	PAVILION
52	FUEL OIL FORWARDING PUMPS
53	TELECOMMUNICATIONS ENCLOSURE
54	AUXILIARY BOILER
55	CTG SPARE GSU PAD
56	STG SPARE GSU PAD

KEY PLAN



ISSUED FOR PERMITTING

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

JOHN C. BARRANCO JR. LICENSE STATE OF FLORIDA PROFESSIONAL ENGINEER

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
1	20/JUL/2017	ISSUED FOR PERMITTING	KED	CC		JCB	EEB
0	12/JUL/2017	ISSUED FOR PERMITTING	KED	CC		JCB	EEB

BLACK & VEATCH

FLORIDA POWER & LIGHT
DANIA BEACH ENERGY CENTER – UNIT 7
SITE ARRANGEMENT

DESIGNER: CC | DRAWN: KED | CHECKED | DATE

PROJECT: 195190 | DRAWING NUMBER: DS-1001 | REV: 1
CODE | AREA

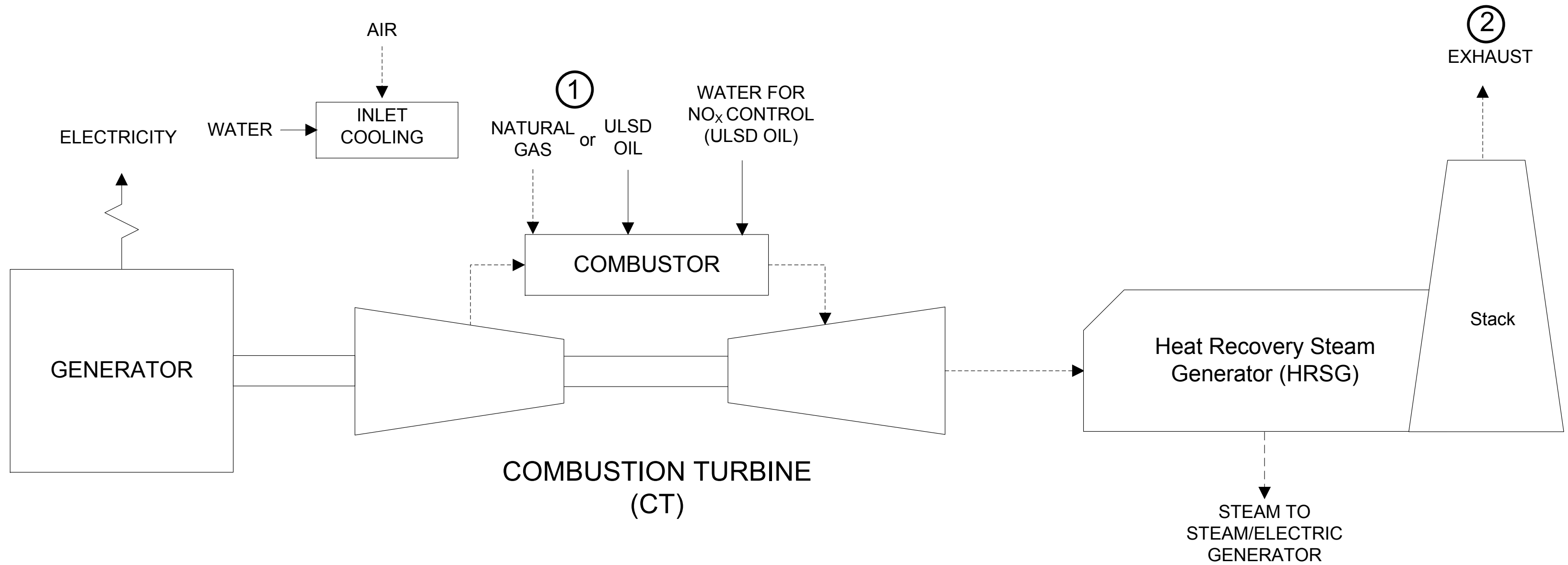
CLIENT
FPL

PROJECT
DANIA BEACH
ENERGY CENTER

YYYY-MM-DD	2017-07-20
PREPARED	NRL
DESIGNED	JGW
REVIEWED	KAB
APPROVED	KFK

TITLE
Conceptual Site Plan

PROJECT NO.	CONTROL	REV.	FIGURE
1773823	F029	0	2-1



	Parameters	Units	Fuel	GE 7HA
1	CT Heat Input (at 75 °F with inlet cooling)	MMBtu/hr (HHV)	Gas	4,015.4
		MMBtu/hr (HHV)	Oil	3,603.6
2	Mass Flow (at 75 °F with inlet cooling)	lb/hr	Gas	6,104,160
		lb/hr	Oil	6,313,360
2	Stack Velocity	ft/sec	Gas	55.2
		ft/sec	Oil	59.2
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 DBEC, Broward County, Florida

Source: GE, 2017; FPL, 2017; Golder, 2017.

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

APPENDIX A
EXPECTED PERFORMANCE, STACK AND EMISSION INFORMATION FOR GE 7HA COMBUSTION TURBINE/HRSG

TABLE A-1
DESIGN INFORMATION AND STACK PARAMETERS
GE 7HA CT, NATURAL GAS, BASE LOAD

Parameter	CT Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	3,560.1	3,639.8	3,621.3	3,604.5
(MMBtu/hr, HHV)	3,947.6	4,035.9	4,015.4	3,996.8
Enhanced Power Output	Off	On	On	On
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	20,566.5	20,566.5	20,566.5	20,566.5
(Btu/lb, HHV)	22,804.9	22,804.9	22,804.9	22,804.9
(HHV/LHV)	1.109	1.109	1.109	1.109
Steam Flow (lb/hr)	NA	NA	NA	NA
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)	6,175,800.0	6,182,640.0	6,104,160.0	6,062,760.0
Temperature (°F)	1,237.3	1,238.6	1,250.8	1,257.6
Moisture (% Vol.)	9.79	11.99	12.94	14.17
Oxygen (% Vol.)	10.41	9.84	9.61	9.37
Molecular Weight	28.3	28.1	28.0	27.9
Volume flow (acfm)	4,504,891	4,551,210	4,542,219	4,551,478
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)	3,560	3,640	3,621	3,604
Heat content (Btu/lb, LHV)	20,566	20,566	20,566	20,566
Fuel usage (lb/hr)	173,104	176,975	176,076	175,260
Heat content (Btu/cf, LHV)	870	870	870	870
Fuel density (lb/ft^3)	0.0423	0.0423	0.0423	0.0423
Fuel usage (cf/hr)	4,092,120	4,183,632	4,162,364	4,143,076
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)	6,175,800	6,182,640	6,104,160	6,062,760
HRSG Stack Temperature (°F)	177	180	182	184
Molecular weight	28.33	28.10	27.99	27.86
Volume flow (acfm)	1,690,429	1,715,077	1,703,199	1,707,599
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)- calculated	54.8	55.6	55.2	55.4

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia).
Source: GE, 2017; Golder Associates, 2017.

TABLE A-2
EMISSIONS FOR CRITERIA POLLUTANTS
GE 7HA, CT NATURAL GAS, BASE LOAD

Parameter	CT 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					
a. PM_{10} (CT front half + back half) (lb/hr)					
Total emission rate (lb/hr)	11.4	11.5	11.4	11.4	
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)	23.4	23.9	23.8	23.7	
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	21.0	21.5	21.4	21.3	
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)	6.13	6.26	6.23	6.20	
Total HRSG stack emission rate (lb/hr) [a + b]	17.6	17.8	17.6	17.6	#
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)	4,092,120	4,183,632	4,162,364	4,143,076	
Sulfur content (grains/ 100 cf)	2	2	2	2	
lb SO_2 /lb S (64/32)	2	2	2	2	
CT calculated emission rate (lb/hr)	23.4	23.9	23.8	23.7	
Vendor (lb/hr)	23.4	23.9	23.8	23.7	
Nitrogen Oxides					
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisture (%)]					
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	35.8	36.2	36.4	46.5	
Basis, ppmvd @15% O_2	25	25	25	32	
Moisture (%)	9.79	11.99	12.94	14.17	
Oxygen (%)	10.41	9.84	9.61	9.37	
Oxygen (%) dry	11.54	11.18	11.04	10.92	
Turbine Flow (acfm)	4,504,891	4,551,210	4,542,219	4,551,478	
Turbine Flow (acfm), dry	4,063,862	4,005,520	3,954,456	3,906,533	
Turbine Exhaust Temperature (°F)	1,237	1,239	1,251	1,258	
CT/DB calculated emission rate (lb/hr)	358.8	366.9	364.9	465.3	
Vendor (lb/hr)	358.8	367.0	365.0	465.4	
HRSG Stack emission rate, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	
HRSG stack emission rate (lb/hr)	28.7	29.4	29.2	29.1	#
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	8.12	7.92	7.84	7.72	
Basis, ppmvd	9.00	9.00	9.00	9.00	
Basis, ppmvd @15% O_2	5.67	5.46	5.38	5.32	
Moisture (%)	9.79	11.99	12.94	14.17	
Oxygen (%)	10.41	9.84	9.61	9.37	
Oxygen (%) dry	11.54	11.18	11.04	10.92	
Turbine Flow (acfm)	4,504,891	4,551,210	4,542,219	4,551,478	
Turbine Flow (acfm), dry	4,063,862	4,005,520	3,954,456	3,906,533	
Turbine Exhaust Temperature (°F)	1,237	1,239	1,251	1,258	
CT/DB calculated emission rate (lb/hr)	49.6	48.8	47.8	47.1	
Vendor (lb/hr)	49.6	48.8	47.9	47.1	
HRSG Stack emission rate, ppmvd @ 15% O_2	5.7	5.7	5.7	5.7	
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	1.40	1.40	1.40	1.40	
Basis, ppmvd @15% O_2	0.98	0.97	0.96	0.96	
Moisture (%)	9.79	11.99	12.94	14.17	
Oxygen (%) dry	11.54	11.18	11.04	10.92	
Turbine Flow (acfm)	4,504,891	4,551,210	4,542,219	4,551,478	
Turbine Flow (acfm), dry	4,063,862	4,005,520	3,954,456	3,906,533	
Turbine Exhaust Temperature (°F)	1,237	1,239	1,251	1,258	
CT/DB calculated emission rate (lb/hr)	4.88	4.93	4.88	4.88	
Vendor (lb/hr)	4.9	4.9	4.9	4.9	
HRSG Stack emission rate (lb/hr)	4.9	4.9	4.9	4.9	
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)	23.4	23.9	23.8	23.7	
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 (lb/hr)(remaining SO_2 after conversion)	21.0	21.5	21.4	21.3	
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3	
HRSG Stack emission rate (lb/hr)	4.55	4.65	4.63	4.60	
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, 2017; Golder Associates, 2017.

TABLE A-3

DESIGN INFORMATION AND STACK PARAMETERS

GE 7HA CT, NATURAL GAS, 75% LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	2,830.9	2,750.0	2,266.8	2,602.4
(MMBtu/hr, HHV)	3,139.0	3,049.3	2,513.5	2,885.6
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	20,566.5	20,566.5	20,566.5	20,566.5
(Btu/lb, HHV)	22,804.9	22,804.9	22,804.9	22,804.9
(HHV/LHV)	1.109	1.109	1.109	1.109
CT/DB Exhaust Flow				
Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (^oF + 460 K)] / [2112.5 x 60 min/hr x MW]				
Mass flow (lb/hr)	4,944,402.8	4,867,580.2	4,247,011.3	4,744,414.0
Temperature (°F)	1,280.0	1,280.0	1,280.0	1,280.0
Moisture (% Vol.)	9.72	10.16	10.35	11.52
Oxygen (% Vol.)	10.48	10.52	10.95	10.52
Molecular Weight	28.3	28.3	28.2	28.1
Volume flow (acfm)	3,696,878	3,646,377	3,186,626	3,574,930
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)	2,831	2,750	2,267	2,602
Heat content (Btu/lb, LHV)	20,566	20,566	20,566	20,566
Fuel usage (lb/hr)	137,644	133,712	110,218	126,535
Heat content (Btu/cf, LHV)	870	870	870	870
Fuel density (lb/ft^3)	0.0423	0.0423	0.0423	0.0423
Fuel usage (cf/hr)	3,253,855	3,160,895	2,605,519	2,991,246
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)	4,944,403	4,867,580	4,247,011	4,744,414
HRSG Stack Temperature (^oF)	171	171	176	182
Molecular weight	28.34	28.28	28.24	28.12
Volume flow (acfm)	1,340,437	1,322,126	1,164,584	1,318,615
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)	43.5	42.9	37.8	42.8

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, 2017; Golder Associates, 2017.

TABLE A-4
EMISSIONS FOR CRITERIA POLLUTANTS
GE 7HA 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)	11.08	11.15	10.93	11.44
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)	18.6	18.1	14.9	17.1
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	16.7	16.3	13.4	15.4
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)	4.87	4.73	3.90	4.48
Total HRSG stack emission rate (lb/hr) [a + b]	16.0	15.9	14.8	15.9
(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)	3,253,855	3,160,895	2,605,519	2,991,246
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2
CT calculated emission rate (lb/hr)	18.6	18.1	14.9	17.1
Vendor (lb/hr)	18.59	18.06	14.88	17.09
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	35.5	35.0	33.0	43.2
Basis, ppmvd @15% O_2	25	25	25	32
Moisture (%)	9.72	10.16	10.35	11.52
Oxygen (%)	10.48	10.52	10.95	10.52
Oxygen (%) dry	11.61	11.71	12.21	11.89
Turbine Flow (acfm)	3,696,878	3,646,377	3,186,626	3,574,930
Turbine Flow (acfm), dry	3,337,412	3,276,054	2,856,837	3,162,952
Turbine Exhaust Temperature (°F)	1,280	1,280	1,280	1,280
CT Emission rate (lb/hr)	285.3	277.1	228.4	335.6
Vendor	285.36	277.19	228.41	335.72
HRSG Stack emission rate, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0
HRSG Stack emission rate (lb/hr)	22.8	22.2	18.3	21.0
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	8.12	8.09	8.07	7.96
Basis, ppmvd	9.0	9.0	9.0	9.0
Basis, ppmvd @15% O_2	5.71	5.78	6.11	5.89
Moisture (%)	9.72	10.16	10.35	11.52
Oxygen (%)	10.48	10.52	10.95	10.52
Oxygen (%) dry	11.61	11.71	12.21	11.89
Turbine Flow (acfm)	3,696,878	3,646,377	3,186,626	3,574,930
Turbine Flow (acfm), dry	3,337,412	3,276,054	2,856,837	3,162,952
Turbine Exhaust Temperature (°F)	1,280	1,280	1,280	1,280
CT calculated emission rate (lb/hr)	39.7	39.0	34.0	37.6
Vendor (lb/hr)	39.7	39.0	34.0	37.6
HRSG Stack emission rate, ppmvd @ 15% O_2	5.71	5.78	6.11	5.89
HRSG Stack emission rate (lb/hr)	39.7	39.0	34.0	37.6
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	1.4	1.4	1.4	1.4
Basis, ppmvd @15% O_2	0.98	1.00	1.06	1.04
Moisture (%)	9.72	10.16	10.35	11.52
Oxygen (%)	10.48	10.52	10.95	10.52
Oxygen (%) dry	11.61	11.71	12.21	11.89
Turbine Flow (acfm)	3,696,878	3,646,377	3,186,626	3,574,930
Turbine Flow (acfm), dry	3,337,412	3,276,054	2,856,837	3,162,952
Turbine Exhaust Temperature (°F)	1,280	1,280	1,280	1,280
CT calculated emission rate (lb/hr)	3.91	3.86	3.37	3.78
Vendor (lb/hr)	3.92	3.86	3.38	3.79
HRSG Stack emission rate (lb/hr)	3.9	3.9	3.4	3.8
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)	18.6	18.1	14.9	17.1
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)	16.7	16.3	13.4	15.4
HRSG Stack emission rate (lb/hr)	3.62	3.51	2.90	3.32
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, 2017; Golder Associates, 2017

TABLE A-5

DESIGN INFORMATION AND STACK PARAMETERS

GE 7HA CT, NATURAL GAS, MECL LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	1,569.0	1,524.0	1,580.3	1,672.9
(MMBtu/hr, HHV)	1,739.8	1,689.9	1,752.3	1,854.9
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	20,566.5	20,566.5	20,566.5	20,566.5
(Btu/lb, HHV)	22,804.9	22,804.9	22,804.9	22,804.9
(HHV/LHV)	1.109	1.109	1.109	1.109
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)	3,306,923.3	3,256,154.3	3,326,188.4	3,471,043.8
Temperature (°F)	1,280.0	1,280.0	1,280.0	1,280.0
Moisture (% Vol.)	8.15	8.61	9.42	10.48
Oxygen (% Vol.)	12.23	12.24	11.99	11.69
Molecular Weight	28.4	28.4	28.3	28.2
Volume flow (acfm)	2,463,990	2,430,929	2,490,599	2,609,416
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)	1,569	1,524	1,580	1,673
Heat content (Btu/lb, LHV)	20,566	20,566	20,566	20,566
Fuel usage (lb/hr)	76,290	74,102	76,837	81,339
Heat content (Btu/cf, LHV)	870	870	870	870
Fuel density (lb/ft^3)	0.0423	0.0423	0.0423	0.0423
Fuel usage (cf/hr)	1,803,460	1,751,756	1,816,405	1,922,835
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)	3,306,923	3,256,154	3,326,188	3,471,044
HRSG Stack Temperature (°F)	168	169	172	178
Molecular weight	28.43	28.38	28.29	28.18
Volume flow (acfm)	889,727	878,627	904,059	956,036
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)	28.8	28.5	29.3	31.0

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia).
Source: GE, 2017; Golder Associates, 2017.

TABLE A-6
EMISSIONS FOR CRITERIA POLLUTANTS
GE 7HA 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)	10.62	10.65	10.72	10.75
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)	10.3	10.0	10.4	11.0
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	9.3	9.0	9.3	9.9
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)	2.70	2.62	2.72	2.88
Total HRSG stack emission rate (lb/hr) [a + b]	13.3	13.3	13.4	13.6
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)	1,803,460	1,751,756	1,816,405	1,922,835
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)	10.3	10.0	10.4	11.0
Vendor (lb/hr)	10.3	10.0	10.4	11.0
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	29.5	29.1	29.4	38.1
Basis, ppmvd @15% O_2	25	25	25	32
Moisture (%)	8.15	8.61	9.42	10.48
Oxygen (%)	12.23	12.24	11.99	11.69
Oxygen (%) dry	13.31	13.39	13.24	13.06
Turbine Flow (acfm)	2,463,990	2,430,929	2,490,599	2,609,416
Turbine Flow (acfm), dry	2,263,061	2,221,558	2,255,968	2,335,947
Turbine Exhaust Temperature (°F)	1,280	1,280	1,280	1,280
CT calculated mission rate (lb/hr)	157.9	153.4	159.1	215.6
Vendor (lb/hr)	158.0	153.4	159.1	215.6
HRSG Stack emission rate, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0
HRSG Stack emission rate (lb/hr)	12.6	12.3	12.7	13.5
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	8.27	8.22	8.15	8.06
Basis, ppmvd	9.0	9.0	9.0	9.0
Basis, ppmvd @15% O_2	7.00	7.08	6.93	6.78
Moisture (%)	8.15	8.61	9.42	10.48
Oxygen (%)	12.23	12.24	11.99	11.69
Oxygen (%) dry	13.31	13.39	13.24	13.06
Turbine Flow (acfm)	2,463,990	2,430,929	2,490,599	2,609,416
Turbine Flow (acfm), dry	2,263,061	2,221,558	2,255,968	2,335,947
Turbine Exhaust Temperature (°F)	1,280	1,280	1,280	1,280
CT calculated emission rate (lb/hr)	26.9	26.4	26.8	27.8
Vendor (lb/hr)	27	26	27	28
HRSG Stack emission rate, ppmvd @ 15% O_2	7.00	7.08	6.93	6.78
HRSG Stack emission rate (lb/hr)	26.9	26.4	26.8	27.8
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	1.4	1.4	1.4	1.4
Basis, ppmvd @15% O_2	1.19	1.20	1.19	1.18
Moisture (%)	8.15	8.61	9.42	10.48
Oxygen (%)	12.23	12.24	11.99	11.69
Oxygen (%) dry	13.31	13.39	13.24	13.06
Turbine Flow (acfm)	2,463,990	2,430,929	2,490,599	2,609,416
Turbine Flow (acfm), dry	2,263,061	2,221,558	2,255,968	2,335,947
Turbine Exhaust Temperature (°F)	1,280	1,280	1,280	1,280
CT calculated emission rate (lb/hr)	2.6	2.6	2.6	2.8
Vendor (lb/hr)	2.6	2.6	2.6	2.8
HRSG Stack emission rate (lb/hr)	2.6	2.6	2.6	2.8
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)	10.3	10.0	10.4	11.0
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	9.3	9.0	9.3	9.9
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3
HRSG Stack emission rate (lb/hr)	2.00	1.95	2.02	2.14
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, 2017; Golder Associates, 2017.

TABLE A-7

DESIGN INFORMATION AND STACK PARAMETERS

GE 7HA CT, ULSD OIL, BASE LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	3,607.3	3,512.2	3,369.4	3,199.7
(MMBtu/hr, HHV)	3,858.0	3,756.3	3,603.6	3,422.1
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)	19,572.0	19,572.0	19,572.0	19,572.0
(HHV/LHV)	1.070	1.070	1.070	1.070
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)	6,623,026.2	6,522,803.4	6,313,360.6	6,057,491.4
Temperature (°F)	1,052.0	1,057.5	1,065.6	1,078.4
Moisture (% Vol.)	12.72	13.23	13.65	14.27
Oxygen (% Vol.)	10.05	10.06	10.05	10.03
Molecular Weight	28.2	28.2	28.1	28.0
Volume flow (acfm)	4,320,829	4,280,734	4,173,349	4,048,544
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)	3,607	3,512	3,369	3,200
Heat content (Btu/lb, LHV)	18,300	18,300	18,300	18,300
Fuel usage (lb/hr)	197,119	191,921	184,119	174,847
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)	6,623,026	6,522,803	6,313,361	6,057,491
HRSG Stack Temperature (°F)	205	204	208	213
Molecular weight	28.22	28.15	28.10	28.03
Volume flow (acfm)	1,901,528	1,872,534	1,827,296	1,771,418
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)	61.7	60.7	59.2	57.4

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia).
Source: GE, 2017; Golder Associates, 2017.

TABLE A-8
EMISSIONS FOR CRITERIA POLLUTANTS
GE 7HA 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)	60.10	60.10	60.10	60.10
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)	5.9	5.8	5.5	5.2
Conversion (%) from SO_2 to SO_3	10.0	10.0	10.0	10.0
Remaining SO_2 (lb/hr) in CT after conversion	5.3	5.2	5.0	4.7
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)	1.55	1.51	1.45	1.37
Total HRSG stack emission rate (lb/hr) [a + b]	61.6	61.6	61.5	61.5
(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)	197,119	191,921	184,119	174,847
lb SO_2 / lb S (64/32)	2	2	2	2
HRSG Stack emission rate (lb/hr)	5.9	5.8	5.5	5.2
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	58.3	57.5	56.9	56.2
Basis, ppmvd @15% O_2	42	42	42	42
Moisture (%)	12.72	13.23	13.65	14.27
Oxygen (%)	10.05	10.06	10.05	10.03
Oxygen (%) dry	11.51	11.59	11.64	11.70
Turbine Flow (acfm)	4,320,829	4,280,734	4,173,349	4,048,544
Turbine Flow (acfm), dry	3,771,242	3,714,460	3,603,792	3,470,915
Turbine Exhaust Temperature (°F)	1,052	1,057	1,066	1,078
CT calculated emission rate (lb/hr)	629.6	613.0	588.1	558.4
Vendor (lb/hr)	629.8	613.1	588.2	558.5
HRSG Stack emission rate, ppmvd @ 15% O_2	8.0	8.0	8.0	8.0
HRSG Stack emission rate (lb/hr)	120.0	116.8	112.0	106.4
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	17.5	17.4	17.3	17.1
Basis, ppmvd	20.0	20.0	20.0	20.0
Basis, ppmvd @15% O_2	12.6	12.7	12.7	12.8
Moisture (%)	12.72	13.23	13.65	14.27
Oxygen (%)	10.05	10.06	10.05	10.03
Oxygen (%) dry	11.51	11.59	11.64	11.70
Turbine Flow (acfm)	4,320,829	4,280,734	4,173,349	4,048,544
Turbine Flow (acfm), dry	3,771,242	3,714,460	3,603,792	3,470,915
Turbine Exhaust Temperature (°F)	1,052	1,057	1,066	1,078
CT calculated emission rate (lb/hr)	114.7	112.6	108.6	103.8
Vendor (lb/hr)	114.8	112.6	108.7	103.8
HRSG Stack emission rate, ppmvd	12.6	12.6	12.6	12.6
HRSG Stack emission rate (lb/hr)	114.8	112.6	108.7	103.8
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	3.5	3.5	3.5	3.5
Basis, ppmvd @ 15% O_2	2.5	2.6	2.6	2.6
Moisture (%)	12.72	13.23	13.65	14.27
Oxygen (%)	10.05	10.06	10.05	10.03
Oxygen (%-dry)	11.51	11.59	11.64	11.70
Turbine Flow (acfm)	4,320,829	4,280,734	4,173,349	4,048,544
Turbine Flow (acfm), dry	3,771,242	3,714,460	3,603,792	3,470,915
Turbine Exhaust Temperature (°F)	1,052	1,057	1,066	1,078
CT calculated emission rate (lb/hr)	13.1	13.0	12.6	12.1
Vendor (lb/hr)	13.2	13.0	12.6	12.1
HRSG Stack emission rate (lb/hr)	13.2	13.0	12.6	12.1
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)	5.9	5.8	5.5	5.2
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)	5.3	5.2	5.0	4.7
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3
HRSG Stack emission rate (lb/hr)	1.15	1.12	1.07	1.02
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	0.0540	0.0526	0.0505	0.0479

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia)
Source: GE, 2017; Golder Associates, 2017

TABLE A-9

DESIGN INFORMATION AND STACK PARAMETERS

GE 7HA CT, ULSD OIL, 75% LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	2,825.4	2,720.4	2,604.5	2,452.8
(MMBtu/hr, HHV)	3,021.8	2,909.5	2,785.5	2,623.3
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)	19,572.0	19,572.0	19,572.0	19,572.0
(HHV/LHV)	1.070	1.070	1.070	1.070
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)	5,305,238.7	5,073,042.7	4,862,973.9	4,634,015.9
Temperature (°F)	1,085.3	1,117.3	1,140.5	1,163.4
Moisture (% Vol.)	11.73	12.27	12.74	13.28
Oxygen (% Vol.)	10.41	10.26	10.19	10.19
Molecular Weight	28.3	28.3	28.2	28.1
Volume flow (acfm)	3,525,338	3,447,724	3,359,966	3,255,481
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)	2,825	2,720	2,604	2,453
Heat content (Btu/lb, LHV)	18,300	18,300	18,300	18,300
Fuel usage (lb/hr)	154,393	148,657	142,320	134,033
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)	5,305,239	5,073,043	4,862,974	4,634,016
HRSG Stack Temperature (°F)	191	188	193	194
Molecular weight	28.31	28.26	28.21	28.14
Volume flow (acfm)	1,485,833	1,416,876	1,370,624	1,312,274
Diameter (feet)	25.6	25.6	25.6	25.6
Velocity (ft/sec)	48.2	45.9	44.4	42.5

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia)
Source: GE, 2017; Golder Associates, 2017.

TABLE A-10
EMISSIONS FOR CRITERIA POLLUTANTS
GE 7HA 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)	60.10	60.10	60.10	60.10
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)	4.6	4.5	4.3	4.0
Conversion (%) from SO_2 to SO_3	10.0	10.0	10.0	10.0
Remaining SO_2 (lb/hr) in CT after conversion	4.2	4.0	3.8	3.6
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)	1.21	1.17	1.12	1.05
Total HRSG stack emission rate (lb/hr) [a + b]	61.3	61.3	61.2	61.2
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)	154,393	148,657	142,320	134,033
lb SO_2 / lb S (64/32)	2	2	2	2
HRSG Stack emission rate (lb/hr)	4.6	4.5	4.3	4.0
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	57.2	57.5	57.3	56.5
Basis, ppmvd @15% O_2	42	42	42	42
Moisture (%)	11.73	12.27	12.74	13.28
Oxygen (%)	10.41	10.26	10.19	10.19
Oxygen (%) dry	11.80	11.69	11.67	11.75
Turbine Flow (acfm)	3,525,338	3,447,724	3,359,966	3,255,481
Turbine Flow (acfm), dry	3,111,866	3,024,524	2,931,886	2,823,046
Turbine Exhaust Temperature (°F)	1,085	1,117	1,141	1,163
CT calculated emission rate (lb/hr)	493.1	474.8	454.5	428.1
Vendor (lb/hr)	493.2	474.9	454.6	428.2
HRSG Stack emission rate, ppmvd @ 15% O_2	8.0	8.0	8.0	8.0
HRSG Stack emission rate (lb/hr)	93.9	90.5	86.6	81.6
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	17.7	17.5	17.5	17.3
Basis, ppmvd	20	20	20	20
Basis, ppmvd @15% O_2	13.0	12.8	12.8	12.9
Moisture (%)	11.73	12.27	12.74	13.28
Oxygen (%)	10.41	10.26	10.19	10.19
Oxygen (%) dry	11.80	11.69	11.67	11.75
Turbine Flow (acfm)	3,525,338	3,447,724	3,359,966	3,255,481
Turbine Flow (acfm), dry	3,111,866	3,024,524	2,931,886	2,823,046
Turbine Exhaust Temperature (°F)	1,085	1,117	1,141	1,163
CT calculated emission rate (lb/hr)	92.6	88.2	84.3	80.0
Vendor (lb/hr)	92.7	88.2	84.3	80.0
HRSG Stack emission rate (lb/hr)	92.6	88.2	84.3	80.0
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	3.5	3.5	3.5	3.5
Basis, ppmvd @ 15% O_2	2.6	2.6	2.6	2.6
Moisture (%)	11.73	12.27	12.74	13.28
Oxygen (%)	10.41	10.26	10.19	10.19
Oxygen (%-dry)	11.80	11.69	11.67	11.75
Turbine Flow (acfm)	3,525,338	3,447,724	3,359,966	3,255,481
Turbine Flow (acfm), dry	3,111,866	3,024,524	2,931,886	2,823,046
Turbine Exhaust Temperature (°F)	1,085	1,117	1,141	1,163
CT calculated emission rate (lb/hr)	10.5	10.1	9.7	9.2
Vendor (lb/hr)	10.5	10.1	9.7	9.2
HRSG Stack emission rate (lb/hr)	10.5	10.1	9.7	9.2
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)	4.6	4.5	4.3	4.0
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)	4.2	4.0	3.8	3.6
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3
HRSG Stack emission rate (lb/hr)	0.90	0.87	0.83	0.78
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)	0.0423	0.0407	0.0390	0.0367

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia)
Source: GE, 2017; Golder Associates, 2017

TABLE A-11

DESIGN INFORMATION AND STACK PARAMETERS

GE 7HA CT, ULSD OIL, 50% LOAD

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	2,093.0	2,017.1	1,938.6	1,841.3
(MMBtu/hr, HHV)	2,238.5	2,157.3	2,073.4	1,969.3
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)	19,572.0	19,572.0	19,572.0	19,572.0
(HHV/LHV)	1.070	1.070	1.070	1.070
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)	4,294,795.5	4,112,797.2	3,930,259.7	3,700,110.2
Temperature (°F)	1,148.4	1,178.2	1,203.6	1,241.4
Moisture (% Vol.)	8.19	8.79	9.52	10.53
Oxygen (% Vol.)	11.75	11.59	11.42	11.17
Molecular Weight	28.7	28.6	28.5	28.4
Volume flow (acfm)	2,935,220	2,869,187	2,792,017	2,698,424
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)	2,093	2,017	1,939	1,841
Heat content (Btu/lb, LHV)	18,300	18,300	18,300	18,300
Fuel usage (lb/hr)	114,371	110,224	105,935	100,617
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)	4,294,796	4,112,797	3,930,260	3,700,110
HRSG Stack Temperature (^{o}F)	175	174	177	180
Molecular weight	28.66	28.59	28.51	28.41
Volume flow (acfm)	1,158,809	1,110,413	1,069,068	1,015,014
Diameter (feet)	25.58333333	25.58333333	25.58333333	25.58333333
Velocity (ft/sec)	37.6	36.0	34.7	32.9

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, 2017; Golder Associates, 2017.

TABLE A-12
EMISSIONS FOR CRITERIA POLLUTANTS
7HA 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)	60.10	60.10	60.10	60.10
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)	3.4	3.3	3.2	3.0
Conversion (%) from SO_2 to SO_3	10.0	10.0	10.0	10.0
Remaining SO_2 (lb/hr) in CT after conversion	3.1	3.0	2.9	2.7
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)	0.90	0.87	0.83	0.79
Total HRSG stack emission rate (lb/hr) [a + b]	61.0	61.0	60.9	60.9
(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)	114,371	110,224	105,935	100,617
lb SO_2 / lb S (64/32)	2	2	2	2
HRSG Stack emission rate (lb/hr)	3.4	3.3	3.2	3.0
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	52.9	53.2	53.3	53.6
Basis, ppmvd @15% O_2	42	42	42	42
Moisture (%)	8.19	8.79	9.52	10.53
Oxygen (%)	11.75	11.59	11.42	11.17
Oxygen (%) dry	12.80	12.71	12.62	12.48
Turbine Flow (acfm)	2,935,220	2,869,187	2,792,017	2,698,424
Turbine Flow (acfm), dry	2,694,772	2,616,888	2,526,159	2,414,359
Turbine Exhaust Temperature (°F)	1,148	1,178	1,204	1,241
CT calculated emission rate (lb/hr)	365.0	351.8	338.1	321.2
Vendor (lb/hr)	365.1	351.9	338.2	321.3
HRSG Stack emission rate, ppmvd @ 15% O_2	8.0	8.0	8.0	8.0
HRSG Stack emission rate (lb/hr)	69.5	67.0	64.4	61.2
Carbon Monoxide				
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]				
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr				
Basis, ppm actual	18.4	18.2	18.1	17.9
Basis, ppmvd	20.0	20.0	20.0	20.0
Basis, ppmvd @15% O_2	14.6	14.4	14.3	14.0
Moisture (%)	8.19	8.79	9.52	10.53
Oxygen (%)	11.75	11.59	11.42	11.17
Oxygen (%) dry	12.80	12.71	12.62	12.48
Turbine Flow (acfm)	2,935,220	2,869,187	2,792,017	2,698,424
Turbine Flow (acfm), dry	2,694,772	2,616,888	2,526,159	2,414,359
Turbine Exhaust Temperature (°F)	1,148	1,178	1,204	1,241
CT calculated emission rate (lb/hr)	77.1	73.5	69.8	65.3
Vendor (lb/hr)	77.1	73.5	69.9	65.3
HRSG Stack emission rate (lb/hr)	77.1	73.5	69.8	65.3
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	3.5	3.5	3.5	3.5
Basis, ppmvd @ 15% O_2	2.8	2.8	2.8	2.7
Moisture (%)	8.19	8.79	9.52	10.53
Oxygen (%)	11.75	11.59	11.42	11.17
Oxygen (%-dry)	12.80	12.71	12.62	12.48
Turbine Flow (acfm)	2,935,220	2,869,187	2,792,017	2,698,424
Turbine Flow (acfm), dry	2,694,772	2,616,888	2,526,159	2,414,359
Turbine Exhaust Temperature (°F)	1,148	1,178	1,204	1,241
CT calculated emission rate (lb/hr)	8.4	8.1	7.7	7.3
Vendor (lb/hr)	8.4	8.1	7.7	7.3
HRSG Stack emission rate (lb/hr)	8.4	8.1	7.7	7.3
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)	3.4	3.3	3.2	3.0
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)	3.1	3.0	2.9	2.7
SCR Conversion to H_2SO_4 (% by weight)	3	3	3	3
HRSG Stack emission rate (lb/hr)	0.67	0.64	0.62	0.59
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	0.0313	0.0302	0.0290	0.0276

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.69 psia).
Source: GE, 2017; Golder Associates, 2017.

TABLE A-13

HAZARDOUS AIR POLLUTANT (HAP) EMISSION FACTORS AND EMISSIONS

WHEN FIRING NATURAL GAS - GE 7HA CT

Parameter	**Emission Rate (lb/hr) firing Natural Gas Base Load** [a]	**Potential Emissions (TPY)** [b]	
Ambient Temperature (°F) and Wet Compression:	75 °F	1	2
HIR (MMBtu/hr):	4,015	CT/HRSG	CTs/HRSGs
HAPs [Section 112(b) of Clean Air Act]			
1,3-Butadiene	0.001727	0.008	0.015
Acetaldehyde	0.1606	0.70	1.41
Acrolein	0.0257	0.11	0.23
Benzene	0.0482	0.21	0.42
Ethylbenzene	0.1285	0.56	1.13
Formaldehyde	2.665	11.67	23.35
Naphthalene	0.00522	0.02	0.05
Polycyclic Aromatic Hydrocarbons (PAH) [c]	0.00883	0.04	0.08
Propylene Oxide	0.1164	0.51	1.02
Toluene	0.1325	0.58	1.16
Xylene	0.257	1.13	2.25
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	0.0000040	0.0	0.000035
Nickel	0.0	0.0	0.0
Selenium	0.0	0.0	0.0
HAPs (Total)	3.550	10.37	31.1

[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		0.280	ppmvd @15% O_2 (see Table 13a)
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

WHEN FIRING NATURAL GAS - GE 7HA CT

Parameter	**CT Only at Baseload Ambient Temperature**			
	35 °F	**59 °F**	**75 °F** **0**	**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	0.401	0.406	0.407	0.407
CT, ppmvd @15% O_2	0.28	0.28	0.28	0.28
Moisture (%)	9.79	11.99	12.94	14.17
Oxygen (%)	10.41	9.84	9.61	9.37
Oxygen (%) dry	11.54	11.18	11.04	10.92
Exhaust Flow (acfm)	1,690,429	1,715,077	1,703,199	1,707,599
Exhaust Temperature (°F)	177	180	182	184
CT Emission rate (lb/hr)	2.621	2.680	2.665	2.655
CT Emission rate (lb/10^{12} Btu) (HHV)	663.8	664.0	663.8	664.3

Note: ppmvd= parts per million, volume dry; O_2= oxygen.
Source: GE, 2017; Golder Associates, 2017.

TABLE A-14
HAZARDOUS AIR POLLUTANT (HAP) EMISSION FACTORS AND EMISSIONS
WHEN FIRING NATURAL GAS AND ULSD OIL - GE 7HA

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) 2 CTs/HRSGs	2 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):	3,604	4,015	1,000	1,000
HAPs [Section 112(b) of Clean Air Act]				
1,3-Butadiene	0.0577	0.0017	0.058	0.07
Acetaldehyde	0.00	0.161	0.00	1.41
Acrolein	0.00	0.026	0.00	0.23
Benzene	0.198	0.048	0.20	0.57
Ethylbenzene	0.00	0.128	0.00	1.13
Formaldehyde	1.004	2.665	1.00	23.35
Naphthalene	0.1261	0.005	0.13	0.17
Polycyclic Aromatic Hydrocarbons (PAH) c	0.1441	0.009	0.14	0.21
Propylene Oxide	0.00	0.116	0.00	1.02
Toluene	0.00	0.133	0.00	1.16
Xylene	0.00	0.257	0.00	2.25
Antimony	0.00	0.00	0.00	0.00
Arsenic	0.0396	0.00	0.040	0.04
Beryllium	0.001117	0.00	0.00	0.00
Cadmium	0.01730	0.00	0.017	0.02
Chromium	0.0396	0.00	0.040	0.04
Lead	0.0505	0.00	0.050	0.05
Manganese	2.85	0.00	2.85	2.85
Mercury	0.00432	0.00	0.004	0.00
Nickel	0.01658	0.00	0.017	0.02
Selenium	0.0901	0.00	0.09	0.09
HAPs (Total)	4.64	3.6	4.64	34.7

[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		0.110	ppmvd @15% O2 (see Table 14a)
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

GE 7HA, 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	0.153	0.151	0.149	0.147
CT, ppmvd @15% O_2	0.11	0.11	0.11	0.11
Moisture (%)	12.72	13.23	13.65	14.27
Oxygen (%)	10.05	10.06	10.05	10.03
Oxygen (%) dry	11.51	11.59	11.64	11.70
Exhaust Flow (acfm)	1,901,528	1,872,534	1,827,296	1,771,418
Exhaust Temperature (°F)	205	204	208	213
CT Emission rate (lb/hr)	1.075	1.047	1.004	0.954
CT Emission rate (lb/10^{12} Btu) (HHV)	278.8	278.7	278.7	278.7

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

Source: GE, 2017; Golder Associates, 2017.

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

Parameter	Units	Value	Annual Emission Basis: Fire Pump Engine	Annual Emission Basis: Emergency Generators
Number			1	2
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	5,897.8
HAPs [Section 112(b) of Clean Air Act]	Emission Factor [a, b]		Emissions (TPY)	
Acrolein	lb/MMBtu	7.88E-06	1.08E-06	2.32E-05
Acetaldehyde	lb/MMBtu	2.52E-05	3.47E-06	7.43E-05
Benzene	lb/MMBtu	7.76E-04	1.07E-04	2.29E-03
Formaldehyde	lb/MMBtu	7.89E-05	1.09E-05	2.33E-04
Naphthalene	lb/MMBtu	1.30E-04	1.79E-05	3.83E-04
Toluene	lb/MMBtu	2.81E-04	3.87E-05	8.29E-04
Xylene	lb/MMBtu	1.93E-04	2.66E-05	5.69E-04
Acenaphthene	lb/MMBtu	4.68E-06	6.44E-07	1.38E-05
Acenaphthylene	lb/MMBtu	9.23E-06	1.27E-06	2.72E-05
Anthracene	lb/MMBtu	1.23E-06	1.69E-07	3.63E-06
Benzo(a)anthracene	lb/MMBtu	6.22E-07	8.56E-08	1.83E-06
Benzo(b)fluoranthene	lb/MMBtu	1.11E-06	1.53E-07	3.27E-06
Benzo(k)fluoranthene	lb/MMBtu	2.18E-07	3.00E-08	6.43E-07
Benzo(g,h,i)perylene	lb/MMBtu	5.56E-07	7.65E-08	1.64E-06
Benzo(a)pyrene	lb/MMBtu	2.57E-07	3.54E-08	7.58E-07
Chrysene	lb/MMBtu	1.53E-06	2.11E-07	4.51E-06
Dibenzo(a,h)anthracene	lb/MMBtu	3.46E-07	4.76E-08	1.02E-06
Fluoanthene	lb/MMBtu	4.03E-06	5.55E-07	1.19E-05
Fluorene	lb/MMBtu	4.47E-06	6.15E-07	1.32E-05
Indo(1,2,3-cd)pyrene	lb/MMBtu	4.14E-07	5.70E-08	1.22E-06
Phenanthrene	lb/MMBtu	1.05E-06	1.45E-07	3.10E-06
Pyrene	lb/MMBtu	3.71E-06	5.11E-07	1.09E-05
Arsenic	lb/10^{12} Btu	4.0	5.51E-07	1.18E-05
Beryllium	lb/10^{12} Btu	3.0	4.13E-07	8.85E-06
Cadmium	lb/10^{12} Btu	3.0	4.13E-07	8.85E-06
Chromium	lb/10^{12} Btu	3.0	4.13E-07	8.85E-06
Lead	lb/10^{12} Btu	9.0	1.24E-06	2.65E-05
Mercury	lb/10^{12} Btu	3.0	4.13E-07	8.85E-06
Manganese	lb/10^{12} Btu	6.0	8.26E-07	1.77E-05
Nickel	lb/10^{12} Btu	3.0	4.13E-07	8.85E-06
Selenium	lb/10^{12} Btu	15.0	2.07E-06	4.42E-05
HAPs (Total)			2.17E-04	4.64E-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

Parameter/Pollutant	Fuel Heater Units	Fuel Heater Value	Fuel Heater Annual Emission Basis	Auxillary Boiler Units	Auxillary Boiler Value	Auxillary Boiler 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 7HA CT, BASE LOAD

Pollutant	Maximum Heat Input at 75 ^{0}F Ambient with Wet Compression (MMBtu/hr) Natural Gas	ULSD Oil	Emission Factor [a] (lb/MMBtu) Natural Gas	ULSD Oil	Hourly GHG Emissions (lb/hr) Natural Gas	ULSD Oil	Operating Hours Natural Gas	ULSD Oil	Annual GHG Emissions (TPY) Natural Gas	ULSD Oil	CO_2e Emission Rate [b] (TPY) Natural Gas	ULSD Oil	Total
Natural Gas Only													
CO_2	4,015.4	0.0	118.9	162.3	477,256.9	0.0	8760	0	2,090,385.3	0	2,090,385.3	0	2,090,385.3
CH_4	4,015.4	0.0	0.002204	0.006612	8.8	0.0	8760	0	38.8	0	969.1	0	969.1
N_2O	4,015.4	0.0	0.0002204	0.001322	0.9	0.0	8760	0	3.9	0	1,155.1	0	1155.1
										Total	2,092,509.5	0.0	2,092,509.5
Natural Gas & Distillate Fuel Oil													
CO_2	4,015.4	3,603.6	118.9	162.3	477,256.9	584,809.3	8260	1000	1,971,071.1	292,404.6	1,971,071.1	292,404.6	2,263,475.8
CH_4	4,015.4	3,603.6	0.002204	0.006612	8.8499	23.8269	8260	1000	36.6	11.9	913.75	297.84	1211.6
N_2O	4,015.4	3,603.6	0.0002204	0.001322	0.8850	4.7654	8260	1000	3.7	2.4	1089.19	710	1799.2
										Total	1,973,074.1	293,412.5	2,266,486.6
										Maximum Total	2,092,509.5	293,412.5	2,266,486.6

[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 shwon.

APPENDIX B

FPL LAUDERDALE UNITS 4 AND 5 EMISSION SUMMARY (2012-2016)

TABLE B-1
FORT LAUDERDALE UNIT 4 AND UNIT 5 ANNUAL HEAT INPUTS AND OPERATING HOURS, 2012 - 2016

Year	Heat Input from Diesel (MMBtu/yr)					Heat Input from Natural Gas (MMBtu/yr)					Total Actual Heat Input (MMBtu/yr)				
	Unit 4A	Unit 4B	Unit 5A	Unit 5B	Total	Unit 4A	Unit 4B	Unit 5A	Unit 5B	Total	Unit 4A	Unit 4B	Unit 5A	Unit 5B	Total
2016	26,352	40,847	27,582	368	95,150	5,314,485	6,189,150	6,568,683	6,674,432	24,746,750	5,340,837	6,229,997	6,596,265	6,674,800	24,841,900
2015	630	7,245	950	243	9,069	8,815,568	9,739,554	8,990,569	9,160,196	36,705,887	8,816,197	9,746,799	8,991,519	9,160,440	36,714,956
2014	2,365	4,875	808	1,794	9,842	9,370,624	8,860,672	9,510,912	9,467,925	37,210,133	9,372,989	8,865,547	9,511,720	9,469,719	37,219,975
2013	1,486	3,286	1,438	3,067	9,277	10,696,806	10,661,211	9,443,862	8,239,644	39,041,523	10,698,292	10,664,497	9,445,300	8,242,711	39,050,800
2012	561	561	924	924	2,971	9,196,000	9,172,000	8,554,000	8,706,000	35,628,000	9,196,561	9,172,561	8,554,924	8,706,924	35,630,971

UNIT 5

Year	Diesel Operating Hours (hr/yr)					Natural Gas Operating Hours (hr/yr)					Total Actual Operating Hours (hr/yr)				
	Unit 4A	Unit 4B	Unit 5A	Unit 5B	Total	Unit 4A	Unit 4B	Unit 5A	Unit 5B	Total	Unit 4A	Unit 4B	Unit 5A	Unit 5B	Total
2016	14	22	15	0	52	4,506	5,108	5,601	5,618	20,832	4,520	5,130	5,616	5,618	20,884
2015	0	4	1	0	5	6,844	7,558	6,883	7,009	28,294	6,844	7,562	6,884	7,009	28,299
2014	1	3	0	1	5	7,168	6,865	7,344	7,301	28,678	7,169	6,868	7,344	7,302	28,683
2013	1	2	1	2	5	7,956	8,007	7,155	6,235	29,354	7,957	8,009	7,156	6,237	29,359
2012	0	0	1	1	2	6,993	7,023	6,586	6,770	27,372	6,993	7,023	6,587	6,771	27,374

Note: All values are based on annual operating reports for the period 2012 - 2016.
Operating hours for 2014-2015 were based on a maximum heat input rate of 1,830 MMBtu/hr (distillate oil) and 1,608 MMBtu/hr (natural gas) as specified in permit 0250003-025-AV

TABLE B-2
ANNUAL EMISSIONS REPORTED IN 2012-2016 ANNUAL OPERATING REPORTS AND ACID RAIN DATABASE FOR LAUDERDALE UNITS 4 and 5

Year	Pollutant	Unit 4A (tons)	Unit 4B (tons)	Unit 5A (tons)	Unit 5B (tons)	Total (tons)
2016	NO_x	291.1	334.0	331.7	346.5	1,303.4
	CO	3.4	12.1	11.2	6.7	33.4
	SO_2	3.1	4.2	3.5	2.0	12.8
	VOC	0.46	0.87	1.32	1.00	3.7
	PM	5.105	6.0	6.3	6.3	23.7
	PM_{10}	5.103	6.0	6.3	6.3	23.7
	$PM_{2.5}$	5.100	6.0	6.3	6.3	23.7
	SAM [a]	--	--	--	--	2.0
	CO_2	318,244.4	371,250.7	392,756.1	396,471.1	1,478,722.3
2015	NO_x	471.6	507.1	446.4	495.8	1,920.8
	CO	3.0	10.1	13.5	9.0	35.6
	SO_2	2.7	3.3	2.8	2.8	11.5
	VOC	0.75	1.37	1.80	1.37	5.3
	PM [b]	8.376	9.27	8.54	8.70	34.9
	PM_{10} [b]	8.376	9.27	8.54	8.70	34.9
	$PM_{2.5}$	8.376	9.27	8.54	8.70	34.9
	SAM [a]	--	--	--	--	1.8
	CO_2	523,948.5	579,397.3	534,380.7	544,374.9	2,182,101.3
2014	NO_x	475.2	447.5	524.8	518.8	1,966.3
	CO	4.2	4.0	4.5	14.7	27.4
	SO_2	3.0	3.0	2.9	3.0	11.8
	VOC	0.06	1.55	1.71	1.37	4.7
	PM	30.93729	29.3	31.4	31.3	122.9
	PM_{10}	30.9	29.3	31.4	31.3	122.9
	SAM [a]	--	--	--	--	1.8
	CO_2	557,200.6	527,027.7	565,529.1	562,596.6	2,212,354.1
2013	NO_x	522.5	536.6	509.8	451.9	2,020.8
	CO	49.8	49.7	44.0	37.6	181.1
	SO_2	3.3	3.4	3.6	3.0	13.3
	VOC	0.0	0.0	0.0	0.0	0.1
	PM [b]	34.7	34.7	30.7	26.3	126.3
	PM_{10} [b]	34.7	34.7	30.7	26.3	126.3
	SAM [a]	--	--	--	--	2.0
	CO_2	635,700.7	633,770.5	561,165.2	490,044.7	2,320,681.1
2012	NO_x	445.1	486.4	447.2	451.2	1,830.0
	CO	43.5	43.4	40.5	41.2	168.6
	SO_2	2.8	2.8	2.6	2.7	11.0
	VOC	0.0	0.0	0.0	0.0	0.0
	PM [b]	30.4	30.3	28.2	28.7	117.6
	PM_{10} [b]	30.4	30.3	28.2	28.7	117.6
	SAM [a]	--	--	--	--	1.7
	CO_2	554,931.1	553,451.2	516,210.2	525,476.7	2,150,069.3

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

[b] Emissions rates reported in the AORs were multiplied by 1000 to correct error in the emission factor used in the AORs for 2012-2013.

Source: Annual Operating Report (AOR) for Fort Lauderdale Power Plant, 2012 - 2016; EPA's Acid Rain database.

TABLE B-3
ACTUAL ANNUAL EMISSIONS OF N_2O AND CH_4 FOR THE PERIOD 2012 - 2016 LAUDERDALE UNITS 4 & 5

Unit	Actual Annual Heat Input [a] (MMBtu/yr)	N_2O Emissions Emission Factor [b] (lb/MMBtu)	N_2O Annual Emissions (lb/yr)	N_2O Annual Emissions (TPY)	N_2O CO_2e [c] Rate (TPY)	CH_4 Emissions Emission Factor [b] (lb/MMBtu)	CH_4 Annual Emissions (lb/yr)	CH_4 Annual Emissions (TPY)	CH_4 CO_2e [c] Rate (TPY)
Units 4&5 - Distillate Oil-Firing									
2016	95,150	1.32E-03	125.8	0.063	18.75	6.6E-03	629.1	0.315	7.86
2015	9,069	1.32E-03	12.0	0.006	1.79	6.6E-03	60.0	0.030	0.75
2014	9,842	1.32E-03	13.0	0.007	1.94	6.6E-03	65.1	0.033	0.81
2013	9,277	1.32E-03	12.3	0.006	1.83	6.6E-03	61.3	0.031	0.77
2012	2,971	1.32E-03	3.9	0.002	0.59	6.6E-03	19.6	0.010	0.25
Units 4&5 - Natural Gas-Firing									
2016	24,746,750	2.20E-04	5,454.2	2.7	812.7	2.2E-03	54,541.8	27.3	681.8
2015	36,705,887	2.20E-04	8,090.0	4.0	1,205.4	2.2E-03	80,899.8	40.4	1,011.2
2014	37,210,133	2.20E-04	8,201.1	4.1	1,222.0	2.2E-03	82,011.1	41.0	1,025.1
2013	39,041,523	2.20E-04	8,604.8	4.3	1,282.1	2.2E-03	86,047.5	43.0	1,075.6
2012	35,628,000	2.20E-04	7,852.4	3.9	1,170.0	2.2E-03	78,524.1	39.3	981.6
Total									
2016	--	--	--	2.8	831.4	--	--	27.6	689.6
2015	--	--	--	4.1	1,207.2	--	--	40.5	1,012.0
2014	--	--	--	4.1	1,223.9	--	--	41.0	1,026.0
2013	--	--	--	4.3	1,283.9	--	--	43.1	1,076.4
2012	--	--	--	3.9	1,170.6	--	--	39.3	981.8

[a] Based on AOR data - see Table 1.
[b] Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu were converted to lb/MMBtu by multiplying by 2.204.
[c] N_2O and CH_4 are multiplied by a factor of 298 and 25, respectively, to determine CO_2 equivalence.

APPENDIX C

BACT DETERMINATIONS FROM EPA RBL CLEARINGHOUSE

TABLE C-1
SUMMARY OF CO BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	CO Limit	Basis
Florida							
Okeechobee Clean Energy Center	FL	3/9/2016	3-on-1 Combined Cycle CT with HRSG	3,096 MMBtu/hr	GCP	4.3 ppmvd @ 15% O_2	BACT-PSD
Duke Energy - Citrus Combined Cycle	FL	12/1/2014	2-on-1 Combined Cycle with HRSG	270 MW	GCP	4.0 ppmvd @ 15% O_2	AC Permit
FPL Port Everglades Power Plant	FL	5/9/2012	3-on-1 Combined Cycle CT with HRSG	250 MW	GCP	9.0 ppmvd @ 15% O_2	AC Permit
FPL Cape Canaveral Energy Center	FL	7/23/2009	3-on-1 Combined Cycle CT with HRSG	265 MW	GCP	5.0 ppmvd @ 15% O_2	AC Permit
FPL Cape Canaveral Energy Center	FL	7/23/2009	3-on-1 Combined Cycle CT with HRSG	265 MW	GCP	7.6 ppmvd @ 15% O_2	AC Permit
FPL Riviera Beach Energy Center	FL	6/10/2009	3-on-1 Combined Cycle CT with HRSG	265 MW	GCP	7.6 ppmvd @ 15% O_2	AC Permit
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	GCP, Clean Fuels	12.0 ppmvd	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
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
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
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
JOHNSONVILLE COGENERATION	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1339 MMBtu/hr	GCP, Catalytic Oxidation	2.0 ppmvd @ 15% O_2	BACT-PSD
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
Other States							
GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generato	426 MW	N/A	2.0 ppmvd @ 15% O_2	BACT-PSD
ST. CHARLES POWER STATION	LA	8/31/2016	(2) SCPS Combined Cycle (Unit 1A & 1B)	3625 MMBTU/hr	Oxidation Catalyst, GCP	2.0 ppm @ 15% O_2	BACT-PSD
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine - 7HA.02	380 MW	Oxidation Catalyst, GCP	2.0 ppmvd @ 15% O_2	BACT-PSD
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle CT w/DB -3462 MMBtu/hr + 499 for DB	3961 mmBtu/hr	Oxidation Catalyst, GCP	2.0 ppmvd @ 15% O_2	BACT-PSD
GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED	3227 mmBtu/hr	Oxidation Catalyst	1.6 ppmvd	Unkown
NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231 MW	Oxidation Catalyst	4.0 ppm	BACT-PSD
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231 MW	Oxidation Catalyst	4.0 ppm	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w/o DB	805 MW	Oxidation Catalyst	0.9 ppmvd @ 15% O_2	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w DB	805 MW	Oxidation Catalyst	1.7 ppmvd @ 15% O_2	BACT-PSD
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
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
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

TABLE C-1
SUMMARY OF CO BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	CO Limit	Basis
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
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

Source: EPA 2017 (RBLC database); Golder, 2017

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

TABLE C-2
SUMMARY OF CO BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	CO Limit	Basis
Florida								
Okeechobee Clean Energy Center	FL	3/9/2016	3-on-1 Combined-cycle CT with HRSG	3,096 MMBtu/hr	Clean burners	GCP	10 ppmvd @ 15% O_2	BACT-PSD
FPL Port Everglades Power Plant	FL	5/9/2012	3-on-1 Combined Cycle CT with HRSG	250 MW	Fuel Oil	GCP	35 ppmvd @ 15% O_2	AC Permit
FPL Cape Canaveral Energy Center	FL	7/23/2009	3-on-1 Combined Cycle CT with HRSG	265 MW	Fuel Oil	GCP	10 ppmvd @ 15% O_2	AC Permit
FPL Riviera Beach Energy Center	FL	6/10/2009	3-on-1 Combined Cycle CT with HRSG	265 MW	Fuel Oil	GCP	10 ppmvd @ 15% O_2	AC Permit
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	AC Permit
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	20 ppmvd	BACT-PSD
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
Other States								
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	COMBINED CYCLE COMBUSTION TURBIN	633 MW	ULSD	GCP, Oxydation Catalyst	2 ppmvd @ 15% O_2	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	805 MW	ULSD	Oxidation Catalyst	2 ppmvd @ 15% O_2	BACT-PSD

Source: EPA 2017 (RBLC database); Golder, 2017

Note: GCP= good combustion practices

TABLE C-3
SUMMARY OF VOC BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	VOC Limit	Basis
Florida							
Okeechobee Clean Energy Center	FL	3/9/2016	3-on-1 Combined-cycle CT with HRSG	3,096 MMBtu/hr	GCP	1.0 ppmvd @ 15 % O_2	BACT-PSD
FPL Port Everglades Power Plant	FL	5/9/2012	3-on-1 Combined-cycle CT with HRSG	250 MW	GCP	1.2 ppmvd @ 15% O_2	AC Permit
FPL Cape Canaveral Energy Center	FL	7/23/2009	3-on-1 Combined-cycle CT with HRSG	265 MW	GCP	1.9 ppmvd @ 15% O_2	AC Permit
FPL Cape Canaveral Energy Center	FL	7/23/2009	3-on-1 Combined-cycle CT with HRSG	265 MW	GCP	1.5 ppmvd @ 15% O_2	AC Permit
FPL Riviera Beach Energy Center	FL	6/10/2009	3-on-1 Combined-cycle CT with HRSG	265 MW	GCP	1.9 ppmvd @ 15% O_2	AC Permit
FPL Riviera Beach Energy Center	FL	6/10/2009	3-on-1 Combined-cycle CT with HRSG	265 MW	GCP	1.5 ppmvd @ 15% O_2	AC Permit
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	GCP, Clean Fuels	1.4 ppmvd	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
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
Other States							
GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Ge	426 MW	GCP, Catalytic Oxidation	3.5 ppmvd @ 15 % O_2	BACT-PSD
ST. CHARLES POWER STATION	LA	8/31/2016	(2) SCPS Combined Cycle (Unit 1A & 1B)	3625 MMBTU/hr	GCP, Catalytic Oxidation	2.0 ppm @ 15% O2	BACT-PSD
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine - 7HA.02	380 MW	Oxidation catalyst, GCP	1.0 ppmvd @ 15% O2	LAER
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle CT w/DB -3462 MMBtu/hr + 499 for DI	3961 mmBtu/hr	Oxidation catalyst, GCP	2.0 ppmvd @ 15% O2	LAER
GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-I	3227 mmBtu/hr	Oxidation catalyst, GCP	1.4 ppmvd	Unknown
NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231 MW	Oxidation Catalyst	2.0 ppm	BACT-PSD
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231 MW	Oxidation Catalyst	2.0 ppm	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w/o DB	805 MW	Oxidation Catalyst	1.0 ppmvd @ 15% O2	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w DB	805 MW	Oxidation Catalyst	2.0 ppmvd @ 15% O2	BACT-PSD
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
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 c	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 prac	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

TABLE C-3
SUMMARY OF VOC BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	VOC Limit	Basis
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
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
Kleen Energy Systems, LLC	CT	2/25/2008	(2) Siemens SGT6-5000f CT+DB	2581 MMBtu/hr	Oxidation Catalyst	5.0 ppmvd @ 15 % O_2	BACT-PSD
CPV Warren LLC	VA	1/14/2008	Electric Generation - Scenario 1	1717 MMBtu/hr	GCP and Oxidation Catalyst.	0.7 ppmvd	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
CPV Warren LLC	VA	1/14/2008	Electric Generation - Secnario 3	2204 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

Source: EPA 2017 (RBLC database); Golder, 2017

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

TABLE C-4
SUMMARY OF VOC BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	VOC Limit	Basis
Florida								
Okeechobee Clean Energy Center	FL	3/9/2016	3-on-1 Combined-cycle CT with HRSG	3,096 MMBtu/hr	Fuel Oil	GCP, Clean Fuels	2 ppmvd @ 15% O_2	BACT-PSD
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	AC Permit
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	AC Permit
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	AC Permit
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	7.0 ppmvw	AC Permit
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	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
Other States								
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	COMBINED CYCLE COMBUSTION TURBINE	633 MW	ULSD	GCP, Catalytic Oxidation	2.0 ppmvd @ 15% O_2	LAER
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	805 MW	ULSD	Oxidation Catalyst	2.0 ppmvd @ 15% O_2	BACT-PSD

Source: EPA 2017 (RBLC database); Golder, 2017

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

TABLE C-5

SUMMARY OF PM BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2007-2017) AS OF 6/2017

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								
Okeechobee Clean Energy Center	FL	3/9/2016	3-on-1 Combined-cycle CT with HRSG	3,096 MMBtu/hr	Clean fuels	2 gr S/100 scf		BACT-PSD
FPL Port Everglades Power Plant	FL	5/9/2012	3-on-1 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-on-1 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-on-1 Combined-cycle CT with HRSG	265 MW	NG Fuel and GCP	2 gr S/100 scf		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
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	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
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Johnsonville Cogeneration	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1,339 MMBtu/hr	GCP	0.005 lb/MMBtu		BACT-PSD
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
Other States								
St. Charles Power Station	LA	8/31/2016	(2) SCPS Combined Cycle (Unit 1A & 1B)	3625 MMBTU/hr	GCP, Clean Fuels	17.52 lb/hr	0.0080 lb/MMBtu	BACT-PSD
Middlesex Energy Center, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine - 7HA.02	380 MW	Clean fuel	11.7 lb/hr		BACT-PSD
Middlesex Energy Center, LLC	NJ	7/19/2016	Combined Cycle CT w/DB -3462 MMBtu/hr + 499 for I	3961 mmBtu/hr	Clean fuel	18.3 lb/hr		BACT-PSD
Greensville Power Station	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT	3227 mmBtu/hr	LSF, GCP	0.0039 LB/MMBTU		Unkown
Neches Station	TX	3/24/2016	Combined Cycle & Cogeneration	231 MW	GCP, LSF	19.35 lb/hr		BACT-PSD
Decordova Steam Electric Station	TX	3/8/2016	Combined Cycle & Cogeneration	231 MW	GCP, LSF	35.47 lb/hr		BACT-PSD
CPV Towantic, LLC	CT	11/30/2015	Combined Cycle Power Plant - w/o DB	805 MW	N/A	9.73 lb/hr		BACT-PSD
CPV Towantic, LLC	CT	11/30/2015	Combined Cycle Power Plant - w DB	805 MW	N/A	20.4 lb/hr		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 maxim	8 lb/hr	0.0027	BACT-PSD

TABLE C-5
SUMMARY OF PM BACT DETERMINATIONS FOR NATURAL GAS-FIRED CTS (2007-2017) AS OF 6/2017

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
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
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

Source: EPA 2017 (RBLC database); Golder, 2017
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 C-6
SUMMARY OF PM BACT DETERMINATIONS FOR FUEL OIL-FIRED CTS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Fuel	Control Method	$PM/PM_{10}/PM_{2.5}$ Limit	Basis
Florida								
Okeechobee Clean Energy Center	FL	3/9/2016	3-on-1 Combined-cycle CT with HRSG	3,096 MMBtu/hr	Fuel Oil	Clean Fuel, GCP	0.0015 % S in Fuel Oil	BACT-PSD
FPL Port Everglades Power Plant	FL	5/9/2012	3-on-1 Combined-cycle CT with HRSG	250 MW	Fuel Oil	Clean Fuel, GCP	0.0015 % S in Fuel Oil	AC Pemrit
FPL Cape Canaveral Energy Center	FL	7/23/2009	3-on-1 Combined-cycle CT with HRSG	265 MW	Fuel Oil	Clean Fuel, GCP	0.0015 % S in Fuel Oil	AC Pemrit
FPL Riviera Beach Energy Center	FL	6/10/2009	3-on-1 Combined-cycle CT with HRSG	265 MW	Fuel Oil	Clean Fuel, GCP	0.0015 % S in Fuel Oil	AC Pemrit
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	AC Pemrit
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	Fuel Oil	GCP, Clean Fuels	17 lb/hr	BACT-PSD
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	
Other States								
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	COMBINED CYCLE COMBUSTION TURBINE FIR	633 MW	ULSD	ULSD, Clean Fuel	34.3 lb/hr	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	805 MW	ULSD	N/A	42.6 lb/hr	BACT-PSD

Source: EPA 2017 (RBLC database); Golder, 2017
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 C-7
SUMMARY OF SO_2 BACT DETERMINATIONS FOR CTS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	MW/Heat Input		Fuel	Control Method	SO2 Limit		Basis
GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam G	426	MW	Natural Gas	Pipeline quality natural gas	1.54	lb/hr	BACT-PSD
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine - 7HA.02	380	MW	Natural Gas	LSF	5.62	lb/hr	CASE-BY-CASE
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle CT w/DB -3462 MMBtu/hr + 499 for D	3961	mmBtu/hr	Natural Gas	LSF	6.64	lb/hr	CASE-BY-CASE
GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT	3227	mmBtu/hr	Natural Gas	LSF	0.0011	lb/mmbtu	Unkown
NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	Natural Gas	LSF, GCP	1	GR/100 SCF	
OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3,096	MMBtu/hr	Natural Gas	LSF	2	GR/100 SCF	BACT-PSD
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	Natural Gas	LSF, GCP	5	GR/100 SCF	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w/o DB	805	MW	Natural Gas	LSF	4.49	LB/HR	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w DB	805	MW	Natural Gas	LSF	6.2	LB/HR	BACT-PSD
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
West Deptford Energy Station	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burne	20,282	MMCF/YR	Natural Gas	Use of natural gas a clean bı	6.56	LB/H	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	3846.0046	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	3846.0046	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 2017 (RBLC database); Golder, 2017

Note: LSF=low sulfur fuel, GCP= good combustion practices.

TABLE C-8

SUMMARY OF O, VOC, PM, AND SO2 BACT DETERMINATIONS FOR AUXILIARY BOILERS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Volatile Organic Compounds (VOC)								
Middlesex Energy Center, LLC	NJ	7/19/2016	Auxiliary Boiler	NG	97.5 MMBtu/hr	GCP and use of clean fuel	0.005 lb/MMBtu	LAER
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	Auxiliary 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 c	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, goo	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 ACCORDANCE	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
Particulate Matter (PM/PM_{10}/$PM_{2.5}$)								
Middlesex Energy Center, LLC	NJ	7/19/2016	Auxiliary Boiler	NG	97.5 MMBtu/hr	Use of clean fuel	0.005 lb/MMBtu	BACT-PSD
SEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler	NG	80 MMBtu/hr	Clean Fuel and GCP	0.005 lb/MMBtu	BACT-PSD
Okeechobee Clean Energy Center	FL	3/9/2016	Auxiliary Boiler	NG	99.8 MMBtu/hr	Clean Fuel and GCP	10% Opacity	BACT-PSD
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
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	Auxiliary 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 Precipitator	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 prop	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 D	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	6/6/2007	Boiler	Diesel Oil	40 MMBtu/hr	GCP	0.024 lb/MMBtu	
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
Fairbault Energy Park	MN	6/5/2007	Boiler	NG	40 MMBtu/hr	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

TABLE C-8
SUMMARY OF O, VOC, PM, AND SO2 BACT DETERMINATIONS FOR AUXILIARY BOILERS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Carbon Monoxide (CO)								
Middlesex Energy Center, LLC	NJ	7/19/2016	Auxiliary Boiler	NG	97.5 MMBtu/hr	Clean Fuel and GCP	0.037 lb/MMBtu	BACT-PSD
SEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler	NG	80 MMBtu/hr	Clean Fuel and GCP	0.036 lb/MMBtu	BACT-PSD
Okeechobee Clean Energy Center	FL	3/9/2016	Auxiliary Boiler	NG	99.8 MMBtu/hr	GCP	0.080 lb/MMBtu	BACT-PSD
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	Auxiliary 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	Auxilliary 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
Sulfur Dioxide (SO_2)								
Middlesex Energy Center, LLC	NJ	7/19/2016	Auxiliary Boiler	NG	97.5 MMBtu/hr	Low sulfur fuel	0.001 lb/MMBtu	CASE-BY-CASE
SEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler	NG	80 MMBtu/hr	Low sulfur fuel	0.002 lb/MMBtu	CASE-BY-CASE
Okeechobee Clean Energy Center	FL	3/9/2016	Auxiliary Boiler	NG	99.8 MMBtu/hr	2 gr S/100 scf	0.080 lb/MMBtu	BACT-PSD
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 2017 (RBLC database); Golder, 2017
Note: LNB= dry low NOx; GCP= good combustion practices; LNB= low NOx burner; FGR= flue gas recirculation

TABLE C-9
SUMMARY OF BACT DETERMINATIONS FOR FUEL HEATERS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Nitrogen Oxides (NOx)								
Indeck Niles, LLC	MI	1/4/2017	Fuel Preheater	NG	27 MMBtu/hr	GCP	0.098 lb/MMBtu	BACT-PSD
MID-KANSAS ELECTRIC COMPANY, LLC - RUBART	KS	3/31/2016	Indirect fuel gas heater	NG	2 MMBtu/hr		0.100 lb/MMBtu	BACT-PSD
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
Volatile Organic Compounds (VOC)								
Indeck Niles, LLC	MI	1/4/2017	Fuel Preheater	NG	27 MMBtu/hr	GCP	0.006 lb/MMBtu	BACT-PSD
MID-KANSAS ELECTRIC COMPANY, LLC - RUBART	KS	3/31/2016	Indirect fuel gas heater	NG	2 MMBtu/hr		0.006 lb/MMBtu	BACT-PSD
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
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)								
Indeck Niles, LLC	MI	1/4/2017	Fuel Preheater	NG	27 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
MID-KANSAS ELECTRIC COMPANY, LLC - RUBART	KS	3/31/2016	Indirect fuel gas heater	NG	2 MMBtu/hr		0.008 lb/MMBtu	BACT-PSD
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 No. 1 (EU 401, EUG 4)	Refinery Gas	20 MMBtu/hr		0.008 LB/H	
Pryor Plant Chemical	OK	2/23/2009	NITRIC ACID PREHEATERS #1, #3, AND #4	NG	20 MMBtu/hr		0.008 lb/MMBtu	BACT-PSD

TABLE C-9
SUMMARY OF BACT DETERMINATIONS FOR FUEL HEATERS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
GP Clarendon LP	SC	2/10/2009	BACKUP THERMAL OIL HEATER	Diesel	75 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
Gp Clarendon Lp	SC	2/10/2009	NATURAL GAS SPACE HEATERS - 14 UNITS (ID 17)	Syngas	20.9 MMBtu/hr		0.007 LB/H	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
Carbon Monoxide (CO)								
Indeck Niles, LLC	MI	1/4/2017	Fuel Preheater	NG	27 MMBtu/hr	GCP	0.082 lb/MMBtu	BACT-PSD
MID-KANSAS ELECTRIC COMPANY, LLC - RUBART	KS	3/31/2016	Indirect fuel gas heater	NG	2 MMBtu/hr		0.08 lb/MMBtu	BACT-PSD
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
Sulfur Dioxide (SO_2)								
Indeck Niles, LLC	MI	1/4/2017	Fuel Preheater	NG	27 MMBtu/hr	GCP and use of NG	0.2 gr/100 scf	BACT-PSD
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 2017 (RBLC database); Golder, 2017

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 C-10
SUMMARY OF BACT DETERMINATIONS FOR COOLING TOWERS (2007-2017) AS OF 6/2017

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	Pollutant Limit	Basis
ST. Charles Power Station	LA	8/31/2016	Cooling Tower	164,400 gal/min	Drift Eliminators 0.005% DR		BACT-PSD
Okeechobee Clean Energy Center	FL	3/9/2016	Cooling Tower	465,815 gal/min	Drift Eliminators 0.0005% DR		BACT-PSD
The Empire District Electric Co.	KS	7/14/2015	Cooling Tower	gal/min	Drift Eliminators 0.0005% DR		BACT-PSD
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	

Source: EPA 2017 (RBLC database); Golder, 2017
Note: DR = Drift rate

TABLE C-11
SUMMARY OF GREENHOUSE GAS BACT DETERMINATIONS FOR NATURAL GAS COMBINED-CYCLE CTs (AS OF 6/2017)

Facility Name	State	Permit Issued	CO_2e Limit (mass)	CO_2e Limit (lb/MWH)	Heat Rate (Btu/kWH)	Note
GAINES COUNTY POWER PLANT	TX	4/28/2017	NA	960	NA	Siemens SGT6-5000F
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	NA	888	NA	12-month rolling average; 560 MW
Okeechobee Clean Energy Center	FL	3/9/2016	NA	850	NA	3-on-1 GE 7HA.02
FGE Eagle Pines Project	TX	11/4/2015	NA	886	NA	3, 2-on-1 Alstom GT36
Colorado Bend Energy Center	TX	4/1/2015	MA	880 *	7,395	2-on-1 GE 7HA.02
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	905 *	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	995 **	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	

* Calculated from heat rate using EPA Part 75 procedures. ** Design value at 59 oF.
Source: EPA RBLC, 2015.

Note: NA = not applicable.

Golder Associates

APPENDIX D

AIR MODELING CT LOAD ANALYSIS

TABLE D-1 (GE)
MAXIMUM CONCENTRATIONS PREDICTED FOR EMISSIONS OF ONE CT/HRSG FIRING NATURAL GAS IN COMBINED-CYCLE OPERATION, DBEC

Natural Gas

	Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature									Averaging	Maximum Predicted Concentrations (μg/m³) for CT by Operating Load and Air Temperature [a]								
	Base Load			75% Load			50% Load				Base Load			75% Load			50% Load		
	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	Time	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.48	0.47	0.46	0.61	0.68	0.58	0.92	0.89	0.82
(10 g/s - 5 g/s/HRSG)										Annual [d]	0.43	0.42	0.41	0.55	0.62	0.53	0.84	0.81	0.74
										24-Hour [c]	2.89	2.79	2.75	4.33	5.50	4.08	8.86	8.45	7.44
										24-Hour [d]	2.60	2.53	2.49	3.42	4.14	3.28	6.46	6.16	5.49
										8-Hour [c]	6.52	6.39	6.31	8.47	10.54	8.22	14.93	14.40	13.15
										3-Hour [c]	9.26	8.81	8.57	13.37	15.32	12.71	22.45	21.47	18.60
										1-Hour [c]	16.11	15.55	15.23	16.43	18.98	15.61	26.00	25.02	22.78
										1-Hour [e]	8.43	8.19	8.06	9.84	11.18	9.44	15.58	15.05	13.98
Emissions for 1 CT																			
SO_2	23.38	23.78	23.67	18.59	14.89	17.09	10.31	10.38	10.99	Annual [c]	0.14	0.14	0.14	0.14	0.13	0.13	0.12	0.12	0.11
										24-Hour [c]	0.85	0.84	0.82	1.01	1.03	0.88	1.15	1.11	1.03
										3-Hour [c]	2.73	2.64	2.56	3.13	2.87	2.74	2.92	2.81	2.58
										1-Hour [e]	2.48	2.46	2.41	2.31	2.10	2.03	2.02	1.97	1.94
PM_{10}	17.55	17.64	17.61	15.95	14.83	15.91	13.32	13.44	13.63	Annual [c]	0.11	0.10	0.10	0.12	0.13	0.12	0.15	0.15	0.14
										24-Hour [c]	0.64	0.62	0.61	0.87	1.03	0.82	1.486	1.432	1.278
$PM_{2.5}$	17.55	17.64	17.61	15.95	14.83	15.91	13.32	13.44	13.63	Annual [d]	0.10	0.09	0.09	0.11	0.11	0.11	0.14	0.14	0.13
										24-Hour [d]	0.58	0.56	0.55	0.69	0.77	0.66	1.08	1.04	0.94
NO_x	28.71	29.20	29.08	22.82	18.27	20.98	12.64	12.73	13.48	Annual [c]	0.17	0.17	0.17	0.18	0.16	0.15	0.15	0.14	0.14
										1-Hour [e]	3.05	3.01	2.96	2.83	2.57	2.49	2.48	2.41	2.37
CO	49.55	50.40	50.21	39.70	33.98	37.62	26.92	26.83	27.79	8-Hour [c]	4.07	4.06	3.99	4.24	4.51	3.90	5.06	4.87	4.60
										1-Hour [c]	10.06	9.87	9.63	8.22	8.13	7.40	8.82	8.46	7.98

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2012 to 2016 consisting of surface and upper air data from the National Weather Service stations at Fort Lauderdale-Hollywood Int'l AP and Florida International University (FIU) in Miami.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 2 CT/HRSGs. 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 (2012-2016).

[d] Based on highest 5-year average concentration (2012-2016).

[e] Based on highest 5-year average daily maximum 1-hour concentration (2012-2016).

TABLE D-2 (GE)
MAXIMUM CONCENTRATIONS PREDICTED FOR EMISSIONS OF ONE CT/HRSG FIRING ULSD OIL IN COMBINED-CYCLE OPERATION, DBEC

Ultra Low-Sulfur Fuel Oil	Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature									Averaging	Maximum Predicted Concentrations (µg/m³) for CT by Operating Load and Air Temperature[a]								
	Base Load			75% Load			50% Load			Time	Base Load			75% Load			50% Load		
	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F		35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.38	0.39	0.39	0.50	0.53	0.55	0.69	0.73	0.76
(10 g/s - 5 g/s/HRSG										Annual [d]	0.34	0.35	0.35	0.45	0.48	0.50	0.62	0.67	0.69
										24-Hour [c]	2.34	2.39	2.41	3.15	3.54	3.75	5.68	6.27	6.60
										24-Hour [d]	2.08	2.13	2.14	2.73	2.94	3.06	4.20	4.69	4.98
										8-Hour [c]	5.44	5.56	5.59	6.95	7.45	7.69	10.95	11.80	12.36
										3-Hour [c]	6.58	6.89	7.01	10.22	11.32	11.85	15.48	16.61	17.17
										1-Hour [c]	12.23	12.65	12.91	12.67	13.65	14.47	19.19	20.67	21.40
										1-Hour [e]	6.59	6.77	6.85	7.96	8.58	8.95	11.37	12.19	12.88
Emissions for 1 CT																			
SO_2	5.91	5.52	5.25	4.63	4.27	4.02	3.43	3.18	3.02	Annual [c]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
										24-Hour [c]	0.17	0.17	0.16	0.18	0.19	0.19	0.25	0.25	0.25
										3-Hour [c]	0.49	0.48	0.46	0.60	0.61	0.60	0.67	0.67	0.65
										1-Hour [e]	0.49	0.47	0.45	0.46	0.46	0.45	0.49	0.49	0.49
PM_{10}	61.6	61.5	61.5	61.3	61.2	61.2	61.0	60.9	60.9	Annual [c]	0.30	0.30	0.30	0.39	0.41	0.43	0.53	0.56	0.58
										24-Hour [c]	1.82	1.86	1.86	2.44	2.73	2.89	4.36	4.81	5.06
$PM_{2.5}$	61.6	61.5	61.5	61.3	61.2	61.2	61.0	60.9	60.9	Annual [d]	0.26	0.27	0.27	0.35	0.37	0.38	0.48	0.51	0.53
										24-Hour [d]	1.62	1.65	1.66	2.11	2.27	2.36	3.23	3.60	3.82
NO_x	120.0	112.0	106.4	93.9	86.6	81.6	69.5	64.4	61.2	Annual [c]	0.58	0.55	0.53	0.59	0.58	0.57	0.60	0.60	0.59
										1-Hour [e]	9.96	9.55	9.18	9.43	9.36	9.20	9.97	9.89	9.93
CO	114.8	108.7	103.8	92.6	84.3	80.0	77.1	69.8	65.3	8-Hour [c]	7.87	7.61	7.32	8.11	7.91	7.75	10.63	10.39	10.17
										1-Hour [c]	17.68	17.32	16.88	14.78	14.49	14.58	18.63	18.19	17.60

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2012 to 2016 consisting of surface and upper air data from the National Weather Service stations at Fort Lauderdale-Hollywood Int'l AP and Florida International University (FIU) in Miami.
[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 2 CT/HRSGs. 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 (2012-2016).
[d] Based on highest 5-year average concentration (2012-2016).
[e] Based on highest 5-year average daily maximum 1-hour concentration (2012-2016).

TABLE D-3 (GE)
MAXIMUM CLASS I CONCENTRATIONS PREDICTED FOR EMISSIONS OF ONE CT/HRSG FIRING NATURAL GAS IN COMBINED-CYCLE OPERATION, DBEC

Natural Gas	Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature									Averaging	Maximum Predicted Concentrations (μg/m³) for CT by Operating Load and Air Temperature [a]								
	Base Load			75% Load			50% Load				Base Load			75% Load			50% Load		
	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	Time	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
(10 g/s - 5 g/s/HRSG)										Annual [d]	0.01	0.01	0.01	0.02	0.02	0.01	0.02	0.02	0.02
										24-Hour [c]	0.19	0.18	0.18	0.21	0.22	0.21	0.26	0.25	0.24
										24-Hour [d]	0.15	0.15	0.15	0.18	0.18	0.17	0.21	0.20	0.20
										8-Hour [c]	0.47	0.46	0.46	0.54	0.56	0.52	0.66	0.65	0.61
										3-Hour [c]	0.67	0.65	0.64	0.82	0.87	0.77	1.03	1.01	0.96
										1-Hour [c]	1.08	1.06	1.05	1.19	1.24	1.16	1.51	1.47	1.38
										1-Hour [e]	8.43	8.19	8.06	9.84	11.18	9.44	15.58	15.05	13.98
Emissions for 1 CT																			
SO_2	23.38	23.78	23.67	18.59	14.89	17.09	10.31	10.38	10.99	Annual [c]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
										24-Hour [c]	0.05	0.05	0.05	0.05	0.04	0.04	0.03	0.03	0.03
										3-Hour [c]	0.20	0.19	0.19	0.19	0.16	0.17	0.13	0.13	0.13
										1-Hour [e]	2.48	2.46	2.41	2.31	2.10	2.03	2.02	1.97	1.94
PM_{10}	17.55	17.64	17.61	15.95	14.83	15.91	13.32	13.44	13.63	Annual [c]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
										24-Hour [c]	0.04	0.04	0.04	0.04	0.04	0.04	0.043	0.043	0.042
$PM_{2.5}$	17.55	17.64	17.61	15.95	14.83	15.91	13.32	13.44	13.63	Annual [d]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
										24-Hour [d]	0.03	0.03	0.03	0.04	0.03	0.03	0.03	0.03	0.03
NO_x	28.71	29.20	29.08	22.82	18.27	20.98	12.64	12.73	13.48	Annual [c]	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
										1-Hour [e]	3.05	3.01	2.96	2.83	2.57	2.49	2.48	2.41	2.37
CO	49.55	50.40	50.21	39.70	33.98	37.62	26.92	26.83	27.79	8-Hour [c]	0.30	0.29	0.29	0.27	0.24	0.25	0.22	0.22	0.21
										1-Hour [c]	0.67	0.67	0.66	0.60	0.53	0.55	0.51	0.50	0.48

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2012 to 2016 consisting of surface and upper air data from the National Weather Service stations at Fort Lauderdale-Hollywood Int'l AP and Florida International University (FIU) in Miami.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 2 CT/HRSGs. 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 (2012-2016).

[d] Based on highest 5-year average concentration (2012-2016).

[e] Based on highest 5-year average daily maximum 1-hour concentration (2012-2016).

Golder Associates

TABLE D-4 (GE)
MAXIMUM CLASS I CONCENTRATIONS PREDICTED FOR EMISSIONS OF ONE CT/HRSG FIRING ULSD OIL IN COMBINED-CYCLE OPERATION, DBEC

Ultra Low-Sulfur Fuel Oil

	Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature										Maximum Predicted Concentrations ($\mu g/m^3$) for CT by Operating Load and Air Temperature[a]								
	Base Load			75% Load			50% Load			Averaging	Base Load			75% Load			50% Load		
	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	Time	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F	35 °F	75 °F	95 °F
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
(10 g/s - 5 g/s/HRSG										Annual [d]	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
										24-Hour [c]	0.17	0.17	0.17	0.19	0.19	0.20	0.23	0.23	0.23
										24-Hour [d]	0.13	0.13	0.13	0.16	0.16	0.16	0.19	0.19	0.19
										8-Hour [c]	0.39	0.40	0.40	0.48	0.49	0.50	0.56	0.58	0.59
										3-Hour [c]	0.52	0.53	0.53	0.67	0.71	0.72	0.87	0.90	0.92
										1-Hour [c]	0.95	0.96	0.96	1.08	1.11	1.12	1.25	1.30	1.32
										1-Hour [e]	6.59	6.77	6.85	7.96	8.58	8.95	11.37	12.19	12.88
Emissions for 1 CT																			
SO_2	5.91	5.52	5.25	4.63	4.27	4.02	3.43	3.18	3.02	Annual [c]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
										24-Hour [c]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
										3-Hour [c]	0.04	0.04	0.03	0.04	0.04	0.04	0.04	0.04	0.03
										1-Hour [e]	0.49	0.47	0.45	0.46	0.46	0.45	0.49	0.49	0.49
PM_{10}	61.6	61.5	61.5	61.3	61.2	61.2	61.0	60.9	60.9	Annual [c]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
										24-Hour [c]	0.13	0.13	0.13	0.15	0.15	0.15	0.17	0.18	0.18
$PM_{2.5}$	61.6	61.5	61.5	61.3	61.2	61.2	61.0	60.9	60.9	Annual [d]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
										24-Hour [d]	0.10	0.10	0.10	0.12	0.12	0.13	0.14	0.15	0.15
NO_x	120.0	112.0	106.4	93.9	86.6	81.6	69.5	64.4	61.2	Annual [c]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01
										1-Hour [e]	9.96	9.55	9.18	9.43	9.36	9.20	9.97	9.89	9.93
CO	114.8	108.7	103.8	92.6	84.3	80.0	77.1	69.8	65.3	8-Hour [c]	0.56	0.54	0.52	0.56	0.52	0.50	0.54	0.51	0.48
										1-Hour [c]	1.38	1.32	1.26	1.26	1.18	1.13	1.21	1.14	1.08

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2012 to 2016 consisting of surface and upper air data from the National Weather Service stations at Fort Lauderdale-Hollywood Int'l AP and Florida International University (FIU) in Miami.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 2 CT/HRSGs. 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 (2012-2016).

[d] Based on highest 5-year average concentration (2012-2016).

[e] Based on highest 5-year average daily maximum 1-hour concentration (2012-2016).

APPENDIX E

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

Department of
Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Florida Power & Light Company**	
2. Site Name: **Lauderdale Plant**	
3. Facility Identification Number: **0110037**	
4. Facility Location... Street Address or Other Locator: **4300 SW 42nd Street** City: **Ft. Lauderdale** County: **Broward** Zip Code: **33414**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Facility Contact Name: **John Hampp, Air Program Manager**
2. Facility Contact Mailing Address... Organization/Firm: **Florida Power & Light Company** Street Address: **700 Universe Boulevard, JES/JB** City: **Juno Beach** State: **FL** Zip Code: **33408**
3. Facility Contact Telephone Numbers: Telephone: **(561) 691-2894** ext. Fax: **(561) 691-7070**
4. Facility Contact E-mail Address: **John.Hampp@FPL.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

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

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

Air Operation Permit

☐ Initial Title V air operation permit.

☒ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

This application is for a major source air construction permit for the construction of the Dania Beach Energy Center (DBEC) to be located at the existing FPL Fort Lauderdale Plant, Broward County, Florida. FPL proposes to replace the existing Lauderdale Plant Units 4 & 5 with a modern, highly efficient, lower-emission next generation clean energy center using the latest combined cycle technology with a net capability of 1,200 megawatts (MW) nominal-net with a two-by-one combined cycle combustion turbines (CTs) and heat recovery steam generators (HRSGs). DBEC will be designated as Unit 7.

The project will be subject to PSD review for CO, SO_2, PM, PM_{10}, $PM_{2.5}$, VOCs, sulfuric acid mist (SAM), and greenhouse gases (GHGs).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
TBD	Two General Electric GE 7HA Combined-Cycle Combustion Turbines, DBEC, Unit 7	AC1A	
TBD	Circuit Breakers (See PSD Report)	AC1A	
TBD	Auxiliary Boiler	AC1A	
TBD	Fuel Gas Heaters	AC1A	
TBD	Emergency Diesel Generators	AC1A	
TBD	Diesel Fire Pump Engine	AC1A	
TBD	Mechanical Draft Auxiliary Cooling System	AC1A	
TBD	Construction Boiler	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 : **Michael W. Sole, Vice President**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Florida Power & Light Company** Street Address: **700 Universe Boulevard** City: **Juno Beach** State: **FL** Zip Code: **33408**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(561) 691-7003** ext. Fax: **(561) 691-7070**
4.	Owner/Authorized Representative E-mail Address: **Michael.Sole@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.* Michael W. Sole Signature July 26, 2017 Date

APPLICATION INFORMATION

Application Responsible Official Certification

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

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

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6026 NW 1st Place** City: **Gainesville** State: **FL** Zip Code: **32607**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. **21156** Fax: **(352) 336-6603**
4.	Professional Engineer E-mail Address: **Ken_Kosky@golder.com**
5.	Professional Engineer Statement:

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

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

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

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

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

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

[signature] 7/25/17

Signature Date

(seal)

KENNARD F. KOSKY LICENSE No. 14996 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

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

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **580.2** North (km) **2883.3**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **26/4/5** Longitude (DD/MM/SS) **80/11/54**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Tony Berros, Plant General Manager**
2. Facility Contact Mailing Address... Organization/Firm: **FPL Lauderdale Plant** Street Address: **4300 SW 42nd Avenue** City: **Fort Lauderdale** State: **FL** Zip Code: **33314**
3. Facility Contact Telephone Numbers: Telephone: **(954) 797-1582** ext. Fax: **(954) 797-1579**
4. Facility Contact E-mail Address: **tony.berros@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: **The proposed combustion turbines are subject to NSPS 40 CFR 60 Subpart KKKK. NESHAP and 40 CFR 63 Subpart YYYY is potentially applicable to these units.** **The facility will have several reciprocating internal combustion engines (RICE) that are subject to 40 CFR 60 Subpart IIII / 40 CFR 63 Subpart ZZZZ.** **See also PSD Report (Air Report), Section 3.0 for a description of applicable classifications.**	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM/PM10	**A**	**N**
NOx	**A**	**N**
CO	**A**	**N**
VOC	**A**	**N**
SO2	**A**	**N**
Pb	**A**	**N**
SAM	**A**	**N**
HAPS	**A**	**N**
GHG (CO_2e)	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: PSD Report ☒ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: PSD Report
3. Rule Applicability Analysis: ☒ Attached, Document ID: 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: PSD Report ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID: PSD Report ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:______ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID: 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 forms for the new 2-on-1 combined cycle unit pursuant to 40 CFR Parts 72 and 96, and FDEP rules. CAIR is no longer applicable (see PSD Report Section 3.0).

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:
   Two General Electric (GE) Model 7H.03 Class CTs

3. Emissions Unit Identification Number: **7A, 7B**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2019**	**2022**	**49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **7HA**

10. Generator Nameplate Rating: **430** MW **(nominal)**

11. Emissions Unit Comment:
   Combined cycle unit will have a nominal capacity of 1,200 MW (nominal net) consisting of 2 CT/HRSG trains. Generator nameplate based on gross generation at ambient temperature of 75°F provided by GE for operating range.

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description: **Natural gas - Dry Low NO_X Combustion** **- SCR**
2. Control Device or Method Code: **025, 139**

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description: **Distillate Fuel Oil - Water Injection** **- SCR**
2. Control Device or Method Code: **028,139**

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:	**4,015.4 (NG); 3,603.6 (ULSD Oil)** 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; **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.** **Based on an ambient temperature of 75 °F at baseload and wet compression. Heat input rates are based on the HHV.**

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: **SV01**	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: **EU01 & EU02**	

5. Discharge Type Code: **V**	6. Stack Height: **149** feet	7. Exit Diameter: **25.6** feet
8. Exit Temperature: **182 °F (NG)** **208 °F (ULSD Oil)**	9. Actual Volumetric Flow Rate: **1,703,199 (NG) acfm** **1,827,296 (ULSD Oil) 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.

See Tables A1 and A7 for the actual volumetric flow rate 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: **26.2**	5. Maximum Annual Rate: **26,170**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **137.7 (HHV)**

10. Segment Comment:

Fuel Usage Rate = Heat input (MMBtu/hr) / Heat content (Btu/lb) x 10^6
Fuel Usage Rate = 3,603.6 (MMBtu/hr)(HHV) / 137.7 MMBtu/10^3 gal = 26.2 x 10^3 gal/hr

Annual rate = 26.2 x 10^3 gallons/hr * 1,000 hrs/yr = 26,170 x 10^3 gallons/yr

Max hourly rate based on 75°F. Based on one GE 7H.03 CT.

See Table A7 for input details.

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: **3.94**	5. Maximum Annual Rate: **34,485**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **970 (HHV)**

10. Segment Comment:

Fuel Usage Rate = Heat input (MMBtu/hr) / Heat content (Btu/lb) x 10^6
Fuel Usage Rate = 4,015.4 (MMBtu/hr)(HHV) / 1,020 MMBtu/10^6 ft = 3.94 x 10^6 ft3/hr

Annual rate = 3.94 Million ft^3/hr * 8,760 hrs/yr = 36,441.6 Million ft^3/yr

Max hourly rate based on 75 °F and 8,760 hr/yr operation. Based on one GE 7HA CT.
See Table A1 for input details.

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			
SO2			
NOX			
CO			
VOC			
CO2e			
SAM			

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 PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD 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 Appendix A in PSD 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 PSD Report, Table 4-1**	4. Equivalent Allowable Emissions: **See PSD Report** lb/hour **See PSD Report** tons/year
5. Method of Compliance: **See PSD 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: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD 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 Appendix A in PSD 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 PSD Report, Table 4-1**	4. Equivalent Allowable Emissions: **See PSD Report, Table 4-1** lb/hour **See PSD Report, Table 4-1** tons/year
5. Method of Compliance: **See PSD 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 PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD 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 Appendix A in PSD 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 2

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

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See PSD Report, Table 4-1**	4. Equivalent Allowable Emissions: **See PSD Report, Table 4-1** lb/hour **See PSD Report, Table 4-1** 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 PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD 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 Appendix A in PSD 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 PSD Report Table 4-1**	4. Equivalent Allowable Emissions: **See PSD Report Table 4-1** lb/hour **See PSD Report Table 4-1** 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: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD 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 Appendix A in PSD 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 PSD Report, Table 4-1**	4. Equivalent Allowable Emissions: **See PSD Report, Table 4-1** lb/hour **See PSD Report, Table 4-1** 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: **Carbon Dioxide Equivalent- CO2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD 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 A-17 in Appendix A of PSD 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 PSD Report, Table 4-1**	4. Equivalent Allowable Emissions: **See PSD Report, Table 4-1** lb/hour **See PSD Report, Table 4-1** 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: **Sufuric Acid Mist- SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD 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 Appendix A in PSD 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 PSD Report, Table 4-1**	4. Equivalent Allowable Emissions: **See PSD Report, Table 4-1** lb/hour **See PSD Report, Table 4-1** 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.; 20% opacity** **See PSD Report, Section 4.2**	

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: **Steady state operation, proposed BACT of 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: **TBD** Model Number: Serial Number: **TBD**	
5. Installation Date: **TBD**	6. Performance Specification Test Date: **TBD**
7. Continuous Monitor Comment: **CEM meeting 40 CFR Part 75 requirements** **NO_X CEM will also include 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: See PSD Report ☐ 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: See PSD Report ☐ 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: **C**	5. Commence Construction Date: **2019**	6. Initial Startup Date: **2022**	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:			

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 **52** weeks/year	**7** days/week **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

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: **60** feet	7. Exit Diameter: **2.75** Feet
8. Exit Temperature: **296**°F	9. Actual Volumetric Flow Rate: **29,325** 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 2-4 in the PSD 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: **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:
Emissions factor = 7.6 lb/MMBtu / 1,020 MMBtu/MMft3 = 0.0075 lb/MMBtu
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: **Hourly: 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** **Annual: 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.

<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: **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:
Hourly: 0.050 lb/MMBtu x 99.77 MMBtu/hr = 4.99 lb/hr

Annual: 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:	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.

<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: **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: **Hourly: 0.08 lb/MMBtu x 99.77 MMBtu/hr = 7.98 lb/hr** **Annual: 7.98 lb/hr x 2000 hr / 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:	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: **Hourly: 0.0054 lb/MMBtu x 99.77 MMBtu/hr = 0.54 lb/hr** **Annual: 0.54 lb/hr x 2000 hr / 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:	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 **11,670.8** 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 in Appendix A of the PSD 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 _____ 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 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

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

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2019**	**2022**	**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:
    One 9.9 MMBtu/hr natural gas heater. See PSD 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.)

Emissions Unit Operating Capacity and Schedule

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 the PSD 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: **Emission Factor = 84 lb/MMscf / 1,020 MMBtu/MMscf = 0.082 lb/MMBtu** **Hourly: 0.082 lb/MMBtu x 9.9 MMBtu/hr = 0.82 lb/hr** **Annual: 0.82 lb/hr x 8760 hr / 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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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:
Emission Factor = 100 lb/MMscf / 1,020 MMBtu/MMscf = 0.098 lb/MMBtu

Hourly: 0.098 lb/MMBtu x 9.9 MMBtu/hr = 0.97 lb/hr
Annual: 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 in the PSD Report.

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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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:

Hourly: 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

Annual: 0.055 lb/hr x 8,760 hr/2,000 lb = 0.24 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

See Table 2-5 in the PSD Report.

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:

Emission Factor = 7.6 lb/MMscf / 1,020 MMBtu/MMscf = 0.0075 lb/MMBtu

Hourly: 0.0075 lb/MMBtu x 9.9 MMBtu/hr = 0.074 lb/hr
Annual: 0.074 lb/hr x 8,760 hr/2,000 lb = 0.32 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

See Table 2-5 in the PSD Report

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.

<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: **0.053** 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:
Emission Factor = 5.5 lb/MMscf / 1,020 MMBtu/MMscf = 0.0054 lb/MMBtu

Hourly: 0.005 lb/MMBtu x 9.9 MMBtu/hr = 0.05 lb/hr
Annual: 0.05 lb/hr x 8,760 hr/2,000 lb = 0.23 TPY

11. Potential, Fugitive, and Actual Emissions Comment:
See Table 2-5 in the PSD Report.

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.

<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: **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 in Appendix A of the PSD 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 _ 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: **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 (2) 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	**2019**	**2022**	**49**

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

   ☐ Acid Rain Unit
   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **Caterpillar** Model Number: **C175**

10. Generator Nameplate Rating: **3,300** MW **(nominal)**

11. Emissions Unit Comment:
    Two 3,300-kW emergency generators, each with a rating of approximately 4,420 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: **29.49** 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 emergency generators will 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 and Part 89.**	

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: **892**°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: **See Table 2-6 in the PSD Report.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **Ultra Low Sulfur 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: **Hourly rate = 21.42 gal/yr x 1 yr/100 hr = 0.214 gal/hr** **Maximum annual rate based on 100 hr/yr operation for one 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

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: **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** **25.4 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 in the PSD Report.**	

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 in the PSD Report.**	

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 in the PSD Report.**	

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.

<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: **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 in the PSD Report.**	

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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.5** 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 in the PSD Report.**	

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):	

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	**2019**	**2022**	**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-UFAAD98**

10. Generator Nameplate Rating:

11. Emissions Unit Comment:
    One diesel fire pump engine rated at approximately 422 hp (nominal).

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 **52** weeks/year	**7** days/week **100** hours/year
6. Operating Capacity/Schedule Comment: **The diesel fire pump engine will normally be operated 1 to 2 hours per month for testing and maintenance. The fire pump engine will meet the requirements of 40 CFR Part 98 Tier III 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: **17** feet	7. Exit Diameter: **0.60** 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 the PSD 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: **Hourly rate = 2.0 (1,000 gallons/yr) x 1/100 (yr/hr) = 0.02 (1,000 gallons/hr)** **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

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: **0.63** lb/hour **0.031** 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: **2.6 g/kW-hr x 315 kW x 1 lb/453.6 g = 0.63 lb/hr** **0.63 lb/hr x 100 hr/yr x 1 ton/2,000 lb = 0.0031 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-7 in the PSD Report.**	

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: **0.63** lb/hour **0.031** 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: **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 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: **3.8 g/kW-hr x 315 kW x 1 lb/453.6 g = 2.64 lb/hr** **2.64 lb/hr x 100 hr/yr x ton/2,000 lb = 0.132 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-7 in the PSD Report.**	

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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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 in the PSD Report.**	

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.

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: **0.09** 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 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: **0.13 g/kW-hr x 315 kW x 1 lb/453.6 g = 0.09 lb/hr** **0.09 lb/hr x 100 hr/yr x 1 ton/2,000 lb = 0.005 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-7 in the PSD Report.**	

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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.07** 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 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: **0.1 g/kW-hr x 315 kW x 1 lb/453.6 g = 0.07 lb/hr** **0.07 lb/hr x 100 hr/yr x 1 ton/2,000 lb = 0.003 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Table 2-7 in the PSD Report.**	

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):	

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	**2019**	**2022**	**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: **14 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: **High Efficiency 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: **14 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: **60.6**feet	7. Exit Diameter: **31.625**feet
8. Exit Temperature: **85.3**°F	9. Actual Volumetric Flow Rate: **1,362,000**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 dimensions are 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**
PM2.5	**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: **20.4** lb/hour **44.1**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, 2017; Golder, 2017**	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 2-8 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: **10.1** lb/hour **44.1**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: **0.89** lb/hour **1.93**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, 2017; Golder, 2017**	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 2-8 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: **0.44** lb/hour **1.93**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: **PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.01** 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: **0.0005 percent Drift Rate** Reference: **FPL, 2017; Golder, 2017**	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 2-8 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: **0.003** lb/hour **0.01**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.

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

Complete 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:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2019**	**2020**	**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 DBEC 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 DBEC 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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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 EU7 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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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-7 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-7 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-7 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 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

See PSD Report