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Prepared for:
Chickahominy Power, LLC
Herndon, Virginia

Prepared by:
AECOM
Chelmsford, Massachusetts
60522108-1
November 2018

Air Permit Application

Chickahominy Combined-Cycle Power Plant Project
Charles City County, Virginia

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Charles City County, Virginia

Prepared by:

Robert Hall

Stephanie Carcieri

Reviewed by:

Sim Deshpande

Jeff Connors

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1.0 Introduction

Chickahominy Power, LLC (CPLLC) is proposing to construct and operate a combined-cycle electric generating facility in Charles City County, Virginia, herein referred to as the "Chickahominy Power Station" (Project). CPLLC plans to build three 1x1 power blocks with a total net nominal generating capacity of 1,650 megawatts (MW) at 95°F ambient temperature. Each power block will have a combustion turbine generator (CTG) and a heat recovery steam generator (HRSG) that will provide steam to a steam turbine generator.

CPLLC plans to build either:

- Three General Electric (GE) 7HA.02 class natural gas-fired combustion turbine generators, each provided with a HRSG and a steam turbine generator, or,
- Three Mitsubishi Hitachi Power Systems (MHPS) M501JAC class natural gas-fired combustion turbine generators, each provided with a HRSG and a steam turbine generator.

Each combustion turbine will be capable of firing pipeline-quality natural gas only. The HRSGs will be equipped with selective catalytic reduction to minimize nitrogen oxide (NO_X) emissions and an oxidation catalyst to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. The HRGS will not include duct burning.

The proposed facility will also include the following ancillary equipment:

- Two 52 MMBtu/hr natural gas-fired auxiliary boilers for the GE 7HA.02 option;
- Two 84 MMBtu/hr natural gas-fired auxiliary boilers for the MHPS M501J option;
- Three 12 MMBtu/hr natural gas-fired fuel gas heaters;
- One 3,000 kW emergency diesel generator operating on ultra-low sulfur diesel (ULSD) fuel;
- One 376 bhp emergency fire-water pump operating on ULSD fuel;
- One 572 gallon diesel tank and one 2,500 gallon diesel tank; and
- Circuit breakers (containing SF_6).

The proposed facility will be a "major source" of criteria air pollutants. CPLLC is applying to the Virginia Department of Environmental Quality (VADEQ) for a Prevention of Significant Deterioration (PSD) Construction Permit. VADEQ has a United States Environmental Protection Agency (USEPA) State Implementation Plan-approved PSD program. The proposed facility will not be a major source of hazardous air pollutants (HAPs).

This application addresses the permitting requirements specified by the VADEQ under the Virginia Regulations for the Control and Abatement of Air Pollution (VAC), Title 9, Agency 5, Chapter 80.

Please note that the air dispersion modeling for the project will be finalized and will be provided later as an addendum to this application.

1.1 Applicant Information

To facilitate VADEQ's review of this document, an individual familiar with both the facility and the preparation of this application is identified below. The VADEQ should contact CPLLC if additional information or clarification is required during the agency review process.

1.1.1 Applicant's Contact

Irfan K. Ali
Chickahominy Power, LLC
13800 Coppermine Road, Suite 115
Herndon, VA 20171
Telephone 703-226-0192
Mobile: 703-371-5867
irfankali@balico.com

Jeffery Connors
AECOM
250 Apollo Drive
Chelmsford, MA 01824
Telephone 978-905-2166
Mobile: 978-660-4097
Jeffery.Connors@aecom.com

1.2 Project Location

The proposed project will be constructed in Charles City County, Virginia on an approximately 185-acre site. The site is located to the east of State Road 106 and fronts Chambers/Landfill Road along its northern boundary. The town of Charles City, Virginia is approximately 11 miles southeast of the site. The coordinates of the proposed site are 309.387 km easting and 4145.395 km northing in Universal Transverse Mercator (UTM) Zone 18 (37.436° N latitude, 77.155° W longitude). The site has nearby access to natural gas pipelines and surrounds the Dominion Virginia Power Chickahominy Substation. An aerial photograph of the region site region is shown in Figure 1-1. A site plan for the proposed project is presented in Appendix D.

1.2.1 Surrounding Property

From review of the surrounding land use, it is noted that the immediate region surrounding the site is characterized as primarily rural, with some commercial/industrial development to the north and east. Within this predominantly rural area are:

- Existing commercial development,
- Existing industrial development,
- Existing county land fill site,
- Transitional land,
- Forest/undeveloped land, and,
- Woody wetlands.

Figure 1-1: Project Site Location

1.3 Facility Classification

There are two major classification criteria for the proposed Project, one related to its industrial character, and the other to its potential to emit air contaminants. The designation of the facility under each of these is reviewed below.

1.3.1 Standard Industrial Classification Code

The United States government has devised a method for grouping all business activities according to their participation in the national commerce system. The system is based on classifying activities into "major groups" defined by the general character of a business operation. For example, electric, gas and sanitary services, which include power production, are defined as a major group. Each major group is given a unique two-digit number for identification. Power production activities have been assigned a major group code “49”.

To provide more detailed identification of a particular operation, an additional two-digit code is appended to the major group code. In the case of power generation facilities, the two digit code is “11” to define the type of production involved. Thus, the proposed project is classified under the Standard Industrial Classification (SIC) code system as:

- Major Group 49 – Electric, Gas, and Sanitary Services
- Electric Services – 4911

The North American Industrial Classification System was introduced as a replacement for SIC codes in 1997. This system's organization is similar to the SIC codes. Under this system, this facility would be classified under 221112, Fossil Fuel Electric Power Generation.

1.3.2 Air Quality Source Designation

With respect to air quality, new and existing industrial sources are classified as either major or minor sources based on their potential to emit (PTE) air contaminants. This classification is also affected in part by whether the area in which the source is located has attained the National Ambient Air Quality Standards (NAAQS)[1]. An area is classified as attainment if the ambient air quality concentration for a specific pollutant, as measured by a monitor, is below the standard concentration level for a set of averaging periods. The area in which the proposed project is located is designated as attainment for all the NAAQS in which EPA has issued a designation under Section 107 of the Clean Air Act.

For most activities, a major source is defined as one which has the PTE of 250 tons per year of any regulated air contaminant. For a special group of 28 special activities, the EPA has defined the major source emission threshold to be 100 tons per year. Steam-Electric Power Generation is one of these special groups. Based on its PTE, the proposed Project (and the Power Station) will be classified as a “major stationary source” of air emissions.

[1] Criteria pollutants are those for which EPA has established NAAQS and consist of particulate matter with a nominal aerodynamic diameter of 10 microns or less (PM_{10}), particulate matter with a nominal aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), carbon monoxide (CO), oxides of nitrogen (NO_x), sulfur dioxide (SO_2), lead, and ozone, which is formed through the photochemical reaction of volatile organic compounds (VOC) and NO_x in the atmosphere.

1.4 Document Organization

The balance of this document is divided into sections which address each component of the PSD air quality review process. The outline below provides an overview of the contents of each of the remaining sections.

Section 2.0 – Process Description provides a general description of the primary combined-cycle processes by which power will be produced at this site as well as a description of the auxiliary and supporting equipment.

Section 3.0 – Emissions Summary presents a detailed review of the air emissions during normal operations and startup/shutdown operations which will occur at the Project site subsequent to the completion of project development.

Section 4.0 – Applicable Requirements and Standards presents a discussion of applicable State and Federal air regulations. The focus of this section will be on establishing which regulations are directly applicable to the proposed combined-cycle turbine generators and the ancillary equipment and how compliance is proposed to be demonstrated.

Section 5.0 - Control Technology Review is a substantial requirement of the PSD program. Since the proposed Project will be classified as a major source and will result in a significant increase in the emissions of NSR-regulated pollutants (as defined under the PSD regulations), a detailed evaluation of control technologies is provided. Project emissions are projected to be significant for NO_X, PM_{10}, $PM_{2.5}$, VOC, SO_2, H_2SO_4, CO and GHGs. As such, "top down" best available control technology (BACT) analyses for these pollutants have been provided for each emission unit.

Pending VADEQ's acceptance of the emission sources' emission rates and stack parameters, the air dispersion modeling for the Project will be finalized, and Sections 6 – 10 and additional Appendices will be provided later as an addendum to this application.

Section 6.0 – PSD Class II Modeling Procedures summarizes the dispersion modeling methodology and the manner in which the predicted impacts were compared to the applicable standards. Specifically, this section discusses the modeling input data and the various modeling scenarios evaluated.

Section 7.0 – Class II Area Significant Impact Level (SIL) Analysis Results presents the results of the Class II Area SIL modeling results performed for the Project.

Section 8.0 – Class II Area Cumulative Impact Assessment Results presents the results of the Class II Area air dispersion modeling analysis performed for the Project. This section compares the predicted impacts to the applicable standards to demonstrate that the Project will operate in compliance.

Section 9.0 – Additional Impact Analyses contains supplemental information regarding the potential impacts of the Project. Specifically, this section discusses the potential for impacts to Class I areas, soils and vegetation, and impacts to the visibility of PSD Class I areas. Compliance with VA Air Toxics rules is discussed here as well.

Section 10.0 - References will include a list of the documents relied upon during the preparation of this document.

Appendices – Appendices A, B, C and D provide permit application forms, emission calculations, supporting BACT information and a site plan. Additional information, figures and diagrams, dispersion modeling files on computer disc and supplemental materials supporting the information presented in the application are provided as an addendum to the application in Appendices E through G.

- Appendix A: VADEQ application forms and tables
- Appendix B: Detailed emissions calculations
- Appendix C: Emission control data from EPA's RACT/BACT/LAER Clearinghouse
- Appendix D: Site plan and plot plan for the proposed project
- Appendix E: EPA Region 3 Approval of ARM2 Lower Ambient Ratio Bound
- Appendix F: Dispersion modeling files and supporting information
- Appendix G: A contour map displaying the air quality impacts

2.0 Process Description

As stated previously, CPLLC plans to construct a facility in Charles City County, Virginia with three 1x1 combined-cycle power blocks. The key elements of the proposed project include:

- Three GE 7HA.02 or three MHPS M501JAC CTGs;
- Three HRSGs without supplementary duct firing – one for each CTG;
- Three reheat condensing steam turbine generators – one for each CTG;
- Three dry air cooled condensers – one for each CTG
- Two 52 MMBtu/hr natural gas-fired auxiliary boilers for the GE 7HA.02 option;
- Two 84 MMBtu/hr natural gas-fired auxiliary boilers for the MHPS M501J option;
- Three 12 MMBtu/hr natural gas-fired fuel gas heaters;
- One 3,000 kW emergency diesel generator operating on ultra-low sulfur diesel fuel;
- One 376 bhp emergency fire-water pump operating on ultra-low sulfur diesel fuel;
- One 572 gallon diesel tank and one 2,500 gallon diesel tank; and
- Circuit breakers (Containing SF_6).

The proposed project will have a net nominal generating capacity of approximately 1,650 MWe at 95°F ambient temperature. Each CTG and HRSG will be capable of firing pipeline quality natural gas only. The Project will employ BACT to minimize emissions of nitrogen oxides (NO_X), SO_2, PM_{10}, $PM_{2.5}$, CO, VOCs, and GHGs.

2.1 Major Facility Components

The primary sources of pollutants associated with the proposed project are the three combustion turbines (either GE 7HA.02 or MHPS M501JAC) and their associated HRSGs. Other sources of criteria pollutants associated with the proposed project include the auxiliary boilers, fuel gas heaters, emergency generator, fire water pump, and supporting equipment. A brief description of the major components of the Project is provided in the following sections.

2.1.1 Combustion Turbine Generators

The proposed project includes the installation of three CTGs (either GE 7HA.02 or MHPS M501JAC) in combined-cycle mode, each provided with its own HRSG that provides steam to a steam turbine generator. The CTGs will be fired using pipeline quality natural gas only.

Maximum annual operation of each combined-cycle combustion turbine generator will be 8,760 hours per year. Each CTG power block will include an advanced firing temperature CTG, air compressor section, gas combustion system (utilizing dry, low NO_X combustors), power turbine, and a generator.

The CTG is the main component of a combined-cycle power system. First, air is filtered, cooled when the ambient air temperature is higher than 59 °F, and compressed in a multiple stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine combustion chamber.

Lean pre-mix dry low-NO_X combustors minimize NO_X formation during natural gas combustion. Hot exhaust gases from the combustion chamber are expanded through a multi-stage power turbine that results in energy to drive both the air compressor and electric power generator.

The hot exhaust gas exiting the power turbine in the CTGs is ducted to a boiler commonly known as an HRSG where steam is produced to generate additional electricity in a steam turbine generator. Natural gas fired duct burners will not be included in the project.

The GE 7HA.02 CTGs are designed to operate in the dry low-NO_X mode at loads from approximately 30% to 45%, depending upon the ambient air temperature, up to 100% rating while firing natural gas. The MHPS 501JAC CTGs are designed to operate in the dry low-NO_X mode at loads from approximately 50 percent up to 100 percent rating while firing natural gas. Operation at lower loads will only occur during startup and shutdown. The CTGs will be periodically taken out of service for scheduled maintenance, or as dictated by economic or electrical demand conditions.

2.1.2 Heat Recovery Steam Generators

Horizontal, natural circulation, three-pressure level HRSGs will extract heat from the exhaust of each combined-cycle CTG. Exhaust gas, entering the HRSG at approximately 1,200°F, will be cooled to the 165°F to 200°F range by the time it leaves the HRSG exhaust stack. The heat recovered is used in the combined-cycle plant for additional steam generation and natural gas/feedwater heating. Each HRSG will include high-pressure superheaters, a high-pressure evaporator, high-pressure economizers, reheat sections (to reheat partially expanded steam), an intermediate-pressure superheater, an intermediate-pressure evaporator, an intermediate-pressure economizer, a low-pressure superheater, a low-pressure evaporator, and a low-pressure economizer. Selective catalytic reduction (SCR) and oxidation catalysts will be installed in the HRSG to control NO_X and CO, and VOC, respectively.

2.1.3 Steam Turbine Generator

The proposed project includes three reheat, condensing steam turbine generators designed for variable pressure operation. The high-pressure portion of the steam turbine generator receives high-pressure super-heated steam from the HRSGs, and exhausts to the reheat section of the HRSGs. The steam from the reheat section for the HRSGs is supplied to the intermediate-pressure section of the steam turbine generator, which expands to the low-pressure section. The low-pressure steam turbine generator also receives excess low-pressure superheated steam from the HRSGs and exhausts to an air cooled condenser. The steam turbine generators are designed to produce approximately 172 MW for the GE option and 178 MW for the MHPS option at ISO conditions.

2.1.4 Dry Air Cooled Condensers

The proposed project will include three air cooled condensers that will provide cooling for the steam turbine generator exhausts. There will be no air emissions from this unit.

2.1.5 Auxiliary Boilers

CPLLC proposes to install two 52 MMBtu/hr auxiliary boilers for the GE 7HA.02 option or two 84 MMBtu/hr auxiliary boilers for the MHPS M501J option to supply sealing steam to the steam turbine generators at start-up and at cold starts to warm up the steam turbine generator rotors. The auxiliary boilers will combust natural gas only and use ultra-low NO_X burners to control NO_X emissions. The steam from the auxiliary boilers will not be used to augment the power generation of the CTGs or

STG. CPLLC requests that each boiler be permitted to operate at a 100% annual capacity factor. The emissions calculations and the air quality modeling analysis reflect this assumption.

2.1.6 Fuel Gas Heaters

CPLLC proposes to install three 12 MMBtu/hr fuel gas heaters to be used as a means to warm up the incoming natural gas fuel to prevent freezing of the gas regulating valves under certain gas system operating conditions. The heaters will fire natural gas exclusively and use ultra-low NO_X burners to control NO_X emissions. CPLLC requests that the heaters be allowed to operate 8,760 hours per year (i.e., without annual operating restrictions). The air quality modeling analysis reflects this assumption.

2.1.7 Diesel-Fired Emergency Generator

The proposed project will include a 3.0 MW ULSD-fired emergency generator that will be operated up to 100 hours per year for maintenance checks and readiness testing. The emergency diesel generator will provide power in emergency situations for turning gears, lube oil pumps, auxiliary cooling water pumps and water supply pumps. The emergency diesel generator is not intended to provide sufficient power for a black start, peak shaving or non-emergency power. Total operating hours including emergency use will not exceed 500 hours per year.

2.1.8 Diesel-Fired Fire Water Pump

The proposed Project will include a 376 bhp ULSD-fired fire water pump operated as a fire water pump driver. The unit will be limited to 100 hours per year for routine testing and maintenance. Total operating hours including emergency use will not exceed 500 hours per year.

2.1.9 Distillate Fuel Oil Tanks

The proposed project will include one 572 gallon tank connected to the fire water pump, and one 2,500 gallon tank connected to the emergency generator, which will both hold ULSD fuel oil for use in the emergency equipment.

2.1.10 Circuit Breakers

The proposed project will include circuit breakers holding 22,800 pounds sulfur hexafluoride (SF_6). The maximum leak rate will not exceed 0.5% annually.

2.1.11 Fuel Gas System

Pipeline quality natural gas will be delivered to the plant where an electric powered compressor will be used to provide pressure sufficient for use in the CTGs. Based on analytical data from the gas companies that will potentially be supplying the fuel for the Chickahominy facility, the facility will use un-odorized natural gas with an average sulfur content of approximately 0.4 gr/100 dscf. The gas will first be sent through a knockout drum for removal of any liquid which may have been carried through from the pipeline. The gas then passes through a filter/separator to remove particulate matter and entrained liquid. The gas flows through the filter/separator's first chamber, the filtration section, which removes particulate matter. The gas then flows through the coalescing filters, where entrained liquid is coalesced on the filter cartridges, drops to the bottom of the chamber and either vaporizes and returns to the main gas stream or drains to the sump below. The gas then passes to the second chamber, the separation section, where any entrained liquid remaining in the stream is further separated by impingement on a net or labyrinth and drains to the bottom sump. There is one filter/separator located

in the gas yard. Hydrocarbon liquids in the sump are removed for off-site disposal. The gas is split into three streams, one for each CTG. Each stream is equipped with a gas scrubber. Finally, the gas is delivered to the CTGs and burned as part of the power generation operation. Similarly, the gas will also be delivered to the auxiliary boilers, as well as the fuel gas heaters.

3.0 Project Emission Summary

This section presents a summary of the Project emissions and a discussion of the methodology used to calculate emissions. The section is organized by emission sources. Within each emission source subsection, the methods used to calculate emissions are discussed followed by a summary of the emission estimates for the specific source as well as, in the case of the CTGs, mode of operation.

The Project consists of the following sources of air emissions:

- Three GE 7HA.02 or three MHPS M501JAC natural gas-fired CTGs;
- Two 52 MMBtu/hr natural gas-fired auxiliary boilers for the GE 7HA.02 option;
- Two 84 MMBtu/hr natural gas-fired auxiliary boilers for the MHPS M501J option;
- Three 12 MMBtu/hr natural gas-fired fuel gas heater;
- One 3,000 kW emergency diesel generator operating on ULSD fuel;
- One 376 bhp emergency fire-water pump operating on ULSD fuel;
- One 572 gallon diesel tank and one 2,500 gallon diesel tank; and
- Circuit breakers (containing SF_6).

The emissions calculation procedures used in determining the potential emissions from the Project are based on CTG information provided by the manufacturer, other equipment vendor data, emission limitations specified by the applicable New Source Performance Standards, emission factors documented in USEPA's "Compilation of Air Pollution Emission Factors, AP-42" and proposed BACT and LAER emission limits. Operational limitations have been accounted for while estimating potential annual emissions.

Detailed emission calculations for each emission source are presented in Appendix B.

3.1 Combustion Turbine Generators

The main sources of emissions at the site are the three CTGs. The following subsections present the maximum hourly emissions per CTG during normal operations and start-up/shutdown events, as well as the total annual emissions for both CTGs including start-up/shutdown emissions. Additional details such as emission and flow calculations at various loads, ambient temperature, with and without inlet air cooling, are provided in Appendix B.

3.1.1 General Electric 7HA.02 Combustion Turbines

3.1.1.1 Continuous Operating Scenario

Normal operation of a combustion turbine generator is characterized as continuous operation at operating loads in the 30% to 45%, depending upon the ambient air temperature, up to 100% while firing natural gas. Each of the three CTGs is proposed to be operated up to 8,760 hr/yr with no annual operational restrictions. Table 3-1 presents the maximum hourly emissions (lb/hr) and the annual emissions (tons per year) for criteria pollutants for normal operations.

Table 3-1 GE 7HA.02 - Hourly and Annual Emissions during Normal Operations [(a)]

Pollutant	Maximum Hourly Emissions Per CTG during Normal Operations (lb/hr/CTG)	Potential Annual Emission Rates Per Turbine during Normal Operations (tons/year/CTG) [(b)]
NO_X	26.5	116.1
CO	8.1	35.5
VOC	3.24	14.2
$PM_{10}/PM_{2.5}$	12.4	54.3
SO_2	4.15	18.2
H_2SO_4	2.77	12.1
NH_3	24.5	107.3
Lead	0.0018	0.0078
GHGs CO_2e	434,064	1,901,202

(a) Emission rates are for one combustion turbine. See Tables B-1.2 to B-1.4 in Appendix B for detailed calculations.
(b) Annual emissions during normal operation (tons per year) are based on 8,760 hours per year at the maximum hourly emission rate for each pollutant.

3.1.1.2 Start-up/Shutdown Operations Scenario

The Project plans to start up the each CTGs in independently. Table 3-2 summarizes the duration of start-up and shutdown events.

Emissions (per CTG) of NO_X, CO, and VOC during each event of start-up and shutdown operations are summarized in Table 3-3. Detailed emissions calculations can be found in Appendix B.

Table 3-2 GE 7HA.02 - Start-up and Shutdown Duration (CTGs Only)

GE 7HA.02				
Type of Start	Duration of Start-up/Shutdown Events (minutes per event per CTG)			
	CTG 1	CTG 2	CTG 3	Average [(a)]
Cold Start	66	66	66	66
Warm Start	48	48	48	48
Hot Start	24	24	24	24
Shutdown	15	15	15	15

(a) Total time from first firing to emission compliance.

Table 3-3 GE 7HA.02 - Average Emissions per CTG during Start-up/Shutdown

Parameter	CTG 1, 2 or 3 Emissions during Start-up/Shutdown (lb/event)
NO_X	
Cold start	312
Warm start	175
Hot start	84
Shutdown	16.3
CO	
Cold start	924
Warm start	470
Hot start	449
Shutdown	190
VOC	
Cold start	66.0
Warm start	48.0
Hot start	45.6
Shutdown	32.5
Fuel, MMBtu/event	
Cold start	1,464
Warm start	1,116
Hot start	384
Shutdown	175

Table 3-4 presents a summary of the emissions with star-up and shutdown events including the offline times associated with these events. Annual emissions resulting from start-up/shutdown operations for the proposed CTGs are based on 18 cold starts/year, 52 warm starts/year, and 208 hot starts/year. For each cold start, the CTGs are conservatively assumed to be offline for 48 hours as a minimum for cold starts, for each warm start the CTGs are conservatively assumed to be offline for 8 hours as minimum and for each hot start, the CTGs are conservatively assumed to be offline for 0 hours as a minimum. Under this operating scenario, it is estimated that the CTGs would be offline for 1,280 hours/year. Additional details are provided in Appendix B, Tables B-1.3 and B-1.4.

Table 3-4 GE 7HA.02 - Annual Emissions Including Start-up/Shutdown (Average per CTG)[(a)]

Operating Mode	hr/yr	NO_X		CO		VOC	
		lb/hr[(a)]	tpy	lb/hr[(a)]	tpy	lb/hr[(a)]	tpy
Offline[(b)]	1,280	0	0	0	0	0	0
Normal operation, without duct burning	7,266	26.5	96.3	8.1	29.4	3.2	11.8
Cold start	19.8	283.6	2.81	840.0	8.32	60.0	0.59
Warm start	41.6	219.0	4.56	588.0	12.23	60.0	1.25
Hot start	83.2	210.0	8.74	1,122	46.68	114.0	4.74
Shutdown	69.5	65.0	2.26	760.0	26.41	130.0	4.52
TOTALS	**8,760**		**114.6**		**123.1**		**22.9**

(a) The lb/hr emissions represent the average lb/hr for the duration of the event, not the maximum hourly emission rate during the event
(b) The offline hours based on 18 cold starts, 52 warm starts and 208 hot starts per year.

3.1.1.3 GE 7HA.02 - Combustion Turbine Generator Emissions: Maximum Annual

Annual emissions for the three CTGs were calculated based on the maximum of either 8,760 hr/year of continuous operation or emissions which include the maximum number of startup/shutdown events. The annual emissions during startup/shutdown include the appropriate downtime based on the assumed number of cold, hot and warm starts and shutdowns. Tables 3-5 and Table 3-6 present the annual emissions (tons/year) of criteria pollutants and HAPs, respectively, for the three CTGs arranged in a 1 on 1 configuration for two cases:

(1) Continuous operations for all turbines 8,760 hours per year (see Table 3-1).
(2) Continuous operations for all turbines 7,266 hours per year, 1,280 hours per year downtime, and 214 hours per year in startup/shutdown operations (see Table 3-4).

Note that the maximum emissions for all pollutants except for CO and VOCs occur during 8,760 hours of continuous operation.

Table 3-5: GE 7HA.02- Combustion Turbine Generators: Annual Criteria Pollutant Emissions

Pollutant	Potential Annual Emission Rates (Per Turbine)			Three 1x1 GE 7HA.02 Configuration
	Annual Emissions for Continuous Operation (tpy)[a]	Annual Emissions with Startup and Shutdown (tpy)[b]	Worst-Case Annual Emissions (tpy)[c]	Worst-Case Annual Emissions (Total) (tpy)
NO_X	116.1	114.6	116.1	348.2
CO	35.5	123.1	123.1	369.2
VOC	14.2	22.9	22.9	68.7
PM_{10} / $PM_{2.5}$	54.3	<54.3	54.3	162.9
SO_2	18.2	<18.2	18.2	54.6
H_2SO_4	12.1	<12.1	12.1	36.4
NH_3	107.3	<107.3	107.3	321.9
Lead	0.0078	<0.0078	0.0078	0.023
GHG CO_2e	1,901,202	<1,901,202	1,901,202	5,703,605

(a) Detailed information for emissions during continuous operation is in Table 3-1.
(b) Detailed information for emissions including startup and shutdown are in Tables 3-3 and 3-4.
(c) Worst-case emissions are the maximum for each pollutant of either continuous operation or with startup and shutdown.

Table 3-6: GE 7HA.02 - Combustion Turbine Generators: Annual Hazardous Air Pollutant (HAP) Emissions

CTGs: Annual HAP Emissions [(a)] (Total Three 1x1Configuration; ton/year)	
Pollutant [(b)]	**GE 7HA.02**
Formaldehyde	8.77E+00
Toluene	4.05E+00
Xylene	1.99E-00
Acetaldehyde	1.24E-00
Ethylbenzene	9.96E-01
Propylene Oxide	9.03E-01
Benzene	3.73E-01
Acrolein	1.99E-01
Nickel	9.86E-02
Chromium	6.57E-02
Other HAPs	2.42E-01
TOTAL	**18.93**

(a) See Table B-1.5 for detailed calculations.
(b) The highest ten HAPs in terms of annual emissions are presented in this table. The remaining HAP emissions are presented under the group “Other HAPs”.

3.1.2 MHPS M501JAC Combustion Turbines

3.1.2.1 Continuous Operations Scenario

Normal operation of a combustion turbine generator is characterized as continuous operation at operating loads in the 50% to 100% range while firing natural gas. Each of the three CTGs is proposed to be operated up to 8,760 hr/yr. Table 3-7 presents the maximum hourly emissions (lb/hr) and the annual emissions (tons per year).

Table 3-7 MHPS M 501JAC - Hourly and Annual Emissions during Normal Operations [(a)]

Pollutant	MHPS M501JAC	
	Maximum Hourly Emissions Per CTG during Normal Operations (lb/hr/CTG)	Potential Annual Emission Rates Per Turbine during Normal Operations (tons/year/CTG)[(b)]
NO_X	29.3	128.3
CO	8.90	39.0
VOC	3.60	15.8
$PM_{10}/PM_{2.5}$	12.3	53.9
SO_2	4.64	20.3
H_2SO_4	4.88	21.4
NH_3	27.1	118.7
Lead	0.00199	0.0087
GHGs CO_2e	484,822	2,123,519

(a) See Tables B-2.2 to B-2.4 in Appendix B for detailed calculations.
(b) Annual emissions (tons per year) are based on 8,760 hours per year firing natural gas.

3.1.2.2 Start-up/Shutdown Operations Scenario

The Project has the capability to start up each CTG independently of the other CTGs. Therefore, the startup time for each CTG will be identical. Table 3-8 summarizes the duration of start-up and shutdown events for each CTG.

Emissions (per CTG) of NO_X, CO, and VOCs during each event of start-up and shutdown operations are summarized in Table 3-9. Detailed emissions calculations can be found in Tables B-2.3 and B-2.4 in Appendix B.

Table 3-8 MHPS M501JAC - Start-up and Shutdown Duration (CTGs Only)

MHPS M501JAC	
Type of Start	**Average Duration of Start-up/Shutdown Events (minutes per CTG)**
Cold Start	42
Warm Start	42
Hot Start	42
Shutdown	15

Table 3-9 MHPS M501JAC - Average Emissions per CTG during Start-up/Shutdown

MHPS M501JAC	
Parameter	**Emissions Per CTG during Start-up/Shutdown (lb/turbine/event)** [(a)]
NO_X	
Cold start	60.0
Warm start	54.0
Hot start	42.0
Shutdown	19.2
CO	
Cold start	444
Warm start	396
Hot start	252
Shutdown	156
VOC	
Cold start	216
Warm start	216
Hot start	168
Shutdown	216
Fuel, MMBtu/event	
Cold start	1,008
Warm start	1,008
Hot start	1,392
Shutdown	348

Table 3-10 presents a summary of the emissions with star-up and shutdown events including the offline times associated with these events. Annual emissions resulting from start-up/shutdown operations for the proposed CTGs are based on 18 cold starts/year, 52 warm starts/year, and 208 hot starts/year. For each cold start, the CTGs are conservatively assumed to be offline for 48 hours as a minimum, for each warm start the CTGs are conservatively assumed to be offline for 8 hours as minimum and for each hot start, the CTGs are conservatively assumed to be offline for 0 hours as a minimum. Under this operating scenario, it is estimated that the each CTGs would be offline for at least 1,280 hours/year. Additional details are provided in Appendix B, Tables B 2.1-3 and B 2.1-4.

Table 3-10 MHPS M501JAC - Annual Emissions Including Start-up/Shutdown (Average per CTG) [(a)]

Operating Mode	Duration	NO_X		CO		VOC	
	hr/yr	lb/hr[(a)]	tpy	lb/hr[(a)]	tpy	lb/hr[(a)]	tpy
Offline [(b)]	1,280	0	0	0	0	0	0
Normal, without duct burning	7,216	29.3	105.71	8.90	32.11	3.60	12.99
Cold start	12.6	85.7	0.54	634	4.00	309	1.94
Warm start	36.4	77.1	1.40	566	10.30	309	5.62
Hot start	145.6	60.0	4.37	360	26.21	240	17.47
Shutdown	69.5	76.8	2.67	624	21.68	864	30.02
Totals	8,760		114.7		94.3		68.0

(a) The lb/hr emissions represent the average lb/hr for the duration of the event, not the maximum hourly emission rate during the event.
(b) The offline hours are based on 18 cold starts, 52 warm starts and 208 hot starts per year.

3.1.2.3 MHPS M501JAC - Combustion Turbine Generator Emissions: Total Annual

Annual emissions for the three CTGs were calculated based on the maximum of either 8,760 hr/year of continuous operation or emissions which include the maximum number of startup/shutdown events. The annual emissions during startup/shutdown include the appropriate downtime based on the assumed number of cold, hot, and warm starts and shutdowns. Tables 3-11 and Table 3-12 present the annual emissions (tons/year) of criteria pollutants and HAPs, respectively, for the two CTGs arranged in a 2 on 1 configuration for two cases:

(1) Continuous operations for all turbines 8,760 hours per year (see Table 3-7).
(2) Continuous operations for all turbines 7,216 hours per year, 1,280 hours per year downtime, and 264 hours per year in startup/shutdown operations (see Table 3-10).

Note that the maximum emissions for all pollutants except for CO and VOC occur during 8,760 hours of normal continuous operation.

Table 3-11: MHPS 501JAC - Combustion Turbine Generators: Annual Criteria Pollutant Emissions

Pollutant	Potential Annual Emission Rates (Per Turbine)			Three 1x1 Configuration
	Annual Emissions for Continuous Operation (tpy)[a]	Annual Emissions with Startup and Shutdown (tpy)[b]	Worst-Case Annual Emissions (tpy)[c]	Worst-Case Annual Emissions (Total) (tpy)
NO_X	128.3	114.7	128.3	385.0
CO	39.0	94.3	94.3	282.9
VOC	15.8	68.0	68.0	204.1
PM_{10} / $PM_{2.5}$	53.9	<53.9	53.9	161.6
SO_2	20.3	<20.3	20.3	61.0
H_2SO_4	21.4	<21.4	21.4	64.2
NH_3	118.7	<118.7	118.7	356.1
Lead	0.0087	<0.0087	0.0087	0.026
GHG CO_2e	2,123,519	<2,123,519	2,123,519	6,370,557

(d) Detailed information for emissions during continuous operation is in Table 3-7.
(e) Detailed information for emissions including startup and shutdown are in Tables 3-9 and 3-10.
(f) Worst-case emissions are the maximum for each pollutant of either continuous operation or with startup and shutdown.

Table 3-12: MHPS 501JAC - Combustion Turbine Generators: Annual Hazardous Air Pollutant (HAP) Emissions

CTGs: Annual HAP Emissions [(a)] (Total Three 1x1 Configuration; ton/year)	
Pollutant [(b)]	**MHPS M501JAC**
Formaldehyde	9.79E+00
Toluene	4.52E+00
Xylene	2.22E+00
Acetaldehyde	1.39E+00
Ethylbenzene	1.11E+00
Propylene Oxide	1.01E-00
Benzene	4.17E-01
Acrolein	2.22E-01
Nickel	1.10E-01
Chromium	7.34E-02
Other HAPs	2.71E-01
TOTAL	**21.14**

(a) See Table B-2.5 for detailed calculations.
(b) The highest ten HAPs in terms of annual emissions are presented in this table. The remaining HAP emissions are presented under the group “Other HAPs”.

3.2 Ancillary Equipment

The facility will include two auxiliary boilers, three fuel gas heaters, and circuit breakers to support CTG operations. A firewater pump and a standby generator will also be installed along with distillate fuel oil tanks on-site to meet the power and electricity demands of the facility during power outages and other emergencies. Emissions of criteria pollutants from the ancillary equipment are presented in Table 3-13 and detailed emissions calculations are provided in Appendix B (Tables B-3 to B-7).

3.2.1 Auxiliary Boilers

For the GE 7HA.02 option, the facility will include two natural gas-fired auxiliary boilers each with a rated heat input rate of 52 MMBtu/hr. The boilers are being permitted with an annual capacity factor limitation of 100% each. Emissions of criteria pollutants and HAPs from the auxiliary boiler are presented in Table 3-13 and detailed emission calculations are presented in Table B-1.5 and B-1.7.

For the MHPS M501JAC option, the facility will include two natural gas-fired auxiliary boilers each with a rated heat input rate of 84 MMBtu/hr. The boilers are being permitted with an annual capacity factor limitation of 100% each. Emissions of criteria pollutants and HAPs from the auxiliary boiler are presented in Table 3-13 and detailed emission calculations are presented in Table B-2.5 and B-2.7.

3.2.2 Fuel Gas Heaters

The facility will also include three natural gas fired fuel gas heaters with heat input ratings of 12 MMBtu/hr each. The fuel gas heaters are also being permitted without any annual operating restrictions. Therefore, annual emissions are based on 8,760 hours/year. Emissions of criteria pollutants from the fuel gas heater are presented in Table 3-13 and detailed emission calculations of criteria pollutants and HAPs are presented in Tables B-1.5, B-2.5 and B-3.

3.2.3 Emergency Engines

The facility will have a 3.0 MW emergency generator and a 376 bhp emergency firewater pump. The diesel fired emergency generator and firewater pump will meet the emission requirements in USEPA's Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, July 11, 2006 (40 CFR Part 60, Subpart IIII). They will also meet the requirements of 40 CFR 63, Subpart ZZZZ, however for these engines the only requirement under Subpart ZZZZ is to be in compliance with 40 CFR Part 60 Subpart IIII. Both the firewater pump and the emergency generator are expected to operate for no more than 100 hours/year for routine testing and maintenance, and 500 hours/year total for each unit (including emergency use). Emissions of criteria pollutants and HAPs from the emergency engines are presented in Tables 3-13 and detailed emissions calculations can be found in Appendix B (Table B-1.5, B-2.5, B-4, and B-5).

3.2.4 Circuit Breakers

The proposed project will include circuit breakers which hold 22,800 pounds Sulfur hexafluoride (SF_6). There will be a maximum leak rate of less than 0.5% annually. The expected emissions from this source are presented in Table B-6 in Appendix B.

3.2.5 Distillate Fuel Oil Storage Tanks

The facility will have one 572 gallon storage tank for the diesel-fired fire water pump and one 2,500 gallon storage tank for the diesel-fired emergency generator. NSPS Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, regulates storage vessels with a capacity

greater than 75 cubic meters (m^3) (19,813 gallons). The proposed tanks fall well under this capacity trigger; thus, Subpart Kb does not apply. VOC emissions from the distillate tanks are presented in Table 3-13 and detailed emissions calculations from the TANKs run can be found in Appendix B (Table B-7, and at the end of Appendix B).

3.2.6 Natural Gas Equipment Leaks

Fugitive GHG emissions from equipment leaks are estimated to be less than 250 tons CO_2e/yr, the same as the Greensville Power Station.[2]

Table 3-13 Annual Criteria Pollutant and HAP Emissions from Ancillary Equipment (tons/year)

Compound	GE 7HA.02 Auxiliary Boilers	MHPS M501JAC Auxiliary Boilers	Fuel Gas Heaters	Emergency Generator	Emergency Fire Water Pump	Circuit Breakers	Storage Tanks	Natural Gas Equipment Leaks
Criteria Pollutants								
Nitrogen Oxides	5.01	8.09	1.73	11.6	0.62	-	-	-
Carbon Monoxide	16.85	27.23	5.83	6.36	0.54	-	-	-
VOCs	2.28	3.68	0.79	2.36	0.023	-	2.11E-03	-
Sulfur Oxides	0.521	0.842	0.180	0.011	0.001	-	-	-
$PM_{10}/PM_{2.5}$	3.19	5.15	1.10	0.36	0.03	-	-	-
Lead	2.23E-04	3.61E-04	7.73E-05	6.51E-05	5.71E-06	-	-	-
H_2SO_4	3.99E-02	6.45E-02	1.38E-02	8.52E-04	7.47E-05	-	-	-
GHG CO_2e	54,262	87,654	18,783	1,203	106	1,140	-	250
HAPs	4.01E-02	6.48E-02	1.39E-02	1.14E-02	2.46E-03	-	-	-

3.3 Total Annual Project Emissions

Tables 3-14 and 3-16 show the annual potential-to-emit of the Project for the GE 7HA.02 and MHPS 501JAC, respectively, along with the ancillary equipment. Total HAP emissions from the Project will not exceed 25 tons/year and individual HAP emissions will not exceed 10 tons per year as shown in Tables 3-15 and 3-17 (see Appendix B, Table B-1.5 and B-2.5 for details).

[2] Virginia DEQ - Dominion - Greensville, Dominion Response to Comments, April 22, 2016.

Table 3-14: Total Annual Project Emissions, Option 1 (GE 7HA.02 CTGs)

Emission Source Description	NO_x (ton/yr)	SO_2 (ton/yr)	PM_{10} (ton/yr)	$PM_{2.5}$ (ton/yr)	CO (ton/yr)	VOC (ton/yr)	H_2SO_4 (ton/yr)	Lead (ton/yr)	GHG CO_2e (ton/yr)
Combustion Turbine #1	116.07	18.19	54.31	54.31	123.06	22.89	12.14	7.82E-03	1,901,202
Combustion Turbine #2	116.07	18.19	54.31	54.31	123.06	22.89	12.14	7.82E-03	1,901,202
Combustion Turbine #3	116.07	18.19	54.31	54.31	123.06	22.89	12.14	7.82E-03	1,901,202
Auxiliary Boilers	5.01	5.21E-01	3.19	3.19	16.85	2.28E+00	3.99E-02	2.23E-04	54,262
Fuel Gas Heaters	1.73	1.80E-01	1.10E+00	1.10E+00	5.83	7.88E-01	1.38E-02	7.73E-05	18,783
Diesel-Fired Emergency Generator	11.63	1.11E-02	3.64E-01	3.64E-01	6.36	2.36E+00	8.52E-04	6.51E-05	1,203
Diesel-Fired Fire Water Pump	0.62	9.76E-04	3.11E-02	3.11E-02	0.54	2.32E-02	7.47E-05	5.71E-06	106
Emergency Generator Fuel Oil Tank						1.83E-03			
Fire Water Pump Fuel Oil Tank						2.85E-04			
Circuit Breakers									1,140
Natural Gas Equipment Leaks									250
Total Project Emissions:	**367.2**	**55.30**	**167.6**	**167.6**	**398.8**	**74.1**	**36.5**	**0.024**	**5,779,348**
PSD Major Source Threshold	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100,000**
PSD Major Source	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**No**	**No**	**No**	**Yes**
PSD Significant Emission Rate	**40**	**40**	**15**	**10**	**100**	**40**	**7**	**0.6**	**75,000**
Proposed Project Subject to PSD	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**

Table 3-15: Facility Wide HAP Emissions, Option 1 (GE 7HA.02 CTGs)

Emission Source Description	HAP Estimates [(a)]	HAP Major Source Determination	Proposed Project Major Source?
CTGs	18.93	-	-
Ancillary Equipment	0.068	-	-
Facility Wide Total	**18.99**	**25**	**No**
Facility Wide Single Maximum HAP	**8.81**	**10**	**No**

(a) See Tables B-1.5 for detailed calculations.

Table 3-16: Total Annual Project Emissions, Option 2 (MHPS M501JAC CTGs)

Emission Source Description	NO_x (ton/yr)	SO_2 (ton/yr)	PM_{10} (ton/yr)	$PM_{2.5}$ (ton/yr)	CO (ton/yr)	VOC (ton/yr)	H_2SO_4 (ton/yr)	Lead (ton/yr)	GHG CO_2e (ton/yr)
Combustion Turbine #1	128.33	20.32	53.87	53.87	94.29	68.04	21.39	8.74E-03	2,123,519
Combustion Turbine #2	128.33	20.32	53.87	53.87	94.29	68.04	21.39	8.74E-03	2,123,519
Combustion Turbine #3	128.33	20.32	53.87	53.87	94.29	68.04	21.39	8.74E-03	2,123,519
Auxiliary Boilers	8.09	8.42E-01	5.15	5.15	27.23	3.68E+00	6.45E-02	3.61E-04	87,654
Fuel Gas Heaters	1.73	1.80E-01	1.10E+00	1.10E+00	5.83	7.88E-01	1.38E-02	7.73E-05	18,783
Diesel-Fired Emergency Generator	11.63	1.11E-02	3.64E-01	3.64E-01	6.36	2.36E+00	8.52E-04	6.51E-05	1,203
Diesel-Fired Fire Water Pump	0.62	9.76E-04	3.11E-02	3.11E-02	0.54	2.32E-02	7.47E-05	5.71E-06	106
Emergency Generator Fuel Oil Tank						1.83E-03			
Fire Water Pump Fuel Oil Tank						2.85E-04			
Circuit Breakers									1,140
Natural Gas Equipment Leaks									250
Total Project Emissions:	**407.1**	**62.00**	**168.3**	**168.3**	**322.8**	**211.0**	**64.3**	**0.027**	**6,479,692**
PSD Major Source Threshold	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100,000**
PSD Major Source	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**No**	**Yes**
PSD Significant Emission Rate	**40**	**40**	**15**	**10**	**100**	**40**	**7**	**0.6**	**75,000**
Proposed Project Subject to PSD	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**

Table 3-17: Facility Wide HAP Emissions, Option 2 (MHPS M501JAC CTGs)

Emission Source Description	HAP Estimates [(a)]	HAP Major Source Determination	Proposed Project Major Source?
CTGs	21.14	-	-
Ancillary Equipment	0.092	-	-
Facility Wide Total	**21.23**	**25**	**No**
Facility Wide Single Maximum HAP	**9.86**	**10**	**No**

(a) See Tables B-2.5 for detailed calculations.

4.0 Applicable Requirements and Standards

This section presents a review of the air quality regulations that will govern permitting and operation of the proposed project. Specifically, the following regulations and standards were reviewed for applicability to the proposed project:

- National Ambient Air Quality Standards (NAAQS);
- Prevention of Significant Deterioration (PSD) Regulations;
- Good Engineering Practice (GEP) Stack Height Regulations;
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Compliance Assurance Monitoring (CAM);
- Acid Rain Program Regulations (ARP);
- Risk Management Program (RMP);
- Title V Permit Program;
- Cross State Air Pollution Rule (CSAPR);
- Virginia Department of Environmental Quality (VADEQ), Virginia Administrative Code (VAC); and
- Virginia State Implementation Plan.

The Federal regulatory programs, as administered and delegated by the U.S. Environmental Protection Agency (EPA), have been developed under the authority of the Clean Air Act (CAA or Act) and its amendments. The following subsections review the key elements of the federal regulatory program and the impact they have on the permitting and operation of the proposed Project. Attention is placed on National Ambient Air Quality Standards (NAAQS) (40 Code of Federal Regulations [CFR] 50), PSD (40 CFR 52.21), NSPS (40 CFR 60), NESHAP (40 CFR 61, 40 CFR 63), CAM (40 CFR 64), RMP (40 CFR 68), ARP regulations (40 CFR 72, 73, 75, 76, 77), and CSAPR (40 CFR 97). Discussion of applicable Virginia regulatory citations is also included in this section.

4.1 Classification with Regard to Ambient Air Quality

The 1970 CAA gave EPA specific authority to establish the minimum level of air quality that all states would be required to achieve. These minimum values or standards were developed to protect the public health (primary) and welfare (secondary). The federally promulgated standards, adopted by Virginia as state standards, are presented in Table 4-1. The Virginia ambient air quality standards also are included in Table 4-1.

Table 4-1: Ambient Air Quality Standards

Pollutant	Averaging Period[2]	NAAQS[1]		Virginia DEQ Regulation Standards[1]	
		Primary	Secondary	Primary	Secondary
Sulfur dioxide (SO_2)	Annual[4]	80	--[3]	80	--[3]
	24-hour[4]	365	--[3]	365	--[3]
	1-hour	196	--[3]	196	--[3]
	3-hour	--[3]	1,300	--[3]	1,300
Particulate matter (PM) with an aerodynamic diameter less than 10 microns (PM_{10})	24-hour	150	150	150	150
PM with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$)	Annual	12	15	15	15
	24-hour	35	35	35	35
Carbon monoxide (CO)	8-hour	10,000	--[3]	10,000	--[3]
	1-hour	40,000	--[3]	40,000	--[3]
Ozone (O_3)	8-hour	0.075 ppm	0.075 ppm	0.075 ppm	0.075 ppm
Nitrogen dioxide (NO_2)	Annual	53 ppb	53 ppb	53 ppb	53 ppb
	1-hour	100 ppb	--[3]	100 ppb	--[3]
Lead (Pb)	3-month[5]	0.15	--[3]	0.15	--[3]

[1]All standards in this table are expressed in µg/m^3 unless otherwise noted.
[2]National short-term ambient standards may be exceeded once per year; annual standards may never be exceeded. Virginia short-term standards may be exceeded once per year, annual standards may never be exceeded. O_3 standard is attained when the expected number of days of an exceedance is equal to or less than one.
[3]No ambient standard for this pollutant and/or averaging period.
[4]Final rule signed June 2, 2010. The 1971 annual and 24-hour SO_2 standards were revoked in this rulemaking. However, these standards remain in effect until one year after an area is designated for the 2010 standard, except in areas designated nonattainment for the 1971 standards, where the 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standard are approved.
[5]The rule signed October 15, 2008 finalized a new lead standard. The 1978 lead standard of 1.5 µg/m^3 as a quarterly average remains in effect until one year after an area is designated for the 2008 standard, except in areas designated nonattainment for the 1978 standard, where, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.
Source: 40 CFR 50, and 9 VAC 5-30

The 1990 CAA Amendments called for a review of the ambient air quality of all regions of the United States (U.S.). By March 15, 1991, states were required to file with EPA designations of all areas as either attainment, non-attainment, or unclassifiable. Areas of the country that had monitored air quality levels equal to or better than these standards (i.e., ambient concentrations less than a standard) as of March 15, 1991, became designated as "attainment areas," while those areas where monitoring data indicated air quality concentrations greater than the standards became known as "non-attainment areas."

The designation of “unclassifiable” indicates that there is insufficient monitoring data to prove that the area has attained the federal standards; however, the limited data available indicates that the standard has been achieved. Areas with this classification are treated by the EPA as attainment areas for permitting purposes.

The current federal air quality classifications for the Project area in Charles City County are listed in Table 4-2, for each criteria pollutant. The designation of an area has particular importance for a proposed project as it is a factor that, in part, determines whether a pollutant is subject to PSD review or Nonattainment New Source Review.

Table 4-2: Classification of Charles City County, VA, for Each Criteria Pollutant

Pollutant	Attainment Status
Carbon Monoxide (CO)	Unclassifiable/Attainment
Sulfur Dioxide (SO_2)	Attainment[1]
Nitrogen Dioxide (NO_2)	Unclassifiable/Attainment
Particulate Matter < 10 µm (PM_{10})	Unclassifiable/Attainment
Particulate Matter < 2.5 µm ($PM_{2.5}$)	Unclassifiable/Attainment
Ozone (O_3 - 8-hour)	Unclassifiable/Attainment
Lead (Pb)	Unclassifiable/Attainment

Source: 40 CFR 81.347.
[1]1-hour SO_2 NAAQS classification has not been finalized.

Major new sources or major modifications to existing major sources located in attainment or unclassifiable areas are required to obtain a PSD permit prior to initiation of construction. Similar sources located in areas designated as non-attainment or that adversely impact such areas are required to undergo permitting under the provisions of the non-attainment New Source Review (NNSR) program. In either case, it is necessary, as a first step, to determine the air quality classification of a project site. For the proposed Project, only PSD review is potentially applicable because the attainment status for Charles City County, which is located in the State Capital Intrastate Air Quality Control Region, is either unclassifiable/attainment or attainment for all applicable pollutants.

4.2 PSD Program

4.2.1 PSD Applicability

The determination of whether PSD regulations are applicable to a specific project must be conducted in two parts: first dealing with the air quality status of the location of the Project and second evaluating the type and quantity of PSD-regulated pollutants that will be emitted. For the regulations to apply to a given project, it must first be determined whether the proposed location is in an area that has been classified as attainment or as unclassifiable. Since the facility is located in Charles City County, which is designated as attainment or unclassifiable for the criteria pollutants, PSD review will potentially apply as discussed below.

First, the Project's PTE is reviewed to determine whether it constitutes a major stationary source or a major modification. A major stationary source is defined as either one of the sources identified in 9 VAC 5-80-1615 C (see Table 4-3) and which has a PTE of 100 tons or more per year of any regulated pollutant, or any other stationary source which has the PTE of 250 tons or more per year of a regulated pollutant. A major modification is defined as a source having an increase in emissions above the PSD significant emission rates, as identified in Table 4-4. Combined-cycle turbine generators with HRSG are considered a fossil fuel-fired steam electric plant under the PSD rules. "Potential to emit" has a special meaning here as it is determined on an annual basis after the application of air pollution control

equipment based on the maximum hourly emissions times 8,760 hours, or any other practically enforceable restriction that would restrict the hours of operation or emissions of the emission source. Once it is determined that a pollutant exceeds the major source threshold, each of the remaining pollutants is subject to PSD review if the PTE exceeds the significant emission rates listed in Table 4-4.

Table 4-3: Major Stationary Source Categories with a 100 TPY Major Source Threshold

Fossil Fuel-Fired Steam Electric Plants of More Than 250 million Btu Per Hour Heat Input
Coal Cleaning Plants (with thermal dryers)
Kraft Pulp Mills
Portland Cement Plants
Primary Zinc Smelters
Iron and Steel Mill Plants
Primary Aluminum Ore Reduction Plants
Primary Copper Smelters
Municipal Incinerators Capable of Charging More Than 250 Tons of Refuse Per Day
Hydrofluoric, Sulfuric or Nitric Acid Plants
Petroleum Refineries
Lime Plants
Phosphate Rock Processing Plants
Coke Oven Batteries
Sulfur Recovery Plants
Carbon Black Plants
Primary Lead Smelters
Fuel Conversion Plants
Sintering Plants
Secondary Metal Production Plants
Chemical Processing Plants
Fossil-Fuel Boilers (or combination thereof) Totaling of More Than 250,000,000 Btu Per Hour Heat Input
Petroleum Storage and Transfer Units with a Total Storage Capacity Exceeding 300,000 Barrels
Taconite Ore Processing Plants
Glass Fiber Processing Plants
Charcoal Production Plants
Source: 9 VAC 5-80-1615 C.

Table 4-4: PSD Significant Emission Rates

Pollutant	Significant Emission Rate (tpy)
CO	100
NO_X	40
SO_2	40
PM	25
PM_{10}	15
$PM_{2.5}$	10
O_3	40 of Volatile Organic Compounds (VOCs)
Lead (Pb)	0.6
Fluorides	3
Sulfuric Acid Mist	7
Total Reduced Sulfur	10
Reduced Sulfur Compounds	10
H_2S	10
Greenhouse Gases CO_2e	75,000
Source: 9 VAC 5-80-1615 C and 9VAC5-85-50	

The Project is subject to PSD for NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, CO, SO_2, H_2SO_4, and GHG, as previously shown in Tables 3-14 and 3-16.

4.2.2 PSD Program Requirements

The following provides a summary of the application requirements for projects subject to PSD.

Best Available Control Technology

The requirements for Best Available Control Technology (BACT) were promulgated within the framework of PSD in the 1977 CAA Amendments. Guidelines for the evaluation of BACT can be found in EPA's Air Pollution Control Cost Manual (EPA 2002) and in the PSD/New Source Review Workshop Manual (EPA 1990 DRAFT). These guidelines were drafted by EPA as a framework or tool for the BACT process. More recently, EPA has published guidance on BACT for greenhouse gas emissions (http://www.epa.gov/nsr/ghgpermitting.html). BACT for most states, including Virginia, is determined by the state permitting authority using permitting procedures that have been adopted consistent with the authority granted through EPA's SIP approval of the Virginia PSD program.

The regulatory definition of BACT for affected sources locating in Virginia is:

> *[A]n emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant that would be emitted from any proposed major stationary source or major modification that the board, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant that would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63. If the board determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means that achieve equivalent results [9 VAC 5-80-1615 C.]*

Although BACT is typically an emission limit, BACT can also be a work practice standard in certain circumstances, typically if an emission limit is not feasible. One example of a work practice standard that can impact a BACT determination is a limitation on the hours of operation for a source. Another example is the specification of a particular control device in lieu of an emission limit. BACT limits are determined by the "permitting authority" (in this instance, the VADEQ) based on a case-by-case analysis that takes into account site-specific characteristics, including "energy, environmental, and economic costs and other costs" [9 VAC 5-80-1615 C]. BACT does not require a redefinition of the proposed source or the use of unproven technology. BACT is not necessarily the lowest emission level ever seen, but the lowest level achievable by the applicant for the proposed source at issue under worst-case foreseeable conditions.

A BACT limit must be "achievable." Generally, "achievable" in the context of BACT means an emission limit that the source can meet on a continual basis over each averaging period for the lifetime of the facility. BACT limits should be set at levels the source can meet under all reasonable foreseeable worst-case conditions. A permitting authority determines what is achievable for a source, exercising its technical judgment on a case-by-case basis.

In addition to being "achievable," a control technology must be "available" to be considered in a BACT determination. To be "available," a control technology must be demonstrated in practice. This means that the technology has progressed beyond the conceptual stage and beyond the research and development or pilot testing phase. The technology must have been demonstrated successfully on full-scale operations for a sufficient time to be considered proven. BACT does not require an applicant to employ technologies that are not proven to work; theoretical, experimental, or developing technologies are not "available" under BACT. Technologies with questionable or dubious reliability are likewise not considered "available" under BACT, and the applicant is not required to use them. Moreover, vendor sales literature about what a technology might be able to achieve in some limited situation is not relevant to a BACT determination.

Finally, BACT is determined on a pollutant-by-pollutant basis. When establishing BACT for individual pollutants, however, a permitting authority must also consider possible interactions among the

pollutants as well as other collateral environmental impacts of particular technologies, such as water usage or the creation of a waste stream. BACT analyses for the Project are presented in Section 5.

Air Quality Monitoring Requirements

In accordance with requirements of 9 VAC 5-80-1735, a PSD application must contain an analysis of existing ambient air quality data in the area to be affected by the proposed Project if the Project would result in a net significant emissions increase. The analysis of existing air quality can be air monitoring data from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source. The requirement for onsite air quality monitoring is based on the impact levels provided in 9 VAC 5-80-1695 E.

Ambient air monitoring for a period of up to 1 year may be required to properly satisfy this monitoring requirement. This condition may be waived if a project would cause an impact less than EPA-specified *de minimis* monitoring levels established by the Virginia State Air Pollution Control Board (see Table 4-5).

Table 4-5: PSD *De Minimis* Monitoring Threshold Concentrations

Pollutant	Averaging Period	Threshold Concentration ($\mu g/m^3$)
CO	8-hour	575
NO_2	Annual	14
SO_2	24-hour	13
PM/PM_{10}	24-hour	10
O_3	NA	(1)
Lead	3-month	0.1
Fluorides	24-hour	0.25
Total Reduced Sulfur	1-hour	10
Reduced Sulfur Compounds	1-hour	10
H_2S	1-hour	0.2

[1] Exempt if VOC emissions are less than 100 tpy.
Source: 9 VAC 5-80-1695 E

Source Impact Analysis

A source impact analysis must be performed for a proposed project subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate to demonstrate that the Project will not cause or contribute to a violation of NAAQS or PSD increment. The PSD regulations specifically provide for the use of atmospheric dispersion modeling in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with NAAQS and allowable PSD increments. In accordance with 9 VAC 5-80-1725, designated EPA models, identified in 40 CFR 51, Appendix W, must normally be used in performing air quality analyses. Use of other than EPA-approved models requires written approval and opportunity for public notice and comment prior to use. Guidance for the use and application of dispersion models is presented in the EPA

publication Guideline on Air Quality Models (EPA 2005) [3]. The source impact analysis for criteria pollutants may be limited to only the new or modified sources if a net increase in impact due to the new or modified source is below the significant impact levels (SILs) presented in Table 4-6.

Table 4-6: Allowable PSD Increments and Significant Impact Levels (µg/m^3)

Pollutant	Averaging Time	PSD Increments		SILs		NAAQS
		Class I	Class II	Class I[3]	Class II	
PM_{10}	Annual Arithmetic Mean[1]	4	17	0.2	1	NA
	24-hour Maximum[2]	8	30	0.3	5	150
$PM_{2.5}$[5]	Annual Arithmetic Mean[1]	1	4	0.06	0.3	12
	24-hour Maximum[2]	2	9	0.07	1.2	35
SO_2	Annual Arithmetic Mean[1]	2	20	0.1	1	80
	24-hour Maximum[2]	5	91	0.2	5	365
	3-hour Maximum[2]	25	512	1	25	1300
	1-hour Maximum[4]	NA	NA	NA	7.86	196
CO	8-hour Maximum	NA	NA	NA	500	10,000
	1-hour Maximum	NA	NA	NA	2000	40,000
NO_2	Annual Arithmetic Mean[1]	2.5	25	0.1	1	100
	1-hour Maximum[4]	NA	NA	NA	7.5	188

[1] PSD Increment not to be exceeded
[2] PSD Increment not to be exceeded more than once per year
[3] Class I SILs were proposed in FR July 23, 1996
[4] While there are no EPA promulgated SILs for the 1-hour SO_2 and NO_2 NAAQS, interim values have been provided.
[5] SILs for $PM_{2.5}$ exist for the purpose of determining if a source has a significant contribution to a modeled violation. The SILs do not exist for the purposes of avoiding a cumulative impact analysis.
Notes: NA = Not applicable, i.e., no increment exists.

Various periods of meteorological data can be utilized for an impact analysis. However, a minimum 1-year period of onsite data, or a 5-year period of representative meteorological data is normally required.

PSD Increments

PSD regulations specify that new major sources or modifications to existing major sources may change baseline air quality only by a defined amount. This limited incremental degradation is known as a PSD increment. PSD increments have been established for Class I and Class II areas for PM_{10}, $PM_{2.5}$, SO_2, and NO_2 (see Table 4-6).

[3] 40 CFR 51, Appendix W

The allowable change, or increment, is dependent on the classification of the area in which the action is to take place. When PSD regulations were first promulgated, three area classifications were proposed based on criteria set in the 1977 CAA.

Class I areas are federally protected areas and include specifically defined national parks, national forests, and wilderness areas. Class III increments are the least restrictive of the three PSD Classes, but to date, no Class III areas have been officially designated. The remainder (and vast majority) of the country (including Charles City County) is designated as a Class II area.

Additional Analyses

In addition to the standard air quality analyses, federal regulations require an analysis of the impairment to visibility and the effects on soils and vegetation that would occur as a result of project construction and operation. Impacts due to commercial, residential, industrial, and other growth in the vicinity of the Project also must be addressed to the extent they are a result of the proposed action. This additional analysis is provided in Section 8 of this application.

4.3 Good Engineering Stack Height Analysis

The 1977 CAA require that the degree of emission limitation required for control of any pollutant not be affected by a stack which exceeds the GEP height (EPA 1985). Further, no dispersion credit is given during air quality modeling for stacks which exceed GEP. GEP stack height is defined as the highest of:

- 65 meters; or
- A height established by applying the formula:

  $H_{GEP} = H + 1.5\ L$

  Where; H_{GEP} = GEP Stack Height,

  H = Height of the structure or nearby structure, and

  L = lesser dimension (height or projected width) of the nearby structure; or
- A height demonstrated by fluid modeling or field study.

A structure or terrain feature is considered nearby if a stack is within a distance of five times the structure's height or maximum projected width. Only the smaller value of the height or projected width is used and the distance to the structure cannot be greater than 0.8 kilometer (EPA 1985). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed GEP stack height, the actual stack height may be greater.

The stack height regulations also increase GEP stack height beyond that resulting from the formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or modeled 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. Based on two criteria cited in a July 8, 1985 Federal Register preamble to the stack height rules discussing the role of terrain in influencing the emitted plume at the source location, there is no significant terrain that would induce downwash within ½ km and at least a 10% terrain height relative to the distance from the source. Therefore, plume impaction was not considered in determining the GEP stack height for the proposed project.

All stacks to be constructed at the Project site will each be less than or equal to 65 meters and will be modeled at their actual stack elevation. Therefore, the modeling will comply with GEP regulations.

4.4 Applicability of New Source Performance Standards (NSPS)

The NSPS potentially applicable to this Project include:

- Subpart A – General Provisions;
- Subpart Db – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units;
- Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units;
- Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels;
- Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines;
- Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines;
- Subpart KKKK – Standards of Performance for Stationary Combustion Turbines; and
- Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

Each of these potentially applicable subparts is discussed below.

4.4.1 Subpart A – General Provisions

Certain provisions of 40 CFR Part 60 Subpart A apply to the owner or operator of any stationary source subject to a NSPS. Since the proposed facility will be subject to a NSPS, the proposed project will be required to comply with applicable provisions of Subpart A. Subpart A provisions which impose requirements on the proposed project are identified in Table 4-7.

Table 4-7: Summary of Regulatory Requirements of NSPS Subpart A – General Provisions

40 CFR 60 Subpart A Section	Requirement	Compliance Action
60.7	Initial notification and recordkeeping	CPLLC will submit NSPS-related notifications to EPA Region III and Virginia DEQ for the proposed project in a timely manner.
60.8	Performance Tests	CPLLC will conduct required performance tests using designated reference test methods.
60.11	Compliance with standards and maintenance requirements	CPLLC will operate and maintain the units using good air pollution control practices.
60.13	Monitoring requirements	CPLLC will utilize pollutant monitoring methods outlined in 60.13.
60.19	General notification and reporting requirements	CPLLC will follow NSPS report and notification formats and schedules set forth in 60.19.

4.4.2 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

NSPS Subpart Db applies to steam generating units which commence construction after June 19, 1984 and that have a maximum design heat input capacity greater than 100 MMBtu/hr. The proposed natural gas-fired auxiliary boilers and the fuel gas heaters will have capacities less than 100 MMBtu/hr. Therefore, NSPS Subpart Db does not apply to the Project.

4.4.3 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

NSPS Subpart Dc applies to steam generating units which commenced construction after June 9, 1989 and that have a maximum design heat input capacity between 10 MMBtu/hr and 100 MMBtu/hr. The proposed natural gas fired boilers, each rated at 52 MMBtu/hr for the GE 7HA.02 option and 84 MMBtu/hr for the MHPS M501J option, are subject to this subpart because each heater is greater than 10 MMBtu/hr and less than 100 MMBtu/hr. The natural gas fired fuel gas heaters, rated at 12 MMBtu/hr, are also subject to Subpart Dc. While the boilers and heaters are subject to Subpart Dc, the PM and SO_2 emission standards under Subpart Dc are not applicable because the boilers and heaters will only burn natural gas. Subpart Dc does not include NO_X emission standards. CPLLC will comply with all applicable Subpart Dc monitoring, recordkeeping and reporting requirements.

4.4.4 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels

As part of the proposed Project, the facility will have storage tanks which will hold ULSD used in the emergency diesel engine and firewater pump. NSPS Subpart Kb regulates storage vessels with a capacity greater than 75 cubic meters (m^3) (19,813 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Also, Subpart Kb does not apply to storage vessels storing a liquid with a maximum true vapor pressure less than 0.5 psia. Subpart Kb does not apply to the proposed storage tanks because the capacity of each tank is less than 75 m^3, and because the maximum true vapor pressure of the stored liquid (ULSD) will be less than 0.02 psia, which is well below the 0.5 psia Subpart Kb applicability criteria.

4.4.5 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The diesel-fired emergency generator and diesel-fired fire water pump are subject to 40 CFR Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Because these units meet EPA Tier 3 emission requirements for off-road engines, they will comply with the emission limitations of Subpart IIII. CPLLC will also comply with all applicable Subpart IIII monitoring, recordkeeping and reporting requirements.

4.4.6 Subpart KKKK – Standards of Performance for Stationary Combustion Turbine Emissions

The EPA Administrator has promulgated a final rule under 40 CFR 60 Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines" (see 71 FR 38482, July 6, 2006). The regulation applies to NOx and SO_2 emissions from each stationary combustion turbine generator with a heat input at peak load equal to or greater than 10 MMBtu/hr based on the higher heating value, which commenced construction, modification, or reconstruction after February 18, 2005.

Only the heat input rate to the combustion turbine generator should be included when determining whether or not this NSPS is applicable to the proposed CTGs. Any additional heat input to the associated HRSGs or duct burners, if applicable, should not be included when determining the peak heat input. However, if applicable to the CTG, the NSPS does apply to emissions from any associated HRSGs and duct burners.

The construction of the proposed CTGs will commence in June 2019, which is after the applicability date of February 2005. The peak load heat input rate of each of the CTGs is greater than 3,000 MMBtu/hr firing natural gas. Therefore, the proposed CTGs are subject to NO_X and SO_2 emission limits in this regulation.

Subpart KKKK does not limit CO_2 emissions from new combustion turbines. Instead, NSPS Subpart TTTT applies to CO_2 emissions from new combustion turbines.

Emission Limits for NO_X

The proposed CTGs are subject to a NO_X emission standard of 15 ppm at 15 percent O_2 or 0.43 lb/MWh when fired with natural gas. If the CTGs operate in partial load (less than 75 percent of peak load) or if the CTGs operate at temperatures less than 0°F, a NO_X limit of 96 ppm at 15 percent O_2 or 4.7 lb/MWh will apply. Compliance is based on the arithmetic average of all hourly applicable NO_X emission limits and emission rates for the most recent 30 unit operating days. If the HRSGs were to operate independently of the combustion turbine generators, the CTGs would be subject to an emission standard of 54 ppm at 15 percent O_2 or 0.86 lb/MWh.

As discussed in the BACT analysis in Section 5.0, the proposed controls on the CTGs will reduce NO_X emissions to 2 ppmvd at 15 percent O_2 using low-NO_X combustors and SCR. Therefore, compliance with the above NO_X emission limits will be achieved. Compliance with these emission standards will be verified based on CEMS data. The HRSGs will not be operating independently of the CTGs; therefore, the 54 ppm NO_X emission standard is not applicable for these CTGs.

Emission Limits for SO_2

The proposed CTGs will be subject to an emission limit of 0.9 lb/MWh gross output or the CTGs must not burn any fuel which contains the total potential sulfur emissions in excess of 0.06 lb SO_2/MMBtu heat input.

CPLLC will comply with the input-based emission standard for SO_2. The proposed CTGs will burn pipeline quality natural gas with a sulfur content of 0.4 grains sulfur/100 scf, therefore the SO_2 emission rate will not exceed 0.00114 lb/MMBtu. Therefore, compliance with the SO_2 emission limit is expected.

4.4.7 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

NSPS Subpart TTTT was promulgated on October 23, 2015 and is applicable to electric utility generating units that commence construction on or after January 8, 2014. As such, Subpart TTTT is applicable to the proposed combined cycle combustion turbines. The emission limit for base load natural gas fired combustion turbines, which is 1,000 lb CO_2/MWh on a gross output basis over a rolling 12-month operating period, is applicable to the proposed combined cycle units. The combined cycle units proposed by CPLLC will operate below 1,000 lb CO_2/MWh on a gross output basis. Therefore,

the project will comply with the Subpart TTTT emission standard. In addition, CPLLC will comply with all applicable Subpart TTTT monitoring, recordkeeping, reporting, and performance test requirements.

4.5 40 CFR Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

The proposed Project is not subject to any of the 40 CFR Part 61 NESHAPs.

4.6 40 CFR Part 63 NESHAPs

A major source of HAPs is any stationary source that has the potential to emit 10 tpy or more of a single HAP or 25 tpy of combined HAPs. 40 CFR Part 63 Maximum Achievable Control Technology standards have been promulgated for major sources and, in a few cases, for area sources. As shown in Section 3 and Appendix B, potential HAP emissions will be below the major source thresholds for single HAP and combined HAPs. Therefore, the Project will not be a major source of HAP emissions.

4.6.1 Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

The Combustion Turbine MACT standard (Subpart YYYY) only applies to major HAP sources. Therefore, Subpart YYYY will not apply to the Project.

4.6.2 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The emergency generators and the fire water pump engine are subject to Subpart ZZZZ since this standard is applicable to sources located at area sources of HAPs as well. Since all the engines are new and are located at an area source, the requirements of 40 CFR 60 Subpart IIII (for the diesel-fired emergency generators), or Subpart JJJJ (for the propane-fired emergency generators), must be met in order to meet the requirements of Subpart ZZZZ. The engines will meet the applicable NSPS requirements as described above in Section 4.4.5.

4.6.3 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

The Major Source Industrial Boiler MACT standard (40 CFR Part 63 Subpart DDDDD) applies to boilers and process heaters located at major HAP emission sources. Because the CPLLC Project is not a major source of HAPs, Subpart DDDDD does not apply.

4.6.4 Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

The Area Source Industrial Boiler MACT standard (40 CFR Part 63 Subpart JJJJJJ) does not apply to gas-fired boilers or process heaters. The proposed auxiliary boilers and fuel gas heater will be exempt because they meet the definition of a gas-fired boiler:

> *"**Boiler*** means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler

unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler."*

"Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year."

4.6.5 Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

The Mercury and Air Toxics (MATS) rule, NESHAP Subpart UUUUU, was promulgated on February 16, 2012. The MATS rule reduces emissions of heavy metals and acid gases from affected emission units. The rule does not apply to the proposed electric generating units because they will only burn natural gas.

4.7 Title IV Acid Rain Provisions

The proposed CTGs are fossil fuel-fired combustion devices used to generate electricity for sale, and its capacity serves a generator that exceeds 25 MW. Therefore, the proposed CTGs meet the definition of an affected Phase II "utility unit" under the Acid Rain Program (ARP) pursuant to Title IV of the 1990 CAA Amendments.

This applicability requires CPLLC to:

- Apply for a Phase II Acid Rain Permit to include the new utility units;
- Install CEMS to demonstrate compliance with the ARP provisions meeting the requirements specified in 40 CFR 75; and
- Hold allowances equivalent to annual NO_X and SO_2 emissions.

An Acid Rain permit application must include the date that the units will commence commercial operation and the deadline for monitoring certification (90 days after commencement of commercial operation). CPLLC will file the appropriate paperwork to apply for their Acid Rain permit.

CPLLC will operate in compliance with applicable provisions of the Title IV Acid Rain rules as adopted by reference under 9 VAC 5-80-360. The facility also will meet applicable Acid Rain requirements that become effective after the issuance of an Acid Rain permit.

The facility will develop a Title IV Acid Rain monitoring plan as required under 40 CFR 72. The plan will include the installation, proper operation, and maintenance of continuous monitoring systems or approved monitoring provisions under 40 CFR 75 for NO_X, SO_2, CO_2 or O_2 (as a diluent), and opacity. Depending on the monitoring technology available at the time of installation, the plan will cite the specific operating practices and maintenance programs that will be applied to the instruments. The plan also will cite the specific form of records that will be maintained, their availability for inspection, and the length of time that they will be archived. The plan will further cite that the Acid Rain permit and applicable regulations will be reviewed at specific intervals for continued compliance and will cite the specific mechanism to be used to keep current on rule applicability.

4.8 Risk Management Program, Section 112(r)

Title III of the 1990 CAA Amendments contains requirements for subject facilities that store and/or process certain hazardous substances for ensuring their safe use. Under these requirements, facilities must identify and assess their hazards and carry out certain activities designed to reduce the likelihood and severity of accidental chemical releases. Section 112(r) of the CAA, codified in 40 CFR Part 68, mandates the EPA to publish rules to develop and implement RMPs for sources with more than the threshold quantity of a listed regulated substance to identify, prevent, and minimize the consequences of accidental releases. The three elements that should be incorporated into an RMP include:

- Hazard Assessment;
- Prevention Program; and
- Emergency Response Program.

The facility will store 19% aqueous ammonia for use in the SCR, and as such the Risk Management Program requirements do not apply.

4.9 Applicability of Title V – Major Source Operating Permit

The state of Virginia has been delegated authority to implement the major source operating permit program (Title V) in accordance with the requirements of 40 CFR Part 70 and Title V of the 1990 CAA Amendments. The operating permit regulations are contained in 9 VAC 5-80 Part II Article 1 and are briefly summarized in the following text. The minimum requirements for operating permit application contents are provided in 9 VAC 5-80-80.

The proposed CTGs have criteria pollutant emission levels above 100 tpy and therefore, the facility is a major source. 9 VAC 5-80-80 requires “major facilities” to obtain a permit under this section. Therefore, CPLLC will submit a Title V Operating Permit Application to the state of Virginia in a timely manner, so that it can be deemed complete within 12 months of first fire of the new combustion turbine units.

4.10 Cross-State Air Pollution Rule

On July 6, 2011, the EPA promulgated the Cross State Air Pollution Rule (CSAPR) to replace the Clean Air Interstate Rule (CAIR). CSAPR requires states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. On August 21, 2012, the CSAPR was overturned, and the CAIR requirements remained in effect. On April 29, 2014, however, the U.S. Supreme Court reversed the D.C. Circuit opinion vacating the CSAPR. On June 26, 2014, the U.S. Supreme Court filed a motion with the U.S. Court of Appeals for the D.C. Circuit to lift the stay of CSAPR. On October 23, 2014, the U.S. Court of Appeals (D.C. Circuit) ordered that EPA’s motion to lift the stay of the CSAPR be granted. The D.C. Circuit also provided a schedule for resolving the remaining legal challenges in the case. Except for the changes in dates (moved forward by three years (2012 to 2015)), the CSAPR is being implemented as is. Consistent with the court-ordered schedule, Phase I of CSAPR began in 2015 and any units subject to the rule must comply with all applicable requirements. The Clean Air Interstate Rule (CAIR) requirements including CAIRNOX, CAIROS and CAIRSO2 Programs have ceased to apply post calendar year 2014.

Aside from the new unit set-asides for ozone season NO_X, annual NO_X and SO_2, the requirements are similar to those of the CAIR. The facility will comply with the permitting, monitoring,

recordkeeping and reporting requirements set forth by CSAPR, including the installation and certification of a continuous emission monitors.

4.11 State Regulatory Review

In general, the VADEQ retains jurisdiction within Charles City County with full delegation from the EPA to enforce the air quality programs under the CAA. The emission sources presented in this document shall comply with applicable VADEQ regulations promulgated under Title 9 of Agency 5, State Air Pollution Control Board. This section lists the citations of the applicable state regulations with regulatory requirements.

9 VAC 5-20 – General Provisions
The facility will comply with the general provisions as outlined in 9 VAC 5-20.

9 VAC 5-50-20 – Compliance
Sixty days after achieving the maximum production rate, but not later than 180 days after initial startup, the facility shall not operate any new source in violation of any standard of performance under this regulation. The facility will comply with this regulation.

9 VAC 5-50-30 – Performance Testing
This regulation describes the performance testing procedures for new or modified sources. The facility will conduct all performance testing in accordance with these regulations.

9 VAC 5-50-40 – Monitoring
These regulations apply to continuous emissions monitoring systems. The facility will comply with these regulations for any continuous emissions monitoring systems located onsite.

9 VAC 5-50-50 – Notification, Records, and Reporting
These regulations outline the notification, recordkeeping, and reporting requirements for new sources. The facility will comply with these regulations.

9 VAC 5-50-260 – Standard for Stationary Sources and 9 VAC 5-80-1705 – Control Technology Review
The regulation states that "a stationary source shall apply best available control technology for each regulated pollutant that it would have the potential to emit in amounts equal to or greater than the levels in 9 VAC 5-80-1105 C." A best available control technology (BACT) analysis has been conducted for the Project and is presented in Section 5.0.

9 VAC 5 Chapter 60 – Standards for Air Toxics
This regulation describes the requirements for a stationary source that emits or may emit any toxic pollutant and that either is subject to the new source review program, or emits or may emit at a level greater than the applicable exemption emission rate. For the proposed facility, air toxics that exceed Virginia Air Toxics Exemption Levels are listed in Table 4-8. For those air toxic pollutants that are above the exemption levels, a dispersion modeling analysis demonstrating compliance with the Virginia Significant Ambient Air Concentrations (SAAC) listed in 9 VAC 5-60-330 is provided in Sections 6 and 7. Detailed information on all air toxics along with SAAC levels for any non-exempt air toxics are provided in Appendix B, Tables B-1.6 and B-2.6.

Table 4-8: Virginia Air Toxic Standards – GE 7HA.02

Pollutant	Facility emission rate (lb/hr)	Facility emission rate (tpy)	VA Exemption Level (lb/hr)	VA Exemption Level (tpy)	Exempt? (Hourly)	Exempt? (Annual)
Acrolein	4.59E-02	1.99E-01	0.02277	0.03335	No	No
Formaldehyde	2.02E+00	8.81E+00	0.0825	0.174	No	No
Beryllium	1.30E-04	5.71E-04	0.000132	0.00029	Yes	No
Cadmium	1.19E-02	5.23E-02	0.0033	0.00725	No	No
Chromium	1.52E-02	6.66E-02	0.0033	0.00725	No	No
Lead	5.43E-03	2.38E-02	0.0099	0.02175	Yes	No
Mercury	2.82E-03	1.24E-02	0.0033	0.00725	Yes	No
Nickel	2.28E-02	9.98E-02	0.0066	0.0145	No	No
See Table B-1.6 in Appendix B						

Table 4-9: Virginia Air Toxic Standards – MHPS M501JAC

Pollutant	Facility emission rate (lb/hr)	Facility emission rate (tpy)	VA Exemption Level (lb/hr)	VA Exemption Level (tpy)	Exempt? (Hourly)	Exempt? (Annual)
Acrolein	5.13E-02	2.23E-01	0.02277	0.03335	No	No
Formaldehyde	2.26E+00	9.86E+00	0.0825	0.174	No	No
Beryllium	1.46E-04	6.40E-04	0.000132	0.00029	Yes	No
Cadmium	1.34E-02	5.86E-02	0.0033	0.00725	No	No
Chromium	1.70E-02	7.46E-02	0.0033	0.00725	No	No
Lead	6.09E-03	2.67E-02	0.0099	0.02175	Yes	No
Mercury	3.16E-03	1.39E-02	0.0033	0.00725	Yes	No
Nickel	2.56E-02	1.12E-01	0.0066	0.0145	No	No
See Table B-2.6 in Appendix B						

9 VAC 5-80-420 – Standard Requirements
These regulations describe the information needed and limitations for facilities subject to the acid rain program. As discussed in Section 4.7, the proposed facility will comply with these regulations.

9 VAC 5-80-1105 - Virginia Minor NSR Program
Virginia has established permitting requirements for projects that do not result in significant increases in emissions, but do result in an increase above the applicable permit exemption thresholds shown in Table 4-9. An analysis of the uncontrolled emissions resulting from the project must be conducted to determine whether Virginia's minor NSR permitting program is triggered. Section 3 includes the necessary emission calculations. Based on that analysis, the project is subject to Virginia's minor NSR permitting program for all pollutants except for lead. The necessary state-level BACT analysis for these pollutants is included in Section 5.

Table 4-10: Virginia Minor NSR Thresholds

Pollutant	Minor Source Threshold (tpy)
CO	100
NO_X	40
SO_2	40
PM	25
PM_{10}	15
$PM_{2.5}$	10
VOC	25
Pb	0.6
H_2SO_4	6
Thresholds from 9 VAC 5-80-1105.C.1	

9 VAC 5-80-1180 – Standards and Conditions for Granting Permits
These regulations outline the standards required for all facilities for which a permit is granted. The proposed facility will comply with all standards and conditions listed in the regulation.

9 VAC 5-80-1210 – Permit Invalidation, Suspension, Revocation, and Enforcement
This regulation describes the conditions in which a permit may be invalidated, suspended, revoked, or enforcement action may be brought upon the facility.

9 VAC 5-80-1715 – Source Impact Analysis
The proposed facility must demonstrate that the proposed equipment does not have emission increases that would cause or contribute to a violation of the ambient air quality standards or the maximum allowable increase over the baseline concentration in any area. The modeling analysis will be presented as an addendum in Sections 6 and 7.

9 VAC 5-80-1785 – Source Obligation
These regulations describe the information the proposed facility is required to maintain onsite prior to construction. The proposed facility will comply with this regulation.

5.0 Control Technology Review

5.1 Technical Approach

As discussed previously, CPLLC proposes to design, construct, and operate a new combined cycle power plant that will burn natural gas. The plant will have an approximate net generation capacity of 1,650 MWe (nominal) at 95°F ambient temperature. According to 9 VAC 5-80, the Project must apply Best Available Control Technology (BACT) for those pollutants that are emitted in significant quantities, that is, PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, SO_2, H_2SO_4, and GHG (CO_2e). The Project will include the following stationary sources:

- Three GE 7HA.02 or three MHPS M501JAC CTGs;
- Two 52 MMBtu/hr natural gas-fired auxiliary boilers for the GE 7HA.02 option;
- Two 84 MMBtu/hr natural gas-fired auxiliary boilers for the MHPS M501J option;
- Three 12 MMBtu/hr natural gas-fired fuel gas heater;
- One 3,000 kW emergency diesel generator operating on ULSD fuel;
- One 376 bhp emergency fire-water pump operating on ULSD fuel;
- One 572 gallon diesel tank and one 2,500 gallon diesel tank; and
- Circuit breakers (Containing SF_6).

5.1.1 Top-Down BACT Analysis

The Virginia regulations require that applicants for a PSD pre-construction permit conduct a BACT analysis for all regulated pollutants emitted in significant quantities from major stationary sources to demonstrate compliance with the control technology requirements of the PSD regulations in Article 8 of 9 VAC 5 Chapter 80. According to 9 VAC 5-80-1615 C, BACT is defined as:

> *"an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant that would be emitted from any proposed major stationary source or major modification that the board, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."*

In no event must application of BACT result in emissions of any pollutant that would exceed those allowed by any applicable requirements in the SAPCB regulations under 9 VAC 5 Chapter 50, New Source Performance Standards under 40 CFR Part 60, or the National Emission Standards for Hazardous Air Pollutants under 40 CFR Parts 61 and 63.

The USEPA and VADEQ recommend a "top down" approach to the BACT analysis. The process begins with the identification of the alternative control technologies available for the source category based upon a review of: (1) those technologies required by previous BACT determinations made by the USEPA or the various state agencies; and (2) those technologies applied in practice to the same category or a similar source category by means of technology transfer. The available control

technologies are then evaluated to determine whether they are technically feasible for the given application. Those control technologies found to be technically infeasible are eliminated from further consideration, while the remaining control technologies are ranked by their performance levels, from the highest to the lowest performance level. The technically feasible control technologies are then evaluated on the basis of the associated economic, energy and environmental impacts. If an alternative technology, starting with the highest performance level, is eliminated based on any of these criteria, the control technology with the next highest performance level is evaluated until a control technology qualifies as BACT. Historically, the cost effectiveness of alternative control technologies in reducing air pollutant emissions is the principle criteria used by both the USEPA and VADEQ in their determinations of BACT. All evaluated control technologies must be capable of meeting the NSPS for the pollutant in question.

According to USEPA guidance, BACT may be achieved by one or a combination of the following: (1) a change in the raw material processes; (2) a process modification; and (3) an add-on control device. A change in raw materials is typically considered for industrial processes that use chemicals, such as solvents, where substitution with a lower emitting chemical may be technically feasible. In this case, natural gas is the lowest emitting fuel for the combustion turbines.

Similar to changes in raw materials, process modifications are typically considered for industrial processes that use chemicals, where a change in the process methods or conditions may result in lower emissions.

In summary, the EPA's preferred "top-down" BACT process consists of five steps as outlined below:

STEP 1 - Identify all available control options with potential for application to the specific emission unit for the regulated pollutant under evaluation;

STEP 2 - Eliminate technically infeasible or unavailable technology options;

STEP 3 - Rank remaining control technologies by control effectiveness;

STEP 4 - Evaluate most effective controls and document results to determine if energy, environmental, and economic impacts are reasonable; if top option is not selected as BACT, evaluate next most effective control option; and

STEP 5 - Select BACT, which will be the most effective option not rejected based on energy, environmental, and economic impacts.

The "top-down" approach was used in this analysis to evaluate available pollution controls for the Project.

5.1.2 State Control Technology Analysis

The VADEQ requires the application of best available control technology to new stationary sources to be located in the Commonwealth of Virginia (9 VAC 5-50-260). The VADEQ defines BACT as *"an emissions limitation (including a visible emission standard) based on the maximum degree of emission reduction for any pollutant which would be emitted from a new stationary source which the board, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for the new stationary source or project through the application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant"* [9 VAC 5-50-250(C)]. In no event must application of BACT result in emissions of any pollutant that would exceed those allowed by any applicable standard under Article 5 (9 VAC 5 Chapter 50). Accordingly, the BACT analysis must also

address those pollutants that do not exceed the significance thresholds triggering review under the PSD regulations.

The analysis is based on the BACT definition in 9 VAC 5-80–1615 and is presented below addressing each of the five steps. EPA has stated that BACT is applied to the source as proposed by the Applicant, and that BACT cannot redefine the source.[4] Therefore, it would not be appropriate to consider any technology other than the proposed combined cycle natural gas combustion turbine in applying the BACT process to the proposed Project.

5.1.3 Previous BACT Determinations

Federal and state data sources were reviewed to determine the control technologies that have been applied to combined cycle power plants around the country. The review focused on the types of air pollution control technologies used in these applications, the design and performance of each air pollution control technology, and the incentive for implementing the preferred control measures. The review considered the following databases:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) which is a national database of approved permits for installation of various facilities including combined cycle power plants;
- EPA Region IV's national combustion turbine data base; and
- Air pollutant emission limits established in the various State Implementation Plans.

Each of these databases has certain limitations that hinder either identifying the control devices currently employed at the power plants or determining the performance levels actually achieved in practice by the control devices. The information found in the USEPA's RBLC is provided in Appendix C. Note that some of these projects have been cancelled and others are not yet operating; hence, some of the emission rates have not been demonstrated as achievable in practice. The results of this review were used, in part, to identify available emission control technologies (STEP 1 in the BACT process), eliminate technically infeasible options (STEP 2), and rank the remaining control technologies based on control effectiveness (STEP 3).

5.2 Combined Cycle Gas Turbine Generator Continuous Operations BACT

5.2.1 BACT for Nitrogen Oxides (NO_X)

NO_X is primarily formed in combustion processes in two ways: 1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_X); and 2) the oxidation of nitrogen contained in the fuel (fuel NO_X). Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen; therefore, NOx emissions from natural gas-fired combustion turbines originate as thermal NO_X only. The rate of formation of thermal NO_X is a function of residence time and free oxygen, and is exponential with peak flame temperature.

"Front end" NO_X control techniques are aimed at controlling thermal NO_X and/or fuel NO_X. The primary front-end combustion controls for gas turbines include water or steam injection and dry low-NO_X combustors. The addition of an inert diluent such as water or steam into the high temperature region of the flame controls thermal NO_X formation by quenching peak flame temperature. This technique can

[4]See, *In re: Desert Rock Energy Company, LLC, PSD Appeal No. 08-03 et al., Slip. Op. at 64 (EAB Sept. 24, 2009) and In re Prairie State Generating Company LLC,* 17 EAD 1 (2006)

be operationally very hard on the turbine and combustors due to vibration and flame instability. Dry low-NO_X combustors limit peak flame temperature and excess oxygen with lean, pre-mix flames that achieve equal or better NO_X control without the addition of water or steam. Catalytic combustion is an emerging front-end technology which uses an oxidation catalyst within the combustor to produce a lower temperature flame and hence, low NO_X. Other control methods, known as "back-end" controls, remove NO_X from the exhaust gas stream once NO_X has been formed.

Available control levels and technologies for control of NO_X from large industrial combustion turbines are reviewed in the following sections.

5.2.1.1 Available Combustion Turbine Generator NO_X Control Alternatives

(STEPS 1 & 2)

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a process which involves post combustion removal of NO_X from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions (Cho, 1994):

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \quad (1)$$

$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O \quad (2)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \quad (3)$$

$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O \quad (4)$$

$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O \quad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NOx decomposition reaction. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to “crumbling”, design of the NH_3 injection system, and high NH_3 slip. SCR using ammonia as a reagent represents the state-of-the-art for back end gas turbine NO_X removal from base load, combined-cycle turbines.

SCONOX™

SCONOX™ is an emerging post-combustion technology that removes NO_X from the exhaust gas stream after formation in the combustion turbine. SCONOX™ employs a potassium carbonate bed that adsorbs NO_X where it reacts to form potassium nitrates. Periodically, a hydrogen gas stream is passed over the bed, resulting in the reaction of the potassium nitrates to re-form the potassium carbonate and the ejection of nitrogen gas and water.

SCONOX™ is reportedly capable of achieving NO_X emission reductions of 90% or more for combustion turbine application, and it is currently operating on several small natural gas-fired turbines. The advantage of SCONOX™ relative to SCR is that SCONOX™ does not require ammonia injection to achieve NO_X emissions control. Similar to SCR, SCONOX™ only operates within a specific temperature range.

SCONOX™ is not technically feasible for application to this project since it is no longer being offered for large combustion turbines. In addition, SCONOX™ is considerably more complex than SCR, would consume significantly more water, and would require more frequent cleaning and other maintenance.

Selective Non-Catalytic Reduction (SNCR) and Non-Selective Catalytic Reduction (NSCR)

Two other back-end catalytic reduction technologies, Selective Non-Catalytic Reduction (SNCR) and Nonselective Catalytic Reduction (NSCR), have been used to control emissions from certain other combustion process applications. However, both of these technologies have limitations that make them inappropriate for application to combustion turbines. SNCR requires a flue gas exit temperature in the range of 1,300 to 2,100°F, with an optimum operating temperature zone between 1,600 and 1,900°F. Simple-cycle combustion turbines have exhaust temperatures of less than 1,200°F, and combined-cycle turbines have exhaust temperatures much lower than simple-cycle turbines. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible for the proposed combustion turbines. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% O_2 in the exhaust), NSCR is infeasible for the proposed combustion turbines.

Dry Low-NOx (DLN) Combustors

DLN combustion control techniques reduce NO_X emissions without injecting water or steam (hence "dry"). DLN combustors are designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NO_X formation. This is accomplished by producing a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors.

DLN combustors have been employed successfully for natural gas-fired combustion turbines for more than twenty years. DLN combustors are technically feasible for the proposed CTGs.

Water or Steam Injection

Water and steam injection are also designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NO_X formation. This technology involves the injection of water or steam into the high temperature region of the flame, which minimizes thermal NO_X formation by quenching peak flame temperature.

Water and steam injection has been employed successfully for nearly thirty years, for both natural gas and oil-fired combustion turbines. Water and steam injection remains the state-of-the-art combustion technology for minimizing NO_X emissions for oil-fired combustion turbines.

In general, water injection is considered to be technically feasible for natural gas-fired combustion turbines. However, water injection has never been applied to the class of natural gas fired gas turbines proposed for this project.

Other Control Technologies

A number of other combustion turbine NO_X emissions control technologies for combustion turbines have been marketed in recent years. None of these technologies has reached the commercial development

stage for large combustion turbines that will be fired with natural gas, and thus none are considered to be technically feasible for application to this project.

5.2.1.2 Ranking of Available Turbine NO_X Control Technologies

(STEP 3)

The top level of control for natural gas-fired combined cycle gas turbines is dry low NO_X combustion to minimize NO_X formation and post combustion treatment with SCR. Numerous natural gas fired combined cycle projects have been permitted at 2.0 ppmvd at 15% O_2 with averaging times typically ranging from a 1-hour average to a 24-hour average. In Virginia, the Greensville County, Brunswick County, Green Energy Partners/Stonewall and Warren County projects have been permitted at 2.0 ppmvd at 15% O_2 based on a 1-hour average. As shown in Appendix C, permits for two combined cycle projects were issued in New Jersey with LAER determined to be 2.0 ppmvd at 15% O_2 based on a 1-hour average. Appendix C shows that 2.0 ppmvd at 15% O_2 is the lowest NO_X emission rate demonstrated in practice.

5.2.1.3 Evaluation of Combustion Turbine NO_X BACT

(STEPS 4 & 5)

For natural gas firing, BACT for the proposed combustion turbines is the use of dry low-NO_X burners and selective catalytic reduction. The following NO_X emission rate is proposed as BACT for both the GE 7HA.02 and the MHPS M501JAC CTG options:

- 2.0 ppmvd @ 15% O_2 as a 1-hour block average.

5.2.2 BACT for Carbon Monoxide (CO)

CO emissions are formed in combustion turbines as a result of incomplete combustion of carbonaceous fuels. Similar to the generation of NO_X emissions, the primary factors influencing the generation of CO emissions are temperature and residence time within the combustion zone. Variations in fuel carbon content have relatively little effect on overall CO emissions. Generally, the effect of the combustion zone temperature and residence time on CO emissions generation is the exact opposite of their effect on NO_X emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions, but higher NO_X emissions.

5.2.2.1 Available Combustion Turbine CO Control Alternatives (STEPS 1 & 2)

Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, CO will react with oxygen present in the exhaust stream, converting it to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst.

As with SCR catalyst technology for NO_X control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to proceed. Rather, the oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust; and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10} and sulfuric acid mist emissions.

As with SCR, CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700°F to 1,100°F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1,200°F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the proper turbine exhaust lateral distribution (it is important to evenly distribute gas flow across the catalyst) and proper operating temperature at base load design conditions. Operation at part load or during startup/shutdown will result in less than optimum temperatures and reduced control efficiency.

Typical pressure losses across an oxidation catalyst reactor (including pressure loss due to ammonium salt formation) are in the range of 0.7 to 1.0 inches of water. Pressure drops in this range correspond roughly to a 0.15 percent loss in power output and fuel efficiency for each 1.0 inch of water pressure loss.

Catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation.

Oxidation catalysts have been employed successfully for two decades on natural gas CTGs. An oxidation catalyst is considered to be technically feasible for application to this project.

Good Combustion Practices

Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time can also be used to minimize the formation of CO.

5.2.2.2 Ranking of Available Control Technologies

(STEP 3)

An oxidation catalyst is a technically feasible control technology and the top level of control for minimizing CO emissions from combined cycle gas turbine generators firing natural gas.

As shown in Table C-2, many projects have been permitted at a 2.0 ppmvd at 15% O_2 as BACT for CO emissions. Typically, CO emission rates of 2.0 ppmvd at 15% O_2 to 4.0 ppmvd at 15% O_2 are determined to be BACT. However, the most recent project (April 26, 2018) in Virginia is the C4GT project with BACT set at 1.0 ppmvd at 15% O_2 without duct burning and 1.6 ppmvd at 15% O_2 with duct burning based on a 3-hour averaging periods for GE 7HA.02 CTs. In June 2016, a permit for the Greensville County project with MHPS 501J gas turbines was issued with BACT set at 1.0 ppmvd without duct burning and 1.6 ppmvd at 15% O_2 with duct burning. Earlier permits, in Virginia, were issued for the Brunswick County and Warren County projects with emission limits set at 1.5 ppmvd without duct burning and 2.4 ppmvd at 15% O_2 for MHPS 501 GAC CTGs. Another relatively recent Virginia project (April 30, 2013) is the Panda/Stonewall project with a 2.0 ppmvd at 15% O_2 permit limit with and without duct burning for both GE 7FA and Siemens SGT6-5000F5 combustion turbines.

5.2.2.3 Evaluation of Combustion Turbine Generator CO BACT

(STEPS 4 & 5)

The use of good combustion control and an oxidation catalyst represent BACT for CO control for the proposed combustion turbines. Emissions depend upon the performance of each turbine, the use of duct burning, and the performance of the oxidation catalyst.

The following CO emission rate, based on control by an oxidation catalyst, is proposed as BACT for both the GE 7HA.02 and the MHPS M501JAC CTGs:

- 1.0 ppmvd @ 15% O_2 based on a 3-hour sampling period.

5.2.3 BACT for Volatile Organic Compounds (VOC)

Formation of VOC emissions in combustion turbines is attributable to the same factors as those for CO emissions described in Section 5.2.2 above. VOC emissions are a result of incomplete combustion of carbonaceous fuels, and this is influenced primarily by the temperature and residence time within the combustion zone.

5.2.3.1 Available Combustion Turbine VOC Control Alternatives

(STEP 1)

Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes VOC (in addition to CO) from the exhaust gas stream of the combustion turbine. In the presence of a catalyst, VOC will react with oxygen present in the exhaust stream, converting it to carbon dioxide and water vapor. The performance of an oxidation catalyst is affected by the VOCs that are actually emitted. No supplementary reactant is used in conjunction with an oxidation catalyst. An oxidation catalyst is considered to be technically feasible for application to this project.

Good Combustion Practices

Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time are used to minimize the formation of VOCs.

5.2.3.2 Ranking of Available Control Technologies

(STEPS 2 & 3)

Typically, VOC emission rates in the 1.0 to 2.0 ppmvd at 15% O_2 range have been determined to be BACT. However, recently some VOC emission limits have been set at 0.7 ppmvd at 15% O_2. Variations in emissions can be associated the type of turbine, the use of duct burning and size of the duct burners. The most recent project (April 26, 2018) in Virginia is the C4GT project with BACT set at 0.7 ppmvd at 15% O_2 without duct burning and 1.6 ppmvd at 15% O_2 with duct burning based on a 3-hour averaging periods for GE 7HA.02 CTs. In June 2016, a permit for the Greensville County project with MHPS 501J gas turbines was issued with BACT set at 0.7 ppmvd without duct burning and 1.4 ppmvd at 15% O_2 with duct burning. Earlier permits, in Virginia, were issued for the Brunswick County and Warren County projects with emission limits set at 1.5 ppmvd without duct burning and 2.4 ppmvd at 15% O_2 for MHPS 501 GAC CTGs. Another relatively recent Virginia project (April 30, 2013) is the Panda/Stonewall project with at 1.0 ppmvd without duct burning and 2.4 ppmvd at 15% O_2 with duct burning for both the GE 7FA option.

5.2.3.3 Valuation of Combustion Turbine Generator VOC BACT

(STEPS 4 & 5)

The use of good combustion control and an oxidation catalyst represent BACT for VOC control for the proposed CTGs. Emissions depend upon the performance of each turbine, the use of duct burning, and the performance of the oxidation catalyst. Available performance guarantees are limited by the low VOC concentrations before control and uncertainties regarding the compounds that are actually emitted.

The following VOC emission rate, based on good combustion and control by an oxidation catalyst, is proposed as BACT for both the GE 7HA.02 and MHPS M501JAC CTGs:

- 0.7 ppmvd @ 15% O_2 based on a 3-hour sampling period.

5.2.4 BACT for Particulate Matter (PM), Particulate Matter Less than 10 Microns (PM_{10}) and Particulate Matter Less than 2.5 Microns ($PM_{2.5}$)

Particulate matter emissions from combustion turbine generators are a combination of filterable (front-half) and condensable (back-half) particulate. Filterable particulate matter is formed from impurities contained in the fuels and from incomplete combustion. Condensable particulate emissions, which contribute to PM_{10} and $PM_{2.5}$ but not PM, are attributable primarily to the formation of sulfates and possibly organic compounds. Since approximately 1996, condensable PM_{10} emissions have been measured using EPA Method 202. The original EPA Method 202 used wet impingers to collect inorganic and organic condensable PM_{10} and $PM_{2.5}$. However, after the method was used for a period of time it was widely recognized that EPA Method 202 results were inconsistent, and tended to be biased high. In March 2009, EPA published in the Federal Register, dry impinger methods to measure condensable PM_{10} and $PM_{2.5}$. The final dry impinger method was published in the Federal Register on

December 21, 2010. Although the 2010 modifications to EPA Method 202 are designed to reduce problems with the original method, EPA has continued to refine the method as recently as April 2014.[5]

5.2.4.1 Available PM, PM_{10}, and $PM_{2.5}$ Control Alternatives

(STEP 1)

When the initial New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA recognized that "particulate emissions from stationary gas turbines are minimal," and noted that particulate control devices are not typically installed on gas turbines and that the cost of installing a particulate control device is prohibitive (EPA, September 1977). Performance standards for particulate control of stationary gas turbines were, therefore, not proposed or promulgated.

Add-on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas fired turbine generators. The use of ESPs and baghouses are considered technically infeasible, and do not represent an available control technology.

The most stringent particulate control method demonstrated for gas turbines is the use of low ash and low sulfur fuel. No add-on control technologies are listed in the RACT/BACT/LAER Clearinghouse listings for combustion turbines. Proper combustion control and the firing of fuels with negligible or zero ash content and low sulfur content is the only control method listed. The maximum PM_{10} concentration, including condensable PM_{10}, from combined cycle combustion units is approximately 0.002 gr/dscf (lower than the typical baghouse performance specification of 0.01 gr/dscf).

Proper combustion control and the firing of fuels with negligible ash content and a low sulfur content is considered to be technically feasible for application to this project.

5.2.4.2 Ranking of Available Control Technologies

(STEPS 2 & 3)

The use of good combustion practices and the use of only natural gas is the top level of PM_{10} and $PM_{2.5}$ control.

For large natural gas fired CTGs, typical emission rates determined to be BACT for PM_{10}, and $PM_{2.5}$ are vary widely in the 8 to 35 lb/hr range and 0.0027 lb/MMBtu to 0.012 lb/MMBtu (see Appendix C, Table C-4). However, uncertainty exists with regard to the reported species (PM, PM_{10}, or $PM_{2.5}$), the required compliance test methods, the size of the CTGs, and which emission rates have actually been achieved in practice.

The most recent project (April 26, 2018) in Virginia is the C4GT project with BACT set at 12.2 lb/hr and 0.0069 lb/MMBtu without duct burning for GE 7HA.02 CTs. In June 2016, a permit for the Greensville County project with MHPS 501J gas turbines was issued with BACT set at 9.2 lb/hr and 0.0030 lb/MMBtu without duct burning. In June 2013, the Brunswick County, Virginia project was issued a permit with BACT set at 9.7 lb/hr and 0.0033 lb/MMBtu without duct burning. Another relatively recent

[5] http://www.epa.gov/ttn/emc/methods/psdnsrinterimcmpmemo4814.pdf

Virginia project (April 30, 2013) is the Panda/Stonewall project with BACT set at 9.6 lb/hr and 0.0033 lb/MMBtu without duct burning for the GE 7FA option.

5.2.4.3 Summary of Combustion Turbine PM_{10}, and $PM_{2.5}$ BACT

(STEPS 4 & 5)

The use of good combustion practices and pipeline quality natural gas is concluded to represent BACT for PM_{10}, and $PM_{2.5}$ control for the proposed combined cycle turbine generators. The emission rates proposed for the combustion turbines vary depending upon the experience of the manufacturer, the size of turbine, and the resulting available guarantees. With an oxidation catalyst and SCR, emissions are also affected by oxidation of SO_2 to SO_3/H_2SO_4 and the formation of ammonia bisulfate.

The following $PM_{10}/PM_{2.5}$ emission rates are proposed as BACT for the GE 7HA.02 CTGs:

- 12.4 lb/hr and 0.0069 lb/MMBtu based on 3 test runs.

The following $PM_{10}/PM_{2.5}$ emission rates are proposed as BACT for the MHPS M501JAC CTGs:

- 12.3 lb/hr and 0.0052 lb/MMBtu based on 3 test runs.

5.2.5 BACT for SO_2 and Sulfuric Acid Mist

Emissions of SO_2 from combustion turbines are a result of oxidation of fuel sulfur. Sulfuric acid mist emissions (SO_3/H_2SO_4) result from oxidation of fuel sulfur as well as oxidation of SO_2 by the catalysts used for NO_X, CO, and VOC control.

5.2.5.1 Available SO_2 and Sulfuric Acid Mist Control Alternatives

(STEP 1)

The use of flue gas desulfurization is not technically feasible because the SO_2 emissions from the proposed combustion turbine generators are two orders of magnitude lower than emission rates achievable using flue gas desulfurization. Therefore, the only technically feasible method for SO_2 and sulfuric acid mist emission control is the use of low sulfur fuels.

5.2.5.2 Ranking of Available Control Technologies

(STEPS 2 & 3)

The use of pipeline quality natural gas is the top level of control for SO_2 and sulfuric acid mist.

Emissions from natural gas vary depending upon the sulfur content of the natural gas supply as shown in Table C-5. BACT emission limits range from approximately 0.0002 lb/MMBtu to 0.02 lb/MMBtu. Reported fuel sulfur range concentrations are in the 0.2 gr/100 dscf to 2.0 gr/100 dscf range although some of the lb/MMBtu emission rates are based on fuel sulfur concentrations outside this range.

5.2.5.3 Summary of Combustion Turbine SO_2 and Sulfuric Acid Mist BACT

(STEPS 4 & 5)

The natural gas sulfur content at the site is expected to be 0.4 gr S/100 scf which is the same as that for the Greensville County project in Virginia. This sulfur content is based on current analytical data for

pipeline natural gas in Central Virginia and Northern North Carolina, which is the region that will supply the facility with natural gas.

The following SO_2 emission rates based on a natural gas higher heating value of 1,020 Btu/scf are proposed for both the GE 7HA.02 and the MHPS M501JAC CTGs:

SO_2

- 0.00114 lb/MMBtu

Based on vendor data, the following sulfuric acid mist emission rates based on a natural gas higher heating value of 1,020 Btu/scf are proposed for the GE 7HA.02 CTGs and the MHPS M501JAC CTGs:

Sulfuric Acid Mist

- 0.00077 lb/MMBtu for the GE 7HA.02 CTGs; and
- 0.0012 lb/MMBtu the MHPS M501JAC CTGs.

5.2.6 BACT for Greenhouse Gas Emissions

Emissions of greenhouse gases (GHG) from combustion turbine generators are 99.9% CO_2 resulting from oxidation of carbon in the fuel. Small quantities of methane and nitrous oxide account for the remaining 0.1% of emissions.

5.2.6.1 GHG Emission Control Technologies

(STEP 1)

GHG emission controls that are available or under development are: 1) Carbon Capture and Sequestration (CCS); 2) use of low carbon fuels; and 3) energy efficiency.

CCS involves the capture of CO_2 from the flue gas, drying and compression, transport, and long term storage or conversion of CO_2. CCS is a potential GHG emission control strategy that is still under development.

GHG emissions from combustion sources are almost entirely attributable to the carbon content of the fuel. The proposed combined cycle units will burn primarily natural gas which is the lowest carbon content fossil fuel on a lb/MMBtu basis.

For electric power production sources, high energy efficiency reduces GHG emissions by reducing the amount of fossil fuel that is required to produce a specific amount of electricity. The performance of electric power production units is often expressed as a heat rate, Btu/kWh net power output. The proposed combined cycle units will be designed for high energy efficiency as describer later in this section.

5.2.6.2 Eliminate Technically Infeasible GHG Emission Control Technologies

(STEP 2)

5.2.6.2.1 Carbon Capture and Sequestration

CCS can be broken down into three key steps 1) capture of CO_2 from the flue gas, drying and compression; 2) transport; and 3) long term storage or conversion of CO_2. In order for CCS to be technically feasible, each step must be technically feasible. While CCS has not been demonstrated on a project of commercial scale, Research, Development, and Demonstration (RD&D) programs are being conducted by the U.S. Department of Energy (DOE) to reduce project uncertainty and improve technology cost and performance. According to DOE:

> "The successful development of advanced CO_2 capture technologies is critical to maintaining the cost-effectiveness of fossil fuel based power generation. Today, there are commercially available First Generation CO_2 capture technologies that are being used in various small-scale industrial applications. At their current state of development, these technologies are not ready for widespread deployment on fossil fuel based power plants for three primary reasons. DOE is focused on supporting research and development (R&D) of novel technology solutions that address the three major issues with existing commercial CO_2 capture technology.
>
> - Reducing the impact of CO_2 capture on power generating capacity;
> - Scaling up novel CO_2 capture technologies to the necessary size for full-scale deployment at fossil energy power system; and
> - Improving the cost effectiveness of novel technologies for CO_2 capture so that fossil based systems with carbon capture are cost competitive.
>
> The core R&D projects being pursued by the program leverage public and private partnerships to support the goal of broad, cost-effective carbon capture deployment. Fossil Energy is targeting demonstration of 2nd generation technologies that result in a captured cost of CO_2 less than $40/tonne in the 2020-2025 timeframe. Fossil Energy is also committed to extending R&D support to even more advanced transformational carbon capture technologies that will further increase competitiveness of fossil based energy systems beyond 2035.
>
> DOE's Carbon Capture Program's approach to achieve these goals is to utilize a combination of developments in process chemistry, new chemical production methods, novel process equipment designs, new equipment manufacturing methods, and optimization of the process integration with other power plant systems (e.g. the steam cycle, cooling water system, carbon dioxide compression, etc.) Additionally, advances in boiler/gasifier technologies, materials of construction, process stream handling, heat integration, compression technologies, gas cleanup and separation, and power cycle technology under development within the Department's Clean Coal Research Program provide synergistic benefits are also required to meet program goals." [6]

In addition to the information detailed by DOE, an Alstom representative testified in September 2012 that CCS is currently not a commercially available technology:

> "It is critical to be at commercial scale to define the risk of offering the technology. This cannot be defined until the technology can be shown to work at full scale. This is the first opportunity that we have to work with the exact equipment in the exact operating conditions that will become the subject of contractual conditions when the technology is declared commercial and is offered under

[6] Carbon Capture R&D | Department of Energy
http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/carbon-capture-rd

> standard commercial terms including performance and other contractual guarantees. This also becomes the first opportunity to optimize the process and equipment to effect best performance and, very importantly, seek cost reduction. These too are required to define commercial contractual conditions.
>
> Based on these criteria, Alstom does not currently deem its technologies for CCS commercial and, to my knowledge, there are no other technology suppliers globally that can meet this criteria or are willing to make a normal commercial contract for CCS at commercial scale." [7]

On January 8, 2014, EPA proposed a GHG NSPS. With regard to natural gas fired stationary turbines, EPA states:

> "First, it is not clear that full or partial capture CCS is technically feasible for this source category. There are significant differences between natural gas-fired combustion turbines and solid fossil fuel-fired Electric Generating Units (EGUs) that lead us to this conclusion. While some of these turbines are used to serve base load power demand, many cycle their operation much more frequently than coal-fired power plants. It is unclear how part-load operation and frequent startup and shutdown events would impact the efficiency and reliability of CCS. We are not aware that any of the pilot-scale CCS projects have operated in a cycling mode. Similarly, none of the larger CCS projects being constructed, or under development, are designed to operate in a cycling mode. Furthermore, the CO_2 concentration in the flue gas of a natural gas combustion turbine is much lower (usually approximately 4 volume percent) than the CO_2 concentration in the flue gas stream of a typical coal-fired plant (which is approximately 16 volume percent for a supercritical pulverized coal or circulating fluidized bed unit) and of the syngas of an IGCC unit (in which CO_2 can be as high as 60 volume percent). Therefore, the overall amount of CO_2 that can be captured in a CCS project is likely lower. Finally, unlike subpart Da affected facilities, where there are full-scale plants with CCS that are currently under construction or in advanced stages of development, the EPA is aware of only one demonstration project, which is an approximately 40 MW slip stream installation on a 320 MW NGCC unit."[8]

On October 23, 2015, EPA promulgated a NSPS (Subpart TTTT) that applies to new fossil fuel fired electric generating units including natural gas-fired combustion turbines. EPA rejected CCS as the best system of emission reduction for natural gas-fired combustion turbines because they did not have sufficient information to determine whether implementing CCS was technically feasible.[9] EPA expressed concerns about applying CCS to fast-start natural gas combined cycle units similar to the proposed units because these units might not be base loaded like a large coal fired electric generating unit. In addition, EPA noted that the DOE has not yet funded a CCS demonstration project for a natural gas-fired combined cycle unit and no natural gas-fired combined cycle CCS demonstration projects are operational or being constructed in the U.S. [10]

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[7] http://democrats.energycommerce.house.gov/sites/default/files/image_uploads/Hilton.Testimony.pdf

[8] Federal Register, Vol 79, No. 5, Page 1430, January 14, 2014

[9] Federal Register, Vol 80, No.205, Page 64612, October 23, 2015

[10] Federal Register, Vol 80, No.205, Page 64614, October 23, 2015

The technical feasibility of each CCS step is discussed further below.

Carbon Capture

Currently the most promising method being considered for capturing and separating CO_2 from a post combustion flue gas is amine absorption. The application of carbon capture, on a relatively small scale to three coal fired power plants and one synthetic natural gas project, was described in the *Report of the Interagency Task Force on Carbon Capture and Storage* in 2010. The report states: “one of the key barriers to their more widespread commercial deployment as a climate change mitigation strategy is the lack of experience with these systems at the appropriate scale in power plant settings”.[11]

In comparison to coal-based generation, combined cycle natural gas plants operate at very high excess air ratios compared to coal fired power plants resulting in relatively large volumes of flue gas and diluted CO_2 concentrations. The CO_2 concentration in the flue gas from the proposed Chickahominy Power Station will only be 3.5% to 5% which is much less than 13% to 15% concentration in the flue gas from a coal fired power plant. It is far more difficult to capture GHGs from a dilute air stream than from a more concentrated one. Moreover, carbon capture has never been applied to a combined cycle natural gas power plant.

In addition, because the Chickahominy Power Station has a nominal net capacity of approximately 1,650 MWe at 95°F ambient temperature, potential CO_2 emissions are at least 5.8 million ton/yr from the power block (the combustion turbines and HRSGs). Carbon capture has never been applied to a project of this size or to a natural gas fired combined cycle power plant. The largest application of carbon capture is the $1.47 billion Boundary Dam Power Station project in Canada, which started up on October 1, 2014. This project is a retrofit of a 110 MW coal-fired boiler designed to collect approximately 1 million tons of CO_2 per year for a local enhanced oil recovery project.

The status of carbon capture for large power plants has been summarized by DOE as follows: [12]

> "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Because the CO_2 capture capacities used in current industrial processes are much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

Based on the information presented in this section, carbon capture has not been demonstrated on a commercially viable scale on a project similar to the proposed Chickahominy Power Station and hence is technically infeasible for this application.

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[11] Report of the Interagency Task Force on Carbon Capture and Storage at Page 31 (Aug. 2010). http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

[12] Report of the Interagency Task Force on Carbon Capture and Storage at Page 50 (Aug. 2010). http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

Carbon Transport

If CO_2 is collected, it must be dried and compressed to a high pressure (approximately 2,200 psia) and then transported by pipeline to a suitable geologic storage site. In overall construction, a CO_2 pipeline would be similar to a natural gas pipeline, requiring the same attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas. Transport of CO_2 is considered to be technically feasible.

Carbon Storage

If CO_2 is successfully captured and compressed, it must be transported to a suitable storage site. The suitability of potential storage sites is a function of volumetric capacity of the geologic formations and CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock).

The U.S. Geological Survey (USGS) uses the following criteria for considering geologic formations as potential storage units:[13]

- A minimum depth of 3,000 feet (914 m) below ground surface; CO_2 at this depth is typically subjected to temperatures and pressures that maintain the CO_2 in a supercritical state. Deep sequestration also helps insure there is an adequate thickness of rock (confining layers) above the potential injection zones to act as a geologic seal;
- Proposed salinity limit of at least 10,000 parts per million (ppm) for total dissolved solids (TDS) of formation waters;
- Geologic formations with the potential to store a minimum of 1 million metric tons (or greater) of CO_2.

In 2010-11, the Division of Geology and Mineral Resources (DGMR) in cooperation with the USGS conducted a preliminary assessment of the deep geologic formations in Virginia that might serve as permanent storage formations for CO_2 as shown in Figure 5-1. Physical data pertinent to CO_2 storage, such as porosity, formation salinity, and permeability were compiled where the information was available.[14] The most extensive areas that might be suitable for CO_2 storage are in Southwest Virginia. While there are other areas shown in Figure 5-1 as having some promise for CO_2 storage, Southwest Virginia presents the best location for the facility due to the large number of potential storage sites and their proximity to the proposed project site. Figure 5-2 presents information on the thickness of the Berea sandstone deposits at depths greater than 3,000 ft in southwest Virginia. The thickness of the sandstone in southwest Virginia greatly increases in the Nora and Break-Haysi Gas Fields in Dickenson and Buchanan Counties.

[13] Virginia Department of Mines, Minerals and Energy - Division of Geology and Mineral Resources

[14] Virginia Department of Mines, Minerals and Energy - Division of Geology and Mineral Resources

Figure 5-1: Preliminary Assessment of Deep Geologic Formations in Virginia[15]

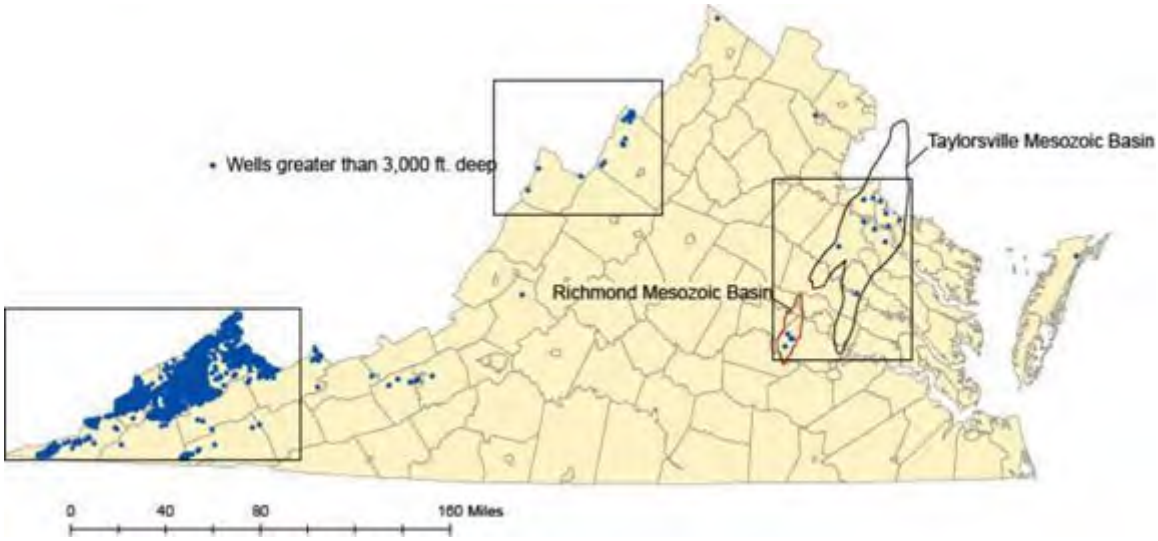
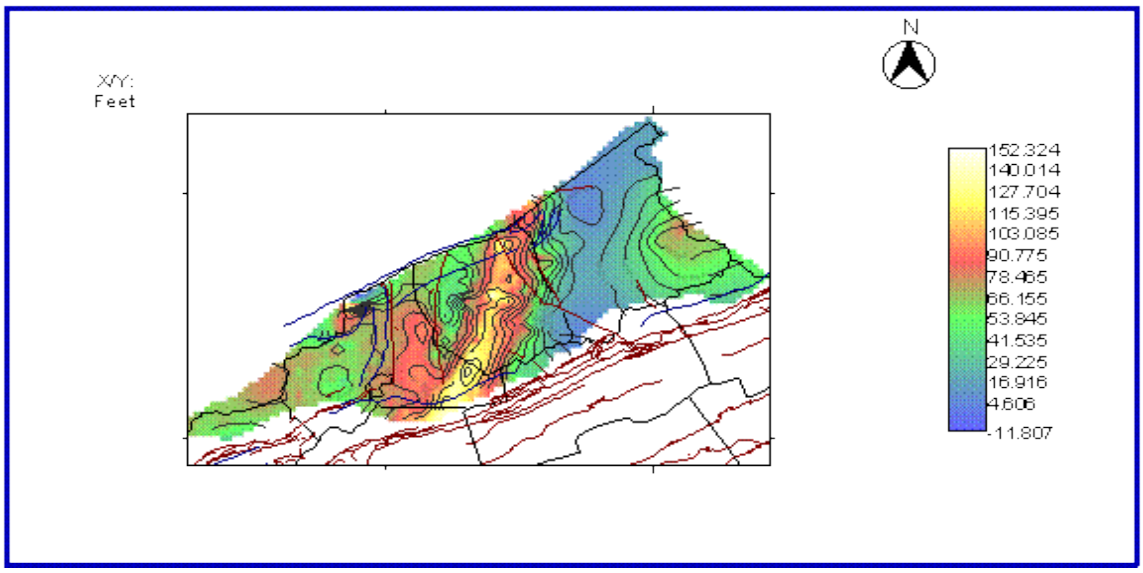


Figure 5-2: Thickness map of the Berea Sandstone at depths greater than 3,000 ft in southwest Virginia.[16]



"The U.S. Department of Energy (DOE) is supporting a number of small-scale field tests (injection of less than 500,000 million metric tons of CO_2 per year) to explore various geologic CO_2 storage

[15] Virginia Department of Mines, Minerals and Energy - Division of Geology and Mineral Resources

[16] Virginia Department of Mines, Minerals and Energy - Division of Geology and Mineral Resources

opportunities within the United States and portions of Canada. DOE's small-scale field test efforts are designed to demonstrate that regional reservoirs have the capability to store thousands of years of CO_2 emissions and provide the basis for larger volume, commercial-scale CO_2 tests."[17] To date, no large scale field tests have been conducted in Virginia.

Based on the Preliminary Assessment of Deep Geologic Formations in Virginia, the most likely acceptable storage site for CO_2 from the Chickahominy Power Station is Southwest Virginia, approximately 200 miles as a straight line, from the Chickahominy Power Station. However, the USGS only describes this as an area potentially suitable for CO_2 storage. At this time it has not been technically demonstrated that this area is suitable for large-scale, long-term CO_2 storage.

The available information supports a conclusion that CCS has not been demonstrated to be technically feasible for the proposed natural gas combined cycle power station. This conclusion is based on significant technical issues associated with the large scale capture of CO_2 and the degree of uncertainty that exists with respect to suitable storage sites in the proximity of the Chickahominy Power Station.

5.2.6.2.2 Low Carbon Fuels

On a ton/MMBtu basis, GHG from coal combustion are 76% higher than natural gas. The use of low carbon fuels is a technically feasible GHG control option. As indicated previously, the proposed project will only burn natural gas in the combustion turbines.

5.2.6.2.3 Energy Efficiency

Energy efficiency improvement is a technically feasible GHG control option. Modern gas turbine combined cycle power plants include many combustion turbine generator, heat recovery steam generator, and steam turbine features designed to achieve very high fuel to electricity efficiencies. The GE 7HA.02 and MHPS 501JAC combined cycle plants are the most efficient currently available systems with higher heating value heat rates, at ISO conditions, well below 7,000 Btu/kWh and efficiencies greater than 60% on an as new basis. The following three sections describe energy features associated with the combustion turbine generator, heat recovery steam generator, and steam turbine.

1) Combustion Turbine

A combustion turbine generator consists of three main components (i.e., compressor, combustor, and turbine) and operates on the thermodynamic Brayton cycle. There are four stages associated with the Brayton cycle: 1) adiabatic compression within the compressor section; 2) constant pressure heat addition within the combustion section; 3) adiabatic expansion in the turbine section; and 4) constant pressure heat rejection to a heat sink. A number of factors influence the overall efficiency of a combustion turbine, but the overriding factor is the efficiency of the three components mentioned below. The combustion turbines proposed for this project are very modern J Class machines. These turbines are of advanced design with high-efficiency compressors combustors, and turbines.

[17] NETL: Carbon Storage - Small-Scale Field Tests

a) Compressor

The compressors for these H and J-Class machines are a high-efficiency axial compressor. The compression ratio of this type of compressor is greater than 20:1. The efficiency of the Brayton cycle, and therefore the combustion turbine, is improved with the increase in compression ratio. To obtain the higher compression ratios, the H and J-Class machines being considered for this project have multiple stages of compression, with a minimum of four variable inlet guide vane for exhaust gas temperature control to allow for efficient cycle performance forepart load operation. The compressor blades and vanes are designed to maximize efficiency of the compressor. The blades and vanes on these modern turbines are typically designed using the latest in 3-D computer-aided technology, which allows for analysis of the air flow through the compressor to achieve the highest efficiency possible. Finally, the air is directed into the compressor through the bell mouth. The design of the compressor inlet is important to reduce the inlet pressure loss and improve the overall combustion turbine efficiency.

b) Combustor

The high-efficiency combustors for the GE 7HA.02 and MHPS 501JAC Class machines are designated as low-NO_X emitting. These combustors have been designed to accommodate efficient combustion while minimizing the formation of thermal NO_X. The combustors for the GE 7HA.02 and MHPS 501JAC machines that may be used for this project utilize pre-mixing of fuel and air in combination with multiple stages of combustion for efficient low- NO_X combustion. An increase in combustor firing temperature improves the overall efficiency of the combustion turbine. The H and J-Class machines have a combustor firing temperature in excess of 2,600°F.

c) Turbine

The third primary component within the combustion turbine is the turbine itself. The turbine converts the hot combustion gases into shaft power, which produces electricity through the generator. The H and J-Class turbines are designed with high-efficiency blades made of advanced materials with thermal barrier coatings and advanced cooling. This is necessary to allow the increased combustor firing temperatures for improved efficiency. Additionally, similar to the compressor, the turbine is modeled using 3-D computer-aided techniques to enhance the overall efficiency of the machine. Turbine clearances are also an important design aspect of the machine, and are designed and maintained as tight as possible to minimize leakage past the blades, thereby improving the efficiency. Finally, the exhaust is directed out of the machine to avoid pressure drops that reduce the overall efficiency.

In addition to the high-efficiency primary components of the turbine, there are a number of other design features employed within the combustion turbine that improve the overall efficiency of the machine. These additional features include those summarized below.

i) Inlet Cooling

Combustion turbine efficiency is affected by the amount of air mass passing through the machine. The amount of air mass is directly related to the inlet air temperature. As the inlet air temperature increases, the air density decreases, and the amount of air

mass entering the combustion turbine decreases. This results in less mass flow through the turbine, which lowers the power generated and the turbine's efficiency. If the inlet air temperature is lowered, the density of the air increases, and the mass flow through the combustion turbine increases. As the mass flow through the combustion turbine increases, more power is generated and the turbine's efficiency increases. In order to decrease combustion turbine inlet air temperature on warm ambient temperature days, inlet air coolers or evaporative cooling can be used. Inlet air coolers consist of cooling coils, which contain refrigerated water, located in the inlet air duct of the turbine. Evaporative cooling decreases intake air temperature through humidification, raising relative humidity and lowering the inlet air temperature. The Project will use evaporative cooling at high ambient air temperatures. This process will increase the amount of air mass flowing through the turbine, increasing the power generated and the turbine's efficiency.

ii) Periodic Burner Tuning

Modern H and J-Class combustion turbines have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the combustion turbine is operated, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore highly efficient low-emission operation.

iii) Reduction in Heat Loss

Modern H and J-Class combustion turbines have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. As discussed previously, the higher the combustion firing temperature, the higher the combustion turbine's efficiency. To minimize heat loss from the combustion turbine and protect the personnel and equipment around the machine, insulation blankets are applied to the combustion turbine casing. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.

iv) Instrumentation and Controls

Modern H and J-Class combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital type and is supplied with the combustion turbine. The distributed control system (DCS) controls all aspects of the turbine's operation, including the fuel feed and burner operations, to achieve efficient low-NO_X combustion. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emission performance for full-load and part-load conditions.

v) Turbine Generator

Hydrogen will be used to cool the generators as opposed to air. Hydrogen has better thermal characteristics and a lower density which creates a lower level of electrical losses and a corresponding higher efficiency.

2) Heat Recovery Steam Generator

HRSGs are heat exchangers designed to capture as much thermal energy as possible from the combustion turbine exhaust gases. This is performed at multiple pressure levels. For a drum type configuration, each pressure level incorporates an economizer section, evaporator section, and superheater section. These heat transfer sections are made up of many thin walled tubes to provide surface area to maximize the transfer of heat to the working fluid. Most of the tubes also include extended surfaces (e.g., fins). The extended surface optimizes the heat transfer, while minimizing the overall size of the HRSG. In addition, flow guides are used to distribute the flow evenly through the HRSG to allow for efficient use of the heat transfer surfaces and post-combustion emissions control components. Low-temperature economizer sections employ recirculation systems to minimize cold-end corrosion, and stack dampers are used for cycling operation to conserve the thermal energy within the HRSG when the unit is off line.

The temperatures inside the HRSGs are nearly equivalent to the exhaust gas temperatures of the turbine. For H and J-Class combustion turbines, these temperatures can approach 1,200°F. HRSGs are designed to maximize the conversion of the waste heat to steam. One energy efficient aspect of the HRSG design is the use of insulation to minimize heat loss to the surroundings, thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high temperature steam and water lines, and typically to the bottom portion of the stack.

HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the combustion turbine exhaust gas waste heat. In order to maximize this heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces, which occurs from the constituents within the exhaust gas stream, impedes the transfer of heat. To minimize fouling, filtration of the inlet air to the combustion turbine is performed. In addition, periodic cleaning of the tubes during outages is performed at least every eighteen months. By reducing the fouling, the efficiency of the unit is maintained.

Minimizing steam vents and repair of steam leaks is important in maintaining the efficiency of all steam generating facilities. A combined cycle facility has just a few locations where steam is vented from the system, including at the de-aerator vents, blow down tank vents, and vacuum pumps/steam jet air ejectors. These vents are necessary to improve the overall heat transfer within the HRSGs and condenser by removing solids and air that potentially blankets the heat transfer surfaces, degrading the equipment's performance. In addition, steam leaks are repaired as soon as possible to prevent losses and maintain performance. Minimization of vented steam and repair of steam leaks will be performed for this project.

3) Steam Turbine Energy Efficiency Processes, Practices, and Designs

The steam turbine for this project will be a modern, high-efficiency, reheat, condensing unit. Steam turbines have been in operation for over a century and are generally classified as impulse or reaction. However, most modern turbines employ both impulse and reaction blading. The overall efficiency of the unit is affected by a number of items, including the inlet steam conditions, the exhaust steam conditions, the blading design, the turbine seals, and the electric generator efficiency.

The efficiency of a steam turbine is directly related to the steam conditions entering the turbine. The higher the steam temperature and pressure, the higher the overall efficiency. To achieve the higher temperatures, reheat cycles are employed. This is necessary to minimize the moisture content of the exhaust steam. If the moisture content of the exhaust steam is too high, erosion of the last-stage turbine blades occurs. This cycle reheats partially expanded steam from the steam turbine. For a modern combined cycle facility, the high-pressure inlet and intermediate-pressure inlet steam temperatures typically are 1,050°F and above, and the high pressure steam turbine inlet pressure is typically in the range of 1,800-2,400 psig. The proposed project will use an inlet steam pressure of 2,400 psig in order to maximize efficiency.

An exhaust steam condenser is used to lower the exhaust steam conditions, which improves efficiency. The lower the exhaust pressure, the higher the overall steam turbine efficiency. For high-efficiency units, the exhaust steam is saturated under vacuum conditions. This is accomplished by the use of a condenser.

Efficient Blade Design also affects the overall efficiency of the turbine. As noted earlier, steam turbines have been used to generate power for over a century and are either impulse or reaction design. The blade design has evolved for high-efficiency transfer of energy in the steam to power generation. Additionally, 3-D computer-aided design technology is also employed to provide the highest efficiency blade design. Blade materials are also important components in blade design, which allow for high-temperature and large exhaust areas to improve performance. Turbine seals are also important in the overall performance of the steam turbine. The high pressure steam will leak to the atmosphere along the turbine shaft, as well as bypass the turbine stages if sealing is not employed. The steam turbine designers use multiple steam seal designs to obtain the highest efficiency from the steam turbine.

The steam turbine generator is also a key element in the overall performance of the steam turbine. The modern generator is a high-efficiency unit cooled by one of three methods. These methods are open-air cooling, totally enclosed water to air-cooling, or hydrogen cooling. The steam turbine for this project will be hydrogen/water-cooled. This cooling method allows for the highest efficiency of the generator, resulting in an overall high-efficiency steam turbine.

Plant-wide Energy Efficiency Processes, Practices, and Designs

There are a number of other components within the combined cycle plant that help improve overall efficiency, including:

- Fuel gas preheating - The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures. For the H and J-Class combustion turbines proposed for the project, the fuel gas will be heated by high temperature water or steam from the HRSG. This improves the efficiency of the combustion turbine.

- Drain operation - Drains are required to allow for draining the equipment for maintenance (i.e., maintenance drains), and also to allow condensate to be removed from the steam circuits for operation (i.e., operation drains). Operation drains will be controlled to minimize the loss of energy from the cycle. This is accomplished by closing the drains as soon as the appropriate steam conditions are achieved.
- Multiple combustion turbine/HRSG trains - Multiple combustion turbine/HRSG trains help with part-load operation. The multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down trains operating at less efficient part-load conditions and ramping up the remain ingrain(s) to high-efficiency full-load operation.
- Steam turbine bypass - A steam turbine bypass system will be used for this project. The steam turbine bypass directs the steam being generated in the HRSG to the condenser during startup and trip conditions. This is performed to conserve the cycle water, avoiding the need for large amounts of makeup water and shortening startup times.

Energy efficiency measures that will be used by the project are summarized below.

Combustion turbine generator design features used to maximize efficiency include:

- High compression ratio, multistage, axial compressor;
- High efficiency annular combustor with a high operating temperature of approximately 2,900° F;
- High efficiency gas turbine;
- Inlet air cooling;
- Periodic tune-ups;
- Insulation to minimize heat loss; and,
- Hydrogen cooled gas turbine generator.

Heat recovery steam generator design features used to maximize efficiency include:

- Multiple pressure levels with economizer, evaporator, and superheater section(s);
- Thin walled, high surface area tubes;
- Flow guides to distribute flow evenly;
- Low temperature economizer sections;
- Stack dampers to conserve thermal energy during cycling operation;
- Insulation;
- Gas turbine inlet air filtration to minimize fouling of heat transfer surfaces;
- Minimization of vented steam and steam leaks (maintenance); and,
- Multiple pressure levels with economizer.

Steam generator design features used to maximize efficiency include:

- High steam pressure of 2,400 psi ;

- High steam temperatures of 1,080°F;
- Reheat cycles to maintain high temperatures and minimize the moisture content of the steam;
- Exhaust steam condenser to main low pressure/low temperature outlet steam conditions;
- Efficient blading; and
- Hydrogen/water cooled steam turbine generator.

Plant-wide energy efficiency designs used to maximize efficiency include:

- Multiple combustion turbine HRSGs to maximize efficient, full load operation;
- LED to minimize plant auxiliary loads; and
- Steam turbine bypass to minimize water losses during startup and shortening startup times.

5.2.6.3 Rank the Remaining Technologies by Control Effectiveness

(STEP 3)

The only technically feasible control option is the use of a low carbon fuel (natural gas) and a high efficiency power generation system (highly efficient and H-class or J–class combustion turbine combined cycle power generation units).

5.2.6.4 Evaluate Most Effective Controls and Document Results

(STEP 4)

Step 4 of the BACT process is a case-by-case evaluation of economic, energy, and environmental impact to determine if these impacts are reasonable. If the top level of control is not selected as BACT, the next most effective control option is evaluated. The Project will apply the top level of control which is the use of a low carbon fuel (natural gas) and a high efficiency power generation system (highly efficient H-class or J–class combustion turbine combined cycle power generation units).

5.2.6.5 Selection of BACT

(STEPS 3, 4 & 5)

BACT is the most effective option not rejected based on energy, environmental, and economic impacts. Based on the five-step BACT analysis presented above, CCS is eliminated as BACT because it is not technically feasible. In addition, even if CCS was technically feasible, there are also substantial negative economic impacts attributable to the very large additional capital and operating costs of implementing this control measure. In addition, the potential negative environmental and energy impacts of increased non-GHG pollutant emissions, the overall loss in energy efficiency, and/or decreased energy produced for use on the grid also provide a basis for excluding CCS as BACT for this facility. This determination is the same conclusion reached by EPA and state agencies on all prior BACT determinations for combined cycle projects. CCS has never been determined to be BACT for a natural gas-fired combined cycle project. There are no new technical or economic developments that would suggest a change from past determinations.

Therefore, the available options are the use of low carbon fuel and energy efficiency. The proposed combined cycle units will only burn natural gas and will employ the energy efficient features described

in Section 5.2.6.1. Specific permit requirements to verify performance and emissions are proposed below.

A search of EPA's RBLC was conducted to identify recent GHG emission limits. Additionally, recent permitting actions were compiled by searching state and federal web sites as well as general internet searches. Appendix C Table C-6 shows that permitted GHG emission rates (as CO_2e) have typically ranged from 800 lb/MWh to 1,050 lb/MWh on a 12-operating month annual average basis. Heat rates, based on higher heating values, are typically in the range of 7,000 Btu/kWh to 7,700 Btu/kWh. Variations in heat rates and emission limits are due to a number of factors including gas turbine model, duct burner size, cooling method, operational variability, averaging times, the use of net or gross power output, use of lower heating value vs. higher heating value, and other factors.

For C4GT, which is the most recent Virginia project (April 26, 2018), BACT for GE 7HA.02 option was determined to be a net heat rate of 6,745 Btu/kWh on an HHV basis and based on an initial performance test without duct burning. On a 12-month rolling average basis BACT for C4GT was set at 883 lb/MWh net. For the Greensville County project with MHPS 501J gas turbines BACT was set at 6,457 Btu/kWh net and HHV based on an initial test and increasing to 7,212 Btu/kWh in year 31 and later based on testing every 5 years. On a 12-month rolling average basis BACT for Greensville was set at 812 lb/MWh on a 12-month rolling average basis during the first 6 years and 890 lb/MWh in year 31 and later. The Brunswick County project had emission limits set at 920 lb/MWh on a 12-month rolling average basis, and 7,500 Btu/kWh net and HHV at full load. The Panda/Stonewall project had permit limits set at 7,340 Btu/kWh gross and HHV without duct burning and 7,780 Btu/kWh gross and HHV with duct burning for GE 7FA and Siemens SGT6-5000F5, respectively. The Middlesex Energy Center and Sewaren Energy Center BACT limits are at 880 lb/MWh as a 12-month rolling average.

Heat Rate/Energy Efficiency

The GE 7HA.02 and MHPS M501JAC gas turbines paired with a high pressure steam turbine were selected for this project based on their superior performance. In new condition, both combined cycle plant options can achieve a heat rate of 6,550 Btu/kWh based on higher heating value, net output, and ISO conditions when burning natural gas.

CPLLC is proposing to verify performance based on American Society of Mechanical Engineers Performance Test Code on Overall Plant Performance, ASME PTC 46-1996 or other method approved by DEQ. In order to establish a permit limit for these performance tests, it is necessary to include margins to account for long term equipment performance.

To determine the heat rate limit for the permit, the following conditions affecting performance were added to the base heat rate of 6,550 Btu (HHV)/net kWh:

1. Efficiency losses due to permanent and recoverable combustion turbine degradation. This information was obtained from degradation curves provided by MHPS. Please note that these degradation curves are not contractual guarantees.
2. Operational variation and auxiliary power degradation. The operational variation assumes differences in operating techniques including but not limited to CT operation, degradation in catalyst life, HRSG tube leaks, excessive wear on equipment and design issues causing temporary derates, etc. Auxiliary power degradation includes efficiency losses over time of auxiliary (balance of plant) equipment including but not limited to pumps, motors, fans, etc.
3. Efficiency losses over time of the steam turbine system including but not limited to CT gas performance (i.e., less mass flow), the HRSG, the air-cooled condenser, etc.

Based on the above cited margins, CPLLC is proposing a HHV/Net kWh heat rate limit at full load adjusted to ISO conditions that increases as the facility ages as shown in Table 5-1. CPLLC is proposing to verify performance initially within 180 days of startup and once every Title V permit term (≈5 years) based on American Society of Mechanical Engineers Performance Test Code on Overall Plant Performance, ASME PTC 46-1996 or other method approved by DEQ. All testing will be conducted at full load with results will be corrected to ISO conditions.

Table 5-1: BACT for GHG Emissions from the Combined Cycle Units – Heat Rate Degradation

Year	Heat Rate (Btu/kWh net output HHV)
Initial Test	6,550
Year 6	6,681
Year 12	6,779
Year 18	6,878
Year 24	6,976
Year 30	7,074
Year 36 and later	7,172

GHG Emission Limits

CPLLC proposes to continuously monitor CO_2 emissions using 40 CFR Part 75 procedures. Based on typical natural gas composition in the area and GHG monitoring data, CO_2 emissions burning natural gas are expected to be 119 lb CO_2/MMBtu, which is slightly higher than the 116.9 lb/MMBtu emission in EPA's Mandatory GHG reporting rule (40 CFR 98). Emissions of CH_4 and N_2O as CO_2e will be based on emission factors and global warming potentials in EPA's Mandatory GHG reporting rule and fuel use. The resulting GHG emission rate is 119.12 lb CO_2e/MMBtu for natural gas. The proposed GHG emission limit will be a lb CO_2e/Net MWh limit as a 12-month rolling average updated monthly. Because the 12-month rolling average will include startups, shutdowns, and low load operations, in order to establish a permit limit for continuous performance, a 3.5% operational margin was added to the heat rate margins cited above. This operational margin accounts for dispatch variability and startup and shutdown events. As noted in this PSD permit application, the facility may be operated as an intermediate load power plant with frequent startups and shutdowns. During startup and shutdown events, the combustion turbine power production efficiency is low, and the steam turbine is not in operation until late in the event resulting in a much higher heat rate. The proposed annual average GHG emission rates are shown in Table 5-2.

Table 5-2: BACT for GHG Emissions from the Combined Cycle Units – Emission Limits

Year	Annual GHG Emissions
	lb CO_{2e}/MWh
Years 1 to 6	824
Years 7 to 12	836
Years 13 to 18	848
Years 19 to 24	860
Years 25 to 30	872
Year 31 and later	884

5.2.7 Other Combustion Turbine Emissions

For all other pollutants, the use of only pipeline quality natural gas with good combustion practices, and an oxidation catalyst represent BACT.

5.2.8 Combustion Turbine BACT Summary for Continuous Operations

A summary of BACT emission control technologies and emission rates for the GE 7HA.02 and the MHPS M501JAC combustion turbines for continuous operation is presented in Table 5-3.

Table 5-3: Summary of Proposed BACT Limits for the Proposed GE 7HA.02 and MHPS M501JAC Combined Cycle Turbine Generators

Pollutant	GE 7HA.02	MHPS M501JAC
	Natural Gas	**Natural Gas**
NOx, ppmvd at 15% O_2	2.0 [(a)]	2.0 [(a)]
CO, ppmvd at 15% O_2	1.0 [(b)]	1.0 [(b)]
VOC, ppmvd at 15% O_2	0.7 [(b)]	0.7 [(b)]
$PM/PM_{10}/PM_{2.5}$, lb/hr	12.4 (0.0069 lb/MMBtu) [(c)]	12.3 (0.0052 lb/MMBtu) [(c)]
SO_2, lb/MMBtu	1.14E-03 [(d)]	1.14E-03 [(d)]
Sulfuric Acid Mist, lb/MMBtu	0.00077 [(d)]	0.0012 [(d)]
Greenhouse Gases – heat rate	See Table 5-1	See Table 5-1
Greenhouse Gases – emissions	See Table 5-2	See Table 5-2
Other pollutants	Good combustion practices with fuel limited to pipeline quality natural gas	Good combustion practices with fuel limited to pipeline quality natural gas

(a) Emission limit shall be demonstrated on a 1-hour block average basis.
(b) Emission limit shall be demonstrated on the average for a 3-hour sampling period.
(c) Emission limit shall be demonstrated on the average of 3 test runs.
(d) Total S in fuel will be limited to 0.4 gr/100 scf on a 12-month rolling average

5.3 Combined Cycle Gas Turbine Generator Startup, Shutdown, and Maintenance Activity BACT

Operation of the CTGs requires that intermittent modes of transient operation must periodically occur. These are comprised of two different types of transient operations: first is the typical operation of starting up and shutting down the CTGs which is a basic operation of an electric generating facility. Secondly, there are expected to be less frequent, transient operations (water wash and tuning) which are part of performing maintenance activities on the combustion turbines. Both of these operations may require alternative emissions limitations or work practice standards from those proposed for steady state operation in Section 5.2. However, the BACT analysis performed in Section 5.2 for steady state operation is also relevant to discussion of BACT for transient periods since many of the same control techniques are applicable to controlling emissions form transient operations. This section also addresses the relevant EPA recommendations for developing and evaluating alternative emission limitations as described in 80 FR 33980, June 12, 2015. In particular, it addresses each of EPA's seven criteria for establishing alternative emissions limitations. Those criteria are:

- Criterion 1: The revision is limited to specific, narrowly defined source categories using specific control strategies *(e.g.,* cogeneration facilities burning natural gas and using selective catalytic reduction);
- Criterion 2: Use of the control strategy for this source category is technically infeasible during startup or shutdown periods;
- Criterion 3: The alternative emission limitation requires that the frequency and duration of operation in startup or shutdown mode are minimized to the greatest extent practicable;
- Criterion 4: As part of its justification of the SIP revision, the state analyzes the potential worst-case emissions that could occur during startup and shutdown based on the applicable alternative emission limitation;
- Criterion 5: The alternative emission limitation requires that all possible steps are taken to minimize the impact of emissions during startup and shutdown on ambient air quality;
- Criterion 6: The alternative emission limitation requires that, at all times, the facility is operated in a manner consistent with good practice for minimizing emissions and the source uses best efforts regarding planning, design, and operating procedures; and
- Criterion 7: The alternative emission limitation requires that the owner or operator's actions during startup and shutdown periods are documented by properly signed, contemporaneous operating logs or other relevant evidence.

5.3.1 Startup/Shutdown Operations Overview

Startup can consist of either cold, warm, or hot depending on the length of time from the previous shutdown. As stated in Section 3, cold starts occur after a minimum of 48 hours after turbine shutdown, a warm start is a minimum of 8 hours, up to 48 hours, and a hot start is less than 8 hours. The dry-low NO_X combustor is not completely effective until reaching approximately 30% minimum steady state load for the GH 7FA.02 option and 50% minimum steady state load for the MHPS M501JAC option. The combustion turbine is designed for operating at a minimum of 50% load on a steady state basis. The SCR and oxidation catalysts require time to reach minimum operating temperatures in order to effectively control emissions.

Shutdown occurs over a maximum of 15 minutes from initialization of the shutdown to cessation of fuel firing in the combustion turbine. The dry-low NO_X combustor, SCR, and oxidation catalysts will continue to be effective for a period of time during the shutdown process.

Alternative emission limitations are requested for NO_X and CO due to the low concentration limitations and short (1-hour and 3-hour) averaging periods which are tracked in real time by NO_X and CO CEMS. Startup and shutdown duration limits are requested for VOC as BACT, as there are no plausible applications of measurement methodology to directly demonstrate compliance with a numerical emission limit for this pollutant during these alternative operating scenarios. No alternative BACT limits are being proposed for startup and shutdown for particulate, SO_2, H_2SO_4, or GHG because the BACT limits during normal operations (low sulfur pipeline quality natural gas for SO_2 & H_2SO_4, proposed in Section 5.2 would cover all modes of operation.

5.3.2 Maintenance Activities Overview

In addition to alternative BACT emission limits for startup and shutdown, alternate BACT emission limits are requested for certain maintenance actions undertaken to ensure that the entire combustion turbine-steam turbine train is working at maximum efficiency during all operating scenarios. The proposed Maintenance activities are for turbine tuning and on-line water washing. These two protective actions

will help CPLLC ensure that emissions are minimized and overall system efficiency is maintained throughout the full range of operating conditions.

Periodic performance tuning is especially important for this proposed application, as these GE 7HA.02 and MHPS M501JAC combustion turbines will be among the first production units of their kind installed in the country. Performing the periodic tuning activities and on-line water washing will enhance and enable the combustion turbines to meet their steady state operation emission limits. A major component of the commissioning and maintenance of these highly complex and efficient CTs is the process of tuning. Turbine tuning is the process of adjusting the air-to-fuel ratio under a wide range of load and atmospheric conditions in order to optimize turbine performance while minimizing emissions, and is recommended by the manufacturer. Tuning is also necessary for the air pollution control equipment such as the SCR system. Periodic combustion tune-ups are listed as one of the energy efficiency measures in Section 5.2.6.2.3 to help maintain efficient low-emission operation. Tuning frequency and duration are both minimized to the greatest extent possible because during tuning, the facility is typically not generating electricity at its maximum capacity. Tuning is conducted when it becomes necessary to optimize combustion characteristics to maintain compliance with the emission limits.

When fine-tuning and adjusting combustion performance, small temporary increases in some pollutants may occur and potentially cause a deviation from permit limits that are appropriate for steady-state operations. The goal of tuning the combustion turbine is to assure that emissions compliance is achieved on a continuous basis. All steps are taken to minimize emissions during tuning to ensure the control equipment (SCR and oxidation catalyst) operates at the maximum extent possible in order to maintain compliance with the proposed NO_X and CO pound per day emission limits. The facility will still be subject to a BACT-based pound per day emission limit during tuning activities which will ensure that the turbines are operated in a manner consistent with good practices for minimizing emissions. The facility plans tuning events in advance and the turbines are designed such that control equipment operates at the maximum extent possible during tuning events. The turbines must be operated during tuning events such that the BACT-based pound-per-day emission limits are not exceeded. The 96 hours of tuning per turbine per year is based on the estimated maximum amount of time needed to conduct annual tuning. Consistent with **EPA Criterion 3**, tuning only will occur when necessary to maintain compliance with short term emission limits because the facility is generally not available to generate electricity at its maximum capacity during tuning. Additionally, operating at varying low, mid and high loads to conduct tuning is a less efficient way of operating the equipment than maximum, steady-state load.

During tuning events, adjustments are made to fuel flow and combustion air. These periodic adjustments are essential for maintaining compliance with the very stringent, 1-hour NO_X and 3-hour CO emission limits. Adjustments to fuel flow and/or airflow impact combustion characteristics which in turn affect inlet NO_X and CO concentrations to the control equipment. Given the very low NO_X and CO emission limits, even very small increases to the inlet concentrations can cause the unit to exceed the steady-state emission limit. With longer averaging periods, the unit may be able to be tuned and stay in compliance with a 1- or 3-hour averaging period, deviations for as little as several minutes in duration are enough to cause an exceedance of the permitted concentration limits.

On-line water washing is another maintenance activity to promote efficiency. Over the course of time, the combustion turbine blades can accumulate foreign substances. These foreign substances (dust, grime, etc.) reduce combustion turbine efficiency. The GE 7HA.02 and MHPS M501J turbines will have the ability to conduct an on-line compressor turbine blade water wash. Water washes are expected to last no more than 60 minutes per turbine. The process of washing the turbine blades may temporarily affect the combustion characteristics which will require an alternate emission limit. Spraying water into the combustion turbine affects combustion characteristics which in turn affect inlet concentrations of

NO_X and CO to the control equipment. With a very low NO_X emission limit on a 1-hour basis, even very small increases to the inlet concentrations can cause the unit to exceed the emission limit. With longer averaging periods (24-hour) water washes could occur while maintaining compliance but with a 1-hour emission limit, deviations for as little as several minutes are enough to cause an exceedance of a 1-hr emission limit.

Consistent with **EPA Criterion 2**, the SCR and oxidation catalysts will continue to be in operation during both of these maintenance activities, but may temporarily experience higher emissions from the combustion turbine outlet which are not experienced in steady state operation. Control efficiency is not reduced because ammonia injection will continue during combustion tuning and water washes. Neither maintenance activity will affect operation of the oxidation catalysts because it is a passive system. The control efficiencies of both catalysts are expected to generally remain unaffected, but the higher inlet concentrations to the control devices may potentially increase emissions above steady-state permit limits. The alternative emission limits and averaging times proposed for maintenance activities are set on a daily basis to take into account short term variations in emissions due to tuning and water wash activities.

Alternative emission limitations applicable during periods of tuning and water wash are requested for NO_X and CO due to the low concentration limitations and short (1-hour and 3-hour) averaging periods which are tracked in real time by NO_X and CO CEMS. The emission limits proposed for NO_X and CO are equivalent to a full day (24 hours) of operation at the maximum permitted steady state capacity. Limits on maintenance duration are requested for VOCs as BACT, as there are no plausible applications of measurement methodology to directly demonstrate compliance with a numerical emission limit for these pollutants during these alternative operation scenarios. No alternative BACT limits are being proposed during maintenance activities for particulates, SO_2, H_2SO_4, or GHG because the BACT limits during normal operations (pipeline quality natural gas for SO_2 & H_2SO_4, lb CO_{2e}/MW-hr for GHG) proposed in Section 5 are sufficient to cover all modes of operation.

5.3.3 Startup and Shutdown BACT

The principal method to limit startup and shutdown emissions is to complete these operations as quickly as possible in accordance with manufacturer's specifications. Typically, startup events have required several hours to complete due to limitation on the steam turbine generator temperature and limitations on the rate that the steam turbine generator temperature can be increased. These typical startup events have required long gas turbine holding times at low loads resulting in NO_X emission limits as high as 1,000 lb/event and CO emission limits as high as 7,000 lb/event. Both the GE 7HA.02 or MHPS M501JAC options being considered for the Project use a number of fast start technologies so that all types of even cold startup events can be completed in less than one hour with emissions lower than recent projects in Virginia.

In general, fast start technologies include:

- A "ready-for-operation" water steam cycle using auxiliary steam;
- Optimized component design (e.g. high capacity and fast acting de-superheaters);
- Stack dampers to limit heat loss during shutdowns;
- Auxiliary steam to maintain heat in the HRSG;
- Monitoring and controlling steam temperatures so the steam turbine can be started with short hold points or without any hold points; and

- Steam turbine bypass systems to lower the reheat pressure and temperature to the steam turbine and allow the gas turbine and HRSG to reach operating temperatures prior to the steam turbine.

The only technically feasible NO_X control options are SCR, dry-low NO_X combustors and good combustion. For CO and VOCs, the only technically feasible control options are the use of an oxidation catalyst and good combustion. For other pollutants, the only technically feasible control technologies are limiting the fuel to natural gas and employing good combustion practices. The effectiveness of all of these technologies can be significantly increased by the use of fast start technologies that minimize gas turbine operation at low loads and enable the control equipment to begin normal operations as soon as possible.

Tables 5-4 and 5-5 summarize proposed startup and shutdown durations and emissions. Note that the proposed startup and shutdown durations and emissions are lower than those approved in 2016 for the Greensville County Power Station.

Table 5-4: BACT for Startup and Shutdown Emissions – Average Duration and Emissions per CTG for the GE 7HA.02 Option

GE 7HA.02	Average Duration and Emissions per CTG
Duration of Event	
Cold Start, min	66
Warm Start, min	48
Hot Start, min	24
Shutdown, min	15
Fuel	
Cold Start, MMBtu/event	1,464
Warm Start, MMBtu/event	1,116
Hot Start, MMBtu/event	384
Shutdown, MMBtu/event	175
NO_X Emissions	
Cold Start, lb/event	312
Warm Start, lb/event	175
Hot Start, lb/event	84.0
Shutdown, lb/event	16.3
CO Emissions	
Cold Start, lb/event	924
Warm Start, lb/event	470
Hot Start, lb/event	449
Shutdown, lb/event	190
VOC Emissions	
Cold Start, lb/event	66.0
Warm Start, lb/event	48.0
Hot Start, lb/event	45.6
Shutdown, lb/event	32.5

Table 5-5: BACT for Startup and Shutdown Emissions – Average Duration and Emissions per CTG for the MHPS M501JAC Option

MHPS M501JAC	Average Duration and Emissions per CTG
Duration of Event	
Cold Start, min	42
Warm Start, min	42
Hot Start, min	42
Shutdown, min	15
Fuel	
Cold Start, MMBtu/event	1,008
Warm Start, MMBtu/event	1,008
Hot Start, MMBtu/event	1,392
Shutdown, MMBtu/event	348
NO_X Emissions	
Cold Start, lb/event	60.0
Warm Start, lb/event	54.0
Hot Start, lb/event	42.0
Shutdown, lb/event	19.2
CO Emissions	
Cold Start, lb/event	444
Warm Start, lb/event	396
Hot Start, lb/event	252
Shutdown, lb/event	156
VOC Emissions	
Cold Start, lb/event	216
Warm Start, lb/event	216
Hot Start, lb/event	168
Shutdown, lb/event	216

5.3.4 Maintenance BACT

5.3.4.1 NO_X BACT for Maintenance Activities (Tuning and Water Wash)

For maintenance activities (tuning and water wash), BACT for the proposed CTGs is the combination of good combustion, dry low- NO_X burners, and SCR. However, dry low-NO_X combustors may not be as effective during tuning and water washing. The following NO_X emission rates are proposed as BACT for the CTGs to be monitored by the NO_X CEMS:

- 636 lb per turbine over a calendar day for the GE 7HA.02 CTGs
- 703 lb per turbine over a calendar day for the MHPS M501JAC CTGs

This proposed alternate emission limit is based on a daily period rather than as a 1-hour average to allow for emissions variations that occur during tuning or water washing. A calendar day total is requested for a numerical emission for NO_X during both tuning and water washing because of the uncertainty in the turbine and control equipment response to these events. Tuning may take up to 18 hours in a calendar day and NO_X may take additional time to re-stabilize after returning to steady state operation. This is also true for water washing which could have lingering effects on NO_X emissions although the actual washing period will be limited to 60 minutes. These units do not yet have extensive operating experience and will be among the first of their kind to enter operation in the country. Since extensive field operational experience is not yet available, an alternative calendar day numerical emission limit is necessary. Regarding **EPA Criterion 4**, the proposed pound per day emission limit is based on BACT for steady state operation. The proposed limit was calculated by taking the existing maximum hourly emissions which were already determined to be BACT (based on 2 ppmvd @ 15% O_2) and multiplied by 24 hours in a calendar day. The hourly emissions are presented from vendor data in Appendix B. Since the limit is based on the same 2 ppm BACT limit as steady-state operation, it will also comply with the applicable NSPS Subpart KKKK limit of 15 ppm.

With the new limits, the CTGs would be limited to emit no more than they are currently allowed to emit in a calendar day, which is based on BACT. NOx controls are still occurring to the maximum extent possible during tuning and water wash. During tuning and water washes, the combustion characteristics are changed causing an increase in the inlet NOx concentration to the SCR, however controls are still in place and operating to the maximum extent possible. Regarding **EPA Criterion 4 and 5**, the proposed pound per day emission limits would ensure that the turbines cannot exceed emission limits on a daily basis that are based on 1-hour BACT limits.

Regarding **EPA Criterion 4**, when tuning and water wash events occur for longer than several minutes (water washes may take up to 60 minutes, tuning takes up to 18 hours per day), the increase in inlet concentrations is enough to increases the outlet concentrations above the 2 ppm permit limit. For this reason, an emissions averaging period longer than 1 hour is necessary for tuning and water wash events.

In practice, application of the proposed limit would work as follows. Example - CPLLC would notify DEQ at least 24 hours in advance of a declared tuning event to occur from 8AM to 4PM. The existing hourly emission limits would apply before 8AM and after 4PM, and the pound per day emission limits would apply for that day. Therefore, BACT emission limits would apply at all times. The 8 hour tuning event would be subtracted from the 96 hour annual allotment of tuning events for that particular turbine.

During tuning events, adjustments are made to fuel flow and combustion air. These periodic adjustments are essential for maintaining compliance with the very stringent, 1-hour emission

limits. Regarding **EPA Criterion 2**, controls are still in place and operational, but may temporarily experience higher emissions from the combustion turbine outlet which are not experienced in steady state operation. Control efficiency is generally not reduced because ammonia injection will continue during tuning and tuning of the combustion process does not affect operation of the SCR. Adjustments to fuel flow and/or airflow impact combustion characteristics which in turn affect inlet NO_X concentrations to the SCR system. Given the very low NO_X emission limit on a 1-hour basis, even very small increases to the inlet concentrations can cause the unit to exceed the emission limit. With longer averaging periods (24-hour), the unit may be able to be tuned and stay in compliance but with a 1-hour averaging period, deviations for as little as several minutes are enough to cause an exceedance of the 1-hr emission limit.

The dry-low NO_X combustor will be operated during these periods, but since the maintenance activity involves adjusting the operating parameters, there may be periods of decreased effectiveness in order to achieve longer term efficient combustion turbine operation. The SCR system will be operating during these periods, but may see a short term increase in NO_X concentration from the turbine outlet.

Regarding **EPA Criterion 3** for tuning, the frequency and duration are both minimized to the greatest extent possible because during tuning, the facility is generally not available to produce electricity at its maximum capacity. Operating at varying low, mid and high loads to conduct tuning is also a less efficient way of operating the equipment. Regarding **EPA Criterion 5**, all steps are taken to minimize emissions during tuning because the control equipment (SCR and oxidation catalyst) is still operating at the maximum extent possible in order to maintain compliance with the proposed pound per day emission limits. Regarding **EPA Criterion 6**, the facility is still subject to a BACT-based pound per day emission limit during tuning activities which will ensure that the turbines are operated in a manner consistent with good practices for minimizing emissions. The facility plans tuning events in advance and the turbines are designed such that control equipment operates at the maximum extent possible during tuning events. The turbines must be operated during tuning events such that the BACT-based pound-per-day emission limits are not exceeded. The 96 hours of tuning per turbine per year is based on the estimated maximum amount of time needed to conduct annual tuning. As stated above, CPLLC conducts tuning only when necessary to maintain compliance with short term emission limits because the facility is typically not available to generate electricity at its maximum capacity during tuning. Additionally, operating at varying low, mid and high loads to conduct tuning is a less efficient way of operating the equipment than maximum, steady-state load.

Regarding **EPA Criterion 3** for water washing, the frequency and duration will be minimized to the greatest extent possible because during water washes, the facility is not available to generate electricity at its maximum capacity. Operation of the equipment while water washing compromises its efficiency. It is in CPLLC's best interest to only conduct water washes when the turbine begins to lose efficiency from accumulation of foreign substances on the turbine blades. In addition, offline water washing will be used to minimize the need for online washing, Regarding **EPA Criterion 5**, all steps are taken to minimize emissions during water washes because the control equipment (SCR and oxidation catalyst) is still operating at the maximum extent possible in order to maintain compliance with the proposed pound per day emission limits. Regarding **EPA Criterion 6**, the facility is still subject to a BACT-based pound per day emission limit during water washes which will ensure that the turbines are operated in a manner consistent with good practices for minimizing emissions. The facility plans water wash events in advance and the turbines are designed such that control equipment operates at the maximum extent possible during water washes. The turbines must be operated during water washes such that the BACT-based pound-per-day emission limits are not exceeded. CPLLC proposes to conduct water washing only when necessary to maintain turbine efficiency because the facility is not available to

generate electricity at its maximum capacity during water washes. The estimated maximum amount of time needed to conduct water washes in a year is 52 hours/year.

5.3.4.2 CO BACT for Maintenance Activities (Tuning and Water Wash)

For maintenance activities (tuning and water wash), BACT for the proposed CTGs is the combination of good combustion, dry low- NO_X burners, and oxidation catalyst. However, dry low-NO_X combustors may not be as effective during tuning and water washing. The following CO emission rates are proposed as BACT to be monitored by the CO CEMS:

- 194 lb per turbine over a calendar day for the GE 7HA.02 CTGs
- 214 lb per turbine over a calendar day for the MHPS M501JAC CTGs

This proposed alternate emission limit is based on a daily period rather than steady state operation which is based on a 3-hour average to allow for variations which may occur during tuning or water washing. Regarding **EPA Criterion 4**, the proposed pound per day emission limit is based on BACT for steady state operation. The proposed limit was calculated by taking the existing maximum hourly emissions which were already determined to be BACT (based on 1.0 ppmvd @ 15% O_2) and multiplied by 24 hours in a calendar day. The hourly emissions from vendor data are presented in Appendix B.

With the new limits, the combustion turbines would be limited to emit no more than they are currently allowed to emit in a calendar day, which is based on BACT. CO controls are still operating to the maximum extent possible during tuning and water wash. During tuning and water washes, the combustion characteristics are changed causing an increase in the inlet CO concentration to the oxidation catalyst, however controls are still in place and operating to the maximum extent possible. Regarding **EPA Criterion 4 and 5**, the proposed pound per day emission limits would ensure that the turbines cannot exceed emission limits on a daily basis that are based on 3-hour BACT limits.

Regarding **EPA Criterion 4**, when tuning and water wash events cause excess emissions for longer than several minutes (water washes may take up to 60 minutes, tuning takes several hours up to 18 hours per day), the increase in inlet concentrations is enough to increases the outlet concentrations above the 2.4 ppm permit limit. For this reason, an averaging period longer than 3 hours is necessary for tuning and water wash events.

In practice, application of the proposed limit would work as follows. Example - CPLLC would notify DEQ at least 24 hours in advance of a planned tuning event to occur from 8AM to 4PM. The existing hourly emission limits would apply before 8AM and after 4PM, and the pound per day emission limits would apply for that day. Therefore, BACT emission limits would apply at all times. The 8 hour tuning event would be subtracted from the 96 hour annual allotment of tuning events for that particular turbine.

During tuning events, adjustments are made to fuel flow and combustion air. These periodic adjustments are essential for maintaining compliance with the very stringent, 1-hour emission limits. Regarding **EPA Criterion 2**, controls are still in place and operational, but may temporarily experience higher emissions from the combustion turbine outlet which are not experienced in steady state operation. Control efficiency is not reduced during these periods because ammonia injection continues during tuning and tuning does not affect operation of the oxidation catalysts (passive system). Adjustments to fuel flow and/or airflow impact combustion characteristics which in turn affect inlet CO concentrations to the oxidation catalyst. Given the very low CO emission limit on a 3-hour basis, even very small increases to the inlet concentrations can cause the unit to exceed the steady-state emission limit. With longer averaging periods (8-hour, 24-hour, etc.) the unit may be able to be

tuned and stay in compliance but with a 3-hour averaging period, deviations for as little as several minutes are enough to cause an exceedance of the 3-hr emission limit. The oxidation catalyst will be operating during these periods, but may see a short term increase in CO concentration from the turbine outlet.

Regarding **EPA Criterion 3** for tuning, the frequency and duration are both minimized to the greatest extent possible because during tuning, the facility is not available to generate electricity at its maximum capacity. Operating at varying low, mid and high loads to conduct tuning is also a less efficient way of operating the equipment. It is in CPLLC's best interest to only conduct tuning when it becomes necessary to maintain compliance with emission limits and operate the turbines more efficiently. Regarding **EPA Criterion 5**, all steps are taken to minimize emissions during tuning because the control equipment (SCR and oxidation catalyst) is still operating at the maximum extent possible in order to maintain compliance with the proposed pound per day emission limits. Regarding **EPA Criterion 6**, the facility is still subject to a BACT-based pound per day emission limit during tuning activities which will ensure that the turbines are operated in a manner consistent with good practices for minimizing emissions. The facility plans tuning events in advance and the turbines are designed such that control equipment operates at the maximum extent possible during tuning events. The turbines must be operated during tuning events such that the BACT-based pound-per-day emission limits are not exceeded. As stated above, CPLLC conducts tuning only when necessary to maintain compliance with short term emission limits because the facility is generally not available to produce electricity at its maximum capacity during tuning. The 96 hours of tuning per turbine per year is based on the estimated maximum amount of time needed to conduct annual tuning.

Regarding **EPA Criterion 3** for water washing, the frequency and duration are both minimized to the greatest extent possible because during water washes, the facility is not typically available to generate electricity at its maximum capacity. Operating the turbines while conducting water washing is also inefficient. It is in CPLLC's best interest to only conduct water washes when the turbines begin to lose generating capacity from accumulation on the turbine blades. Regarding **EPA Criterion 5**, all steps are taken to minimize emissions during water washes because the control equipment (SCR and oxidation catalyst) is still operating at the maximum extent possible in order to maintain compliance with the proposed pound per day emission limits. Regarding **EPA Criterion 6**, the facility is still subject to a BACT-based pound per day emission limit during water washes which will ensure that the turbines are operated in a manner consistent with good practices for minimizing emissions. The facility plans water wash events in advance and the turbines are designed such that control equipment operates at the maximum extent possible during water washes. The turbines must be operated during water washes such that the BACT-based pound-per-day emission limits are not exceeded. CPLLC conducts water washing only when necessary to maintain turbine efficiency because the facility is not available to generate electricity at its maximum capacity during water washes. Water washing is expected to be conducted for 52 hours/year.

5.3.4.3 VOC BACT for Maintenance Activities (Tuning and Water Wash)

During tuning activities, adjustment of the combustion process may lead to the temporary formation of additional VOCs which may increase above the concentration permit limits for a short term duration. Water washing activities may result in a temporary elevation or creation of VOCs due to the addition of water mass into the system affecting the combustion process for a short period of time. The oxidation catalyst effectiveness from the steady-state value may be affected by an increase in VOC emissions since the exact characterization of the individual organic compounds may temporarily differ from those at steady state conditions which were used in the design of the oxidation catalyst. Due to both the uncertainty of control equipment effectiveness and inability to demonstrate compliance, imposition of a

numerical limit is infeasible at this time. Therefore, CPLLC is proposing operational practices in lieu of emission limits.

- 18 hour tune-up duration per day and 96 hours per year per turbine
- 60 minute water wash duration per event and 52 hours per year per turbine

Limiting the duration of each maintenance activity in addition to an oxidation catalyst and good combustion practices will control VOC emissions. Specifically limiting the short term and annual duration of tuning and water washing are practically enforceable operational standards which will limit VOC emissions. The tuning and water washing maintenance activities will result in a cleaner burning combustion turbine which will result in lower volatile organic compound formation.

Regarding **EPA Criterion 3** for tuning, the frequency and duration are both minimized to the greatest extent possible because during tuning, the facility is generally not available to produce electricity at its maximum capacity. Operating at varying low, mid and high loads to conduct tuning is also a less efficient way of operating the equipment. It is in CPLLC's best interest to only conduct tuning when it becomes necessary to maintain compliance with emission limits and/or increase turbine efficiency. Regarding **EPA Criterion 5**, all steps are taken to minimize emissions during tuning because the oxidation catalyst which controls VOC emissions will not be affected by the tuning process because it is a passive system operating downstream of the turbine exhaust. Regarding **EPA Criterion 6**, the facility is still subject to a BACT-based pound per day emission limits for other pollutants (NO_X and CO) which will be measured in real time to ensure that the turbines are operated in a manner consistent with good practices for minimizing emissions. The facility plans tuning events in advance and the turbines are designed such that control equipment operates at the maximum extent possible during tuning events. The turbines must be operated during tuning events such that the BACT-based NO_X and CO pound-per-day emission limits are not exceeded. As stated above, CPLLC proposes to conduct tuning only when necessary to maintain compliance with short term emission limits because the facility is not available to generate electricity at its maximum capacity during tuning. The operational limits of 18 hours per day and 96 hours of tuning per turbine per year are based on the estimated maximum amount of time needed to conduct the tuning process.

Regarding **EPA Criterion 3** for water washing, the frequency and duration are both minimized to the greatest extent possible because during water washes, the facility is not available to generate electricity at its maximum capacity. It is in CPLLC's best interest to only conduct water washes when the turbines begin to lose generating capacity from accumulation on the turbine blades. Regarding **EPA Criterion 5**, all steps are taken to minimize emissions during tuning because the oxidation catalyst which controls VOC emissions will not be affected by the tuning process because it is a passive system operating downstream of the turbine exhaust. Regarding **EPA Criterion 6,** the facility is still subject to a BACT-based pound per day emission limits for other pollutants (NO_X and CO) which will be measured in real time to ensure that the turbines are operated in a manner consistent with good practices for minimizing emissions. The facility plans water wash events in advance and the turbines are designed such that control equipment operates at the maximum extent possible during water washes. The turbines must be operated during water washes such that the BACT-based NOx and CO pound-per-day emission limits are not exceeded. CPLLC will conduct water washing only when necessary to maintain turbine efficiency because the facility is not available to generate electricity at its maximum capacity during water washes. Water washing will be limited to 60 minutes per water wash event and 52 hours of water washes per turbine per year.

5.3.4.4 $PM_{10}/PM_{2.5}$ BACT for Maintenance Activities (Tuning and Water Wash)

During tuning activities, adjustment of the combustion process may lead to the temporary formation of additional condensable particulates on both a lb/MMBtu and a lb/hr basis which may increase above permit limits for a short duration. Water washing activities may result in a temporary elevation of particulates due to cleaning the combustion turbine blades of dust, dirt or other accumulated matter. This may lead to the temporary emission of additional filterable particulate on both a lb/MMBtu and a lb/hr basis which may increase permit limits for a short duration.

The use of limiting maintenance activity operation, good combustion practices and pipeline quality natural gas with a sulfur content less than 0.4 grains/100 scf is concluded to represent BACT for PM, PM_{10}, and $PM_{2.5}$ control for the proposed combined cycle turbine generators. Specifically, combustion tuning and water washing maintenance activities will be limited to the following durations:

- 18 hour tune-up duration per day and 96 hours per year per turbine
- 60 minute water wash duration per event and 52 hours per year per turbine

Limiting the duration of each maintenance activity will control particulate emissions to the maximum extent possible. These are practically enforceable and operational standards which will limit particulate emissions. The tuning and water washing maintenance activities will result in a cleaner burning combustion turbine which will potentially result in lower condensable particulate.

Regarding **EPA Criterion 3** for tuning, the frequency and duration are both minimized to the greatest extent possible because during tuning, the facility is generally not available to produce electricity at its maximum capacity. Operating at varying low, mid and high loads to conduct tuning is also a less efficient way of operating the equipment. It is in CPLLC's best interest to only conduct tuning when it becomes necessary to maintain compliance with emission limits and/or increase turbine efficiency. Regarding **EPA Criterion 5**, all steps are taken to minimize emissions during tuning because the fuel sulfur content which affects particulate matter formation will not be affected by the tuning process. Regarding **EPA Criterion 6**, the facility is still subject to a BACT-based pound per day emission limits for other pollutants (NO_X and CO) which will be measured in real time to ensure that the turbines are operated in a manner consistent with good practices for minimizing emissions. The facility plans tuning events in advance and the turbines are designed such that control equipment operates at the maximum extent possible during tuning events. The turbines must be operated during tuning events such that the BACT-based NO_X and CO pound-per-day emission limits are not exceeded. Additionally, the operational limits of 18 hours per day and 96 hours of tuning per turbine per year are based on the estimated maximum amount of time needed to conduct the tuning process. As stated above, CPLLC conducts tuning only when necessary to maintain compliance with short term emission limits because the facility is typically not available to generate electricity at its maximum capacity during tuning. Additionally, operating at varying low, mid and high loads to conduct tuning is a less efficient way of operating the equipment than maximum, steady-state load.

Regarding **EPA Criterion 3** for water washing, the frequency and duration are both minimized to the greatest extent possible because during water washes, the facility is typically not available to produce electricity at its maximum capacity. It is in CPLLC's best interest to only conduct water washes when the turbines begin to lose generating capacity from accumulation on the turbine blades. Regarding **EPA Criterion 5**, all steps are taken to minimize emissions during tuning because the fuel sulfur content which affects particulate matter formation will not be affected by the tuning process. Regarding **EPA Criterion 6**, the facility is still subject to a BACT-based pound per day emission limits for NO_X and CO which will be measured in real time to ensure that the turbines are operated in a manner consistent with

good practices for minimizing emissions. The facility plans water wash events in advance and the turbines are designed such that control equipment operates at the maximum extent possible during water washes. The turbines must be operated during water washes such that the BACT-based NO_X and CO pound-per-day emission limits are not exceeded. The operational limits of 60 minutes per water wash event and 52 hours of water washes per turbine per year are based on the estimated maximum amount of time needed to conduct water washing. CPLLC conducts water washing only when necessary to maintain turbine efficiency because the facility is typically not available to generate electricity at its maximum capacity during water washes.

5.3.4.5 Combustion Turbine BACT Summary for Startup, Shutdown, and Maintenance Activities

Criterion 2, 3, 5, and 6 are addressed above. **Criterion 1** must apply to a narrowly defined source category using specific control strategies. The facility is a natural gas-fired combined-cycle power station using SCR and dry low NO_X combustors to control NO_X, and oxidation catalysts to control CO and VOC. **Criterion 4** requires that the state analyze potential worst-case emissions that could occur during the alternate operating conditions. Startup and shutdown emissions are considered to be the highest of the alternative operating conditions. Startup and shutdown emissions have been provided in this application and will be included in the air impact analysis. The modeling analysis demonstrates that these emissions do not cause violations of any air quality standards. **Criterion 7** requires the owner or operator to document actions during alternative operating conditions in a signed contemporaneous operating log or other relevant evidence. The facility maintains operating logs and emissions data to demonstrate proper operation of the equipment.

A summary of BACT emission control technologies and emission rates for the GE 7HA.02 and MHPS M501J combustion turbines for startup and shutdown operations is presented in Tables 5-6 and 5-7, respectively.

Table 5-6 Summary of Selected Alternate BACT Limits for Startup, Shutdown, and Maintenance Activities: GE 7HA.02

Pollutant	Startup/Shutdown	Maintenance Activities (Tuning / Water Washing)
NO_X	cold start event - 312 lb/turbine, warm start event - 175 lb/turbine, hot start event – 84.0 lb/turbine shutdown event – 16.3 lb/turbine	636 lb/turbine/day
CO	cold start event - 924 lb/turbine, warm start event - 470 lb/turbine, hot start event – 449 lb/turbine shutdown event - 190 lb/turbine	194 lb/turbine/day
VOC	Good combustion practices, cold start duration - 66 minutes, warm start duration - 48 minutes, hot start duration - 24 minutes, shutdown duration – 15 minutes	18 hours per day tuning & 96 hours per year, 60 minutes per wash event & 52 hours per year
$PM/PM_{10}/PM_{2.5}$	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf	Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf, 18 hours per day tuning & 96 hours per year, 60 minutes per wash event & 52 hours per year
SO_2	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf
Sulfuric Acid Mist	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf
Greenhouse Gases	No alternate BACT limit requested	No alternate BACT limit requested

Table 5-7 Summary of Selected Alternate BACT Limits for Startup, Shutdown, and Maintenance Activities: MHPS M501JAC

Pollutant	Startup/Shutdown	Maintenance Activities (Tuning / Water Washing)
NO_X	cold start event – 60.0 lb/turbine, warm start event – 54.0 lb/turbine, hot start event – 42.0 lb/turbine shutdown event – 19.2 lb/turbine	703 lb/turbine/day
CO	cold start event - 444 lb/turbine, warm start event - 396 lb/turbine, hot start event - 252 lb/turbine shutdown event - 156 lb/turbine	214 lb/turbine/day
VOC	Good combustion practices, cold start duration - 42 minutes, warm start duration - 42 minutes, hot start duration - 42 minutes, shutdown duration – 15 minutes	18 hours per day tuning & 96 hours per year, 60 minutes per wash event & 52 hours per year
$PM/PM_{10}/PM_{2.5}$	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf	Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf 18 hours per day tuning & 96 hours per year, 60 minutes per wash event & 52 hours per year
SO_2	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf
Sulfuric Acid Mist	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf	No alternate BACT limit requested Low sulfur pipeline quality natural gas containing maximum fuel sulfur content 0.4 gr/100 scf
Greenhouse Gases	No alternate BACT limit requested	No alternate BACT limit requested

5.4 Auxiliary Boiler and Fuel Gas Heaters BACT

CPLLC plans to install two 52 MMBtu/hr auxiliary boilers for the GE 7HA.02 option or two 84 MMBtu/hr auxiliary boilers for the MHPS M501JAC option and three fuel gas heaters each rated at 12 MMBtu/hr. The auxiliary boilers and the fuel gas heaters will burn only pipeline quality natural gas. The top-down BACT process was applied to the auxiliary boilers and fuel gas heater by either accepting a well-established top level of control as BACT or by evaluating the cost effectiveness of alternative emission controls.

5.4.1 BACT for Nitrogen Oxides (NO_X)

NO_X formation mechanisms for combustion sources are discussed in Section 5.2.1. The top-down BACT process was applied to the auxiliary boiler and fuel gas heaters by accepting the top level of control as BACT (STEPs 1, 2, 3, 4 and 5).

The primary front-end combustion controls for boilers and heaters are low excess air, low NO_X burners, and ultra-low NO_X burners. Selective catalytic reduction can be used to remove NOx from the exhaust gas stream once NO_X has been formed.

For natural gas combustion, both ultra-low NO_X burners and selective catalytic reduction are capable of limiting NO_X emissions to approximately 0.011 lb/MMBtu or 9 ppmvd at 3% O_2. Data from EPA's RACT/BACT/LAER Clearinghouse (see Appendix C, Tables C-7 and C-9) show that typical BACT emission rates for natural gas fired boilers and fuel gas heaters less than 250 MMBtu/hr are in the 0.035 lb/MMBtu to 0.060 lb/MMBtu range. However, several projects have been permitted in the 0.010 lb/MMBtu to 0.012 lb/MMBtu range. Recent projects in Virginia have been permitted at 0.011 lb/MMBtu.

CPLLC proposes to burn only pipeline quality natural gas in the auxiliary boilers and fuel gas heaters, and to use ultra-low NO_X burners to limit NO_X emissions to 0.011 lb/MMBtu (approximately 9 ppmvd at 3% O_2). Annual NO_X emissions from each of the auxiliary boilers will be limited to 2.51 tons/year for the GE HA.02 option and 4.05 tons/yr for the MHPS M501JAC option. Emissions from each fuel gas heater will be limited to 0.58 tons/year.

Although the proposed emission rate appears to be the top level of control based on data from EPA's RACT/BACT/LAER Clearinghouse, it may be technically feasible to achieve lower NO_X emissions by also applying selective catalytic reduction. Table 5-8 and Table 5-9 present capital and annual costs, respectively, for applying SCR to these units. As shown in Table 5-8, SCR is not BACT for either of the auxiliary boiler options or for the fuel gas heaters due to the very high cost effectiveness, which is in excess of $54,000 per ton of NO_X emissions controlled.

Table 5-8: Selective Catalytic Reduction Capital Costs for the Auxiliary Boiler and Fuel Gas Heaters

	GE Auxiliary Boiler	MHPS Auxiliary Boiler	Fuel Gas Heater	Factor	Basis for Cost and Factor
Capacity, MMBtu/hr	**52**	**84**	**12.0**		
DIRECT COSTS:					
PURCHASED EQUIPMENT					
(a) Primary and Auxiliary Equipment (PE)	$244,000	$326,000	$97,000	Extrapolated from vendor data for a 88.1 MMBtu/hr boiler and a 52 MMBtu/hr fuel gas heater.	
(b) Instrumentation & Controls	$24,400	$32,600	$9,700	10% of PE	EPA[(a)]
(c) Sales Tax	$7,320	$9,780	$2,910	3% of PE	EPA[(a)]
(d) Freight	$12,200	$16,300	$4,850	5% of PE	EPA[(a)]
TOTAL PURCHASED EQUIPMENT Cost (PEC):	$287,920	$384,680	$114,460		
DIRECT INSTALLATION					
(a) Foundations	$23,034	$30,774	$9,157	8% of PEC	EPA[(a)]
(b) Handling and Erection	$40,309	$53,855	$16,024	14% of PEC	EPA[(a)]
(c) Electrical	$11,517	$15,387	$4,578	4% of PEC	EPA[(a)]
(d) Piping	$5,758	$7,694	$2,289	2% of PEC	EPA[(a)]
(f) Insulation for ductwork	$2,879	$3,847	$1,145	1% of PEC	EPA[(a)]
(g) Painting	$2,879	$3,847	$1,145	1% of PEC	EPA[(a)]
TOTAL DIRECT INSTALLATION (DI):	**$86,376**	**$115,404**	**$34,338**		
TOTAL DIRECT COST (DC):	**$374,296**	**$500,084**	**$148,798**		
INDIRECT COSTS					
INDIRECT INSTALLATION					
(a) Engineering & Project Management	$28,792	$28,792	$11,446	10% of PEC	EPA[(a)]
(b) Construction & Field Expenses	$14,396	$14,396	$5,723	5% of PEC	EPA[(a)]
(c) Contractor Fees	$28,792	$28,792	$11,446	10% of PEC	EPA[(a)]
(d) Startup Expenses	$5,758	$5,758	$2,289	2% of PEC	EPA[(a)]
(g) Performance Tests	$2,879	$2,879	$1,145	1% of PEC	EPA[(a)]
(h) Contingencies	$8,638	$8,638	$3,434	3% of PEC	EPA[(a)]
TOTAL INDIRECT COST:	**$89,255**	**$89,255**	**$35,483**		
TOTAL INSTALLED COST (TIC)	**$464,000**	**$589,000**	**$184,000**		

(a) EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, Page 2-44. EPA/452/B-002-001. January 2002.

Table 5-9: Selective Catalytic Reduction Annual Costs for the Auxiliary Boiler and Fuel Gas Heaters

	GE Auxiliary Boiler	MHPS Auxiliary Boiler	Fuel Gas Heater	Basis for Cost and Factor
Capital Cost				
Total Installed Cost	$ 464,000	$ 589,000	$ 184,000	See Table 5-8
Source Capacity, MMBtu/hr	52.0	84.0	12.0	
NOx Emissions before Control, lb/MMBtu (Natural Gas)	0.0110	0.0110	0.0110	Ultra Low NOx burners
Annual Capacity Factor, %	100%	100%	100%	
NOx Emissions before Control, ton/yr	2.505	4.047	0.578	
NOx Emissions after Control, lb/MMBtu	0.0020	0.0020	0.0020	
Control Efficiency, %	81.8%	81.8%	81.8%	
NOx Emissions after Control, ton/yr	0.46	0.74	0.11	
NOx Emission Reduction, ton/yr	2.05	3.31	0.47	
Annual Costs, $/yr				
Catalyst Annual Cost				
Catalyst Replacement Cost	$ 143,960	$ 192,340	$ 57,230	50% of primary equipment cost to account for capital and labor costs
Catalyst Life	5.0	5.0	5.0	
Annual Costs, $/yr	$ 35,111	$ 46,910	$ 13,958	7% interest [(a)]
Urea	$ 879	$ 1,421	$ 203	1.3 ton urea per ton NOx removed at a delivered cost of $330/ton
Operating Labor	$ 12,775	$ 12,775	$ 12,775	1.0 hr/day at $35/hr
Supervisor	$ 1,916	$ 1,916	$ 1,916	15% of operating labor [(a)]
Maintenance Labor	$ 12,775	$ 12,775	$ 12,775	1.0 hr/day at $35/hr
Maintenance Materials	$ 12,775	$ 12,775	$ 12,775	100% of maintenance labor[(a)]
Electricity	$ 3,644	$ 5,887	$ 841	0.1 kW/MMBtu/hr for pressure drop and other operating requirmeents at $0.08/kWh
Overhead	$ 24,145	$ 24,145	$ 24,145	60% of oper, maint. & supv labor + maint. material costs [(a)]
Taxes, Insurance, and Administration	$ 18,560	$ 23,560	$ 7,360	4% of total installed cost [(a)]
Capital Recovery	$ 30,210	$ 37,442	$ 11,966	7.0%, 20 years, 0.0944 x (TCI-catalyst) [(a)]
Total Annual Cost	$ 152,790	$ 179,605	$ 98,714	
Cost Effectiveness, $ per ton NOx emission reduction	$ 75,000	$ 54,000	$ 209,000	

(a) EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, Page 2-44. EPA/452/B-002-001. January 2002.

5.4.2 BACT for Carbon Monoxide (CO) and Volatile Organic Compounds (VOCs)

Mechanisms of formation of CO and VOC emissions are discussed in Section 5.2.2. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO and VOC emissions, but higher NO_X emissions. The top-down CO and VOC BACT process was applied to the auxiliary boiler and fuel gas heaters by accepting a well-established top level of control as BACT (STEPs 1, 2, 3, 4 and 5).

Available emission control techniques for CO and VOC are good combustion practices and oxidation catalysts. Good combustion practices are capable of limiting CO emissions to 0.037 lb/MMBtu, which is equivalent to 50 ppmvd at 3% O_2, when firing natural gas. Data from EPA's RACT/BACT/LAER Clearinghouse (see Appendix C, Table C-8 and Table C-10) show that a typical CO BACT emission rate for natural gas fired boilers and fuel gas heaters less than 250 MMBtu/hr is in the 0.035 lb/MMBtu to 0.040 lb/MMBtu range. Recent BACT emission limits in Virginia are based on 50 ppmvd at 3% O_2.

Although the proposed emission rate appears to be the top level of control based on data from EPA's RACT/BACT/LAER Clearinghouse, it may be technically feasible to achieve lower CO emissions by also applying an oxidation catalyst. Table 5-10 and Table 5-11 present capital and annual costs, respectively, for applying an oxidation catalyst. An oxidation catalyst is not BACT for either the auxiliary boiler or the fuel gas heaters due to the high cost, which is in excess of $8,300 per ton of CO emissions controlled as shown in Table 5-11.

Table 5-10: CO Oxidation Catalyst Capital Costs for the Auxiliary Boiler and Fuel Gas Heaters

	GE Auxiliary Boiler	MHPS Auxiliary Boiler	Fuel Gas Heater	Factor	Basis for Cost and Factor
Capacity, MMBtu/hr	**52**	**84**	**12.0**		
DIRECT COSTS:					
PURCHASED EQUIPMENT					
(a) Primary and Auxiliary Equipment (PE)	$ 43,700	$ 58,300	$ 16,600	Extrapolated from vendor data for a 88.1 MMBtu/hr boiler and a 52 MMBtu/hr fuel gas heater.	
(b) Instrumentation & Controls	$4,370	$5,830	$1,660	10% of PE	EPA[(a)]
(c) Sales Tax	$1,311	$1,749	$498	3% of PE	EPA[(a)]
(d) Freight	$2,185	$2,915	$830	5% of PE	EPA[(a)]
TOTAL PURCHASED EQUIPMENT Cost (PEC):	$51,566	$68,794	$19,588		
DIRECT INSTALLATION					
(a) Foundations	$4,125	$5,504	$1,567	8% of PEC	EPA[(a)]
(b) Handling and Erection	$7,219	$9,631	$2,742	14% of PEC	EPA[(a)]
(c) Electrical	$2,063	$2,752	$784	4% of PEC	EPA[(a)]
(d) Piping	$1,031	$1,376	$392	2% of PEC	EPA[(a)]
(f) Insulation for ductwork	$516	$688	$196	1% of PEC	EPA[(a)]
(g) Painting	$516	$688	$196	1% of PEC	EPA[(a)]
TOTAL DIRECT INSTALLATION (DI):	$15,470	$20,638	$5,876		
TOTAL DIRECT COST (DC):	**$67,036**	**$89,432**	**$25,464**		
INDIRECT COSTS					
INDIRECT INSTALLATION					
(a) Engineering & Project Management	$5,157	$5,156.60	$1,959	10% of PEC	EPA[(a)]
(b) Construction & Field Expenses	$2,578	$2,578.30	$979	5% of PEC	EPA[(a)]
(c) Contractor Fees	$5,157	$5,156.60	$1,959	10% of PEC	EPA[(a)]
(d) Startup Expenses	$1,031	$1,031.32	$392	2% of PEC	EPA[(a)]
(g) Performance Tests	$516	$515.66	$196	1% of PEC	EPA[(a)]
(h) Contingencies	$1,547	$1,546.98	$588	3% of PEC	EPA[(a)]
TOTAL INDIRECT COST:	**$15,985**	**$15,985**	**$6,072**		
TOTAL INSTALLED COST (TIC)	**$83,000**	**$105,000**	**$32,000**		

(a) USEPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, Page 2-44. EPA/452/B-002-001. January 2002.

Table 5-11: CO Oxidation Catalyst Annual Costs for the Auxiliary Boiler and Fuel Gas Heaters

	GE Auxiliary Boiler	MHPS Auxiliary Boiler	Fuel Gas Heater	Basis for Cost and Factor
Capital Cost				
Total Installed Cost	$83,000	$105,000	$32,000	See Table 5-10
Source Capacity, MMBtu/hr	52.0	84.0	12.0	
CO Emissions before Control, lb/MMBtu	0.0370	0.0370	0.0370	Good combustion practices
Annual Capacity Factor, %	100%	100%	100%	
CO Emissions before Control, ton/yr	8.43	13.61	1.94	
CO Emissions after Control, lb/MMBtu (Natural Gas)	0.0060	0.0060	0.0060	
Control Efficiency, %	83.8%	83.8%	83.8%	
CO Emissions after Control, ton/yr	1.37	2.21	0.32	
CO Emission Reduction, ton/yr	7.06	11.41	1.63	
Annual Costs, $/yr				
Catalyst Annual Cost				
Catalyst Replacement Cost	$51,566	$68,794	$19,588	100% of primary equipment cost to account for capital and labor costs
Catalyst Life	5.0	5.0	5.0	
Annual Costs, $/yr	$12,576	$16,778	$4,777	7% interest [(a)]
Operating Labor	$12,775	$12,775	$12,775	1.0 hr/day at $35/hr
Supervisor	$1,916	$1,916	$1,916	15% of operating labor [(a)]
Maintenance Labor	$12,775	$12,775	$12,775	1.0 hr/day at $35/hr
Maintenance Materials	$12,775	$12,775	$12,775	100% of maintenance labor[(a)]
Electricity	$3,644	$5,887	$841	0.1 kW/MMBtu/hr for operating requirements at $0.08/kWh
Overhead	$24,145	$24,145	$24,145	60% of oper, maint. & supv labor + maint. material costs [(a)]
Taxes, Insurance, and Administration	$3,320	$4,200	$1,280	4% of total installed cost [(a)]
Capital Recovery	$2,967	$3,418	$1,172	7.0%, 20 years, 0.0944 x (TCI-catalyst) [(a)]
Total Annual Cost	$86,894	$94,669	$72,456	
Cost Effectiveness, $ per ton CO emission reduction	**$12,300**	**$8,300**	**$44,500**	

(a) EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, Page 2-44. EPA/452/B-002-001. January 2002.

For VOC emissions, in addition to employing good combustion practices, CPLLC proposes to burn only pipeline quality natural gas in the auxiliary boiler and fuel gas heaters. CPLLC proposes to limit VOC emissions to 0.005 lb/MMBtu. Recent BACT emission limits for similar emission sources in Virginia have been set at 0.005 lb/MMBtu. Annual VOC emissions from each of the auxiliary boilers will be limited to 1.14 tons/year for the GE HA.02 option and 1.84 tons/yr for the MHPS M501JAC option. Emissions from each of the fuel gas heaters will be limited to 0.26 ton/yr.

5.4.3 BACT for Particulate Matter (PM), Particulate Matter, Particulate Matter Less than 10 Microns (PM_{10}) and Particulate Matter Less than 2.5 Microns ($PM_{2.5}$)

Particulate matter emissions formation was discussed previously in Section 5.2.4. The top-down BACT process was applied to the auxiliary boilers and fuel gas heater by accepting a well-established top level of control as BACT (STEPs 1, 2, 3, 4 and 5).

Good combustion practices and limiting fuel to only pipeline quality natural gas in the auxiliary boiler and fuel gas heaters, are proposed as BACT for PM, PM_{10}, and $PM_{2.5}$ emissions from the auxiliary boilers and fuel gas heaters. Annual PM, PM_{10}, and $PM_{2.5}$ emissions from each auxiliary boiler will be limited to 1.59 ton/yr for the GE HA.02 option and 2.58 ton/yr for the MHPS M501JAC option while emissions from the each of the fuel gas heaters will be limited to 0.37 ton/yr.

5.4.4 BACT for SO_2 and Sulfuric Acid Mist

Emissions of SO_2 and sulfuric acid mist from the auxiliary boilers and fuel gas heaters are a result of oxidation of fuel sulfur. BACT is the use of pipeline quality natural gas in the auxiliary boilers and fuel gas heaters.

5.4.5 BACT for GHGs

The top-down BACT process was applied to the auxiliary boiler and fuel gas heaters by accepting a well-established top level of control as BACT (STEPs 1, 2, 3, 4 and 5). The only available GHG emission controls for the auxiliary boiler and fuel gas heaters are use of low carbon fuels, oxidation catalyst (for controlling methane emissions) and efficient design. Carbon capture and sequestration is not an available technology as described in Section 5.2.6. The auxiliary boilers and fuel gas heaters will burn only natural gas and will be designed for high efficiency.

It may be technically feasible to achieve lower methane emissions by also applying an oxidation catalyst. It is estimated that an oxidation catalyst could remove 25% of methane emissions[18]. Table 5-10 in Section 5.4.2 presents capital costs for applying an oxidation catalyst, and Table 5-12 presents annual costs. An oxidation catalyst is not BACT for either the auxiliary boiler or the fuel gas heaters due to the very high cost effectiveness, which exceeds $470,000 per ton of methane emissions controlled (as shown in Table 5-12).

[18] Control efficiency for a natural gas fired boiler from We Energies Control Technology Review for Greenhouse Gas Emissions for the proposed 50 MW Biomass Fuels-Fired Cogeneration Facility.

Table 5-12: Oxidation Catalyst Annual Costs for the Auxiliary Boiler and Fuel Gas Heaters

	GE Auxiliary Boiler	MHPS Auxiliary Boiler	Fuel Gas Heater	Basis for Cost and Factor
Capital Cost				
Total Installed Cost	$83,000	$105,000	$32,000	See Table 5-10
Source Capacity, MMBtu/hr	52.0	84.0	12.0	
CH4 Emissions before Control, lb/MMBtu	0.0022	0.0022	0.0022	Good combustion practices
Annual Capacity Factor, %	100%	100%	100%	
CH4 Emissions before Control, ton/yr	0.50	0.81	0.12	
CH4 Emissions after Control, lb/MMBtu (Natural Gas)	0.0017	0.0017	0.0017	
Control Efficiency, %	25.0%	25.0%	25.0%	
CH4 Emissions after Control, ton/yr	0.38	0.61	0.087	
CH4 Emission Reduction, ton/yr	0.126	0.203	0.029	
Annual Costs, $/yr				
Catalyst Annual Cost				
Catalyst Replacement Cost	$51,566	$68,794	$19,588	100% of primary equipment cost to account for capital and labor costs
Catalyst Life	5.0	5.0	5.0	
Annual Costs, $/yr	$12,576	$16,778	$4,777	7% interest [(a)]
Operating Labor	$12,775	$12,775	$12,775	1.0 hr/day at $35/hr
Supervisor	$1,916	$1,916	$1,916	15% of operating labor [(a)]
Maintenance Labor	$12,775	$12,775	$12,775	1.0 hr/day at $35/hr
Maintenance Materials	$12,775	$12,775	$12,775	100% of maintenance labor[(a)]
Electricity	$3,644	$5,887	$841	0.1 kW/MMBtu/hr for pressure drop and other operating requirmeents at $0.08/kWh
Overhead	$24,145	$24,145	$24,145	60% of oper, maint. & supv labor + maint. material costs [(a)]
Taxes, Insurance, and Administration	$3,320	$4,200	$1,280	4% of total installed cost [(a)]
Capital Recovery	$2,967	$3,418	$1,172	7.0%, 20 years, 0.0944 x (TCI-catalyst) [(a)]
Total Annual Cost	$86,894	$94,669	$72,456	
Cost Effectiveness, $ per ton CO emission reduction	$692,200	$466,800	$2,501,200	

(a) EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, Page 2-44. EPA/452/B-002-001. January 2002.

5.4.6 Other Emissions from the Auxiliary Boiler and Fuel Gas Heaters

BACT for other pollutant emissions from the auxiliary boilers and fuel gas heaters is good combustion practices and the use of pipeline quality natural gas.

5.4.7 Auxiliary Boiler and Fuel Gas Heaters BACT Summary

A summary of BACT emission control technologies and emission rates for the auxiliary boilers and fuel gas heaters is presented in Table 5-13.

Table 5-13: Summary of Proposed BACT for the Auxiliary Boiler and Fuel Gas Heaters

Compound	BACT Emission Rate (lb/MMBtu)
Nitrogen Oxides	0.011
Carbon Monoxide	0.037
VOC	0.005
$PM/PM_{10}/PM_{2.5}$	0.007
Sulfur Dioxide	1.14E-03
Sulfuric Acid Mist	8.76E-05
Other Pollutants	Pipeline quality natural gas and good combustion

5.5 Emergency Diesel Generator and Fire-Water Pump BACT

The top-down BACT process was applied to the diesel-fired emergency diesel generator and fire-water pump by accepting a well-established top level of control as BACT (STEPs 1, 2, 3 and 5) for all pollutants except GHGs. For GHG, the cost effectiveness of alternative emission controls was also evaluated (STEPs 4 and 5).

Operation of the emergency generator and fire-water pump will each be limited to 500 total operating hours per year, which includes 100 normal operating hours per year for maintenance and testing. Only ULSD fuel containing 15 ppmw sulfur or less will be fired in these units. Compliance with the NSPS for Stationary Compression Ignition Engines (40 CFR Part 60 Subpart IIII) is proposed as BACT for NO_X, CO, VOC, $PM/PM_{10}/PM_{2.5}$ and SO_2. BACT emission rates are presented in Appendix B.

For GHG emissions, the only available emission control methods are efficient design and the use of low carbon fuels. The use of biodiesel is not technically feasible due to storage concerns. Carbon capture and sequestration is not an available control technology as described in Section 5.2.6.

A spark ignited natural gas fired engine would result in lower GHG emissions for the emergency generator. However, the capital cost for a spark ignited natural gas fired engines is typically twice that of a diesel engine. In addition, the reliability of spark ignited engines is substantially poorer than diesel engines. Available guidance on reasonable BACT cost effectiveness is limited to the Interim Phase I Report of the Climate Change Work Group, which identifies a range of cost effectiveness recommendations from $3 to $150 per ton CO_2. Based on a calculated cost effectiveness of $457 per ton of CO_2 emissions controlled, a spark ignited natural gas fired engine is not cost effective for this application as shown in Table 5-15.

For the firewater pump, natural gas is not allowed by the National Fire Protection Association (NFPA 20). Use of a 2012 or later model year diesel fired engine is the top ranked technology. No ranking for cost effectiveness is required for the firewater pump.

Table 5-14: Emergency Generator GHG BACT Cost Analysis for Emergency Generator Options

Capital Costs				
	Value			
Item	**Diesel Generator**	**Natural Gas Generator**	**Difference (Natural Gas minus Diesel)**	**Basis**
Direct Costs				3 MW generator
1.) Purchased Equipment Cost				
a.) Equipment cost + auxiliaries	$1,050,000	$1,986,000	$936,000	Extrapolated from 06/29/2011 e-mail from Caterpillar representative. Cost for engine and walk-in enclosure
b.) Instrumentation	$105,000	$198,600	$93,600	0.10 x A [(a)]
c.) Sales taxes	$73,500	$139,020	$65,520	0.07 x A [(a)]
d.) Freight	$52,500	$99,300	$46,800	0.05 x A [(a)]
Total Purchased equipment cost, (PEC)	$1,281,000	$2,422,920	$1,141,920	B = 1.22 x A
Direct installation Costs			$0	Typically, 0.3 times total purchased equipment. Conservatively assumed to be no difference for this analysis
Total Direct Cost, DC			$1,141,920	
Indirect Costs (installation)				
2.) Engineering, Construction and Field Expenses, Contractor Fees, Startup and Performance test			$0	Typically, 0.28 times total purchased equipment. Conservatively assumed to be no difference for this analysis
3.) Contingencies			$34,258	0.03 x B [(a)]
Total Indirect Cost, IC			$34,258	
Total Capital Investment (TCI) = DC + IC			**$1,176,178**	

Table 5-15 Emergency Generator GHG BACT Cost Analysis for Emergency Generator Options

Annual Costs				
	Value			
Item	**Diesel Generator**	**Natural Gas Generator**	**Difference (Natural Gas minus Diesel)**	**Basis**
1) Electricity			$0.00	Not applicable
2) Labor Costs			$0.00	No difference
3) Fuel Costs				
Fuel Use (MMBtu/yr)	28.8	28.8	0.0	Similar performance
Annual Operation (hr/yr)	100	100	0.0	
Annual Fuel Use (MMBtu/yr)	2,878.2	2,878.2	0.0	
Unit Cost ($/MMBtu)	26.74	6.68		Average for the years 2015 through 2025 based on Table A.3 in Annual Energy Outlook 2011 with Projections to 2035, U.S. Energy Information Administration, DOE/EIA-0383(2011), April 2011
Total Fuel Costs ($/year)	$77,342	$19,319	($58,023)	
4) Supervisory Labor			$0.00	No difference
5) Maintenance			$0.00	Conservatively assumed to be no difference but natural gas spark ignition may be higher
6) Indirect Annual Costs				
Overhead			$0	60% of O&M Costs
Administration			$23,524	2% of Total Capital Investment [(a)]
Property Tax			$11,762	1% of Total Capital Investment [(a)]
Insurance			$11,762	1% of Total Capital Investment [(a)]
Capital Recovery			$167,460	10 yr life; 7% interest [(a)]
Total Indirect ($/yr)			$214,507	
Total Annualized Cost ($/yr)			**$156,484**	
Total GHG Emissions CO_{2e} (tpy)	**1,203**	**860**	**-342.5**	
Cost Effectiveness ($/ton)			**$457**	

(a) Typical factor used in BACT analysis: EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, US EPA, January 2002

(b) Annual operation for BACT analysis and costing is based on expected typical use.

5.6 Fuel Oil Storage Tank BACT

The top-down BACT process was applied to the storage tank by accepting a well-established top level of control as BACT (STEPs 1, 2, 3 and 5) for VOC emissions.

Breathing and working losses from the emergency equipment ULSD storage tanks will result in VOC emissions. These small tanks will be fixed roof tanks with conservation vents. Annual VOC emissions from these tanks are 0.002 tons/yr. Add-on emission controls are not used for storage of low vapor pressure liquids such as ULSD. The NSPS for large storage tanks (40 CFR Part 60 Subpart Kb) does

not require emission controls for storage of distillate oil in any size tank, even multi-million gallon tanks. The use of fixed roof tanks with conservation vents is proposed as BACT for VOC emissions for this equipment.

5.7 Circuit Breakers GHG BACT

The circuit breakers are electrical equipment insulated with sulfur hexafluoride, which is a greenhouse gas. SF_6 is a dielectric gas used in high voltage applications because of its ease of use and excellent insulation and arc-interruption properties. A GHG BACT analysis was performed for the circuit breakers. The top-down BACT process was applied by accepting an established top level of control as BACT (STEPs 1, 2, 3 and 5).

5.7.1 Available GHG Control Alternatives

(STEP 1)

Step 1 of the top-down BACT analysis is to identify all available control technologies. The two technologies available for GHG control of insulated electrical equipment are the use of state of the art technology with leak detection equipment, and substituting SF_6 with an alternative, non-GHG substance.

Unlike older SF_6 circuit breakers, modern breakers are designed as a completely enclosed-pressure system, which results in a substantially lower potential for SF_6 leaks. In addition, circuit breakers can be equipped with a density alarm that provides a warning when 10% of the total mass of SF_6 has been released. This allows any potential leak issues to be identified proactively so that emissions of SF_6 can be limited.

Another way to control emissions is to use an alternate, non-GHG substance as the dielectric material for the circuit breakers. This would eliminate SF_6 emissions altogether. Potential alternatives to SF_6 were detailed by the National Institute of Standards and Technology (NIST) in Technical Note 1425[19].

5.7.2 Eliminate Technically Infeasible Options

(STEP 2)

The use of modern circuit breakers with leak detection technology is a technically feasible option and is already being proposed as part of this project. Although there are other substances that could potentially be used as the dielectric material, these are not considered technically feasible alternatives. As concluded by the NIST in Technical Note 1425, while other gas mixtures show promise for use in new equipment, this equipment must be designed specifically for the gas mixture to be used, and much more research is needed in order to pursue this option. Therefore, the use of other, non-GHG substances instead of SF_6 is not a commercially available technology and is eliminated as BACT.

[19] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*, NTIS Technical Note 1425, November 1997.

5.7.3 Ranking and Evaluation of Available GHG Control Technologies

(STEPS 3 & 4)

The use of state of the art equipment with leak detection installed is the only technically feasible control technology for the circuit breakers. Therefore, this is the highest ranking GHG control technology.

5.7.4 Select GHG BACT for Circuit Breakers

(STEP 5)

Based on the top-down analysis for GHG control, state of the art enclosed-pressure circuit breakers with leak detection equipment have been selected as BACT. The manufacturer guarantee is an annual leak rate of 0.5% for the proposed circuit breakers, and a low-pressure alarm will be installed to alert of fugitive leaks before a substantial quantity of SF_6 is released.

5.8 Natural Gas Piping Components GHG BACT

Fugitive emissions from natural gas components (valves, flanges, etc.) are similar to the Greensville County project.[20] Maximum estimated emissions are 250 tons CO_2e/yr, assuming 1% leaking components, which is less than 0.005% of total facility emissions. A leak detection and repair (LDAR) program is estimated to cost $75,000/yr. Even if a LDAR program could eliminate all emissions, the cost effectiveness would be $300, which is excessive. An Audio, Visual, and Olfactory program conducted in conjunction with routine equipment inspections is proposed as BACT for control of natural gas releases.

[20]. Virginia DEQ - Dominion - Greensville, http://www.deq.virginia.gov/Programs/Air/PermittingCompliance/Permitting/PowerPlants/DominionGreensville.aspxVirginia Electric Power Company Response to Comments, April 22, 2016.

6.0 PSD Class II Modeling Procedures

The dispersion modeling analyses conducted for this Project adheres to the United States Environmental Protection Agency (US EPA) "Guideline on Air Quality Models" (GAQM, which is contained in 40 CFR Part 51, Appendix W) (US EPA 2017) and direction received from the VA DEQ Modeling Section. The following sections present the source data to be modeled, the proposed procedure for assessing ambient air impacts from the proposed Project's emissions and the standards to which the predicted impacts were compared.

6.1 Background Discussion

The proposed Project will be a major source for VOCs, CO, NO_2, $PM_{2.5}$, and PM_{10} as discussed in **Section 4.2** of the document; therefore, PSD review and associated dispersion modeling analysis was required for these pollutants. In addition, the proposed Project will have potential SO_2 emissions greater than 40 TPY; therefore, PSD review and associated dispersion modeling analysis was required for SO_2 as well. Modeling analyses performed evaluated compliance with applicable PSD increments for these pollutants. In addition, compliance with the National Ambient Air Quality Standards (NAAQS) was evaluated. Although potential H_2SO_4 mist emissions will be greater than the 7 TPY SER threshold, there are no NAAQS or PSD increments for this regulated pollutant. Additionally, there are no modeling requirements for VOCs. The modeling analysis addresses impacts associated with secondary $PM_{2.5}$ and Ozone as described further in **Section 6.10**.

Based on the current Project design, the CTs (for both turbine options) are the primary sources of pollutant emissions at this plant. Much smaller quantities of criteria pollutants are emitted from the auxiliary boilers, emergency diesel-fired generator, emergency diesel-fired fire water pump, and fuel gas heaters.

As discussed in the following sections, the dispersion modeling for this Project was conducted in a manner that utilizes the combustion turbine's worst-case operating conditions associated with the ambient temperature range and impacts from startup and shutdown (for short term averaging periods) in an effort to predict the highest impact for each averaging period. The Significant Impact Levels (SILs), as shown in **Table 6-1**, were compared to the maximum predicted impacts from these worst-case scenarios. This comparison is provided in **Section 7**.

For those pollutants which have predicted impacts below the applicable SIL, no additional analysis was necessary since, by regulatory definition, the pollutant could not cause or contribute to a NAAQS violation or an exceedance of a PSD increment. The modeling results for both turbine options indicate that the Project will have insignificant modeled impacts for CO (1- and 8-hour), SO_2 (1-, 3-, 24-, and annual), and PM_{10} (annual).

For those pollutants which have predicted impacts that exceed the SILs, a cumulative impact assessment was undertaken based on the corresponding worst-case operating conditions. The results of the cumulative modeling were analyzed for comparison to Federal and State ambient air quality standards and PSD increments. The modeling results for both turbine options indicate that the Project will have significant modeling impacts for NO_2 (1-hour and annual) and PM_{10} (24-hour). In addition, because the SILs have been remanded for $PM_{2.5}$ for the purposes of avoiding a cumulative impact

analysis, cumulative modeling was also performed to demonstrate compliance with the 24-hour and annual NAAQS and PSD increments for $PM_{2.5}$.

Table 6-1: Criteria Pollutant Significant Impact Levels for PSD Class II Areas

Pollutant	Averaging Time (1)				
	Annual *µg/m³*	**24-hour** *µg/m³*	**8-hour** *µg/m³*	**3-hour** *µg/m³*	**1-hour** *µg/m³*
NO_2	1	-	-	-	7.5
CO	-	-	500	-	2000
PM_{10}	1	5	-	-	-
$PM_{2.5}$(2)	0.2	1.2			
SO_2	1	5		25	7.9

(1) High 1st high modeled concentration.

(2) SILs for PM2.5 have been remanded for the purposes of avoiding a cumulative impact analysis.

Sources: 9 VAC 5-80-1715 B.1, 40 CFR 50, 64864 Federal Registrar - Vol 75 - No. 202, US EPA Clarification Memorandums

6.2 Source Data

6.2.1 Combined-Cycle Combustion Turbines – Normal Operations

Based on current Project design parameters, the Project intends to apply for a permit that will allow unrestricted annual operation (8,760 hours per year) of each combustion turbine.

Since turbine emission rates and flue gas characteristics for a given turbine load vary as a function of ambient temperature, data was derived for the following ambient temperatures and load scenarios for both of the proposed turbine options.

<u>GE 7HA.02 – Combustion Turbines – Natural Gas Operations</u>

- 3 operating loads (Base, 75%, 30-40%)
- 4 ambient temperatures (99°F, 59°F, 20°F, -12°F)

<u>MHPS M501JAC –Combustion Turbines – Natural Gas Operations</u>

- 3 operating loads (Base Load, 75%, and 50%)
- 4 ambient temperatures (99°F, 59°F, 22.1°F, 10.4°F)

A summary of the GE 7HA.02 turbine exhaust data and emission rates for the PSD-regulated pollutants for each ambient temperature and operating load during natural gas combustion is provided in **Table 6-2**. A summary of the MHPS M501JAC turbine exhaust data and emission rates for the PSD-regulated pollutants for each ambient temperature and operating load during natural gas combustion is provided in **Table 6-3**.

In order to conservatively calculate ground-level concentrations, a composite "worst-case" set of emission parameters was used in the modeling as an initial approach. For each combined-cycle operating load in the modeling, the highest pollutant-specific emission rate coupled with the lowest exhaust temperature and exhaust flow rate was selected. **Tables 6-4** and **6-5** summarize the worst-case emission parameters for the GE 7HA.02 and MHPS M501JAC turbine operating loads firing natural gas, respectively.

Table 6-2: Source Parameters and Criteria Pollutant Emission Rates Natural Gas-Fired GE 7HA.02 Combustion Turbine Operation

Scenario(1)	Ambient Temp. (˚F)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr/CT)(2), (3)				
						NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2
Base Load	-12	180.0	22.0	189.0	77.11	26.3	8.0	12.4	12.4	4.12
Base Load	20	180.0	22.0	188.0	77.06	***26.5***	***8.1***	***12.4***	***12.4***	***4.15***
Base Load, Evap Cooling	59	180.0	22.0	186.0	75.05	26.1	8.0	12.4	12.4	4.10
Base Load	59	180.0	22.0	***185.0***	74.22	25.9	7.9	12.3	12.3	4.05
Base Load, Evap Cooling	99	180.0	22.0	202.0	76.52	25.9	7.9	12.3	12.3	4.05
Base Load	99	180.0	22.0	197.0	***70.55***	23.8	7.3	12.1	12.1	3.74
75% Load	-12	180.0	22.0	179.0	60.77	***20.8***	***6.4***	***11.7***	***11.7***	***3.27***
75% Load	20	180.0	22.0	178.0	60.21	20.8	6.3	11.7	11.7	3.26
75% Load	59	180.0	22.0	***175.0***	57.79	20.2	6.2	11.6	11.6	3.17
75% Load	99	180.0	22.0	188.0	***56.77***	18.7	5.7	11.4	11.4	2.93
30-40% Load	-12	180.0	22.0	173.0	46.55	***14.5***	***4.4***	***10.8***	***10.8***	***2.27***
30-40% Load	20	180.0	22.0	166.0	41.61	13.3	4.1	10.7	10.7	2.09
30-40% Load	59	180.0	22.0	***165.0***	38.67	11.8	3.6	10.5	10.5	1.86
30-40% Load	99	180.0	22.0	179.0	***37.09***	10.8	3.3	10.3	10.3	1.69

Note: Data are provided per emission units unless otherwise noted.

(1) Data presented are for multiple operating loads/conditions at three ambient temperatures.

(2) Hourly emissions reflect operation of a single GE 7HA.02 combustion turbine firing pipeline natural gas only.

(3) Bold italicized numbers indicate highest emissions, lowest temperature, and lowest exhaust over the ambient temperatures.

Table 6-3: Source Parameters and Criteria Pollutant Emission Rates Natural Gas-Fired MHPS M501JAC Combustion Turbine Operation

Scenario(1)	Ambient Temp. (˚F)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr/CT)(2), (3)				
						NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2
Base Load	10.4	180.0	22.0	***174.0***	***74.40***	28.5	8.7	12.3	12.3	4.51
Base Load	22.1	180.0	22.0	175.0	76.42	***29.3***	***8.9***	***12.3***	***12.3***	***4.64***
Base Load, Evap Cooling	59.0	180.0	22.0	174.0	75.63	28.4	8.7	12.3	12.3	4.50
Base Load	59.0	180.0	22.0	174.0	75.68	28.3	8.6	12.3	12.3	4.03
Base Load, Evap Cooling	99.0	180.0	22.0	195.0	77.56	27.7	8.4	12.3	12.3	4.39
Base Load	99.0	180.0	22.0	192.0	74.75	26.5	8.1	12.3	12.3	3.78
75% Load	10.4	180.0	22.0	173.0	67.56	***24.9***	***7.6***	***12.3***	***12.3***	***3.95***
75% Load	22.1	180.0	22.0	171.0	66.12	24.3	7.4	12.3	12.3	3.85
75% Load	59.0	180.0	22.0	***166.0***	***60.86***	22.5	6.9	12.3	12.3	3.56
75% Load	99.0	180.0	22.0	183.0	61.03	21.1	6.4	12.3	12.3	3.35
50% Load	10.4	180.0	22.0	165.0	53.67	***18.8***	***5.7***	***12.3***	***12.3***	***2.98***
50% Load	22.1	180.0	22.0	162.0	51.96	18.4	5.6	12.3	12.3	2.92
50% Load	59.0	180.0	22.0	***161.0***	***50.25***	17.2	5.2	12.3	12.3	2.73
55% Load	99.0	180.0	22.0	177.0	51.65	16.9	5.2	12.3	12.3	2.70

Note: Data are provided per emission units unless otherwise noted.

(1) Data presented are for multiple operating loads/conditions at three ambient temperatures.

(2) Hourly emissions reflect operation of a single MHPS M501JAC combustion turbine firing pipeline natural gas only.

(3) Bold italicized numbers indicate highest emissions, lowest temperature, and lowest exhaust over the ambient temperatures.

Table 6-4: Worst Case Data (1) for Proposed Natural Gas-Fired GE 7HA.02 Combustion Turbine Operation

Parameter		Percent Load		
Load (%)		**Base**	**75**	**30-40**
Stack Height (ft)		180.0	180.0	180.0
Stack Diameter (ft)		22.0	22.0	22.0
Exit Temperature (°F)		185.0	175.0	165.0
Exit Velocity (ft/sec)		70.55	56.77	37.09
Pollutant Emissions Per Combustion Turbine (lb/hr/CT)	**SO_2**	4.15	3.27	2.27
	PM_{10}	12.4	11.7	10.8
	$PM_{2.5}$	12.4	11.7	10.8
	NO_X	26.5	20.8	14.5
	CO	8.1	6.4	4.4

Note: Data are provided per emission units unless otherwise noted.

(1) The values in the table represent the worst-case stack parameters and the emission rates for the four operating loads taken from the Table 6-2 (bold and italicized)

Table 6-5: Worst Case Data (1) for Proposed Natural Gas-Fired MHPS M501JAC Combustion Turbine Operation

Parameter		Load		
Load (%)		**Base**	**75**	**50**
Stack Height (ft)		180.0	180.0	180.0
Stack Diameter (ft)		22.0	22.0	22.0
Exit Temperature (°F)		174.0	166.0	161.0
Exit Velocity (ft/sec)		74.40	60.86	50.25
Pollutant Emissions Per Combustion Turbine (lb/hr/CT)	**SO_2**	4.64	3.95	2.98
	PM_{10}	12.3	12.3	12.3
	$PM_{2.5}$	12.3	12.3	12.3
	NO_X	29.3	24.9	18.8
	CO	8.9	7.6	5.7

Note: Data are provided per emission units unless otherwise noted.

(1) The values in the table represent the worst-case stack parameters and the emission rates for the four operating loads taken from the Table 6-3 (bold and italicized)

6.2.2 Combined-Cycle Combustion Turbines - Startup/Shutdown Operations

Startup/Shutdown (SUSD) modeling was conducted for the short-term pollutants and averaging periods that have the potential for elevated emissions combined with lower plume rise during SUSD conditions. The pollutants and averaging periods evaluated include: 1-hour NO_2 and 1- and 8-hour CO. Since the SO_2 and $PM_{10}/PM_{2.5}$ emissions are typically a function of the fuel, elevated SO_2 and $PM_{10}/PM_{2.5}$ emissions are not expected during SUSD conditions. This has been confirmed by vendor data to be provided in **Appendix B**. As such, modeling for SO_2 and $PM_{10}/PM_{2.5}$ during SUSD conditions was not performed as a part of this analysis.

Both turbine vendors provided data indicating startup times of approximately one hour or less (even for cold starts). As such, evaluation of SUSD conditions was based on vendor provided emission estimates per event and event durations. **Table 6-6** shows a summary of the startup emissions for each scenario (cold, warm, and hot starts) for each pollutant modeled for each turbine option. As shown in **Table 6-6**, the maximum emissions for each turbine option occur under a cold start scenario. Therefore, the cold start scenario was modeled for 1-hour NO_2 and CO 1- and 8-hour.

Short-term emissions for the turbines were calculated based on the maximum of either startup/ shutdown emissions or a mix of startup/shutdown and normal operation emissions (if the startup period is shorter than the total averaging period). For averaging periods for which the duration of the startup is shorter than the averaging period, the remaining time (in the averaging period) for the turbines were assumed to be associated with worst-case load conditions (100% load). **Table 6-7** presents a summary of the startup emissions for each of the short- term averaging periods.

For annual modeling, since the worst-case annual emissions occur with 8,760 hours per year of continuous operation for all pollutants except CO, no additional analyses was considered for annual startup/shutdown modeling because there is not an applicable NAAQS or PSD increment for annual impacts of CO.

Table 6-6: Summary of Startup Emissions (per Turbine)

Event	GE 7HA.02 Total Per Event (lb/start)		Duration	MHPS M501JAC Total Per Event (lb/start)		Duration
	CO	NOx	(Min)	CO	NOx	(Min)
Cold	924.0	312.0	66	444.0	60.0	42
Warm	470.0	175.2	48	396.0	54.0	42
Hot	449.0	84.0	24	252.0	42.0	42

Table 6-7: Short-term Averaging Period Startup Summary

Pollutant	Avg. Period	Startup Duration (min)	Avg. Period Duration (min)	Start Emissions[1]				Normal Operation Emissions[2]			
				Total Start (3 turbs) (lbs/ event)	Modeled Emission Rate CC1 (lbs/hr)	Modeled Emission Rate CC2 (lbs/hr)	Modeled Emission Rate CC3 (lbs/hr)	Max Hourly (lbs/hr/turb)	Modeled Emission Rate CC1 (lbs/hr)	Modeled Emission Rate CC2 (lbs/hr)	Modeled Emission Rate CC3 (lbs/hr)
GE 7HA.02 Combustion Turbine											
NO_2	1-hour	66	60	936.0	283.64	283.64	283.64	n/a	n/a	n/a	n/a
CO	1-hour	66	60	2,772.0	840.00	840.00	840.00	n/a	n/a	n/a	n/a
	8-hour	66	480	2,772.0	127.05	127.05	127.05	8.1	6.99	6.99	6.99
MHPS M501JAC Combustion Turbine											
NO_2	1-hour	42	60	180.0	60.00	60.00	60.00	29.3	8.79	8.79	8.79
CO	1-hour	42	60	1,332.0	444.00	444.00	444.00	8.9	2.67	2.67	2.67
	8-hour	42	480	1,332.0	38.85	38.85	38.85	8.9	8.12	8.12	8.12

(1) Modeled SUSD assumes that all three turbines are starting up at the same time.

(2) Normal operation modeled emissions for averaging periods of 1-hour and 8-hour are based on the 100% Load case maximum emissions weighed by the ratio of the balance of non-startup duration relative to the averaging period duration.

6.2.3 Ancillary Source Data

Table 6-8 provides stack parameters and criteria pollutant emission rates for the auxiliary boilers and the fuel gas heaters. Since the performance data for the auxiliary equipment are not affected by ambient conditions, only one set of parameters were modeled (e.g., stack parameters and emission rates associated with 100% load). The auxiliary boilers and the fuel gas heaters are expected to operate 8,760 hours/year. Thus, the emission rates in **Table 6-8** are for both short term and annual modeling.

The emergency diesel generator and emergency fire-water pump are expected to operate intermittently 1 hour per week per unit and 100 hours/year per unit under non-emergency conditions (operability testing) and no more than 500 total hours/year total. Therefore, the modeled short-term emissions (24-hour or less) were normalized to operate 1 hour within the averaging period for the assessment of short-term modeled averaging periods. The modeled annual emission rates were normalized based on the 500 hours per year for the assessment of annual modeled averaging periods.

Additionally, for the 1-hour NO_2 and SO_2 modeling, these units were not included in the modeling due to their intermittent operations based on US EPA guidance for modeling intermittent sources (US EPA 2011).

Table 6-9 provides stack parameters and criteria pollutant emission rates for the emergency diesel generator and the emergency fire-water pump. Please note that the Project will accept a permit condition for each unit that limits the non-emergency use to 100 hours/year and no more than 500 total hours/year of combined emergency and non-emergency use.

Table 6-8: Source Parameters and Criteria Pollutant Emission Rates for the Auxiliary Equipment

Source ID	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Hourly Emissions (lb/hr/unit)				
					NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2
Auxiliary Boilers									
AUXB1-GE	40.0	3.00	300.0	38.50	0.57	1.92	0.36	0.36	0.059
AUXB2-GE	40.0	3.00	300.0	38.50	0.57	1.92	0.36	0.36	0.059
AUXB1-MHPS	40.0	3.50	300.0	44.0	0.92	3.11	0.59	0.59	0.096
AUXB2-MHPS	40.0	3.50	300.0	44.0	0.92	3.11	0.59	0.59	0.096
Fuel Gas Heaters									
FGH1	20.0	1.50	810.0	50.53	0.13	0.44	0.08	0.08	0.014
FGH2	20.0	1.50	810.0	50.53	0.13	0.44	0.08	0.08	0.014
FGH3	20.0	1.50	810.0	50.53	0.13	0.44	0.08	0.08	0.014
Note: Data are provided per emission units unless otherwise noted.									

Table 6-9: Source Parameters and Criteria Pollutant Emission Rates for the Emergency Equipment

Parameter		Averaging Period	Units	Emergency Equipment[1]	
Model ID		---	---	**EDG**	**FWP**
Stack Height (ft)		---	---	21.0	15.0
Stack Diameter (ft)		---	---	1.67	0.50
Exit Temperature (°F)		---	---	892.0	842.0
Exit Velocity (ft/sec)		---	---	196.0	158.0
Maximum Potential Emission Rates	**NO_X**	1 Hour	lb/hr	46.54	2.49
		Annual	tpy	11.63	0.62
	CO	1 Hour	lb/hr	25.45	2.16
		Annual	tpy	6.36	0.54
	PM_{10}	1 Hour	lb/hr	1.45	0.12
		Annual	tpy	0.36	0.031
	$PM_{2.5}$	1 Hour	lb/hr	1.45	0.12
		Annual	tpy	0.36	0.031
	SO_2	1 Hour	lb/hr	0.0445	0.0039
		Annual	tpy	0.0111	0.0010
Modeled Emission Rates (2)	**NO_X**	Annual	lb/hr	2.655E+00	1.416E-01
	CO	1 Hour		2.545E+01	2.160E+00
		8 Hour		3.181E+00	2.700E-01
	PM_{10}	24 Hour		6.042E-02	5.000E-03
		Annual		8.219E-02	7.078E-03
	$PM_{2.5}$	24 Hour		6.042E-02	5.000E-03
		Annual		8.219E-02	7.078E-03
	SO_2	3 Hour		1.483E-02	1.300E-03
		24 Hour		1.854E-03	1.625E-04
		Annual		2.534E-03	2.283E-04

(1) EDG is the ULSD-Fired Emergency Generator and FWP is the ULSD-Fired Fire Water Pump Engine.
(2) Modeled emission rates reflect 1 hour of operation in the averaging period and annual emission rates reflect 500 hours per year of operation.

6.3 AERMOD Model Applicability and Model Options

The suitability of an air quality dispersion model for a particular application is dependent upon several factors. The following selection criteria were evaluated:

- stack height relative to nearby structures;
- dispersion environment;
- local terrain; and
- representative meteorological data.

The US EPA GAQM prescribes a set of approved models for regulatory applications for a wide range of source types and dispersion environments. Based on a review of the factors discussed below, the latest version of AERMOD (18081) (US EPA 2018a) was used to assess air quality impacts for the Project.

Based on US EPA current guidance, NO_2 impacts can be determined by using a 3-tiered NO_X to NO_2 conversion rate system, where:

- Tier 1 assumes 100 percent NO to NO_2 conversion;
- Tier 2 utilizes the Ambient Ratio Method 2 (ARM2);
- Tier 3 allows the use of refined techniques such as the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM). Both OLM and PVMRM options AERMOD.

For this Project, the Tier 2 ARM2 approach was utilized. For the MHPS M501JAC turbine option, the upper and lower bounds of ARM2 were set to be the default 0.9 and 0.5, respectively. For the GE 7HA.02 turbine option, the upper and lower bounds of ARM2 were set to be 0.9 and 0.3, respectively. After consultation with US EPA Region 3 and VA DEQ, the lower bound for the GE 7HA.02 was adjusted to reflect a lower in-stack ratio for this turbine option. US EPA Region 3's approval of this is included in the modeling archive contained in **Appendix E**.

6.4 Good Engineering Practice Stack Height Analysis

A Good Engineering Practice (GEP) stack height analysis was performed based on the proposed plant design to determine the potential for building-induced aerodynamic downwash for all modeled stacks. The analysis procedures described in US EPA's Guidelines for Determination of Good Engineering Practice Stack Height (US EPA, 1985), Stack Height Regulations (40 CFR 51), and current Model Clearing house guidance was used.

The GEP formula height is based on the observed phenomena of disturbed atmospheric flow in the immediate vicinity of a structure resulting in higher ground level concentrations at a closer proximity to the building than would otherwise occur. It identifies the minimum stack height at which significant aerodynamic downwash is avoided. The GEP formula stack height, as defined in the 1985 final regulations, is calculated from:

$$H_{GEP} = H_{BLDG} + 1.5L$$

Where:

- H_{GEP} is the maximum GEP stack height
- H_{BLDG} is the height of the nearby structure, and
- L is the lesser dimension (height or projected width) of the nearby structure

For a squat structure, i.e., height less than projected width, the formula reduces to:

$$H_{GEP} = 2.5H_B$$

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. In all instances, the GEP stack height is based on the plane projections of any nearby building which result in the greatest justifiable height. For purposes of the GEP analysis, nearby refers to the "sphere of influence", defined as five times (5L) the height or width of the building, whichever is less, downwind from the trailing edge of the structure. In the case where a stack is not influenced by nearby structures, the maximum GEP stack height is defined as 65 meters.

The current facility design has all modeled stacks less than 65 meters. As such, all stacks were modeled with their actual stack height. In addition, the US EPA's Building Profile Input Program (BPIP-Version 04274) version that is appropriate for use with PRIME algorithms in AERMOD was used to incorporate downwash effects in the model for all modeled stacks. The building dimensions of each structure were input in BPIPPRM program to determine direction specific building data. PRIME addresses the entire structure of the wake, from the cavity immediately downwind of the building, to the far wake. **Figure 6-1** shows the buildings/structures and source locations considered in the modeling analysis.

6.5 Receptor Grid and AERMAP Processing

The Class II grid consists of receptors spaced 25 m apart along the fence line. The facility plot plan shows a depiction of the fence line established for the Project site (see **Appendix D**). A spacing of 50 m was used for the receptors beyond the fence line and extending out to 1 km from the fence line. Beyond 1 km from the fence line, a spacing of 100 m was used up to 3 km from the plant. Between 3 and 5 km, a spacing of 250 m was used. Between 5 and 10 km, a spacing of 500 m was used. Beyond 10 km, a spacing of 1000 m was used.

The receptor grid used in the modeling analysis was based in UTM Zone 18 and NAD 1983. The extent of this grid was sufficient to capture maximum impacts in the Class II area within the 50-meter spaced receptor grid for all pollutants and averaging periods with insignificant modeled impacts. **Figures 6-2** and **6-3** show the far-field and near field Cartesian receptor grid respectively considered for the modeling analysis. Modeled design concentration for the PSD increment and NAAQS modeling analyses were also resolved to 50-meter spaced receptors as applicable.

The receptors used for the cumulative modeling were limited to those receptors within a concentration that exceed the applicable SILs.

AERMAP (version 18081) (US EPA, 2018d), AERMOD's terrain preprocessor program, was used to calculate terrain elevations and critical hill heights for the modeled receptors (UTM Zone 18 and NAD 1983) using National Elevation Data (NED). The dataset that was downloaded from the USGS website (http://seamless.usgs.gov/) consists of 1/3 arc second (~10 m resolution) NED. As per the AERMAP User's Guide (US EPA, 2018d), the domain was sufficient to ensure that all terrain features that exceed a 10% elevation slope from any given receptor are considered.

Figure 6-1: Source Locations and Main Building Structures Included in GEP Analysis

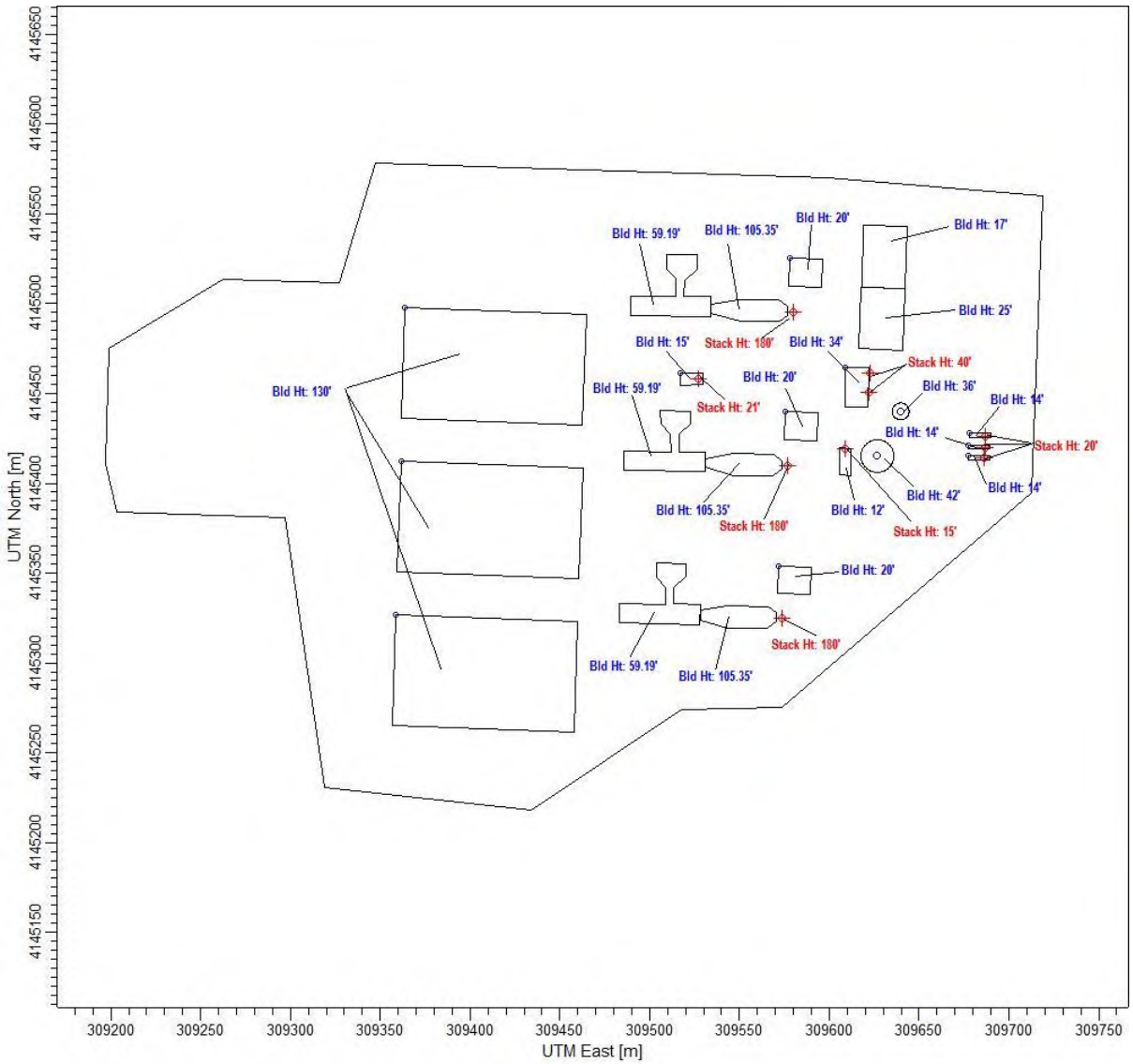


Figure 6-2: 20-km Receptor Grid for SIL AERMOD Modeling Analysis

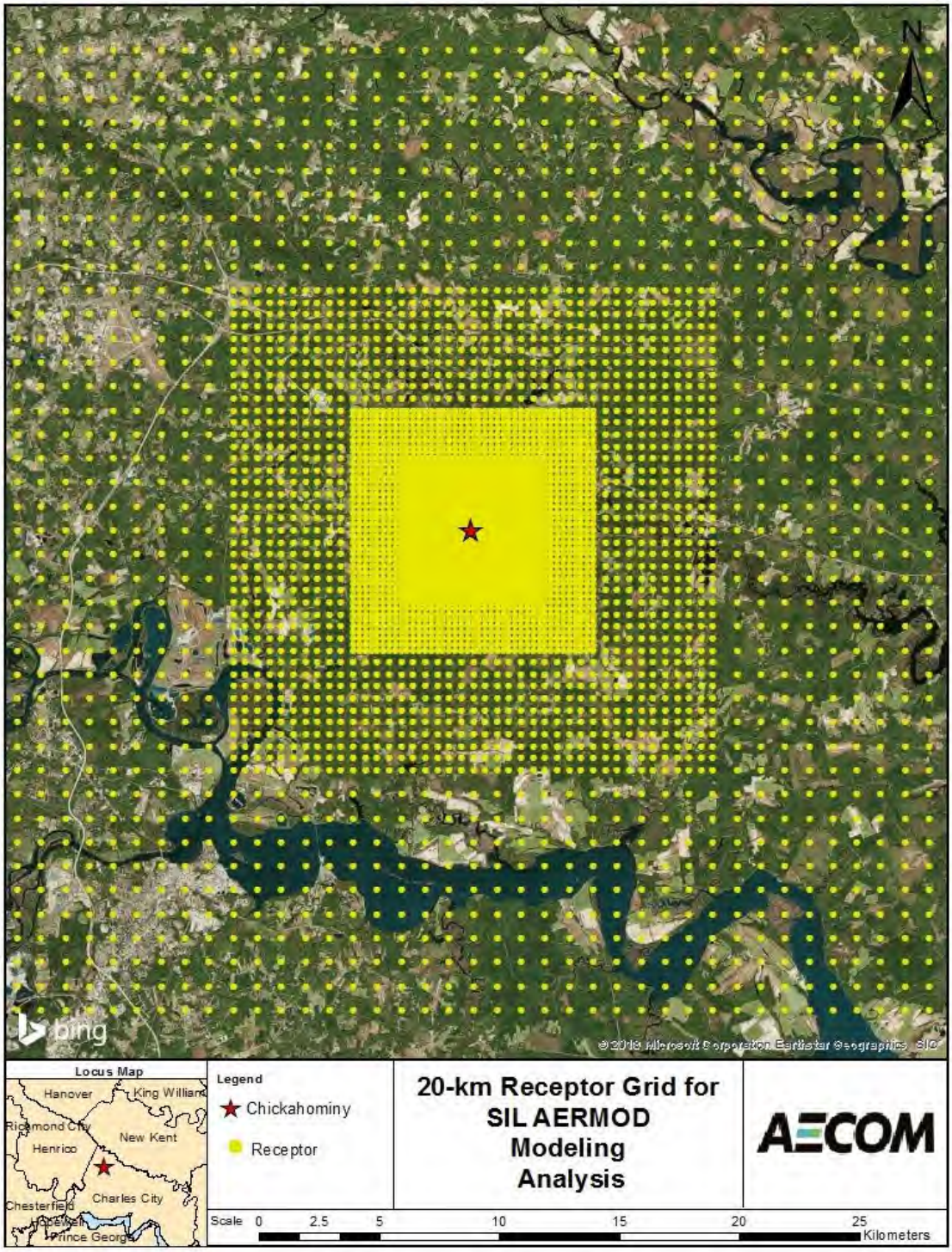
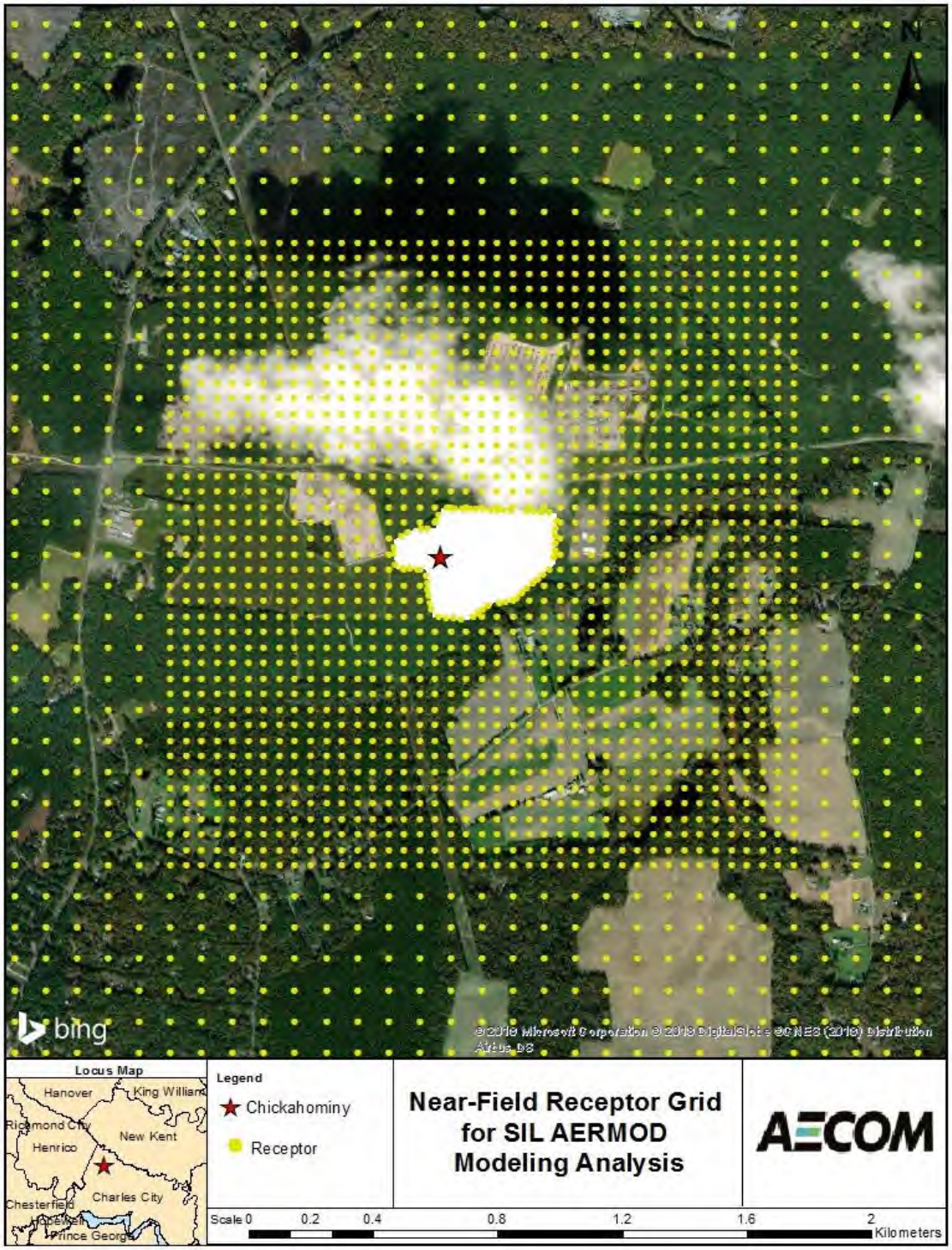


Figure 6-3: Near-Field Receptor Grid for SIL AERMOD Modeling Analysis



6.6 Meteorological Data for AERMOD

Meteorological data required for AERMOD include hourly values of wind speed, wind direction, and ambient temperature. Since the AERMOD dispersion algorithms are based on atmospheric boundary layer dispersion theory, additional boundary layer variables are derived by parameterization formulas, which are computed by the AERMOD meteorological preprocessor, AERMET (US EPA 2018b). These parameters include sensible heat flux, surface friction velocity, convective velocity scale, vertical potential temperature gradient, convective and mechanical mixing heights, Monin-Obukhov length, surface roughness length, Bowen ratio, and albedo.

6.6.1 Available Meteorological Data

The hourly meteorological data was processed with the latest version of AERMET (Version 18081) (US EPA 2018b), the meteorological preprocessor for AERMOD. Specifically, AERMET was run utilizing five concurrent years (2012-2016) of hourly surface observations from Richmond International Airport, VA along with concurrent upper air data from Sterling, VA. **Figure 6-4** shows the location of meteorological stations in relationship to the Project.

The AERMET inputs were based on surface meteorological data from the National Climatic Data Center's (NCDC) Integrated Surface Hourly (ISH) database along with 1-minute Automated Surface Observing System (ASOS) data. The upper air data input to AERMET was downloaded from the NOAA/ESRL/GSD - RAOB database[21]. **Table 6-10** gives the site location and information on these data sets. The surface wind data are measured 10.0 meters above ground level. The temperature and relative humidity are measured 2.0 meters above ground level.

US EPA guidance provided in Meteorological Monitoring Guidance for Regulatory Modeling Applications (February 2000) (US EPA 2000), Section 5.3, specifies a completeness requirement of 90% on a quarterly basis. The 90 percent requirement applies to each of the variables wind direction, wind speed, stability, and temperature and to the joint recovery of wind direction, wind speed, and stability. **Table 6-11** summarizes the quarterly joint data completeness by year. As shown in **Table 6-11**, all quarters show the data capture is above 90 percent.

Additionally, there are only 5 missing soundings over the five-year period. These missing soundings also account for the joint data completeness as these vales reflect the missing data report from the end of the AERMOD output file.

Table 6-10: Meteorological Data Used in Running AERMET

Met Site	Latitude	Longitude	Base Elevation (m)	Data Source	Data Format
Richmond Airport, VA	37.5115	-77.3234	49	NCDC	ISHD and 1-min ASOS
Sterling, VA	38.983	-77.467	85	FSL	FSL

[21] http://esrl.noaa.gov/raobs/

Table 6-11: Meteorological Data Completeness Percentage per Quarter

Quarter[1]	2012	2013	2014	2015	2016
1	100.0	100.0	97.6	100.0	100.0
2	99.7	100.0	95.4	100.0	99.8
3	100.0	100.0	100.0	99.8	98.6
4	99.2	99.6	100.0	100.0	100.0
Total	99.7	99.9	98.3	99.9	99.6

1. Quarter 1 = Jan, Feb, Mar; Quarter 2 = April, May, June; Quarter 3 = July, Aug, Sept; and Quarter 4 = Oct, Nov, Dec

6.6.2 AERSURFACE Analysis – Meteorological Site Land Use Characteristics

AERMET requires specification of site characteristics including surface roughness (z_0), albedo (r), and Bowen ratio (B_0). These parameters were developed according to the guidance provided by US EPA in the recently revised AERMOD Implementation Guide (AIG) (US EPA 2018c) and input provided by VA DEQ.

The AIG provides the following recommendations for determining the site characteristics:

1. The determination of the surface roughness length should be based on an inverse distance weighted geometric mean for a default upwind distance of 1 kilometer relative to the measurement site. Surface roughness length may be varied by sector to account for variations in land cover near the measurement site; however, the sector widths should be no smaller than 30 degrees.
2. The determination of the Bowen ratio should be based on a simple un-weighted geometric mean (i.e., no direction or distance dependency) for a representative domain, with a default domain defined by a 10-km by 10-km region centered on the measurement site.
3. The determination of the albedo should be based on a simple un-weighted arithmetic mean (i.e., no direction or distance dependency) for the same representative domain as defined for Bowen ratio, with a default domain defined by a 10-km by 10-km region centered on the measurement site.

The AIG recommends that the surface characteristics be determined based on digitized land cover data. US EPA has developed a tool called AERSURFACE (US EPA 2013) that can be used to determine the site characteristics based on digitized land cover data in accordance with the recommendations from the AIG discussed above. AERSURFACE incorporates look-up tables of representative surface characteristic values by land cover category and seasonal category. AERSURFACE was applied with the instructions provided in the AERSURFACE User's Guide.

The current version of AERSURFACE (Version 13016) supports the use of land cover data from the USGS National Land Cover Data 1992 archives[22] (NLCD92). The NLCD92 archive provides data at a spatial

[22] https://www.mrlc.gov/nlcd1992.php

resolution of 30 meters based upon a 21-category classification scheme applied over the continental US The AIG recommends that the surface characteristics be determined based on the land use surrounding the site where the surface meteorological data were collected.

As recommended in the AIG for surface roughness, the 1-km radius circular area centered at the meteorological station site can be divided into sectors for the analysis; each chosen sector has a mix of land uses that is different from that of other selected sectors. Sectors used to define the meteorological surface characteristics for the airport site are shown in **Figure 6-5**.

In AERSURFACE, the various land cover categories are linked to a set of seasonal surface characteristics. As such, AERSURFACE requires specification of the seasonal category for each month of the year. Based on the climatology of high and low daily temperatures (**Figure 6-6**) for a 30-year period of record (1971-2000) in Richmond, VA, the following five seasonal categories, as offered by AERSURFACE, were be mapped to the following months[23]:

1. Midsummer with lush vegetation (May-September);
2. Autumn with un-harvested cropland (October-November);
3. Late autumn after frost and harvest, or winter with no snow (December-February);
4. Winter with continuous snow on ground (none); and
5. Transitional spring with partial green coverage or short annuals (March-April).

For Bowen ratio, the land use values are linked to three categories of surface moisture corresponding to average, wet and dry conditions. The surface moisture condition for the site may vary depending on the meteorological data period for which the surface characteristics are applied. AERSURFACE applies the surface moisture condition for the entire data period. Therefore, if the surface moisture condition varies significantly across the data period, then AERSURFACE can be applied multiple times to account for those variations.

As recommended in AERSURFACE User's Guide, the surface moisture condition for each month was determined by comparing precipitation for the period of data to be processed to the 30-year climatological record, selecting "wet" conditions if precipitation is in the upper 30th-percentile, "dry" conditions if precipitation is in the lower 30th-percentile, and "average" conditions if precipitation is in the middle 40th-percentile. The 30-year precipitation data set used in this modeling will be taken from Richmond International Airport, Virginia and obtained from National Weather Service NOWData[24].

The 30-year period of record used to establish the 30-year average monthly precipitation totals include 1987 through 2016. The monthly designations of surface moisture input to AERSURFACE are summarized in **Table 6-12**.

[23] For the winter-to-spring designation a month needed approximately more than 50% of the low temperatures > freezing; conversely the transition from autumn-to-winter occurred when the low temperatures dipping below freezing exceeded approximately 50% of the time.

[24] http://w2.weather.gov/climate/index.php?wfo=akq

Table 6-12: AERSURFACE Bowen Ratio Condition Designations

Month	2012	2013	2014	2015	2016
January	Dry	Wet	Average	Average	Average
February	Wet	Average	Average	Wet	Wet
March	Dry	Wet	Average	Average	Dry
April	Average	Average	Wet	Wet	Dry
May	Dry	Dry	Dry	Dry	Wet
June	Average	Wet	Average	Average	Wet
July	Average	Wet	Dry	Wet	Average
August	Average	Wet	Average	Dry	Dry
September	Average	Dry	Dry	Average	Wet
October	Wet	Wet	Average	Average	Wet
November	Dry	Average	Average	Wet	Dry
December	Average	Wet	Average	Wet	Average

As such, AERSURFACE was then be applied for surface roughness, based on the 1-km radius circular area centered at the Richmond International Airport's anemometer location. The 1-km radius was divided into sectors for the AERSURFACE analysis; each chosen sector has a mix of land uses that is different from that of other selected sectors. Sectors used to define the meteorological surface characteristics are shown in **Figure 6-5**.

6.6.3 AERMET Data Processing

AERMET (Version 18081) and AERMINUTE (Version 15272) were used to process data required for input to AERMOD. Boundary layer parameters used by AERMOD, which also are required as input to the AERMET processor, include albedo, Bowen ratio, and surface roughness. The land classifications and associated boundary layer parameters were determined following procedures outlined **Section 6.6.2**. In running AERMET, the observed airport hourly wind direction were randomized and the default ADJ_U* option was utilized.

AERMET was applied to create two meteorological data files required for input to AERMOD:

Surface: A file with boundary layer parameters such as sensible heat flux, surface friction velocity, convective velocity scale, vertical potential temperature gradient in the 500-meter layer above the planetary boundary layer, and convective and mechanical mixing heights. Also provided are values of Monin-Obukhov length, surface roughness, albedo, Bowen ratio, wind speed, wind direction, temperature, and heights at which measurements were taken.

Profile: A file containing multi-level meteorological data with wind speed, wind direction, temperature, sigma-theta (σ_θ) and sigma-w (σ_w) when such data are available. For this application, the profile file will contain a single level of wind data (10 meters) and the temperature data only.

A wind-rose for the Richmond Airport from the 10-meter level is provided in **Figure 6-7**. The wind-rose was generated using the AERMET surface file (which include the 1-minute ASOS data). As shown in the wind rose, the predominant wind direction for the site is from the south-southwest, although winds out of the north-northeast are also common.

Figure 6-4: Location of Meteorological Stations Relative to the Project Site

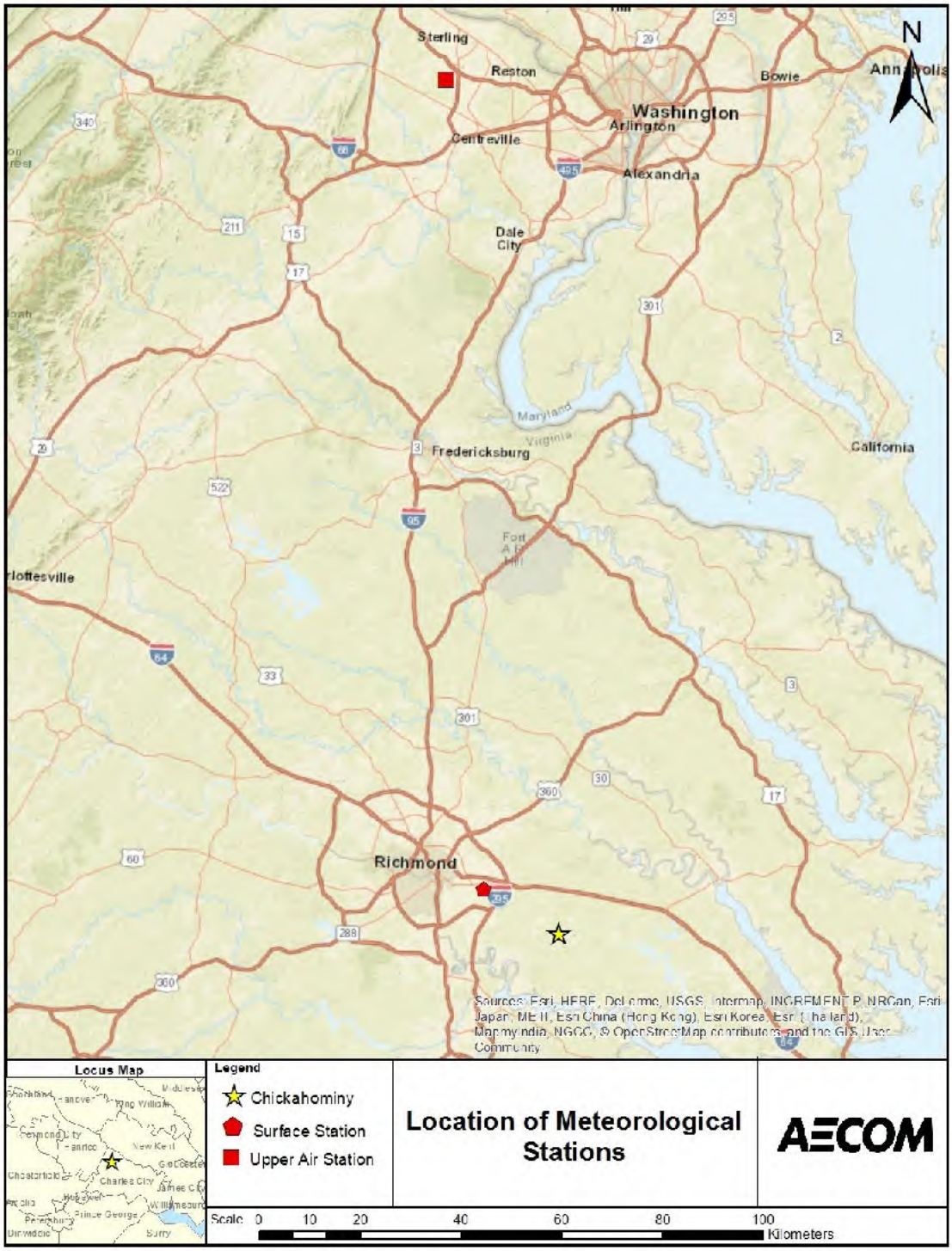
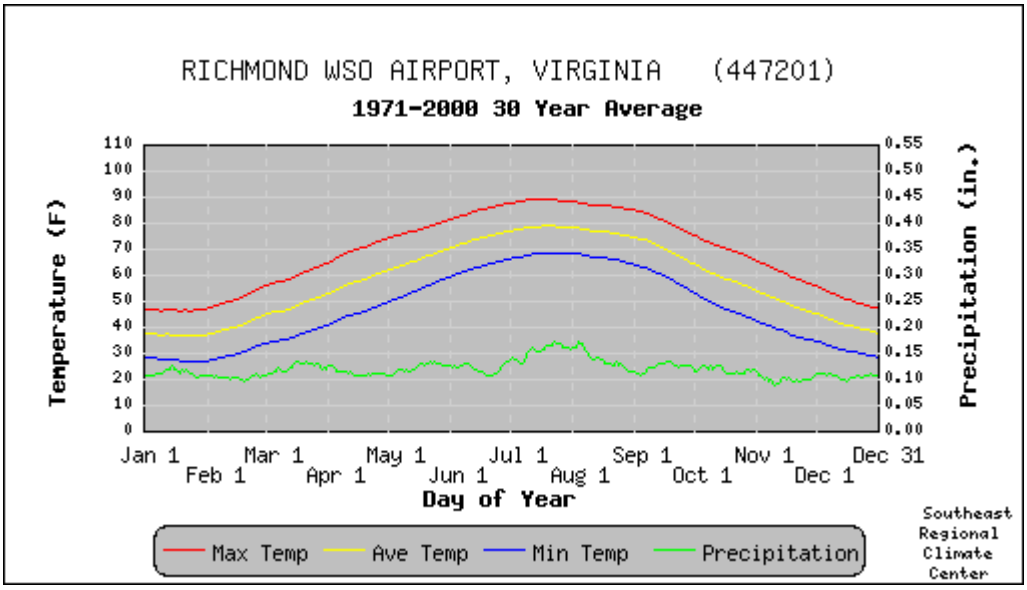


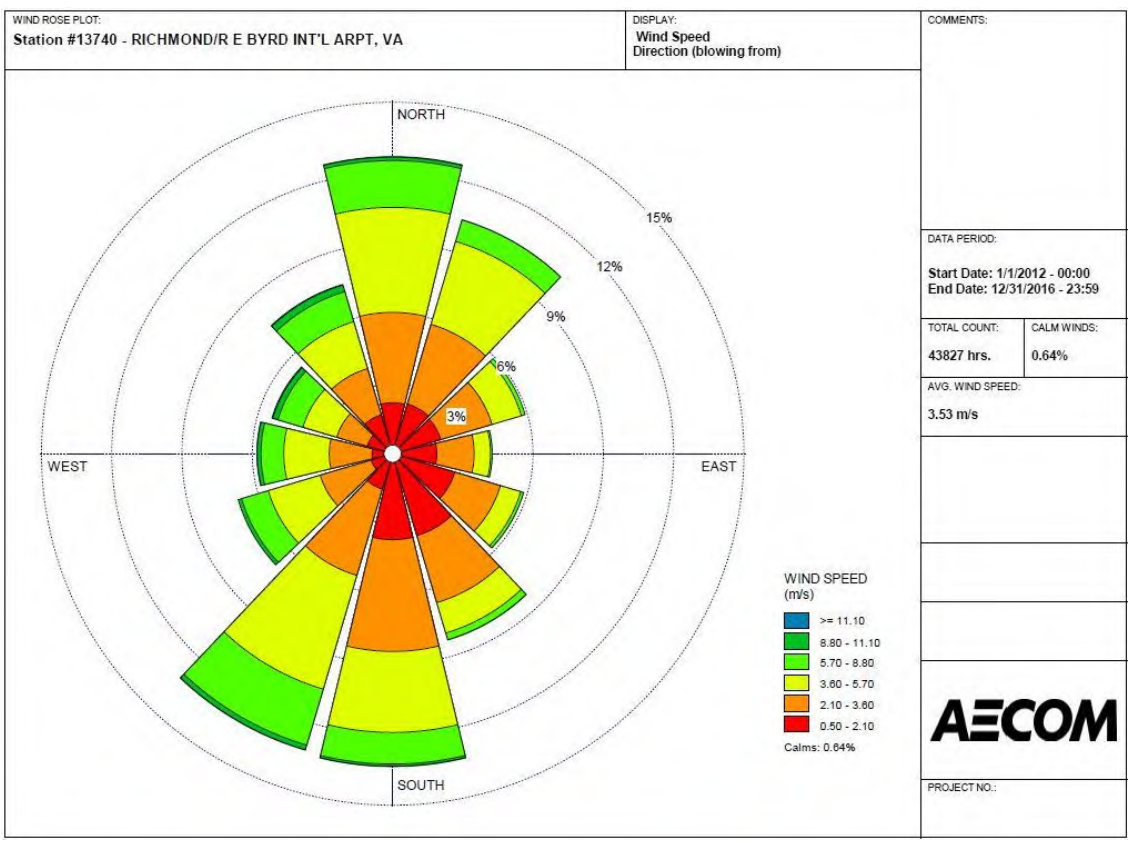
Figure 6-5: Sectors Used for Surface Characteristics at Richmond International Airport

Figure 6-6: Regional Temperature Climatology



(1) Based on data from the South East Regional Climate Center (SERCC).

Figure 6-7: Wind Rose for Richmond Airport (2012-2016)



6.7 Compliance with Class II Air Quality Standards

The predicted impacts from the air quality impact analysis, presented in **Sections 7** and **8**, for the Project were compared to the appropriate standards as summarized in the tables listed below:

Table 6-1 Criteria Pollutant Significant Impact Levels
Table 6-13 PSD Increments
Table 6-14 Ambient Air Quality Standards

As stated previously for those pollutants and averaging periods determined to be less than the SILs, no further analysis was performed. With the exception of $PM_{2.5}$, for those pollutants and averaging periods with modeled impacts that exceed their respective SILs, cumulative modeling was conducted to demonstrate compliance with the PSD increments and NAAQS. $PM_{2.5}$ modeled impacts for the project alone are presented for informational purposes only since the $PM_{2.5}$ SILs are only allowed to be used for determining if a source has a significant concentration to a modeled violation. They cannot be used to avoid a cumulative impact analysis.

The air quality impact analysis addresses impact of secondary $PM_{2.5}$ and compliance with the ozone NAAQS as described in **Section 6.10**.

Compliance with the PSD increments and NAAQS was based on the sum of the following:

- Modeled impacts attributable to the Project.
- Modeled impacts from “nearby” sources.
- Representative ambient background concentration (NAAQS only).

Table 6-13: PSD Increments for PSD Class II Areas

Pollutant	Averaging Period	Class II PSD	Units	Form (Design)
NO_2	Annual	25	$\mu g/m^3$	Annual Mean not to be exceeded.
PM_{10}	24-hour	30	$\mu g/m^3$	Not to be exceeded more than once per year.
	Annual	17	$\mu g/m^3$	Annual Mean not to be exceeded.
$PM_{2.5}$	24-hour	9	$\mu g/m^3$	Not to be exceeded more than once per year.
	Annual	4	$\mu g/m^3$	Annual Mean not to be exceeded.
SO_2	3-hour	512	$\mu g/m^3$	Not to be exceeded more than once per year.
	24-hour	91	$\mu g/m^3$	Not to be exceeded more than once per year.
	Annual*	20	$\mu g/m^3$	Annual Mean not to be exceeded.
Source: 9 VAC 5-80-1635, 40 CFR 50, 64864 Federal Registrar - Vol 75 - No. 202				

Table 6-14: Ambient Air Quality Standards for PSD Class II Areas

Pollutant	Averaging Period	Class II NAAQS	Units	Form (Design)
CO	1-hour	40,000	μg/m^3	Not to be exceeded more than once per year.
	8-hour	10,000	μg/m^3	
NO_2	1-hour	188	μg/m^3	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years.
	Annual	100	μg/m^3	Annual mean.
PM_{10}	24-hour	150	μg/m^3	Not to be exceeded more than once per year on average over 3 years.
$PM_{2.5}$	24-hour	35	μg/m^3	98th percentile, averaged over 3 years.
	Annual	12	μg/m^3	Annual mean, averaged over 3 years.
SO_2	1-hour	196.5	μg/m^3	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
	3-hour	1,300	μg/m^3	Not to be exceeded more than once per year.
	24-hour	365	μg/m^3	Not to be exceeded more than once per year.
	Annual	80	μg/m^3	Annual Mean.
Ozone	8-hour	70	ppb	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years
Source: 9 VAC 5 Chapter 30				

6.8 Background Air Quality and Pre-Construction Monitoring

Ambient air quality data are used to represent the contribution to total ambient air pollutant concentrations from non-modeled sources. In accordance with 40 CFR 52.21(m), an application for a PSD permit must contain an analysis of ambient air quality in the vicinity of the proposed Project for each pollutant subject to PSD review. The objective of reviewing these data is to develop representative background concentrations which, when added to modeled impacts, are used in the NAAQS compliance analysis.

The representative background concentrations contained in **Table 6-15** were used for this Project. **Table 6-15** summarizes background concentrations that was used as part of the NAAQS modeling demonstration as applicable. This data is based on observations over a three year period of 2014-2016. The design concentration values listed in **Table 6-15** were added to the modeled design concentration to estimate the total impact, for applicable pollutants.

For this application a refinement was made to the ambient background data for NO_2 NAAQS modeling. In accordance with US EPA guidance in the March 1, 2011 Clarification Memo[25], seasonal and hour of day background concentrations were used when pairing the modeled and monitored concentrations.

[25] http://www.epa.gov/ttn/scram/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

Table 6-16 shows the resultant seasonal and hour of day varying background used as input to AERMOD in units of ppb based on monitoring data from 2015-2017.

Table 6-15: Monitored Background Concentrations (2014-2016 Design Concentrations) (VA DEQ 2016 Ambient Monitoring Report[26])

Pollutant	Averaging Period	Concentration	Units	Location (AQS ID)	State
PM_{10}	24-hour	23	$\mu g/m^3$	Woodson Middle School (51-670-0010)	VA
$PM_{2.5}$	24-hour	16	$\mu g/m^3$	Shirley Plantation (51-036-0002)	VA
	Annual	7.3	$\mu g/m^3$	Shirley Plantation (51-036-0002)	VA
NO_2	1-hour	42	ppb	Shirley Plantation (51-036-0002)	VA
	Annual	5	ppb	Shirley Plantation (51-036-0002)	VA
CO	1-hour	1.5	ppm	Math & Science Center (51-087-0014)	VA
	8-hour	1.2	ppm	Math & Science Center (51-087-0014)	VA
SO_2	1-hour	27	ppb	Shirley Plantation (51-036-0002)	VA
	3-hour	33.6	ppb	Shirley Plantation (51-036-0002)	VA
	24-hour	6.2	ppb	Shirley Plantation (51-036-0002)	VA
	Annual	0.5	ppb	Shirley Plantation (51-036-0002)	VA
Ozone	8-hour	63	ppb	Shirley Plantation (51-036-0002)	VA

For NO_2, SO_2, and $PM_{2.5}$, the Shirley Plantation background monitor is located in Charles City County (same as the Project) within 14 kilometers and generally downwind of the proposed Project site or upwind of the industrialized area in Hopewell, VA. Shirley Plantation should be very representative of background air quality data for the proposed Project site.

The Woodson Middle School PM_{10} background monitor is located downwind of the proposed Project at about 20 km away in Hopewell City and is adjacent to the industrialized area in Hopewell, VA. Based on 2014 National Emission Inventory (NEI) data, the PM_{10} emissions density in Hopewell City is about 90 tons/square mile compared to only about 4 tons/square mile in Charles City. This would make the Woodson Middle School monitor conservatively representative of the Project site. Similarly, the CO emissions density in Henrico County is about 198 tons/square mile compared to only about 13 tons/square mile in Charles City. This would make the Math & Science Center CO monitor conservatively represent background air quality for the proposed project site. In addition, the proposed Project site is located in a

[26] http://www.deq.virginia.gov/Portals/0/DEQ/Air/AirMonitoring/Annual_Report_2016.pdf

more rural area within a population density of 40 pop/mi^2 as compared to the location of the CO monitor, which has a population density in Henrico County of 1,313 pop/mi^2.[27]

Table 6-16: Season and Hour of Day Varying Background NO_2 Design Concentrations (ppb) for the Shirley Plantation Monitor

Hour of Day	Season 1	Season 2	Season 3	Season 4
	(Dec-Jan-Feb)	(Mar-Apr-May)	(Jun-Jul-Aug)	(Sep-Oct-Nov)
1	19.6	27.1	21.4	14.3
2	21.3	22.1	18.1	14.5
3	23.9	22.1	18.2	15.4
4	27.2	21.7	16.7	14.4
5	23.5	22.7	17.0	14.8
6	18.6	21.3	18.2	13.6
7	17.2	25.5	16.1	11.6
8	19.1	18.2	18.3	11.5
9	17.3	15.3	17.7	15.7
10	18.6	11.7	11.8	13.1
11	18.4	9.0	9.9	14.9
12	15.0	5.7	9.8	10.9
13	13.6	5.7	6.8	10.3
14	15.0	5.3	6.9	9.9
15	12.3	6.3	6.9	10.6
16	15.1	7.0	7.5	9.6
17	13.8	9.0	6.6	10.3
18	17.1	12.8	8.0	13.4
19	19.4	19.3	12.7	12.9
20	21.4	26.9	14.7	16.2
21	19.0	25.8	20.5	15.2
22	17.2	23.2	21.5	16.4
23	19.8	20.1	20.2	15.8
24	21.4	27.4	19.9	17.5

6.9 Pre-construction Monitoring

The PSD regulations require that a PSD permit application contain an analysis of existing air quality for all regulated pollutants that the source has the potential to emit in significant amounts. The definition of existing air quality can be satisfied by air measurements from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of

[27] https://www.census.gov/quickfacts/table/PST045215/51036,51087

the proposed source. To fulfill the pre-construction monitoring requirement for PSD without conducting on-site monitoring a source may either:

1. Justify that data collected from existing monitoring sites are conservatively representative of the air quality in the vicinity of the proposed Project site; or

2. Demonstrate through modeling the ambient impacts from the proposed Project is less than the de minimis levels established by the US EPA (see **Table 6-17**).

As such, if the source-only modeled impacts are greater than the de minimis monitoring concentrations found in **Table 6-17**, the proposed Project proposes to use the background air quality data summarized in **Section 6.8** to quantify existing air quality for the proposed Project site.

Table 6-17: De Minimis Monitoring Concentrations

Pollutant	Averaging Time		
	Annual *µg/m³*	**24-hour** *µg/m³*	**8-hour** *µg/m³*
NO_2	14	-	-
CO	-	-	575
PM_{10}	-	10	-
SO_2	-	13	-
O_3	-	-	VOC emission increase > 100 TPY

6.10 Secondary $PM_{2.5}$ and Ozone - Approach

In December 2016, US EPA released the draft *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program (EPA-454/R-16-006)* [28] (US EPA MERP Guidance).

As US EPA has noted in its MERP Guidance, the Tier 1 approach for estimating ozone and secondary $PM_{2.5}$ concentrations from new proposed sources can utilize estimates based upon existing modeling information. The MERPs are one form of the Tier 1 approach for which estimated concentrations below the SILs for various source types and emission strengths throughout the country are sufficient grounds to exempt the source from modeling. However, if the Project emissions are above the MERPs, then the Tier 1 information should be considered a relevant and conservative indicator of the source's impact for the PSD assessment without the need for new modeling if the result is acceptable.

In the January 2017 Guidance on the Use of Models for Assessing the Impacts of Emissions from Single Sources on the Secondarily Formed Pollutants: Ozone and PM2.5, US EPA suggests that a Tier I type of demonstration can be developed for a project using the following: (1) existing modeling data,

[28] https://www3.epa.gov/ttn/scram/guidance/guide/EPA454_R_16_006.pdf

(2) the relationship of the modeled precursor emissions and resultant ozone concentrations of that model, and (3) the project precursor emissions.

In this case, Project ozone and secondary $PM_{2.5}$ concentration were extrapolated based on the modeled ozone concentration and a ratio of the Project emissions over the modeled emissions. This provides a very conservative estimate of the project-specific modeled ozone and secondary $PM_{2.5}$ concentrations. For this application, the modeling results found in Appendix A of US EPA's MERP Guidance that provides estimated ozone and secondary $PM_{2.5}$ concentrations for hypothetical sources was used as a Tier 1 approach to estimate the Project's ozone and secondary $PM_{2.5}$ concentration.

In order to determine the Project's ozone and secondary $PM_{2.5}$ concentrations, the closest hypothetical site modeled by US EPA with modeled ozone and secondary $PM_{2.5}$ concentrations found in Appendix A of EPA's MERP Guidance is located in Dinwiddie, VA. This site should be reasonably representative of the Project location.

The resultant US EPA-modeled ozone and secondary $PM_{2.5}$ concentrations for the Dinwiddie, VA site, along with the modeled precursor emission levels, are provided in **Table 6-18**. Since this is an elevated source, the US EPA results for the "H" source was utilized.

Table 6-18 also shows the combined Project ozone and secondary $PM_{2.5}$ concentrations by scaling the US EPA modeled concentrations by a ratio of Project emissions over the US EPA-modeled emissions, respectively. Secondary $PM_{2.5}$ and ozone concentrations were estimated for both the GE 7HA.02 and MHPS M501JAC turbine options. The calculation of secondary $PM_{2.5}$ and ozone impacts also accounted for the C4GT project which has not been constructed and is not reflected in the ambient monitoring data used to estimate impact from sources already operating in the air shed.

The Project secondary $PM_{2.5}$ concentration calculated in **Table 6-18** was added to modeled AERMOD concentrations to demonstrate compliance with the NAAQS and PSD increments as applicable.

Table 6-18: Project Estimated Ozone and Secondary $PM_{2.5}$ Concentrations

Pollutant	Averaging Period	NO_X				SO_2				Project Secondary Modeled Concentration ($\mu g/m^3$)
		EPA Precursor Emissions (TPY)	EPA Modeled Concentration ($\mu g/m^3$)	Project Precursor Emissions (TPY)	Project Modeled Concentration ($\mu g/m^3$)	EPA Precursor Emissions (TPY)	EPA Modeled Concentration ($\mu g/m^3$)	Project Precursor Emissions (TPY)	Project Modeled Concentration ($\mu g/m^3$)	
Chickahominy Power Station – GE Option										
$PM_{2.5}$	24-hour	500	0.09	367.2	0.07	500	0.27	55.3	0.03	0.096
	Annual	500	0.002	367.2	0.001	500	0.007	55.3	0.001	0.002
Chickahominy Power Station – MHPS Option										
$PM_{2.5}$	24-hour	500	0.09	407.1	0.07	500	0.27	62	0.03	0.107
	Annual	500	0.002	407.1	0.002	500	0.007	62	0.001	0.002
C4GT										
$PM_{2.5}$	24-hour	500	0.09	296	0.05	500	0.27	39	0.02	0.074
	Annual	500	0.002	296	0.001	500	0.007	39	0.001	0.002
Total GE 24-hour Secondary $PM_{2.5}$										**0.170**
Total GE Annual Secondary $PM_{2.5}$										**0.004**
Total MHPS 24-hour Secondary $PM_{2.5}$										**0.181**
Total MHPS Annual Secondary $PM_{2.5}$										**0.004**

Pollutant	Averaging Period	NO_X				VOC				Project Ozone Modeled Concentration (ppb)
		EPA Precursor Emissions (TPY)	EPA Modeled Concentration (ppb)	Project Precursor Emissions (TPY)	Project Modeled Concentration (ppb)	EPA Precursor Emissions (TPY)	EPA Modeled Concentration (ppb)	Project Precursor Emissions (TPY)	Project Modeled Concentration (ppb)	
Chickahominy Power Station – GE Option										
Ozone	8-hour	500	2.01	367.2	1.48	500	0.07	74.1	0.01	1.49
Chickahominy Power Station – MHPS Option										
Ozone	8-hour	500	2.01	407.1	1.64	500	0.07	211	0.03	1.67
C4GT										
Ozone	8-hour	500	2.01	296	1.19	500	0.07	114	0.02	1.21
									Total GE Ozone	**2.69**
									Total MHPS Ozone	**2.87**

7.0 Class II Area Significant Impact Level Analysis Results

In this section, results of the air quality impact analyses for the Project alone are presented. These air quality analyses were conducted using the inputs and methodologies described in **Section 6** of this report. Discussions to be found in this section include the estimated impacts of the Project as they relate to Significant Impact Levels. All modeling input and output files are included in **Appendix F**.

7.1 Normal Operation

The first step in an air quality analysis is to determine if the Project will result in significant impacts for any criteria pollutant. **Section 6** contains a discussion of the pollutant specific criteria for determination of significant impacts. The Federal SILs are presented in **Table 6-1**. SILs define the impact thresholds that establish the complexity of the air quality analysis required to support the permitting of a new or modified facility. A refined modeling analysis, consisting of a cumulative impact study, must be conducted for each pollutant predicted to exceed its respective SIL. If results of the modeling analysis demonstrate that all maximum impacts are less that the SILs, then a cumulative evaluation is not required for criteria pollutants.

Note that the modeling reflects the following operational restrictions/assumptions:

- The annual emission rate for the combined-cycle turbines is based on 8,760 hours per year.
- The auxiliary boilers and fuel gas heaters will operate up to 8,760 hours per year.
- The diesel-fired fire-water pump and diesel-fired emergency generator are expected to operate 100 hours per year per unit (operability testing, typically 1 hour per week intermittently) and no more than 500 hours per year.

For all short-term modeled pollutants and averaging periods (except 1-hour SO_2 and NO_2), modeled emission rates for the diesel generator and the fire-water pump engine were normalized based on 1 hour of operation within the averaging periods. Similarly, the annual emission rates were annualized based on the 500 hours per year for these units. These units were not included in the 1-hour SO_2 and NO_2 modeling based on guidance from US EPA for modeling intermittent sources (US EPA, 2011).

Table 7-1 and **Table 7-2** provide summaries of the AERMOD modeling results for the Class II Cartesian grid and fence line receptors for the GE 7HA.02 and MHPS M501JAC turbine options respectively. For each turbine option, these tables present the maximum modeled ground level concentrations at each of the three operating loads for the Cartesian receptor grid for NO_2 (1-hour and annual), SO_2 (1-, 3, 24-hour and annual), PM_{10} (24-hour and annual), $PM_{2.5}$ (24-hour and annual), and CO (1- and 8-hour). Also, for each turbine option, each of the three load groups include the three combined-cycle combustion turbines at the respective load, two auxiliary boilers, three fuel gas heaters, diesel-fired fire-water pump (except 1-hour SO_2 and NO_2), and diesel-fired emergency generator (except 1-hour SO_2 and NO_2).

Table 7-1: AERMOD SIL Modeling Results – Normal Operations GE 7HA.02 Turbine Option

Pollutant	Averaging Period	Modeled Concentration (μg/m³)				SIL (μg/m³)	Significant? (Yes or No)
		100% Load	75% Load	30-40% Load	Maximum		
NO_2	1-hour	17.63	17.63	17.63	17.63	7.5	Yes
	Annual	2.04	2.04	2.04	2.04	1	Yes
SO_2	1-hour	2.70	2.63	2.62	2.70	7.9	No
	3-hour	2.05	2.36	2.47	2.47	25	No
	24-hour	1.04	1.02	1.25	1.25	5	No
	Annual	0.07	0.07	0.08	0.08	1	No
PM_{10}	24-Hour	6.52	6.52	6.52	6.52	5	Yes
	Annual	0.47	0.47	0.47	0.47	1	No
$PM_{2.5}$	24-Hour	4.61	4.61	5.29	5.29	--	Yes
	Annual	0.42	0.42	0.42	0.42	--	Yes
CO	1-Hour	552.82	552.82	552.82	552.82	2,000	No
	8-Hour	44.31	44.31	44.31	44.31	500	No

Table 7-2: AERMOD SIL Modeling Results – Normal Operations MHPS M501JAC Turbine Option

Pollutant	Averaging Period	Modeled Concentration (μg/m³)				SIL (μg/m³)	Significant? (Yes or No)
		100% Load	75% Load	50% Load	Maximum		
NO_2	1-hour	19.54	19.97	19.54	19.97	7.5	Yes
	Annual	2.08	2.08	2.08	2.08	1	Yes
SO_2	1-hour	3.10	3.19	2.95	3.19	7.9	No
	3-hour	2.30	2.75	2.77	2.77	25	No
	24-hour	1.30	1.30	1.30	1.30	5	No
	Annual	0.08	0.08	0.08	0.08	1	No
PM_{10}	24-Hour	8.04	8.04	8.04	8.04	5	Yes
	Annual	0.49	0.49	0.49	0.49	1	No
$PM_{2.5}$	24-Hour	6.04	6.04	6.04	6.04	--	Yes
	Annual	0.44	0.44	0.44	0.44	--	Yes
CO	1-Hour	552.83	552.83	552.83	552.83	2,000	No
	8-Hour	53.96	53.96	53.96	53.96	500	No

7.2 Startup/Shut Down Operations

Modeling analyses were also conducted for startup/shut down operations as described in **Section 6.2.2**. **Table 7-3** and **Table 7-4** provide a summary of the maximum modeled ground level concentrations for the Class II Cartesian grid and fence line receptors for the GE 7HA.02 and MHPS M501JAC turbine options, respectively.

The modeling was conducted using the emissions and stack parameters referenced in **Section 6.2.2**.

Table 7-3: AERMOD SIL Modeling Results – Startup/Shutdown Operations GE 7HA.02 Turbine Option

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Significant? (Yes or No)
NO_2	1-hour	141.82	7.5	Yes
CO	1-Hour	968.88	2,000	No
	8-Hour	102.40	500	No

Table 7-4: AERMOD SIL Modeling Results – Startup/Shutdown Operations MHPS M501JAC Turbine Option

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Significant? (Yes or No)
NO_2	1-hour	50.32	7.5	Yes
CO	1-Hour	552.84	2,000	No
	8-Hour	53.96	500	No

7.3 Summary of Significant Impact Analysis

A comparison of the overall maximum modeled ground level concentrations with the Class II Significant Impact Levels is presented in **Table 7-5** and **Table 7-6** for the GE 7HA.02 and MHPS M501JAC turbine options, respectively.

For each pollutant and averaging period, the table lists the maximum predicted concentration and worst-case turbine operating loads during the normal operations or startup/shutdown operations.

Table 7-5: Summary of Maximum AERMOD Concentrations to Significant Impact Levels - GE 7HA.02 Turbine Option

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Load Case	SIL ($\mu g/m^3$)	Significant? (Yes or No)
NO_2	1-hour	141.82	SUSD	7.5	Yes
	Annual	2.04	30%-40% Load	1	Yes
SO_2	1-hour	2.70	100% Load	7.9	No
	3-hour	2.47	30%-40% Load	25	No
	24-hour	1.25	30%-40% Load	5	No
	Annual	0.08	30%-40% Load	1	No
PM_{10}	24-Hour	6.52	100% Load	5	Yes
	Annual	0.47	30%-40% Load	1	No
$PM_{2.5}$	24-Hour	5.29	30%-40% Load	--	--
	Annual	0.42	30%-40% Load	--	--
CO	1-Hour	968.88	SUSD	2,000	No
	8-Hour	102.40	SUSD	500	No

Table 7-6: Summary of Maximum AERMOD Concentrations to Significant Impact Levels - MHPS M501JAC Turbine Option

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Load Case	SIL ($\mu g/m^3$)	Significant? (Yes or No)
NO_2	1-hour	50.32	SUSD	7.5	Yes
	Annual	2.08	75% Load	1	Yes
SO_2	1-hour	3.19	75% Load	7.9	No
	3-hour	2.77	50% Load	25	No
	24-hour	1.30	100% Load	5	No
	Annual	0.08	75% Load	1	No
PM_{10}	24-Hour	8.04	100% Load	5	Yes
	Annual	0.49	50% Load	1	No
$PM_{2.5}$	24-Hour	6.04	50% Load	--	--
	Annual	0.44	50% Load	--	--
CO	1-Hour	552.84	SUSD	2,000	No
	8-Hour	53.96	SUSD	500	No

As is depicted in **Table 7-5** and **Table 7-6**, modeled concentrations for SO_2 1-, 3-, 24-hour, and annual, CO 1- and 8-hour, and PM_{10} annual are below their corresponding SILs for both turbine options. No further analyses were required for these pollutants and averaging periods. However, modeled concentrations for

1-hour and annual NO_2 and 24-hour PM_{10} are greater than the corresponding SIL. Therefore, a cumulative impact assessment for 1-hour and annual NO_2 and 24-hour PM_{10} was conducted as documented in **Section 8**. In addition, cumulative modeling was also performed for $PM_{2.5}$ 24-hour and annual as the use of the SIL for avoiding a cumulative impact analysis has been remanded.

The contours showing the maximum impacts across all the operating loads and the worst- case year consistent with the impacts shown in **Table 7-5** and **Table 7-6** are presented in **Appendix G** for all the criteria pollutants.

7.4 Pre-Construction Monitoring

Table 7-7 and **Table 7-8** present a comparison of the Project's highest predicted impacts with the monitoring exemption concentrations for the GE 7HA.02 and MHPS M501JAC turbine options respectively. The modeled concentrations are below the monitoring exemption concentrations for all pollutants except $PM_{2.5}$. The VA DEQ monitoring network was used to satisfy the requirement for pre-construction monitoring for $PM_{2.5}$ concentrations for the project. As such, PSD pre-construction monitoring for $PM_{2.5}$ is not required for this project.

As stated in **Section 6.9**, the VOC emissions increase exceeds the 100 TPY de minimis trigger requiring the Application address pre-construction monitoring for ozone. Similar to $PM_{2.5}$, the Application utilized existing monitoring data to satisfy the requirement for pre-construction monitoring for the Project. As such, PSD pre-construction monitoring for ozone is not required for this project.

Table 7-7: Comparison of Predicted Impacts with Monitoring Exemption Concentrations - GE 7HA.02 Turbine Option

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)(1)	De Minimis Monitoring Concentration ($\mu g/m^3$) (2)
NO_2	Annual	2.04	14
SO_2	24-Hour	1.25	13
CO	8-Hour	102.40	575
PM_{10}	24-Hour	6.52	10

(1) Highest impacts from AERMOD Modeling (from **Table 7-5**)
(2) 9 VAC 5-80-1695 E

Table 7-8: Comparison of Predicted Impacts with Monitoring Exemption Concentrations - MHPS M501JAC Turbine Option

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)(1)	De Minimis Monitoring Concentration ($\mu g/m^3$) (2)
NO_2	Annual*	2.08	14
SO_2	24-Hour	1.30	13
CO	8-Hour	53.96	575
PM_{10}	24-Hour	8.04	10

(1) Highest impacts from AERMOD Modeling (from **Table 7-6**)
(2) 9 VAC 5-80-1695 E

8.0 Class II Area Cumulative Impact Assessment Results

8.1 Methodology for the Cumulative Impact Assessment

As demonstrated in **Section 7**, a cumulative impact assessment is required for 1-hour and annual NO_2, 24-hour PM_{10}, and 24-hour and annual $PM_{2.5}$ for both the GE 7HA.02 and MHPS M501JAC turbine options. The sections that follow describe the methods that were used to compile the data and perform the multi-source modeling analysis.

8.2 Modeling Approach

The area to be assessed for compliance with the PSD increment and NAAQS was limited to the areas where the Project has a significant air quality impact. Listed below is a general summary of the multi-source modeling that was performed for compliance with the NAAQS and PSD increment consumption. A conservative approach for the PSD increment analysis was followed. All the background sources that were modeled as NAAQS sources were also considered to be PSD increment-consuming sources with the exception of $PM_{2.5}$ PSD increment. The only additional source included in the $PM_{2.5}$ PSD increment analysis was C4GT.

The steps followed to perform the cumulative modeling are as follows for both turbine options:

- The background source inventories were developed with the assistance of the VA DEQ. The complete background emission inventory is provided (along with the other modeling files) in **Appendix F**.
- AERMOD was used to model the background sources along with the Project sources.
- The modeling results were compared to NAAQS and PSD increments to determine compliance. The appropriate regional background concentrations for the NAAQS compliance demonstration were obtained from VA DEQ as summarized **Section 6.8**. The background component of the NAAQS analysis is designed to account for distant or minor sources that were not explicitly modeled.
- Secondary $PM_{2.5}$ concentrations estimated using methodology outlined in **Section 6.10** were added to the model components to estimate the total Project $PM_{2.5}$ concentration. The regional background $PM_{2.5}$ represents both primary and secondary components from the nearby sources.

8.3 Application of the Multi-Source Modeling Analysis

As stated previously for those pollutants and averaging periods determined to be less than the SILs, no further analysis was performed. The discussion below applies only to those pollutants and averaging periods for which significant impacts were predicted with AERMOD for both turbine options.

Compliance with the PSD increments and NAAQS was based on the sum of the following:

- Modeled impacts attributable to the Project.
- Modeled impacts from “nearby” sources.

- Representative ambient background concentration (NAAQS only).

Impacts attributable to Project and "nearby" sources were both modeled with AERMOD.

For the Project sources, the same stack parameters and emission rates (see **Section 6** for details) used for the SIL modeling were used for the cumulative impact analyses. All Project load cases assessed for the SIL analyses (including SUSD cases) were also included in the cumulative impacts analyses. In addition, the same set of meteorological data from the SIL analysis was used for the cumulative impact analysis.

For the cumulative impact analysis, the modeled design short-term and annual impacts from the Project and background sources were compared with the NAAQS and PSD increments. For NAAQS modeling, a background concentration (see **Table 6-15**) was added to modeled design short-term and annual impacts to determine compliance. As noted, the project secondary $PM_{2.5}$ concentrations estimated using methodology outlined in **Section 6.10** were added to the model components to estimate the total project $PM_{2.5}$ concentration. The regional background $PM_{2.5}$ represents both primary and secondary components from other nearby sources.

The same modeling procedures and applications described above were applied to the PSD Increment analysis, with the exception that monitored background concentrations were not added to the modeled impacts for the PSD Increment compliance evaluation.

8.4 Results of the Multi-Source Modeling Analysis

The results of the multi-source modeling analysis are presented in the following sub-sections for both turbine options.

8.4.1 Summary of NAAQS Analysis

A summary of the NAAQS analysis is presented in **Table 8-1** and **Table 8-2** for the GE 7HA.02 and MHPS M501JAC turbine options respectively. The predicted impacts for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$, and 24-hour PM_{10} are less than the NAAQS. The results of the cumulative modeling analysis show that the Project will be in compliance with the applicable NAAQS standards.

Table 8-1: Summary of NAAQS Analysis - GE 7HA.02 Combustion Turbine

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Monitored Background Concentration ($\mu g/m^3$) (1)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Complies (Yes/No)?
NO_2	1-hour	180.23	season and hour of day varying	180.23	188	Yes
	Annual	3.58	9.4	12.98	100	Yes
$PM_{2.5}$	24-hour	2.90 (primary) 0.170 (secondary) **3.07 (total)**	16	19.07	35	Yes

Pollutant	Averaging Period	Modeled Concentration (μg/m³)	Monitored Background Concentration (μg/m³) (1)	Total Concentration (μg/m³)	NAAQS (μg/m³)	Complies (Yes/No)?
	Annual	0.63 (primary) 0.004 (secondary) **0.63 (total)**	7.3	7.93	12	Yes
PM_{10}	24-hour	5.08	23	28.08	150	Yes
(3) Monitored background concentrations are taken from **Table 6-15** except for 1-hour NO_2 which used seasonal and hour of day background from **Table 6-16**.						

Table 8-2: Summary of NAAQS Analysis - MHPS M501JAC Combustion Turbine

Pollutant	Averaging Period	Modeled Concentration (μg/m³)	Monitored Background Concentration (μg/m³) (1)	Total Concentration (μg/m³)	NAAQS (μg/m³)	Complies (Yes/No)?
NO_2	1-hour	134.57	season and hour of day varying	134.57	188	Yes
	Annual	3.63	9.4	13.03	100	Yes
$PM_{2.5}$	24-hour	3.42 (primary) 0.181 (secondary) **3.60 (total)**	16	19.60	35	Yes
	Annual	0.65 (primary) 0.004 (secondary) **0.65 (total)**	7.3	7.95	12	Yes
PM_{10}	24-hour	5.30	23	28.30	150	Yes
(1) Monitored background concentrations are taken from **Table 6-15** except for 1-hour NO_2 which used seasonal and hour of day background from **Table 6-16**.						

8.4.2 Summary of PSD Increment Consumption Analysis

A summary of the PSD Increment Analysis is presented in **Table 8-3** and **Table 8-4** for the GE 7HA.02 and MHPS M501JAC turbine options, respectively. The predicted impacts for annual NO_2, 24-hour and annual $PM_{2.5}$, and 24-hour PM_{10} are less than the PSD increments. The results of the PSD increment modeling analysis show that the Project will not exceed the allowable increments. Hence, the Project will be in compliance with the applicable PSD increments.

Table 8-3: Summary of PSD Increment Analysis - GE 7HA.02 Combustion Turbine

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	PSD Increments ($\mu g/m^3$)	Complies (Yes/No)?
NO_2	Annual	3.58	25	Yes
$PM_{2.5}$	24-hour	5.57 (primary) 0.170 (secondary) **5.74 (total)**	9	Yes
	Annual	0.52(primary) 0.004 (secondary) **0.52 (total)**	4	Yes
PM_{10}	24-hour	5.58	30	Yes

Table 8-4: Summary of PSD Increment Analysis - MHPS M501JAC Combustion Turbine

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	PSD Increments ($\mu g/m^3$)	Complies (Yes/No)?
NO_2	Annual	3.63	25	Yes
$PM_{2.5}$	24-hour	6.79 (primary) 0.181 (secondary) **6.97 (total)**	9	Yes
	Annual	0.54 (primary) 0.004 (secondary) **0.54 (total)**	4	Yes
PM_{10}	24-hour	6.86	30	Yes

8.5 Ozone NAAQS Analysis Results

The Project ozone concentration was estimated using MERP guidance and methodology described in **Section 6.10**. The Project-estimated ozone concentration (inclusive of C4GT) calculated in **Table 6-18** of 2.69 and 2.87 ppb, respectively for the GE 7HA.02 and MHPS M501JAC turbine options, was added to the design concentration from a representative monitor. Per direction from VA DEQ, the most representative ozone monitor is the Shirley Plantation monitor (see **Table 6-15** for design concentration) and has a 2014-2016 design concentration of 63 ppb. The total ozone concentrations of 65.69 ppb (2.69 ppb + 63 ppb) and 65.87 ppb (2.87 ppb + 63 ppb), respectively for the GE 7HA.02 and MHPS M501JAC turbine options, are compliance with the NAAQS.

9.0 Additional Impact Analysis

In accordance with 9 VAC 5-80-1755, additional impacts must be addressed for projects subject to PSD review. The various components of the additional impact analyses are discussed below.

9.1 Class I Area Analysis

Based on communications with the National Park Service (NPS), United States Forest Service (USFS) and United States Fish and Wildlife Service (FWS), an AQRV analysis (including regional haze) is not being requested for this Project based on the low ratio of proposed emissions (Q) relative to the large distances (D) from the proposed Project location to the nearest Class I areas. The Q/D ratio for each class I area is presented in **Table 9-1**. As shown in **Table 9-1**, the proposed Project's short-term Q/D is less than 10 which is the recommended screening exemption level in the Federal Land Managers' Air Quality Related Values Work Group Phase 1 Report (Revised 2010) (FLAG, 2010). Therefore, the proposed Class I area Analysis addresses only PSD increment consumption at the nearby Class I areas. Appendix C of the Modeling Protocol contained communications from the NPS, USFS, and FWS regarding their intentions not to request an AQRV analysis or comment any further on the permitting of this proposed Project.

There are five Class I areas within 300 km of the proposed Project site. These Class I areas are as follows:

1. Shenandoah National Park, approximately 153 km away
2. James River Face Wilderness Area, approximately 205 km away
3. Swanquarter National Wildlife Refuge, approximately 244 km away
4. Dolly Sods Wilderness Area, approximately 254 km away
5. Otter Creek Wilderness Area, approximately 273 km away

Figure 9-1 shows the location of the Class I areas in relationship to the proposed Project site.

As stated, this Class I area analysis addresses only PSD increment consumption at the five Class I areas noted above. In accordance with Appendix W (Section 4.2.c.i), since AERMOD (Version 18081) is being used for the Project's nearfield assessment, it can be utilized in a screening-level analysis to estimate the Project's potential for a significant modeled impact at the PSD Class I areas.

As such, AERMOD was used as a screening tool with the meteorological data described in **Section 6.6** along with a radial arc of receptors located 50 kilometers from the Project. Receptors along the 50-kilometer arc were placed every 1 degree and conservatively cover 360 degrees around the CIPGS. The emission inputs and stack parameters used for the Class I area modeling are the same as those used for the Class II Area SIL modeling.

The modeled concentrations along the 50-kilometer arc of receptors were then modeled compared to the Class I area SILs (shown in **Table 9-2**) for both turbine options. The secondary $PM_{2.5}$ concentrations described in **Section 6.10** were also included to estimate the total $PM_{2.5}$ concentration.

The results of the Class I area SIL modeling (using AERMOD), shown in **Table 9-3** and **Table 9-4** for the GE 7HA.02 and MHPS M501JAC turbine options, respectively, shows the maximum modeled concentration of SO_2, NO_2, PM_{10}, and $PM_{2.5}$ compared to the Class I area SILs. The maximum modeled concentrations for all pollutants and averaging periods are less than their respective SILs, thus no additional modeling is required to demonstrate compliance with the Class I area PSD increments.

Table 9-1: Class I Q/D Ratios

Class I Area	Project Emissions(1) of SO_2,H_2SO_4, NO_X, and PM_{10} (TPY)	Distance from Proposed Project (km)	Q/D Ratio
Shenandoah National Park,	SO_2 = 62.0 H_2SO_4 = 64.3 NO_X = 394.8 PM_{10} / $PM_{2.5}$ = 167.9 **Total = 689.0**	153	4.5
James River Face Wilderness Area		205	3.4
Swanquarter National Wildlife Refuge		244	2.8
Dolly Sods Wilderness Area		254	2.7
Otter Creek Wilderness Area		273	2.5

(1) Project emission represent worst-case (the MHPS M501JAC turbines) short-term potential converted to TPY assuming 8760 hrs/yr for all three combustion turbines at base load, three fuel gas heaters, and two the auxiliary boilers.

Table 9-2: Criteria Pollutant Class I Significant Impact Levels

Pollutant	Averaging Time (1)		
	Annual *µg/m³*	**24-hour** *µg/m³*	**3-hour** *µg/m³*
NO_2	0.1	-	-
PM_{10}	0.2	0.3	-
$PM_{2.5}$	0.05	0.27	-
SO_2	0.1	0.2	1

(1) High 1st high modeled concentration.

Figure 9-1: Class I Areas within 300 km of the Proposed Project Site

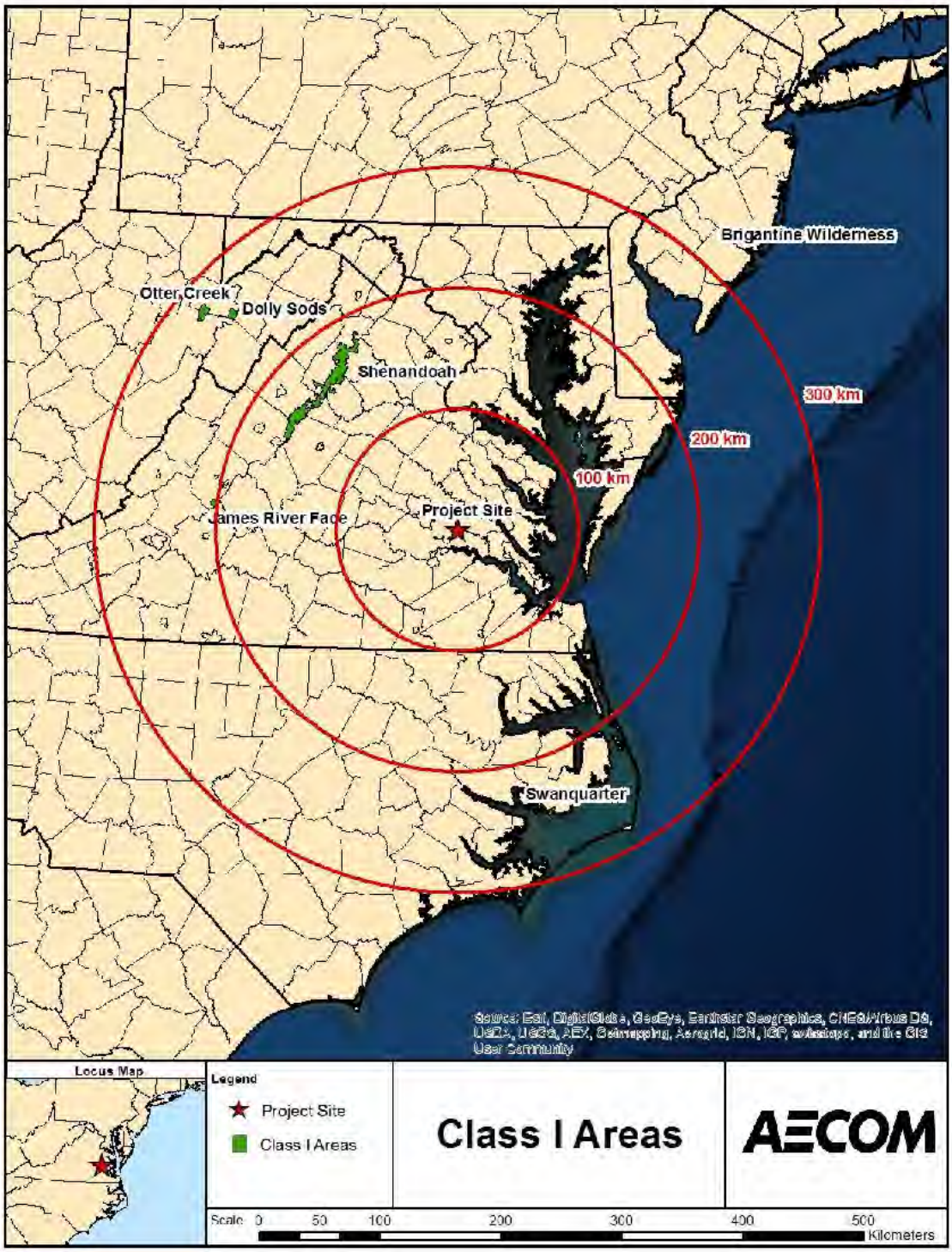


Table 9-3: AERMOD Class I Area SIL Modeling Results - GE 7HA.02 Combustion Turbine

Pollutant	Averaging Period	Maximum Modeled AERMOD Concentrations for Each Load (µg/m³)				USEPA Class I SIL (µg/m³)	Significant? (Yes or No)
		100%	75%	30-40%	Worst-Case Load		
NO_2	Annual	0.02	0.02	0.01	0.02	0.1	No
PM_{10}	24-hr	0.09	0.09	0.09	0.09	0.3	No
	Annual	0.01	0.01	0.01	0.01	0.2	No
$PM_{2.5}$	24-hr	0.09	0.09	0.09	0.09 (primary) 0.096 (secondary) 0.19 (total)	0.27	No
	Annual	0.01	0.01	0.01	0.01 (primary) 0.002 (secondary) 0.01 (total)	0.05	No
SO_2	3-hr	0.11	0.10	0.08	0.11	1.0	No
	24-hr	0.03	0.02	0.02	0.03	0.2	No
	Annual	0.003	0.002	0.002	0.003	0.1	No

Table 9-4: AERMOD Class I Area SIL Modeling Results - MHPS M501JAC Combustion Turbine

Pollutant	Averaging Period	Maximum Modeled AERMOD Concentrations for Each Load (µg/m³)				USEPA Class I SIL (µg/m³)	Significant? (Yes or No)
		100%	75%	50%	Worst-Case Load		
NO_2	Annual	0.02	0.02	0.02	0.02	0.1	No
PM_{10}	24-hr	0.09	0.09	0.10	0.10	0.3	No
	Annual	0.01	0.01	0.01	0.01	0.2	No
$PM_{2.5}$	24-hr	0.09	0.09	0.10	0.10 (primary) 0.107 (secondary) 0.21 (total)	0.27	No
	Annual	0.01	0.01	0.01	0.01 (primary) 0.002 (secondary) 0.01 (total)	0.05	No
SO_2	3-hr	0.13	0.12	0.10	0.13	1.0	No
	24-hr	0.03	0.03	0.02	0.03	0.2	No
	Annual	0.003	0.003	0.002	0.003	0.1	No

9.2 Visible Plume Analysis

Federal Land Managers' Air Quality Related Values Work Group Phase 1 Report – Revised (2010) recommends that an analysis of visibility impairment (i.e., plume blight) at Class I areas within 50 kilometers of the proposed Project site. As discussed earlier and in **Section 9.1**, the nearest Class I area is more than 150 km of the proposed Project site. Therefore, a visible plume analysis is not warranted for any Class I areas. In addition, there are no Class II area protected vistas in the vicinity of the project.

The visibility in the area near the proposed facility will be protected by operational requirements such as air pollution controls and clean burning fuels, and stringent limits on visible emissions that will be incorporated into the air permit.

9.3 Growth Analysis

A growth analysis examines the potential emissions from secondary sources associated with the proposed Project. While these activities are not directly involved in Project operation, the emissions involve those that can reasonably be expected to occur; for instance, industrial, commercial, and residential growth that will occur in the Project area due to the Project itself. Secondary emissions do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of any on-road motor vehicle or the propulsion of a train (US EPA 1990). They also do not include sources that do not impact the same general area as the source under review.

The work force expected for the Project will range from 400 to 1,100 jobs during various phases of construction. It is expected that a significant regional construction force is already available to build the Project. Therefore, it is expected that no new housing, commercial or industrial construction will be necessary to support the Project during the two-year construction schedule. The Project will also require approximately 40 to 45 permanent positions. Individuals that already live in the region will perform a number of these jobs. For any new personnel moving to the area, no new housing requirements are expected. Further, due to the small number of new individuals expected to move into the area to support the Project and existence of some commercial activity in the area, new commercial construction will not be necessary to support the Project's permanent work force. In addition, no significant level of industrial related support will be necessary for the Project, thus industrial growth is not expected.

Based on the growth expectations above, no new significant emissions from secondary growth during Project construction and operation are anticipated.

9.4 Soils and Vegetation Analysis

The screening methodology provided in the US EPA's guidance document for soils and vegetation, "*A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA 450/2-81-078)",* was supplemented with a more robust soils and vegetation analysis for the Project.

Vegetation Analysis

For both turbine options, as an indication of whether emissions from the proposed Project will significantly impact the surrounding vegetation (i.e., cause acute or chronic exposure to each evaluated pollutant), the modeled emission concentrations were compared against both a range of injury thresholds found in various peer-reviewed research articles that specifically examine effects of different pollutants on vegetation as well as established NAAQS secondary standards. Since the NAAQS secondary standards were set to protect public welfare, including protection against damage to crops and vegetation, comparing the modeled emissions to these standards provides an indication as to whether potential impacts are likely

to be significant. However, given that secondary standards for some criteria pollutants are under review, comparison to the secondary NAAQS may not be definitive.

For the vegetation analysis, modeled concentrations of SO_2, NO_x, PM_{10}, and CO for both turbine options were compared against the vegetation sensitivity thresholds listed in the aforementioned 1980 US EPA guidance, secondary NAAQS, and plant injury thresholds found in the literature. **Table 9-5** illustrates injury threshold ranges determined through a review of readily available research. The same meteorological data and Cartesian grid (20-km extent) as described in **Section 6** was used for the vegetation analysis.

As shown in **Table 9-6** and **Table 9-7** for the GE 7HA.02 and MHPS M501JAC turbine options, respectively, the results clearly indicate that no adverse impacts will occur to sensitive vegetation as a result of operation of the proposed Project.

Table 9-5: Injury Threshold for Vegetation

Pollutants	**Injury Threshold (Dose)[1]** (µg/*m*^{3})	**Secondary NAAQS** (µg/*m*^{3})	**US EPA's 1980 Screening Concentration[2]** (µg/ *m*^{3})
SO_2	131-5,240 (8 hour)	1,300 (3 hour)	18 (annual)
	1,310 (4 hour)		786 (3 hour)
	393-3,930 (2 hour)		917 (1 hour)
NO_x (as NO_2)	280 – 38,000 (1 hour to long term)940 (1 hour)	100 (annual)	94 (annual)
			3,760 (4 hour)
			564 (1 month)
PM (as PM_{10})	See NAAQS	150 (24 hour)	None
CO	None		1,800,000 (weekly)

1. Values, suggested in the Spiritwood Station PSD permit application.
2. "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals". EPA 450/2-81-078, December 1980

Table 9-6: Comparison to US EPA Criteria for Gaseous Pollutant Impacts on Natural Vegetation and Crops - GE 7HA.02 Combustion Turbine

Pollutant	Averaging Period	Maximum Impact of Proposed Facility Impact (µg/m³)	Minimum Impact Level for Effects On Sensitive Plants (µg/m³) (1)
SO_2	1-hour(2)	2.70	393
	3-hour	2.47	786
	Annual	0.08	18
NO_2	1-hour(2),(3)	17.63	280
	4-hour(3)	108.91	3,760
	1-month(3)	3.38	564
	Annual	2.04	94
PM_{10}	24-Hour	6.52	150
CO	1-week(4)	35.45	1,800,000

(1) Minimum Impact Level is the lowest threshold found in **Table 9-5**.
(2) Please note the 1-hour NO_2 and SO_2 concentration are the highest modeled concentrations.
(3) 1-hour NO_2 does not include emergency equipment to be consistent with the SIL analysis. However, 4-hour and 1-month concentrations include 1 hour of operation of emergency equipment in the averaging period.
(4) 24-hour average used to conservatively represent 1 week average impact.

Table 9-7: Comparison to US EPA Criteria for Gaseous Pollutant Impacts on Natural Vegetation and Crops - MHPS M501JAC Combustion Turbine

Pollutant	Averaging Period	Maximum Impact of Proposed Facility Impact (µg/m³)	Minimum Impact Level for Effects On Sensitive Plants (µg/m³) (1)
SO_2	1-hour(2)	3.19	393
	3-hour	2.77	786
	Annual	0.08	18
NO_2	1-hour(2),(3)	19.97	280
	4-hour(3)	108.94	3,760
	1-month(3)	3.44	564
	Annual	2.08	94
PM_{10}	24-Hour	8.04	150
CO	1-week(4)	42.94	1,800,000

(1) Minimum Impact Level is the lowest threshold found in **Table 9-5**.
(2) Please note the 1-hour NO_2 and SO_2 concentration are the highest modeled concentrations.
(3) 1-hour NO2 does not include emergency equipment to be consistent with the SIL analysis. However, 4-hour and 1-month concentrations include 1 hour of operation of emergency equipment in the averaging period.
(4) 24-hour average used to conservatively represent 1 week average impact.

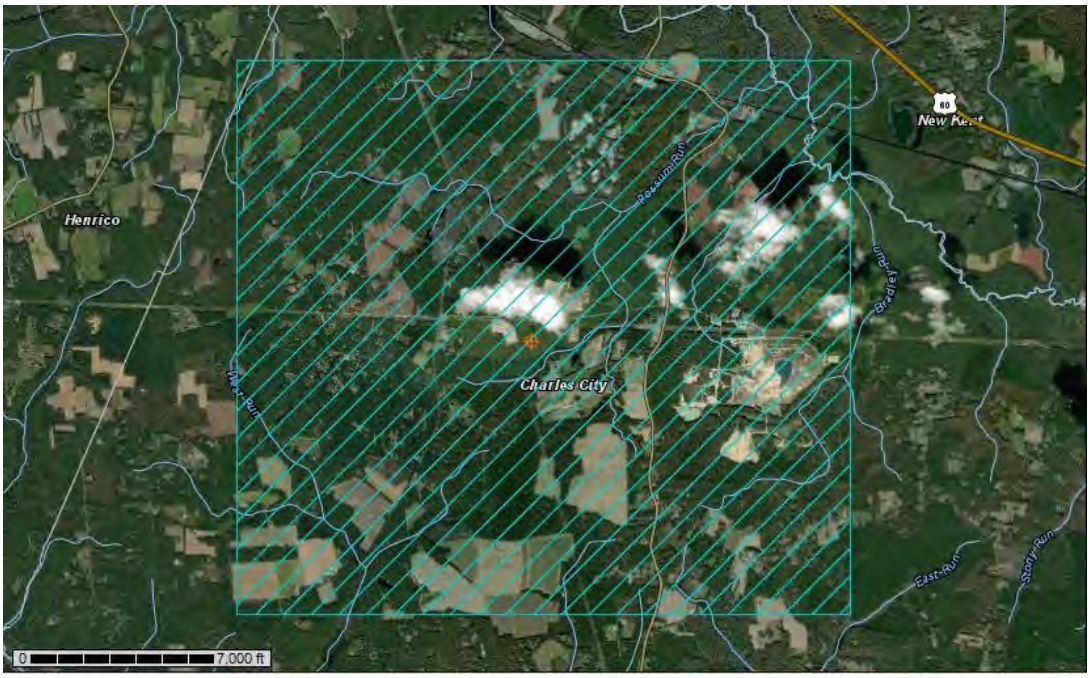
Soil assessment

To determine whether the project emissions could adversely affect the soil in the vicinity of the Project, the type of soil surrounding the Project site was reviewed. The soil type was determined from data collected from the US Department of Agriculture, National Resource Conservation Service's (NRCS), Soil Survey Geographic (SSGUGO) database[29] and the NRCS Web Soil Survey tool[30].

Soil types within Charles City, Henrico, and New Kent Counties were examined using information taken from the SSGUGO database. These counties were chosen because the Project site is within Charles City County and Henrico and New Kent Counties are adjacent to the Project site.

An area of approximately 10,000 acres in size around the Project site using the NRCS Web Soil Survey tool (see blue-hatched box in **Figure 9-2**) indicates that the predominate soil type is sandy loams and loams. Sandy loams and loams are considered to have a moderate buffering capacity, thus having decent capacity to absorb acidic deposition without changing the soil pH[31]. The comparison of soil types within the project site is provided in **Table 9-8** and shows that greater than 95% of the soil types in the vicinity of the project area are classified as having high and moderate buffering capacities. Given the relatively low emissions due to the proposed project, and because the soil types immediately around the proposed Project site have moderate to high buffering capacity, no adverse impacts on soils due to Project emissions are anticipated.

Figure 9-2: Soil Evaluation Areas of Interest



[29] U.S. Department of Agriculture, National Resource Conservation Service's (NRCS), Soil Survey Geographic (SSGUGO) database . Accessed 17 December 2009. http://soils.usda.gov/survey/geography/ssurgo/

[30] U.S. Department of Agriculture, National Resource Conservation Service's Web Soil Survey Tool. Accessed 19 October 2015. http://websoilsurvey.sc.egov.usda.gov/App/WebSoilSurvey.aspx

[31] Murphy, Stephanie Ph.D., Rutgers Soil Testing Laboratory, New Jersey Agricultural Experiment Station. "Soil pH and Lime Requirements for Home Grounds Plantings".

Table 9-8: Buffering Capacity of Soils Around Project Site

High, Moderate, Low Buffering Capacity Soils	Project Site (% in area of interest)
	100%
High Buffer Capacity	
Clay Loom	3.1%
TOTAL	**3.1%**
Moderate Buffer Capacity	
Loam	22.5%
Sandy Loam	18.2%
Silt Loam	25.6%
Fine Sandy Loam	26.3%
Gravelly Fine Sandy Loam	1.0%
Mucky Loam	0.1%
TOTAL	**93.7%**
Low Buffer Capacity	
Loamy Sand	2.6%
Loamy Fine sand	0.0%
Fine Sand	0.1%
TOTAL	**2.7%**
Other	
Other	0.4%
TOTAL	**0.4%**

9.5 Air Toxics Analysis

In addition to predicting the ambient air concentrations of criteria pollutants, the concentrations of other pollutants from the Project emission sources regulated under VA DEQ air toxics program were evaluated.

Table 9-9 and **Table 9-10** contains a listing of the potential Project emissions of HAP pollutants for the GE 7HA.02 and MHPS M501JAC turbine options, respectively. The emissions were estimated using emission factors (AP-42) and vendor data. In addition to the potential emissions, the VA DEQ exemption levels for each pollutant are also listed in **Table 9-9** and **Table 9-10**. As shown in **Table 9-9** and **Table 9-10**, for both turbine options all HAPs are exempt except for Acrolein, Formaldehyde, Beryllium (1-hour only for MHPS M501JAC turbine), Cadmium, Chromium, Lead, Mercury, and Nickel.

These non-exempt HAPs were modeled with the worst-case emission rate for the base (100 percent) load operating scenarios and impacts were compared to the VA DEQ State Ambient Air Concentrations (SAAC). Results are presented in **Table 9-11** and **Table 9-12** for the GE 7HA.02 and MHPS M501JAC turbine options, respectively. The same set of meteorological data and Cartesian grid (20-km extent) as described in **Section 6** was used for the toxics analysis.

The modeling results presented in **Table 9-11** and **Table 9-12** indicates that no air toxic modeled exceeds its respective SAAC for both turbine options. The air toxics modeling files are provided (along with the other modeling files) in **Appendix F**.

Table 9-9: Summary of HAP Emission Rates and VA DEQ Exemption Levels - GE 7HA.02 Combustion Turbine

Pollutant	Total HAP Emissions		Virginia Air Toxics Exemption Levels		Exempt? (hourly)	Exempt? (annual)
	Hourly	Annual	Hourly	Annual		
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	Yes/No	Yes/No
1,3-Butadiene	3.15E-03	1.34E-02	1.452	3.19	Yes	Yes
2-Methylnaphthalene	3.29E-06	1.44E-05	*	*	Yes	Yes
3-Methylchloranthrene	2.47E-07	1.08E-06	*	*	Yes	Yes
7,12-Dimethylbenz(a)anthracene	2.20E-06	9.62E-06	*	*	Yes	Yes
Acenaphthene	1.39E-04	3.58E-05	*	*	Yes	Yes
Acenaphthylene	2.80E-04	7.10E-05	*	*	Yes	Yes
Acetaldehyde	2.87E-01	1.25E+00	8.91	26.1	Yes	Yes
Acrolein	**4.59E-02**	**1.99E-01**	**0.02277**	**0.03335**	**No**	**No**
Anthracene	4.06E-05	1.15E-05	*	*	Yes	Yes
Benz(a)anthracene	2.25E-05	6.64E-06	*	*	Yes	Yes
Benzene	1.10E-01	3.81E-01	2.112	4.64	Yes	Yes
Benzo(a)pyrene	8.07E-06	2.70E-06	*	*	Yes	Yes
Benzo(b)flouoranthene	3.26E-05	9.17E-06	*	*	Yes	Yes
Benzo(g,h,I)perylene	1.62E-05	4.74E-06	*	*	Yes	Yes
Benzo(k)fluoranthene	6.94E-06	2.76E-06	*	*	Yes	Yes
Chrysene	4.54E-05	1.24E-05	*	*	Yes	Yes
Dibenzo(a,h)anthracene	1.16E-05	3.59E-06	*	*	Yes	Yes
Dichlorobenzene	1.65E-04	7.21E-04	21.813	65.395	Yes	Yes
Ethylbenzene	2.27E-01	9.96E-01	17.919	62.93	Yes	Yes
Fluoranthene	1.36E-04	3.58E-05	*	*	Yes	Yes
Fluorene	4.45E-04	1.13E-04	*	*	Yes	Yes
Formaldehyde (g)	**2.02E+00**	**8.81E+00**	**0.0825**	**0.174**	**No**	**No**
Hexane	1.78E-04	7.82E-04	11.616	25.52	Yes	Yes
Indeno(1,2,3-cd)pyrene	1.32E-05	4.31E-06	*	*	Yes	Yes
Naphthalene	1.33E-02	4.18E-02	2.607	7.54	Yes	Yes
PAHs	1.56E-02	6.85E-02	*	*	Yes	Yes
Phenanathrene	1.26E-03	3.24E-04	*	*	Yes	Yes
Propylene Oxide	2.06E-01	9.03E-01	3.168	6.96	Yes	Yes
Pyrene	1.20E-04	3.29E-05	*	*	Yes	Yes
Toluene	9.33E-01	4.05E+00	18.645	54.665	Yes	Yes
Xylene	4.61E-01	1.99E+00	21.483	62.93	Yes	Yes
Arsenic	2.17E-03	9.51E-03	0.0132	0.029	Yes	Yes
Beryllium	1.30E-04	**5.71E-04**	0.000132	**0.00029**	Yes	**No**
Cadmium	**1.19E-02**	**5.23E-02**	**0.0033**	**0.00725**	**No**	**No**
Chromium	**1.52E-02**	**6.66E-02**	**0.0033**	**0.00725**	**No**	**No**
Cobalt	9.12E-04	3.99E-03	0.0033	0.00725	Yes	Yes

Pollutant	Total HAP Emissions		Virginia Air Toxics Exemption Levels		Exempt? (hourly)	Exempt? (annual)
	Hourly	Annual	Hourly	Annual		
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	Yes/No	Yes/No
Lead	**5.43E-03**	**2.38E-02**	**0.0099**	**0.02175**	**Yes**	**No**
Manganese	4.12E-03	1.81E-02	0.33	0.725	Yes	Yes
Mercury	**2.82E-03**	**1.24E-02**	**0.0033**	**0.00725**	**Yes**	**No**
Nickel	**2.28E-02**	**9.98E-02**	**0.0066**	**0.0145**	**No**	**No**
Selenium	2.61E-04	1.14E-03	0.0132	0.029	Yes	Yes

Source: 9 VAC 5-60
* indicates that neither the exemption levels nor the SAACs exist.

Table 9-10: Summary of HAP Emission Rates and VA DEQ Exemption Levels - MHPS M501JAC Combustion Turbine

Pollutant	Total HAP Emissions		Virginia Air Toxics Exemption Levels		Exempt? (hourly)	Exempt? (annual)
	Hourly	Annual	Hourly	Annual		
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	Yes/No	Yes/No
1,3-Butadiene	3.51E-03	1.50E-02	1.452	3.19	Yes	Yes
2-Methylnaphthalene	4.80E-06	2.10E-05	*	*	Yes	Yes
3-Methylchloranthrene	3.60E-07	1.58E-06	*	*	Yes	Yes
7,12-Dimethylbenz(a)anthracene	3.20E-06	1.40E-05	*	*	Yes	Yes
Acenaphthene	1.39E-04	3.63E-05	*	*	Yes	Yes
Acenaphthylene	2.80E-04	7.15E-05	*	*	Yes	Yes
Acetaldehyde	3.20E-01	1.39E+00	8.91	26.1	Yes	Yes
Acrolein	**5.13E-02**	**2.23E-01**	**0.02277**	**0.03335**	**No**	**No**
Anthracene	4.08E-05	1.22E-05	*	*	Yes	Yes
Benz(a)anthracene	2.26E-05	7.14E-06	*	*	Yes	Yes
Benzene	1.20E-01	4.25E-01	2.112	4.64	Yes	Yes
Benzo(a)pyrene	8.15E-06	3.03E-06	*	*	Yes	Yes
Benzo(b)flouoranthene	3.27E-05	9.66E-06	*	*	Yes	Yes
Benzo(g,h,I)perylene	1.63E-05	5.07E-06	*	*	Yes	Yes
Benzo(k)fluoranthene	7.06E-06	3.25E-06	*	*	Yes	Yes
Chrysene	4.55E-05	1.29E-05	*	*	Yes	Yes
Dibenzo(a,h)anthracene	1.17E-05	3.92E-06	*	*	Yes	Yes
Dichlorobenzene	2.40E-04	1.05E-03	21.813	65.395	Yes	Yes
Ethylbenzene	2.54E-01	1.11E+00	17.919	62.93	Yes	Yes
Fluoranthene	1.36E-04	3.66E-05	*	*	Yes	Yes
Fluorene	4.45E-04	1.14E-04	*	*	Yes	Yes
Formaldehyde (g)	**2.26E+00**	**9.86E+00**	**0.0825**	**0.174**	**No**	**No**
Hexane	2.60E-04	1.14E-03	11.616	25.52	Yes	Yes
Indeno(1,2,3-cd)pyrene	1.33E-05	4.81E-06	*	*	Yes	Yes
Naphthalene	1.44E-02	4.67E-02	2.607	7.54	Yes	Yes
PAHs	1.75E-02	7.65E-02	*	*	Yes	Yes
Phenanathrene	1.26E-03	3.28E-04	*	*	Yes	Yes
Propylene Oxide	2.30E-01	1.01E+00	3.168	6.96	Yes	Yes

Pollutant	Total HAP Emissions		Virginia Air Toxics Exemption Levels		Exempt? (hourly)	Exempt? (annual)
	Hourly	Annual	Hourly	Annual		
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	Yes/No	Yes/No
Pyrene	1.20E-04	3.42E-05	*	*	Yes	Yes
Toluene	1.04E+00	4.52E+00	18.645	54.665	Yes	Yes
Xylene	5.14E-01	2.23E+00	21.483	62.93	Yes	Yes
Arsenic	2.43E-03	1.07E-02	0.0132	0.029	Yes	Yes
Beryllium	**1.46E-04**	**6.40E-04**	**0.000132**	**0.00029**	**No**	**No**
Cadmium	**1.34E-02**	**5.86E-02**	**0.0033**	**0.00725**	**No**	**No**
Chromium	**1.70E-02**	**7.46E-02**	**0.0033**	**0.00725**	**No**	**No**
Cobalt	1.02E-03	4.48E-03	0.0033	0.00725	Yes	Yes
Lead	**6.09E-03**	**2.67E-02**	**0.0099**	**0.02175**	Yes	**No**
Manganese	4.62E-03	2.03E-02	0.33	0.725	Yes	Yes
Mercury	**3.16E-03**	**1.39E-02**	**0.0033**	**0.00725**	Yes	**No**
Nickel	**2.56E-02**	**1.12E-01**	**0.0066**	**0.0145**	**No**	**No**
Selenium	2.92E-04	1.28E-03	0.0132	0.029	Yes	Yes

Source: 9 VAC 5-60
* indicates that neither the exemption levels nor the SAACs exist.

Table 9-11: Maximum Concentrations for Non-Exempt HAPs - GE 7HA.02 Combustion Turbine

HAP	Averaging period	Maximum Modeled Concentration ($\mu g/m^3$)	VA SAAC ($\mu g/m^3$)	Complies
				Yes/No
Acrolein	1 Hour	0.02	17.25	Yes
	Annual	0.0001	0.46	Yes
Beryllium	Annual	7.7E-07	0.004	Yes
Cadmium	1 Hour	0.003	2.5	Yes
	Annual	0.0001	0.1	Yes
Chromium	1 Hour	0.003	2.5	Yes
	Annual	0.0001	0.1	Yes
Formaldehyde	1 Hour	0.44	62.5	Yes
	Annual	0.006	2.4	Yes
Lead	Annual	0.00003	0.3	Yes
Mercury	Annual	0.00002	0.1	Yes
Nickel	1 Hour	0.005	5	Yes
	Annual	0.0001	0.2	Yes

Table 9-12: Maximum Concentrations for Non-Exempt HAPs - MHPS M501JAC Combustion Turbine

HAP	Averaging period	Maximum Modeled Concentration ($\mu g/m^3$)	VA SAAC ($\mu g/m^3$)	Complies Yes/No
Acrolein	1 Hour	0.02	17.25	Yes
	Annual	0.0001	0.46	Yes
Beryllium	1 Hour	0.00003	0.1	Yes
	Annual	8.0E-07	0.004	Yes
Cadmium	1 Hour	0.003	2.5	Yes
	Annual	0.0001	0.1	Yes
Chromium	1 Hour	0.004	2.5	Yes
	Annual	0.0001	0.1	Yes
Formaldehyde	1 Hour	0.48	62.5	Yes
	Annual	0.007	2.4	Yes
Lead	Annual	0.00003	0.3	Yes
Mercury	Annual	0.00002	0.1	Yes
Nickel	1 Hour	0.006	5	Yes
	Annual	0.0001	0.2	Yes

10.0 References

National Park Service,. Phase I Report of the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Revised 2010. National Park Service, Air Resources Division; U.S. Forest Service, Air Quality Program; U.S. Fish and Wildlife Service, Air Quality Branch. http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf.

US EPA 1980. A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals. EPA-450/2-81-078. US EPA, Research Triangle Park, NC 27711.

US EPA 1985. Guideline for the Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) - Revised. EPA-450/4-80-023R, US EPA, Research Triangle Park, NC 27711.

US EPA 1990. New Source Review Workshop Manual. Prevention of Significant Deterioration and Nonattainment Area Permitting. Draft. October 1990.

US EPA 2010. Modeling Procedures for Demonstrating Compliance with the $PM_{2.5}$ NAAQS. (March 23, 2010). Office of Air Quality Planning and Standards, Research Triangle Park, NC. Available at: http://www.epa.gov/ttn/scram/Official%20Signed%20Modeling%20Proc%20for%20 Demo%20Compli%20w%20PM2.5.pdf

US EPA 2011. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS. (March 1, 2011). Office of Air Quality Planning and Standards, Research Triangle Park, NC. Available at: http://www.epa.gov/ttn/scram/Additional_Clarifications_ AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

US EPA 2013. AERSURFACE User's Guide. (EPA-454/B-08-001, revised 2013). Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

US EPA 2017. Guideline on Air Quality Models (Revised). Codified in the Appendix W to 40 CFR Part 51. Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2017.

US EPA 2018a. User's Guide for the AMS/EPA Regulatory Model (AERMOD). EPA-454/B-18-001 (April 2018). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2018b. User's Guide for the AERMOD Meteorological Preprocessor (AERMET). EPA-454/B-18-002 (April 2018). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2018c. AERMOD Implementation Guide. EPA-454-B-18-003 (April 2018) US EPA, Research Triangle Park, NC.

US EPA 2018d. User's Guide for the AERMOD Terrain Preprocessor (AERMAP). EPA-454/B-18-004 (April 2018). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

Appendix A

Application Forms

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY - AIR PERMITS

LOCAL GOVERNING BODY CERTIFICATION FORM	
Facility Name: **Chickahominy Power Station**	Registration Number: **TBD**
Applicant's Name: **Chickahominy Power, LLC**	Name of Contact Person at the site: **TBD**
Applicant's Mailing address: **13800 Coppermine Road, Suite 115** **Herndon, VA 20171**	Contact Person Telephone Number: **TBD**
Facility location (also attach map): **The site is located east of State Road 106 and fronts Chambers/Landfill Road along its northern boundary. The town of Charles City, Virginia is approximately 11 miles southeast of the site.**	
Facility type, and list of activities to be conducted: **Combined cycle power plant**	
The applicant is in the process of completing an application for an air pollution control permit from the Virginia Department of Environmental Quality. In accordance with § 10.1-1321.1. Title 10.1, Code of Virginia (1950), as amended, before such a permit application can be considered complete, the applicant must obtain a certification from the governing body of the county, city or town in which the facility is to be located that the location and operation of the facility are consistent with all applicable ordinances adopted pursuant to Chapter 22 (§§ 15.2-2200 et seq.) of Title 15.2. The undersigned requests that an authorized representative of the local governing body sign the certification below.	
Applicant's signature:	Date:
The undersigned local government representative certifies to the consistency of the proposed location and operation of the facility described above with all applicable local ordinances adopted pursuant to Chapter 22 (§§15.2-2200 et seq.) of Title 15.2. of the Code of Virginia (1950) as amended, as follows: (**Check one block**) ☐ The proposed facility is **fully consistent** with all applicable local ordinances. ☐ The proposed facility is **inconsistent** with applicable local ordinances; see attached information.	
Signature of authorized local government representative:	Date:
Type or print name:	Title:
County, city or town:	

[THE LOCAL GOVERNMENT REPRESENTATIVE SHOULD FORWARD THE SIGNED CERTIFICATION TO THE APPROPRIATE DEQ REGIONAL OFFICE AND SEND A COPY TO THE APPLICANT.]

General Electric Option

Three GE 7HA.02

Gas Turbines

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY – 2018 AIR PERMIT APPLICATION FEES

Air permit applications are subject to a fee. The fee does not apply to administrative amendments or true minor sources. Applications will be considered incomplete if the proper fee is not paid and will not be processed until full payment is received. Air permit application fees are not refundable.

Fees are adjusted January 1 of each calendar year. THIS FORM IS VALID JANUARY 1, 2018 TO DECEMBER 31, 2018.

Send this form and a check (or money order) payable to "Treasurer of Virginia" to:

Department of Environmental Quality
Receipts Control
P.O. Box 1104
Richmond, VA 23218

Send a copy of this form with the permit application to:
The DEQ Regional Office

Please retain a copy for your records. Any questions should be directed to the DEQ regional office to which the application will be submitted. **Unsure of your fee? Contact the Regional Air Permit Manager.**

COMPANY NAME:	**Chickahominy Power, LLC**	**FIN:**	**TBD**
COMPANY REPRESENTATIVE:	**Irfan K. Ali (Balico, LLC)**	**REG. NO.**	**TBD**
MAILING ADDRESS:	**13800 Coppermine Road, Suite 115 Herndon, VA 20171**		
BUSINESS PHONE:	**703-371-5867**	**FAX:**	**703-226-0198**
FACILITY NAME:	**Chickahominy Power Station**		
PHYSICAL LOCATION:	**East of State Road 106 and fronting Chambers/Landfill Road along its northern boundary. Charles City, Virginia is approximately 11 miles southeast of the site.**		

PERMIT ACTIVITY	APPLICATION FEE AMOUNT	CHECK ONE
Sources subject to Title V permitting requirements:		
• Major NSR permit (Articles 7, 8, 9)	$63,000	
• Major NSR permit amendment (Articles 7, 8, 9)*	$10,000	X
• State major permit (Article 6)	$25,000	
• Title V permit (Articles 1, 3)	$35,000	
• Title V permit renewal (Articles 1, 3)	$15,000	
• Title V permit modification (Articles 1, 3)	$4,000	
• Minor NSR permit (Article 6)	$5,000	
• Minor NSR amendment (Article 6)*	$2,500	
• State operating permit (Article 5)	$10,000	
• State operating permit amendment (Article 5)*	$4,000	
Sources subject to Synthetic Minor permitting requirements:		
• Minor NSR permit (Article 6)	$3,000	
• Minor NSR amendment (Article 6)*	$1,000	
• State operating permit (Article 5)	$5,000	
• State operating permit amendment (Article 5)*	$2,500	
***FEES DO NOT APPLY TO ADMINISTRATIVE AMENDMENTS AIR PERMIT APPLICATION FEES ARE NOT REFUNDABLE**		

DEQ OFFICE TO WHICH PERMIT APPLICATION WILL BE SUBMITTED (check one)

AIR PERMIT APPLICATION
CHECK ALL PAGES ATTACHED AND LIST ALL ATTACHED DOCUMENTS

x Local Government Certification Form, Page 3
x Application Fee Form, Pages 4-6
x Document Certification Form, Page 7
x General Information, Pages 8-9
x Fuel Burning Equipment, Page 10
x Stationary Internal Combustion Engines, Page 11
___ Incinerators, Page 12
x Processing, Page 13
___ Inks, Coatings, Stains, and Adhesives, Page 14
x VOC/Petroleum Storage Tanks, Pages 15-16
___ Loading Rack and Oil-Water Separators, Page 17
___ Fumigation Operations, Page 18
x Air Pollution Control and Monitoring Equipment, Page 19
x Air Pollution Control/Supplemental Information, Page 20
x Stack Parameters and Fuel Data, Page 21
x Proposed Permit Limits for Criteria Pollutants, Page 22
x Proposed Permit Limits for Toxic Pollutants/HAPs, Page 23
x Proposed Permit Limits for Other Reg. Pollutants, Page 24
x Proposed Permit Limits for GHGs on Mass Basis, Page 25
x Proposed Permit Limits for GHGs on CO_2e Basis, Page 26
___ BAE for Criteria Pollutants, Page 27
___ BAE for GHGs on Mass Basis, Page 28
___ BAE for GHGs on CO_2e Basis, Page 29
x Operating Periods, Page 30

___ ATTACHED DOCUMENTS:
x Map of Site Location
x Facility Site Plan
___ Process Flow Diagram/Schematic
___ MSDS or CPDS Sheets
x Estimated Emission Calculations
___ Stack Tests
x Air Modeling Data (will be submitted later as addendum)
___ Confidential Information (see Instructions)
x BACT Analysis

Check added form sheets above; also indicate the number of copies of each form in blank provided.

DOCUMENT CERTIFICATION FORM

I certify under penalty of law that this document and all attachments [as noted above] were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering and evaluating the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

I certify that I understand that the existence of a permit under [Article 6 of the Regulations] does not shield the source from potential enforcement of any regulation of the board governing the major NSR program and does not relieve the source of the responsibility to comply with any applicable provision of the major NSR regulations.

SIGNATURE: _____ DATE: _____

NAME: _____ REGISTRATION NO: _____

TITLE: _____ COMPANY: _____

PHONE: _____ ADDRESS: _____

EMAIL: _____ _____

References: Virginia Regulations for the Control and Abatement of Air Pollution (Regulations), 9 VAC 5-20-230B and 9 VAC 5-80-1140E.

GENERAL INFORMATION

Person Completing Form: **Irfan K. Ali**	Date: **November 2018**	Registration Number: **TBD**
Company and Division Name: **Chickahominy Power, LLC**		FIN: **TBD**
Mailing Address: **13800 Coppermine Road, Suite 115 Herndon, VA 20171**		
Exact Source Location – Include Name of City (County) and Full Street Address or Directions: **East of State Road 106 and fronting Chambers/Landfill Road along its northern boundary. Charles City, Virginia is approximately 11 miles southeast of the site.**		
Telephone Number: **704-371-5867**	No. of Employees: **TBD**	Property Area at Site: **185 acres**
Person to Contact on Air Pollution Matters – Name and Title: **Jeffery Connors**	Phone Number: **978-905-2166** Fax: Email: Jeffery.Connors@aecom.com	
Latitude and Longitude Coordinates **OR** UTM Coordinates of Facility: **37.436 N, -77.155 W**		

Reason(s) for Submission (Check all that apply):

☐ State Operating Permit

This permit is applied for pursuant to provisions of the Virginia Administrative Code, 9 VAC 5 Chapter 80, Article 5 (SOP)

☒ New Source

☐ Modification of a Source

☐ Relocation of a Source

This permit is applied for pursuant to the following provisions of the Virginia Administrative Code:

- ☐ 9 VAC 5 Chapter 80, Article 6 (Minor Sources)
- ☒ 9 VAC 5 Chapter 80, Article 8 (PSD Major Sources)
- ☐ 9 VAC 5 Chapter 80, Article 9 (Non-Attainment Major Sources)

☐ Amendment to a Permit Dated: _____ Permit Type: ☐ SOP (Art. 5) ☐ NSR (Art. 6, 8, 9)

Amendment Type:

- ☐ Administrative Amendment
- ☐ Minor Amendment
- ☐ Significant Amendment

This amendment is requested pursuant to the provisions of:

☐ 9 VAC 5-80-970 (Art. 5 Adm.)	☐ 9 VAC 5-80-1935 (Art. 8 Adm.)
☐ 9 VAC 5-80-980 (Art. 5 Minor)	☐ 9 VAC 5-80-1945 (Art. 8 Minor)
☐ 9 VAC 5-80-990 (Art. 5 Sig.)	☐ 9 VAC 5-80-1955 (Art. 8 Sig.)
☐ 9 VAC 5-80-1270 (Art. 6 Adm.)	☐ 9 VAC 5-80-2210 (Art. 9 Adm.)
☐ 9 VAC 5-80-1280 (Art. 6 Minor)	☐ 9 VAC 5-80-2220 (Art. 9 Minor)
☐ 9 VAC 5-80-1290 (Art. 6 Sig.)	☐ 9 VAC 5-80-2230 (Art. 9 Sig.)

☐ Other (specify): _____

Explanation of Permit Request (attach documents if needed):

Chickahominy Power, LLC is proposing to construct a new combined cycle power generation facility in Charles City County, Virginia. Chickahominy Power, LLC has engaged an affiliated entity Balico, LLC to act as its Development Manager.

GENERAL INFORMATION (CONTINUED)

For Portable Plants:

Is this facility designed to be portable? ☐ Yes ☒ No

- If yes, is this facility already permitted as a portable plant? ☐ Yes ☐ No Permit Date: _____

If not permitted, is this an application to be permitted as a portable plant? ☐ Yes ☐ No

If permitted as a portable facility, is this a notification of relocation? ☐ Yes ☐ No

- Describe the new location or address (include a site map): _____

- Will the portable facility be co-located with another source? ☐ Yes ☐ No Reg. No. _____
- Will the portable facility be modified or reconstructed as a result of the relocation? ☐ Yes ☐ No
- Will there be any new emissions other than those associated with the relocation? ☐ Yes ☐ No
- Is the facility suitable for the area to which it will be located? (attach documentation) ☐ Yes ☐ No

Describe the products manufactured and/or services performed at this facility:

Chickahominy Power Station is a new proposed electric generation facility.

List the Standard Industrial Classification (SIC) Code(s) for the facility:

4	9	1	1																

List the North American Industry Classification System (NAICS) Code(s) for the facility:

2	2	1	1	1	2																

List all the facilities in Virginia under common ownership or control by the owner of this facility:

None

Milestones: This section is to be completed if the permit application includes a new emissions unit or modification to existing operations.

Milestones*:	Starting Date:	Estimated Completion Date:
New Equipment Installation	**June 2019**	**August 2022**
Modification of Existing Process or Equipment	**N/A**	
Start-up Dates	**September 2021**	**April 2022**

*For new or modified installations to be constructed in phased schedule, give construction/installation starting and completion date for each phase.

FUEL BURNING EQUIPMENT: (Boilers, Turbines, Kilns, and Other External Combustion Units)

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Max. Rated Input Heat Capacity For Each Fuel (Million Btu/hr)	Type of Fuel	Type of Equip. (use Code A)	Usage (use Code B)	Requested Throughput* (hrs/yr OR fuel/yr)	Federal Regulations that Apply
CT-1	GE 7HA.02 combustion turbine	TBD	TBD	3,644	Natural Gas	15	6	8,760 hr/yr per turbine	NSPS Subpart KKKK and TTTT 40 CFR Part 97 Subpart AAAAA, BBBBB, CCCCC 40 CFR Part 72
CT-2	GE 7HA.02 combustion turbine	TBD	TBD	3,644	Natural Gas	15	6		
CT-3	GE 7HA.02 combustion turbine	TBD	TBD	3,644	Natural Gas	15	6		
B-1	Auxiliary Boiler	TBD	TBD	52	Natural Gas	12	1	8,760 hr/yr	NSPS Subpart Dc
B-2	Auxiliary Boiler	TBD	TBD	52	Natural Gas	12	1	8,760 hr/yr	NSPS Subpart Dc
FGH-1	Fuel Gas Heater	TBD	TBD	12	Natural Gas	12	4	8,760 hr/yr	NSPS Subpart Dc
FGH-2	Fuel Gas Heater	TBD	TBD	12	Natural Gas	12	4	8,760 hr/yr	NSPS Subpart Dc
FGH-3	Fuel Gas Heater	TBD	TBD	12	Natural Gas	12	4	8,760 hr/yr	NSPS Subpart Dc

[x] Estimated Emission Calculations Attached (include references of emission factors) and/or Stack Test Results if Available

Code A – Equipment

BOILER TYPE:
1. Pulverized Coal - Wet Bottom
2. Pulverized Coal - Dry Bottom
3. Pulverized Coal - Cyclone Furnace
4. Circulating Fluidized Bed
5. Spreader Stoke
6. Chain or Travelling Grate Stoker
7. Underfeed Stoker
8. Hand Fired Coal
9. Oil, Tangentially Fired
10. Oil, Horizontally Fired (except rotary cup)
11. Gas, Tangentially Fired
12. Gas, Horizontally Fired
13. Wood with Flyash Reinjection
14. Wood without Flyash Reinjection
15. Other (specify) Combustion Turbine

OTHER COMBUSTION UNITS:
16. Oven / Kiln
17. Rotary Kiln
18. Process Furnace
19. Other (specify) _____

Code B - Usage

1. Steam Production
2. Drying / Curing
3. Space Heating
4. Process Heat
5. Food Processing
6. Electrical Generation
7. Mechanical Work
8. Other (specify) _____

***Pick only one option for a requested throughput.**

NOTE: Dryers, kilns, and furnaces also have to fill out Page 13.

STATIONARY INTERNAL COMBUSTION ENGINES:

Company Name: **Chickahominy Power, LLC**	**Date: November 2018**	**Registration Number: TBD**

Unit Ref. No.	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Output Brake Horsepower (bhp)	Output Electrical Power (kW)	Type of Fuel	Usage* (use Code C)	Requested Throughput** (hrs/yr OR fuel/yr)	Federal Regulations that Apply
EG-1	Emergency Generator	TBD	TBD	---	3,000	Diesel	1	500 hr/yr	40 CFR Part 60 Subpart IIII, 40 CFR Part 63 Subpart ZZZZ
FWP-1	Emergency Fire Pump	TBD	TBD	376	---	Diesel	1	500 hr/yr	40 CFR Part 60 Subpart IIII, 40 CFR Part 63 Subpart ZZZZ

[x] Estimated Emission Calculations Attached (include references of emission factors and manufacturer specifications per engine) and/or Stack Test Results if
Available

Code C – Usage

1. Emergency Generator
2. Participates in Emergency Load Response Program
3. Non-Emergency Generator
4. Participates in Demand Response Program(s)
5. Other (specify) _____

***Can pick more than one option**
(i.e. 1 and 2 **OR** 3 and 4)

****Pick only one option for a requested throughput.**

PROCESSING, MANUFACTURING, SURFACE COATING AND DEGREASING OPERATIONS:

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Process or Operation Name	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Max. Rated Capacity (gal/hr)*	Requested Throughput*			Federal Regulations that Apply
						(gal/hr)	(_____/day)	(_____/yr)	
CB-1	Circuit Breakers	TBD	TBD	TBD	8,760 hr/yr (0.5% leak rate)	----	----	----	40 CFR Part 98 Subpart DD
NGL-1	Natural Gas Equipment Leaks	TBD	TBD	TBD	----	----	----	----	----

[x] Estimated Emission Calculations Attached (include references of emission factors) and/or Stack Test Results if Available

*** Specify units for each operation in tons, pounds, gallons, etc., as applicable. <u>For coating operations</u>, the maximum rated capacity is the spray gun capacity.**

<u>NOTE:</u> Fill out one page for each ink, coating, stain, and adhesive.

VOLATILE ORGANIC COMPOUND (VOC)/PETROLEUM LIQUID STORAGE TANKS:

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Tank Type (use Code H)	Source of Tank Contents (use Code I)	Date of Manuf.	Date of Const.	Material Stored - Name and CAS # (include Reid Vapor Pressure for Gasoline)	Max. True Vapor Pressure (psia)	Density* (lbs/gal)	Max. Average Storage Temp. (ºF)	Tank Diameter (feet)	Tank Capacity (gal)	Requested Throughput (gal/yr)	Federal Regulations that Apply
T-1	1b	3	TBD	TBD	ULSD 68476-34-6	0.022	6.91 @ 60 ºF	100	4.0	572	9,400	----
T-2	1b	3	TBD	TBD	ULSD 68476-34-6	0.022	6.91 @ 60 ºF	100	6.5	2,500	107,100	----

[x] Estimated Emission Calculations Attached (include TANKS Program printouts)

Code H – Tank Type		**Code I – Source of Tank Contents**
1. Fixed Roof a. Vertical Tank b. Horizontal Tank 2. Floating Roof a. Internal (welded deck) b. Internal (bolted deck) – Specify Panel or Sheet c. External (welded deck) d. External (riveted deck)	3. Variable Vapor Space 4. Pressure Tank (over 15 psig) 5. Underground Splash Loading 6. Underground Submerged Loading 7. Underground Submerged Loading, Balanced 8. Other:_____	1. Pipeline 2. Rail Car 3. Tank Truck 4. Ship or Barge 5. Process

*** Specify the ASTM temperature standard at which the density was measured.**

VOLATILE ORGANIC COMPOUND (VOC)/PETROLEUM LIQUID STORAGE TANKS (CONTINUED):

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Tank Color		Fixed Roof Only					Floating Roof Only				
	Shell	Roof	Internal Tank Height or Length (feet)	Max. Hourly Filling (gallons)	External Fixed Roof			Seal Type (use Code J)	Max. Hourly Withdrawal (gallons)	Internal Floating Roof		
					Type of Roof (cone or dome)	Cone height (ft) and slope (ft/ft)	Dome height (ft) and radius (ft)			Self Supporting?	If no, No. of Columns	If no, Column Diameter (ft)
T-1	Gray	N/A	7	572	N/A	N/A	N/A					
T-2	Gray	N/A	12	2,500	N/A	N/A	N/A					

Code J – Seal Type (Pontoon External Only)	**(Double Deck External Only)**	**(Internal Only)**
1. Mechanical Shoe a. Primary only b. Shoe mounted secondary c. Rim mounted secondary 2. Liquid Mounted a. Primary only b. Weather shield secondary c. Rim mounted secondary 3. Vapor Mounted a. Primary only b. Weather shield secondary c. Rim mounted secondary	4. Mechanical Shoe a. Primary only b. Shoe mounted secondary c. Rim mounted secondary 5. Liquid Mounted a. Primary only b. Weather shield secondary c. Rim mounted secondary 6. Vapor Mounted a. Primary only b. Weather shield secondary c. Rim mounted secondary	7. Mechanical Shoe a. Primary only b. Shoe mounted secondary c. Rim mounted secondary 8. Liquid Mounted a. Primary only b. Rim mounted secondary 9. Vapor Mounted a. Primary only b. Rim mounted secondary

AIR POLLUTION CONTROL AND MONITORING EQUIPMENT:

Company Name:	Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Vent/ Stack No.	Device Ref. No.	Pollutant / Parameter	Air Pollution Control Equipment			Monitoring Instrumentation
				Manufacturer and Model No.	Type (use Code N)	Percent Efficiency (%)	Specify Type, Measured Pollutant, and Recorder Used
CT-1	S-1	D-1	NOx	Dry Low NOx combustion with selective catalytic reduction (SCR)	16	See Appendix B	CEMS for NOx
CT-1	S-1	D-2	CO	Oxidation Catalyst	21	See Appendix B	CEMS for CO
CT-2	S-2	D-3	NOx	Dry Low NOx combustion with SCR	16	See Appendix B	CEMS for NOx
CT-2	S-2	D-4	CO	Oxidation Catalyst	21	See Appendix B	CEMS for CO
CT-3	S-3	D-5	NOx	Dry Low NOx combustion with SCR	16	See Appendix B	CEMS for NOx
CT-3	S-3	D-6	CO	Oxidation Catalyst	21	See Appendix B	CEMS for CO

[x] **Manufacturer Specifications Included**

Code N – Type of Air Pollution Control Equipment

1. Settling Chamber
2. Cyclone
3. Multicyclone
4. Cyclone scrubber
5. Orifice scrubber
6. Mechanical scrubber
7. Venturi scrubber
   a. Fixed throat
   b. Variable throat
8. Mist eliminator
9. Filter
   a. Baghouse
   b. Other:_____
10. Electrostatic Precipitator
    a. Hot side
    b. Cold side
    c. High voltage
    d. Low voltage
    e. Single stage
    f. Two stage
    g. Other:_____
11. Catalytic Afterburner
12. Direct Flame Afterburner
13. Diesel Oxidation Catalyst (DOC)
14. Thermal Oxidizer
15. Regenerative Thermal Oxidizer (RTO)
16. Selective Catalytic Reduction (SCR)
17. Selective Non-Catalytic Reduction (SNCR)
18. Absorber
    a. Packed tower
    b. Spray tower
    c. Tray tower
    d. Venturi
    e. Other:_____
19. Adsorber
    a. Activated carbon
    b. Molecular sieve
    c. Activated alumina
    d. Silica gel
    e. Other:_____
20. Condenser (specify)
21. Other:__ **Oxidation Catalyst**

AIR POLLUTION CONTROL EQUIPMENT - SUPPLEMENTAL INFORMATION:

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Device Ref. No.	Type (use Code N)	Liquid Flow Rate (gpm) (4, 5, 6, 7, 17 ,19)	Liquid Medium (4, 5, 6, 7, 17, 19)	Cleaning Method (9, 10, 17, 18)	Number of Fields (10)	Number of Sections (9, 10)	Air to Cloth Ratio (fpm) (9)	Filter Material (9)	Inlet Temp. (ºF)	Regeneration Method & Cycle Time (sec) (18)	Chamber Temp. (ºF) (11, 12, 14, 15)	Retention Time (sec) (11, 12, 14, 15)	Pressure Drop (inch H_2O) (3, 4, 5, 6, 7, 9, 17)
					Not applicable								

NOTE: **Numbers listed in parenthesis in the columns above represent the Control Equipment in Code N below.**

Code N – Type of Air Pollution Control Equipment

1. Settling Chamber
2. Cyclone
3. Multicyclone
4. Cyclone scrubber
5. Orifice scrubber
6. Mechanical scrubber
7. Venturi scrubber
   a. Fixed throat
   b. Variable throat
8. Mist eliminator
9. Filter
   a. Baghouse
   b. Other:_____
10. Electrostatic Precipitator
    a. Hot side
    b. Cold side
    c. High voltage
    d. Low voltage
    e. Single stage
    f. Two stage
    g. Other:_____
11. Catalytic Afterburner
12. Direct Flame Afterburner
13. Diesel Oxidation Catalyst (DOC)
14. Thermal Oxidizer
15. Regenerative Thermal Oxidizer (RTO)
16. Selective Catalytic Reduction (SCR)
17. Selective Non-Catalytic Reduction (SNCR)
18. Absorber
    a. Packed tower
    b. Spray tower
    c. Tray tower
    d. Venturi
    e. Other:_____
19. Adsorber
    a. Activated carbon
    b. Molecular sieve
    c. Activated alumina
    d. Silica gel
    e. Other:_____
20. Condenser (specify)
21. Other:_____

STACK PARAMETERS AND FUEL DATA:

Company Name:	Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Vent/ Stack No.	Vent/Stack or Exhaust Data						Fuel(s) Data				
		Vent/Stack Config. (use Code O)	Vent/Stack Height (feet)	Exit Diameter (feet)	Exit Gas Velocity (ft/sec)	Exit Gas Flow Rate (acfm)	Exit Gas Temp. (ºF)	Type of Fuel	Heating Value* (Btu/_)	Max. Rated Burned/hr (specify units)	Max. Sulfur %	Max. Ash %
CT-1[a]	1	5	180	22.0	74.2	1,692,833	185	Natural Gas	1,020 Btu/scf	3,644 MMBtu/hr	0.4 grains /100 scf	-
CT-2[a]	2	5	180	22.0	74.2	1,692,833	185	Natural Gas	1,020 Btu/scf	3,644 MMBtu/hr	0.4 grains /100 scf	-
CT-3[a]	3	5	180	22.0	74.2	1,692,833	185	Natural Gas	1,020 Btu/scf	3,644 MMBtu/hr	0.4 grains /100 scf	-
B-1	4	5	40.0	3.0	38.5	16,320	300	Natural Gas	1,020 Btu/scf	52.0 MMBtu/hr	0.4 grains /100 scf	-
B-2	5	5	40.0	3.0	38.5	16,320	300	Natural Gas	1,020 Btu/scf	52.0 MMBtu/hr	0.4 grains /100 scf	-
FGH-1	6	5	20.0	1.50	50.53	5,358	810	Natural Gas	1,020 Btu/scf	12.00 MMBtu/hr	0.4 grains /100 scf	-
FGH-2	6	5	20.0	1.50	50.53	5,358	810	Natural Gas	1,020 Btu/scf	12.00 MMBtu/hr	0.4 grains /100 scf	-
FGH-3	6	5	20.0	1.50	50.53	5,358	810	Natural Gas	1,020 Btu/scf	12.00 MMBtu/hr	0.4 grains /100 scf	-
EG-1	7	5	21.0	1.67	196	25,620	892	ULSD	135,000 Btu/gal	28.9 MMBtu/hr	0.0015%	-
FWP-1	8	5	15.0	0.50	158	1,867	842	ULSD	135,000 Btu/gal	2.54 MMBtu/hr	0.0015%	-

[a] Stack parameters for the annual average temperature of 59 °F without evaporative cooling are listed.

Code O – Vent/Stack Configuration

1. Stack discharging downward, or nearly download
2. Equivalent stack representing a combination of multiple actual stacks
3. Gooseneck stack
4. Stack discharging in a horizontal direction
5. Stack with an unobstructed opening discharge in a vertical direction
6. Vertical stack with a weather cap or similar obstruction in exhaust system

*** Specify units for each heating value in Btus per unit of fuel.**

PROPOSED PERMIT LIMITS FOR CRITERIA POLLUTANTS:

Company Name:	Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Proposed Permit Limits for Criteria Pollutants(**)															
	PM [a] (Particulate Matter)		PM-10 [a,b] (10 µM or smaller particulate matter)		PM 2.5 [a,b] (2.5 µM or smaller particulate matter)		SO_2 (Sulfur Dioxide)		NO_X (Nitrogen Oxides)		CO (Carbon Monoxide)		VOC [a] (Volatile Organic Compounds)		Pb (Lead)	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT-1	12.4	54.3	12.4	54.3	12.4	54.3	4.15	18.2	26.5	116.1	8.1	123.1	3.24	22.9	0.0018	0.0078
CT-2	12.4	54.3	12.4	54.3	12.4	54.3	4.15	18.2	26.5	116.1	8.1	123.1	3.24	22.9	0.0018	0.0078
CT-3	12.4	54.3	12.4	54.3	12.4	54.3	4.15	18.2	26.5	116.1	8.1	123.1	3.24	22.9	0.0018	0.0078
B-1	0.36	1.59	0.36	1.59	0.36	1.59	0.059	0.261	0.57	2.51	1.92	8.43	0.26	1.14	2.5E-05	1.1E-04
B-2	0.36	1.59	0.36	1.59	0.36	1.59	0.059	0.261	0.57	2.51	1.92	8.43	0.26	1.14	2.5E-05	1.1E-04
FGH-1	0.08	0.37	0.08	0.37	0.08	0.37	0.014	0.060	0.13	0.58	0.44	1.94	0.06	0.26	5.9E-06	2.6E-05
FGH-2	0.08	0.37	0.08	0.37	0.08	0.37	0.014	0.060	0.13	0.58	0.44	1.94	0.06	0.26	5.9E-06	2.6E-05
FGH-3	0.08	0.37	0.08	0.37	0.08	0.37	0.014	0.060	0.13	0.58	0.44	1.94	0.06	0.26	5.9E-06	2.6E-05
EG-1	1.45	0.36	1.45	0.36	1.45	0.36	0.044	0.011	46.5	11.6	25.4	6.36	9.45	2.36	2.6E-04	6.5E-05
FWP-1	0.12	0.03	0.12	0.03	0.12	0.03	0.004	0.001	2.49	0.62	2.16	0.54	0.09	0.02	2.3E-05	5.7E-06
T-1	-	-	-	-	-	-	-	-	-	-	-	-	6.5E-05	2.9E-04	-	-
T-2	-	-	-	-	-	-	-	-	-	-	-	-	4.2E-04	1.8E-03	-	-
TOTAL:	**39.7**	**167.6**	**39.7**	**167.6**	**39.7**	**167.6**	**12.7**	**55.3**	**130.0**	**367.2**	**57.0**	**398.8**	**20.0**	**74.1**	**0.0058**	**0.024**

[X] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

[a] PM, PM-10, PM 2.5, and VOC should also be split up by component and reported under the Proposed Permit Limits for Toxic Pollutants/HAPs.

[b] PM-10 and PM 2.5 includes filterable and condensable.

[**] Slight differences in calculated totals may occur due to rounding issues.

PROPOSED PERMIT LIMITS FOR TOXIC POLLUTANTS/HAPS:

Company Name:	Chickahominy Power, LLC	Date:	November 2018	Registration Number:	TBD

Unit Ref. No.	Proposed Permit Limits for Toxic/HAP Pollutants*															
	HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
					See Appendix B, Table B-1.5											
TOTAL:																

[x] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

*** Specify the name of the toxic pollutant/HAP for each Unit Ref. No. along with the respective CAS Number**. Toxic Pollutant means a pollutant on the designated list in the Form 7 Instructions document. Particulate matter and volatile organic compounds are not toxic pollutants as generic classes of substances, but individual substances within these classes may be toxic pollutants because their toxic properties or because a TLV (tm) has been

established.

PROPOSED PERMIT LIMITS FOR OTHER REGULATED POLLUTANTS:

Company Name:	Chickahominy Power, LLC	Date:	November 2018	Registration Number:	TBD

Unit Ref. No.	Proposed Permit Limits for Other Regulated Pollutants* [(a)]															
	Pollutant Name: Sulfuric Acid Mist		Pollutant Name: Ammonia		Pollutant Name:		Pollutant Name:		Pollutant Name:		Pollutant Name:		Pollutant Name:		Pollutant Name:	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT-1	2.77	12.1	24.5	107.3												
CT-2	2.77	12.1	24.5	107.3												
CT-3	2.77	12.1	24.5	107.3												
B-1	0.0046	0.020	-	-												
B-2	0.0046	0.020	-	-												
FGH-1	0.0011	0.0046	-	-												
FGH-2	0.0011	0.0046														
FGH-3	0.0011	0.0046	-	-												
EG-1	0.0034	0.00085	-	-												
FWP-1	0.0003	0.00007	-	-												
TOTAL:	**8.33**	**36.5**	**73.5**	**321.9**												

[x] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

*** Other Regulated Pollutant** include Fluorides, Sulfuric Acid Mist, Hydrogen Sulfide (H_2S), Total Reduced Sulfur (including H_2S), Reduced Sulfur Compounds (including H_2S), Municipal Waste Combustor Organics (measured as total tetra-through octa-chlorinated dibenzo-p-dioxins and dibenzofurans), Municipal Waste Combustor Metals (measured as particulate matter), Municipal Waste Combustor Acid Gases (measured as the sum of SO_2 and HCl), and Municipal Solid Waste Landfill Emissions (measured as nonmethane organic compounds).

(a) Slight differences in calculated totals may occur due to rounding issues.

PROPOSED PERMIT LIMITS FOR GREENHOUSE GASES (GHGs) ON MASS BASIS: FOR PSD MAJOR SOURCES ONLY

Company Name:	Chickahominy Power, LLC	Date:	November 2018	Registration Number:	TBD

Unit Ref. No.	Proposed Permit Limits for GHG Pollutants on Mass Basis [a]													
	CO_2 (Carbon Dioxide)		N_2O (Nitrous Oxide)		CH_4 (Methane)		HFCs (Hydrofluoro-carbons)		PFCs (Perfluoro-carbons)		SF_6 (Sulfur Hexafluoride)		Total GHGs	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT-1	433,624	1,899,274	0.803	3.52	8.03	35.2	-	-	-	-	-	-	**433,633**	**1,899,313**
CT-2	433,624	1,899,274	0.803	3.52	8.03	35.2	-	-	-	-	-	-	**433,633**	**1,899,313**
CT-3	433,624	1,899,274	0.803	3.52	8.03	35.2	-	-	-	-	-	-	**433,633**	**1,899,313**
B-1	6,188	27,103	0.011	0.050	0.11	0.50	-	-	-	-	-	-	**6,188**	**27,104**
B-2	6,188	27,103	0.011	0.050	0.11	0.50	-	-	-	-	-	-	**6,188**	**27,104**
FGH-1	1,428	6,255	0.0026	0.012	0.026	0.12	-	-	-	-	-	-	**1,428**	**6,255**
FGH-2	1,428	6,255	0.0026	0.012	0.026	0.12	-	-	-	-	-	-	**1,428**	**6,255**
FGH-3	1,428	6,255	0.0026	0.012	0.026	0.12	-	-	-	-	-	-	**1,428**	**6,255**
EG-1	4,794	1,199	0.038	0.0096	0.19	0.048	-	-	-	-	-	-	**4,794**	**1,199**
FWP-1	421	105	0.0034	0.00084	0.017	0.0042	-	-	-	-	-	-	**421**	**105**
CB-1	-	-	-	-	-	-	-	-	-	-	0.011	0.050	**0.011**	**0.050**
NGL-1	-	-	-	-	2.28	10.0	-	-	-	-	-	-	**2.28**	**10.0**
TOTAL:	**1,322,747**	**5,772,097**	**2.48**	**10.7**	**26.9**	**117.0**	**-**	**-**	**-**	**-**	**0.011**	**0.050**	**1,322,776**	**5,772,225**

[x] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

(b) Slight differences in calculated totals may occur due to rounding issues.

PROPOSED PERMIT LIMITS FOR GREENHOUSE GASES (GHGs) ON CO_2 EQUIVALENT EMISSIONS (CO_2e) BASIS: FOR PSD MAJOR SOURCES ONLY

Company Name:	Chickahominy Power, LLC	Date:	November 2018	Registration Number:	TBD

Unit Ref. No.	Proposed Permit Limits for GHG Pollutants on CO_2 Equivalent Basis													
	CO_2 (Carbon Dioxide)		N_2O (Nitrous Oxide)		CH_4 (Methane)		HFCs (Hydrofluoro-carbons)		PFCs (Perfluoro-carbons)		SF_6 (Sulfur Hexafluoride)		Total GHGs	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
C`T-1	433,624	1,899,274	239.4	1,049	200.8	879.7	-	-	-	-	-	-	**434,064**	**1,901,202**
CT-2	433,624	1,899,274	239.4	1,049	200.8	879.7	-	-	-	-	-	-	**434,064**	**1,901,202**
CT-3	433,624	1,899,274	239.4	1,049	200.8	879.7	-	-	-	-	-	-	**434,064**	**1,901,202**
B-1	6,188	27,103	3.42	15.0	2.87	12.6	-	-	-	-	-	-	**6,194**	**27,131**
B-2	6,188	27,103	3.42	15.0	2.87	12.6	-	-	-	-	-	-	**6,194**	**27,131**
FGH-1	1,428	6,255	0.79	3.45	0.66	2.90	-	-	-	-	-	-	**1,429**	**6,261**
FGH-2	1,428	6,255	0.79	3.45	0.66	2.90	-	-	-	-	-	-	**1,429**	**6,261**
FGH-3	1,428	6,255	0.79	3.45	0.66	2.90							**1,429**	**6,261**
EG-1	4,794	1,199	11.4	2.85	4.78	1.20	-	-	-	-	-	-	**4,810**	**1,203**
FWP-1	421	105	1.00	0.25	0.42	0.10	-	-	-	-	-	-	**422**	**106**
CB-1	-	-	-	-	-	-	-	-	-	-	260.3	1,140	**260**	**1,140**
NGL-1	-	-	-	-	57.1	250.0	-	-	-	-	-	-	**57**	**250**
TOTAL:	**1,322,747**	**5,772,097**	**739.8**	**3,190**	**672.4**	**2,924**	**-**	**-**	**-**	**-**	**260.3**	**1,140**	**1,324,420**	**5,779,348**

[x] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

OPERATING PERIODS:

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Percent Annual Use/Throughput by Season				Normal Process/Equipment Operating Schedule			Maximum Process/Equipment Operating Schedule		
	December February	March May	June August	September November	Hours per Day	Days per Week	Weeks per Year	Hours per Day	Days per Week	Weeks per Year
CT-1	25	25	25	25				24	7	52
CT-2	25	25	25	25				24	7	52
CT-3	25	25	25	25				24	7	52
B-1	25	25	25	25				24	7	52
B-2	25	25	25	25				24	7	52
FGH-1	25	25	25	25				24	7	52
FGH-2	25	25	25	25				24	7	52
FGH-3	25	25	25	25				24	7	52
EG-1	25	25	25	25				1[1]	2[1]	52
FWP-1	25	25	25	25				1[1]	2[1]	52
T-1	25	25	25	25				24	7	52
T-2	25	25	25	25				24	7	52
CB-1	25	25	25	25				24	7	52
NGL-1	25	25	25	25				24	7	52

Maximum Facility Operating Schedule		
Hours per Day 24	Days per Week 7	Weeks per Year 52

[1] The schedule provided for the emergency generator and fire-water pump engine represents 100 hours for maintenance and testing purposes. Emergency use combined will be limited to 500 hours/year.

Mitsubishi Option

Three MHPS M501JAC

Gas Turbines

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY – 2018 AIR PERMIT APPLICATION FEES

Air permit applications are subject to a fee. The fee does not apply to administrative amendments or true minor sources. Applications will be considered incomplete if the proper fee is not paid and will not be processed until full payment is received. Air permit application fees are not refundable.

Fees are adjusted January 1 of each calendar year. THIS FORM IS VALID JANUARY 1, 2018 TO DECEMBER 31, 2018.

Send this form and a check (or money order) payable to "Treasurer of Virginia" to:

Department of Environmental Quality
Receipts Control
P.O. Box 1104
Richmond, VA 23218

Send a copy of this form with the permit application to:
The DEQ Regional Office

Please retain a copy for your records. Any questions should be directed to the DEQ regional office to which the application will be submitted. **Unsure of your fee? Contact the Regional Air Permit Manager.**

COMPANY NAME:	**Chickahominy Power, LLC**	**FIN:**	**TBD**
COMPANY REPRESENTATIVE:	**Irfan K. Ali (Balico, LLC)**	**REG. NO.**	**TBD**
MAILING ADDRESS:	**13800 Coppermine Road, Suite 115 Herndon, VA 20171**		
BUSINESS PHONE:	**703-371-5867**	**FAX:**	**703-226-0198**
FACILITY NAME:	**Chickahominy Power Station**		
PHYSICAL LOCATION:	**East of State Road 106 and fronting Chambers/Landfill Road along its northern boundary. Charles City, Virginia is approximately 11 miles southeast of the site.**		

PERMIT ACTIVITY	APPLICATION FEE AMOUNT	CHECK ONE
Sources subject to Title V permitting requirements:		
• Major NSR permit (Articles 7, 8, 9)	$63,000	
• Major NSR permit amendment (Articles 7, 8, 9)*	$10,000	X
• State major permit (Article 6)	$25,000	
• Title V permit (Articles 1, 3)	$35,000	
• Title V permit renewal (Articles 1, 3)	$15,000	
• Title V permit modification (Articles 1, 3)	$4,000	
• Minor NSR permit (Article 6)	$5,000	
• Minor NSR amendment (Article 6)*	$2,500	
• State operating permit (Article 5)	$10,000	
• State operating permit amendment (Article 5)*	$4,000	
Sources subject to Synthetic Minor permitting requirements:		
• Minor NSR permit (Article 6)	$3,000	
• Minor NSR amendment (Article 6)*	$1,000	
• State operating permit (Article 5)	$5,000	
• State operating permit amendment (Article 5)*	$2,500	
***FEES DO NOT APPLY TO ADMINISTRATIVE AMENDMENTS AIR PERMIT APPLICATION FEES ARE NOT REFUNDABLE**		

DEQ OFFICE TO WHICH PERMIT APPLICATION WILL BE SUBMITTED (check one)

AIR PERMIT APPLICATION
CHECK ALL PAGES ATTACHED AND LIST ALL ATTACHED DOCUMENTS

x Local Government Certification Form, Page 3
x Application Fee Form, Pages 4-6
x Document Certification Form, Page 7
x General Information, Pages 8-9
x Fuel Burning Equipment, Page 10
x Stationary Internal Combustion Engines, Page 11
___ Incinerators, Page 12
x Processing, Page 13
___ Inks, Coatings, Stains, and Adhesives, Page 14
x VOC/Petroleum Storage Tanks, Pages 15-16
___ Loading Rack and Oil-Water Separators, Page 17
___ Fumigation Operations, Page 18
x Air Pollution Control and Monitoring Equipment, Page 19
x Air Pollution Control/Supplemental Information, Page 20
x Stack Parameters and Fuel Data, Page 21
x Proposed Permit Limits for Criteria Pollutants, Page 22
x Proposed Permit Limits for Toxic Pollutants/HAPs, Page 23
x Proposed Permit Limits for Other Reg. Pollutants, Page 24
x Proposed Permit Limits for GHGs on Mass Basis, Page 25
x Proposed Permit Limits for GHGs on CO_2e Basis, Page 26
___ BAE for Criteria Pollutants, Page 27
___ BAE for GHGs on Mass Basis, Page 28
___ BAE for GHGs on CO_2e Basis, Page 29
x Operating Periods, Page 30

___ ATTACHED DOCUMENTS:
x Map of Site Location
x Facility Site Plan
___ Process Flow Diagram/Schematic
___ MSDS or CPDS Sheets
x Estimated Emission Calculations
___ Stack Tests
x Air Modeling Data (will be submitted later as addendum)
___ Confidential Information (see Instructions)
x BACT Analysis

Check added form sheets above; also indicate the number of copies of each form in blank provided.

DOCUMENT CERTIFICATION FORM

I certify under penalty of law that this document and all attachments [as noted above] were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering and evaluating the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

I certify that I understand that the existence of a permit under [Article 6 of the Regulations] does not shield the source from potential enforcement of any regulation of the board governing the major NSR program and does not relieve the source of the responsibility to comply with any applicable provision of the major NSR regulations.

SIGNATURE: _____ DATE: _____

NAME: _____ REGISTRATION NO: _____

TITLE: _____ COMPANY: _____

PHONE: _____ ADDRESS: _____

EMAIL: _____ _____

References: Virginia Regulations for the Control and Abatement of Air Pollution (Regulations), 9 VAC 5-20-230B and 9 VAC 5-80-1140E.

GENERAL INFORMATION

Person Completing Form: **Irfan K. Ali**	Date: **November 2018**	Registration Number: **TBD**
Company and Division Name: **Chickahominy Power, LLC**		FIN: **TBD**
Mailing Address: **13800 Coppermine Road, Suite 115 Herndon, VA 20171**		
Exact Source Location – Include Name of City (County) and Full Street Address or Directions: **East of State Road 106 and fronting Chambers/Landfill Road along its northern boundary. Charles City, Virginia is approximately 11 miles southeast of the site.**		
Telephone Number: **704-371-5867**	No. of Employees: **TBD**	Property Area at Site: **185 acres**
Person to Contact on Air Pollution Matters – Name and Title: **Jeffery Connors**	Phone Number: **978-905-2166** Fax: Email: Jeffery.Connors@aecom.com	
Latitude and Longitude Coordinates **OR** UTM Coordinates of Facility: **37.436 N, -77.155 W**		

Reason(s) for Submission (Check all that apply):

☐ State Operating Permit

This permit is applied for pursuant to provisions of the Virginia Administrative Code, 9 VAC 5 Chapter 80, Article 5 (SOP)

☒ New Source

☐ Modification of a Source

☐ Relocation of a Source

This permit is applied for pursuant to the following provisions of the Virginia Administrative Code:

- ☐ 9 VAC 5 Chapter 80, Article 6 (Minor Sources)
- ☒ 9 VAC 5 Chapter 80, Article 8 (PSD Major Sources)
- ☐ 9 VAC 5 Chapter 80, Article 9 (Non-Attainment Major Sources)

☐ Amendment to a Permit Dated: _____ Permit Type: ☐ SOP (Art. 5) ☐ NSR (Art. 6, 8, 9)

Amendment Type:

- ☐ Administrative Amendment
- ☐ Minor Amendment
- ☐ Significant Amendment

This amendment is requested pursuant to the provisions of:

☐ 9 VAC 5-80-970 (Art. 5 Adm.)	☐ 9 VAC 5-80-1935 (Art. 8 Adm.)
☐ 9 VAC 5-80-980 (Art. 5 Minor)	☐ 9 VAC 5-80-1945 (Art. 8 Minor)
☐ 9 VAC 5-80-990 (Art. 5 Sig.)	☐ 9 VAC 5-80-1955 (Art. 8 Sig.)
☐ 9 VAC 5-80-1270 (Art. 6 Adm.)	☐ 9 VAC 5-80-2210 (Art. 9 Adm.)
☐ 9 VAC 5-80-1280 (Art. 6 Minor)	☐ 9 VAC 5-80-2220 (Art. 9 Minor)
☐ 9 VAC 5-80-1290 (Art. 6 Sig.)	☐ 9 VAC 5-80-2230 (Art. 9 Sig.)

☐ Other (specify): _____

Explanation of Permit Request (attach documents if needed):

Chickahominy Power, LLC is proposing to construct a new combined cycle power generation facility in Charles City County, Virginia. Chickahominy Power, LLC has engaged an affiliated entity Balico, LLC to act as its Development Manager.

GENERAL INFORMATION (CONTINUED)

For Portable Plants:

Is this facility designed to be portable? ☐ Yes ☒ No

- If yes, is this facility already permitted as a portable plant? ☐ Yes ☐ No Permit Date: _____

If not permitted, is this an application to be permitted as a portable plant? ☐ Yes ☐ No

If permitted as a portable facility, is this a notification of relocation? ☐ Yes ☐ No

- Describe the new location or address (include a site map): _____

- Will the portable facility be co-located with another source? ☐ Yes ☐ No Reg. No. _____
- Will the portable facility be modified or reconstructed as a result of the relocation? ☐ Yes ☐ No
- Will there be any new emissions other than those associated with the relocation? ☐ Yes ☐ No
- Is the facility suitable for the area to which it will be located? (attach documentation) ☐ Yes ☐ No

Describe the products manufactured and/or services performed at this facility:

Chickahominy Power Station is a new proposed electric generation facility.

List the Standard Industrial Classification (SIC) Code(s) for the facility:

4	9	1	1																

List the North American Industry Classification System (NAICS) Code(s) for the facility:

2	2	1	1	1	2																		

List all the facilities in Virginia under common ownership or control by the owner of this facility:

None

Milestones: This section is to be completed if the permit application includes a new emissions unit or modification to existing operations.

Milestones*:	Starting Date:	Estimated Completion Date:
New Equipment Installation	**June 2019**	**August 2022**
Modification of Existing Process or Equipment	**N/A**	
Start-up Dates	**September 2021**	**April 2022**

*For new or modified installations to be constructed in phased schedule, give construction/installation starting and completion date for each phase.

FUEL BURNING EQUIPMENT: (Boilers, Turbines, Kilns, and Other External Combustion Units)

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Max. Rated Input Heat Capacity For Each Fuel (Million Btu/hr)	Type of Fuel	Type of Equip. (use Code A)	Usage (use Code B)	Requested Throughput* (hrs/yr OR fuel/yr)	Federal Regulations that Apply
CT-1	MHPS M501JAC combustion turbine	TBD	TBD	4,070	Natural Gas	15	6	8,760 hr/yr per turbine	NSPS Subpart KKKK and TTTT 40 CFR Part 97 Subpart AAAAA, BBBBB, CCCCC 40 CFR Part 72
CT-2	MHPS M501JAC combustion turbine	TBD	TBD	4,070	Natural Gas	15	6		
CT-3	MHPS M501JAC combustion turbine	TBD	TBD	4,070	Natural Gas	15	6		
B-1	Auxiliary Boiler	TBD	TBD	84	Natural Gas	12	1	8,760 hr/yr	NSPS Subpart Dc
B-2	Auxiliary Boiler	TBD	TBD	84	Natural Gas	12	1	8,760 hr/yr	NSPS Subpart Dc
FGH-1	Fuel Gas Heater	TBD	TBD	12	Natural Gas	12	4	8,760 hr/yr	NSPS Subpart Dc
FGH-2	Fuel Gas Heater	TBD	TBD	12	Natural Gas	12	4	8,760 hr/yr	NSPS Subpart Dc
FGH-3	Fuel Gas Heater	TBD	TBD	12	Natural Gas	12	4	8,760 hr/yr	NSPS Subpart Dc

[x] Estimated Emission Calculations Attached (include references of emission factors) and/or Stack Test Results if Available

Code A – Equipment

BOILER TYPE:
1. Pulverized Coal - Wet Bottom
2. Pulverized Coal - Dry Bottom
3. Pulverized Coal - Cyclone Furnace
4. Circulating Fluidized Bed
5. Spreader Stoke
6. Chain or Travelling Grate Stoker
7. Underfeed Stoker
8. Hand Fired Coal
9. Oil, Tangentially Fired
10. Oil, Horizontally Fired (except rotary cup)
11. Gas, Tangentially Fired
12. Gas, Horizontally Fired
13. Wood with Flyash Reinjection
14. Wood without Flyash Reinjection
15. Other (specify) _Combustion Turbine

OTHER COMBUSTION UNITS:
16. Oven / Kiln
17. Rotary Kiln
18. Process Furnace
19. Other (specify) _____

Code B - Usage

1. Steam Production
2. Drying / Curing
3. Space Heating
4. Process Heat
5. Food Processing
6. Electrical Generation
7. Mechanical Work
8. Other (specify) _____

***Pick only one option for a requested throughput.**

NOTE: Dryers, kilns, and furnaces also have to fill out Page 13.

STATIONARY INTERNAL COMBUSTION ENGINES:

Company Name: **Chickahominy Power, LLC**	**Date: November 2018**	**Registration Number: TBD**

Unit Ref. No.	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Output Brake Horsepower (bhp)	Output Electrical Power (kW)	Type of Fuel	Usage* (use Code C)	Requested Throughput** (hrs/yr OR fuel/yr)	Federal Regulations that Apply
EG-1	Emergency Generator	TBD	TBD	---	3,000	Diesel	1	500 hr/yr	40 CFR Part 60 Subpart IIII, 40 CFR Part 63 Subpart ZZZZ
FWP-1	Emergency Fire Pump	TBD	TBD	376	---	Diesel	1	500 hr/yr	40 CFR Part 60 Subpart IIII, 40 CFR Part 63 Subpart ZZZZ

[x] Estimated Emission Calculations Attached (include references of emission factors and manufacturer specifications per engine) and/or Stack Test Results if
Available

Code C – Usage

1. Emergency Generator
2. Participates in Emergency Load Response Program
3. Non-Emergency Generator
4. Participates in Demand Response Program(s)
5. Other (specify) _____

***Can pick more than one option**
(i.e. 1 and 2 **OR** 3 and 4)

****Pick only one option for a requested throughput.**

PROCESSING, MANUFACTURING, SURFACE COATING AND DEGREASING OPERATIONS:

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Process or Operation Name	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Max. Rated Capacity (gal/hr)*	Requested Throughput*			Federal Regulations that Apply
						(gal/hr)	(_____/day)	(_____/yr)	
CB-1	Circuit Breakers	TBD	TBD	TBD	8,760 hr/yr (0.5% leak rate)	----	----	----	40 CFR Part 98 Subpart DD
NGL-1	Natural Gas Equipment Leaks	TBD	TBD	TBD	----	----	----	----	----

[x] Estimated Emission Calculations Attached (include references of emission factors) and/or Stack Test Results if Available

*** Specify units for each operation in tons, pounds, gallons, etc., as applicable. <u>For coating operations</u>, the maximum rated capacity is the spray gun capacity.**

<u>NOTE:</u> Fill out one page for each ink, coating, stain, and adhesive.

VOLATILE ORGANIC COMPOUND (VOC)/PETROLEUM LIQUID STORAGE TANKS:

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Tank Type (use Code H)	Source of Tank Contents (use Code I)	Date of Manuf.	Date of Const.	Material Stored - Name and CAS # (include Reid Vapor Pressure for Gasoline)	Max. True Vapor Pressure (psia)	Density* (lbs/gal)	Max. Average Storage Temp. (ºF)	Tank Diameter (feet)	Tank Capacity (gal)	Requested Throughput (gal/yr)	Federal Regulations that Apply
T-1	1b	3	TBD	TBD	ULSD 68476-34-6	0.022	6.91 @ 60 ºF	100	4.0	572	9,400	----
T-2	1b	3	TBD	TBD	ULSD 68476-34-6	0.022	6.91 @ 60 ºF	100	6.5	2,500	107,100	----

[x] Estimated Emission Calculations Attached (include TANKS Program printouts)

Code H – Tank Type		**Code I – Source of Tank Contents**
1. Fixed Roof a. Vertical Tank b. Horizontal Tank 2. Floating Roof a. Internal (welded deck) b. Internal (bolted deck) – Specify Panel or Sheet c. External (welded deck) d. External (riveted deck)	3. Variable Vapor Space 4. Pressure Tank (over 15 psig) 5. Underground Splash Loading 6. Underground Submerged Loading 7. Underground Submerged Loading, Balanced 8. Other:_____	1. Pipeline 2. Rail Car 3. Tank Truck 4. Ship or Barge 5. Process

*** Specify the ASTM temperature standard at which the density was measured.**

VOLATILE ORGANIC COMPOUND (VOC)/PETROLEUM LIQUID STORAGE TANKS (CONTINUED):

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Tank Color		Fixed Roof Only					Floating Roof Only				
	Shell	Roof	Internal Tank Height or Length (feet)	Max. Hourly Filling (gallons)	External Fixed Roof			Seal Type (use Code J)	Max. Hourly Withdrawal (gallons)	Internal Floating Roof		
					Type of Roof (cone or dome)	Cone height (ft) and slope (ft/ft)	Dome height (ft) and radius (ft)			Self Supporting?	If no, No. of Columns	If no, Column Diameter (ft)
T-1	Gray	N/A	7	572	N/A	N/A	N/A					
T-2	Gray	N/A	12	2,500	N/A	N/A	N/A					

Code J – Seal Type (Pontoon External Only)	**(Double Deck External Only)**	**(Internal Only)**
1. Mechanical Shoe a. Primary only b. Shoe mounted secondary c. Rim mounted secondary 2. Liquid Mounted a. Primary only b. Weather shield secondary c. Rim mounted secondary 3. Vapor Mounted a. Primary only b. Weather shield secondary c. Rim mounted secondary	4. Mechanical Shoe a. Primary only b. Shoe mounted secondary c. Rim mounted secondary 5. Liquid Mounted a. Primary only b. Weather shield secondary c. Rim mounted secondary 6. Vapor Mounted a. Primary only b. Weather shield secondary c. Rim mounted secondary	7. Mechanical Shoe a. Primary only b. Shoe mounted secondary c. Rim mounted secondary 8. Liquid Mounted a. Primary only b. Rim mounted secondary 9. Vapor Mounted a. Primary only b. Rim mounted secondary

AIR POLLUTION CONTROL AND MONITORING EQUIPMENT:

Company Name:	Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Vent/ Stack No.	Device Ref. No.	Pollutant / Parameter	Air Pollution Control Equipment			Monitoring Instrumentation
				Manufacturer and Model No.	Type (use Code N)	Percent Efficiency (%)	Specify Type, Measured Pollutant, and Recorder Used
CT-1	S-1	D-1	NOx	Dry Low NOx combustion with selective catalytic reduction (SCR)	16	See Appendix B	CEMS for NOx
CT-1	S-1	D-2	CO	Oxidation Catalyst	21	See Appendix B	CEMS for CO
CT-2	S-2	D-3	NOx	Dry Low NOx combustion with SCR	16	See Appendix B	CEMS for NOx
CT-2	S-2	D-4	CO	Oxidation Catalyst	21	See Appendix B	CEMS for CO
CT-3	S-3	D-5	NOx	Dry Low NOx combustion with SCR	16	See Appendix B	CEMS for NOx
CT-3	S-3	D-6	CO	Oxidation Catalyst	21	See Appendix B	CEMS for CO

[x] **Manufacturer Specifications Included**

Code N – Type of Air Pollution Control Equipment

1. Settling Chamber
2. Cyclone
3. Multicyclone
4. Cyclone scrubber
5. Orifice scrubber
6. Mechanical scrubber
7. Venturi scrubber
   a. Fixed throat
   b. Variable throat
8. Mist eliminator
9. Filter
   a. Baghouse
   b. Other:_____
10. Electrostatic Precipitator
    a. Hot side
    b. Cold side
    c. High voltage
    d. Low voltage
    e. Single stage
    f. Two stage
    g. Other:_____
11. Catalytic Afterburner
12. Direct Flame Afterburner
13. Diesel Oxidation Catalyst (DOC)
14. Thermal Oxidizer
15. Regenerative Thermal Oxidizer (RTO)
16. Selective Catalytic Reduction (SCR)
17. Selective Non-Catalytic Reduction (SNCR)
18. Absorber
    a. Packed tower
    b. Spray tower
    c. Tray tower
    d. Venturi
    e. Other:_____
19. Adsorber
    a. Activated carbon
    b. Molecular sieve
    c. Activated alumina
    d. Silica gel
    e. Other:_____
20. Condenser (specify)
21. Other:__ **Oxidation Catalyst**

AIR POLLUTION CONTROL EQUIPMENT - SUPPLEMENTAL INFORMATION:

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Device Ref. No.	Type (use Code N)	Liquid Flow Rate (gpm) (4, 5, 6, 7, 17 ,19)	Liquid Medium (4, 5, 6, 7, 17, 19)	Cleaning Method (9, 10, 17, 18)	Number of Fields (10)	Number of Sections (9, 10)	Air to Cloth Ratio (fpm) (9)	Filter Material (9)	Inlet Temp. (ºF)	Regeneration Method & Cycle Time (sec) (18)	Chamber Temp. (ºF) (11, 12, 14, 15)	Retention Time (sec) (11, 12, 14, 15)	Pressure Drop (inch H_2O) (3, 4, 5, 6, 7, 9, 17)
					Not applicable								

NOTE: **Numbers listed in parenthesis in the columns above represent the Control Equipment in Code N below.**

Code N – Type of Air Pollution Control Equipment

1. Settling Chamber
2. Cyclone
3. Multicyclone
4. Cyclone scrubber
5. Orifice scrubber
6. Mechanical scrubber
7. Venturi scrubber
   a. Fixed throat
   b. Variable throat
8. Mist eliminator
9. Filter
   a. Baghouse
   b. Other:_____
10. Electrostatic Precipitator
    a. Hot side
    b. Cold side
    c. High voltage
    d. Low voltage
    e. Single stage
    f. Two stage
    g. Other:_____
11. Catalytic Afterburner
12. Direct Flame Afterburner
13. Diesel Oxidation Catalyst (DOC)
14. Thermal Oxidizer
15. Regenerative Thermal Oxidizer (RTO)
16. Selective Catalytic Reduction (SCR)
17. Selective Non-Catalytic Reduction (SNCR)
18. Absorber
    a. Packed tower
    b. Spray tower
    c. Tray tower
    d. Venturi
    e. Other:_____
19. Adsorber
    a. Activated carbon
    b. Molecular sieve
    c. Activated alumina
    d. Silica gel
    e. Other:_____
20. Condenser (specify)
21. Other:_____

STACK PARAMETERS AND FUEL DATA:

Company Name:	Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Vent/ Stack No.	Vent/Stack or Exhaust Data						Fuel(s) Data				
		Vent/Stack Config. (use Code O)	Vent/Stack Height (feet)	Exit Diameter (feet)	Exit Gas Velocity (ft/sec)	Exit Gas Flow Rate (acfm)	Exit Gas Temp. (ºF)	Type of Fuel	Heating Value* (Btu/_)	Max. Rated Burned/hr (specify units)	Max. Sulfur %	Max. Ash %
CT-1[a]	1	5	180	22.0	75.7	1,726,000	174	Natural Gas	1,020 Btu/scf	4,070 MMBtu/hr	0.4 grains /100 scf	-
CT-2[a]	2	5	180	22.0	75.7	1,726,000	174	Natural Gas	1,020 Btu/scf	4,070 MMBtu/hr	0.4 grains /100 scf	-
CT-3[a]	3	5	180	22.0	75.7	1,726,000	174	Natural Gas	1,020 Btu/scf	4,070 MMBtu/hr	0.4 grains /100 scf	-
B-1	4	5	40.0	3.5	44.0	25,391	300	Natural Gas	1,020 Btu/scf	84.0 MMBtu/hr	0.4 grains /100 scf	-
B-2	5	5	40.0	3.5	44.0	25,391	300	Natural Gas	1,020 Btu/scf	84.0 MMBtu/hr	0.4 grains /100 scf	-
FGH-1	6	5	20.0	1.50	50.53	5,358	810	Natural Gas	1,020 Btu/scf	12.00 MMBtu/hr	0.4 grains /100 scf	-
FGH-2	6	5	20.0	1.50	50.53	5,358	810	Natural Gas	1,020 Btu/scf	12.00 MMBtu/hr	0.4 grains /100 scf	-
FGH-3	6	5	20.0	1.50	50.53	5,358	810	Natural Gas	1,020 Btu/scf	12.00 MMBtu/hr	0.4 grains /100 scf	-
EG-1	7	5	21.0	1.67	196	25,620	892	ULSD	135,000 Btu/gal	28.9 MMBtu/hr	0.0015%	-
FWP-1	8	5	15.0	0.50	158	1,867	842	ULSD	135,000 Btu/gal	2.54 MMBtu/hr	0.0015%	-

[a] Stack parameters for the annual average temperature of 59 °F without evaporative cooling are listed.

Code O – Vent/Stack Configuration

1. Stack discharging downward, or nearly download
2. Equivalent stack representing a combination of multiple actual stacks
3. Gooseneck stack
4. Stack discharging in a horizontal direction
5. Stack with an unobstructed opening discharge in a vertical direction
6. Vertical stack with a weather cap or similar obstruction in exhaust system

*** Specify units for each heating value in Btus per unit of fuel.**
PROPOSED PERMIT LIMITS FOR CRITERIA POLLUTANTS:

Company Name: Chickahominy Power, LLC	Date: November 2018	Registration Number: TBD

Unit Ref. No.	Proposed Permit Limits for Criteria Pollutants(**)															
	PM [a] (Particulate Matter)		PM-10 [a,b] (10 µM or smaller particulate matter)		PM 2.5 [a,b] (2.5 µM or smaller particulate matter)		SO_2 (Sulfur Dioxide)		NO_X (Nitrogen Oxides)		CO (Carbon Monoxide)		VOC [a] (Volatile Organic Compounds)		Pb (Lead)	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT-1	12.3	53.9	12.3	53.9	12.3	53.9	4.64	20.3	29.3	128.3	8.90	94.3	3.60	68.0	0.0020	0.0087
CT-2	12.3	53.9	12.3	53.9	12.3	53.9	4.64	20.3	29.3	128.3	8.90	94.3	3.60	68.0	0.0020	0.0087
CT-3	12.3	53.9	12.3	53.9	12.3	53.9	4.64	20.3	29.3	128.3	8.90	94.3	3.60	68.0	0.0020	0.0087
B-1	0.59	2.58	0.59	2.58	0.59	2.58	0.096	0.421	0.92	4.05	3.11	13.6	0.42	1.84	4.1E-05	1.8E-04
B-2	0.59	2.58	0.59	2.58	0.59	2.58	0.096	0.421	0.92	4.05	3.11	13.6	0.42	1.84	4.1E-05	1.8E-04
FGH-1	0.08	0.37	0.08	0.37	0.08	0.37	0.014	0.060	0.13	0.58	0.44	1.94	0.06	0.26	5.9E-06	2.6E-05
FGH-2	0.08	0.37	0.08	0.37	0.08	0.37	0.014	0.060	0.13	0.58	0.44	1.94	0.06	0.26	5.9E-06	2.6E-05
FGH-3	0.08	0.37	0.08	0.37	0.08	0.37	0.014	0.060	0.13	0.58	0.44	1.94	0.06	0.26	5.9E-06	2.6E-05
EG-1	1.45	0.36	1.45	0.36	1.45	0.36	0.044	0.011	46.5	11.6	25.45	6.36	9.45	2.36	2.6E-04	6.5E-05
FWP-1	0.12	0.03	0.12	0.03	0.12	0.03	0.004	0.001	2.49	0.62	2.16	0.54	0.09	0.02	2.3E-05	5.7E-06
T-1	-	-	-	-	-	-	-	-	-	-	-	-	6.5E-05	2.9E-04	-	-
T-2	-	-	-	-	-	-	-	-	-	-	-	-	4.2E-04	1.8E-03	-	-
TOTAL:	**39.9**	**168.3**	**39.9**	**168.3**	**39.9**	**168.3**	**14.2**	**62.0**	**139.1**	**407.1**	**61.9**	**322.8**	**21.4**	**211.0**	**0.0063**	**0.027**

[X] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

[a] PM, PM-10, PM 2.5, and VOC should also be split up by component and reported under the Proposed Permit Limits for Toxic Pollutants/HAPs.

[b] PM-10 and PM 2.5 includes filterable and condensable.

[**] Slight differences in calculated totals may occur due to rounding issues.

PROPOSED PERMIT LIMITS FOR TOXIC POLLUTANTS/HAPS:

Company Name:	Chickahominy Power, LLC	Date:	November 2018	Registration Number:	TBD

Unit Ref. No.	Proposed Permit Limits for Toxic/HAP Pollutants*															
	HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:		HAP Name: CAS #:	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
					See Appendix B, Table B-2.5											
TOTAL:																

[x] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

*** Specify the name of the toxic pollutant/HAP for each Unit Ref. No. along with the respective CAS Number**. Toxic Pollutant means a pollutant on the designated list in the Form 7 Instructions document. Particulate matter and volatile organic compounds are not toxic pollutants as generic classes of substances, but individual substances within these classes may be toxic pollutants because their toxic properties or because a TLV (tm) has been

established.

PROPOSED PERMIT LIMITS FOR OTHER REGULATED POLLUTANTS:

Company Name:	Chickahominy Power, LLC	Date:	November 2018	Registration Number:	TBD

Unit Ref. No.	Proposed Permit Limits for Other Regulated Pollutants* [(a)]															
	Pollutant Name: Sulfuric Acid Mist		Pollutant Name: Ammonia		Pollutant Name:		Pollutant Name:		Pollutant Name:		Pollutant Name:		Pollutant Name:		Pollutant Name:	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT-1	4.88	21.4	27.1	118.7												
CT-2	4.88	21.4	27.1	118.7												
CT-3	4.88	21.4	27.1	118.7												
B-1	0.0074	0.032	-	-												
B-2	0.0074	0.032	-	-												
FGH-1	0.0011	0.0046	-	-												
FGH-2	0.0011	0.0046														
FGH-3	0.0011	0.0046	-	-												
EG-1	0.0034	0.00085	-	-												
FWP-1	0.0003	0.00007	-	-												
TOTAL:	**14.66**	**64.3**	**81.3**	**356.1**												

[x] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

*** Other Regulated Pollutant** include Fluorides, Sulfuric Acid Mist, Hydrogen Sulfide (H_2S), Total Reduced Sulfur (including H_2S), Reduced Sulfur Compounds (including H_2S), Municipal Waste Combustor Organics (measured as total tetra-through octa-chlorinated dibenzo-p-dioxins and dibenzofurans), Municipal Waste Combustor Metals (measured as particulate matter), Municipal Waste Combustor Acid Gases (measured as the sum of SO_2 and HCl), and Municipal Solid Waste Landfill Emissions (measured as nonmethane organic compounds).

(a) Slight differences in calculated totals may occur due to rounding issues.

PROPOSED PERMIT LIMITS FOR GREENHOUSE GASES (GHGs) ON MASS BASIS: FOR PSD MAJOR SOURCES ONLY

Company Name:	Chickahominy Power, LLC	Date:	November 2018	Registration Number:	TBD

Unit Ref. No.	Proposed Permit Limits for GHG Pollutants on Mass Basis [a]													
	CO_2 (Carbon Dioxide)		N_2O (Nitrous Oxide)		CH_4 (Methane)		HFCs (Hydrofluoro-carbons)		PFCs (Perfluoro-carbons)		SF_6 (Sulfur Hexafluoride)		Total GHGs	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT-1	484,330	2,121,365	0.897	3.93	8.97	39.3	-	-	-	-	-	-	**484,340**	**2,121,409**
CT-2	484,330	2,121,365	0.897	3.93	8.97	39.3	-	-	-	-	-	-	**484,340**	**2,121,409**
CT-3	484,330	2,121,365	0.897	3.93	8.97	39.3	-	-	-	-	-	-	**484,340**	**2,121,409**
B-1	9,996	43,782	0.019	0.081	0.19	0.81	-	-	-	-	-	-	**9,996**	**43,783**
B-2	9,996	43,782	0.019	0.081	0.19	0.81	-	-	-	-	-	-	**9,996**	**43,783**
FGH-1	1,428	6,255	0.0026	0.012	0.026	0.12	-	-	-	-	-	-	**1,428**	**6,255**
FGH-2	1,428	6,255	0.0026	0.012	0.026	0.12	-	-	-	-	-	-	**1,428**	**6,255**
FGH-3	1,428	6,255	0.0026	0.012	0.026	0.12	-	-	-	-	-	-	**1,428**	**6,255**
EG-1	4,794	1,199	0.038	0.0096	0.19	0.048	-	-	-	-	-	-	**4,794**	**1,199**
FWP-1	421	105	0.0034	0.00084	0.017	0.0042	-	-	-	-	-	-	**421**	**105**
CB-1	-	-	-	-	-	-	-	-	-	-	0.011	0.050	**0.011**	**0.050**
NGL-1	-	-	-	-	2.28	10.0	-	-	-	-	-	-	**2.28**	**10.0**
TOTAL:	**1,482,481**	**6,471,728**	**2.78**	**12.0**	**29.9**	**129.9**	**-**	**-**	**-**	**-**	**0.011**	**0.050**	**1,482,514**	**6,472,002**

[x] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

(b) Slight differences in calculated totals may occur due to rounding issues.

PROPOSED PERMIT LIMITS FOR GREENHOUSE GASES (GHGs) ON CO_2 EQUIVALENT EMISSIONS (CO_2e) BASIS: FOR PSD MAJOR SOURCES ONLY

Company Name:	Chickahominy Power, LLC	Date:	November 2018	Registration Number:	TBD

Unit Ref. No.	Proposed Permit Limits for GHG Pollutants on CO_2 Equivalent Basis													
	CO_2 (Carbon Dioxide)		N_2O (Nitrous Oxide)		CH_4 (Methane)		HFCs (Hydrofluoro-carbons)		PFCs (Perfluoro-carbons)		SF_6 (Sulfur Hexafluoride)		Total GHGs	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT-1	484,330	2,121,365	267.4	1,171	224.3	982.5	-	-	-	-	-	-	**484,822**	**2,123,519**
CT-2	484,330	2,121,365	267.4	1,171	224.3	982.5	-	-	-	-	-	-	**484,822**	**2,123,519**
CT-3	484,330	2,121,365	267.4	1,171	224.3	982.5	-	-	-	-	-	-	**484,822**	**2,123,519**
B-1	9,996	43,782	5.52	24.2	4.63	20.3	-	-	-	-	-	-	**10,006**	**43,827**
B-2	9,996	43,782	5.52	24.2	463	20.3	-	-	-	-	-	-	**10,006**	**43,827**
FGH-1	1,428	6,255	0.79	3.45	0.66	2.90	-	-	-	-	-	-	**1,429**	**6,261**
FGH-2	1,428	6,255	0.79	3.45	0.66	2.90	-	-	-	-	-	-	**1,429**	**6,261**
FGH-3	1,428	6,255	0.79	3.45	0.66	2.90							**1,429**	**6,261**
EG-1	4,794	1,199	11.4	2.85	4.78	1.20	-	-	-	-	-	-	**4,810**	**1,203**
FWP-1	421	105	1.00	0.25	0.42	0.10	-	-	-	-	-	-	**422**	**106**
CB-1	-	-	-	-	-	-	-	-	-	-	260.3	1,140	**260.3**	**1,140**
NGL-1	-	-	-	-	57.1	250.0	-	-	-	-	-	-	**57.1**	**250**
TOTAL:	**1,482,481**	**6,471,728**	**828.0**	**3,575**	**1,205**	**3,248**	**-**	**-**	**-**	**-**	**260.3**	**1,140**	**1,484,774**	**6,479,692**

[x] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

OPERATING PERIODS:

Company Name:	Chickahominy Power, LLC	Date:	November 2018	Registration Number:	TBD

Unit Ref. No.	Percent Annual Use/Throughput by Season				Normal Process/Equipment Operating Schedule			Maximum Process/Equipment Operating Schedule		
	December / February	March / May	June / August	September / November	Hours per Day	Days per Week	Weeks per Year	Hours per Day	Days per Week	Weeks per Year
CT-1	25	25	25	25				24	7	52
CT-2	25	25	25	25				24	7	52
CT-3	25	25	25	25				24	7	52
B-1	25	25	25	25				24	7	52
B-2	25	25	25	25				24	7	52
FGH-1	25	25	25	25				24	7	52
FGH-2	25	25	25	25				24	7	52
FGH-3	25	25	25	25				24	7	52
EG-1	25	25	25	25				1[1]	2[1]	52
FWP-1	25	25	25	25				1[1]	2[1]	52
T-1	25	25	25	25				24	7	52
T-2	25	25	25	25				24	7	52
CB-1	25	25	25	25				24	7	52
NGL-1	25	25	25	25				24	7	52

Maximum Facility Operating Schedule		
Hours per Day	Days per Week	Weeks per Year
24	7	52

[1] The schedule provided for the emergency generator and fire-water pump engine represents 100 hours for maintenance and testing purposes. Emergency use combined will be limited to 500 hours/year.

Appendix B

Emission Calculations

Appendix B
Emission Calculations

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Table B-1.1 Maximum Potential Project Emissions GE 7HA.02

Potential Emissions

Emission Source Description	NO_x (ton/yr)	SO_2 (ton/yr)	PM_{10} (ton/yr)	$PM_{2.5}$ (ton/yr)	CO (ton/yr)	VOC (ton/yr)	H_2SO_4 (ton/yr)	Lead (ton/yr)	GHG CO_2e (ton/yr)
Combustion Turbine #1	116.07	18.19	54.31	54.31	123.06	22.89	12.14	7.82E-03	1,901,202
Combustion Turbine #2	116.07	18.19	54.31	54.31	123.06	22.89	12.14	7.82E-03	1,901,202
Combustion Turbine #3	116.07	18.19	54.31	54.31	123.06	22.89	12.14	7.82E-03	1,901,202
Auxiliary Boilers	5.01	5.21E-01	3.19	3.19	16.85	2.28E+00	3.99E-02	2.23E-04	54,262
Fuel Gas Heaters	1.73	1.80E-01	1.10E+00	1.10E+00	5.83	7.88E-01	1.38E-02	7.73E-05	18,783
Diesel-Fired Emergency Generator	11.63	1.11E-02	3.64E-01	3.64E-01	6.36	2.36E+00	8.52E-04	6.51E-05	1,203
Diesel-Fired Fire Water Pump	0.62	9.76E-04	3.11E-02	3.11E-02	0.54	2.32E-02	7.47E-05	5.71E-06	106
Emergency Generator Fuel Oil Tank						1.83E-03			
Fire Water Pump Fuel Oil Tank						2.85E-04			
Circuit Breakers									1,140
Natural Gas Equipment Leaks									250
Total Project Emissions:	**367.2**	**55.30**	**167.6**	**167.6**	**398.8**	**74.1**	**36.5**	**0.024**	**5,779,348**
PSD Major Source Threshold	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100,000**
PSD Major Source	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**No**	**No**	**No**	**Yes**
PSD Significant Emission Rate	**40**	**40**	**15**	**10**	**100**	**40**	**7**	**0.6**	**75,000**
Proposed Project Subject to PSD	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**

NA = Not applicable

Table B-1.2 GE 7HA.02 Detailed Operating and Emissions Calculations

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14
SITE CONDITIONS															
Ambient Temperature	°F	-12	-12	-12	20	20	20	59	59	59	59	99	99	99	99
Ambient Pressure	psia	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Ambient Relative Humidity	%	90	90	90	60	60	60	60	60	60	60	60	60	60	60
PLANT STATUS															
HRSG Duct Burner		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Evaporative Cooler state (On or Off)		Off	Off	Off	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off
Gas Turbine Load	%	BASE	75.0%	43.6%	BASE	75.0%	38.0%	BASE	BASE	75.0%	33.3%	BASE	BASE	75.0%	31.8%
FUEL DATA															
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
HHV	Btu/lb	23,031	23,031	23,031	23,031	23,031	23,031	23,031	23,031	23,031	23,031	23,031	23,031	23,031	23,031
LHV	Btu/lb	20,781	20,781	20,781	20,781	20,781	20,781	20,781	20,781	20,781	20,781	20,781	20,781	20,781	20,781
Fuel Sulfur Content	grains/100 SCF @ 60°F	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Gas Turbine Heat Consumption per Unit	MMBtu/hr, HHV	3,616	2,868	1,993	3,644	2,858	1,837	3,593	3,556	2,782	1,627	3,557	3,277	2,574	1,486
Fuel Sulfur Content	grains/100 scf (60°F)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Duct Burner Heat Consumption	MMBtu/hr, HHV	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Heat Input	MMBtu/hr, HHV	3,616	2,868	1,993	3,644	2,858	1,837	3,593	3,556	2,782	1,627	3,557	3,277	2,574	1,486
HRSG EXIT EXHAUST GAS															
Composition:															
Ar	mol %	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.87	0.89	0.86	0.86	0.87	0.87
CO2	mol %	4.36	4.33	3.89	4.39	4.34	3.96	4.43	4.43	4.27	3.78	4.41	4.38	4.21	3.67
H2O	mol %	8.48	8.41	7.55	8.67	8.58	7.84	9.76	9.53	10.52	8.26	11.78	11.16	10.84	9.81
N2	mol %	74.74	74.77	75.10	74.61	74.64	74.93	73.79	73.97	73.07	74.47	72.20	72.65	72.78	73.18
O2	mol %	11.53	11.61	12.56	11.44	11.54	12.37	11.14	11.18	11.27	12.61	10.75	10.94	11.30	12.47
Molecular weight		28.43	28.44	28.49	28.41	28.41	28.46	28.30	28.32	28.20	28.40	28.07	28.13	28.16	28.22
Mass Flow	lb/hr	6,305,400	5,043,700	3,910,500	6,311,000	5,003,500	3,910,500	6,135,400	6,082,300	4,812,500	3,278,700	6,056,500	5,636,300	4,606,400	3,059,100
Std Volume Flow	scf/hr (68°F)	85,451,152	68,341,085	52,888,157	85,579,102	67,834,007	47,839,783	83,540,840	82,749,743	65,451,898	44,475,101	83,117,234	77,180,764	63,025,833	41,762,372
Stack Gas Temperature	°F	189	179	173	188	178	166	186	185	175	165	202	197	188	179
Stack Gas Flow	million acfh	105.520	83.156	63.699	105.450	82.397	56.945	102.700	101.570	79.080	52.923	104.710	96.541	77.684	50.752
Stack Gas Flow	acfm	1,758,667	1,385,933	1,061,650	1,757,500	1,373,283	949,083	1,711,667	1,692,833	1,318,000	882,050	1,745,167	1,609,017	1,294,733	845,867
Stack Diameter	ft	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Stack Diameter	ft	180	180	180	180	180	180	180	180	180	180	180	180	180	180
Stack Exit Gas Velocity	ft/s	77.11	60.77	46.55	77.06	60.21	41.61	75.05	74.22	57.79	38.67	76.52	70.55	56.77	37.09

Table B-1.2 GE 7HA.02 Detailed Operating and Emissions Calculations

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14
SITE CONDITIONS															
Ambient Temperature	°F	-12	-12	-12	20	20	20	59	59	59	59	99	99	99	99
HRSG EXIT EXHAUST GAS EMISSIONS															
NOx	ppmvd @ 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx	lb/hr as NO2	26.3	20.8	14.5	26.5	20.8	13.3	26.1	25.9	20.2	11.8	25.9	23.8	18.7	10.8
NOx	lb/MMBtu	0.0073	0.0073	0.0073	0.0073	0.0073	0.0072	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
CO	ppmvd @ 15% O2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CO	lb/hr	8.0	6.4	4.4	8.1	6.3	4.1	8.0	7.9	6.2	3.6	7.9	7.3	5.7	3.3
CO	lb/MMBtu	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022
VOC	ppmvd @ 15% O2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
VOC	lb/hr as methane	3.22	2.52	1.75	3.24	2.52	1.6	3.22	3.15	2.45	1.47	3.15	2.94	2.31	1.33
VOC	lb/MMBtu	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009
SO2	lb/hr	4.12	3.27	2.27	4.15	3.26	2.09	4.10	4.05	3.17	1.86	4.05	3.74	2.93	1.69
SO2	lb/MMBtu	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114
Sulfuric Acid Mist	lb/hr	2.75	2.17	1.50	2.77	2.17	1.42	2.67	2.67	2.08	1.25	2.67	2.42	1.92	1.08
Sulfuric Acid Mist	lb/MMBtu	0.00076	0.00076	0.00075	0.00076	0.00076	0.00077	0.00074	0.00075	0.00075	0.00077	0.00075	0.00074	0.00074	0.00073
Particulates - Filterable + Condensible	lb/hr	12.4	11.7	10.8	12.4	11.7	10.7	12.4	12.3	11.6	10.5	12.3	12.1	11.4	10.3
Particulates - Filterable + Condensible	lb/MMBtu	0.0034	0.0041	0.0054	0.0034	0.0041	0.0058	0.0035	0.0035	0.0042	0.0065	0.0035	0.0037	0.0044	0.0069
NH3	ppmvd @ 15% O2	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NH3	lb/hr	24.3	19.3	13.4	24.5	19.2	12.3	24.2	23.9	18.7	10.9	23.9	22.0	17.3	10.0
NH3	lb/MMBtu	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067
Lead	lb/hr	1.77E-03	1.41E-03	9.76E-04	1.79E-03	1.40E-03	9.00E-04	1.76E-03	1.74E-03	1.36E-03	7.97E-04	1.74E-03	1.61E-03	1.26E-03	7.28E-04
Lead	lb/MMBtu	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07
CO2	lb/MMBtu	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00
CO2	lb/hr	430,268	341,328	237,108	433,624	340,114	218,567	427,591	423,140	331,070	193,649	423,259	389,927	306,306	176,858
CH4	lb/MMBtu	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022
CH4	lb/hr	7.97	6.32	4.39	8.03	6.30	4.05	7.92	7.84	6.13	3.59	7.84	7.22	5.67	3.28
N2O	lb/MMBtu	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
N2O	lb/hr	0.80	0.63	0.44	0.80	0.63	0.40	0.79	0.78	0.61	0.36	0.78	0.72	0.57	0.33
GHG Total Mass	lb/MMBtu	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00
GHG Total Mass	lb/hr	430,277	341,335	237,112	433,633	340,121	218,572	427,600	423,149	331,077	193,653	423,268	389,935	306,312	176,861
GHG Total CO2e	lb/MMBtu	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12
GHG Total CO2e	lb/hr	430,705	341,674	237,348	434,064	340,459	218,789	428,025	423,570	331,406	193,845	423,689	390,323	306,617	177,037

Table B-1.3 Annual Emissions with Startups and Shutdowns - GE 7HA.02

Start-up, Shutdown and Offline Events / Hours (Average Each Turbine)

Operating Mode	Number	Duration (SU/SD)		Offline Minimum		NO_x	CO	VOC	Fuel
	of Events/yr	min/event	hr/yr	hr/event	hr/yr	lb/event	lb/event	lb/event	MMBtu/event
Cold start	18	66.0	19.8	48	864	312.0	924	66.0	1,464
Warm start	52	48.0	41.6	8	416	175.2	470	48.0	1,116
Hot start	208	24.0	83.2	0	0	84.0	449	45.6	384
Shutdown	278	15.0	69.5	n/a	n/a	16.3	190	32.5	175
TOTALS			**214.1**		**1280**				

NOx, CO, and VOC emissions and SUSD durations and fuel use are based on Gemma data, October 2018. SO_2, $PM_{10}/PM_{2.5}$, NH_3, H_2SO_4, and GHG emissions are less than normal operating emissions. Event durations and emissions are averages.

Annual Emissions with Start-up and Shutdown (One Turbine)

Operating Mode		NOx		CO		VOC	
	hr/yr	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Offline	1,280	0	0	0	0	0	0
Normal, without duct burning	7,266	26.5	96.3	8.1	29.4	3.2	11.8
Cold start	19.8	283.6	2.81	840.0	8.32	60.0	0.59
Warm start	41.6	219.0	4.56	588.0	12.23	60.0	1.25
Hot start	83.2	210.0	8.74	1122.0	46.68	114.0	4.74
Shutdown	69.5	65.0	2.26	760.0	26.41	130.0	4.52
TOTALS	**8,760**		**114.6**		**123.1**		**22.9**

The lb/hr emissions represent the average lb/hr for the duration of the event.

Offline hours are the minimums. For each hot start, the CTGs are assumed to be offline for at least 0 hours (maximum 8 hours), for each warm start the CTGs are offline for at least 8 hours up to 48 hours, and for each cold start the CTGs are offline for 48 hours minimum, typically at least 72 hours.

Table B-1.4 Maximum Annual Emissions with Startups and Shutdowns - GE 7HA.02

Operating Parameters - Each Unit

		Potential Emission Rates (Per Turbine)			Three 1x1 Configuration
Parameter	**Maximum Combustion Turbine**	**Annual Emissions Based on CT Only (Year-Round)**	**Annual Emissions with Startup and Shutdown**	**Maximum Annual Emissions**	**Maximum Annual Emissions (Total for Three Turbines)**
Operating Hours	8,760 hr/yr				
NO_x	26.5 lb/hr	116.1 ton/yr	114.6 ton/yr	116.1 ton/yr	348.2 ton/yr
CO	8.1 lb/hr	35.5 ton/yr	123.1 ton/yr	123.1 ton/yr	369.2 ton/yr
VOC	3.24 lb/hr	14.2 ton/yr	22.9 ton/yr	22.9 ton/yr	68.7 ton/yr
$PM_{10}/PM_{2.5}$	12.4 lb/hr	54.3 ton/yr	<54.3 ton/yr	54.3 ton/yr	162.9 ton/yr
SO_2	4.15 lb/hr	18.2 ton/yr	<18.2 ton/yr	18.2 ton/yr	54.6 ton/yr
H_2SO_4	2.77 lb/hr	12.1 ton/yr	<12.1 ton/yr	12.1 ton/yr	36.4 ton/yr
NH_3	24.5 lb/hr	107.3 ton/yr	<107.3 ton/yr	107.3 ton/yr	321.9 ton/yr
Lead	0.0018 lb/hr	0.0078 ton/yr	<0.0078 ton/yr	0.0078 ton/yr	0.023 ton/yr
CO_2	433,624 lb/hr	1,899,274 ton/yr	<1,899,274 ton/yr	1,899,274 ton/yr	5,697,821 ton/yr
CH_4	8.03 lb/hr	35.2 ton/yr	<35.2 ton/yr	35.2 ton/yr	105.6 ton/yr
N_2O	0.803 lb/hr	3.52 ton/yr	<3.52 ton/yr	3.52 ton/yr	10.556 ton/yr
GHG Total Mass	433,633 lb/hr	1,899,312 ton/yr	<1,899,312 ton/yr	1,899,312 ton/yr	5,697,937 ton/yr
GHG CO_2e	434,064 lb/hr	1,901,202 ton/yr	<1,901,202 ton/yr	1,901,202 ton/yr	5,703,605 ton/yr

Notes:

Hourly emission estimates are based on worst-case ambient conditions (i.e., temperature, % relative humidity) at normal operations.

For "annual emissions with no DB firing", emission estimates for the natural gas firing (CT only) were based on 8760 operating hours per year.

Table B-1.5 Hazardous Air Pollutant Emissions - GE 7HA.02

Combustion Turbines

Number:	3		Natural Gas Heating Value:	1,020	Btu/scf (HHV)
Maximum Heat Input - CT	3,644	MMBtu/hr (HHV)			
Maximum Heat Input - Duct Burner	-	MMBtu/hr (HHV)			
Operating Hours with Duct Burner	8,760	hr/yr	**Combined Cycle VOHAP Efficiency:**	**35% reduction**	
Operating Hours - No Duct Burner	-	hr/yr			

Auxiliary Boilers			**Fuel Gas Heaters**			**Emergency Firewater Pump**			**Emergency Generator**		
Number:	2		Number:	3		Number:	1		Number:	1	
Maximum Heat Input	52.0	MMBtu/hr	Maximum Heat Input	12.0	MMBtu/hr	Maximum Heat Input	2.54	MMBtu/hr	Maximum Heat Input	28.9	MMBtu/hr
Operating Hours	8,760	hr/yr	Operating Hours	8,760	hr/yr	Operating Hours	500	hr/yr	Operating Hours	500	hr/yr

						Combustion Turbine		Auxiliary Boiler		Fuel Gas Heater		Emergency Firewater		Emergency Generator		Total - New Sources	
	Emission Factor	Emission Factor		Emission Factor	Emission Factor	Emission Rate, 1 Turbine		Emission Rate, 1 Boiler		Emission Rate, 1 Boiler		Emission Rate, 1 Firewater Pump		Emission Rate, 1 Generator		Emission Rate, Total	
Pollutant	AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas	AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion		AP-42 Section 3.3 04/00 - Gasoline and Diesel Industrial Engines (up to 600 HP)	AP-42 Section 3.4 04/00 - Large Stationary Diesel Engines (> 600 HP)	Maximum Hourly[b]	Annual[c]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly[d]	Annual[e]	Maximum Hourly	Annual
	(lb/MMBtu)[a]	(lb/10^6scf)	(lb/MMBtu)[a]	(lb/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
1,3-Butadiene	4.30E-07			3.91E-05		1.02E-03	4.46E-03					9.92E-05	2.48E-05			3.15E-03	1.34E-02
2-Methylnaphthalene		2.40E-05	2.35E-08			0.00E+00	0.00E+00	1.22E-06	5.36E-06	2.82E-07	1.24E-06					3.29E-06	1.44E-05
3-Methylchloranthrene		1.80E-06	1.76E-09			0.00E+00	0.00E+00	9.18E-08	4.02E-07	2.12E-08	9.28E-08					2.47E-07	1.08E-06
7,12-Dimethylbenz(a)anthracene		1.60E-05	1.57E-08			0.00E+00	0.00E+00	8.16E-07	3.57E-06	1.88E-07	8.24E-07					2.20E-06	9.62E-06
Acenaphthene		1.80E-06	1.76E-09	1.42E-06	4.68E-06	0.00E+00	0.00E+00	9.18E-08	4.02E-07	2.12E-08	9.28E-08	3.60E-06	9.01E-07	1.35E-04	3.38E-05	1.39E-04	3.58E-05
Acenaphthylene		1.80E-06	1.76E-09	5.06E-06	9.23E-06	0.00E+00	0.00E+00	9.18E-08	4.02E-07	2.12E-08	9.28E-08	1.28E-05	3.21E-06	2.67E-04	6.67E-05	2.80E-04	7.10E-05
Acetaldehyde	4.00E-05			7.67E-04	2.52E-05	9.47E-02	4.15E-01					1.95E-03	4.87E-04	7.29E-04	1.82E-04	2.87E-01	1.25E+00
Acrolein	6.40E-06			9.25E-05	7.88E-06	1.52E-02	6.64E-02					2.35E-04	5.87E-05	2.28E-04	5.70E-05	4.59E-02	1.99E-01
Anthracene		2.40E-06	2.35E-09	1.87E-06	1.23E-06	0.00E+00	0.00E+00	1.22E-07	5.36E-07	2.82E-08	1.24E-07	4.75E-06	1.19E-06	3.56E-05	8.89E-06	4.06E-05	1.15E-05
Benz(a)anthracene		1.80E-06	1.76E-09	1.68E-06	6.22E-07	0.00E+00	0.00E+00	9.18E-08	4.02E-07	2.12E-08	9.28E-08	4.26E-06	1.07E-06	1.80E-05	4.50E-06	2.25E-05	6.64E-06
Benzene	1.20E-05	2.10E-03	2.06E-06	9.33E-04	7.76E-04	2.84E-02	1.24E-01	1.07E-04	4.69E-04	2.47E-05	1.08E-04	2.37E-03	5.92E-04	2.24E-02	5.61E-03	1.10E-01	3.81E-01
Benzo(a)pyrene		1.20E-06	1.18E-09	1.88E-07	2.57E-07	0.00E+00	0.00E+00	6.12E-08	2.68E-07	1.41E-08	6.18E-08	4.77E-07	1.19E-07	7.43E-06	1.86E-06	8.07E-06	2.70E-06
Benzo(b)flouoranthene		1.80E-06	1.76E-09	9.91E-08	1.11E-06	0.00E+00	0.00E+00	9.18E-08	4.02E-07	2.12E-08	9.28E-08	2.52E-07	6.29E-08	3.21E-05	8.02E-06	3.26E-05	9.17E-06
Benzo(g,h,I)perylene		1.20E-06	1.18E-09		5.56E-07	0.00E+00	0.00E+00	6.12E-08	2.68E-07	1.41E-08	6.18E-08			1.61E-05	4.02E-06	1.62E-05	4.74E-06
Benzo(k)fluoranthene		1.80E-06	1.76E-09	1.55E-07	2.18E-07	0.00E+00	0.00E+00	9.18E-08	4.02E-07	2.12E-08	9.28E-08	3.93E-07	9.83E-08	6.30E-06	1.58E-06	6.94E-06	2.76E-06
Chrysene		1.80E-06	1.76E-09	3.53E-07	1.53E-06	0.00E+00	0.00E+00	9.18E-08	4.02E-07	2.12E-08	9.28E-08	8.96E-07	2.24E-07	4.42E-05	1.11E-05	4.54E-05	1.24E-05
Dibenzo(a,h)anthracene		1.20E-06	1.18E-09	5.83E-07	3.46E-07	0.00E+00	0.00E+00	6.12E-08	2.68E-07	1.41E-08	6.18E-08	1.48E-06	3.70E-07	1.00E-05	2.50E-06	1.16E-05	3.59E-06
Dichlorobenzene		1.20E-03	1.18E-06			0.00E+00	0.00E+00	6.12E-05	2.68E-04	1.41E-05	6.18E-05					1.65E-04	7.21E-04
Ethylbenzene	3.20E-05					7.58E-02	3.32E-01									2.27E-01	9.96E-01
Fluoranthene		3.00E-06	2.94E-09	7.61E-06	4.03E-06	0.00E+00	0.00E+00	1.53E-07	6.70E-07	3.53E-08	1.55E-07	1.93E-05	4.83E-06	1.17E-04	2.91E-05	1.36E-04	3.58E-05
Fluorene		2.80E-06	2.75E-09	2.92E-05	1.28E-05	0.00E+00	0.00E+00	1.43E-07	6.25E-07	3.29E-08	1.44E-07	7.41E-05	1.85E-05	3.70E-04	9.25E-05	4.45E-04	1.13E-04
Formaldehyde (g)	1.83E-04	7.50E-02	7.35E-05	1.18E-03	7.89E-05	6.67E-01	2.92E+00	3.82E-03	1.67E-02	8.82E-04	3.86E-03	2.99E-03	7.49E-04	2.28E-03	5.70E-04	2.02E+00	8.81E+00
Hexane (i)		1.30E-03	1.27E-06			0.00E+00	0.00E+00	6.63E-05	2.90E-04	1.53E-05	6.70E-05					1.78E-04	7.82E-04
Indeno(1,2,3-cd)pyrene		1.80E-06	1.76E-09	3.75E-07	4.14E-07	0.00E+00	0.00E+00	9.18E-08	4.02E-07	2.12E-08	9.28E-08	9.52E-07	2.38E-07	1.20E-05	2.99E-06	1.32E-05	4.31E-06
Naphthalene	1.30E-06	6.10E-04	5.98E-07	8.48E-05	1.3E-04	3.08E-03	1.35E-02	3.11E-05	1.36E-04	7.18E-06	3.14E-05	2.15E-04	5.38E-05	3.76E-03	9.40E-04	1.33E-02	4.18E-02
PAHs	2.20E-06					5.21E-03	2.28E-02									1.56E-02	6.85E-02
Phenanathrene		1.70E-05	1.67E-08	2.94E-05	4.08E-05	0.00E+00	0.00E+00	8.67E-07	3.80E-06	2.00E-07	8.76E-07	7.46E-05	1.87E-05	1.18E-03	2.95E-04	1.26E-03	3.24E-04
Propylene Oxide	2.90E-05					6.87E-02	3.01E-01									2.06E-01	9.03E-01
Pyrene		5.00E-06	4.90E-09	4.78E-06	3.71E-06	0.00E+00	0.00E+00	2.55E-07	1.12E-06	5.88E-08	2.58E-07	1.21E-05	3.03E-06	1.07E-04	2.68E-05	1.20E-04	3.29E-05
Toluene	1.30E-04	3.40E-03	3.33E-06	4.09E-04	2.81E-04	3.08E-01	1.35E+00	1.73E-04	7.59E-04	4.00E-05	1.75E-04	1.04E-03	2.60E-04	8.13E-03	2.03E-03	9.33E-01	4.05E+00
Xylene	6.40E-05			2.85E-04	1.93E-04	1.52E-01	6.64E-01					7.23E-04	1.81E-04	5.58E-03	1.40E-03	4.61E-01	1.99E+00

Table B-1.5 Hazardous Air Pollutant Emissions - GE 7HA.02

Combustion Turbines

Number:	3		Natural Gas Heating Value:	1,020	Btu/scf (HHV)
Maximum Heat Input - CT	3,644	MMBtu/hr (HHV)			
Maximum Heat Input - Duct Burner	-	MMBtu/hr (HHV)			
Operating Hours with Duct Burner	8,760	hr/yr	**Combined Cycle VOHAP Efficiency:**	**35% reduction**	
Operating Hours - No Duct Burner	-	hr/yr			

Auxiliary Boilers			**Fuel Gas Heaters**			**Emergency Firewater Pump**			**Emergency Generator**		
Number:	2		Number:	3		Number:	1		Number:	1	
Maximum Heat Input	52.0	MMBtu/hr	Maximum Heat Input	12.0	MMBtu/hr	Maximum Heat Input	2.54	MMBtu/hr	Maximum Heat Input	28.9	MMBtu/hr
Operating Hours	8,760	hr/yr	Operating Hours	8,760	hr/yr	Operating Hours	500	hr/yr	Operating Hours	500	hr/yr

						Combustion Turbine		Auxiliary Boiler		Fuel Gas Heater		Emergency Firewater		Emergency Generator		Total - New Sources	
Pollutant	**Emission Factor**	**Emission Factor**		**Emission Factor**	**Emission Factor**	**Emission Rate, 1 Turbine**		**Emission Rate, 1 Boiler**		**Emission Rate, 1 Boiler**		**Emission Rate, 1 Firewater Pump**		**Emission Rate, 1 Generator**		**Emission Rate, Total**	
	AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas	**AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion**		**AP-42 Section 3.3 04/00 - Gasoline and Diesel Industrial Engines (up to 600 HP)**	**AP-42 Section 3.4 04/00 - Large Stationary Diesel Engines (> 600 HP)**	**Maximum Hourly[b]**	**Annual[c]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly**	**Annual**
	(lb/MMBtu)[a]	**(lb/10^{6}scf)**	**(lb/MMBtu)[a]**	**(lb/MMBtu)**	**(lb/MMBtu)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
Arsenic [f]		2.00E-04	1.96E-07			7.14E-04	3.13E-03	1.02E-05	4.47E-05	2.35E-06	1.03E-05					2.17E-03	9.51E-03
Beryllium [f]		1.20E-05	1.18E-08			4.29E-05	1.88E-04	6.12E-07	2.68E-06	1.41E-07	6.18E-07					1.30E-04	5.71E-04
Cadmium [f]		1.10E-03	1.08E-06			3.93E-03	1.72E-02	5.61E-05	2.46E-04	1.29E-05	5.67E-05					1.19E-02	5.23E-02
Chromium [f]		1.40E-03	1.37E-06			5.00E-03	2.19E-02	7.14E-05	3.13E-04	1.65E-05	7.21E-05					1.52E-02	6.66E-02
Cobalt [f]		8.40E-05	8.24E-08			3.00E-04	1.31E-03	4.28E-06	1.88E-05	9.88E-07	4.33E-06					9.12E-04	3.99E-03
Lead [f]		5.00E-04	4.90E-07			1.79E-03	7.82E-03	2.55E-05	1.12E-04	5.88E-06	2.58E-05					5.43E-03	2.38E-02
Manganese [f]		3.80E-04	3.73E-07			1.36E-03	5.95E-03	1.94E-05	8.49E-05	4.47E-06	1.96E-05					4.12E-03	1.81E-02
Mercury [f]		2.60E-04	2.55E-07			9.29E-04	4.07E-03	1.33E-05	5.81E-05	3.06E-06	1.34E-05					2.82E-03	1.24E-02
Nickel [f]		2.10E-03	2.06E-06			7.50E-03	3.29E-02	1.07E-04	4.69E-04	2.47E-05	1.08E-04					2.28E-02	9.98E-02
Selenium [f]		2.40E-05	2.35E-08			8.57E-05	3.76E-04	1.22E-06	5.36E-06	2.82E-07	1.24E-06					2.61E-04	1.14E-03
															Total HAPS (tpy)		**18.99**
															Max Single HAP (tpy)		**8.81**

Notes:
(a) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (Volumetric Heat Content, Btu/scf)
(b) For Turbines, Hourly Emission Rate (lb/hr) = [Max Heat Input - CT (MMBtu/hr) * Emission Factor - CT (lb/MMBtu) + Max Heat Input - DB (MMBtu/hr) * Emission Factor - non-CT (lb/MMBtu)]
(c) For Turbines, Annual Emission Rate (tpy) = [Max Heat Input - CT (MMBtu/Hr) * 8760 hr/yr * Emission Factor - CT (lb/MMBtu) + Max Heat Input - DB (MMBtu/Hr) * Operating Hours - DB (hr/yr) * Emission Factor - non-CT (lb/MMBtu)] / (2,000 lb/ton)
(d) For Boiler/Heaters/Engines, Hourly Emission Rate (lb/hr) = Max Heat Input (MMBtu/Hr) * Emission Factor - non-CT (lb/MMBtu)
(e) For Boilers/ Heaters/ Engines, Annual Emission Rate (ton/yr) = Max Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu) * Annual Operation (hr/yr) / 2000 (lb/ton)
(f) Combustion turbine emissions of metallic HAPs calculated using non-CT natural gas combustion emission factors.
(g) 78 ppbvd at 15% O2 after control by the oxidation catalyst.
(i) Ventura County APCD.

Table B-1.6 Hazardous Air Pollutant Air Toxics Analysis- GE 7HA.02

Pollutant	Total - New Sources (Table B-1.5) Emission Rate, Total		Virginia Air Toxics Exemption Levels		Exempt? (hourly)	Exempt? (annual)	SAAC (ug/m3)	
	Maximum Hourly	Annual	Maximum Hourly	Annual				
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	Yes/No	Yes/No	Hourly	Annual
1,3-Butadiene	3.15E-03	1.34E-02	1.452	3.19	Yes	Yes		
2-Methylnaphthalene	3.29E-06	1.44E-05	*	*	Yes	Yes		
3-Methylchloranthrene	2.47E-07	1.08E-06	*	*	Yes	Yes		
7,12-Dimethylbenz(a)anthracene	2.20E-06	9.62E-06	*	*	Yes	Yes		
Acenaphthene	1.39E-04	3.58E-05	*	*	Yes	Yes		
Acenaphthylene	2.80E-04	7.10E-05	*	*	Yes	Yes		
Acetaldehyde	2.87E-01	1.25E+00	8.91	26.1	Yes	Yes		
Acrolein	4.59E-02	1.99E-01	0.02277	0.03335	No	No	17.25	0.46
Anthracene	4.06E-05	1.15E-05	*	*	Yes	Yes		
Benz(a)anthracene	2.25E-05	6.64E-06	*	*	Yes	Yes		
Benzene	1.10E-01	3.81E-01	2.112	4.64	Yes	Yes		
Benzo(a)pyrene	8.07E-06	2.70E-06	*	*	Yes	Yes		
Benzo(b)flouoranthene	3.26E-05	9.17E-06	*	*	Yes	Yes		
Benzo(g,h,I)perylene	1.62E-05	4.74E-06	*	*	Yes	Yes		
Benzo(k)fluoranthene	6.94E-06	2.76E-06	*	*	Yes	Yes		
Chrysene	4.54E-05	1.24E-05	*	*	Yes	Yes		
Dibenzo(a,h)anthracene	1.16E-05	3.59E-06	*	*	Yes	Yes		
Dichlorobenzene	1.65E-04	7.21E-04	21.813	65.395	Yes	Yes		
Ethylbenzene	2.27E-01	9.96E-01	17.919	62.93	Yes	Yes		
Fluoranthene	1.36E-04	3.58E-05	*	*	Yes	Yes		
Fluorene	4.45E-04	1.13E-04	*	*	Yes	Yes		
Formaldehyde (g)	2.02E+00	8.81E+00	0.0825	0.174	No	No	62.5	2.4
Hexane	1.78E-04	7.82E-04	11.616	25.52	Yes	Yes		
Indeno(1,2,3-cd)pyrene	1.32E-05	4.31E-06	*	*	Yes	Yes		
Naphthalene	1.33E-02	4.18E-02	2.607	7.54	Yes	Yes		
PAHs	1.56E-02	6.85E-02	*	*	Yes	Yes		
Phenanathrene	1.26E-03	3.24E-04	*	*	Yes	Yes		
Propylene Oxide	2.06E-01	9.03E-01	3.168	6.96	Yes	Yes		
Pyrene	1.20E-04	3.29E-05	*	*	Yes	Yes		
Toluene	9.33E-01	4.05E+00	18.645	54.665	Yes	Yes		
Xylene	4.61E-01	1.99E+00	21.483	62.93	Yes	Yes		
Arsenic	2.17E-03	9.51E-03	0.0132	0.029	Yes	Yes		
Beryllium	1.30E-04	5.71E-04	0.000132	0.00029	Yes	No	0.1	0.004
Cadmium	1.19E-02	5.23E-02	0.0033	0.00725	No	No	2.5	0.1
Chromium	1.52E-02	6.66E-02	0.0033	0.00725	No	No	2.5	0.1
Cobalt	9.12E-04	3.99E-03	0.0033	0.00725	Yes	Yes		
Lead	5.43E-03	2.38E-02	0.0099	0.02175	Yes	No		0.3
Manganese	4.12E-03	1.81E-02	0.33	0.725	Yes	Yes		
Mercury	2.82E-03	1.24E-02	0.0033	0.00725	Yes	No		0.1
Nickel	2.28E-02	9.98E-02	0.0066	0.0145	No	No	5	0.2
Selenium	2.61E-04	1.14E-03	0.0132	0.029	Yes	Yes		

Notes:

* indicates that neither exemption levels or SAACs exist.

Table B-1.7 Auxiliary Boiler Emissions - GE 7HA.02

Emission Source	Auxiliary Boiler
Source Type	Natural Gas-Fired Boiler
Heat Input (MMBtu/hr)	52.0
Maximum Fuel Usage (MMcf/hr)	0.0510
Number of Units	2
Natural Gas Heating Value (Btu/scf)	1,020
Sulfur Content of Natural Gas (gr S /100 scf)	0.40
Annual Capacity Factor (%)	100

Compound	Emission Factor	Emission Rate - per Unit		Total Units
		Hourly (c)	Annual (d)	Annual (d)
	(lb/MMBtu)	(lb/hr)	(ton/year)	(ton/year)
Nitrogen Oxides (a)	0.011	0.57	2.51	5.01
Carbon Monoxide (a)	0.037	1.92	8.43	16.85
VOC (a)	0.0050	0.26	1.14	2.28
Sulfur Oxides (a)	1.14E-03	0.059	0.261	0.521
$PM_{10}/PM_{2.5}$ (a)	0.0070	0.36	1.59	3.189
Lead (b)	4.9E-07	2.5E-05	1.1E-04	2.23E-04
H_2SO_4 (f)	8.76E-05	4.6E-03	2.0E-02	3.99E-02
CO_2 (g)	119.00	6,188	27,103	54,207
CH_4 (g)	0.00220	1.1E-01	5.0E-01	1.0E+00
N_2O (g)	0.00022	1.1E-02	5.0E-02	1.0E-01
GHG mass (g)	119.00	6,188	27,104	54,208
GHG CO_2e (h)	119.12	6,194	27,131	54,262

Notes:

(a) Emission factors (lb/MMBtu) are based on the proposed BACT emission rates for natural gas-fired boilers.

(b) Emission factors (lb/MMBtu) are based on emission factors (lb/MMcf) referenced from AP-42, Section 1.4 dated July 1998 and a heat content value of 1020 Btu/scf.

(c) Hourly Emission Rate (lb/hr) = Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu)

(d) Annual Emission Rate (ton/yr) = Hourly Emission Rate (lb/hr) * Annual Operating Hours (hr/yr) / (2,000 lb/ton)

(e) H_2SO_4 emissions based on a 5% conversion of SO_2 to SO_3.

(g) CO2 emission factor is based on monitoring experience in Virginian (Greensville PSD permit application). Emission factors for CH4 and NO2 are based on the EPA rule "Mandatory Reporting of Greenhouse Gases", Tables C-1 and C-2.

(h) Global Warming Potentials, Federal Register Vol. 78, No. 230, November 29, 2013.

Stack Parameters

Stack Height	40.0	ft
Stack Diameter	3.00	ft
Stack Exit Velocity	38.5	ft/s
Exhaust Flow	16,320	acfm
Exhaust Temp	300	F

Table B-2.1 Maximum Potential Project Emissions MHPS M501JAC

Potential Emissions

Emission Source Description	NO_x (ton/yr)	SO_2 (ton/yr)	PM_{10} (ton/yr)	$PM_{2.5}$ (ton/yr)	CO (ton/yr)	VOC (ton/yr)	H_2SO_4 (ton/yr)	Lead (ton/yr)	GHG CO_2e (ton/yr)
Combustion Turbine #1	128.33	20.32	53.87	53.87	94.29	68.04	21.39	8.74E-03	2,123,519
Combustion Turbine #2	128.33	20.32	53.87	53.87	94.29	68.04	21.39	8.74E-03	2,123,519
Combustion Turbine #3	128.33	20.32	53.87	53.87	94.29	68.04	21.39	8.74E-03	2,123,519
Auxiliary Boilers	8.09	8.42E-01	5.15	5.15	27.23	3.68E+00	6.45E-02	3.61E-04	87,654
Fuel Gas Heaters	1.73	1.80E-01	1.10E+00	1.10E+00	5.83	7.88E-01	1.38E-02	7.73E-05	18,783
Diesel-Fired Emergency Generator	11.63	1.11E-02	3.64E-01	3.64E-01	6.36	2.36E+00	8.52E-04	6.51E-05	1,203
Diesel-Fired Fire Water Pump	0.62	9.76E-04	3.11E-02	3.11E-02	0.54	2.32E-02	7.47E-05	5.71E-06	106
Emergency Generator Fuel Oil Tank						1.83E-03			
Fire Water Pump Fuel Oil Tank						2.85E-04			
Circuit Breakers									1,140
Natural Gas Equipment Leaks									250
Total Project Emissions:	**407.1**	**62.00**	**168.3**	**168.3**	**322.8**	**211.0**	**64.3**	**0.027**	**6,479,692**
PSD Major Source Threshold	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100,000**
PSD Major Source	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**No**	**Yes**
PSD Significant Emission Rate	**40**	**40**	**15**	**10**	**100**	**40**	**7**	**0.6**	**75,000**
Proposed Project Subject to PSD	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**

NA = Not applicable

Table B-2.2 MHPS M501JAC Detailed Operating and Emissions Calculations

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14
SITE CONDITIONS															
Ambient Temperature	°F	10.4	10.4	10.4	22.1	22.1	22.1	59	59	59	59	99	99	99	99
Ambient Pressure	psia	14.63	14.63	14.63	14.63	14.63	14.63	14.63	14.63	14.63	14.63	14.63	14.63	14.63	14.63
Ambient Relative Humidity	%	70.1	70.1	70.1	85.9	85.9	85.9	60.0	60.0	60.0	60.0	45.7	45.7	45.7	45.7
PLANT STATUS															
HRSG Duct Burner		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Evaporative Cooler	On or Off	Off	Off	Off	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off
Gas Turbine Load	%	BASE	75%	50%	BASE	75%	50%	BASE	BASE	75%	50%	BASE	BASE	75%	55%
FUEL DATA															
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Fuel Sulfur Content	grains/100 SCF @ 60°F	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Gt Fuel Flow	lb/hr	171,548	150,289	113,324	176,580	146,644	111,024	171,331	170,289	135,667	103,866	167,035	159,660	127,424	102,651
Gas Turbine Heat Consumption per Unit	MMBtu/hr, HHV	3,954	3,464	2,612	4,070	3,380	2,559	3,949	3,925	3,127	2,394	3,850	3,680	2,937	2,366
Fuel Sulfur Content	grains/100 scf (60°F)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Duct Burner Heat Consumption	MMBtu/hr, HHV	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Heat Input	MMBtu/hr, HHV	3,954	3,464	2,612	4,070	3,380	2,559	3,949	3,925	3,127	2,394	3,850	3,680	2,937	2,366
HRSG EXIT EXHAUST GAS															
Composition:															
Ar	mol %	0.93	0.93	0.94	0.93	0.93	0.94	0.92	0.93	0.93	0.93	0.91	0.91	0.91	0.92
CO2	mol %	4.76	4.58	4.30	4.77	4.55	4.32	4.68	4.64	4.54	4.17	4.59	4.54	4.37	4.11
H2O	mol %	9.39	9.05	8.49	9.60	9.15	8.72	10.28	10.00	9.79	9.08	12.21	11.56	11.26	10.76
N2	mol %	74.30	74.43	74.65	74.15	74.33	74.49	73.54	73.73	73.82	74.08	71.97	72.42	72.54	72.73
O2	mol %	10.62	11.01	11.63	10.55	11.03	11.53	10.59	10.70	10.93	11.73	10.33	10.57	10.92	11.49
Molecular weight		28.37	28.39	28.43	28.35	28.38	28.40	28.27	28.29	28.31	28.35	28.05	28.11	28.13	28.16
Std Volume Flow	scf/hr (68°F)	84,398,334	76,760,929	61,750,815	86,549,578	75,355,208	60,071,608	85,790,882	85,840,616	69,912,756	58,188,118	85,158,465	82,455,206	68,260,514	58,310,552
Stack Gas Temperature	°F	174	173	165	175	171	162	174	174	166	161	195	192	183	177
Stack Gas Flow	acfm	1,697,000	1,541,000	1,224,000	1,743,000	1,508,000	1,185,000	1,725,000	1,726,000	1,388,000	1,146,000	1,769,000	1,705,000	1,392,000	1,178,000
Stack Height	ft	180	180	180	180	180	180	180	180	180	180	180	180	180	180
Stack Diameter	ft	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Stack Exit Gas Velocity	ft/s	74.40	67.56	53.67	76.42	66.12	51.96	75.63	75.68	60.86	50.25	77.56	74.75	61.03	51.65

Table B-2.2 MHPS M501JAC Detailed Operating and Emissions Calculations

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14
SITE CONDITIONS															
Ambient Temperature	°F	10.4	10.4	10.4	22.1	22.1	22.1	59	59	59	59	99	99	99	99
HRSG EXIT EXHAUST GAS EMISSIONS															
NOx	ppmvd @ 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx	lb/hr as NO2	28.5	24.9	18.8	29.3	24.3	18.4	28.4	28.3	22.5	17.2	27.7	26.5	21.1	16.9
NOx	lb/MMBtu	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0071
CO	ppmvd @ 15% O2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CO	lb/hr	8.7	7.6	5.7	8.9	7.4	5.6	8.7	8.6	6.9	5.2	8.4	8.1	6.4	5.2
CO	lb/MMBtu	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022
VOC	ppmvd @ 15% O2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
VOC	lb/hr as methane	3.5	3.0	2.3	3.6	3.0	2.2	3.5	3.4	2.7	2.1	3.4	3.2	2.6	2.1
VOC	lb/MMBtu	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009
SO2	lb/hr	4.51	3.95	2.98	4.64	3.85	2.92	4.50	4.47	3.56	2.73	4.39	4.20	3.35	2.70
SO2	lb/MMBtu	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114	0.00114
Sulfuric Acid Mist	lb/hr	4.74	4.16	3.13	4.88	4.06	3.07	4.74	4.71	3.75	2.87	4.62	4.42	3.52	2.84
Sulfuric Acid Mist	lb/MMBtu	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012
Particulates - Filterable + Condensible	lb/hr	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3
Particulates - Filterable + Condensible	lb/MMBtu	0.0031	0.0036	0.0047	0.0030	0.0036	0.0048	0.0031	0.0031	0.0039	0.0051	0.0032	0.0033	0.0042	0.0052
NH3	ppmvd @ 15% O2	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NH3	lb/hr	26.4	23.1	17.4	27.1	22.5	17.0	26.3	26.1	20.8	15.9	25.6	24.5	19.6	15.7
NH3	lb/MMBtu	0.0067	0.0067	0.0067	0.0067	0.0067	0.0066	0.0067	0.0066	0.0067	0.0066	0.0066	0.0067	0.0067	0.0066
Lead	lb/hr	1.94E-03	1.70E-03	1.28E-03	1.99E-03	1.66E-03	1.25E-03	1.94E-03	1.92E-03	1.53E-03	1.17E-03	1.89E-03	1.80E-03	1.44E-03	1.16E-03
Lead	lb/MMBtu	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07
CO2	lb/MMBtu	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00
CO2	lb/hr	470,526	412,216	310,828	484,330	402,220	304,521	469,931	467,075	372,113	284,886	458,150	437,920	349,503	281,554
CH4	lb/MMBtu	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022
CH4	lb/hr	8.72	7.64	5.76	8.97	7.45	5.64	8.71	8.65	6.89	5.28	8.49	8.11	6.48	5.22
N2O	lb/MMBtu	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
N2O	lb/hr	0.87	0.76	0.58	0.90	0.75	0.56	0.87	0.87	0.69	0.53	0.85	0.81	0.65	0.52
GHG Total Mass	lb/MMBtu	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00	119.00
GHG Total Mass	lb/hr	470,536	412,224	310,834	484,340	402,228	304,527	469,941	467,085	372,121	284,892	458,159	437,929	349,510	281,560
GHG Total CO2e	lb/MMBtu	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12	119.12

Table B-2.2 MHPS M501JAC Detailed Operating and Emissions Calculations

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14
SITE CONDITIONS															
Ambient Temperature	°F	10.4	10.4	10.4	22.1	22.1	22.1	59	59	59	59	99	99	99	99
GHG Total CO2e	lb/hr	471,004	412,634	311,144	484,822	402,628	304,830	470,408	467,549	372,491	285,175	458,615	438,365	349,858	281,840

Table B-2.3 Annual Emissions with Startups and Shutdowns - MHPS M501JAC

Start-up, Shutdown and Offline Events / Hours (Average Each Turbine)

Operating Mode	Number	Duration (SU/SD)		Offline Minimum		NO_x	CO	VOC	Fuel
	of Events/yr	min/event	hr/yr	hr/event	hr/yr	lb/event	lb/event	lb/event	MMBtu/event
Cold start	18	42.0	12.60	48.0	864	60.0	444.0	216.0	1,008
Warm start	52	42.0	36.40	8.0	416	54.0	396.0	216.0	1,008
Hot start	208	42.0	145.60	0.0	0.0	42.0	252.0	168.0	1,392
Shutdown	278	15.0	69.50	n/a	n/a	19.2	156.0	216.0	348
TOTALS			**264.1**		**1280**				

NOx, CO, and VOC emissions and SUSD durations and fuel use are based on Gemma data, October 2018. SO_2, $PM_{10}/PM_{2.5}$, NH_3, H_2SO_4, and GHG emissions are less than normal operating emissions. Event durations and emissions are averages.

Annual Emissions with Start-up and Shutdown (One Turbine)

Operating Mode		NOx		CO		VOC	
	hr/yr	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Offline	1,280	0	0	0	0	0	0
Normal, without duct burning	7,216	29.3	105.71	8.90	32.11	3.60	12.99
Cold start	12.6	85.7	0.54	634	4.00	309	1.94
Warm start	36.4	77.1	1.40	566	10.30	309	5.62
Hot start	145.6	60.0	4.37	360	26.21	240	17.47
Shutdown	69.5	76.8	2.67	624	21.68	864	30.02
TOTALS	**8,760**		**114.7**		**94.3**		**68.0**

The lb/hr emissions represent the average lb/hr for the duration of the event.

Offline hours are the minimums. For each hot start, the CTGs are assumed to be offline for at least 0 hours (maximum 8 hours), for each warm start the CTGs are offline for at least 8 hours up to 48 hours, and for each cold start the CTGs are offline for 48 hours minimum, typically at least 72 hours.

Table B-2.4 Maximum Annual Emissions with Startups and Shutdowns - MHPS M501JAC

Each Combustion Turbine					Three 1x1 Configuration
Parameter	**Maximum Combustion Turbine**	**Annual Emissions Based on CT Only (Year-Round)**	**Annual Emissions with Startup and Shutdown**	**Maximum Annual Emissions**	**Maximum Annual Emissions (Total for Three Turbines)**
Operating Hours	8,760 hr/yr				
NO_x	29.3 lb/hr	128.3 ton/yr	114.7 ton/yr	128.3 ton/yr	385.0 ton/yr
CO	8.90 lb/hr	39.0 ton/yr	94.3 ton/yr	94.3 ton/yr	282.9 ton/yr
VOC	3.60 lb/hr	15.8 ton/yr	68.0 ton/yr	68.0 ton/yr	204.1 ton/yr
$PM_{10}/PM_{2.5}$	12.3 lb/hr	53.9 ton/yr	<53.9 ton/yr	53.9 ton/yr	161.6 ton/yr
SO_2	4.64 lb/hr	20.3 ton/yr	<20.3 ton/yr	20.3 ton/yr	61.0 ton/yr
H_2SO_4	4.88 lb/hr	21.4 ton/yr	<21.4 ton/yr	21.4 ton/yr	64.2 ton/yr
NH_3	27.1 lb/hr	118.7 ton/yr	<118.7 ton/yr	118.7 ton/yr	356.1 ton/yr
Lead	0.00199 lb/hr	0.0087 ton/yr	<0.0087 ton/yr	0.0087 ton/yr	0.026 ton/yr
CO_2	484,330 lb/hr	2,121,365 ton/yr	<2,121,365 ton/yr	2,121,365 ton/yr	6,364,096 ton/yr
CH_4	8.97 lb/hr	39.3 ton/yr	<39.3 ton/yr	39.3 ton/yr	117.9 ton/yr
N_2O	0.897 lb/hr	3.93 ton/yr	<3.93 ton/yr	3.93 ton/yr	11.790 ton/yr
GHG Total Mass	484,340 lb/hr	2,121,409 ton/yr	<2,121,409 ton/yr	2,121,409 ton/yr	6,364,226 ton/yr
GHG CO_2e	484,822 lb/hr	2,123,519 ton/yr	<2,123,519 ton/yr	2,123,519 ton/yr	6,370,557 ton/yr

Notes:

Hourly emission estimates are based on worst-case ambient conditions (i.e., temperature, % relative humidity) at normal operations.

Table B-2.5 Hazardous Air Pollutant Emissions - MHPS M501JAC

Combustion Turbines

Number:	3		Natural Gas Heating Value:	1,020	Btu/scf (HHV)
Maximum Heat Input - CT	4,070	MMBtu/hr (HHV)			
Maximum Heat Input - Duct Burner	0	MMBtu/hr (HHV)			
Operating Hours with Duct Burner	0	hr/yr	**Combined Cycle VOHAP Efficiency:**	**35% reduction**	
Operating Hours - No Duct Burner	8,760	hr/yr			

Auxiliary Boilers			**Fuel Gas Heaters**			**Emergency Firewater Pump**			**Emergency Generator**		
Number:	2		Number:	3		Number:	1		Number:	1	
Maximum Heat Input	84.0	MMBtu/hr	Maximum Heat Input	12.0	MMBtu/hr	Maximum Heat Input	2.54	MMBtu/hr	Maximum Heat Input	28.9	MMBtu/hr
Operating Hours	8,760	hr/yr	Operating Hours	8,760	hr/yr	Operating Hours	500	hr/yr	Operating Hours	500	hr/yr

						Combustion Turbine		Auxiliary Boiler		Fuel Gas Heater		Emergency Firewater		Emergency Generator		Total - New Sources	
						Emission Rate, 1 Turbine		Emission Rate, 1 Boiler		Emission Rate, 1 Boiler		Emission Rate, 1 Firewater Pump		Emission Rate, 1 Generator		Emission Rate, Total	
Pollutant	**Emission Factor**	**Emission Factor**		**Emission Factor**	**Emission Factor**												
	AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas	**AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion**		**AP-42 Section 3.3 04/00 - Gasoline and Diesel Industrial Engines (up to 600 HP)**	**AP-42 Section 3.4 04/00 - Large Stationary Diesel Engines (> 600 HP)**	**Maximum Hourly[b]**	**Annual[c]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly**	**Annual**
	(lb/MMBtu)[a]	**(lb/10^{6}scf)**	**(lb/MMBtu)[a]**	**(lb/MMBtu)**	**(lb/MMBtu)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
1,3-Butadiene	4.30E-07			3.91E-05		1.14E-03	4.98E-03					9.92E-05	2.48E-05			3.51E-03	1.50E-02
2-Methylnaphthalene		2.40E-05	2.35E-08			0.00E+00	0.00E+00	1.98E-06	8.66E-06	2.82E-07	1.24E-06					4.80E-06	2.10E-05
3-Methylchloranthrene		1.80E-06	1.76E-09			0.00E+00	0.00E+00	1.48E-07	6.49E-07	2.12E-08	9.28E-08					3.60E-07	1.58E-06
7,12-Dimethylbenz(a)anthracene		1.60E-05	1.57E-08			0.00E+00	0.00E+00	1.32E-06	5.77E-06	1.88E-07	8.24E-07					3.20E-06	1.40E-05
Acenaphthene		1.80E-06	1.76E-09	1.42E-06	4.68E-06	0.00E+00	0.00E+00	1.48E-07	6.49E-07	2.12E-08	9.28E-08	3.60E-06	9.01E-07	1.35E-04	3.38E-05	1.39E-04	3.63E-05
Acenaphthylene		1.80E-06	1.76E-09	5.06E-06	9.23E-06	0.00E+00	0.00E+00	1.48E-07	6.49E-07	2.12E-08	9.28E-08	1.28E-05	3.21E-06	2.67E-04	6.67E-05	2.80E-04	7.15E-05
Acetaldehyde	4.00E-05			7.67E-04	2.52E-05	1.06E-01	4.63E-01					1.95E-03	4.87E-04	7.29E-04	1.82E-04	3.20E-01	1.39E+00
Acrolein	6.40E-06			9.25E-05	7.88E-06	1.69E-02	7.42E-02					2.35E-04	5.87E-05	2.28E-04	5.70E-05	5.13E-02	2.23E-01
Anthracene		2.40E-06	2.35E-09	1.87E-06	1.23E-06	0.00E+00	0.00E+00	1.98E-07	8.66E-07	2.82E-08	1.24E-07	4.75E-06	1.19E-06	3.56E-05	8.89E-06	4.08E-05	1.22E-05
Benz(a)anthracene		1.80E-06	1.76E-09	1.68E-06	6.22E-07	0.00E+00	0.00E+00	1.48E-07	6.49E-07	2.12E-08	9.28E-08	4.26E-06	1.07E-06	1.80E-05	4.50E-06	2.26E-05	7.14E-06
Benzene	1.20E-05	2.10E-03	2.06E-06	9.33E-04	7.76E-04	3.17E-02	1.39E-01	1.73E-04	7.57E-04	2.47E-05	1.08E-04	2.37E-03	5.92E-04	2.24E-02	5.61E-03	1.20E-01	4.25E-01
Benzo(a)pyrene		1.20E-06	1.18E-09	1.88E-07	2.57E-07	0.00E+00	0.00E+00	9.88E-08	4.33E-07	1.41E-08	6.18E-08	4.77E-07	1.19E-07	7.43E-06	1.86E-06	8.15E-06	3.03E-06
Benzo(b)flouoranthene		1.80E-06	1.76E-09	9.91E-08	1.11E-06	0.00E+00	0.00E+00	1.48E-07	6.49E-07	2.12E-08	9.28E-08	2.52E-07	6.29E-08	3.21E-05	8.02E-06	3.27E-05	9.66E-06
Benzo(g,h,I)perylene		1.20E-06	1.18E-09		5.56E-07	0.00E+00	0.00E+00	9.88E-08	4.33E-07	1.41E-08	6.18E-08			1.61E-05	4.02E-06	1.63E-05	5.07E-06
Benzo(k)fluoranthene		1.80E-06	1.76E-09	1.55E-07	2.18E-07	0.00E+00	0.00E+00	1.48E-07	6.49E-07	2.12E-08	9.28E-08	3.93E-07	9.83E-08	6.30E-06	1.58E-06	7.06E-06	3.25E-06
Chrysene		1.80E-06	1.76E-09	3.53E-07	1.53E-06	0.00E+00	0.00E+00	1.48E-07	6.49E-07	2.12E-08	9.28E-08	8.96E-07	2.24E-07	4.42E-05	1.11E-05	4.55E-05	1.29E-05
Dibenzo(a,h)anthracene		1.20E-06	1.18E-09	5.83E-07	3.46E-07	0.00E+00	0.00E+00	9.88E-08	4.33E-07	1.41E-08	6.18E-08	1.48E-06	3.70E-07	1.00E-05	2.50E-06	1.17E-05	3.92E-06
Dichlorobenzene		1.20E-03	1.18E-06			0.00E+00	0.00E+00	9.88E-05	4.33E-04	1.41E-05	6.18E-05					2.40E-04	1.05E-03
Ethylbenzene	3.20E-05					8.47E-02	3.71E-01									2.54E-01	1.11E+00
Fluoranthene		3.00E-06	2.94E-09	7.61E-06	4.03E-06	0.00E+00	0.00E+00	2.47E-07	1.08E-06	3.53E-08	1.55E-07	1.93E-05	4.83E-06	1.17E-04	2.91E-05	1.36E-04	3.66E-05
Fluorene		2.80E-06	2.75E-09	2.92E-05	1.28E-05	0.00E+00	0.00E+00	2.31E-07	1.01E-06	3.29E-08	1.44E-07	7.41E-05	1.85E-05	3.70E-04	9.25E-05	4.45E-04	1.14E-04
Formaldehyde (g)	1.83E-04	7.50E-02	7.35E-05	1.18E-03	7.89E-05	7.45E-01	3.26E+00	6.18E-03	2.71E-02	8.82E-04	3.86E-03	2.99E-03	7.49E-04	2.28E-03	5.70E-04	2.26E+00	9.86E+00
Hexane (i)		1.30E-03	1.27E-06			0.00E+00	0.00E+00	1.07E-04	4.69E-04	1.53E-05	6.70E-05					2.60E-04	1.14E-03
Indeno(1,2,3-cd)pyrene		1.80E-06	1.76E-09	3.75E-07	4.14E-07	0.00E+00	0.00E+00	1.48E-07	6.49E-07	2.12E-08	9.28E-08	9.52E-07	2.38E-07	1.20E-05	2.99E-06	1.33E-05	4.81E-06
Naphthalene	1.30E-06	6.10E-04	5.98E-07	8.48E-05	1.3E-04	3.44E-03	1.51E-02	5.02E-05	2.20E-04	7.18E-06	3.14E-05	2.15E-04	5.38E-05	3.76E-03	9.40E-04	1.44E-02	4.67E-02
PAHs	2.20E-06					5.82E-03	2.55E-02									1.75E-02	7.65E-02
Phenanathrene		1.70E-05	1.67E-08	2.94E-05	4.08E-05	0.00E+00	0.00E+00	1.40E-06	6.13E-06	2.00E-07	8.76E-07	7.46E-05	1.87E-05	1.18E-03	2.95E-04	1.26E-03	3.28E-04
Propylene Oxide	2.90E-05					7.67E-02	3.36E-01									2.30E-01	1.01E+00
Pyrene		5.00E-06	4.90E-09	4.78E-06	3.71E-06	0.00E+00	0.00E+00	4.12E-07	1.80E-06	5.88E-08	2.58E-07	1.21E-05	3.03E-06	1.07E-04	2.68E-05	1.20E-04	3.42E-05
Toluene	1.30E-04	3.40E-03	3.33E-06	4.09E-04	2.81E-04	3.44E-01	1.51E+00	2.80E-04	1.23E-03	4.00E-05	1.75E-04	1.04E-03	2.60E-04	8.13E-03	2.03E-03	1.04E+00	4.52E+00
Xylene	6.40E-05			2.85E-04	1.93E-04	1.69E-01	7.42E-01					7.23E-04	1.81E-04	5.58E-03	1.40E-03	5.14E-01	2.23E+00

Table B-2.5 Hazardous Air Pollutant Emissions - MHPS M501JAC

Combustion Turbines

Number:	3		Natural Gas Heating Value:	1,020	Btu/scf (HHV)
Maximum Heat Input - CT	4,070	MMBtu/hr (HHV)			
Maximum Heat Input - Duct Burner	0	MMBtu/hr (HHV)			
Operating Hours with Duct Burner	0	hr/yr	**Combined Cycle VOHAP Efficiency:**	**35% reduction**	
Operating Hours - No Duct Burner	8,760	hr/yr			

Auxiliary Boilers			**Fuel Gas Heaters**			**Emergency Firewater Pump**			**Emergency Generator**		
Number:	2		Number:	3		Number:	1		Number:	1	
Maximum Heat Input	84.0	MMBtu/hr	Maximum Heat Input	12.0	MMBtu/hr	Maximum Heat Input	2.54	MMBtu/hr	Maximum Heat Input	28.9	MMBtu/hr
Operating Hours	8,760	hr/yr	Operating Hours	8,760	hr/yr	Operating Hours	500	hr/yr	Operating Hours	500	hr/yr

						Combustion Turbine		Auxiliary Boiler		Fuel Gas Heater		Emergency Firewater		Emergency Generator		Total - New Sources	
Pollutant	**Emission Factor**	**Emission Factor**		**Emission Factor**	**Emission Factor**	**Emission Rate, 1 Turbine**		**Emission Rate, 1 Boiler**		**Emission Rate, 1 Boiler**		**Emission Rate, 1 Firewater Pump**		**Emission Rate, 1 Generator**		**Emission Rate, Total**	
	AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas	**AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion**		**AP-42 Section 3.3 04/00 - Gasoline and Diesel Industrial Engines (up to 600 HP)**	**AP-42 Section 3.4 04/00 - Large Stationary Diesel Engines (> 600 HP)**	**Maximum Hourly[b]**	**Annual[c]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly[d]**	**Annual[e]**	**Maximum Hourly**	**Annual**
	(lb/MMBtu)[a]	**(lb/10^6scf)**	**(lb/MMBtu)[a]**	**(lb/MMBtu)**	**(lb/MMBtu)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
Arsenic [f]		2.00E-04	1.96E-07			7.98E-04	3.50E-03	1.65E-05	7.21E-05	2.35E-06	1.03E-05					2.43E-03	1.07E-02
Beryllium [f]		1.20E-05	1.18E-08			4.79E-05	2.10E-04	9.88E-07	4.33E-06	1.41E-07	6.18E-07					1.46E-04	6.40E-04
Cadmium [f]		1.10E-03	1.08E-06			4.39E-03	1.92E-02	9.06E-05	3.97E-04	1.29E-05	5.67E-05					1.34E-02	5.86E-02
Chromium [f]		1.40E-03	1.37E-06			5.59E-03	2.45E-02	1.15E-04	5.05E-04	1.65E-05	7.21E-05					1.70E-02	7.46E-02
Cobalt [f]		8.40E-05	8.24E-08			3.35E-04	1.47E-03	6.92E-06	3.03E-05	9.88E-07	4.33E-06					1.02E-03	4.48E-03
Lead [f]		5.00E-04	4.90E-07			2.00E-03	8.74E-03	4.12E-05	1.80E-04	5.88E-06	2.58E-05					6.09E-03	2.67E-02
Manganese [f]		3.80E-04	3.73E-07			1.52E-03	6.64E-03	3.13E-05	1.37E-04	4.47E-06	1.96E-05					4.62E-03	2.03E-02
Mercury [f]		2.60E-04	2.55E-07			1.04E-03	4.54E-03	2.14E-05	9.38E-05	3.06E-06	1.34E-05					3.16E-03	1.39E-02
Nickel [f]		2.10E-03	2.06E-06			8.38E-03	3.67E-02	1.73E-04	7.57E-04	2.47E-05	1.08E-04					2.56E-02	1.12E-01
Selenium [f]		2.40E-05	2.35E-08			9.58E-05	4.19E-04	1.98E-06	8.66E-06	2.82E-07	1.24E-06					2.92E-04	1.28E-03
																Total HAPS (tpy)	**21.23**
																Max Single HAP (tpy)	**9.86**

Notes:

(a) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (Volumetric Heat Content, Btu/scf)

(b) For Turbines, Hourly Emission Rate (lb/hr) = [Max Heat Input - CT (MMBtu/hr) * Emission Factor - CT (lb/MMBtu) + Max Heat Input - DB (MMBtu/hr) * Emission Factor - non-CT (lb/MMBtu)]

(c) For Turbines, Annual Emission Rate (tpy) = [Max Heat Input - CT (MMBtu/Hr) * 8760 hr/yr * Emission Factor - CT (lb/MMBtu) + Max Heat Input - DB (MMBtu/Hr) * Operating Hours - DB (hr/yr) * Emission Factor - non-CT (lb/MMBtu)] / (2,000 lb/ton)

(d) For Boiler/Heaters/Engines, Hourly Emission Rate (lb/hr) = Max Heat Input (MMBtu/Hr) * Emission Factor - non-CT (lb/MMBtu)

(e) For Boilers/ Heaters/ Engines, Annual Emission Rate (ton/yr) = Max Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu) * Annual Operation (hr/yr) / 2000 (lb/ton)

(f) Combustion turbine emissions of metallic HAPs calculated using non-CT natural gas combustion emission factors.

(g) 78 ppbvd at 15% O2 after control by the oxidation catalyst based on information from MHPS.

(i) Ventura County APCD.

Table B-2.6 Hazardous Air Pollutant Air Toxics Analysis- MHPS M501JAC

Pollutant	Total - New Sources (Table B-2.5) Emission Rate, Total		Virginia Air Toxics Exemption Levels		Exempt? (hourly)	Exempt? (annual)	SAAC (ug/m3)	
	Maximum Hourly (lb/hr)	Annual (tpy)	Maximum Hourly (lb/hr)	Annual (tpy)	Yes/No	Yes/No	Hourly	Annual
1,3-Butadiene	3.51E-03	1.50E-02	1.452	3.19	Yes	Yes		
2-Methylnaphthalene	4.80E-06	2.10E-05	*	*	Yes	Yes		
3-Methylchloranthrene	3.60E-07	1.58E-06	*	*	Yes	Yes		
7,12-Dimethylbenz(a)anthracene	3.20E-06	1.40E-05	*	*	Yes	Yes		
Acenaphthene	1.39E-04	3.63E-05	*	*	Yes	Yes		
Acenaphthylene	2.80E-04	7.15E-05	*	*	Yes	Yes		
Acetaldehyde	3.20E-01	1.39E+00	8.91	26.1	Yes	Yes		
Acrolein	5.13E-02	2.23E-01	0.02277	0.03335	No	No	17.25	0.46
Anthracene	4.08E-05	1.22E-05	*	*	Yes	Yes		
Benz(a)anthracene	2.26E-05	7.14E-06	*	*	Yes	Yes		
Benzene	1.20E-01	4.25E-01	2.112	4.64	Yes	Yes		
Benzo(a)pyrene	8.15E-06	3.03E-06	*	*	Yes	Yes		
Benzo(b)flouoranthene	3.27E-05	9.66E-06	*	*	Yes	Yes		
Benzo(g,h,I)perylene	1.63E-05	5.07E-06	*	*	Yes	Yes		
Benzo(k)fluoranthene	7.06E-06	3.25E-06	*	*	Yes	Yes		
Chrysene	4.55E-05	1.29E-05	*	*	Yes	Yes		
Dibenzo(a,h)anthracene	1.17E-05	3.92E-06	*	*	Yes	Yes		
Dichlorobenzene	2.40E-04	1.05E-03	21.813	65.395	Yes	Yes		
Ethylbenzene	2.54E-01	1.11E+00	17.919	62.93	Yes	Yes		
Fluoranthene	1.36E-04	3.66E-05	*	*	Yes	Yes		
Fluorene	4.45E-04	1.14E-04	*	*	Yes	Yes		
Formaldehyde (g)	2.26E+00	9.86E+00	0.0825	0.174	No	No	62.5	2.4
Hexane	2.60E-04	1.14E-03	11.616	25.52	Yes	Yes		
Indeno(1,2,3-cd)pyrene	1.33E-05	4.81E-06	*	*	Yes	Yes		
Naphthalene	1.44E-02	4.67E-02	2.607	7.54	Yes	Yes		
PAHs	1.75E-02	7.65E-02	*	*	Yes	Yes		
Phenanathrene	1.26E-03	3.28E-04	*	*	Yes	Yes		
Propylene Oxide	2.30E-01	1.01E+00	3.168	6.96	Yes	Yes		
Pyrene	1.20E-04	3.42E-05	*	*	Yes	Yes		
Toluene	1.04E+00	4.52E+00	18.645	54.665	Yes	Yes		
Xylene	5.14E-01	2.23E+00	21.483	62.93	Yes	Yes		
Arsenic	2.43E-03	1.07E-02	0.0132	0.029	Yes	Yes		
Beryllium	1.46E-04	6.40E-04	0.000132	0.00029	No	No	0.1	0.004
Cadmium	1.34E-02	5.86E-02	0.0033	0.00725	No	No	2.5	0.1
Chromium	1.70E-02	7.46E-02	0.0033	0.00725	No	No	2.5	0.1
Cobalt	1.02E-03	4.48E-03	0.0033	0.00725	Yes	Yes		
Lead	6.09E-03	2.67E-02	0.0099	0.02175	Yes	No		0.1
Manganese	4.62E-03	2.03E-02	0.33	0.725	Yes	Yes		
Mercury	3.16E-03	1.39E-02	0.0033	0.00725	Yes	No		0.1
Nickel	2.56E-02	1.12E-01	0.0066	0.0145	No	No	5	0.2
Selenium	2.92E-04	1.28E-03	0.0132	0.029	Yes	Yes		

Notes:

* indicates that the neither exemption levels or SAACs exist.

Table B-2.7 Auxiliary Boiler Emissions - MHPS M501JAC

Emission Source	Auxiliary Boiler
Source Type	Natural Gas-Fired Boiler
Heat Input (MMBtu/hr)	84.0
Maximum Fuel Usage (MMcf/hr)	0.0824
Number of Units	2
Natural Gas Heating Value (Btu/scf)	1,020
Sulfur Content of Natural Gas (gr S /100 scf)	0.40
Annual Capacity Factor (%)	100

Compound	Emission Factor	Emission Rate - per Unit		Total Units
		Hourly (c)	Annual (d)	Annual (d)
	(lb/MMBtu)	(lb/hr)	(ton/year)	(ton/year)
Nitrogen Oxides (a)	0.011	0.92	4.05	8.09
Carbon Monoxide (a)	0.037	3.11	13.61	27.23
VOC (a)	0.0050	0.42	1.84	3.68
Sulfur Oxides (a)	1.14E-03	0.096	0.421	0.842
$PM_{10}/PM_{2.5}$ (a)	0.0070	0.59	2.58	5.151
Lead (b)	4.9E-07	4.1E-05	1.8E-04	3.61E-04
H_2SO_4 (f)	8.76E-05	7.4E-03	3.2E-02	6.45E-02
CO_2 (g)	119.00	9,996	43,782	87,565
CH_4 (g)	0.00220	1.9E-01	8.1E-01	1.6E+00
N_2O (g)	0.00022	1.9E-02	8.1E-02	1.6E-01
GHG mass (g)	119.00	9,996	43,783	87,567
GHG CO_2e (h)	119.12	10,006	43,827	87,654

Notes:

(a) Emission factors (lb/MMBtu) are based on the proposed BACT emission rates for natural gas-fired boilers.

(b) Emission factors (lb/MMBtu) are based on emission factors (lb/MMcf) referenced from AP-42, Section 1.4 dated July 1998 and a heat content value of 1020 Btu/scf.

(c) Hourly Emission Rate (lb/hr) = Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu)

(d) Annual Emission Rate (ton/yr) = Hourly Emission Rate (lb/hr) * Annual Operating Hours (hr/yr) / (2,000 lb/ton)

(e) H_2SO_4 emissions based on a 5% conversion of SO_2 to SO_3.

(g) CO2 emission factor is based on monitoring experience in Virginian (Greensville PSD permit application). Emission factors for CH4 and NO2 are based on the EPA rule "Mandatory Reporting of Greenhouse Gases", Tables C-1 and C-2.

(h) Global Warming Potentials, Federal Register Vol. 78, No. 230, November 29, 2013.

Stack Parameters

Stack Height	40.0	ft
Stack Diameter	3.50	ft
Stack Exit Velocity	44.0	ft/s
Exhaust Flow	25,391	acfm
Exhaust Temp	300	F

Table B-3 Fuel Gas Heater Emissions

Emission Source	Gas Fired Heater
Source Type	Natural Gas-Fired Boiler
Heat Input (MMBtu/hr)	12.0
Maximum Fuel Usage (MMcf/hr)	0.0118
Number of Units:	3
Natural Gas Heating Value (Btu/scf)	1,020
Sulfur Content of Natural Gas (gr / 100 scf)	0.40
Annual Capacity Factor (%)	100

Compound	Emission Factor (lb/MMBtu)	Emission Rate - per Unit Hourly (c) (lb/hr)	Emission Rate - per Unit Annual (d) (ton/year)	Total Units Annual (d) (ton/year)
Nitrogen Oxides (a)	0.011	0.13	0.58	1.73
Carbon Monoxide (a)	0.037	0.44	1.94	5.83
VOC (a)	0.0050	0.06	0.26	0.79
Sulfur Oxides	1.14E-03	0.014	0.060	0.180
$PM_{10}/PM_{2.5}$ (b)	0.0070	0.08	0.37	1.10
Lead (b)	4.9E-07	5.9E-06	2.6E-05	7.73E-05
H_2SO_4 (f)	8.76E-05	1.1E-03	4.6E-03	1.38E-02
CO_2 (f)	119.00	1,428	6,255	18,764
CH_4 (f)	0.0022	0.026	0.12	0.35
N_2O (f)	0.00022	0.0026	0.012	0.035
GHG mass (f)	119.00	1,428	6,255	18,764
GHG CO_2e (f)	119.12	1,429	6,261	18,783

Notes:

(a) Emission factors (lb/MMBtu) are based on the proposed BACT or LAER emission rates for natural gas-fired boilers.

(b) Emission factors (lb/MMBtu) are based on emission factors (lb/MMcf) referenced from AP-42, Section 1.4 dated July 1998 and a heat content value of 1020 Btu/scf.

(c) Hourly Emission Rate (lb/hr) = Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu)

(d) Annual Emission Rate (ton/yr) = Hourly Emission Rate (lb/hr) * Annual Operating Hours (hr/yr) / (2,000 lb/ton)

(e) H_2SO_4 emissions based on a 5% conversion of SO_2 to SO_3.

(f) CO2 emission factor is based on monitoring experience in Virginian (Greensville PSD permit application). Emission factors for CH4 and NO2 are based on the EPA rule "Mandatory Reporting of Greenhouse Gases", Tables C-1 and C-2.

Stack Parameters

Stack Height	20.0	ft
Stack Diameter	1.50	ft
Stack Exit Velocity	50.53	ft/s
Exhaust Flow	2,236	scfm
Exhaust Flow	5,358	acfm
Exhaust Temp	810	F

Table B-4 Emergency Generator Emissions

Emission Source:	Emergency Generator	
Source Type:	Diesel Engine	
Power Output (MW):	3.00	electrical output
Power Output (bhp):	4,423	engine power
Heat Input (MM Btu/hr):	28.92	
Maximum Fuel Usage (gal/hr)	214.2	
Number of Units:	1	
Fuel Oil Heating Value (Btu/gal)	135,000	
Sulfur Content of Fuel (wt. %):	0.0015	(a)
Operating Hours per Year:	500	

Compound	Emission Factor (g/kW-hr)	Emission Factor (g/hp-hr)	Emission Rate Hourly (c) (lb/hr)	Emission Rate Annual (d) (ton/year)
Nitrogen Oxides (a)	6.40	4.8	46.54	11.63
Carbon Monoxide (a)	3.50	2.6	25.45	6.36
VOC (a)	1.30	1.0	9.45	2.36
$PM_{10}/PM_{2.5}$ (c)	0.20	0.15	1.45	0.36
	lb/MMBtu			
Sulfur Oxides (b)	0.00154		0.0445	0.0111
Lead (e)	9.00E-06		2.60E-04	6.51E-05
H_2SO_4	1.18E-04		3.41E-03	8.52E-04
CO_2 (f)	165.79		4,794	1,199
CH_4 (f)	0.0066		0.1913	0.0478
N_2O (f)	0.0013		0.0383	0.0096
GHG mass (f)	165.80		4,794	1,199
GHG CO_2e (g)	166.35		4,810	1,203

Notes:

(a) Emission factors for NOx, CO, VOCs, SO_2, and PM are based on compliance with NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines (reference 40 CFR 89.112 Table 1). Operation for maintenance checks and readiness testing is limited to 100 hr/yr.

(b) lb/MMBtu based on fuel sulfur.

(c) Hourly Emission Rate (lb/hr) = Emission Factor (g/hp-hr) * Engine Power (hp) * (1 lb / 453.6 g)

(d) Annual Emission Rate (ton/yr) = Hourly Emission Rate (lb/hr) * Hour of Operation Per Year (hr/yr) / (2,000 lb/ton)

(e) No lead emission factor is available for oil-fired engines. The AP-42 emission factor from Table 1.3-10 for oil-fired boiler was used instead.

(f) lb/MMBtu factors are based on the EPA rule "Mandatory Reporting of Greenhouse Gases", Tables C-1 and C-2.

(g) Global Warming Potentials, Federal Register Vol. 78, No. 230, November 29, 2013.

Stack Parameters

Stack Height	21.0	ft
Stack Diameter	1.67	ft
Stack Exit Velocity	196	ft/sec
Exhaust Flow	25,620	ACFM
Exhaust Temp	892	F

Table B-5 Emergency Fire Water Pump Emissions

Emission Source:	Fire Water Pump	
Source Type:	Diesel Engine	
Power Output (MW):	0.280	engine power
Power Output (bhp):	376	enigne power
Heat Input (MMBtu/hr):	2.54	
Maximum Fuel Usage (gal/hr)	18.8	
Number of Units:	1	
Fuel Oil Heating Value (Btu/gal)	135,000	
Sulfur Content of Fuel (wt. %):	0.0015	(a)
Operating Hours per Year:	500	

Compound	Emission Factor (g/kW-hr)	Emission Factor (g/hp-hr)	Emission Rate Hourly (c) (lb/hr)	Emission Rate Annual (d) (ton/year)
Nitrogen Oxides (a)	4.0	3.0	2.49	0.62
Carbon Monoxide (a)	3.5	2.6	2.16	0.54
VOC (a)	0.15	0.11	0.093	0.023
$PM_{10}/PM_{2.5}$ (c)	0.20	0.15	0.12	0.031
	lb/MMBtu			
Sulfur Oxides (b)	0.00154		0.0039	0.0010
Lead (e)	9.00E-06		2.28E-05	5.71E-06
H_2SO_4	1.18E-04		2.99E-04	7.47E-05
CO_2 (f)	165.79		421	105
CH_4 (f)	0.0066		0.0168	0.0042
N_2O (f)	0.0013		0.0034	0.00084
GHG mass (f)	165.80		421	105
GHG CO_2e (g)	166.35		422	106

Notes:

(a) Emission factors for NOx, CO, VOCs, SO2, and PM are based on compliance with NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines (reference 40 CFR 89.112 Table 1) and data from Cummins. Operation for maintenance checks and readiness testing is limited to 100 hr/yr.

(b) lb/MMBtu based on fuel sulfur.

(c) Hourly Emission Rate (lb/hr) = Emission Factor (g/hp-hr) * Engine Power (hp) * (1 lb / 453.6 g)

(d) Annual Emission Rate (ton/yr) = Hourly Emission Rate (lb/hr) * Hour of Operation Per Year (hr/yr) / (2,000 lb/ton)

(e) No lead emission factor is available for oil-fired engines. The AP-42 emission factor from Table 1.3-10 for oil-fired boiler was used instead.

(f) lb/MMBtu factors are based on the EPA rule "Mandatory Reporting of Greenhouse Gases", Tables C-1 and C-2.

(g) Global Warming Potentials, Federal Register Vol. 78, No. 230, November 29, 2013.

Stack Parameters

Stack Height	15.0	ft
Stack Diameter	0.50	ft
Stack Exit Velocity	158	ft/sec
Exhaust Flow	1,867	ACFM
Exhaust Temp	842	F

Table B-6 SF6 Emissions from Circuit Breaker Leaks

Source	Maximum Leak Rate	SF_6 Capacity lb	SF_6 Emissions lb/yr	CO_2 Equivalent Global Warming Potential [(a)]	CO_2e Emissions ton/yr
Circuit Breakers	0.50%	20,000	100	22,800	1,140

(a) Global Warming Potentials, Federal Register Vol. 78, No. 230, November 29, 2013.

Table B-7 Storage Tank Emissions

Emergency Generator distillate oil storage tank VOC emissions:	**3.65**	**lb/yr**
Fire Water Pump distillate oil storage tank VOC emissions:	**0.57**	**lb/yr**

Note: Please see tank run at end of Appendix B for detailed information.

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

Identification

User Identification:	CP-T-1
City:	Chickahominy
State:	Virginia
Company:	Chickahominy Power, LLC
Type of Tank:	Horizontal Tank
Description:	ULSD storage tank for FWP

Tank Dimensions

Shell Length (ft):	8.00
Diameter (ft):	4.00
Volume (gallons):	572.00
Turnovers:	16.43
Net Throughput(gal/yr):	9,400.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good

Breather Vent Settings

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

Meterological Data used in Emissions Calculations: Richmond, Virginia (Avg Atmospheric Pressure = 14.67 psia)

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

CP-T-1 - Horizontal Tank
Chickahominy, Virginia

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	66.60	56.23	76.97	60.78	0.0082	0.0057	0.0111	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

CP-T-1 - Horizontal Tank
Chickahominy, Virginia

Annual Emission Calcaulations	
Standing Losses (lb):	0.3290
Vapor Space Volume (cu ft):	64.0325
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0751
Vented Vapor Saturation Factor:	0.9991
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	64.0325
Tank Diameter (ft):	4.0000
Effective Diameter (ft):	6.3847
Vapor Space Outage (ft):	2.0000
Tank Shell Length (ft):	8.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0082
Daily Avg. Liquid Surface Temp. (deg. R):	526.2736
Daily Average Ambient Temp. (deg. F):	57.6958
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	520.4458
Tank Paint Solar Absorptance (Shell):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,337.1080
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0751
Daily Vapor Temperature Range (deg. R):	41.4845
Daily Vapor Pressure Range (psia):	0.0053
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0082
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0057
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0111
Daily Avg. Liquid Surface Temp. (deg R):	526.2736
Daily Min. Liquid Surface Temp. (deg R):	515.9024
Daily Max. Liquid Surface Temp. (deg R):	536.6447
Daily Ambient Temp. Range (deg. R):	22.2583
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9991
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0082
Vapor Space Outage (ft):	2.0000
Working Losses (lb):	0.2372
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0082
Annual Net Throughput (gal/yr.):	9,400.0000
Annual Turnovers:	16.4336
Turnover Factor:	1.0000

Tank Diameter (ft):	4.0000
Working Loss Product Factor:	1.0000

Total Losses (lb):	0.5662

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

Emissions Report for: Annual

CP-T-1 - Horizontal Tank
Chickahominy, Virginia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.24	0.33	0.57

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

Identification

User Identification:	CP-T-2
City:	Chickahominy
State:	Virginia
Company:	Chickahominy Power, LLC
Type of Tank:	Horizontal Tank
Description:	ULSD storage tank for emergency generator

Tank Dimensions

Shell Length (ft):	12.00
Diameter (ft):	6.50
Volume (gallons):	2,500.00
Turnovers:	42.84
Net Throughput(gal/yr):	107,100.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good

Breather Vent Settings

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

Meterological Data used in Emissions Calculations: Richmond, Virginia (Avg Atmospheric Pressure = 14.67 psia)

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

CP-T-2 - Horizontal Tank
Chickahominy, Virginia

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	66.60	56.23	76.97	60.78	0.0082	0.0057	0.0111	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

CP-T-2 - Horizontal Tank
Chickahominy, Virginia

Annual Emission Calcaulations	
Standing Losses (lb):	1.3026
Vapor Space Volume (cu ft):	253.6286
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0751
Vented Vapor Saturation Factor:	0.9986
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	253.6286
Tank Diameter (ft):	6.5000
Effective Diameter (ft):	9.9681
Vapor Space Outage (ft):	3.2500
Tank Shell Length (ft):	12.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0082
Daily Avg. Liquid Surface Temp. (deg. R):	526.2736
Daily Average Ambient Temp. (deg. F):	57.6958
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	520.4458
Tank Paint Solar Absorptance (Shell):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,337.1080
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0751
Daily Vapor Temperature Range (deg. R):	41.4845
Daily Vapor Pressure Range (psia):	0.0053
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0082
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0057
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0111
Daily Avg. Liquid Surface Temp. (deg R):	526.2736
Daily Min. Liquid Surface Temp. (deg R):	515.9024
Daily Max. Liquid Surface Temp. (deg R):	536.6447
Daily Ambient Temp. Range (deg. R):	22.2583
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9986
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0082
Vapor Space Outage (ft):	3.2500
Working Losses (lb):	2.3425
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0082
Annual Net Throughput (gal/yr.):	107,100.0000
Annual Turnovers:	42.8400
Turnover Factor:	0.8669

Tank Diameter (ft):	6.5000
Working Loss Product Factor:	1.0000

Total Losses (lb):	3.6451

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

Emissions Report for: Annual

CP-T-2 - Horizontal Tank
Chickahominy, Virginia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	2.34	1.30	3.65

Appendix C

PSD Permit Limits from EPA's RACT/BACT/LAER Clearinghouse

Appendix C

PSD Permit Limits from EPA'S RACT/BACT/LAER Clearinghouse

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Table C-1 Natural Gas Turbine NOx Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size		CASE-BY-CASE BASIS	Emission Limit		
*MI-0432	NEW COVERT GENERATING FACILITY	NEW COVERT GENERATING COMPANY, LLC	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1,230	MW	LAER	2.00	PPMVD	AT 15%O2; EACH INDIV. CT/HRSG TRAIN
*MI-0431	INDECK NILES LLC	INDECK NILES LLC	6/26/2018	FGCTGHRSG (2 Combined Cycle CTG with HRSGs)	3,421	MMBTU/H	LAER	2.00	PPM	AT 15%O2; 24-HR ROLL AVG
NA	C4GT	NOVI ENERGY	4/26/2018	Natural Gas with or without Duct Firing	3,482	MMBtu/hr	BACT-PSD	2.00	PPMVD @15% O2	1 HOUR AVERAGE
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	ENTERGY TEXAS INC	3/30/2018	Combined Cycle Turbine	2,635	MMBTU/HR/UNIT	LAER	2.00	PPMVD	15% O2 1-HOUR AVERAGE
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	Natural Gas w/o Duct Firing	2,969	MMBtu/hr	LAER	2.00	PPMVD @15% O2	1 HOUR BLOCK
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	Natural Gas w/Duct Firing	2,639	MMBtu/hr	LAER	2.00	PPMVD @15% O2	1 HOUR BLOCK
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	LAER	2.00	PPMVD	15% O2 3-H AVG
*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	New 633 megawatt (MW) gross facility consisting of 1.One General Electric (GE) 7HA.02 CCCT nominally rated at 380 MW at ISO conditions without duct firing with a maximum heat input rate of: o 3,462 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting natural gas o 3,613 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting ULSD which will be the backup fuel	683	MW	LAER	2.00	ppmvd at 15% O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
NA	Greensville County	VIRGINIA ELECTRIC AND POWER COMPANY	6/17/2016	MHPS M501J	3,227	MMBtu/hr	BACT-PSD	2.00	PPMVD @ 15 % O2	1-hr average
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/10/2016	Combined Cycle Combustion Turbine with Duct Burner firing natural gas			LAER	2.00	ppmvd at 15% O2	3 H ROLLING AV BASED ON ONE H BLOCK

Table C-1 Natural Gas Turbine NOx Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size		CASE-BY-CASE BASIS	Emission Limit		
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3-on-1 combined cycle unit. GE 7HA.02 turbines, approximately 350 MW per turbine. Total unit generating capacity is approximately 1,600 MW. Primarily fueled with natural gas. Permitted to burn the base-load equivalent of 500 hr/yr per turbine on ULSD.	3,096	MMBtu/hr per turbine	BACT-PSD	2.00	ppmvd at 15% O2	GAS, 24-HR BLOCK, EXCLUDING SSM
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	231	MW	BACT-PSD	2.00	PPM	
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015				LAER	2.00	PPMVD @15% O2	1 HR BLOCK
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	Alstom GT36 combustion turbines (321 MW)+ 799 million British thermal units per hour (MMBtu/hr) duct burner	321	MW	BACT-PSD	2.00	PPM	24-HR AVERAGE
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	Two power configuration options authorized Siemens â€“ 240 MW + 250 million British thermal units per hour (MMBtu/hr) duct burner GE â€“ 195 MW + 670 MMBtu/hr duct burner	195	MW	BACT-PSD	2.00	PPM	ROLLING 24-HR AVERAGE
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	6/18/2015	Two power configuration options authorized Siemens 231 MW + 500 million British thermal units per hour (MMBtu/hr) duct burner GE 210 MW + 349.2 MMBtu/hr duct burner	210	MW	LAER	2.00	PPM	ROLLING 24-HR AVERAGE
*TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	Combined Cycle Turbine	1,100	MW		2.00	PPMVD	@15% O2, 24-HR AVERAGE
*TX-0714	S R BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	12/19/2014	Combined Cycle Turbine	240	MW	BACT-PSD	2.00	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
*TX-0710	VICTORIA POWER STATION	VICTORIA WLE L.P.	12/1/2014	Combined Cycle Turbine	197	MW	BACT-PSD	2.00	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
*WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	11/21/2014	Combined Cycle Turbine/Duct Burner	2,159	MMBTU/H	BACT-PSD	2.00	PPM	@ 15% O2

Table C-1 Natural Gas Turbine NOx Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit	
*TX-0712	TRINIDAD GENERATING FACILITY	SOUTHERN POWER COMPANY	11/20/2014	Combined Cycle Turbine	497 MW	BACT-PSD	2.00 PPMVD	@15% O2, 24-HR ROLLING AVERAGE
*TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	NRG TEXAS POWER	8/29/2014	Combined Cycle Turbine	225 MW	BACT-PSD	2.00 PPM	24HR ROLLING AVG.
*TX-0641	PINECREST ENERGY CENTER	PINECREST ENERGY CENTER LLC	11/12/2013	Combined Cycle Turbine	700 MW	BACT-PSD	2.00 PPMVD	
VA-0322	GREEN ENERGY PARTNERS/ STONEWALL, LLC	GREEN ENERGY PARTNERS/ STONEWALL, LLC	4/30/2013	Large combustion turbines (>25MW) CCT1 and CCT2	2,230 MMBTU/hr	BACT-PSD	2.00 PPMVD @ 15 % O2	1-hr average
VA-0321	BRUNSWICK COUNTY POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	3/12/2013	COMBUSTION TURBINE GENERATORS, MHI 501GAC	3,442 MMBTU/H	BACT-PSD	2.00 PPMVD @ 15 % O2	1-hr average
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	Combined Cycle Turbine	180 MW	LAER	2.00 PPMVD	
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	Combined Cycle Turbine	180 MW	LAER	2.00 PPMVD	
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	Combined cycle gas turbine	195 MW	BACT-PSD	2.00 PPMVD	
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	Natural gas-fired turbines	390 MW	BACT-PSD	2.00 PPMVD	ROLLING 24-HR AT 15% OXYGEN
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	Natural gas-fired turbines	390 MW	BACT-PSD	2.00 PPMVD	
OR-0048	CARTY PLANT	PORTLAND GENERAL ELECTRIC	12/29/2010	COMBINED CYCLE NATURAL GAS-FIRED ELECTRIC GENERATING UNIT	2,866 MMBTU/H	BACT-PSD	2.00 PPM@15%O 2	3-HOUR ROLLING
NA	WARREN COUNTY POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	COMBINED CYCLE MHI 501 GAC NATURAL GAS-FIRED COMBUSTION TURBINE WITHOUT DUCT BURNING	1,280 MW	BACT-PSD	2.00 PPMVD @ 15 % O2	1-hr average
TX-0590	KING POWER STATION	PONDERA CAPITAL MANAGEMENT GP INC	8/5/2010	Turbine	1,350 MW	LAER	2.00 PPMVD AT 15% O2	1-HOUR AVERAGE

Table C-1 Natural Gas Turbine NOx Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit	
ID-0018	LANGLEY GULCH POWER PLANT	IDAHO POWER COMPANY	6/25/2010	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,375 MMBTU/H	BACT-PSD	2.00 PPMVD	3-HR ROLLING / 15% O2
*TX-0548	MADISON BELL ENERGY CENTER	MADISON BELL PARTNERS LP	8/18/2009	ELECTRICITY GENERATION	275 MW	BACT-PSD	2.00 PPMVD	@ 15% O2 24-HR ROLLING AVG
*TX-0547	NATURAL GAS-FIRED POWER GENERATION FACILITY	LAMAR POWER PARTNERS II LLC	6/22/2009	ELECTRICITY GENERATION	250 MW	BACT-PSD	2.00 PPMVD	@ 15% O2 24-HR ROLLING AVG
*TX-0546	PATTILLO BRANCH POWER PLANT	PATTILLO BRANCH POWER COMPANY LLC	6/17/2009	ELECTRICITY GENERATION	350 MW	BACT-PSD	2.00 PPMVD	@ 15% O2 24-HR ROLLING AVG
*OK-0129	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1,882 MMBTU/H	BACT-PSD	2.00 PPMVD	@ 15% O2 24-HR ROLLING AVG
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	7/30/2008	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	2,333 MMBTU/H	BACT-PSD	2.00 PPMVD (GAS)	@ 15% O2 24-HR ROLLING AVG
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	2 MMCF/H	LAER	2.00 PPM @ 15% O2	1-HR BLOCK
*VA-0308	WARREN COUNTY FACILITY	VIRGINIA ELECTRIC AND POWER COMPANY	1/14/2008	ELECTRIC GENERATION SECNARIO 3	2,204 MMBTU/H	BACT-PSD	2.00 PPMVD	
*VA-0308	WARREN COUNTY FACILITY	VIRGINIA ELECTRIC AND POWER COMPANY	1/14/2008	ELECTRIC GENERATION - SCENARIO 1	1,717 MMBTU/H	BACT-PSD	2.00 PPM	
*VA-0308	WARREN COUNTY FACILITY	VIRGINIA ELECTRIC AND POWER COMPANY	1/14/2008	ELECTRIC GENERATION - SCENARIO 2	1,944 MMBTU	BACT-PSD	2.00 PPMVD	
CA-1144	BLYTHE ENERGY PROJECT II	CAITHNESS BLYTHE II, LLC	4/25/2007	2 COMBUSTION TURBINES	170 MW	BACT-PSD	2.00 PPMVD	AT 15% O2, 3-HR AVG
NY-0098	ATHENS GENERATING PLANT	NEW ATHENS GENERATING CO. LLC	1/19/2007	FUEL COMBUSTION (GAS)	3,100 MMBTU/H	LAER	2.00 ppmvd at 15% O2	3 HOUR BLOCK AVAEAGE/STEADY STATE

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit	
FL-0286	FPL WEST COUNTY ENERGY CENTER	FLORIDA POWER AND LIGHT COMPANY	1/10/2007	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	2,333 MMBTU/H	BACT-PSD	2.00 ppmvd at 15% O2	24-HR (GAS)
*NY-0095	CAITHNES BELLPORT ENERGY CENTER	CAITHNESS BELLPORT, LLC	5/10/2006	COMBUSTION TURBINE	2,221 MMBUT/H	BACT-PSD	2.00 ppmvd at 15% O2	
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	8/16/2005	TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG AND DUCT BURNER.	306 MW	BACT-PSD	2.00 ppmvd at 15% O2	3-HOUR ROLLING
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	8/16/2005	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG AND DUCT BURNER.	306 MW	BACT-PSD	2.00 ppmvd at 15% O2	3-HOUR ROLLING
*OR-0041	WANAPA ENERGY CENTER	DIAMOND WANAPA I, L.P.	8/8/2005	COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	2,384 MMBTU/H	BACT-PSD	2.00 ppmvd at 15% O2	3 HOURS
NY-0100	EMPIRE POWER PLANT	EMPIRE GENERATING CO. LLC	6/23/2005	FUEL COMBUSTION (NATURAL GAS)	2,099 MMBTU/H	LAER	2.00 ppmvd at 15% O2	3-HOUR BLOCK AVE./ STEADY STATE
FL-0263	FPL TURKEY POINT POWER PLANT	FLORIDA POWER AND LIGHT	2/8/2005	170 MW COMBUSTION TURBINE, 4 UNITS	170 MW	BACT-PSD	2.00 ppmvd at 15% O2	STACK TEST (CT & DUCT BURNER)
AZ-0047	WELLTON MOHAWK GENERATING STATION	DOME VALLEY ENERGY PARTNERS	12/1/2004	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	170 MW	BACT-PSD	2.00 ppmvd at 15% O2	THREE-HOUR
AZ-0047	WELLTON MOHAWK GENERATING STATION	DOME VALLEY ENERGY PARTNERS	12/1/2004	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	180 MW	BACT-PSD	2.00 ppmvd at 15% O2	3-HOUR AVERAGE
*VA-0291	CPV WARREN LLC	CPV WARREN LLC	7/30/2004	TURBINE, COMBINED CYCLE (2)	1,717 MMBTU/H	Other Case-by-Case	2.00 ppmvd at 15% O2	AS A ONE HOUR AVERAGE
NV-0037	COPPER MOUNTAIN POWER	SEMPRA ENERGY RESOURCES	5/14/2004	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	600 MW	BACT-PSD	2.00 ppmvd at 15% O2	15% OXYGEN, 3-HR AVERAGE
UT-0066	CURRANT CREEK	PACIFICORP	5/17/2004	NATURAL GAS FIRED TURBINES AND HEAT RECOVERY STEAM GENERATORS		BACT-PSD	2.25 ppmvd at 15% O2	3-H COMBINED CYCLE AV
GA-0138	LIVE OAKS POWER PLANT	LIVE OAKS COMPANY, LLC	4/8/2010	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	600 MW	BACT-PSD	2.50 ppmvd at 15% O2	3 HOUR AVERAGE/CONDITIO N 2.11

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FL-0304	CANE ISLAND POWER PARK	FLORIDA MUNICIPAL POWER AGENCY (FMPA	9/8/2008	300 MW COMBINED CYCLE COMBUSTION TURBINE	1,860 MMBTU/H	BACT-PSD	2.50 ppmvd at 15% O2	24-HR
FL-0265	HINES POWER BLOCK 4	PROGRESS ENERGY	6/8/2005	COMBINED CYCLE TURBINE	530 MW	BACT-PSD	2.50 ppmvd at 15% O2	
MI-0366	BERRIEN ENERGY, LLC	BERRIEN ENERGY, LLC	4/13/2005	3 COMBUSTION TURBINES AND DUCT BURNERS	1,584 MMBTU/H	BACT-PSD	2.50 ppmvd at 15% O2	24-HOUR ROLLING AVG EACH HOUR
*WA-0328	BP CHERRY POINT COGENERATION PROJECT	BP WEST COAST PRODUCTS, LLC	1/11/2005	GE 7FA COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	174 MW	BACT-PSD	2.50 3-HR @ 15%O2	*SEE NOTES
CA-1142	PASTORIA ENERGY FACILITY	CALPINE WESTERN REGIONAL OFFICE	12/23/2004	3 COMBUSTION TURBINES	168 MW	BACT-PSD	2.50 @ 15% O2, 1-HR AVG	@ 15% O2, 1-HR AVG
CA-1143	SUTTER POWER PLANT	CALPINE CORPORATION	8/16/2004	2 COMBUSTION TURBINES	170 MW	BACT-PSD	2.50 AT 15% O2, 1-HR AVG	AT 15% O2, 1-HR AVG
VA-0289	DUKE ENERGY WYTHE, LLC	DUKE ENERGY WYTHE, LLC	2/5/2004	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	170 MW	BACT-PSD	2.50 PPM @ 15% O2	
VA-0289	DUKE ENERGY WYTHE, LLC	DUKE ENERGY WYTHE, LLC	2/5/2004	TURBINE, COMBINED CYCLE, NATURAL GAS	170 MW	BACT-PSD	2.50 PPM @ 15% O2	
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	EUCCT (Combined cycle CTG with unfired HRSG)	1,935 MMBTU/H	LAER	3.00 PPM	24-H ROLL.AVG., EXCEPT STARTUP/SHUTDOWN

Table C-2 Natural Gas Turbine CO Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	Throughput is for turbine only	2969 MMBtu/hr	BACT-PSD	0.90 PPMVD @15% O2	1 HOUR BLOCK
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle, two GE 7HA.01	805 MW	BACT-PSD	0.90 ppmvd @15% O2 without DB 1.70 ppmvd @15% O2 with DB	1 HR-BLOCK
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	2 MMCF/H	BACT-PSD	0.90 PPMVD @ 15 % O2	1 HR-BLOCK (W/OUT DUCT BURNER)
NA	C4GT	NOVI ENERGY	4/26/2018	Natural Gas without Duct Firing	3,482 MMBtu/hr	BACT-PSD	1.00 PPMVD @15% O2	3-hr average
NA	Greensville County	VIRGINIA ELECTRIC AND POWER COMPANY	6/17/2016	COMBINED CYCLE MHPS 501J NATURAL GAS-FIRED COMBUSTION TURBINE WITHOUT DUCT BURNING	3,227 MMBtu/hr	BACT-PSD	1.00 ppmvd @15% O2 without DB 1.60 ppmvd @15% O2 with DB	3-hr average
VA-0321	BRUNSWICK COUNTY POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	3/12/2013	COMBUSTION TURBINE GENERATORS, MHI 501GAC	3,442 MMBTU/H	BACT-PSD	1.50 ppmvd @15% O2 without DB 2.40 ppmvd @15% O2 with DB	3-hr average
NA	WARREN COUNTY POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	COMBINED CYCLE MHI 501 GAC NATURAL GAS-FIRED COMBUSTION TURBINE WITHOUT DUCT BURNING	1,280 MW	BACT-PSD	1.50 ppmvd @15% O2 without DB 2.40 ppmvd @15% O2 with DB	1-hr average
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	154 MW	BACT-PSD	1.50 PPMVD	@15% O2, 1-HR AVG (NO DUCT BURNING)
NA	C4GT	NOVI ENERGY	4/26/2018	Natural Gas with Duct Firing	3,482 MMBtu/hr	BACT-PSD	1.70 PPMVD @15% O2	3-hr average
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	Duct burner MRC is 946 MMbtu/hr	2639 MMBtu/hr	BACT-PSD	1.70 LB/MMBTU	1 HOUR BLOCK

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit	
*MI-0432	NEW COVERT GENERATING FACILITY	NEW COVERT GENERATING COMPANY, LLC	7/30/2018	Three (3) combined-cycle combustion turbine (CT) / heat recovery steam generator (HRSG) trains. Each CT is a natural gas fired Mitsubishi model 501G, equipped with dry low NOx combustor and inlet air evaporative cooling. Each HRSG includes a natural gas fired duct burner with a 256 MMBtu/hr heat input capacity and a dry low NOx burner.	1230 MW	BACT-PSD	2.00 PPMVD	EACH CT/HRSG TRAIN; 24-HR ROLL AVG
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	ENTERGY TEXAS INC	3/30/2018	Two Mitsubishi M501GAC turbines (without fast start)	2635 MMBTU/HR/UNIT	BACT-PSD	2.00 PPMVD	15% O2 3 HOUR AVERAGE
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	4/28/2017	Four Siemens SGT6-5000F5 natural gas fired combustion turbines with HRSGs and Steam Turbine Generators	426 MW	BACT-PSD	2.00 PPMVD	15% O2 3-H AVG
*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	New 633 megawatt (MW) gross facility consisting of 1.One General Electric (GE) 7HA.02 CCCT nominally rated at 380 MW at ISO conditions without duct firing with a maximum heat input rate of: o 3,462 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting natural gas o 3,613 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting ULSD which will be the backup fuel	683 MW	BACT-PSD	2.00 PPMVD@15 %O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/10/2016	Combined Cycle Combustion Turbine with Duct Burner firing natural gas		BACT-PSD	2.00 PPMVD@15 %O2	3 H ROLLING AV BASED ON ONE H BLOCK
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	Alstom GT36 combustion turbines (321 MW)+ 799 million British thermal units per hour (MMBtu/hr) duct burner	321 MW	BACT-PSD	2.00 PPM	3-HR AVERAGE
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	Two power configuration options authorized Siemens â€“ 240 MW + 250 million British thermal units per hour (MMBtu/hr) duct burner GE â€“ 195 MW + 670 MMBtu/hr duct burner	195 MW	BACT-PSD	2.00 PPM	ROLLING 24-HR AVERAGE

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TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	6/18/2015	Two power configuration options authorized□ Siemens 231 MW + 500 million British thermal units per hour (MMBtu/hr) duct burner□ GE 210 MW + 349.2 MMBtu/hr duct burner	210 MW	BACT-PSD	2.00 PPM	ROLLING 24-HR AVERAGE
*WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	11/21/2014	Combined Cycle Turbine/Duct Burner	2159 MMBTU/H	BACT-PSD	2.00 PPM	@ 15% O2
*TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	NRG TEXAS POWER	8/29/2014	Combined cycle natural gas turbines	225 MW	BACT-PSD	2.00 PPM	ROLLING 12 MONTHS
*IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	Combustion turbine #1 - combined cycle	2258 mmBtu/hr	BACT-PSD	2.00 ppmvd @ 15% O2	
*TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	FGE POWER LLC	3/24/2014	Alstom Turbine	230.7 MW	BACT-PSD	2.00 PPMVD	CORRECTED TO 15% O2, ROLLING 3 HR AVE
*TX-0641	PINECREST ENERGY CENTER	PINECREST ENERGY CENTER LLC	11/12/2013	combined cycle turbine	700 MW	BACT-PSD	2.00 PPMVD	3-HR ROLL AVG, 15% OXYGEN, 80-100% LOAD
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917 MMSCF/rolling 12-MO	BACT-PSD	2.00 PPM	PPMVD AT 15% O2
VA-0322	GREEN ENERGY PARTNERS/ STONEWALL, LLC	GREEN ENERGY PARTNERS/ STONEWALL, LLC	4/30/2013	Large combustion turbines CCT1 and CCT2	2,230 MMBTU/hr	BACT-PSD	2.00 PPMVD @ 15 % O2	1-hr average
*PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4 MMCF/HR	OTHER CASE-BY-CASE	2.00 PPMVD @ 15% OXYGEN	WITH OR WITHOUT DUCT BURNER
*PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)	0	BACT-PSD	2.00 ppmvd @ 15% O2	
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300 MMBTU/H	BACT-PSD	2.00 ppmvd @ 15% O2	3-hr average
TX-0590	KING POWER STATION	PONDERA CAPITAL MANAGEMENT GP INC	8/5/2010	Turbine	1,350 MW	BACT-PSD	2.00 PPMVD AT 15% O2	THREE-HOUR ROLLING

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ID-0018	LANGLEY GULCH POWER PLANT	IDAHO POWER COMPANY	6/25/2010	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,375 MMBTU/H	BACT-PSD	2.00 PPMVD	3-HR ROLLING / 15% O2
GA-0138	LIVE OAKS POWER PLANT	LIVE OAKS COMPANY, LLC	4/8/2010	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	600 MW	BACT-PSD	2.00 PPM@15%02	3 HOUR AVERAGE WO/O DUCT FIRING/CONDITIO
*TX-0546	PATTILLO BRANCH POWER PLANT	PATTILLO BRANCH POWER COMPANY LLC	6/17/2009	ELECTRICITY GENERATION	350 MW	BACT-PSD	2.00 PPMVD	@ 15% O2, 3-HR ROLLING AVG
*NY-0095	CAITHNES BELLPORT ENERGY CENTER	CAITHNESS BELLPORT, LLC	5/10/2006	COMBUSTION TURBINE	2,221 MMBUT/H	BACT-PSD	2.00 PPMVD@15%02	
NA	WARREN COUNTY POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	COMBINED CYCLE MHI 501 GAC NATURAL GAS-FIRED COMBUSTION TURBINE WITH AND DUCT BURNING	1,280 MW	BACT-PSD	2.40 PPM@15%O2	1-HOUR AVERAGE
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LLC	CALPINE CORP.	5/2/2006	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	300 MW	BACT-PSD	3.00 PPM @ 15 O2	
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	A 1,934.7 MMBTU/H natural gas fired heavy frame industrial combustion turbine. The turbine operates in combined-cycle with an unfired heat recovery steam generator (HRSG).	1934.7 MMBTU/H	BACT-PSD	4.00 PPM	24-H ROLL.AVG., EXCEPT STARTUP/SHUTDOWN
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	231 MW	BACT-PSD	4.00 PPM	
*TX-0714	S R BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	12/19/2014	(2) combined cycle turbines	240 MW	BACT-PSD	4.00 PPMVD	@15% O2, ONE HOUR
*TX-0710	VICTORIA POWER STATION	VICTORIA WLE L.P.	12/1/2014	combined cycle turbine	197 MW	BACT-PSD	4.00 PPMVD	@15% O2, 3-HR ROLLING AVERAGE
*TX-0712	TRINIDAD GENERATING FACILITY	SOUTHERN POWER COMPANY	11/20/2014	combined cycle turbine	497 MW	BACT-PSD	4.00 PPMVD	@15% O2, 24-HR ROLLING AVERAGE
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	Combined Cycle Turbine	180 MW	BACT-PSD	4.00 PPMVD	@ 15% O2 ON A 24-HR ROLLING AVG
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	Combined Cycle Turbine	180 MW	BACT-PSD	4.00 PPMVD	@ 15% O2 ON A 24-HR ROLLING AVG
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	Combined cycle gas turbine	195 MW	BACT-PSD	4.00 PPMVD	@ 15% O2 ON A 24-HR ROLLING AVG

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TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	Natural gas-fired turbines	390 MW	BACT-PSD	4.00 PPMVD	ROLLING 3-HR AT 15% OXYGEN /LOAD >= 60%
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	Natural gas-fired turbines	390 MW	BACT-PSD	4.00 PPMVD	ROLLING 3-HR AT 15% OXYGEN /LOAD >= 60%
CA-1144	BLYTHE ENERGY PROJECT II	CAITHNESS BLYTHE II, LLC	4/25/2007	2 COMBUSTION TURBINES	170 MW	BACT-PSD	4.00 PPMVD	AT 15% O2, 3-HR AVG
*FL-0363	DANIA BEACH ENERGY CENTER	FLORIDA POWER AND LIGHT COMPANY	12/4/2017	Two nominal 430 MW combustion turbines, coupled to a steam turbine generator	4000 MMBtu/hr	BACT-PSD	4.30 PPMVD@15 % O2	AT LOADS > 90%
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3-on-1 combined cycle unit. GE 7HA.02 turbines, approximately 350 MW per turbine. Total unit generating capacity is approximately 1,600 MW. Primarily fueled with natural gas. Permitted to burn the base-load equivalent of 500 hr/yr per turbine on ULSD.	3096 MMBtu/hr per turbine	BACT-PSD	4.30 PPMVD@15 % O2	3-HR AVERAGE, NATURAL GAS OPERATION
*OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172 MW	BACT-PSD	6.00 PPM	PPMVD AT 15% O2 ON 24-H BLOCK AVERAGE
FL-0304	CANE ISLAND POWER PARK	FLORIDA MUNICIPAL POWER AGENCY (FMPA	9/8/2008	300 MW COMBINED CYCLE COMBUSTION TURBINE	1,860 MMBTU/H	BACT-PSD	6.00 PPMVD	12-MONTH
*PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNE E	BERKS HOLLOW ENERGY ASSOC LLC	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046 MMBtu/hr	BACT-PSD	7.00 ppmvd @ 15% O2	12-MONTH ROLLING TOTAL
*OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172 MW	BACT-PSD	8.00 PPM	PPMVD AT 15% O2 ON 24-H BLOCK AVERAGE
FL-0285	PROGRESS BARTOW POWER PLANT	PROGRESS ENERGY FLORIDA (PEF)	1/26/2007	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	1,972 MMBTU/H	BACT-PSD	8.00 PPMVD	24-HR BLOCK AVERAGE CEMS
FL-0286	FPL WEST COUNTY ENERGY CENTER	FLORIDA POWER AND LIGHT COMPANY	1/10/2007	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	2,333 MMBTU/H	BACT-PSD	8.00 PPMVD @15%O2	24-HR
*MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237 MMBtu/hour	BACT-PSD	9.00 PPM	EACH CTG; 24-H ROLLING AVG.

Table C-2 Natural Gas Turbine CO Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit	
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	TWO COMBINED CYCLE GAS TURBINES	2,110 MMBTU/H	BACT-PSD	10.00 PPMVD@15 %O2	ANNUAL AVERAGE
MN-0066	NORTHERN STATES POWER CO. DBA XCEL ENERGY - RIVERSIDE PLANT	NORTHERN STATES POWER CO. DBA XCEL ENERGY	5/16/2006	TURBINE, COMBINED CYCLE (2)	1,885 mmbtu/h	BACT-PSD	10.00 PPM @ 15% O2	

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

Table C-3 Natural Gas Turbine VOC Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit	
*OK-0129	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1882 MMBTU/H	BACT-PSD	0.30 PPM	3-HR AVG @ 15% O2
NA	Greensville County	VIRGINIA ELECTRIC AND POWER COMPANY	6/17/2016	COMBINED CYCLE MHPS 501J NATURAL GAS-FIRED COMBUSTION TURBINE WITHOUT DUCT BURNING	3,227 MMBtu/hr	BACT-PSD	ppmvd @15% O2 0.70 without DB 1.40 ppmvd @15% O2 with DB	3-hr average
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	550 MW Combined Cycle Plant	2,969 MMBtu/hr	BACT-PSD	0.70 PPMVD @15% O2	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	550 MW Combined Cycle Plant	2,639 MMBtu/hr	BACT-PSD	1.60 PPMVD @15% O2	
*FL-0363	DANIA BEACH ENERGY CENTER	FLORIDA POWER AND LIGHT COMPANY	12/4/2017	1200 megawatt 2-on-1 combined cycle facility, natural gas-fired, with limited ULSD use. GE 7HA turbines	4,000 MMBtu/hr	BACT-PSD	1.00 PPMVD@15% O2	FOR NATURAL GAS OPERATION
FL-0364	SEMINOLE GENERATING STATION	SEMINOLE ELECTRIC COOPERATIVE, INC.	3/21/2018	Existing fossil-fueled power plant. Two coal-fired units each rated at 736 MW. Project entails retirement of one coal-fired unit and construction of a 2-on-1 natural gas combined cycle unit.	3,514 MMBtu/hr	BACT-PSD	1.00 PPMVD@15% O2	WITHOUT DUCT BURNER FIRING
*MI-0432	NEW COVERT GENERATING FACILITY	NEW COVERT GENERATING COMPANY, LLC	7/30/2018	Power plant	1,230 MW	BACT-PSD	1.00 PPMVD	HOURLY; EACH CT/HRSG TRAIN
TX-0817	CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION	INEOS USALLC	2/17/2017	support facility providing steam and electricity	50 MW	BACT-PSD	1.00 PPMDV	
VA-0321	BRUNSWICK COUNTY POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	3/12/2013	COMBUSTION TURBINE GENERATORS, MHI 501GAC	3,442 MMBTU/H	BACT-PSD	ppmvd @15% O2 0.70 without DB 1.60 ppmvd @15% O2 with DB	3-hr average
NA	C4GT	NOVI ENERGY	4/26/2018	Natural Gas combustion turbine	3,482 MMBtu/hr	BACT-PSD	ppmvd @15% O2 0.70 without DB 1.4 ppmvd @15% O2 with DB	3-hr average
NA	WARREN COUNTY POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	COMBINED CYCLE MHI 501 GAC NATURAL GAS-FIRED COMBUSTION TURBINE WITHOUT DUCT BURNING	1,280 MW	BACT-PSD	ppmvd @15% O2 1.50 without DB 2.40 ppmvd @15% O2 with DB	3-hr average
VA-0322	GREEN ENERGY PARTNERS/ STONEWALL, LLC	GREEN ENERGY PARTNERS/ STONEWALL, LLC	4/30/2013	Large combustion turbines CCT1 and CCT2	2,230 MMBTU/hr	BACT-PSD	ppmvw @15% O2 1.00 without DB 1.50 ppmvw @15% O2 with DB	3-hr average
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle, two GE 7HA.01		BACT-PSD	ppmvd @15% O2 1.0 without DB 2.0 ppmvd @15% O2 with DB	

Table C-3 Natural Gas Turbine VOC Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	New 633 megawatt (MW) gross facility consisting of 1.One General Electric (GE) 7HA.02 CCCT nominally rated at 380 MW at ISO conditions without duct firing with a maximum heat input rate of: o 3,462 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting natural gas o 3,613 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting ULSD which will be the backup fuel	683 MW	LAER	1.00 PPMVD@15%O2	Avg of three 1-hour stack tests, every 5 years
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3-on-1 combined cycle unit. GE 7HA.02 turbines, approximately 350 MW per turbine. Total unit generating capacity is approximately 1,600 MW. Primarily fueled with natural gas. Permitted to burn the base-load equivalent of 500 hr/yr per turbine on ULSD.	3096 MMBtu/hr per turbine	BACT-PSD	1.00 PPMVD@15%O2	GAS OPERATION
NY-0100	EMPIRE POWER PLANT	EMPIRE GENERATING CO. LLC	6/23/2005	FUEL COMBUSTION (NATURAL GAS)	2099 MMBTU/H	LAER	1.00 PPMVD@15%O2	AS PER EPA METHOD 25A
MN-0053	FAIRBAULT ENERGY PARK	MN MUNICIPAL POWER AGENCY	7/15/2004	TURBINE, COMBINED CYCLE, NATURAL GAS (1)	1876 MMBTU/H	BACT-PSD	1.00 PPMVD@15%O2	3 HOUR AVERAGE
NJ-0043	LIBERTY GENERATING STATION	LIBERTY GENERATING STATION	3/28/2002	COMBINED CYCLE TURBINE (3)	2964 MMBTU/H	Other Case-by-Case	1.00 PPMVD@15%O2	
*TX-0714	S R BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	12/19/2014	(2) combined cycle turbines	240 MW	BACT-PSD	1.00 PPMVD	@15% O2
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300 MMBTU/H	BACT-PSD	1.00 PPMVD	3 HOURS
*VA-0291	CPV WARREN LLC	CPV WARREN LLC	7/30/2004	TURBINE, COMBINED CYCLE AND DUCT BURNER (2)	1717 MMBTU/H	Other Case-by-Case	1.00 PPMVD	
NC-0095	MIRANT GASTONIA POWER FACILITY	MIRANT GASTONIA LLC	5/28/2002	TURBINES, COMBINED CYCLE, MHI/SW	175 MW	BACT-PSD	1.00 PPMVD	3-h avg
*PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)	0	BACT-PSD	1.00 PPMDV	WITHOUT DUCT BURNER
*IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	Combustion turbine #1 - combined cycle	2258 mmBtu/hr	BACT-PSD	1.00 PPM	AVG. OF 3 ONE HOUR TEST RUNS
*IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	Combustion turbine #2 -combined cycle	2258 mmBtu/hr	BACT-PSD	1.00 PPM	AVERAGE 0F 3 ONE-HOUR TEST RUNS
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	11/12/2003	TURBINE, COMBINED CYCLE	325 MW	BACT-PSD	1.00 PPM	3 hr avg
PA-0189	CONECTIV BETHLEHEM, INC.	CONECTIV BETHLEHEM, INC	1/16/2002	TURBINE, COMBINED CYCLE, (6)	122 MW	Other Case-by-Case	1.20 PPMVD@15%O2	
VA-0255	VA POWER - POSSUM POINT	Virginia Power	11/18/2002	TURBINE, NATURAL GAS, NO DUCT BURNER FIRING	1937 MMBTU/H	BACT-PSD	1.20 PPMVD@15%O2	EACH UNIT
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	7/30/2008	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	2333 MMBTU/H	BACT-PSD	1.20 PPMVD	
FL-0285	PROGRESS BARTOW POWER PLANT	PROGRESS ENERGY FLORIDA (PEF)	1/26/2007	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	1972 MMBTU/H	BACT-PSD	1.20 PPMVD	@ 15% O2 FOR CT ONLY - GAS
FL-0244	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	4/16/2003	TURBINE, COMBINED CYLE, NATURAL GAS, (4)	170 MW	BACT-PSD	1.30 PPMVD@15%O2	
FL-0245	FPL MANATEE PLANT - UNIT 3	FLORIDA POWER & LIGHT	4/15/2003	TURBINE, COMBINED CYCLE, NATURAL GAS (4)	170 MW	Other Case-by-Case	1.30 PPMVD@15%O2	normal operation

Table C-3 Natural Gas Turbine VOC Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

FL-0263	FPL TURKEY POINT POWER PLANT	FLORIDA POWER AND LIGHT	2/8/2005	170 MW COMBUSTION TURBINE, 4 UNITS	170 MW		1.30 PPMVD@15%O2	STACK TEST (CT NORMAL) GAS
NC-0095	MIRANT GASTONIA POWER FACILITY	MIRANT GASTONIA LLC	5/28/2002	TURBINES, COMBINED CYCLE, GE	175 MW	BACT-PSD	1.30 PPMVD	
*FL-0337	POLK POWER STATION	TAMPA ELECTRIC COMPANY	10/14/2012	Combine cycle power block (4 on 1)	1160 MW	BACT-PSD	1.40 PPMVD@15%O2	
AR-0070	GENOVA ARKANSAS I, LLC	GENOVA ARKANSAS I, LLC	8/23/2002	TURBINE, COMBINED CYCLE, (2), (GE)	170 MW	BACT-PSD	1.40 PPMVD@15%O2	
LA-0157	PERRYVILLE POWER STATION	PERRYVILLE ENERGY PARTNERS, LLC	3/8/2002	TURBINES, COMBINED CYCLE, GAS, (2) EPNS 1-1, 1-2	170 MW	BACT-PSD	1.40 PPMV @ 15% O2	
CA-0997	SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO MUNICIPAL UTILITY DISTRICT	9/1/2003	GAS TURBINES, (2)	1611 MMBTU/H	LAER	1.40 PPM @ 15% O2	
AZ-0038	GILA BEND POWER GENERATING STATION	GILA BEND POWER GENERATING STATION	5/15/2002	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	170 MW	BACT-PSD	1.40 PPM @ 15% O2	
VA-0287	JAMES CITY ENERGY PARK	JAMES CITY ENERGY PARK LLC	12/1/2003	TURBINE, COMBINED CYCLE, NATURAL GAS	1973 MMBTU/H	BACT-PSD	1.40 PPM	
*PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4 MMCF/HR	OTHER CASE-BY-CASE	1.50 PPMVD@15%O2	WITH OR WITHOUT DUCT BURNER
FL-0286	FPL WEST COUNTY ENERGY CENTER	FLORIDA POWER AND LIGHT COMPANY	1/10/2007	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	2333 MMBTU/H	BACT-PSD	1.50 PPMVD@15%O2	GAS
*MN-0071	FAIRBAULT ENERGY PARK	MINNESOTA MUNICIPAL POWER AGENCY	6/5/2007	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	1758 MMBTU/H	BACT-PSD	1.50 PPMVD	CTG NG NO DB
NJ-0043	LIBERTY GENERATING STATION	LIBERTY GENERATING STATION	3/28/2002	COMBINED CYCLE TURBINE WITH DUCT BURNER	3202 MMBTU/H	Other Case-by-Case	1.70 PPMVD@15%O2	
VA-0261	CPV CUNNINGHAM CREEK	COMPETITIVE POWER VENTURE	9/6/2002	TURBINE, COMBINED CYCLE, (2)	2132 MMBTU/H	BACT-PSD	1.80 PPMVD@15%O2	<70% LOAD
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	ENTERGY TEXAS INC	3/30/2018		2,635 MMBTU/HR/UNIT	LAER	2.00 PPMVD	15% O2 3 HOUR AVERAGE
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/10/2016	Combined Cycle Combustion Turbine with Duct Burner firing natural gas		LAER	2.00 PPMVD	3 H ROLLING AV BASED ON ONE H BLOCK
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	231 MW	BACT-PSD	2.00 PPM	
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	Alstom GT36 combustion turbines (321 MW)+ 799 million British thermal units per hour (MMBtu/hr) duct burner	321 MW	BACT-PSD	2.0 PPM	
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	Two power configuration options authorized Siemens â€“ 240 MW + 250 million British thermal units per hour (MMBtu/hr) duct burner GE â€“ 195 MW + 670 MMBtu/hr duct burner	195 MW	LAER	2.0 PPM	
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	6/18/2015	Two power configuration options authorized Siemens 231 MW + 500 million British thermal units per hour (MMBtu/hr) duct burner GE 210 MW + 349.2 MMBtu/hr duct burner	210 MW	LAER	2.0 PPM	
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	4/28/2017		426 MW	BACT-PSD	3.50 PPMVD	15% O2

Table C-3 Natural Gas Turbine VOC Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

*TX-0710	VICTORIA POWER STATION	VICTORIA WLE L.P.	12/1/2014	combined cycle turbine	197 MW	BACT-PSD	4.00 PPMVD	@15% O2, 3-HR ROLLING AVERAGE
*TX-0712	TRINIDAD GENERATING FACILITY	SOUTHERN POWER COMPANY	11/20/2014	combined cycle turbine	497 MW	BACT-PSD	4.00 PPMVD	@15% O2 1-HR
*TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	FGE POWER LLC	3/24/2014	Alstom Turbine	230.7 MW	BACT-PSD	2.00 PPMVD	CORRECTED TO 15% O2, ROLLING 3 HR AVE
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	FUTURE POWER PA INC	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267 MMBtu/hr	BACT-PSD	2.00 PPMVD	@ 15% OXYGEN
*TX-0641	PINECREST ENERGY CENTER	PINECREST ENERGY CENTER LLC	11/12/2013	combined cycle turbine	700 MW	BACT-PSD	2.00 PPMVD	INITIAL STACK TEST, 15% OXYGEN
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	Combined Cycle Turbine	180 MW	BACT-PSD	2.00 PPMVD	@15% O2
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	Combined Cycle Turbine	180 MW	BACT-PSD	2.00 PPMVD	@15% O2
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	Combined cycle gas turbine	195 MW	BACT-PSD	2.00 PPMVD	@15% O2
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	8/28/2012	Combined Cycle Turbine (EP01)	40 MW	BACT-PSD	3.00 PPMV AT 15% O2	1-HOUR
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	8/28/2012	Combined Cycle Turbine (EP02)	40 MW	BACT-PSD	3.00 PPMV AT 15% O2	3-HOUR AVERAGE
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	Natural gas-fired turbines	390 MW	BACT-PSD	2.00 PPMVD	3-HR AT 15% OXYGEN
ID-0018	LANGLEY GULCH POWER PLANT	IDAHO POWER COMPANY	6/25/2010	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	2375.28 MMBTU/H	BACT-PSD	11.50 PPMVD	3-HR ROLLING / 15% O2 DURING LL
*TX-0548	MADISON BELL ENERGY CENTER	MADISON BELL PARTNERS LP	8/18/2009	ELECTRICITY GENERATION	275 MW	BACT-PSD	2.50 PPMVD	@ 15% O2, 1-HR ROLLING AVG
*TX-0547	NATURAL GAS-FIRED POWER GENERATION FACILITY	LAMAR POWER PARTNERS II LLC	6/22/2009	ELECTRICITY GENERATION	250 MW	BACT-PSD	4.00 PPMVD	@ 15% O2, 24-HR ROLLING AVG
*TX-0546	PATTILLO BRANCH POWER PLANT	PATTILLO BRANCH POWER COMPANY LLC	6/17/2009	ELECTRICITY GENERATION	350 MW	BACT-PSD	2.00 PPMVD	@ 15% O2, 3-HR ROLLING AVG
*GA-0127	PLANT MCDONOUGH COMBINED CYCLE	SOUTHERN COMPANY/GEORGIA POWER	1/7/2008	COMBINED CYCLE COMBUSTION TURBINE	254 MW	LAER	1.80 PPM @ 15% O2	3-HOUR, WITH DUCT BURNER
*GA-0127	PLANT MCDONOUGH COMBINED CYCLE	SOUTHERN COMPANY/GEORGIA POWER	1/7/2008	COMBINED CYCLE COMBUSTION TURBINE	254 MW	LAER	1.80 PPM @ 15% O2	3-HOUR, WITH DUCT BURNER
NY-0098	ATHENS GENERATING PLANT	NEW ATHENS GENERATING CO. LLC	1/19/2007	FUEL COMBUSTION (GAS)	3100 MMBTU/H	LAER	4.00 PPMVD@15%O2	3 HOUR BLOCK AVERAGE/ STEADY STATE
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	8/16/2005	TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG AND DUCT BURNER.	306 MW	BACT-PSD	4.00 PPM @ 15% O2	3-HOUR ROLLING
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	8/16/2005	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG AND DUCT BURNER.	306 MW	BACT-PSD	4.00 PPM @ 15% O2	3-HOUR ROLLING
MN-0060	HIGH BRIDGE GENERATING PLANT	NORTHERN STATES POWER CO. DBA XCEL ENERGY	8/12/2005	2 COMBINED-CYCLE COMBUSTION TURBINES	330 MEGAWATTS	BACT-PSD	2.00 PPM @ 15% O2	W/O DUCT-BURNER
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	Natural gas combined cycle power plant.	8,322 MMBTU/H	BACT-PSD	4.00 PPM	TEST PROTOCOL WILL SPECIFY

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

Table C-4 Natural Gas Turbine Particulate Matter Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size			Emission Limit		
RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CASE-BY-CASE BASIS	EMISSSION LIMIT	EMISSION LIMIT UNIT	EMISSION CONDITION
NA	Greensville County	VIRGINIA ELECTRIC AND POWER COMPANY	6/17/2016	MHPS M501J	3,227	MMBtu/hr	BACT-PSD	0.0030 /9.2 0.0039/14.1	lb/MMBtu/lb/hr without DB lb/MMBtu/lb/hr with DB	avg. of 3 test runs
NA	C4GT	NOVI ENERGY	4/26/2018	Natural Gas combustion turbine	3,482	MMBtu/hr	BACT-PSD	0.0069 /12.2 0.0049/17.3	lb/MMBtu/lb/hr without DB lb/MMBtu/lb/hr with DB	avg. of 3 test runs
VA-0322	GREEN ENERGY PARTNERS/ STONEWALL, LLC	GREEN ENERGY PARTNERS/ STONEWALL, LLC	4/30/2013	Large combustion turbines	2,230	MMBTU/hr	BACT-PSD	0.0034/9.9 0.0034/12.7	lb/MMBtu/lb/hr without DB lb/MMBtu/lb/hr with DB	3-hr average
VA-0321	BRUNSWICK COUNTY POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	3/12/2013	COMBUSTION TURBINE GENERATORS, MHI 501GAC	3,442	MMBTU/H	BACT-PSD	0.0033 /9.7 0.0047/16.3	lb/MMBtu/lb/hr without DB lb/MMBtu/lb/hr with DB	3-hr average
NA	WARREN COUNTY POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	COMBINED CYCLE MHI 501 GAC NATURAL GAS-FIRED COMBUSTION TURBINE WITHOUT DUCT BURNING	1,280	MW	BACT-PSD	0.0027 /8.0 0.0040/14.0	lb/MMBtu/lb/hr without DB lb/MMBtu/lb/hr with DB	3-hr average
*WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	11/21/2014	Combined Cycle Turbine/Duct Burner	2159	MMBTU/H	BACT-PSD	0.0035	LB/MMBTU	
*MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	BACT-PSD	0.0040	lb/MMBtu	TEST PROTOCOL
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	550 MW Combined Cycle Plant	2,969	MMBtu/hr	BACT-PSD	0.0044	LB/MMBTU	
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	154	MW	BACT-PSD	0.0048	lb/MMBtu	9-HR AVG (NO DUCT BURNING)
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	550 MW Combined Cycle Plant	2,639	MMBtu/hr	BACT-PSD	0.0050	LB/MMBTU	
*NY-0095	CAITHNES BELLPORT ENERGY CENTER	CAITHNESS BELLPORT, LLC	5/10/2006	COMBUSTION TURBINE	2,221	MMBUT/H	BACT-PSD	0.0055	lb/MMBtu	NO DUCT BURNING
*PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)			OTHER CASE-BY-CASE	0.0057	lb/MMBtu	
*MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBtu/hour	BACT-PSD	0.0060	lb/MMBtu	EACH CTG; TEST PROTOCOL
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	1,935	MMBTU/H	BACT-PSD	0.0066	LB/MMBTU	
*MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	Combined cycle combustion turbine w/ HRSG	130	MW electrical output	BACT-PSD	0.0066	lb/MMBtu	TEST
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LLC	CALPINE CORP.	5/2/2006	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	300	MW	BACT-PSD	0.0074	lb/MMBtu	
*MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	BACT-PSD	0.0080	lb/MMBtu	TEST PROTOCOL

Table C-4 Natural Gas Turbine Particulate Matter Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size		Emission Limit	
*IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	Combustion turbine #1 - combined cycle	2258 mmBtu/hr	BACT-PSD	0.010 lb/MMBtu	AVG. OF 3 ONE HOUR TEST RUNS
*MN-0071	FAIRBAULT ENERGY PARK	MINNESOTA MUNICIPAL POWER AGENCY	6/5/2007	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	1,758 MMBTU/H	BACT-PSD	0.0100 lb/MMBtu	CTG NG OR CTG & DB NG
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	12/6/2011	Combined Cycle Refrigeration Compressor Turbines (8)	286 MMBTU/H	BACT-PSD	2.08 lb/hr	HOURLY MAXIMUM
LA-0256	COGENERATION PLANT	WESTLAKE VINYLS COMPANY LP	12/6/2011	COGENERATION TRAINS 1-3 (1-10, 2-10, 3-10)	475 MMBTU/H	BACT-PSD	3.72 lb/hr	HOURLY MAXIMUM
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	8/28/2012	Combined Cycle Turbine (EP01)	40 MW	BACT-PSD	4.00 lb/hr	3-HOUR AVERAGE
*VA-0319	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	GATEWAY GREEN ENERGY	8/27/2012	COMBUSTION TURBINES, (2)	593 MMBTU/H	BACT-PSD	5.00 lb/hr	3 H AVG
CA-1144	BLYTHE ENERGY PROJECT II	CAITHNESS BLYTHE II, LLC	4/25/2007	2 COMBUSTION TURBINES	170 MW	BACT-PSD	6.00 lb/hr	
*OK-0129	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1,882 MMBTU/H	N/A	6.59 lb/hr	3-HR AVG
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917 MMSCF/rolling 12-MO	BACT-PSD	10.10 lb/hr	
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	FUTURE POWER PA INC	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267 MMBtu/hr	BACT-PSD	10.40 lb/hr	WITH DUCT BURNER
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	2 MMCF/H	BACT-PSD	11.00 lb/hr	W/OUT DUCT BURNER
TX-0590	KING POWER STATION	PONDERA CAPITAL MANAGEMENT GP INC	8/5/2010	Turbine	1,350 MW	BACT-PSD	11.10 lb/hr	
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917 MMSCF/rolling 12-MO	BACT-PSD	11.30 lb/hr	
*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	New 633 megawatt (MW) gross facility consisting of 1.One General Electric (GE) 7HA.02 CCCT nominally rated at 380 MW at ISO conditions without duct firing with a maximum heat input rate of: o 3,462 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting natural gas o 3,613 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting ULSD which will be the backup fuel	683 MW	BACT-PSD	11.70 lb/hr	Avg of three 1-hour stack tests, every 5 years. EPA OTM 27 and 202
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600 MMSCF/rolling 12-months	BACT-PSD	13.30 lb/hr	
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560 MMSCF/rolling 12-MO	BACT-PSD	14.00 lb/hr	
*OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172 MW	BACT-PSD	15.00 lb/hr	

Table C-4 Natural Gas Turbine Particulate Matter Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size		Emission Limit	
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	FUTURE POWER PA INC	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267 MMBtu/hr	BACT-PSD	15.60 lb/hr	WITH DUCT BURNER
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	Two power configuration options authorized Siemens 240 MW + 250 million British thermal units per hour (MMBtu/hr) duct burner GE 195 MW + 670 MMBtu/hr duct burner	195 MW	BACT-PSD	16.00 LB/HR	
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015			BACT-PSD	9.73 LB/H without DB 20.4 LB/H with DB	
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300 MMBTU/H	BACT-PSD	18.00 lb/hr	3 HOURS
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300 MMBTU/H	BACT-PSD	18.00 lb/hr	3 HOURS
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	Combined cycle gas turbine	195 MW	BACT-PSD	18.00 lb/hr	PER TURBINE
*OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172 MW	BACT-PSD	19.90 lb/hr	
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	Alstom GT36 combustion turbines (321 MW)+ 799 million British thermal units per hour (MMBtu/hr) duct burner	321 MW	BACT-PSD	21.40 LB/H	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/10/2016	Combined Cycle Combustion Turbine with Duct Burner firing natural gas		BACT-PSD	22.60 LB/H	AV OF THREE ONE H STACK TESTS, total including CPM
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	TWO COMBINED CYCLE GAS TURBINES	2,110 MMBTU/H	BACT-PSD	24.23 lb/hr	MAX
*TX-0641	PINECREST ENERGY CENTER	PINECREST ENERGY CENTER LLC	11/12/2013	combined cycle turbine	700 MW	BACT-PSD	26.20 lb/hr	
TX-0502	NACOGDOCHES POWER STERNE GENERATING FACILITY	NACOGDOCHES POWER LLC	6/5/2006	WESTINGHOUSE/SIEMENS MODEL SW501F GAS TURBINE W/ 416.5 MMBTU DUCT BURNERS	190 MW	BACT-PSD	26.90 lb/hr	
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	Combined Cycle Turbine	180 MW	BACT-PSD	27.00 lb/hr	
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	Combined Cycle Turbine	180 MW	BACT-PSD	27.00 lb/hr	
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	Natural gas-fired turbines	390 MW	BACT-PSD	33.43 lb/hr	1-H
LA-0136	PLAQUEMINE COGENERATION FACILITY	THE DOW CHEMICAL COMPANY	7/23/2008	(4) GAS TURBINES/DUCT BURNERS	2,876 MMBTU/H	BACT-PSD	33.50 lb/hr	HOURLY MAXIMUM
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	231 MW	BACT-PSD	35.47 LB/H	

Table C-4 Natural Gas Turbine Particulate Matter Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size		Emission Limit	
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	6/18/2015	Two power configuration options authorized Siemens 231 MW + 500 million British thermal units per hour (MMBtu/hr) duct burner GE 210 MW + 349.2 MMBtu/hr duct burner	210 MW	BACT-PSD	35.47 LB/H	

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

Table C-5 Gas Turbine SO2 Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit	
MI-0362	MIDLAND COGENERATION (MCV)	MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP	4/21/2003	TURBINE, COMBINED CYCLE, (11)	984 MMBTU/H	BACT-PSD	0.20 GR/100 SCF	NATURAL GAS SPECIFICATION
MI-0361	SOUTH SHORE POWER LLC	SOUTH SHORE POWER LLC	1/30/2003	TURBINE, COMBINED CYCLE, (2)	172 MW	BACT-PSD	0.20 GR/100 SCF	NATURAL GAS SPECIFICATION
VA-0262	MIRANT AIRSIDE INDUSTRIAL PARK	MIRANT DANVILLE, LLC	12/6/2002	TURBINE, COMBINED CYCLE, (2)	170 MW	BACT-PSD	0.80 GR/100 SCF	FUEL LIMIT
*MI-0432	NEW COVERT GENERATING FACILITY	NEW COVERT GENERATING COMPANY, LLC	7/30/2018	Power plant	1230 MW	BACT-PSD	0.80 GR/100 SCF	NAT.GAS BURNED IN FG-TURB/DB1-3
MN-0054	MANKATO ENERGY CENTER		12/4/2003	COMBUSTION TURBINE, LARGE, 2 EACH	1,916 MMBTU/H	BACT-PSD	0.80 GR/100 SCF	CALENDAR YEAR AVG.
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	ENTERGY TEXAS INC	3/30/2018	0	2635 MMBTU/HR/UNIT	BACT-PSD	1.00 GR/100 SCF	
CA-0997	SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO MUNICIPAL UTILITY DISTRICT	9/1/2003	GAS TURBINES, (2)	1,611 MMBTU/H	LAER	1.00 GR/100 SCF	FUEL SPECIFICATION
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	4/28/2017	GAS TURBINES	426 MW	BACT-PSD	1.54 GR/100 SCF	
FL-0286	FPL WEST COUNTY ENERGY CENTER	FLORIDA POWER AND LIGHT COMPANY	1/10/2007	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	2,333 MMBTU/H	BACT-PSD	2.00 GR/100 SCF	
FL-0263	FPL TURKEY POINT POWER PLANT	FLORIDA POWER AND LIGHT	2/8/2005	170 MW COMBUSTION TURBINE, 4 UNITS	170 MW	BACT-PSD	2.00 GR/100 SCF	
FL-0245	FPL MANATEE PLANT - UNIT 3	FLORIDA POWER & LIGHT	4/15/2003	TURBINE, COMBINED CYCLE, NATURAL GAS (4)	170 MW	BACT-PSD	2.00 GR/100 SCF	
FL-0285	PROGRESS BARTOW POWER PLANT	PROGRESS ENERGY FLORIDA (PEF)	1/26/2007	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	1,972 MMBTU/H	BACT-PSD	2.00 GR/100 SCF	
FL-0265	HINES POWER BLOCK 4	PROGRESS ENERGY	6/8/2005	COMBINED CYCLE TURBINE	530 MW	BACT-PSD	2.00 GR/100 SCF	CONTINUOUS
FL-0239	JEA/BRANDY BRANCH	JACKSONVILLE ELECTRIC AUTHORITY (JEA)	3/27/2002	TURBINES, COMBINED CYCLE, (2)	1,911 MMBTU/H	Other Case-by-Case	2.00 GR/100 SCF	
MN-0053	FAIRBAULT ENERGY PARK	MN MUNICIPAL POWER AGENCY	7/15/2004	TURBINE, COMBINED CYCLE, NATURAL GAS (1)	1,876 MMBTU/H	BACT-PSD	0.80 GR/SCF	gr/scf nat gas, CALENDAR YR AVE
TN-0144	HAYWOOD ENERGY CENTER, LLC	CALPINE CONSTRUCTION FINANCE COMPANY, L. P.	2/1/2002	TURBINE, COMBINED CYCLE, W/ DUCT FIRING	1,990 MMBTU/H	BACT-PSD	0.0006 LB/MMBTU	
NC-0101	FORSYTH ENERGY PLANT	FORSYTH ENERGY PROJECTS, LLC	9/29/2005	TURBINE & DUCT BURNER, COMBINED CYCLE, NAT GAS, 3	1,844 MMBTU/H	BACT-PSD	0.0006 LB/MMBTU	3-hr avg
NC-0086	FAYETTEVILLE GENERATION, LLC	FAYETTEVILLE GENERATION, LLC	1/10/2002	TURBINE, COMBINED CYCLE, NATURAL GAS, (2)	154 MW	BACT-PSD	0.0006 LB/MMBTU	3-h avg
TX-0391	OXY COGENERATION FACILITY	OXY VINYLS LP	12/20/2002	HRSG UNIT NO. 3	255 MMBTU/H	Other Case-by-Case	0.0008 LB/MMBTU	
VA-0255	VA POWER - POSSUM POINT	Virginia Power	11/18/2002	TURBINE, COMBINED CYCLE, NATURAL GAS, DUCT BURNER	1,937 MMBTU/H	BACT-PSD	0.0011 LB/MMBTU	
*NY-0095	CAITHNES BELLPORT ENERGY CENTER	CAITHNESS BELLPORT, LLC	5/10/2006	COMBUSTION TURBINE	2,221 MMBUT/H	BACT-PSD	0.0011 LB/MMBTU	

Table C-5 Gas Turbine SO2 Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	550 MW Combined Cycle Plant	2639 MMBtu/hr	OTHER CASE-BY-CASE	0.0015 LB/MMBTU	
PA-0188	FAIRLESS ENERGY LLC	FAIRLESS ENERGY LLC	3/28/2002	TURBINE, COMBINED CYCLE	1,190 MW	Other Case-by-Case	0.0020 LB/MMBTU	
AZ-0049	LA PAZ GENERATING FACILITY	ALLEGHENY ENERGY SUPPLY LLC	9/4/2003	GE COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS	1,040 MW	BACT-PSD	0.0021 LB/MMBTU	3-HR AVERAGE
AZ-0047	WELLTON MOHAWK GENERATING STATION	DOME VALLEY ENERGY PARTNERS	12/1/2004	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	180 MW	BACT-PSD	0.0023 LB/MMBTU	3-HOUR AVERAGE
IN-0114	MIRANT SUGAR CREEK LLC	MIRANT SUGAR CREEK LLC	7/24/2002	TURBINE, COMBINED CYCLE, NATURAL GAS (4)	1,491 MMBTU/H	BACT-PSD	0.0028 LB/MMBTU	
NM-0044	CLOVIS ENERGY FACILITY	DUKE ENERGY CURRY LLC	6/27/2002	TURBINES, COMBINED CYCLE, NATURAL GAS (4)	1,515 MMBTU/H	BACT-PSD	0.0028 LB/MMBTU	
IN-0114	MIRANT SUGAR CREEK LLC	MIRANT SUGAR CREEK LLC	7/24/2002	TURBINE, COMBINED CYCLE AND DUCT BURNER, NAT GAS	1,491 MMBTU/H	BACT-PSD	0.0030 LB/MMBTU	
OK-0096	REDBUD POWER PLANT	REDBUD ENERGY LP	6/3/2003	COMBUSTION TURBINE AND DUCT BURNERS	1,832 MMBTU/H	BACT-PSD	0.0030 LB/MMBTU	
TX-0391	OXY COGENERATION FACILITY	OXY VINYLS LP	12/20/2002	HRSG UNITS 1 & 2 (2)	255 MMBTU/H	BACT-PSD	0.0033 LB/MMBTU	
WA-0299	SUMAS ENERGY 2 GENERATION FACILITY	SUMAS ENERGY 2, INC.	9/6/2002	TURBINES, COMBINED CYCLE, (2)	335 MW	BACT-PSD	0.0038 LB/MMBTU	1 h avg
NJ-0043	LIBERTY GENERATING STATION	LIBERTY GENERATING STATION	3/28/2002	COMBINED CYCLE TURBINE (3)	2,964 MMBTU/H	Other Case-by-Case	0.0040 LB/MMBTU	
NJ-0043	LIBERTY GENERATING STATION	LIBERTY GENERATING STATION	3/28/2002	COMBINED CYCLE TURBINE WITH DUCT BURNER	3,202 MMBTU/H	Other Case-by-Case	0.0040 LB/MMBTU	
TN-0144	HAYWOOD ENERGY CENTER, LLC	CALPINE CONSTRUCTION FINANCE COMPANY, L. P.	2/1/2002	TURBINE, COMBINED CYCLE, W/O DUCT FIRING	1,990 MMBTU/H	BACT-PSD	0.0049 LB/MMBTU	
TX-0351	WEATHERFORD ELECTRIC GENERATION FACILITY	SEI TEXAS LLC	3/11/2002	(2) GE7121EA GAS TURBINES, S-3&4	1,079 MMBTU/H	N/A	0.0056 LB/MMBTU	
OK-0056	HORSESHOE ENERGY PROJECT	MUSTANG POWER LLC	2/12/2002	TURBINES AND DUCT BURNERS	310 MW TOTAL	BACT-PSD	0.0056 LB/MMBTU	
VA-0287	JAMES CITY ENERGY PARK	JAMES CITY ENERGY PARK LLC	12/1/2003	TURBINE, COMBINED CYCLE, NATURAL GAS,DUCT BURNER	1,973 MMBTU/H	BACT-PSD	0.0057 LB/MMBTU	
OH-0248	LAWRENCE ENERGY	CALPINE CORPORATION	9/24/2002	TURBINES (3), COMBINED CYCLE, DUCT BURNERS ON	180 MW	BACT-PSD	0.0057 LB/MMBTU	with duct burner
OH-0248	LAWRENCE ENERGY	CALPINE CORPORATION	9/24/2002	TURBINES (3), COMBINED CYCLE, DUCT BURNERS OFF	180 MW	BACT-PSD	0.0057 LB/MMBTU	
VA-0287	JAMES CITY ENERGY PARK	JAMES CITY ENERGY PARK LLC	12/1/2003	TURBINE, COMBINED CYCLE, NATURAL GAS	1,973 MMBTU/H	BACT-PSD	0.0058 LB/MMBTU	
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	DUKE ENERGY	3/21/2003	TURBINES, COMBINED CYCLE (2)	1,701 MMBTU/H	BACT-PSD	0.0060 LB/MMBTU	
VA-0260	HENRY COUNTY POWER	Cogentrix Energy Inc	11/21/2002	TURBINE, COMBINED CYCLE, (4), 100% LOAD	171 MW	BACT-PSD	0.0060 LB/MMBTU	
AL-0185	BARTON SHOALS ENERGY	BARTON SHOALS ENERGY, LLC	7/12/2002	FOUR (4) COMBINED CYCLE COMBUSTION TURBINE UNITS	173 MW	BACT-PSD	0.0070 LB/MMBTU	
MS-0059	PIKE GENERATION FACILITY	LSP-PIKE ENERGY, LLC	9/24/2002	TURBINE, AA-002 W /DUCT BURNER	2,168 MMBTU/H	BACT-PSD	0.0072 LB/MMBTU	

Table C-5 Gas Turbine SO2 Emisison Limits from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	Size	CASE-BY-CASE BASIS	Emission Limit
MS-0055	EL PASO MERCHANT ENERGY CO.	EL PASO MERCHANT ENERGY CO.	6/24/2002	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, (2)	1,737 MMBTU/H	BACT-PSD	0.0072 LB/MMBTU
VA-0261	CPV CUNNINGHAM CREEK	COMPETITIVE POWER VENTURE	9/6/2002	TURBINE, COMBINED CYCLE, (2)	2,132 MMBTU/H	BACT-PSD	0.0119 LB/MMBTU

Table C-6 Summary of PSD Permits Issued to Electric Generating Units For GHGs August 2018)

Source	Permit Applicant, Issuing Agency, & Date of Issuance	Type of Facility & Location	GHG BACT Limits and Technologies Chosen	BACT Comments
PSD Permit	C4GT, April 26, 2018	GE 7HA.02 combined cycle	6,745 Btu/kWh net output HHV without duct burning based on an initial test. 883 lb/MWh net calculated on a 12-month rolling basis.	
PSD Permit	C4GT, April 26, 2018	Siemens SGT-8000H	6,625 Btu/kWh net output HHV without duct burning based on an initial test. 883 lb/MWh net calculated on a 12-month rolling basis.	
PSD Permit	Greensville Power Station, 6/17/2016 Final	MHPS M501J	6,457 Btu/kWh net output HHV without duct burning based on an initial test increasing to 7,212 Btu/kWh net output HHV in year 31 and later basedon testing every 5 years. 812 lb/MWh net calculated on a 12-month rolling basisin years 1 to 6, increasing to 890 lb/MWh in year 31 and later.	
***TX-0834**	3/30/2018	MONTGOMERY COUNTY POWER STATIOIN, ENTERGY TEXAS INC	884 lb/MWh	
***FL-0363**	12/4/2017	DANIA BEACH ENERGY CENTER, FLORIDA POWER AND LIGHT COMPANY	850 lb/MWh, 12-month rollign average	
CT-0161	6/30/2017	KILLINGLY ENERGY CENTER, NTE CONNECTICUT, LLC	816 lb/MWh	
TX-0819	4/28/2017	GAINES COUNTY POWER PLANT, SOUTHWESTERN PUBLIC SERVICE COMPANY	960 lb/MWh	
NJ-0085	11/3/2016	MIDDLESEX ENERGY CENTER, LLC, STONEGATE POWER, LLC	880 lb/MWh, consecutive 12 month rolling	
NJ-0084	7/25/2016	PSEG FOSSIL LLC SEWAREN GENERATING STATION, PSEG FOSSIL LLC	880 lb/MWh, consecutive 12 month rolling	efficient processes, practices, and designs
***TX-0730**	4/1/2015	Colorado Bend Energy Station Permit Issued - 04/01/2015 NGCC; 1100 MW	879 lb/MWh	efficient processes, practices, and designs
***IA-0107**	4/14/2014	MARSHALLTOWN GENERATING STATION, MARSHALL, IA NGCC, 2258 MMBtu/hr	951 lb/MW hr gross as a 12-month rolling average	
***PA-0296**	4/14/2014	BERKS HOLLOW ENERGY ASSOC LLC, PA NGCC, 3,046 MMBtu/hr	1,000 lb/MW hr	
***MI-0405**	2/14/2014	MIDLAND COGENERATION VENTURE, MINGCC, 2,486 MMBtu/hr	1,071 lb/MWh as a 12-month rolling average	
***DE-0023**	10/31/2012	NRG ENERGY CENTER DOVER LLC, DE NGCC, 655 MMBtu/hr	1,085 lb/MW hr gross as a 12-month rolling average	
***MI-0402**	5/27/2011	WOLVERINE POWER SUPPLY COOPERATIVE INC., MI NGCC, 135 MW	954 lb/MWh as a 12-month rolling average	
***VA-0319**	8/27/2012	GATEWAY GREEN ENERGY, VA Natural gas combustion turbines, 593 MMBtu/hr	1,050 lb/MWh as a 12-month rolling average	

Table C-6 Summary of PSD Permits Issued to Electric Generating Units For GHGs August 2018)

Source	Permit Applicant, Issuing Agency, & Date of Issuance	Type of Facility & Location	GHG BACT Limits and Technologies Chosen	BACT Comments
***WV-0025**	11/21/2014	MOUNDSVILLE COMBINED CYCLE POWER PLAMT, WV Natural gas combustion turbine, GE	793 lb/MWh	
PSD Permit	**Cricket Valley Energy Center[ii]New York Department of Environmental Conservation(May 25, 2011 – Draft)**	1,000-MW NGCC power plant	· 7,605 Btu/kWh annual net heat rate limit and thermal efficiency of 57.4% with no duct firing	· CCS (not commercially available or economically feasible)
			· Combined cycle units: 3,576,943 tons CO_2e per rolling 12-month period	- No NGCC CO_2 absorption systems
			· Auxiliary boiler: 15,887 tons CO_2e/rolling 12-mo. period	- Compression: increase CO_2 emissions, large parasitic load
			· Fire pump: 114 tons CO_2e per rolling 12-month period	· Lower emitting alternative technologies (not feasible)
			· High efficiency CTGs and HRSG	
			· Black start generator: 4,822 tons CO_2e per rolling 12-month period	
PSD Permit	Lower Colorado River Authority[iv] EPA Region VI (TX) (November 10, 2011 – Final)	590-MW NGCC power plan (Thomas Ferguson plant) Texas	· 7,720 Btu/kWh annual net heat rate limit based on 365-day rolling average	· CCS (not feasible or cost-effective)
			· 0.459 tons CO_2/MWh (net) based on 365-day rolling average	· Non-GHG substitutes for SF6
			· For each turbine:	
			- CO_2: 908,957.6 tons/year	
			- CH_4: 16.8 tons/year (353.3 tpy CO2e)	
			- N_2O: 1.7 tons/year (521.6 tpy CO2e)	
			· High efficiency CTGs and HRSG	
			· Plant-wide energy efficiency practices and designs	
			· Includes limits for fugitive emissions, emergency generator, fire water pump, circuit breakers, etc.	
PSD Permit	Palmdale Hybrid Power Project[v]	570-MW NGCC power plant + 50 MW solar plant	· CO2: 774 lb/MWH source-wide net output based on 365-day rolling average (for each CTG)	· CCS (economically infeasible) – would cost twice as much as the facility's annual capital coasts
			· 7,319 Btu/kWh source-wide net heat rate based on 365-day rolling average (for each CTG)	· Lower emitting alternative technologies (determined to be infeasible)
	EPA Region IX (CA)	California	· CO_2e: 1,913,000 tpy	
	(October 18, 2011 – Final)		· Solar component required part of facility	
PSD Permit	**Robinson Power Company**	148-MW NGCC power plant	· CO_2e: 619,360 tpy based on 12-month rolling average and 70.7 tons/hr based on 60-minute average	
			· No BACT analysis required (not a major source of attainment pollutants other than GHGs)	
	Pennsylvania Department of Environmental Protection	Pennsylvania		
	(June 30, 2011 – Final)			
PSD Permit	PacifiCorp[viii]	629-MW NGCC power plant (Lakeside)	· CO_2e emissions limit of 950 lb/MWH based on a 12-month rolling average	· CCS (not technically or financially feasible at this time)
			· High efficiency CTGs and HRSG	
	Utah Department of Environmental Quality	Utah	· Use of low-NO_x controls	
	(May 4, 2011 – Final)			
PSD Permit	**Russell City Energy Center (Calpine)**	600-MW natural gas power plant (Russell City)	· CO_2e emission limit for turbines: 1.928 MMT/yr	· Non-fossil fired generation (not feasible)
			· Heat rate limit for each turbine: 7,730 Btu/KWH	· CCS (not feasible)
	Bay Area Air Quality Management District	California	· State-of-the-art SF_6 circuit breakers: 39.3 metric tons CO_2e based on 12-month rolling average	· Dielectric oil or compressed air circuit breaker (not feasible)

Table C-6 Summary of PSD Permits Issued to Electric Generating Units For GHGs August 2018)

Source	Permit Applicant, Issuing Agency, & Date of Issuance	Type of Facility & Location	GHG BACT Limits and Technologies Chosen	BACT Comments
	(February 3, 2010 – Final)		· Use of most efficient fire pump engine: 7.6 metric tons CO_2e based on 12-month rolling average	
			· Use of most efficient generating technology (natural gas)	
PSD Permit	Sand Hill Energy Center	222-MW NGCC power plant	· CO_2e emission limit for turbines: 1,461,908 tpy	· CCS (not technically or financially feasible at this time)
		GE 7FA.04	· 930 lb CO_2/MWh 365-day rolling avg.	
	EPA Region 6	Texas	· Heat rate limit for turbine: 7,943 Btu/KWH	
			· Energy Efficiency Processes, Practices, and Design	
	August 2014 - Draft			
PSD Permit	FGE Power, LLC	1620-MW NGCC power plant	· CO_2e emission limit for turbines (each of four): 1,472,228 tpy each	· CCS (not technically or financially feasible at this time)
		Alstom GT24	· 889 lb CO_2/MWh 12-mo. rolling avg.	
	EPA Region 6	Texas	· Heat rate limit for turbine: 7,625 Btu/KWH	
			· Energy Efficiency Processes, Practices, and Design	
	4/28/14 - Final			
PSD Permit	Pinecrest Energy Center	637-735-MW NGCC power plant	· CO_2e emission limit for GE 7FA.05 turbines (each): 1,447,653 tpy	· CCS (not technically or financially feasible at this time). CCS - Although the carbon capture technology is available and technically feasible for some applications (such as natural gas processing industries and petroleum refining), it is not a proven option for a natural gas, combined cycle combustion turbine whose exhaust is characterized by high flow and low CO_2 concentration. Of the 22 CCS projects around the world, only three are power plants (all coal) and only one of them is currently operating in Canada (www.carbonbrief.org) dated Oct. 7, 2014)
			· CO_2e emission limit for SGT6-5000F(4) turbines (each): 1,399,842 tpy	
		2 Turbines (tbd from those listed below)	· CO_2e emission limit for SGT6-5000F(4) turbines (each): 1,570,854 tpy	
		GE 7FA.05 or Siemens SGT6-5000F(4), or SGT6-5000F(5)	· GE 7FA.05: 942 lb CO_2/MWh	
			· SGT6-5000F(4): 909.2 lb CO_2/MWh	
			· SGT6-5000F(5): 912.7 lb CO_2/MWh	
	EPA Region 6	Texas	· Heat rate limit for GE 7FA.05: 7,925 Btu/KWH	
			· Heat rate limit for SGT6-5000F(4) or SGT6-5000F(5): 7,649 Btu/KWH	
			· Energy Efficiency Processes, Practices, and Design	
	7/31/14 - Final			
PSD Permit	Greensville Power Station Virginia DEQ 06/17/2016 Final	1,600 MW, 3x1 MHPS M501 J	Net heat rate limtied to 6,457 Btu HHV/kWh (initial test) to 7,212 Btu HHV/kWh (year 31 and later). CO2e emissions limited to 812 lb CO2e/MWh (years 1 to 6) to 890 lb CO2e/MWh (years 31 and later)	CCS - Although carbon capure technoloogy is avaialble and techncially feasible for some applicatins (such as natural gas processing industires and petroleum refining), it is not a proven option for a natural gas, combined cycle combustion turbine whose exhaust is characterized by high flor and low CO2 concentrations. Of the 22 CCS proejcts around the world, only three are pwoer plants (all coal) and one one of them is currently operating (www.carbonbrief.org, October 7, 2014).

Table C-6 Summary of PSD Permits Issued to Electric Generating Units For GHGs August 2018)

Source	Permit Applicant, Issuing Agency, & Date of Issuance	Type of Facility & Location	GHG BACT Limits and Technologies Chosen	BACT Comments
PSD Permit	Green Energy/Stonewall Virginia DEQ 04/30/2013 Final	GE 7FA.02 or Siemens SGT6-5000F5	Heat rate limtied to7,340 Btu HHV/kWh gross output at full load and corrected to ISO conditions. Heat rate limtied to7,780 Btu HHV/kWh gross output at full load and corrected to ISO conditions. An exceedance of the heat rate limit is not considered a violation of this permit but require the permitte to submit a maintenance plant which specifies actions the permitte plans to take in order to achieve the heat rate limit.	CCS - Although carbon capure technoloogy is avaialble and techncially feasible for some applicatins (such as natural gas processing industires and petroleum refining), it is not a proven option for a natural gas, combined cycle combustion turbine whose exhaust is characterized by high flor and low CO2 concentrations. Of the 22 CCS proejcts around the world, only three are pwoer plants (all coal) and one one of them is currently operating (www.carbonbrief.org, October 7, 2014).
PSD Permit	Brunswick County Power Station Virginia DEQ 03/12/13 - Final	1360-MW 3x1 NGCC power plant Mitsubishi M501GAC Virginia	· CO_2e emission limit for turbines: 1,765,324 tpy (each) · 920 lb CO_2/MWh net (HHV) based on a 12-operating month annual average · Heat rate limit for combined cyle turbine: 7,500 Btu/KWh net (HHV) based on initial testing and once every 5 years. · Energy Efficiency Processes, Practices, and Design	· CCS (not technically or financially feasible at this time) · CCS (if technically feasible, not cost effective)
NJ-0085	11/3/2016	MIDDLESEX ENERGY CENTER, LLC, STONEGATE POWER, LLC	880 lb/MWh, consecutive 12 month rolling	
NJ-0084	7/25/2016	PSEG FOSSIL LLC SEWAREN GENERATING STATION, PSEG FOSSIL LLC	880 lb/MWh, consecutive 12 month rolling	efficient processes, practices, and designs
***TX-0730**	4/1/2015	Colorado Bend Energy Station Permit Issued - 04/01/2015 NGCC; 1100 MW	879 lb/MWh	efficient processes, practices, and designs

Table C-6 Summary of PSD Permits Issued to Electric Generating Units For GHGs August 2018)

Source	Permit Applicant, Issuing Agency, & Date of Issuance	Type of Facility & Location	GHG BACT Limits and Technologies Chosen	BACT Comments
***IA-0107**	4/14/2014	MARSHALLTOWN GENERATING STATION, MARSHALL, IA NGCC, 2258 MMBtu/hr	951 lb/MW hr gross as a 12-month rolling average	
***PA-0296**	4/14/2014	BERKS HOLLOW ENERGY ASSOC LLC, PA NGCC, 3,046 MMBtu/hr	1,000 lb/MW hr	
***MI-0405**	2/14/2014	MIDLAND COGENERATION VENTURE, MINGCC, 2,486 MMBtu/hr	1,071 lb/MWh as a 12-month rolling average	
***DE-0023**	10/31/2012	NRG ENERGY CENTER DOVER LLC, DE NGCC, 655 MMBtu/hr	1,085 lb/MW hr gross as a 12-month rolling average	
***MI-0402**	5/27/2011	WOLVERINE POWER SUPPLY COOPERATIVE INC., MI NGCC, 135 MW	954 lb/MWh as a 12-month rolling average	
***VA-0319**	8/27/2012	GATEWAY GREEN ENERGY, VA Natural gas combustion turbines, 593 MMBtu/hr	1,050 lb/MWh as a 12-month rolling average	
***WV-0025**	11/21/2014	MOUNDSVILLE COMBINED CYCLE POWER PLAMT, WV Natural gas combustion turbine, GE 7EA	793 lb/MWh	

Table C-7 NOx Emisison Limits for <250 MMBtu/hr Natural Gas Boilers from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size		Control Device description	CASE-BY-CASE BASIS	Emission Limit	
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	12/17/2013	Auxiliary Boiler	40	MMBtu/hr			0.0058 lb/MMBtu	Calculaed from 1.01 ton/yr and 40 MMBtu/hr.
CA-1206	STOCKTON COGEN COMPANY	9/16/2011	AUXILIARY BOILER	178	MMBTU/H		BACT-PSD	0.0085 lb/MMBtu	Calculated from 7 ppmvd@ 3% O2
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	One 97.5 MMBtu/hr(HHV) natural gas fired auxiliary boiler, equipped with low NOx burners and flue gas recirculation for control of NOx emissions	98	MMBtu/hr	Ultra Low NOx Burners	LAER	0.0100 lb/MMBtu	AV OF THREE ONE H INITIAL STACK TEST
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/10/2016	Auxiliary Boiler	80	MMBtu/hr	Ultra Low NOx Burners	LAER	0.0100 lb/MMBtu	AV OF THREE ONE H INITIAL STACK TEST
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/2015	Auxiliary Boiler	42	MMBtu/hr	Ultra Low NOx Burners	BACT-PSD	0.0100 LB/MMBTU	3-HOUR BLOCK AVERAGE
*AK-0083	KENAI NITROGEN OPERATIONS	1/6/2015	Three (3) Package Boilers	243	MMBtu/h	Ultra Low NOx Burners	BACT-PSD	0.0100 lb/MMBtu	30-DAY ROLLING AVG
MD-0046	KEYS ENERGY CENTER	10/31/2014	Auxiliary Boiler	93	MMBtu/hr	Ultra Low NOx Burners	BACT-PSD	0.0100 LB/MMBTU	3-HOUR BLOCK AVERAGE
NJ-0079	WOODBRIDGE ENERGY CENTER	7/25/2012	Commercial/Institutional size boilers less than 100 MMBtu/hr	2000	hours/year	Low NOx burners	LAER	0.0100 lb/MMBtu	AVERAGE OF THREE TESTS
TX-0499	SANDY CREEK ENERGY STATION	7/24/2006	AUXILLARY BOILER	175	MMBTU/H		BACT-PSD	0.0103 lb/MMBtu	CALCULATED, NOT PERMIT LIMIT
NA-Virginia	C4GT, NOVI Energy	4/26/2018	AUXILIARY BOILER	105	MMBTU/H	ULNB	BACT-PSD	0.0110 lb/MMBtu	Calculated from 1.2 lb/hr and 105 MMBtu/hr
*WV-0029	HARRISON COUNTY POWER PLANT	3/27/2018	Auxiliary boiler	78	MMBtu/hr	ULNB	BACT-PSD	0.0110 lb/MMBtu	
NA-Virginia	Greensville County	6/17/2016	AUXILIARY BOILER	185	MMBTU/H	ULNB	BACT-PSD	0.0110 lb/MMBtu	Calculated from 2.1 lb/hr and 185 MMBtu/hr
	TRINIDAD GENERATING FACILITY	11/20/2014	Auxiliary Boiler	110	MMBtu/hr	ultra-low NOx burners, limited use	BACT-PSD	0.0110 lb/MMBtu	Calculated from 9 PPMVD @3% O2, 3-HR AVG
NA-Virginia	Brunswick County	6/17/2014	AUXILIARY BOILER	67	MMBTU/H	ULNB	BACT-PSD	0.0110 lb/MMBtu	Calculated from 0.8 lb/hr and 66.7 MMBtu/hr
NA-Virginia	Warren County	6/17/2014	AUXILIARY BOILER	48	MMBTU/H	ULNB	BACT-PSD	0.0110 lb/MMBtu	

Table C-7 NOx Emisison Limits for <250 MMBtu/hr Natural Gas Boilers from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size		Control Device description	CASE-BY-CASE BASIS	Emission Limit	
NA-Virginia	Warren County	6/17/2014	AUXILIARY BOILER	48	MMBTU/H	ULNB	BACT-PSD	0.0110 lb/MMBtu	
NA-Virginia	Panda Energy	4/30/2013	AUXILIARY BOILER	75	MMBTU/H	ULNB	BACT-PSD	0.0110 lb/MMBtu	
*PA-0291	HICKORY RUN ENERGY STATION	4/23/2013	AUXILIARY BOILER	40	MMBTU/H		OTHER CASE-BY-CASE	0.0110 lb/MMBtu	
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011	AUXILIARY BOILER	110	MMBTU/H		BACT-PSD	0.0110 lb/MMBtu	Calculated from 9 PPMVD @3% O2, 3-HR AVG
OR-0046	TURNER ENERGY CENTER, LLC	1/6/2005	AUXILIARY BOILER	48	MMBTU/YR	SELECTIVE CATALYTIC REDUCTION	BACT-PSD	0.0110 lb/MMBtu	Calculated from 0.83 lb/hr and 75 MMBtu/hr
MN-0076	BLANDIN PAPER/RAPIDS ENERGY CENTER	9/18/2008	BOILER	280	MMBTU/H	FLUE GAS RECIRCULATION WITH LOW-NOX BURNERS	Other Case-by-Case	0.0120 lb/MMBtu	
*AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	8/17/2007	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	65	MMBTU each	ULNB & EGR (ULTRA-LOW NOX BURNERS (ULNB)(EXHAUST GAS RECIRCULATION (EGR) – SAME FLUE GAS RECIRCULATION (FGR)	BACT-PSD	0.0120 lb/MMBtu	
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012	Auxiliary Boiler	472	MMBTU/H	Low NOx Burners (LNB) and Flue Gas Recirculation (FGR)	BACT-PSD	0.0125 lb/MMBtu	ROLLING 30 DAY AVERAGE
*IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	Auxiliary Boiler	60	mmBtu/hr		BACT-PSD	0.0130 lb/MMBtu	AVERAGE OF 3 ONE-HOUR TEST RUNS
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	AUXILARY BOILER	220	MMBTU/H	LOW NOX BURNER	BACT-PSD	0.0180 lb/MMBtu	
*TX-0641	PINECREST ENERGY CENTER	11/12/2013	Auxiliary boiler	150	MMBtu/hr	low NOx burners	BACT-PSD	0.0195 lb/MMBtu	calculated from 16 ppmvd@ 3% O2
*WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	11/21/2014	Auxiliary Boiler	100	MMBtu/hr	Ultra Low-NOx Burners, Flue-Gas Recirculation, & Good Combustion Practices	BACT-PSD	0.0200 lb/MMBtu	
*OH-0352	OREGON CLEAN ENERGY CENTER	6/18/2013	Auxillary Boiler	99	MMBtu/H	low NOx burners and flue gas recirculation	BACT-PSD	0.0200 lb/MMBtu	
*ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	2/10/2009	250 MMBTU/H PACKAGE BOILER, SRC24	250	MMBTU/H	LOW-NOX BURNER AND FGR	BACT-PSD	0.0200 lb/MMBtu	
CA-1189	PETROROCK- TUNNELL LEASE	1/24/2012	Boiler	2	MMBTU/H	Low NOx Burner	OTHER CASE-BY-CASE	0.0250 lb/MMBtu	calculated from 20 ppmvd@ 3% O2
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80	MMBTU/H	LOW NOX BURNER WITH FLUE GAS RECIRCULATION	BACT-PSD	0.0320 lb/MMBtu	3 HOURS
NA-Ohio	Harrsion Power	4/19/2018	AUXILIARY BOILER	45	MMBTU/H	Low NOx burners	BACT-PSD	0.0350 lb/MMBtu	0.84 tpy (equivalent to approx. 1,020 hr/yr at 100% load)

Table C-7 NOx Emisison Limits for <250 MMBtu/hr Natural Gas Boilers from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size		Control Device description	CASE-BY-CASE BASIS	Emission Limit	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	BOILER - UNIT HA08	35	MMBTU/H	EQUIPPED WITH A LOW-NOX BURNER	BACT-PSD	0.0350 lb/MMBtu	
*SC-0149	KLAUSNER HOLDING USA, INC	1/3/2013	NATURAL GAS BOILER EU003	46	MMBTU/H		OTHER CASE-BY-CASE	0.0360 lb/MMBtu	3-HOUR
FL-0335	SUWANNEE MILL	9/5/2012	Four(4) Natural Gas Boilers - 46 MMBtu/hour	46	MMBTU/H	Low NOx Burner and Flue Gas Recirculation	BACT-PSD	0.0360 lb/MMBtu	
MI-0427	FILER CITY STATION	11/17/2017	EUAUXBOILER (Auxiliary boiler)	182	MMBTU/H	LOW NOX BURNER	BACT-PSD	0.0400 BACT-PSD	30 DAY ROLLING AVERAGE
MI-0423	INDECK NILES, LLC	1/4/2017	EUAUXBOILER (Auxiliary Boiler)	182	MMBTU/H	LOW NOX BURNER	BACT-PSD	0.0400 BACT-PSD	30 DAY ROLLING AVG TIME PERIOD
*OH-0336	CAMPBELL SOUP COMPANY	12/14/2010	Boilers (3)				OTHER CASE-BY-CASE	0.0400 lb/MMBtu	
MN-0062	HEARTLAND CORN PRODUCTS	12/22/2005	BOILER	198	MMBTU/H		BACT-PSD	0.0400 lb/MMBtu	
ID-0015	J R SIMPLOT COMPANY - DON SIDING PLANT	4/5/2004	BOILER, 175 MMBTU/H	175	MMBTU/H	LOW-NOX BURNER	RACT	0.0400 lb/MMBtu	30-DAY ROLLING AVG
ID-0015	J R SIMPLOT COMPANY - DON SIDING PLANT	4/5/2004	BOILER, 64 MMBTU/H	64	MMBTU/H	LOW-NOX BURNER	RACT	0.0450 lb/MMBtu	CALCULATED, NOT PERMIT LIMIT
NV-0049	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	BOILER - UNIT IP04	17	MMBTU/H	LOW NOX BURNER	BACT-PSD	0.0490 lb/MMBtu	
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	3/9/2016	Auxiliary Boiler	100	MMBtu/hr	Low NOx Burners	BACT-PSD	0.0500 lb/MMBtu	
*LA-0272	AMMONIA PRODUCTION FACILITY	3/27/2013	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	218	MM BTU/HR	FLUE GAS RECIRCULATION, LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES (I.E., PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE).	BACT-PSD	0.0500 lb/MMBtu	ANNUAL AVERAGE
NJ-0080	HESS NEWARK ENERGY CENTER	11/1/2012	Boiler less than 100 MMBtu/hr	52	mmcubic ft/year	Low NOx burners and flue gas recirculation	LAER	0.0500 lb/MMBtu	AVERAGE OF THREE TESTS
NE-0024	CARGILL - BLAIR PLANT	6/22/2004	BOILER D (NO. 21)	277	MMBTU/H	LOW NOX BURNERS AND INDUCED FLUE GAS RECIRCULATION AT 16%.	Other Case-by-Case	0.0500 lb/MMBtu	
*OH-0350	REPUBLIC STEEL	7/18/2012	Steam Boiler	65	MMBtu/H		N/A	0.0700 lb/MMBtu	

Table C-7 NOx Emisison Limits for <250 MMBtu/hr Natural Gas Boilers from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size		Control Device description	CASE-BY-CASE BASIS	Emission Limit	
NE-0024	CARGILL - BLAIR PLANT	6/22/2004	BOILERS A, B & C	198	MMBTU/H	LOW NOX BURNERS AND INDUCED DRAFT FLUE GAS RECIRCULATION	Other Case-by-Case	0.0700 lb/MMBtu	
MS-0069	DUPONT DELISLE FACILITY	6/8/2004	BOILER #3	231	MMBTU/H	LOW-NOX BURNER WITH FGR.	BACT-PSD	0.0900 lb/MMBtu	
MS-0069	DUPONT DELISLE FACILITY	6/8/2004	BOILER (RENTAL/TEMPORARY)	231	MMBTU/H	LOW-NOX BURNER WITH FGR.	BACT-PSD	0.0900 lb/MMBtu	
WV-0023	MAIDSVILLE	3/2/2004	AUXILIARY BOILER	225	MMBTU/H	LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	BACT-PSD	0.0980 lb/MMBtu	3 HOUR ROLLING AVERAGE
*OH-0354	KRATON POLYMERS U.S. LLC	1/15/2013	Two 249 MMBtu/H boilers	249	MMBtu/H	Low-NOx burners	N/A	0.1000 lb/MMBtu	BURNING NATURAL GAS
WI-0228	WPS - WESTON PLANT	10/19/2004	AUXILLIARY NAT. GAS FIRED BOILER (B25, S25)	230	MMBTU/H	NATURAL GAS, GOOD COMBUSTION PRACTICES, LOW NOX BURNERS	BACT-PSD	0.1000 lb/MMBtu	2000 H / 12 MO. ROLLING

Table C-8 CO Emisison Limits for <250 MMBtu/hr Boilers from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit	
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	auxiliary boiler	60.1 mmBtu/hr	CO catalytic oxidizer	BACT-PSD	0.0164 lb/MMBtu	AVERAGE OF 3 ON-HOUR TEST RUNS
NV-0049	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	BOILER - UNIT CP01	35.40 MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	Other Case-by-Case	0.0210 lb/MMBtu	Calculated from 29 ppmvd at 3% O2
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	AUXILARY BOILER	220 MMBTU/H	EFFICIENT COMBUSTION	OTHER CASE-BY-CASE	0.0350 lb/MMBtu	TEST METHOD
OR-0040	KLAMATH GENERATION, LLC	3/12/2003	BOILER, AUXILIARY, NATURAL GAS	50,000 LB/H		BACT-PSD	0.0350 lb/MMBtu	
*IN-0287	DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING STATION	7/10/2018	Auxiliary Boiler	213 MMBtu/hr	good combustion practices	BACT-PSD	0.0360 LB/MMBTU	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/10/2016	Auxiliary Boiler	80 MMBtu/hr	Ultra Low NOx Burners	BACT-PSD	0.0360 lb/MMBtu	Calculated from 2.88 lb/hr and 80 MMBtu/hr
*PA-0291	HICKORY RUN ENERGY STATION	4/23/2013	AUXILIARY BOILER	40 MMBTU/H		OTHER CASE-BY-CASE	0.0360 LB/MMBTU	
NJ-0042	ROCHE VITAMINS	2/5/1999	BOILER 1 (NATURAL GAS)	84.40 MMBTU/H	NONE LISTED	BACT-PSD	0.0360 lb/MMBtu	
NA	C4GT, NOVI Energy, Virginia	4/26/2018	AUXILIARY BOILER	105 MMBTU/H		BACT-PSD	0.0370 lb/MMBtu	Calculated from 3.9 lb/hr and 105 MMBtu/hr
*WV-0029	HARRISON COUNTY POWER PLANT	3/27/2018	Auxiliary Boiler	77.8 mmBtu/hr	good combustion practices	BACT-PSD	0.0370 LB/HR	
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	One 97.5 MMBtu/hr(HHV) natural gas fired auxiliary boiler, equipped with low NOx burners and flue gas recirculation for control of NOx emissions	97.5 MMBtu/hr	Good Combustion	BACT-PSD	0.0370 lb/MMBtu	Calculated from 3.61 lb/hr and 97.5MMBtu/hr
NA	Greensville County, Virginia	6/17/2016	AUXILIARY BOILER	185 MMBTU/H		BACT-PSD	0.0370 lb/MMBtu	Calculated from 6.6 lb/hr and 185 MMBtu/hr
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/2015	Auxiliary Boiler	42 MMBtu/hr	Ultra Low NOx Burners	BACT-PSD	0.0370 lb/MMBtu	3-HOUR BLOCK AVERAGE
*TX-0714	S R BERTRON ELECTRIC GENERATING STATION	12/19/2014	Auxiliary Boiler	80 MMBtu/hr	low-NOx burners	BACT-PSD	0.0370 lb/MMBtu	3-HOUR
NV-0049	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	BOILER - UNIT HA08	8.37 MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	Other Case-by-Case	0.0370 lb/MMBtu	

Table C-8 CO Emisison Limits for <250 MMBtu/hr Boilers from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit	
*GA-0127	PLANT MCDONOUGH COMBINED CYCLE	1/7/2008	AUXILLARY BOILERS	200.00 MMBTU/H		BACT-PSD	0.0370 lb/MMBtu	3-HOUR
WV-0023	MAIDSVILLE	3/2/2004	AUXILIARY BOILER	225.00 MMBTU/H	GOOD COMBUSTION PRACTICES, USE OF NATURAL GAS	BACT-PSD	0.0370 lb/MMBtu	3-HOUR
OR-0046	TURNER ENERGY CENTER, LLC	1/6/2005	AUXILIARY BOILER	48.00 MMBTU/YR	OXIDATION CATALYST	BACT-PSD	0.0380 lb/MMBtu	
*SC-0149	KLAUSNER HOLDING USA, INC	1/3/2013	NATURAL GAS BOILER EU003	46 MMBTU/H		OTHER CASE-BY-CASE	0.0390 LB/MMBTU	3-HOUR
FL-0335	SUWANNEE MILL	9/5/2012	Four(4) Natural Gas Boilers - 46 MMBtu/hour	46 MMBTU/H	Good Combustion Practice	BACT-PSD	0.0390 lb/MMBtu	
*WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	11/21/2014	Auxiliary Boiler	80 MMBTU/H	Good Combustion Practices	BACT-PSD	0.0400 lb/MMBtu	
*OH-0350	REPUBLIC STEEL	7/18/2012	Steam Boiler	65 MMBtu/H	Proper burner design and good combustion practices	BACT-PSD	0.0400 LB/MMBTU	
*AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	8/17/2007	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	64.90 MMBTU each		BACT-PSD	0.0400 lb/MMBtu	
MN-0062	HEARTLAND CORN PRODUCTS	12/22/2005	BOILER	198.00 MMBTU/H		BACT-PSD	0.0400 lb/MMBtu	
AR-0070	GENOVA ARKANSAS I, LLC	8/23/2002	AUXILIARY BOILER	33.00 MMBTU/H	GOOD COMBUSTION PRACTICE	BACT-PSD	0.0400 lb/MMBtu	
NJ-0036	AES RED OAK LLC	10/24/2001	AUXILIARY BOILER	120.00 MMBTU/H	GOOD COMBUSTION PRACTICE	BACT-PSD	0.0500 lb/MMBtu	
*OH-0352	OREGON CLEAN ENERGY CENTER	6/18/2013	Auxillary Boiler	99 MMBtu/H	Good combustion practices and using combustion optimization technology	BACT-PSD	0.0550 LB/MMBTU	
*NV-0049	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	BOILER - UNIT IP04	16.70 MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	Other Case-by-Case	0.0700 lb/MMBtu	
*ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	2/10/2009	250 MMBTU/H PACKAGE BOILER, SRC24	250.00 MMBTU/H	GOOD COMBUSTION PRACTICES	BACT-PSD	0.0740 lb/MMBtu	
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUAUXBOILER: Auxiliary Boiler	99.9 MMBTU/H	Good combustion practices	BACT-PSD	0.0750 LB/MMBTU	
*OH-0354	KRATON POLYMERS U.S. LLC	1/15/2013	Two 249 MMBtu/H boilers	249 MMBtu/H	Use of clean fuels and good combustion practices	BACT-PSD	0.0750 LB/MMBTU	BURNING NATURAL GAS W/ BELPRE NAPHTHA
*OH-0336	CAMPBELL SOUP COMPANY	12/14/2010	Boilers (3)	0		BACT-PSD	0.0750 lb/MMBtu	BASED ON MFG. GUARANTEE
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	61.5 MMBTU/H	good combustion practices	BACT-PSD	0.0800 LB/MMBTU	

Table C-8 CO Emisison Limits for <250 MMBtu/hr Boilers from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit	
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	3/9/2016	Auxiliary Boiler	99.8 MMBtu/hr	Low NOx Burners	BACT-PSD	0.0800 lb/MMBtu	
MD-0046	KEYS ENERGY CENTER	10/31/2014	Auxiliary Boiler	93 MMBtu/hr	Ultra Low NOx Burners	BACT-PSD	0.0800 lb/MMBtu	3-HOUR BLOCK AVERAGE
MN-0066	NORTHERN STATES POWER CO. DBA XCEL ENERGY - RIVERSIDE PLANT	5/16/2006	BOILER, AUXILIARY, NATURAL GAS	160.00 mmbtu/h	GOOD COMBUSTION	BACT-PSD	0.0800 lb/MMBtu	
WI-0228	WPS - WESTON PLANT	10/19/2004	AUXILLIARY NAT. GAS FIRED BOILER (B25, S25)	229.80 MMBTU/H	NATURAL GAS, GOOD COMBUSTION PRACTICES, LOW NOX BURNER	BACT-PSD	0.0800 lb/MMBtu	
TX-0386	AMELLA ENERGY CENTER	3/26/2002	AUXILIARY BOILER	155.00 MMBTU/H		Other Case-by-Case	0.0800 lb/MMBtu	
*AK-0083	KENAI NITROGEN OPERATIONS	1/16/2015	Startup Heater	101 MMBtu/hr	Limited Use (200 hr/yr)	BACT-PSD	0.082 LB/MMBTU	
OK-0045	REDBUD POWER PLT	8/15/2001	BOILER, AUXILIARY	20.00 MMBTU/H	GOOD OPERATING PRACTICE	BACT-PSD	0.0820 lb/MMBtu	
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY	6/7/2001	AUXILIARY BOILER, NATURAL GAS	124.60 MMBTU/H	GOOD COMBUSTION. NATURAL GAS ONLY	BACT-PSD	0.0820 lb/MMBtu	
NC-0101	FORSYTH ENERGY PLANT	9/29/2005	AUXILLIARY BOILER	110.20 MMBTU/H	LOW-NOX BURNERS, GOOD COMBUSTION CONTROL AND CLEAN BURNING, LOW-SULFUR FUEL (NATURAL GAS).	BACT-PSD	0.0824 lb/MMBtu	calculated
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80 MMBTU/H	GOOD COMBUTSTION PRACTICES	BACT-PSD	0.0830 lb/MMBtu	
*OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/8/2009	AUXILIARY BOILER	150.00 MMBTU/H		BACT-PSD	0.0840 lb/MMBtu	calculated based on lb/hr
OH-0241	MILLER BREWING COMPANY - TRENTON	5/27/2004	BOILER (2), NATURAL GAS	238.00 MMBTU/H		BACT-PSD	0.0840 lb/MMBtu	
NJ-0043	LIBERTY GENERATING STATION	3/28/2002	AUXILIARY BOILER	200.00 MMBTU/H	CO CATALYST	Other Case-by-Case	0.0870 lb/MMBtu	
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	BOILER, NO. 9	95.00 MMBTU/H		BACT-PSD	0.0900 lb/MMBtu	
LA-0184	TITANIUM DIOXIDE FACILITY	5/13/2003	UTILITY BOILERS D841-1X & D841-2X (135 MM BTU/H EA.)	135.00 MMBTU/H	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES	BACT-PSD	0.0910 lb/MMBtu	ANNUAL AVERAGE
VA-0270	VCU EAST PLANT	3/31/2003	BOILER NATUAL GAS	150.00 MMBTU/H	GOOD COMBUSTION PRACTICES.	BACT-PSD	0.1000 lb/MMBtu	
VA-0278	VCU EAST PLANT	3/31/2003	BOILER, NATURAL GAS, (3)	150.60 MMBTU/H	GOOD COMBUSTION PRACTICE	BACT-PSD	0.1000 lb/MMBtu	calculated

Table C-8 CO Emisison Limits for <250 MMBtu/hr Boilers from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit
AR-0057	TENASKA ARKANSAS PARTNERS, LP	10/9/2001	BOILER, NATURAL GAS, (2)	122.00 MMBTU/H	GOOD COMBUSTION PRACTICES.	BACT-PSD	0.1100 lb/MMBtu
NE-0024	CARGILL - BLAIR PLANT	6/22/2004	BOILER D (NO. 21)	276.67 MMBTU/H	GOOD COMBUSTION PRACTICES	Other Case-by-Case	0.1400 lb/MMBtu
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	BOILER, NO. 10	180.00 MMBTU/H		BACT-PSD	0.1800 lb/MMBtu

Table C-9 NOx Emisison Limits for Fuel Gas Heater from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit	
MD-0031	CHALK POINT	4/1/2005	(2) NATURAL GAS FUEL HEATERS	10 MMBtu/hr	LOW NOX BURNER TECHNOLOGY AND NATURAL GAS FIRING	BACT-PSD	0.010 lb/MMBtu	CALCULATED
NA	C4GT, NOVI Energy, Virginia	4/26/2018	Dew Point Heater	16.0 MMBTU/H	ULNB	BACT-PSD	0.011 lb/MMBtu	Based on engineering analysis, pemit limit is 0.5 ton/yr
NA	Greensville County, Virginia	6/17/2016	Dew Point Heater	7.8 MMBTU/H	ULNB	BACT-PSD	0.011 lb/MMBtu	
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	dew point heater	13.3 mmBtu/hr		BACT-PSD	0.013 LB/MMBTU	3-HOUR AVERAGE
MD-0036	DOMINION	3/10/2006	FUEL GAS PROCESS HEATER		DRY LNB AND GOOD COMBUSTION PRACTICES	BACT-PSD	0.021 lb/MMBtu	CALCULATED
*PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	12/17/2013	Fuel Preheater	8.5 MMBtu/hr			0.035 lb/MMBtu	
CO-0058	CHEYENNE STATION	6/12/2004	HEATERS	45.00 MMBtu/hr	LOW NOX BURNERS	BACT-PSD	0.035 lb/MMBtu	
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8 MMBTU/H	Low NOx burner	BACT-PSD	0.036 lb/MMBtu	Calculated from 0.75 lb/hr and 20.8 MMBtu/hr
TX-0693	ANTELOPE ELK ENERGY CENTER	4/22/2014	heater	5.5 MMBTU/H		BACT-PSD	0.036 LB/MMBTU	1 HOUR
NJ-0062	CONSOLIDATE EDISON DEVELOPMENT (CED)	10/22/2002	FUEL GAS HEATERS (3 UNITS)	4.62 MMBtu/hr	LOW NOX -COMBUSTOR	LAER	0.036 lb/MMBtu	
IA-0058	GREATER DES MOINES ENERGY CENTER	4/10/2002	DEW POINT HEATER			BACT-PSD	0.036 lb/MMBtu	
IA-0058	GREATER DES MOINES ENERGY CENTER	4/10/2002	EFFICIENCY HEATER			BACT-PSD	0.041 lb/MMBtu	
TX-0359	LIMESTONE ELECTRIC GENERATING STATION	5/23/2001	HEATERS, H-8,H-60,H-42,H-43,H-61,H-63		NONE INDICATED	Other Case-by-Case	0.045 lb/MMBtu	1 H AV @ <= 90% FIRING RATE
IA-0068	EMERY GENERATING STATION	6/26/2003	GAS HEATER	9.00 MMBtu/hr	DLN	Other Case-by-Case	0.049 lb/MMBtu	

Table C-9 NOx Emisison Limits for Fuel Gas Heater from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit	
IA-0062	EMERY GENERATING STATION	12/20/2002	GAS HEATER, (2)	16.40 MMBtu/hr	DLN	Other Case-by-Case	0.049 lb/MMBtu	
IA-0060	HAWKEYE GENERATING, LLC	7/23/2002	FUEL PREHEATER	6.50 MMBtu/hr	GCP	BACT-PSD	0.054 lb/MMBtu	
IA-0060	HAWKEYE GENERATING, LLC	7/23/2002	FUEL PREHEATER	6.50 MMBtu/hr	GCP	BACT-PSD	0.054 lb/MMBtu	
*PA-0288	SUNBURY GENERATION LP/SUNBURY SES	4/1/2013	DEW POINT HEATER	15 MMBtu/hr		OTHER CASE-BY-CASE	0.085 lb/MMBtu	
OH-0264	NORTON ENERGY STORAGE, LLC	5/23/2002	FUEL SUPPLY HEATERS (9)	11.45 MMBtu/hr		BACT-PSD	0.094 lb/MMBtu	
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	7/30/2008	TWO NOMINAL 10 MMBTU/H NATURAL GAS-FIRED PROCESS HEATERS	10.00 MMBtu/hr	GOOD COMBUSTION	BACT-PSD	0.095 lb/MMBtu	
FL-0286	FPL WEST COUNTY ENERGY CENTER	1/10/2007	TWO GAS-FUELED 10 MMBTU/H PROCESS HEATERS	10.00 MMBtu/hr		BACT-PSD	0.095 lb/MMBtu	
IA-0063	WISDOM GENERATION STATION	2/5/2003	HEATER , NATURAL GAS	5.38 MMBtu/hr	DLN	Other Case-by-Case	0.095 lb/MMBtu	
MI-0423	INDECK NILES, LLC	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27.0 MMBTU/H	Good combustion practices.	BACT-PSD	0.100 lb/MMBtu	Calculated from 2.65 lb/hr and 27.0 MMBtu/hr
TX-0694	INDECK WHARTON ENERGY CENTER	2/2/2015	heater	3.0 MMBTU/H		BACT-PSD	0.100 LB/MMBTU	1 HOUR
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	5/20/2014	fuel gas heater	18.0 MMBTU/H		BACT-PSD	0.100 LB/MMBTU	
*SC-0142	SHOWA DENKO CARBON, INC.	6/8/2012	HOT OIL HEATER	5 MMBTU/H	GOOD COMBUSTION PRACTICES, ANNUAL TUNE UP, LOW NOX BURNERS	BACT-PSD	0.100 lb/MMBtu	
MD-0040	CPV ST CHARLES	11/12/2008	HEATER	1.70 MMBtu/hr		BACT-PSD	0.100 lb/MMBtu	

Table C-9 NOx Emisison Limits for Fuel Gas Heater from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit	
*WY-0064	DRY FORK STATION	10/15/2007	INLET GAS HEATER (ES1-06)	8.36 MMBtu/hr	GOOD COMBUSTION PRACTICES-LIMITED TO 2000 HOURS OF ANNUAL OPERATION.	Other Case-by-Case	0.100 lb/MMBtu	ANNUAL
WI-0227	PORT WASHINGTON GENERATING STATION	10/13/2004	GAS HEATER (P06, S06)	10.00 MMBtu/hr	NATURAL GAS FUEL	N/A	0.100 lb/MMBtu	
NJ-0036	AES RED OAK LLC	10/24/2001	FUEL GAS HEATER	16.00 MMBtu/hr	NONE- CONCLUDED THAT FUEL GAS HEATER HAS FAR LOWER HEAT INPUT RATE AND SUCH NOX CONTROLS ARE NOT PROBABLE BASED ON COST-EFFECTIVENESS	LAER	0.120 lb/MMBtu	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7 MMBTU/H	Good combustion practices.	BACT-PSD	0.140 lb/MMBtu	Calculated from 0.55 lb/hr and 3.7 MMBtu/hr
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7 MMBTU/H	Good combustion practices.	BACT-PSD	0.140 lb/MMBtu	Calculated from 0.55 lb/hr and 3.7 MMBtu/hr
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	8/16/2005	FUEL PREHEATER #1	4.00 MMBtu/hr	BEST COMBUSTION PRACTICES	BACT-PSD	0.140 lb/MMBtu	
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	8/16/2005	FUEL PREHEATER #2	4.00 MMBtu/hr	BEST COMBUSTION PRACTICES	BACT-PSD	0.140 lb/MMBtu	
IN-0116	PSEG LAWRENCEBURG ENERGY CO., INC.	12/23/2002	HEATER, STARTUP GAS, NATURAL GAS	2.40 MMBtu/hr		BACT-PSD	0.140 lb/MMBtu	
*IA-0064	ROQUETTE AMERICA	1/31/2003	DEW POINT HEATER	1.60 MMBtu/hr	GOOD COMBUSTION PRACTICES	BACT-PSD	0.150 lb/MMBtu	
LA-0262	SULFURIC ACID REGENERATION PLANT	5/3/2012	START-UP HEATER STACK (37-88, EQT 0053)	61 MMBTU/H	GOOD ENGINEERING DESIGN	BACT-PSD	0.166 lb/MMBtu	

Table C-10 CO Emisison Limits for Fuel Gas Heater from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit	
GA-0107	TALBOT ENERGY FACILITY	6/9/2003	FUEL GAS PREHEATERS, (3)	5.00 MMBtu/hr	GOOD COMBUSTION PRACTICE	BACT-PSD	0.022 lb/MMBtu	
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	8/16/2005	FUEL PREHEATER #1	4.00 MMBtu/hr	BEST COMBUSTION PRACTICES	BACT-PSD	0.030 lb/MMBtu	
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	8/16/2005	FUEL PREHEATER #2	4.00 MMBtu/hr	BEST COMBUSTION PRACTICES	BACT-PSD	0.030 lb/MMBtu	
IA-0058	GREATER DES MOINES ENERGY CENTER	4/10/2002	EFFICIENCY HEATER	MMBtu/hr		BACT-PSD	0.032 lb/MMBtu	
IA-0060	HAWKEYE GENERATING, LLC	7/23/2002	FUEL PREHEATER	6.50 MMBtu/hr	GCP	BACT-PSD	0.033 lb/MMBtu	
IA-0060	HAWKEYE GENERATING, LLC	7/23/2002	FUEL PREHEATER	6.50 MMBtu/hr	GCP	BACT-PSD	0.033 lb/MMBtu	
IA-0058	GREATER DES MOINES ENERGY CENTER	4/10/2002	DEW POINT HEATER	MMBtu/hr		BACT-PSD	0.036 lb/MMBtu	
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8 MMBTU/H	Good combustion controls.	BACT-PSD	0.037 lb/MMBtu	Calculated from 0.77 lb/hr and 20.8 MMBtu/hr
NA	C4GT, NOVI Energy	4/26/2018	Dew Point Heater	16.00 MMBTU/H		BACT-PSD	0.037 lb/MMBtu	
NA	Greensville County, Virginia	6/17/2016	Dew Point Heater	7.8 MMBTU/H		BACT-PSD	0.037 lb/MMBtu	
*PA-0288	SUNBURY GENERATION LP/SUNBURY SES	4/1/2013	DEW POINT HEATER	15 MMBtu/hr		OTHER CASE-BY-CASE	0.037 LBS/MMBTU	3-HOUR ROLLING
CO-0058	CHEYENNE STATION	6/12/2004	HEATERS	45.00 MMBtu/hr	GOOD COMBUSTION PRACTICES	BACT-PSD	0.037 lb/MMBtu	
TX-0694	INDECK WHARTON ENERGY CENTER	2/2/2015	heater	3 MMBTU/H	Good combustion controls.	BACT-PSD	0.040 LB/MMBTU	1 HOUR
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	dew point heater	13.32 mmBtu/hr	Good combustion controls.	BACT-PSD	0.041 LB/MMBTU	3-HOUR AVERAGE
WI-0227	PORT WASHINGTON GENERATING STATION	10/13/2004	GAS HEATER (P06, S06)	10.00 MMBtu/hr	NATURAL GAS FUEL	BACT-PSD	0.047 lb/MMBtu	
*PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	12/17/2013	Fuel Preheater	8.5 MMBtu/hr			0.050 lb/MMBtu	3-HOUR ROLLING
NJ-0036	AES RED OAK LLC	10/24/2001	FUEL GAS HEATER	16.00 MMBtu/hr	GOOD COMBUSTION PRACTICE	BACT-PSD	0.054 lb/MMBtu	
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	5/20/2014	fuel gas heater	18 MMBTU/H	Good combustion controls.	BACT-PSD	0.054 LB/MMBTU	
WI-0195	SENA NIAGARA MILL	10/18/2002	PROCESS HEATER, PAPER MACHINE P51	34.40 MMBtu/hr	ANY NEW (REPLACEMENT) IR BURNERS WILL BE LOW NOX BURNERS, FIRING NATURAL GAS	BACT-PSD	0.060 lb/MMBtu	EACH

Table C-10 CO Emisison Limits for Fuel Gas Heater from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

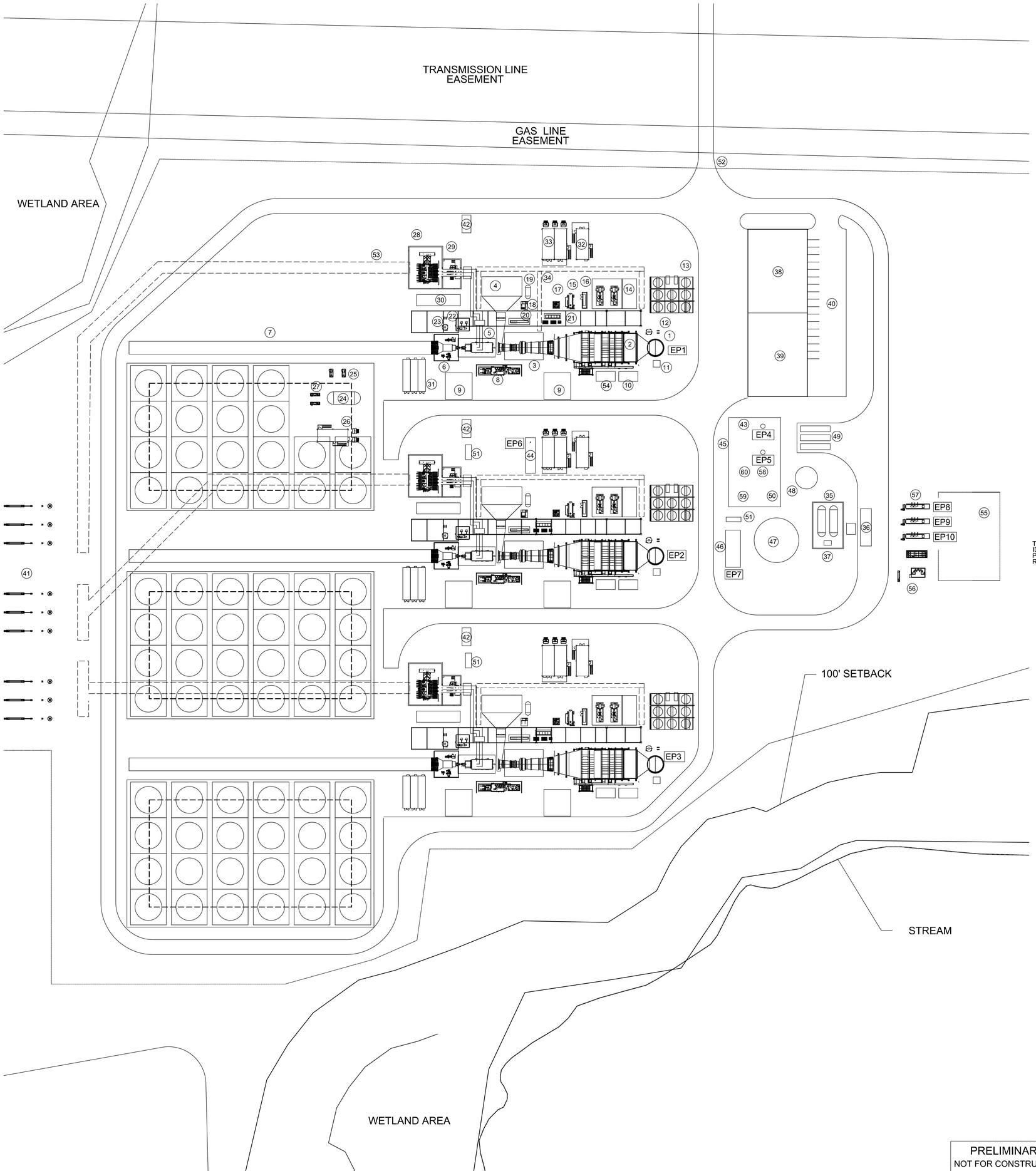
RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit	
MI-0423	INDECK NILES, LLC	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27 MMBTU/H	Good combustion controls.	BACT-PSD	0.080 lb/MMBtu	Calculated from 2.22 lb/hr and 27.0 MMBtu/hr
TX-0693	ANTELOPE ELK ENERGY CENTER	4/22/2014	heater	5.5 MMBTU/H	Good combustion controls.	BACT-PSD	0.080 LB/MMBTU	1 HOUR
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7 MMBTU/H	Good combustion controls.	BACT-PSD	0.080 lb/MMBtu	Calculated from 2.22 lb/hr and 27.0 MMBtu/hr
*FL-0334	ANCLOTE POWER GENERATING FACILITY	9/14/2012	Natural Gas Process Heater	16.5 MMBtu/hr		BACT-PSD	0.080 LB/MMBTU	
MD-0040	CPV ST CHARLES	11/12/2008	HEATER	1.70 MMBtu/hr		BACT-PSD	0.080 lb/MMBtu	
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	7/30/2008	TWO NOMINAL 10 MMBTU/H NATURAL GAS-FIRED PROCESS HEATERS	10.00 MMBtu/hr	GOOD COMBUSTION	BACT-PSD	0.080 lb/MMBtu	
*WY-0064	DRY FORK STATION	10/15/2007	INLET GAS HEATER (ES1-06)	8.36 MMBtu/hr	GOOD COMBUSTION PRACTICES-LIMITED TO 2000 HOURS OF ANNUAL OPERATION.	Other Case-by-Case	0.080 lb/MMBtu	Based on engineering analysis, pemit limit is 2.6 ton/yr
FL-0285	PROGRESS BARTOW POWER PLANT	1/26/2007	FIVE 3 MM BTU/HR GASEOUS-FUELED PROCESS HEATERS	3.00 MMBtu/hr		BACT-PSD	0.080 lb/MMBtu	1-HR AVERAGE
FL-0286	FPL WEST COUNTY ENERGY CENTER	1/10/2007	TWO GAS-FUELED 10 MMBTU/H PROCESS HEATERS	10.00 MMBtu/hr		BACT-PSD	0.080 lb/MMBtu	
LA-0192	CRESCENT CITY POWER	6/6/2005	FUEL GAS HEATERS (3)	19.00 MMBtu/hr	GOOD COMBUSTION PRACTICES	BACT-PSD	0.080 lb/MMBtu	HOURLY AVERAGE
*SC-0142	SHOWA DENKO CARBON, INC.	6/8/2012	HOT OIL HEATER	5 MMBTU/H	GOOD COMBUSTION PRACTICES, ANNUAL TUNE UP, LOW NOX BURNERS	BACT-PSD	0.082 LB/MMBTU	
IA-0068	EMERY GENERATING STATION	6/26/2003	GAS HEATER	9.00 MMBtu/hr	GOOD COMBUSTION PRACTICES	Other Case-by-Case	0.082 lb/MMBtu	

Table C-10 CO Emisison Limits for Fuel Gas Heater from EPA'S RACT/BACT/LAER Clearinghouse (August 2018)

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	Size	Control Device description	CASE-BY-CASE BASIS	Emission Limit	
IA-0062	EMERY GENERATING STATION	12/20/2002	GAS HEATER, (2)	16.40 MMBtu/hr		Other Case-by-Case	0.082 lb/MMBtu	
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	4/17/2003	FUEL GAS HEATER	5.00 MMBtu/hr		BACT-PSD	0.083 lb/MMBtu	
LA-0184	TITANIUM DIOXIDE FACILITY	5/13/2003	OXYGEN SUPERHEATERS W340-AX & W340-BX (5.61 MM BTU/H EA.)	5.61 MMBtu/hr	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES	BACT-PSD	0.091 lb/MMBtu	
MD-0031	CHALK POINT	4/1/2005	(2) NATURAL GAS FUEL HEATERS	10.00 MMBtu/hr	GOOD COMBUSTION CONTROL AND NATURAL GAS FIRING ONLY	BACT-PSD	0.100 lb/MMBtu	ANNUAL
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7 MMBTU/H	Good combustion controls.	BACT-PSD	0.110 lb/MMBtu	Calculated from 0.41 lb/hr and 3.7 MMBtu/hr
NJ-0062	CONSOLIDATE EDISON DEVELOPMENT (CED)	10/22/2002	FUEL GAS HEATERS (3 UNITS)	4.62 MMBtu/hr	GOOD COMBUSTION PRACTICE	Other Case-by-Case	0.150 lb/MMBtu	HOURLY MAXIMUM

Appendix D

Plot Plan



LEGEND

1 HRSG STACK
2 HEAT RECOVERY STEAM GENERATOR (HRSG)
3 GAS TURBINE
4 GAS TURBINE AIR INTAKE
5 GAS TURBINE GENERATOR
6 STEAM TURBINE
7 AIR COOLED CONDENSER
8 TURBINE LUBE OIL AND CONTAINMENT
9 CRANE PAD
10 AMMONIA FLOW CONTROL SKID
11 CONTINUOS EMISSIONS MONITORING SYSTEM (CEMS)
12 HRSG BLOWDOWN TANK AND PUMPS
13 FIN FAN COOLER AND PUMPS
14 BOILER FEEDWATER PUMP AND ELECTRICAL ENCLOSURE
15 GAS TURBINE FUEL GAS HEATER
16 HRSG DUCT BURNER SKID
17 GAS TURBINE FILTER
18 GAS TURBINE WATER WASH SKID
19 GAS TURBINE DRAIN TANK (BURIED)
20 SAMPLING PANEL ENCLOSURE
21 CHEMICAL FEED TOTE ENCLOSURE AND PUMPS
22 GLAND STEAM CONDENSER
23 STEAM TURBINE DRAINS TANK
24 CONDENSATE TANK
25 CONDENSATE PUMPS
26 AIR COOLED CONDENSER ELECTRICAL PDC
27 CONDENSER VACUUM PUMPS
28 GENERATOR STEP UP TRANSFORMER
29 AUXILIARY TRANSFORMER
30 GENERATOR ACCESSORY BUILDING
31 GAS TURBINE ELECTRICAL PACKAGE
32 CONTROL/LV ELECTRICAL PDC
33 MAIN ELECTRICAL PDC
34 ELECTRICAL CORRIDOR
35 AMMONIA TANKS
36 AMMONIA UNLOADING PAD
37 AMMONIA FORWARDING PUMPS
38 ADMINISTRATION/CONTROL BUILDING
39 WAREHOUSE BUILDING
40 PARKING
41 SWITCHYARD
42 HYDROGEN STORAGE PAD
43 AUXILIARY BOILER
44 EMERGENCY DIESEL GENERATOR
45 AUXILIARY SHELTER
46 FIRE WATER PUMPS
47 SERVICE/FIRE WATER TANK
48 DEMINERALIZED WATER TANK
49 DEMINERALIZED WATER TRAILERS
50 SERVICE/DEMINERALIZED WATER PUMPS
51 OILY WATER SEPARATOR (3)
52 PLANT GATE
53 500 KV CABLE CORRIDOR
54 CO_2, NITROGEN BOTTLE STORAGE PAD
55 FUEL GAS YARD
56 FUEL GAS CONDITIONING EQUIPMENT
57 FUEL GAS WATER BATH HEATERS
58 AIR COMPRESSOR EQUIPMENT
59 BOP ELECTRICAL ROOM
60 BLOWDOWN RECOVERY EQUIPMENT

EMISSION POINT LIST

EMISSION POINTS		UTM COORDINATES
EP1	HRSG STACK 1	309579.83, 4145495.32
EP2	HRSG STACK 2	309576.66, 4145410.03
EP3	HRSG STACK 3	309573.50, 4145324.73
EP4	AUXILIARY BOILER STACK 1	309622.66, 4145461.55
EP5	AUXILIARY BOILER STACK 2	309622.26, 4145450.89
EP6	EMERGENCY DIESEL GENERATOR EXHAUST	309527.21, 4145458.38
EP7	DIESEL FIREWATER PUMP EXHAUST	309608.58, 4145419.36
EP8	FUEL GAS WATER BATH HEATER 1	309686.93, 4145426.22
EP9	FUEL GAS WATER BATH HEATER 2	309686.70, 4145420.12
EP10	FUEL GAS WATER BATH HEATER 3	309686.48, 4145414.03

THE PLANT COORDINATES ARE BASED ON THE LOCATION OF CONTROL MONUMENTS IDENTIFIED ON ALTA/ACSM LAND TITLE SURVEY BOUNDARY PLAT SHOWING: TWO PARCELS OF LAND SITUATED ON BOTH SIDES OF CHAMBERS ROAD, REVISION DATED 03/25/02, PROJECT NUMBER R01249.01, SHEET 1 OF 4.

PRELIMINARY
NOT FOR CONSTRUCTION

PLANT NORTH

GRAPHIC SCALE
50' 0 50 100 150'

DRAWING SCALE
1" = 50'-0"

HOLD INFORMATION

NO.	DESCRIPTION

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION
A	05-22-2018	FOR PROPOSAL
B	10-26-2018	FOR INFORMATION

ISSUE PURPOSE: -
SPECIFICATION: -
PROJECT NO.: -

CAD FILE NAME: CHIC-GA-M0002.DGN
PREPARED BY: GMH
REVIEWED BY: -
APPROVED BY: -

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC

SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780

Gemma

GEMMA POWER SYSTEMS LLC
769 HEBRON AVENUE
GLASTONBURY, CONNECTICUT 06033

PROJECT

CHICKAHOMINY POWER STATION

DRAWING TITLE

GENERAL ARRANGEMENT
POWERBLOCK

DRAWING NUMBER: CHIC-GA-M0002
REVISION: B
SHEET 1

ZL10818/0m1761/C:\Users\0m1761\Desktop\General Arrangements\CHIC-MSK-002opt.dgn
Form GDG-0401-01-08, ANSI (Imperial) MicroStation Border - Size E - 34 x 44
Revision 10, Revision Date: 10-16-2009

10/26/2018 4:27:01 PM

Appendix E

EPA Region 3 Approval of ARM2 Lower Ambient Ratio Bound

From: Leon-Guerrero, Tim
To: Kiss, Michael; Connors, Jeffrey
Subject: RE: FW: [External] ARM2 Ambient Ratio Justification - Lincoln Station
Date: Wednesday, November 21, 2018 8:47:06 AM

This is a follow-up email to the conference call we had on Monday afternoon to discuss the use of non-default in-stack ratios (ISR) in ARM2 for a project in VA; thanks again for putting this call together on such short notice. During the call we discussed the ISR information I shared detailing start-up emissions for the GE turbines. This information suggests a more proper start-up ISR for the GE turbines is 0.3, as opposed the proposed 0.2 ratio that was based on previous analysis/discussions with R4 (model Clearinghouse Record No: 15-IV-01). All parties were agreeable to the proposed ISRs discussed during the call.

While the recent revisions to Appendix W no longer require and alternative model demonstration under section 3.2, section 4.2.3.4 (d) does provide the reviewing authority an opportunity to establish non-default values for use in ARM2. Region 3 believes our discussions on Monday would allow for use of the ISR values discussed during the call to be used in the analysis provided they are documented in a modeling protocol for this project. Additionally, EPA reminds the state and the applicant that additional justification for use of ARM2 (for NO2 modeling) needs to be performed and documented. Additional consideration should be given to NOx and ozone levels as more fully described in EPA's 30 September 2014 Clarification Memo. Again, this information should be included in the project's modeling protocol.

Please feel free to contact me if you have any questions or concerns regarding this matter and have a great and safe Thanksgiving.

Tim LG

From: Leon-Guerrero, Tim
Sent: Thursday, October 25, 2018 3:25 PM
To: 'Kiss, Michael' <michael.kiss@deq.virginia.gov>
Subject: RE: FW: [External] ARM2 Ambient Ratio Justification - Lincoln Station

Mike,

Let me know if you're available for a quick call on Monday. Chris has been out of the office for a while and I'm not sure when he will be back.

Tim LG

From: Kiss, Michael [mailto:michael.kiss@deq.virginia.gov]
Sent: Thursday, October 25, 2018 10:19 AM
To: Leon-Guerrero, Tim <Leon-Guerrero.Tim@epa.gov>
Subject: Fwd: FW: [External] ARM2 Ambient Ratio Justification - Lincoln Station

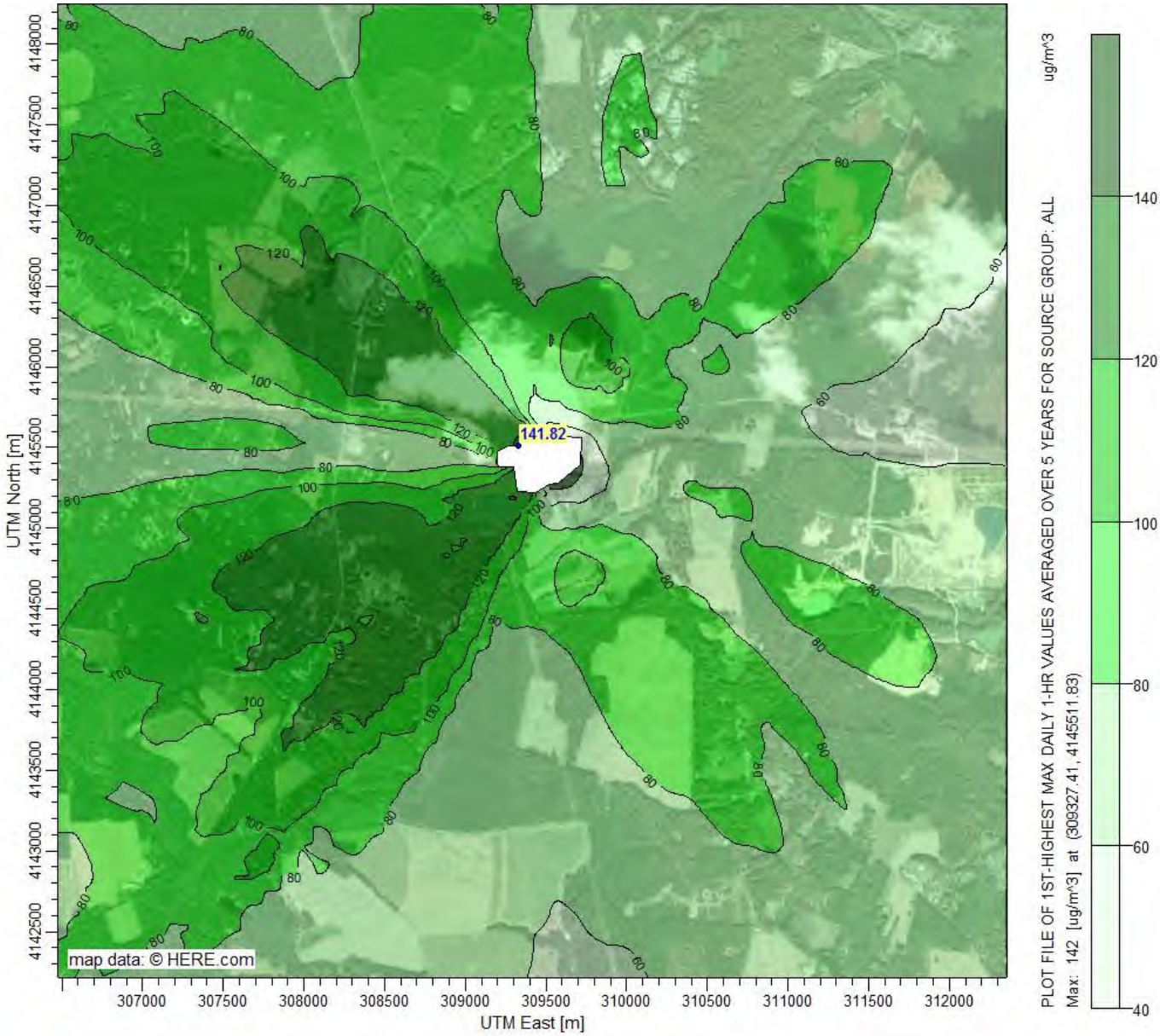
Appendix F

Air Dispersion Modeling Files

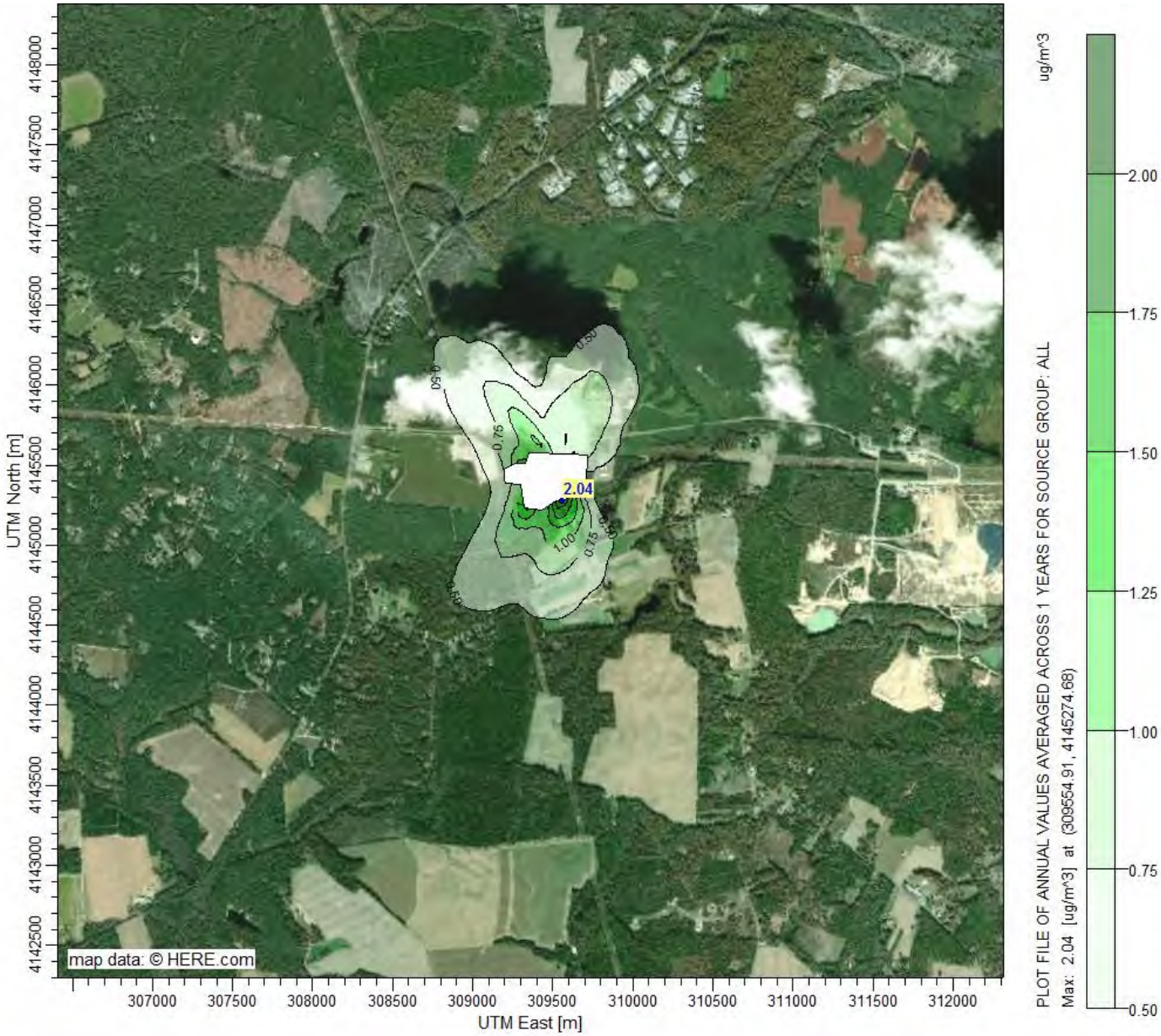
Appendix G

Air Quality Impacts – Contour Map

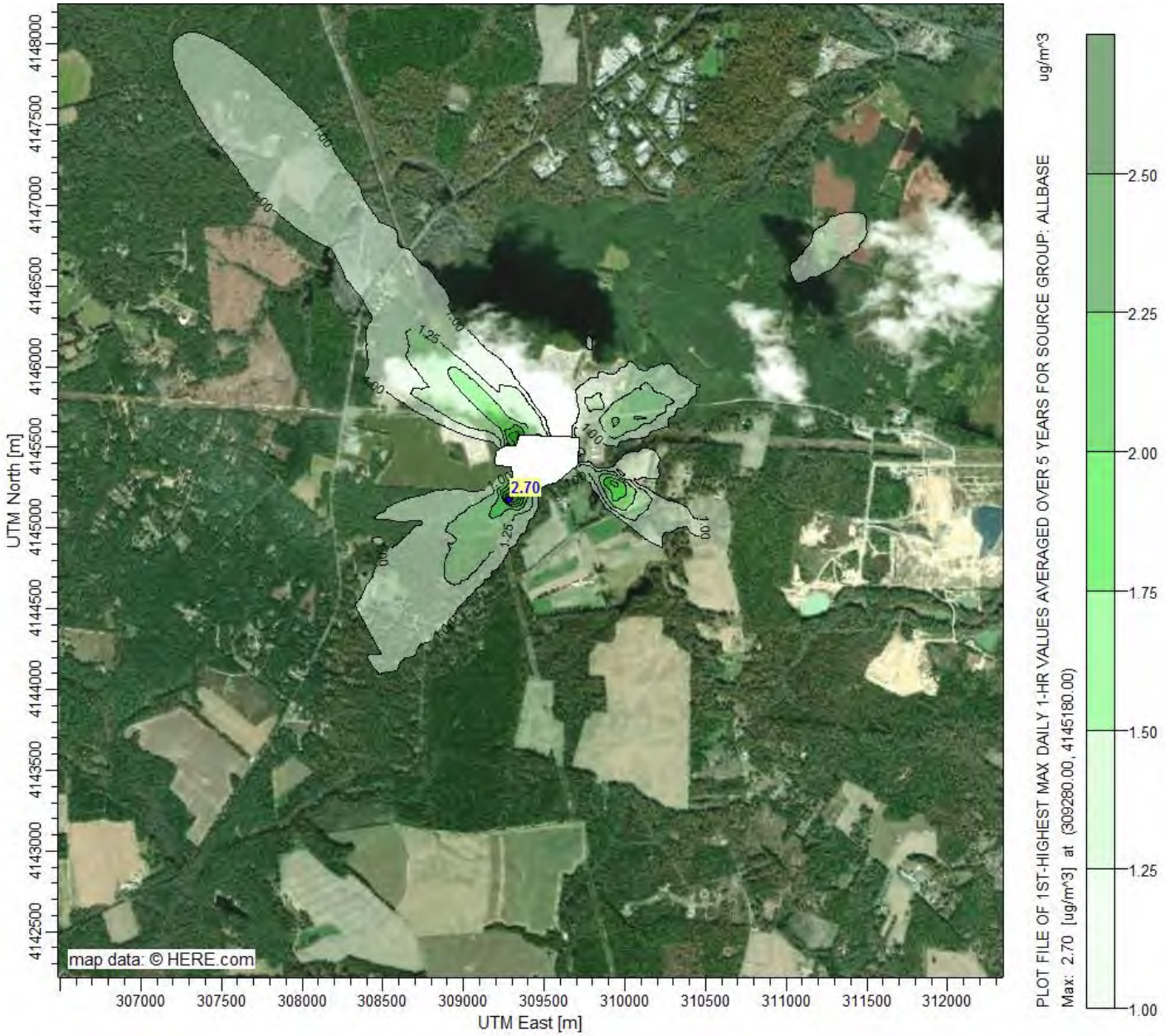
GE 7HA.02 Combustion Turbine – 1-hour NO_2 SIL



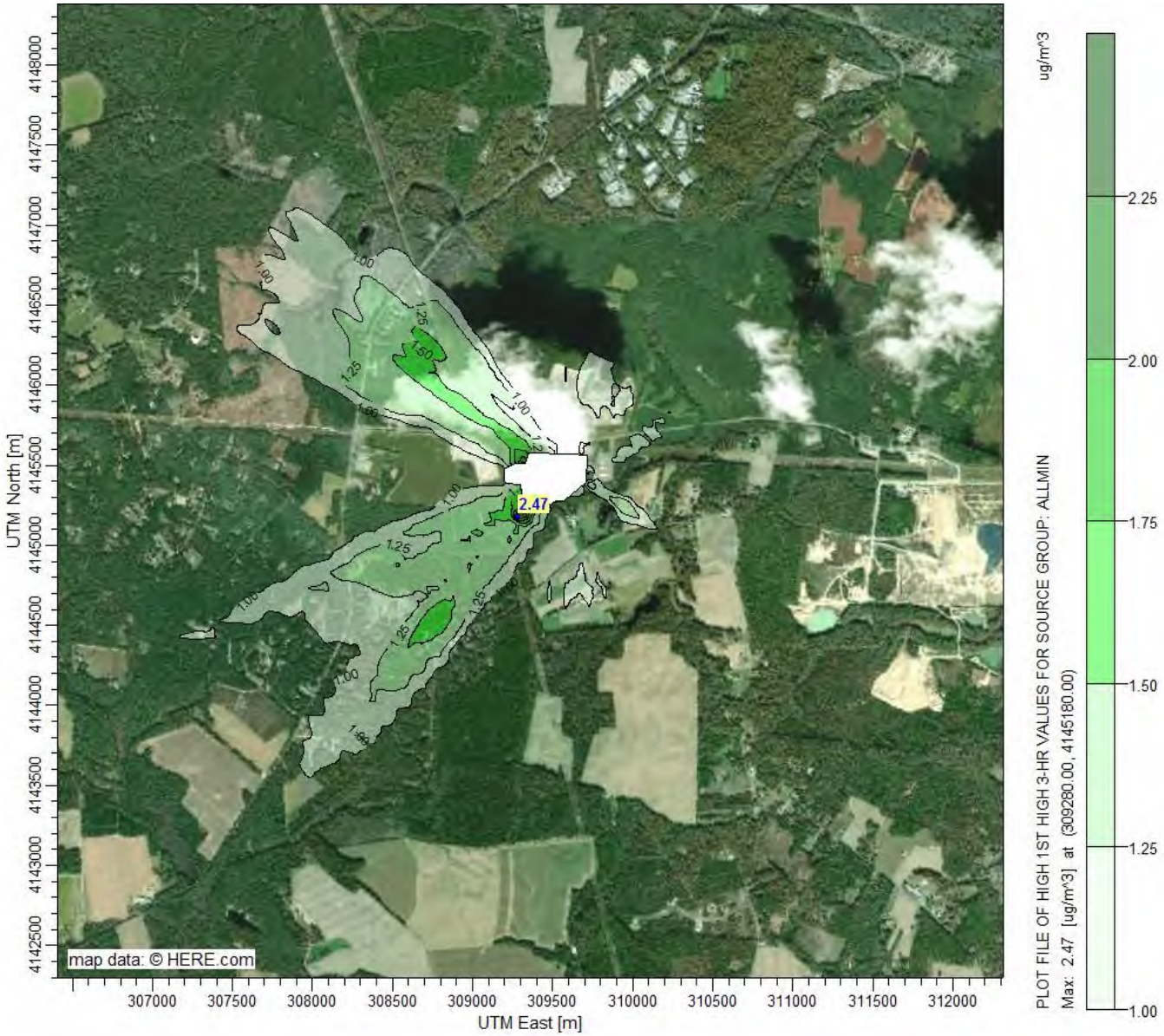
GE 7HA.02 Combustion Turbine – Annual NO_2 SIL



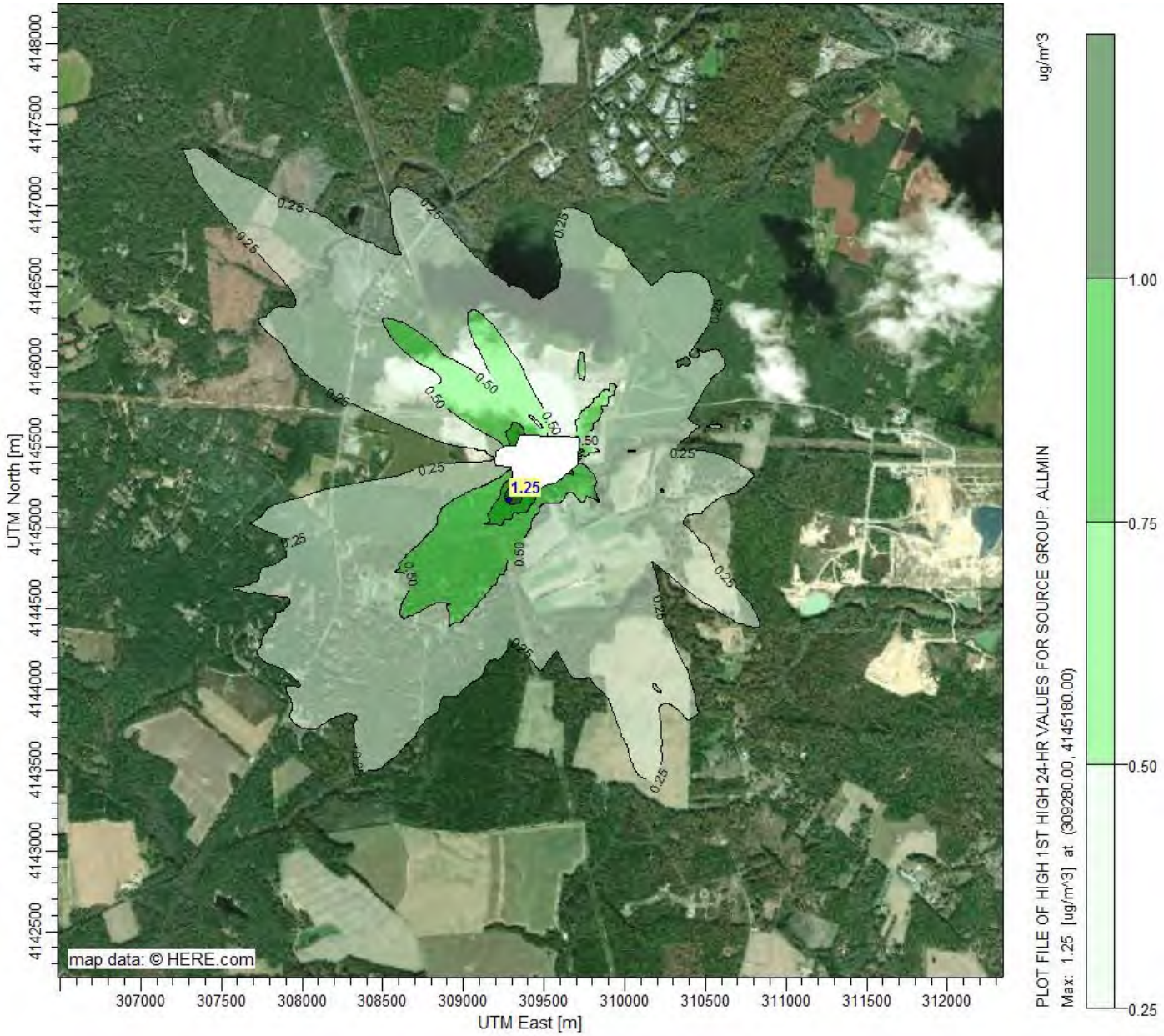
GE 7HA.02 Combustion Turbine – 1-hour SO_2 SIL



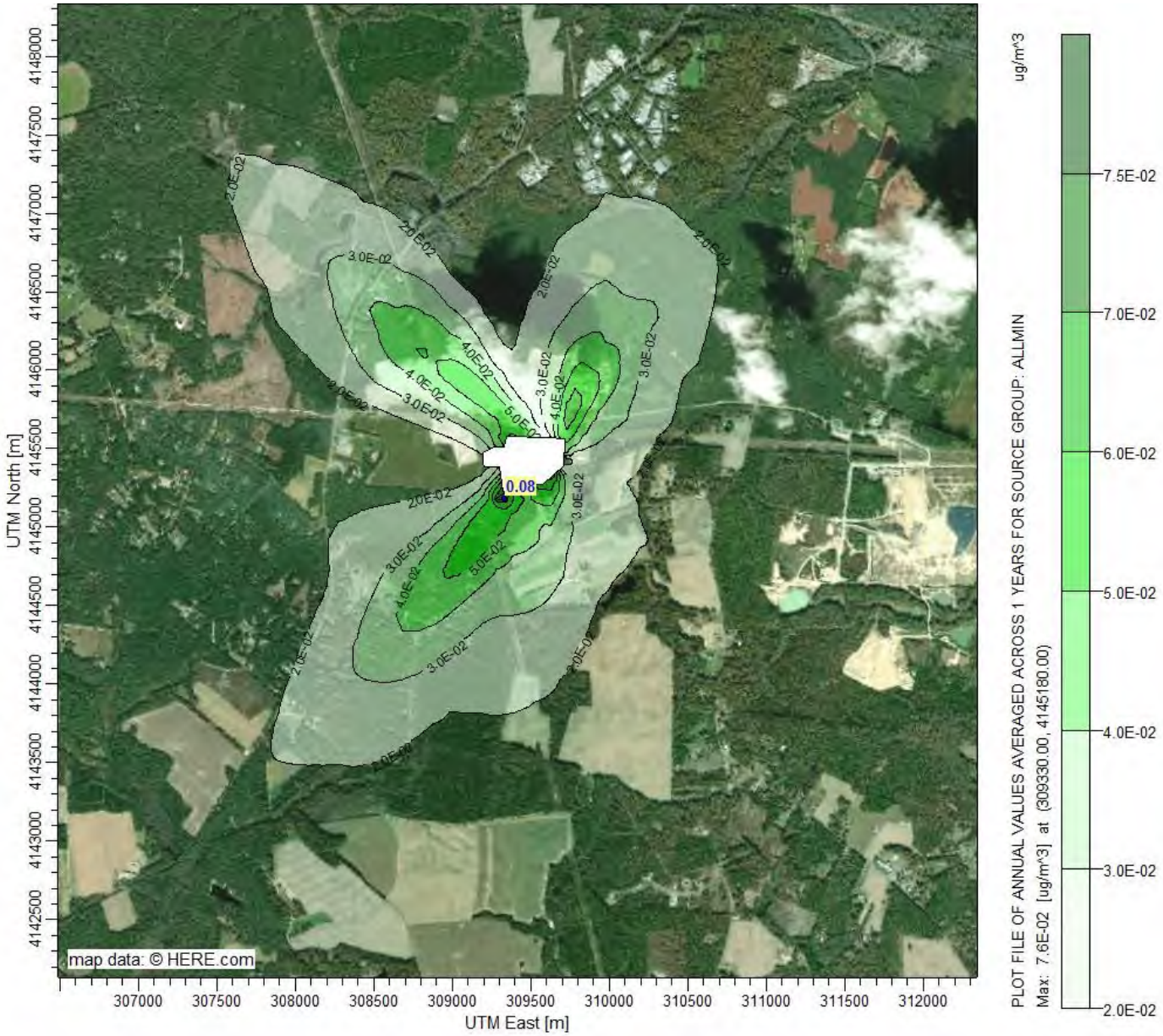
GE 7HA.02 Combustion Turbine – 3-hour SO_2 SIL



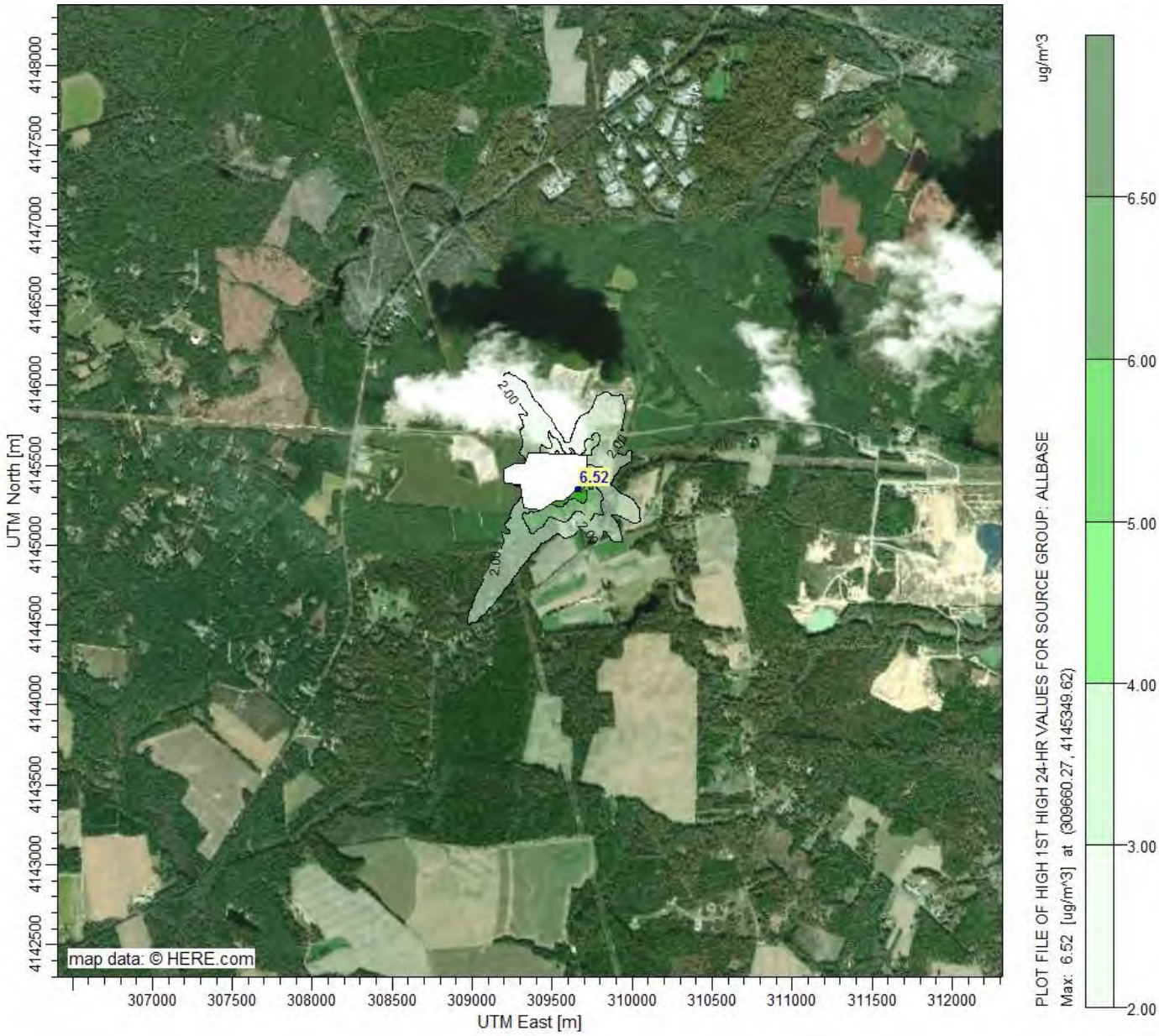
GE 7HA.02 Combustion Turbine – 24-hour SO_2 SIL



GE 7HA.02 Combustion Turbine – Annual SO_2 SIL



GE 7HA.02 Combustion Turbine – 24-hour PM_{10} SIL



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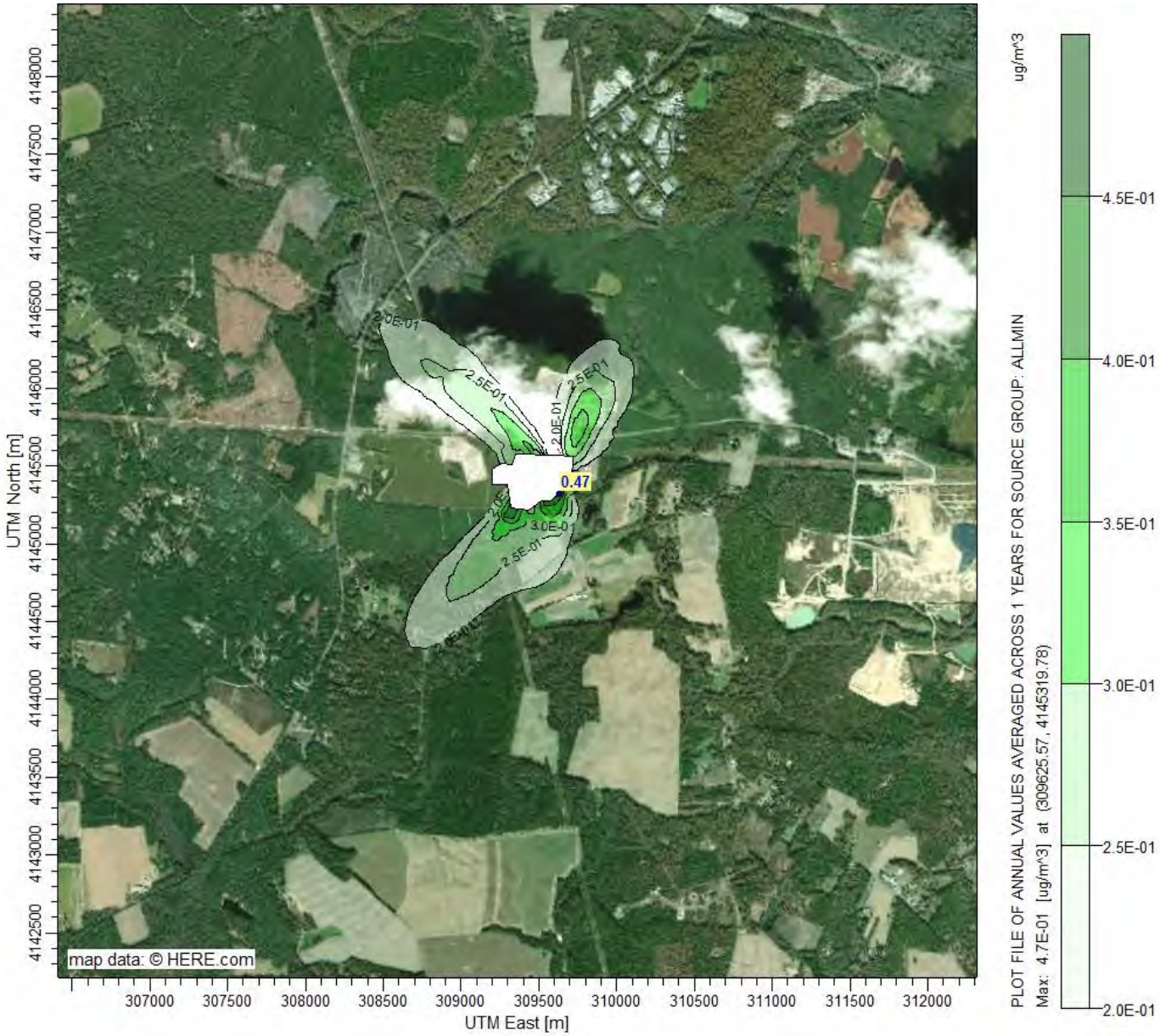
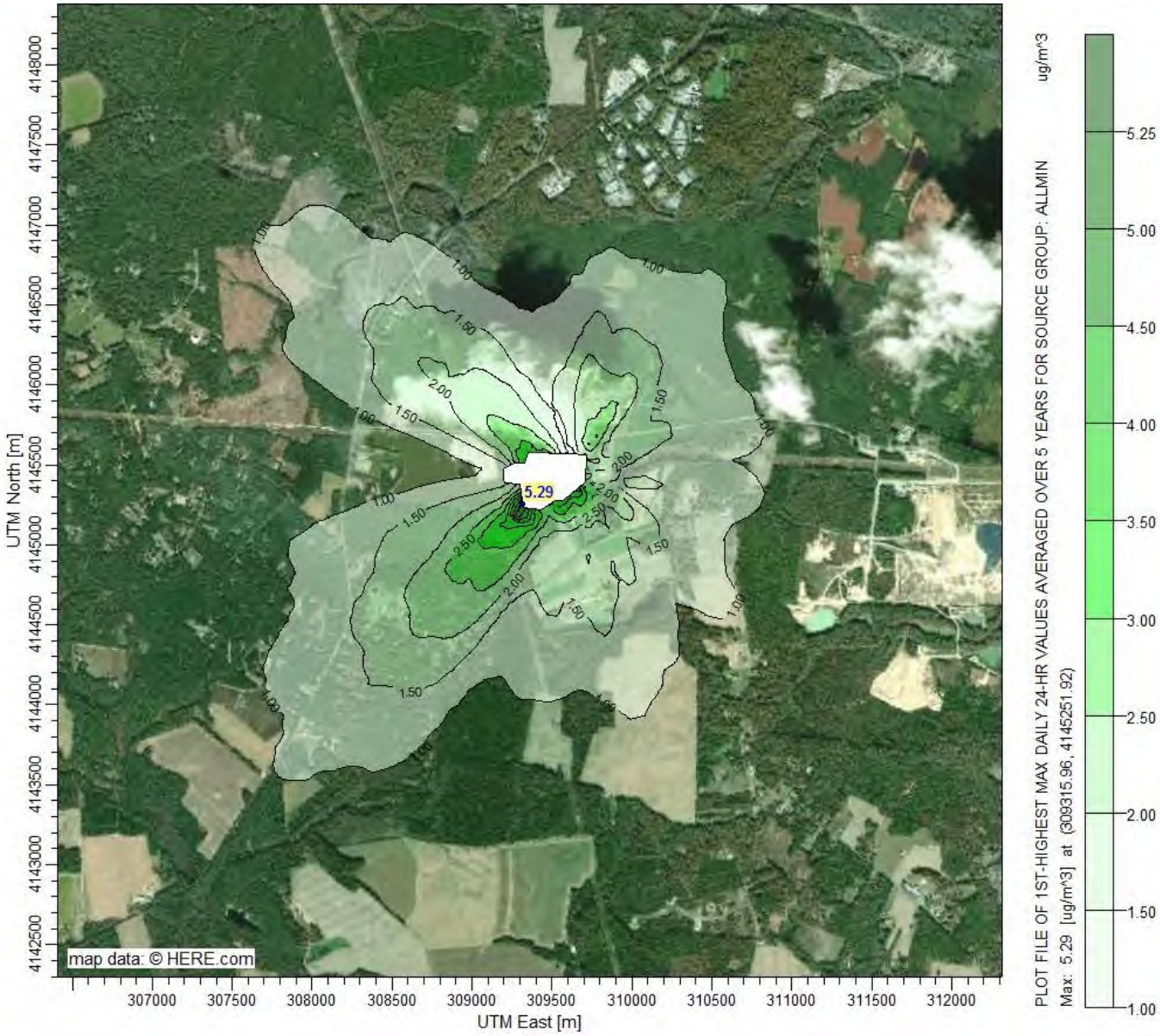


GE 7HA.02 Combustion Turbine – 24-hour $PM_{2.5}$ SIL



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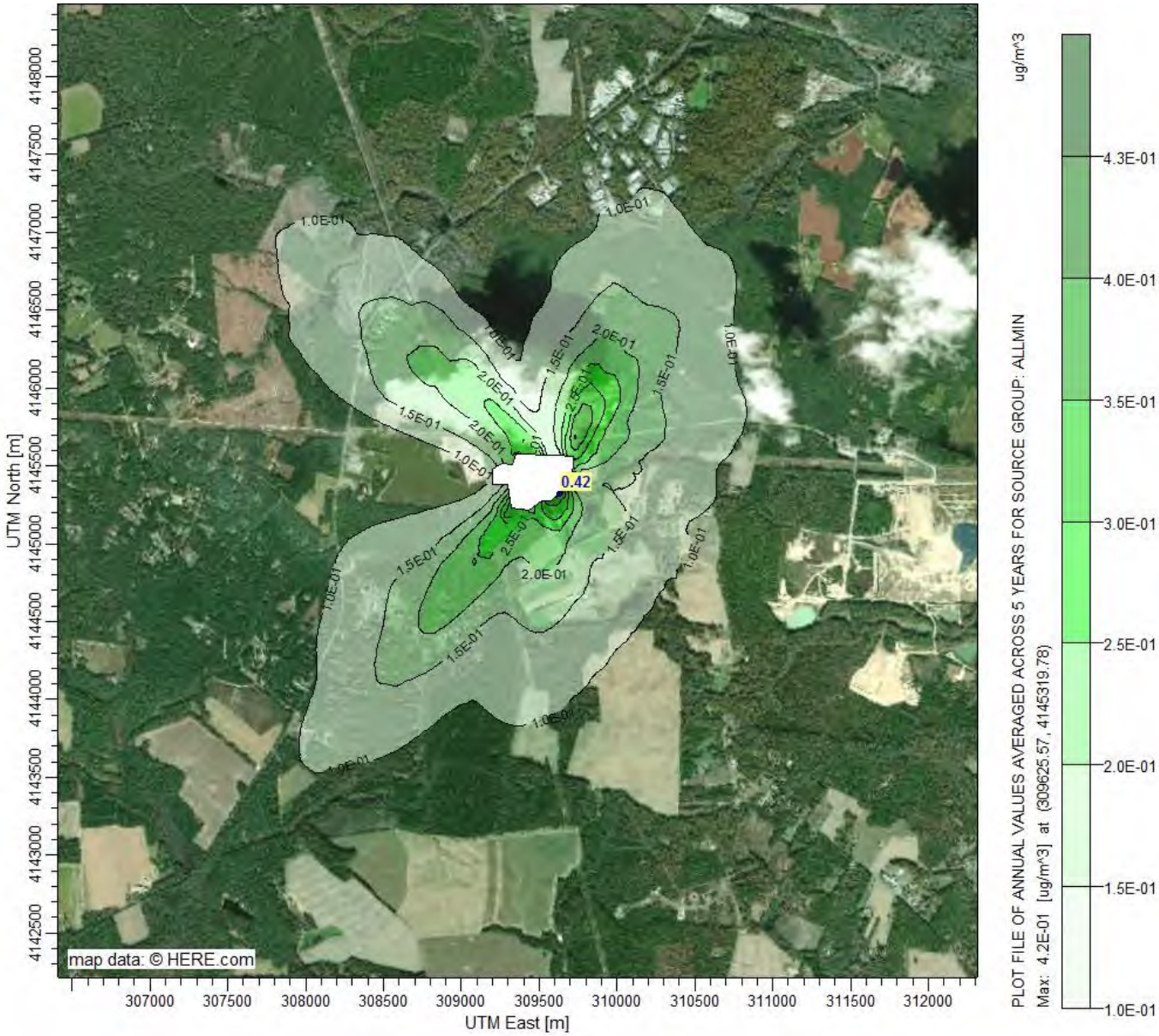
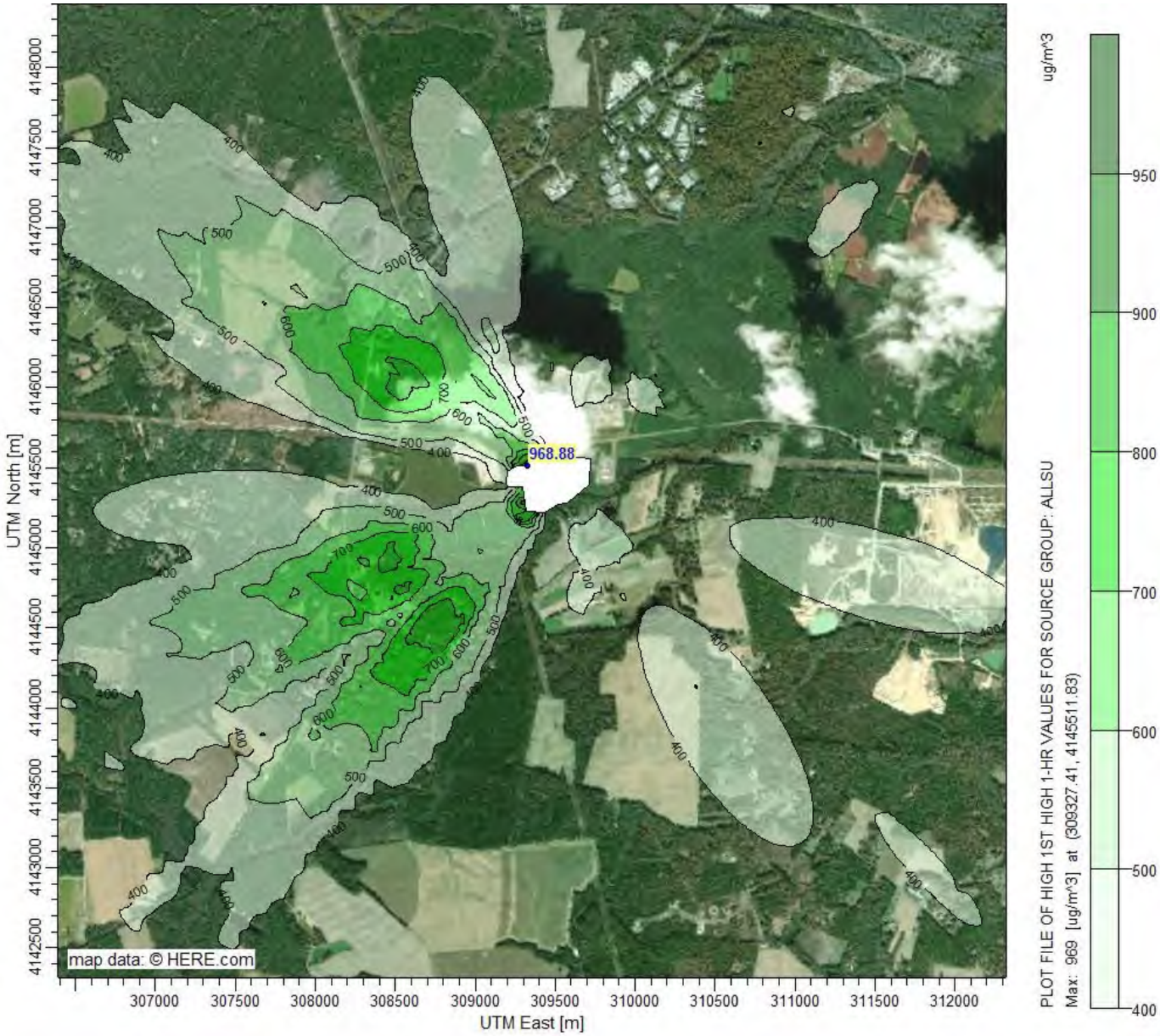
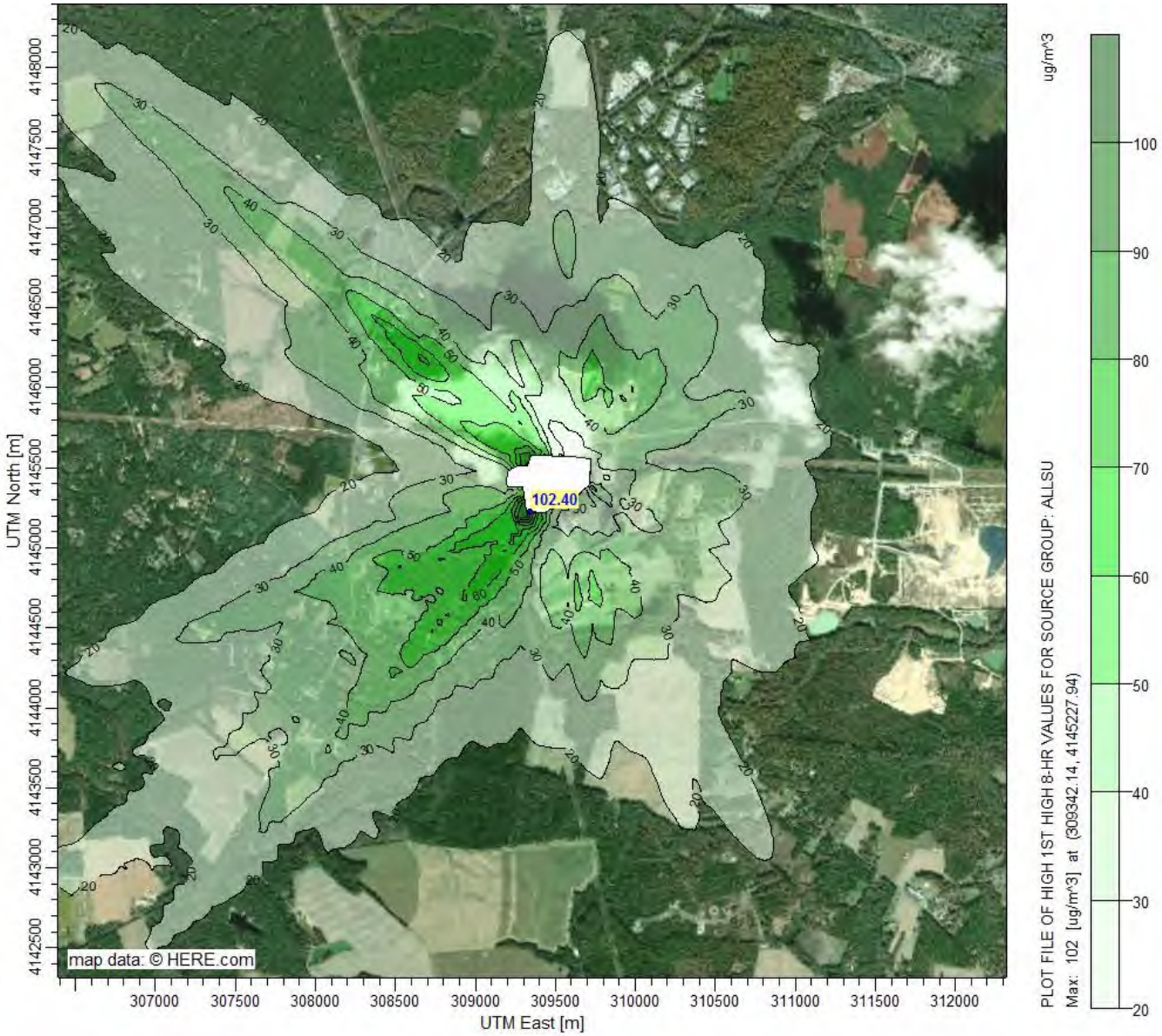


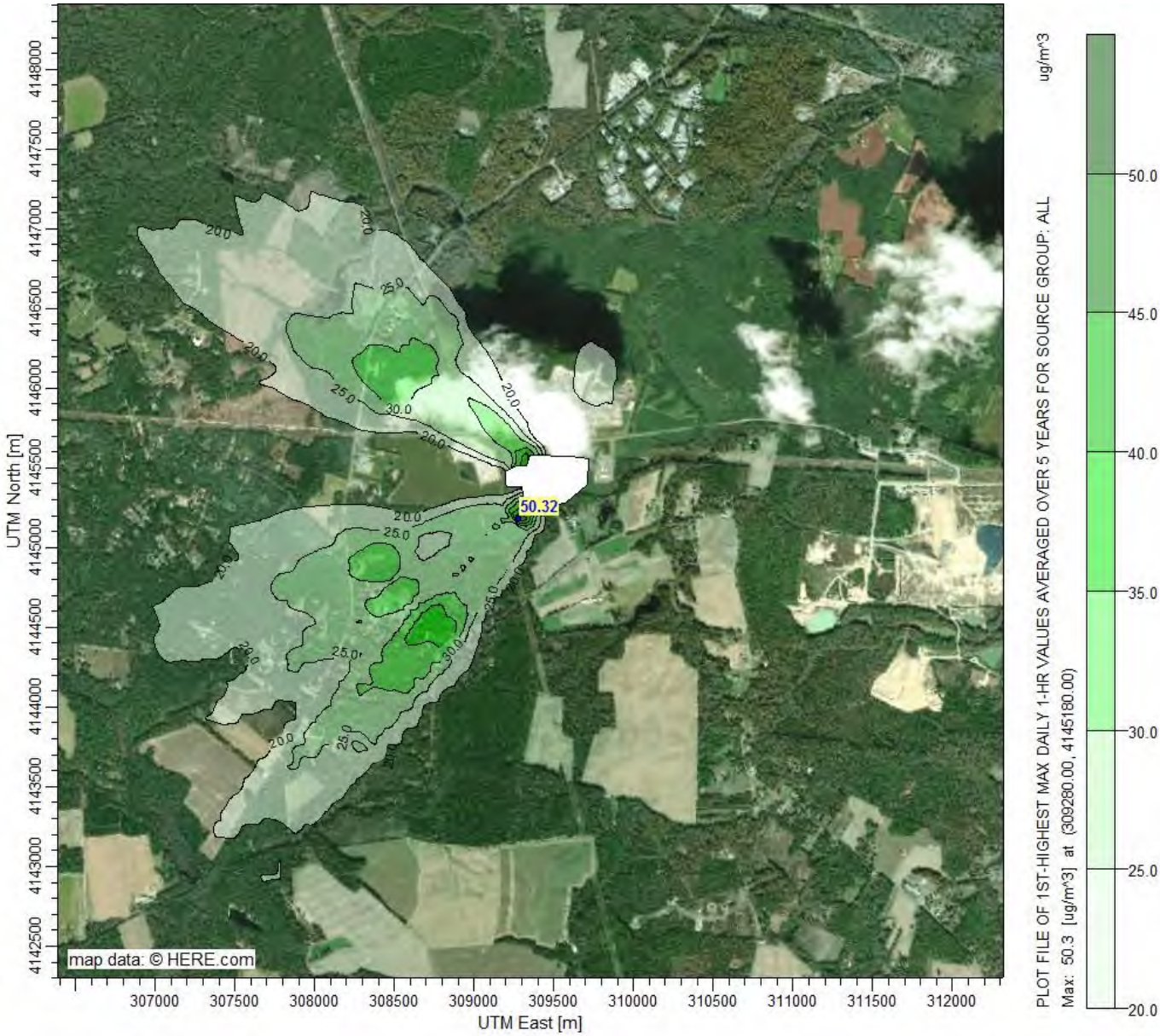
GE 7HA.02 Combustion Turbine – 1-hour CO SIL



GE 7HA.02 Combustion Turbine – 8-hour CO SIL



MHPS M501JAC Combustion Turbine – 1-hour NO_2 SIL



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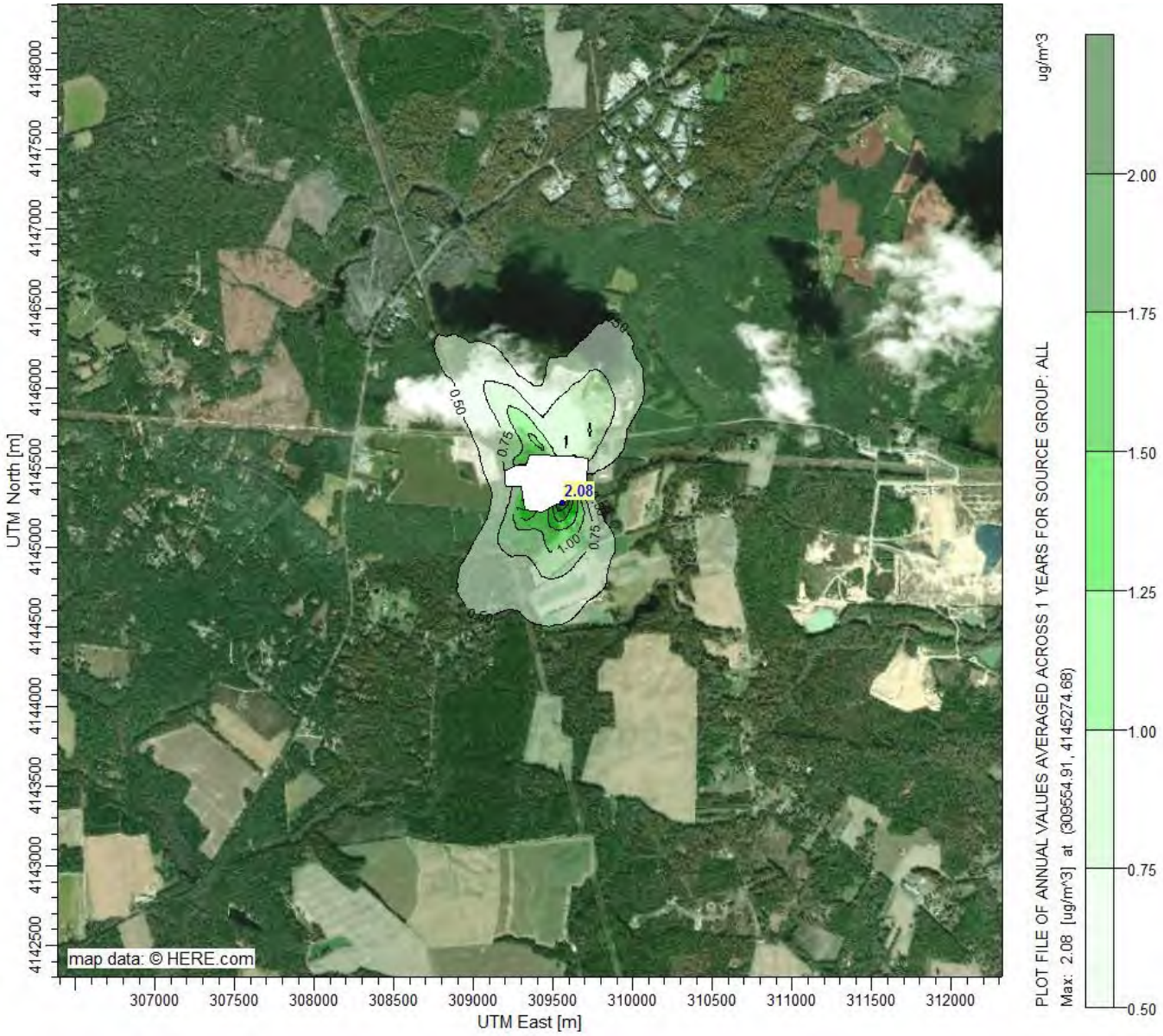

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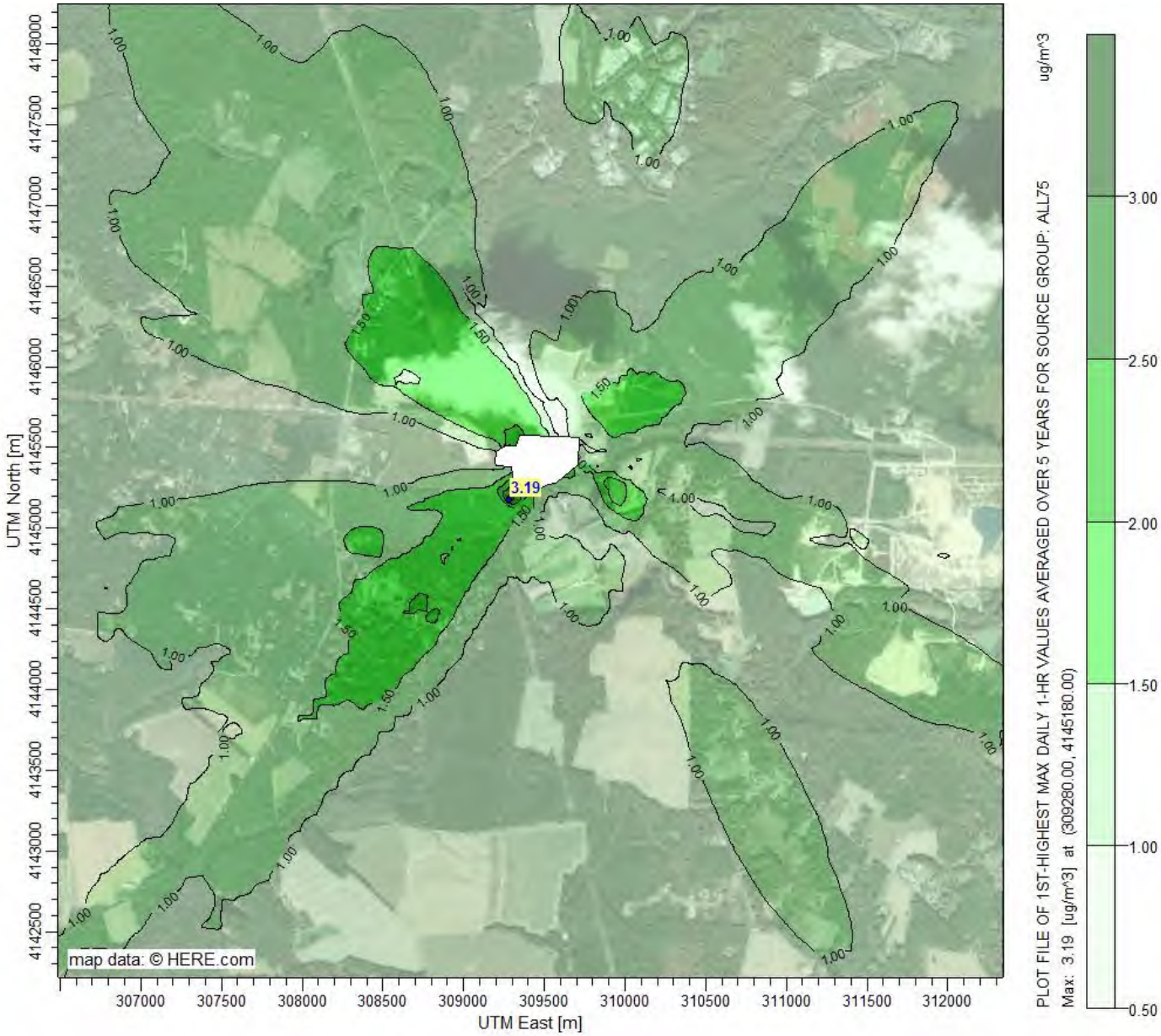

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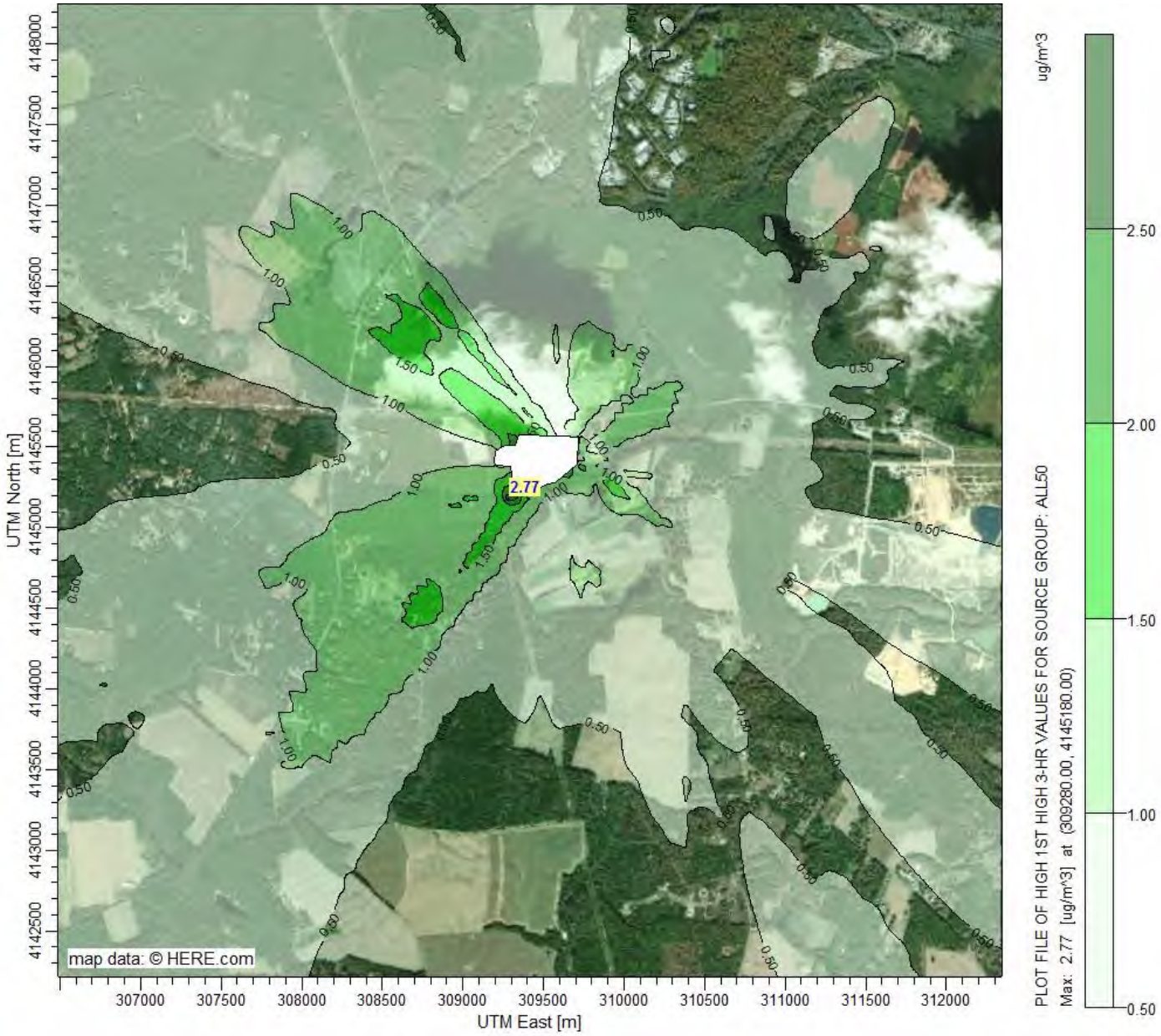

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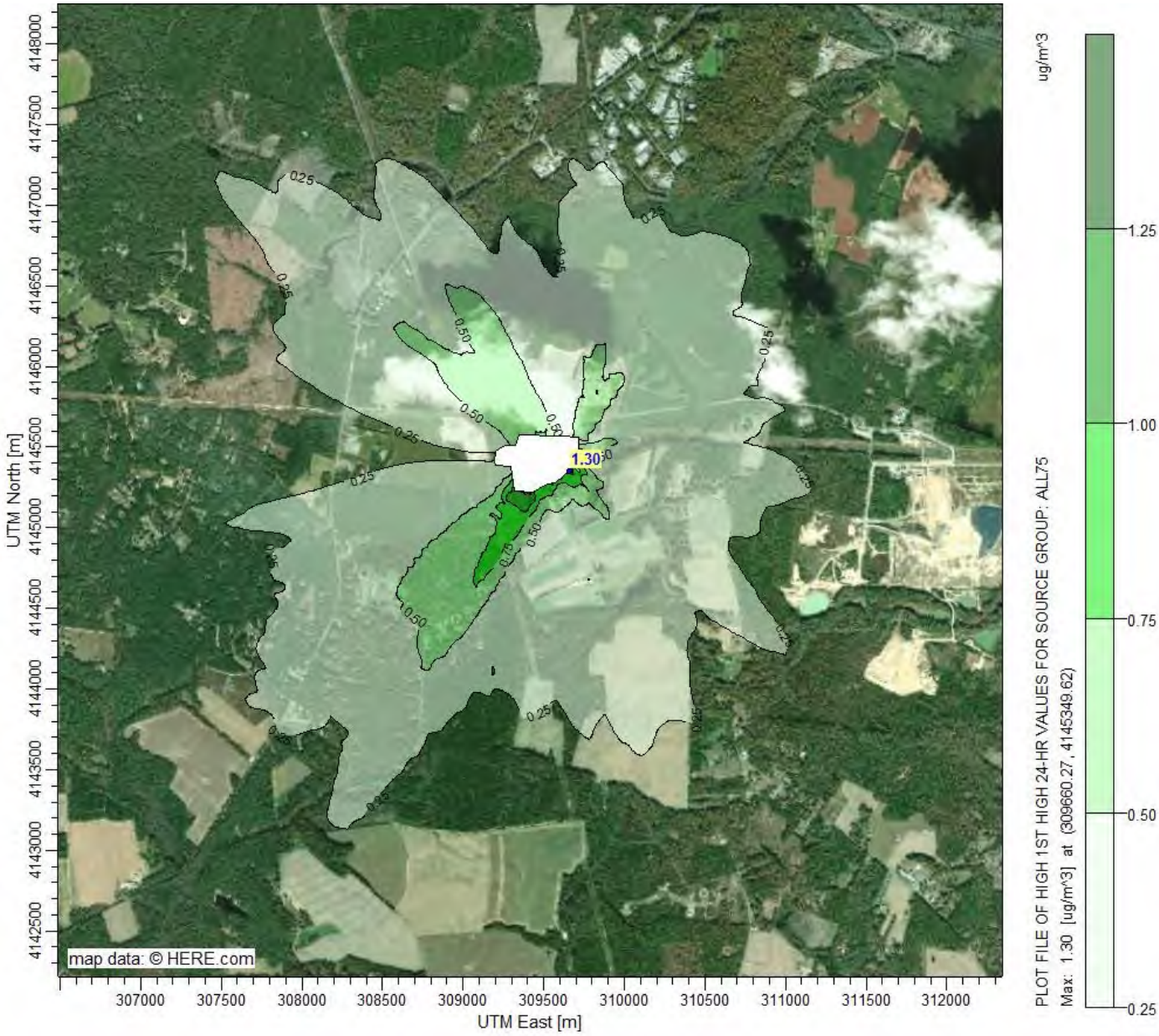

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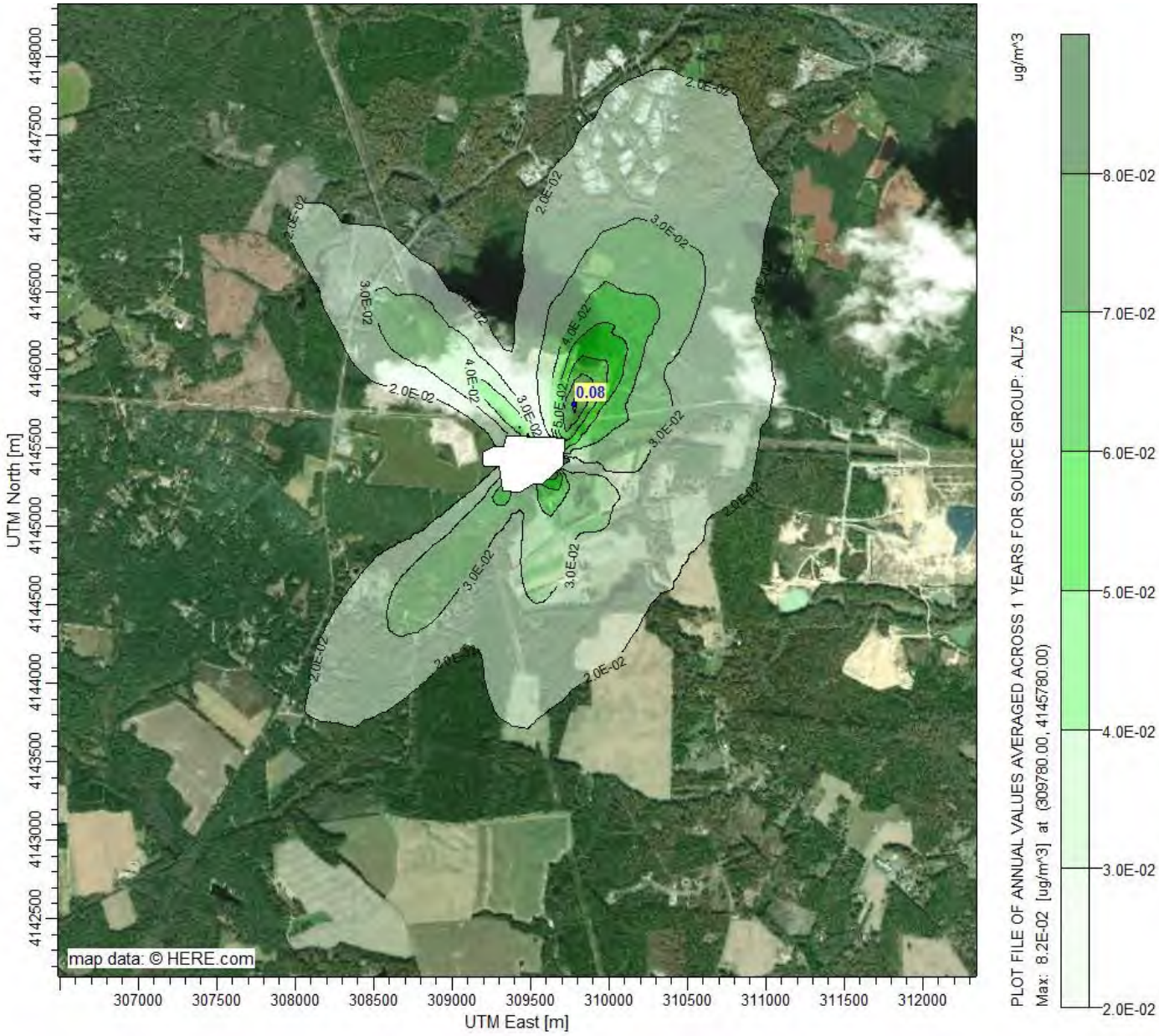

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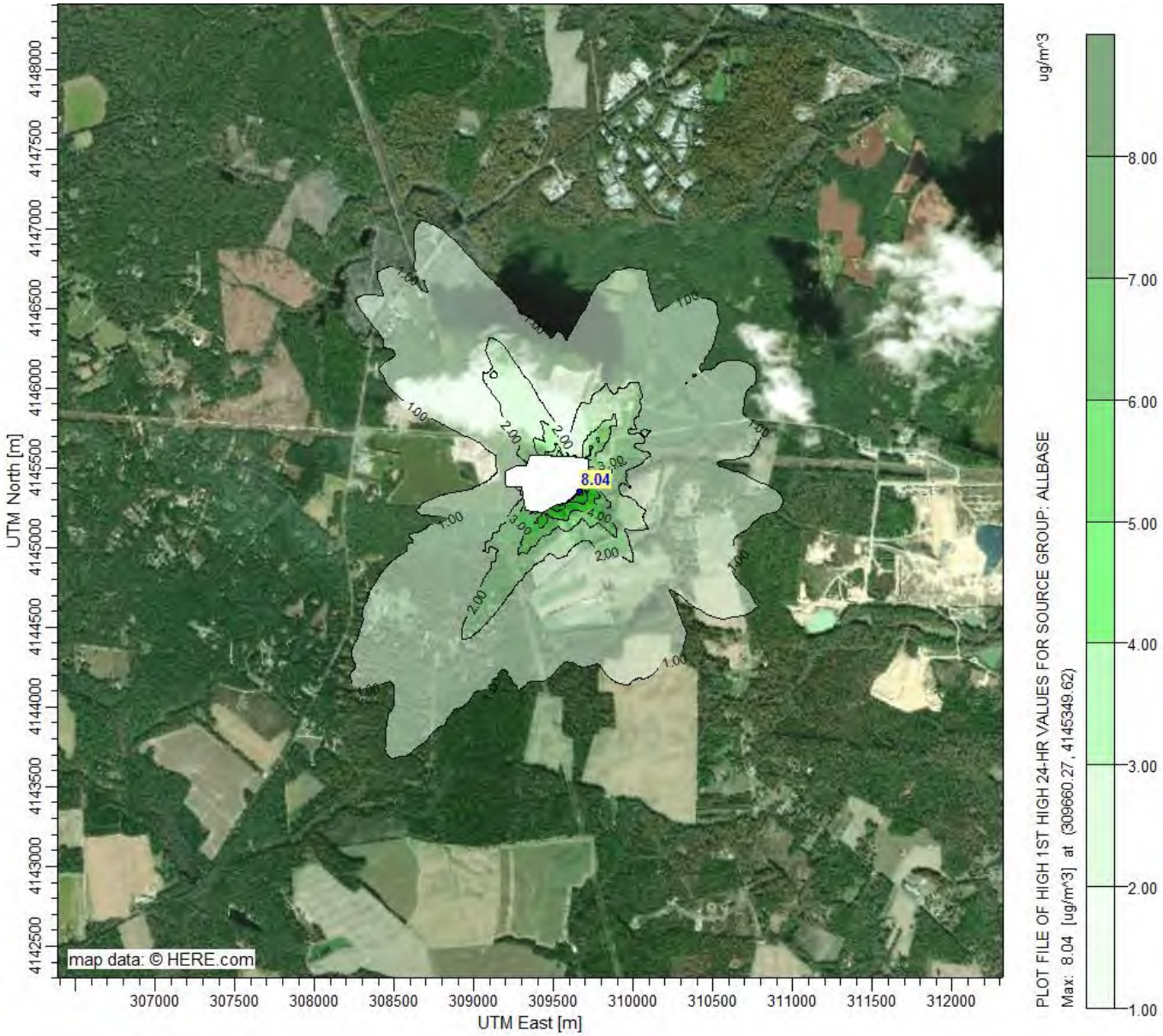

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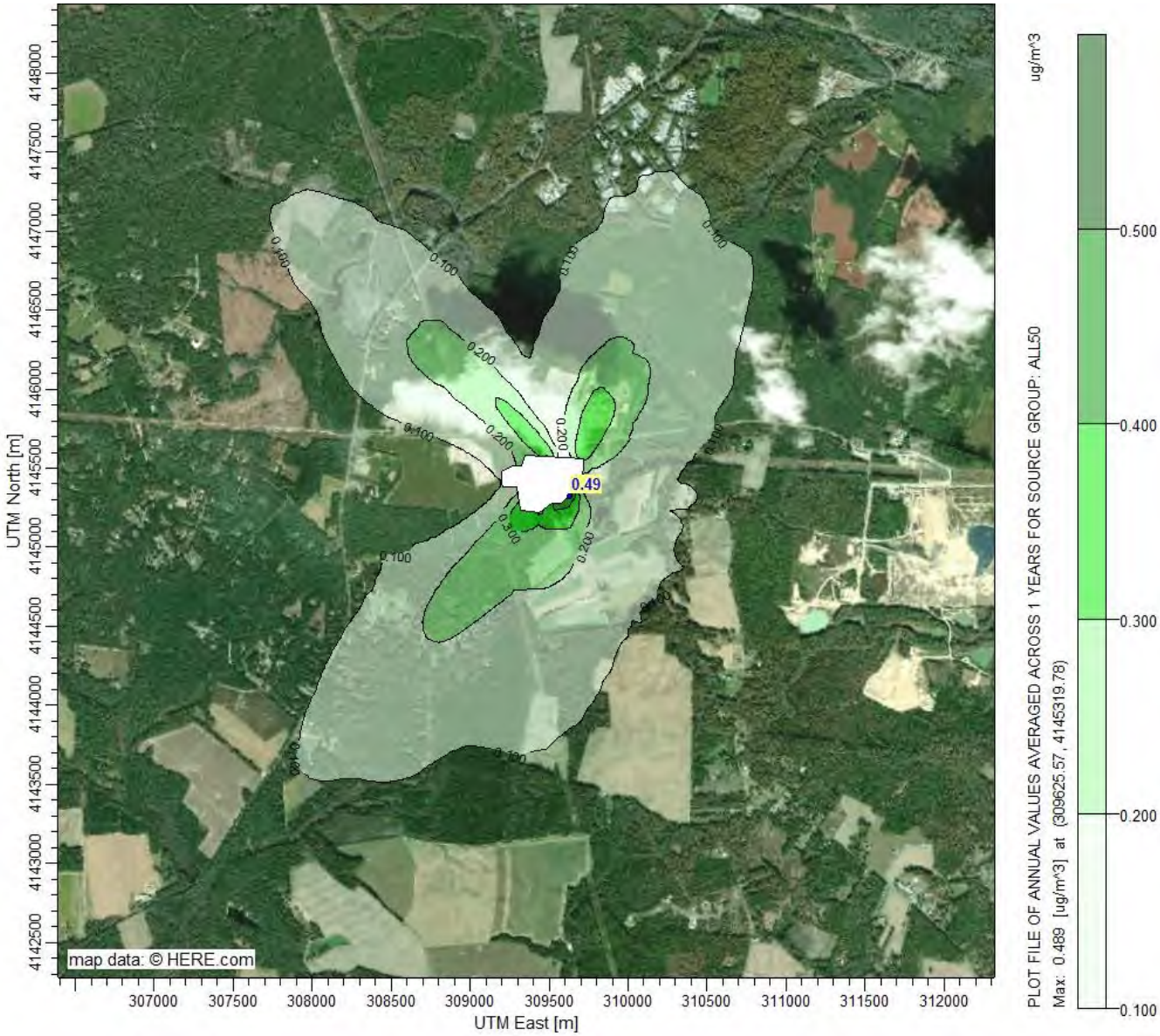

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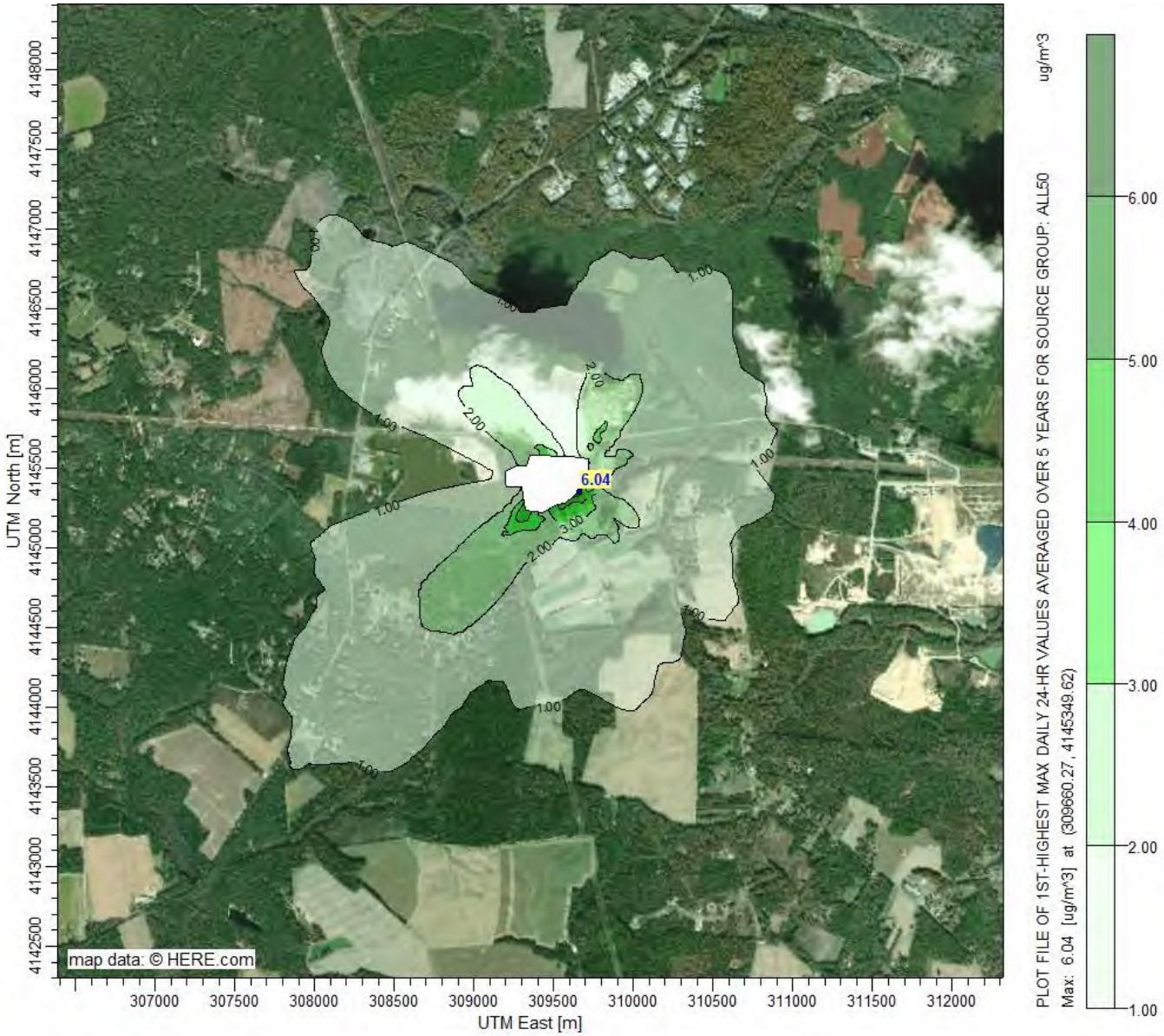

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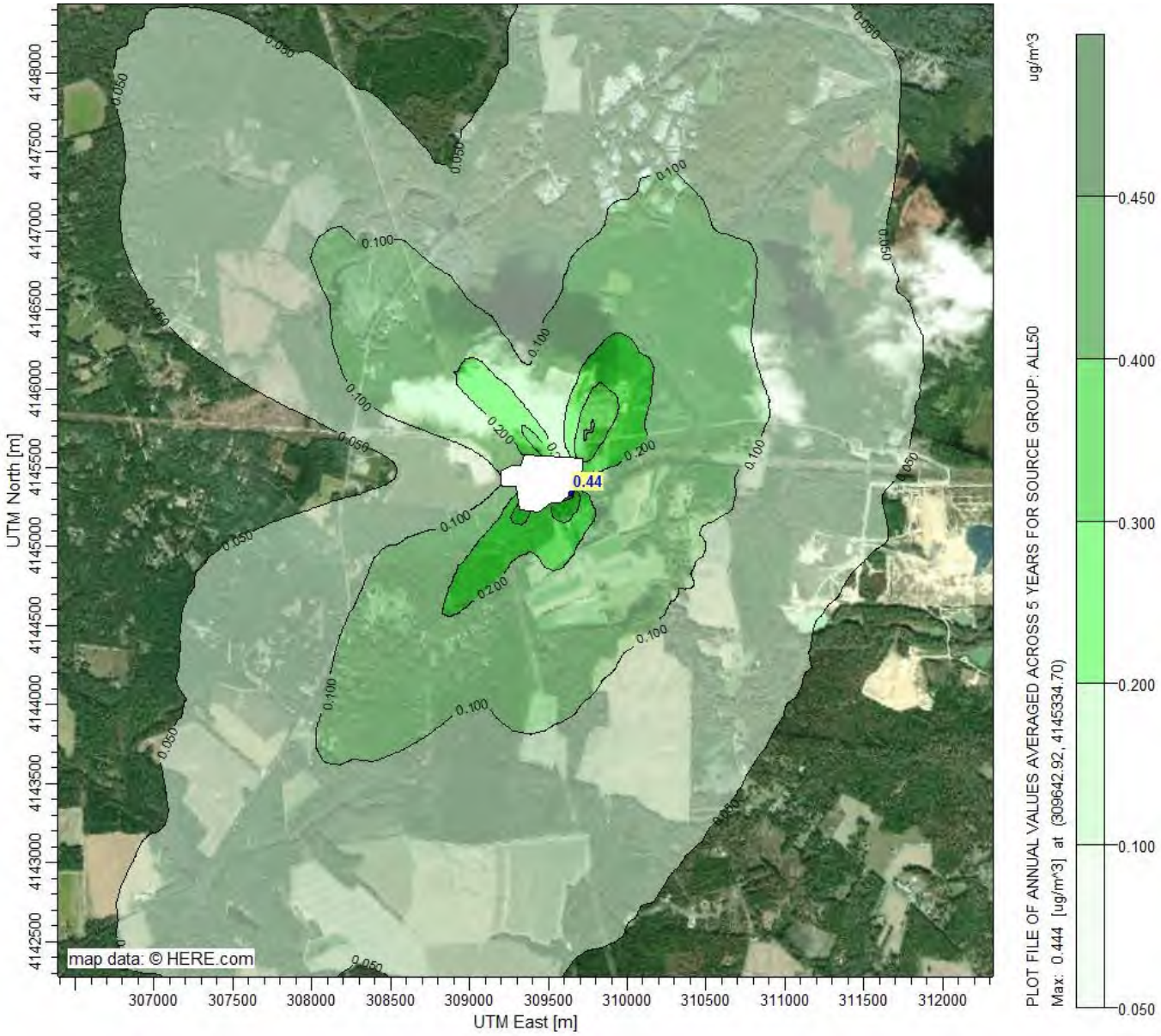
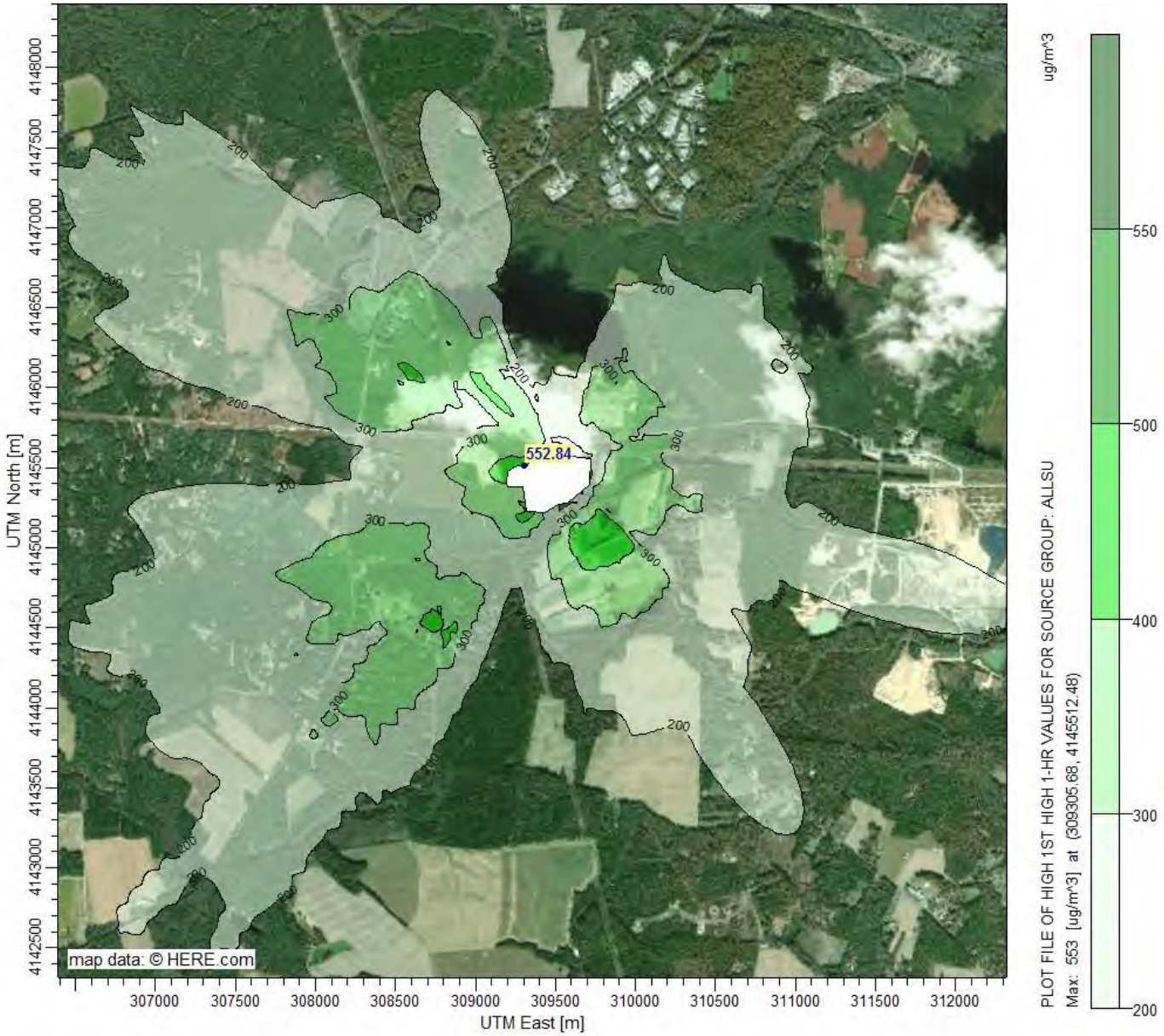
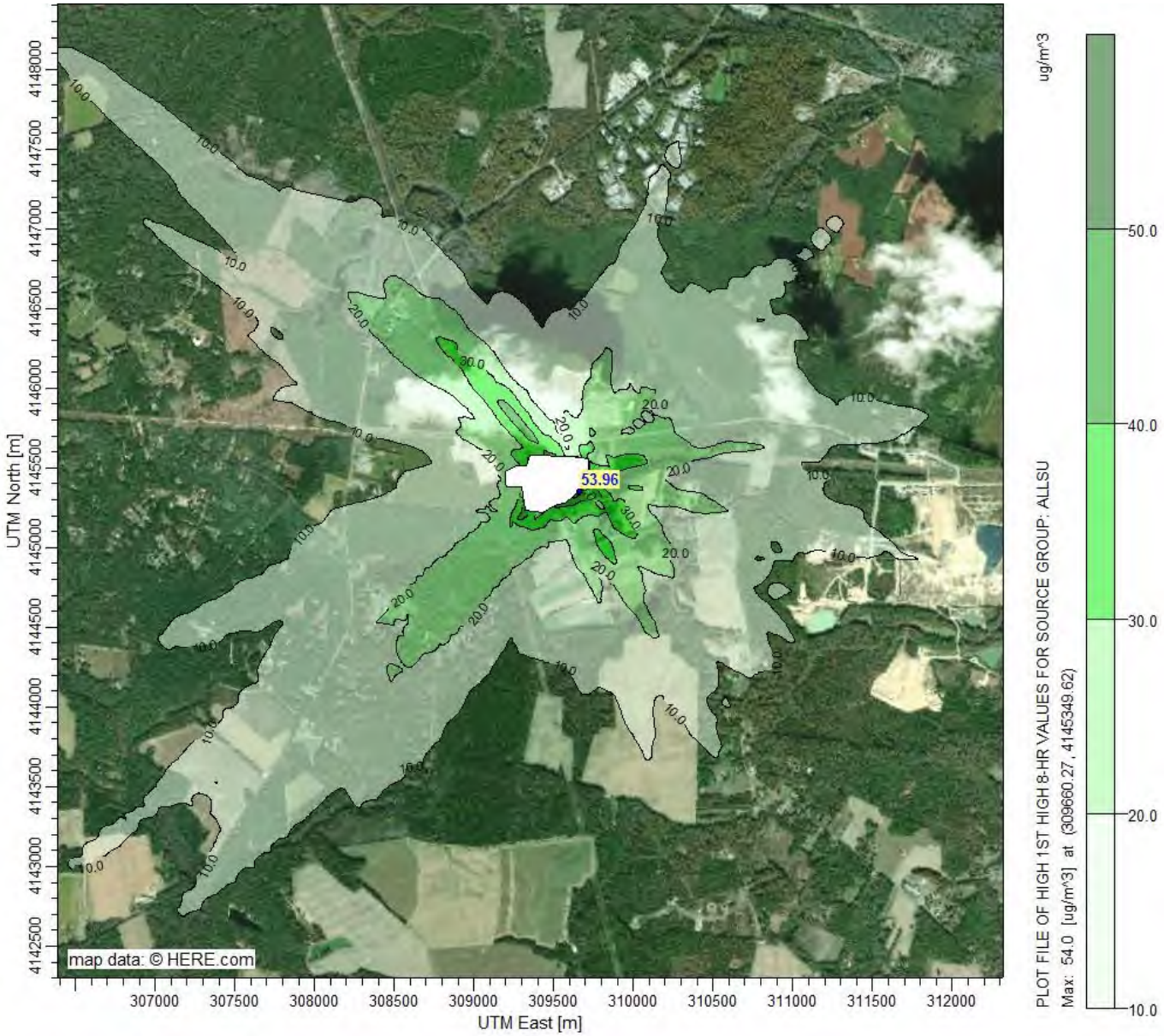


MHPS M501JAC Combustion Turbine – 1-hour CO SIL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