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Prepared for

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AIR QUALITY CONSTRUCTION PERMIT APPLICATION

DORCHESTER COMPRESSOR STATION
COUNTY ROAD S-18-37
ST. GEORGE, SOUTH CAROLINA

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Project Number GSC5940

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1. EXECUTIVE SUMMARY

Dominion Carolina Gas Transmission, LLC (DCG) is proposing to construct a new natural gas compressor station (facility) near St. George, Dorchester County, SC. The proposed facility will be outfitted with existing gas mover equipment currently located at the DCG's Southern Compressor Station. The primary emission sources to be located at the proposed facility include three simple-cycle natural gas-fired combustion turbines (D-1, D-2, and D-3), which are each part of a combustion turbine compressor set. DCG will also relocate certain ancillary equipment associated with the three units, including intake and exhaust systems. The compressors, driven by the combustion turbines, will be re-staged prior to their relocation to Dorchester. No impact in emissions from the compressors is anticipated as a result of restaging of these units. The purpose of this application is to request an air quality construction permit authorizing the installation of the D-1, D-2, and D-3 at the proposed facility pursuant to South Carolina Regulation (SC R.) 61-62.1, Section II.A. Applicable SCDHEC air quality construction permit application forms are included with this application as Appendix A.

Maximum potential emissions from the proposed facility have been estimated based on manufacturer's information and United States Environmental Protection Agency (EPA) AP-42 emission factors (see Appendix B). Two criteria pollutants, carbon monoxide (CO) and nitrogen oxides (NO_x), will be above the applicable Title V major source thresholds of 100 tons per year (tons/yr). The potential emissions from the proposed facility will be below Title V major source threshold for the remaining criteria pollutants, individual (10 tons/yr) and total (25 tons/yr) hazardous air pollutants (HAP), and greenhouse gases (GHG). The proposed facility will be a minor source with respect to the Prevention of Significant Deterioration (PSD) Program, codified in 40 CFR Part 52.21, as the potential emissions do not exceed the 250 tons/yr PSD major source threshold for any regulated New Source Review (NSR) pollutant.

2. PROJECT DESCRIPTION

The proposed facility is located near the community of St. George in Dorchester County, South Carolina. The approximate location of the facility is shown on a United States Geological Survey (USGS) 7.5-minute topographic quadrangle (see Figure 1). The Universal Transverse Mercator (UTM) coordinates of the facility are (approximately) 544.5 kilometers east and 3,676.7 kilometers north (Zone 17).

The primary purpose of the proposed facility is to increase pressure in the natural gas transmission pipelines passing through the facility. This will be accomplished using three simple-cycle natural gas-fired combustion turbine compressor sets. The activities at the proposed facility will generally fall under Standard Industrial Classification (SIC) code 4922 – *Natural Gas Transmission* – and North American Industry Classification System (NAICS) code 486210 – *Pipeline Transportation of Natural Gas*.

DCG is requesting an air quality construction permit from SCDHEC for the installation of the three natural gas-fired combustion turbine compressor sets at the proposed facility. Additionally, DCG proposes to install several emission units at the facility that are considered insignificant activities exempt from construction permitting requirements in accordance with SC R. 61-62.1, Section II. The emission units proposed to be constructed as a part of this project are summarized in the following tables.

Table 2-1: Dorchester Compressor Station Primary Emission Units

Equipment ID	Equipment Description	Manufacturer and Model	Rated Capacity (MMBtu/hr)[a]	Emission Point
D-1	Simple Cycle Combustion Turbine D-1	Solar Saturn 10	13.92	S-1
D-2	Simple Cycle Combustion Turbine D-2	Solar Saturn 10	13.92	S-2
D-3	Simple Cycle Combustion Turbine D-3	Solar Saturn 10	13.92	S-3

a. The listed capacity is the worst-case heat input at full-load operation based on a lower heating value (LHV) of 939.2 British thermal units per standard cubic foot (Btu/scf), an engine inlet temperature of 30 °F, and site elevation. Note that the rated capacity provided above reflects operation at the elevation of the proposed facility and therefore differs from the rated capacity listed in the Southern Title V Permit (TV-0080-0107).

Table 2-2: Dorchester Compressor Station Insignificant Activities

Equipment ID	Description	Basis for Exemption
IA-PD [a]	Pneumatic Devices	SC R. 61-62.1, Section II.B.2.h
IA-EG1	125-kW natural gas-fired emergency generator	SC R. 61-62.1, Section II.B.2.f
IA-ST1	165-gallon Lube Oil Storage Tank	SCDHEC Bureau of Air Quality (BAQ) Exemption List, Section B.5 (Oct. 2015)
IA-ST2	1,000-gallon Underground Oily Water Storage Tank	SC R. 61-62.1, Section II.B.2.h
IA-ST3	500-gallon Aboveground Condensate Storage Tank	SC R. 61-62.1, Section II.B.2.h
IA-ST4	20-gallon Safety-Kleen Parts Washer	SC R. 61-62.1, Section II.B.2.h
IA-FBC	Two (2) 0.045 MMBtu/hr Wall Mounted Catalytic Heaters and one (1) 0.075 MMBtu/hr Comfort Heating System	SC R. 61-62.1, Section II.B.2.b
IA-WSD	Wet Seal Degassing	SC R. 61-62.1, Section II.B.2.h
IA-BD	Blowdowns	SC R. 61-62.1, Section II.B.2.h
IA-EL	Equipment Leaks	SC R. 61-62.1, Section II.B.2.h

a. IA-PD covers all pneumatic devices at the facility, including pneumatic auxiliary oil pumps and starters.

3. EMISSIONS ESTIMATION

Potential emission of regulated air pollutants from the proposed facility have been estimated as described in the following sections. Potential emissions from the proposed facility are summarized in Table 3-1.

Table 3-1: Dorchester Compressor Station Facility-Wide Estimated Potential Emissions

Pollutant	Post-Construction Potential Emissions (tons/yr)
NO_x	109.8
CO	178.6
SO_2	5.7E-01
VOC	13.5
PM	1.1
PM_{10}	1.1
$PM_{2.5}$	1.1
CO_2	19,730
CH_4	119.3
N_20	3.8E-02
GHG (mass)	19,850
GHG (CO_2e)	22,724
Hexane	0.32
Total HAP	0.53

3.1 Estimation of Potential Emissions from Primary Emission Units

3.1.1 Combustion Turbines

The proposed primary emission units include D-1, D-2, and D-3, Solar Saturn 10-T1000 natural gas-fired simple-cycle combustion turbines which will exhaust through stacks S-1, S-2, and S-3, respectively. Each combustion turbine is part of a combustion turbine compressor set, including a combustion turbine, a compressor, and other ancillary

equipment such as a pneumatic starter and lube oil pump. D-1 through D-3 have a manufacturer-predicted heat input rate of 13.92 million British thermal units per hour (MMBtu/hr) based the following operational data: (i) full-load operation; (ii) an inlet air temperature of 30°F; and (iii) a fuel LHV of 939.2 Btu/scf (see Appendix D).

Emissions from D-1 through D-3 are associated with the combustion of natural gas and include criteria pollutants, HAP, and GHG. Potential emissions of NO_x, CO, and volatile organic compounds (VOC) from the combustion turbines were estimated using manufacturer-provided hourly emission rate data (see Appendix D).[1] Potential emissions of other criteria pollutants and HAP were estimated using emission factors from EPA's *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, Fifth Edition* (AP-42), Section 3.1 for stationary gas turbines. Potential emissions of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) were estimated using emission factors for natural gas combustion from 40 CFR Part 98, Subpart C, Tables C-1 and C-2, respectively. Emissions estimates are included with this application as Appendix B.

Estimated emissions of NO_x, CO, and VOC from startup (SU) and shutdown (SD) events were provided by the manufacturer (Solar). Hourly and annual emission rates for these pollutants were calculated both including and excluding startup (SU) and shutdown (SD) events. Hourly emissions estimates inclusive of SU/SD emissions assume one SU and SD event per hour, ten minutes per SU and three minutes per SD event, and full-load operation for the remainder of the hour. Annual emissions estimates inclusive of SU/SD emissions assume 180 SU and 180 SD events per year[2] (each event occurring over a period of ten and three minutes, respectively), with full-load operations occurring for the remainder of the 8,760 hours. Maximum hourly and annual potential emissions estimates for NO_x, CO, and VOC are based on the greater of estimates including SU and SD emissions and those excluding SU and SD emissions (see Appendix B).

[1] The manufacturer provided an hourly emission rate for unburned hydrocarbons (UHC). It was conservatively assumed that 20 percent of UHC emissions are VOC.

[2] Expected maximum annual number of startup and shutdown events.

3.2 Estimation of Emissions from Insignificant Activities

This section describes the emission estimation methodologies for the sources that are considered insignificant activities exempt from construction permitting requirements (see Table 2-2).

3.2.1 Insignificant Fuel Combustion Equipment

DCG is proposing to install two 0.045 MMBtu/hr (or less) natural gas-fired catalytic heaters at the facility as a part of this project. Additionally, DCG is proposing to install a 0.075 MMBtu/hr (or less) natural gas-fired comfort heating system for use in the proposed office building. These fuel combustion sources are collectively referred to herein as insignificant activity ID IA-FBC. Each fuel combustion source under IA-FBC will have a rated heat input capacity less than 10 MMBtu/hr and will only fire virgin fuels and are therefore exempt from construction permitting requirements per SC R. 61-62.1, Section II.B.2.b.

The combustion of natural gas generates emissions of criteria pollutants, HAP, and GHG. Potential emissions of these pollutants from the heaters were estimated using AP-42 Section 1.4 emission factors for natural gas combustion and engineering calculations (see Appendix B).

3.2.2 Natural Gas-Fired Emergency Generator

DCG is proposing to install one 125-kilowatt (kW) natural gas-fired reciprocating internal combustion engine (RICE), insignificant activity ID IA-EG1, at the facility for emergency purposes. As an emergency generator with a rated capacity less than or equal to 150 kW, IA-EG1 will be exempt from air construction permitting requirements per SC R. 61-62.1, Section II.B.2.f.

Potential emissions of criteria pollutants, HAP, and GHG from IA-EG1 were primarily estimated using emission factors from AP-42, Section 3.2 and a maximum of 500 hours[3] of operation per year. A conservative brake-specific fuel consumption of 12,000 British thermal units per horsepower-hour was used to convert horsepower to hourly

[3] The September 6, 1995 memorandum from John S. Seitz (EPA Office of Air Quality Planning and Standards) entitled *Calculating Potential to Emit (PTE) for Emergency Generators* indicates 500 hours per year should be used to calculate PTE from emergency generators.

heat input, where needed. Emission factors for NO_x, CO, and VOC were taken from 40 CFR Part 60, Subpart JJJJ, Table 1. Potential emissions estimates are included with this application as Appendix B.

3.2.3 Storage Vessels

3.2.3.1 Lube Oil Storage Tank

DCG is proposing to install a 165-gallon aboveground lube oil storage tank (insignificant activity ID IA-ST1) at the facility as a part of this project. Given that IA-ST1 will have a total storage capacity equal to or less than 5,042,000 gallons and will be used to store lube oil, it is exempt from construction permitting requirements in accordance with SC R. 61-62.1, Section II.B.3 and SCDHEC BAQ Air Quality Exemption List (October 2015), Section B.5.iv. Potential VOC emissions from IA-ST1 have been estimated using the EPA TANKS model, version 4.09d (see Appendix B).

3.2.3.2 Underground Oily Water Storage Tank

DCG is proposing to install a 1,000 gallon underground oily water storage tank (insignificant activity ID IA-ST2) at the facility as a part of this project. Oil vapors that condense in the oil reservoir vent lines associated with D-1 through D-3 will be routed to this tank for storage. IA-ST2 will be exempt from permitting requirements pursuant to SC R. 61-62.1, Section II.B.2.h since the total uncontrolled emission rate from the tank will be less than five tons/yr for particulate matter (PM), sulfur dioxide (SO_2), NO_x, and CO and less than 1,000 pounds per month (lbs/month) for VOC. Potential VOC emissions from IA-ST2 have been estimated using the EPA TANKS model, version 4.09d (see Appendix B).

3.2.3.3 Aboveground Condensate Storage Tank

DCG is proposing to install a 500-gallon aboveground condensate storage tank (insignificant activity ID IA-ST3). IA-ST3 will be used to store condensate that is removed from natural gas passing through the facility by the scrubbers. Since the total uncontrolled emission rate from this tank will be less than five tons/yr for PM, SO_2, NO_x, and CO, and less than 1,000 lbs/month for VOC, the tank is exempt from construction permitting requirements per SC R. 61-62.1, Section II.B.2.h. Potential VOC emissions from IA-ST3 have been estimated using the EPA TANKS model, version 4.09d (see Appendix B).

3.2.3.4 Safety-Kleen Parts Washer

DCG is proposing to install a 20-gallon Safety-Kleen parts washer (insignificant ID IA-ST4). Since the total uncontrolled emission rate from this tank will be less than five tons/yr for PM, SO_2, NO_x, and CO, and less than 1,000 lbs/month for VOC, the tank is exempt from construction permitting requirements per SC R. 61-62.1, Section II.B.2.h. Potential VOC emissions from IA-ST4 have been estimated assuming a cleaning solvent VOC content of 100%, a solvent density of 7.9 pounds per gallon,[4] and that 50% of solvent is subject to evaporative losses in the time between purchase and disposal of the solvent (see Appendix B).

3.2.4 Natural Gas Venting

The equipment discussed in this section will have the potential to emit natural gas into the atmosphere. Venting of natural gas will result in emissions of GHG (CO_2 and CH_4), VOC, and HAP, components of natural gas. Natural gas venting emission estimates have been performed using the average of natural gas composition data from calendar year 2013 through 2014 based on DCG's gas quality report.[5] The DCG gas quality report provides information on the volume fraction of species containing six or more carbon atoms (hexane+). For the purposes of estimating HAP emissions from natural gas venting, it has been conservatively assumed that all such species are hexane, a HAP.

3.2.4.1 Pneumatic Devices (PD)

The proposed combustion turbine compressor sets will be equipped with a natural gas-driven pneumatic auxiliary oil pump and a natural gas-driven pneumatic starter.[6] Additionally, several miscellaneous natural-gas driven pneumatic devices (PD) will be installed at the facility for process control (e.g., pneumatic shuttle valves, pneumatic control valves, etc.). For the purpose of this construction permit application, DCG assumed a total of 38 natural gas-driven PDs (collectively insignificant activity ID IA-PD) will be installed at the facility. The installation of PDs at the proposed facility is

[4] Assumption based on MSDS for Safety-Kleen Immersion Cleaner and Cold Parts Cleaner: http://safety-kleen.com/File%20Library/msds/82411-rev-10-12.pdf

[5] DCG daily average gas quality report: https://ebb.carolinagastransmission.com/InformationalPostings/GasQuality/Report.aspx, accessed 3 December 2015.

[6] DCG may replace natural gas-driven pneumatic starters and pumps with electric-driven equipment.

exempt from construction permitting requirements in accordance with SC R. 61-62.1, Section II.B.2.h because total uncontrolled VOC emissions from pneumatic devices at the facility will be less than 1,000 lbs/month.

During operation, natural gas-driven intermittent-bleed PDs vent natural gas to the atmosphere, resulting in emissions of GHG (CO_2 and CH_4) and VOC. Emissions of GHG and VOC from PDs at the facility have been calculated using methodologies outlined in the applicable subparts of 40 CFR Part 98 and engineering estimates based on best available data (see Appendix B).

3.2.4.2 Wet Seal Degassing (WSD)

Each proposed combustion turbine compressor set will be equipped with a high-pressure oil seal ("wet seal") system composed of a seal oil pump, wet seals, and an oil/gas separator. During wet seal system operation, oil from the reservoir is pressurized by the seal oil pump and conveyed to the wet seals where the pressurized seal oil is used to keep natural gas from escaping the compressor. While in the wet seals, the seal oil may become contaminated with natural gas due to the seal oil absorbing natural gas on the inboard side of the compressor. Contaminated seal oil leaving the wet seals is routed through an oil/gas separator, after which recovered natural gas is sent back to the suction side of the compressor and recovered seal oil is routed to the oil reservoir. Due to inefficiencies in the oil/gas separation process, some of the seal oil may still contain natural gas when it enters the oil reservoir. This gas may flash off in the oil reservoir and be emitted to the atmosphere through the oil reservoir vent, resulting in emissions of GHG (CO_2 and CH_4) and VOC. Emissions from wet seal degassing at the proposed facility are collectively referred to herein as insignificant activity ID IA-WSD. Since potential emissions of VOC attributable to IA-WSD will be below 1,000 lbs/month, the installation of the proposed WSD systems is exempt from construction permitting requirements in accordance with SC R. 61-62.1, Section II.B.2.h.

Emissions of GHG from WSD associated with the proposed combustion turbine compressor sets have been calculated using the methodologies incorporated in EPA's screening tool for onshore natural gas transmission compression.[7] VOC emissions were estimated using the EPA's screening tool along with assumptions regarding the VOC

[7] The EPA's screening tool can be found at:
http://www.epa.gov/climate/ghgreporting/help/tool2014/documents/SubW_Screening_Tool_Transmission_2014.xls

content of natural gas (see Appendix B). For the purpose of calculating emissions, it was assumed that the high-pressure oil seal system on each proposed combustion turbine compressor set will recover 99 percent[8] of the natural gas from the contaminated seal oil.

3.2.4.3 Blowdowns (BD)

There are several scenarios during which a blowdown event may occur at the proposed facility, including: 1) blowdown of the compressors during compressor shutdown; 2) blowdown of the fuel supply system during maintenance; and, 3) blowdown of the facility during an emergency shutdown (ESD) event. Emissions from blowdown events at the proposed facility are collectively referred to herein as insignificant ID IA-BD. Per SC R. 61-62.1, Section II.B.2.h, the emissions associated with IA-BD are exempt from construction permitting requirements because total uncontrolled VOC emissions from IA-BD will be below 1,000 lbs/month.

During each blowdown event, natural gas is vented to the atmosphere resulting in emissions of GHG (CO_2 and CH_4) and VOC. Emissions from blowdown events were estimated using methodologies outlined in the applicable subparts of 40 CFR Part 98, and engineering estimates based on best available data (see Appendix B).

3.2.4.4 Equipment Leaks (EL)

Leaking components, such as valves, connectors, open-ended lines, pressure relief valves, and meters, vent natural gas to the atmosphere, thus resulting in emissions of GHG (CO_2 and CH_4) and VOC. Emissions associated with leaks from components at the proposed facility are collectively referred to herein as insignificant activity ID IA-EL. Potential emissions of VOC from IA-EL will be below 1,000 lbs/month. As such, IA-EL is exempt from permitting requirements per SC R. 61-62.1, Section II.B.2.h.

Emissions from equipment leaks at the facility have been estimated based on methodologies outlined in applicable subparts of 40 CFR Part 98, engineering estimates based on best available data, and results of leak detection events conducted other DCG compressor stations and a 20 percent contingency factor (see Appendix B).

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[8] http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/smith.pdf

4. REGULATORY APPLICABILITY ANALYSIS AND REQUIREMENTS

An air quality regulatory applicability analysis has been conducted for the facility. The applicability of Federal and state regulations is discussed in the following subsections.

4.1 Permitting Programs

4.1.1 Prevention of Significant Deterioration

The Federal PSD Program, codified in 40 CFR Part 52.21, requires any new major stationary source of air pollution, and existing major source undergoing a major modification, to obtain a major source air construction permit before commencing construction. The PSD Program applies to new facilities if potential emissions from the facility exceed applicable major source thresholds. For facilities that are not one of the 28 source categories listed in §52.21(b)(1)(i)(a), such as natural gas compressor stations, the major source threshold is 250 tons/yr of any regulated NSR pollutant. Based on a Supreme Court ruling[9], GHG emissions are only considered during PSD review when a facility must undergo PSD review for another pollutant and potential emissions of GHG exceed a *de minimis* threshold.

The proposed facility will not have the potential to emit a regulated NSR pollutant in amounts greater than the applicable PSD major source thresholds. As such, the facility will not be subject to the PSD Program.

4.1.2 Nonattainment New Source Review (NNSR)

Dorchester County is listed as either being in attainment or unclassifiable status[10] with all National Ambient Air Quality Standards (NAAQS). Therefore, the provisions of the NNSR Program do not apply to the facility.

4.1.3 Title V (Part 70) Operating Permit

The Federal Title V operating permit is established in 40 CFR Part 70. A Title V operating permit is required for facilities that meet the definition of a major source

[9] *Utility Air Regulatory Group v. Environmental Protection Agency et al* decided June 23, 2014. http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf.

[10] 40 CFR §81.341.

under §70.2. South Carolina has incorporated the Federal Part 70 program at SC R. 61-62.70. Because potential emissions of CO and NO_x from the facility will be greater than 100 tons/yr, the proposed facility will be considered a major source under the Title V Program. Potential emissions of all other regulated pollutants from the proposed facility will be below applicable Title V major source thresholds.

SC R. 61-62.70.5(a)(1)(ii) requires an initial Title V application within twelve months of after commencing operations of a Title V major source. An initial Title V application will be submitted in a timely manner under the Title V Operating Permit Program.

4.1.4 South Carolina Permitting

South Carolina Regulation 61-62.1 requires a facility to obtain a construction permit, unless otherwise exempt from permitting. This permit application is being submitted to request a construction permit for the equipment to be located at the facility that is not otherwise exempt from construction permitting requirements.

4.2 New Source Performance Standards

Federal New Source Performance Standards (NSPS), codified in 40 CFR Part 60, establish pollutant emission limits and monitoring, reporting, and recordkeeping requirements for various emission sources based on source type and size. The NSPS apply to new, modified, or reconstructed sources. South Carolina has incorporated the Federal NSPS by reference at SC R. 61-62.60. The potentially applicable NSPS are described below.

4.2.1 40 CFR Part 60, Subpart A – NSPS General Provisions

Due to the operation of equipment subject to individual NSPS, the facility is subject to the applicable requirements of 40 CFR Part 60, Subpart A, *General Provisions* (NSPS General Provisions).

4.2.2 40 CFR Part 60, Subparts D, Db, and Dc – NSPS for Steam Generating Units

40 CFR Part 60, Subparts D, Db, and Dc cover steam-generating units. DCG is not proposing to install any steam generating units at the facility as a part of this project. As such, Subparts D, Db, and Dc do not apply.

4.2.3 40 CFR 60, Subpart K, Ka, and Kb – NSPS for Volatile Organic Liquid Storage Vessels

40 CFR Part 60, Subparts K, Ka, and Kb apply to volatile organic liquids (VOL) storage vessels of certain sizes that have been constructed, reconstructed, or modified during various time periods. Subpart K applies to storage vessels constructed, reconstructed, or modified prior to 1978 and Subpart Ka applies to storage vessels constructed reconstructed, or modified prior to 1984. Both Subpart K and Ka apply to storage vessels with a capacity greater than 40,000 gallons. Subpart Kb applies to storage vessels with a capacity greater than or equal to 75 cubic meters (m^3), or approximately 19,813 gallons, that are used to store VOL for which construction, reconstruction, or modification commenced after July 23, 1984. The VOL storage vessels at the facility have capacities less than the 40,000-gallon applicability threshold for Subparts K and Ka, and less than the 19,813-gallon applicability threshold for Subpart Kb. As such, Subparts K, Ka, and Kb do not apply.

4.2.4 40 CFR Part 60, Subpart GG – NSPS for Stationary Gas Turbines

40 CFR Part 60, Subpart GG (Subpart GG) applies to stationary gas turbines with a heat input at peak load greater than or equal to 10 MMBtu/hr, and that were constructed, modified, or reconstructed after October 3, 1977[11]. As previously discussed, units D-1, D-2, and D-3 are being transferred to the proposed facility from DCG's Southern Compressor Station (Title V Operating Permit No. TV-0080-0107). With the exception of unit CT13, which is not being relocated as a part of this project, all of the combustion turbines at the Southern Compressor Station were initially constructed prior to October 3, 1977 and have not been modified or reconstructed. Additionally, the combustion turbines that will be relocated to the proposed facility will not be modified or reconstructed as a part of their relocation. Therefore, D-1, D-2, and D-3 are not subject to Subpart GG.

4.2.5 40 CFR Part 60, Subpart IIII – Stationary Compression Ignition Engines

40 CFR Part 60, Subpart IIII (Subpart IIII) applies to compression ignition (CI) internal combustion engines (ICE) constructed, modified, or reconstructed after various applicability dates, the earliest of which is July 11, 2005. Any stationary CI ICE for

[11] §60.330(a) and §60.330(b).

which construction, modification, or reconstruction commences after July 11, 2005 is potentially subject to this regulation. IA-EG1 will be a spark ignition (SI) ICE, not a CI ICE. Therefore, IA-EG1 will not subject to this Subpart IIII.

4.2.6 40 CFR Part 60, Subpart JJJJ – NSPS for Stationary Spark Ignition Internal Combustion Engines

40 CFR Part 60, Subpart JJJJ (Subpart JJJJ) applies to emergency stationary SI ICE with a maximum engine power greater than 19 kW that are manufactured after January 1, 2009. IA-EG1 will be manufactured after January 1, 2009 and have a maximum engine power greater than 19 kW. Therefore, IA-EG1 will be subject to Subpart JJJJ per §60.4230(a)(4)(iv). On May 1, 2015, the US Court of Appeals for the DC Circuit reversed certain provisions of Subpart JJJJ related to the 100-hour-per-year limit for maintenance checks and readiness testing.[12] These provisions have been remanded to EPA for further consideration. The regulatory analysis presented in this section uses the latest published version of Subpart JJJJ as its basis.

DCG will purchase an emergency generator that meets the standards in Subpart JJJJ, Table 1, as required by §60.4233(e). Per §60.4243(b)(1), the emergency generator will be certified according to the procedures in Subpart JJJJ for the same model year. In accordance with §60.4243(a)(1), compliance with Subpart JJJJ is demonstrated by: (i) operating and maintaining each emergency generator in accordance with the manufacturer's emission-related instructions and (ii) keeping records of maintenance conducted. In order for the engine to be considered an emergency stationary ICE under Subpart JJJJ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs §60.4243(d)(1) through (3) of this section, is prohibited. Per §60.4243(d)(1) and (2), there is no time limit on the use of emergency stationary ICE in emergency situations and it can be operated for a maximum of 100 hours per calendar year for maintenance checks and readiness testing.

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[12] *Delaware Department of Natural Resources and Environmental Control v. Environmental Protection Agency et al* decided May 1, 2015.
http://www.cadc.uscourts.gov/internet/opinions.nsf/2E87E0199203E71B85257E3800500091/$file/13-1093-1550129.pdf

4.2.7 40 CFR Part 60, Subpart KKKK – NSPS for Stationary Combustion Turbines

40 CFR Part 60, Subpart KKKK (Subpart KKKK) addresses requirements for stationary gas turbines with a heat input at peak load greater than or equal to 10 MMBtu/hr, which commenced construction, modification, or reconstruction after February 18, 2005, per §60.4305(a). As previously mentioned, the proposed combustion turbines were originally constructed prior to October 3, 1977 and have not been modified or reconstructed, nor will they be modified or reconstructed as a part of their relocation to the proposed facility. As such, Subpart KKKK does not apply to D-1, D-2, or D-3.

4.2.8 40 CFR Part 60, Subpart OOOO – NSPS for Crude Oil and Natural Gas Production, Transmission and Distribution

40 CFR Part 60, Subpart OOOO (Subpart OOOO) applies to certain onshore affected facilities listed in paragraphs (a) through (g) of 40 CFR 60.5365 used in the oil and natural gas production, transmission, and distribution industries that were constructed, reconstructed, or modified after August 23, 2011. The combustion turbine compressor sets are not one of the onshore affected facilities listed in paragraphs (a) through (g) of §60.5365; thus they are not covered under Subpart OOOO. The proposed storage vessels to be located at the facility are the only equipment that could potentially be covered under Subpart OOOO. However, because potential emissions from each storage vessel will be less than six tons/yr of VOC, they are not considered affected sources under Subpart OOOO, per §60.5365I.

4.2.9 Proposed 40 CFR Part 60, Subpart OOOOa – Amended NSPS for Crude Oil and Natural Gas Facilities

The EPA is proposing to amend the NSPS for crude oil and natural gas facilities.[13] The amended NSPS is proposed to be codified at 40 CFR Part 60, Subpart OOOOa (Subpart OOOOa) and will apply to certain onshore affected facilities that were constructed, reconstructed, or modified after September 18, 2015. Based on this applicability date, it is anticipated that the project will be required to comply with the requirements of

[13] 80 FR 56593, September 18, 2015

Subpart OOOOa, if finalized. The potential applicability of proposed Subpart OOOOa to the project is summarized in the following table:[14]

Table 4-1: Potential Applicability of NSPS OOOOa

NSPS OOOOa Affected Facility	Proposed Citation	Potential NSPS OOOOa Applicability
Centrifugal Compressors Using Wet Seals	§60.5365a(b)	Proposed centrifugal compressors associated with D-1, D-2, and D-3.
Reciprocating Compressors	§60.5365a(c)	Not applicable. No reciprocating compressors will be constructed, modified, or reconstructed as a part of this project.
Each continuous bleed natural gas-driven pneumatic controller	§60.5365a(d) (1)	Each new continuous bleed natural gas-driven pneumatic controller.
Each storage vessel affected facility with potential emissions greater than six tons/yr	§60.5365a(e)	Not applicable. Potential VOC emissions from the storage vessels will be less than six tpy.
Each natural gas-driven pneumatic pump	§60.5365a(h) (2)	Each new natural gas-driven pneumatic pump.
The collection of all fugitive emission components	§60.5365a(j)	All fugitive emission components at the proposed facility will be subject to the fugitive emission standards.

Uncertainty remains with respect to whether or not Subpart OOOOa will be finalized, or what the final requirements of Subpart OOOOa will entail. Based on the proposed language, Subpart OOOOa will impose emission reduction requirements beyond those required by Subpart OOOO, including: a 95 percent reduction in VOC and CH_4 emissions from centrifugal compressor WSD; the use of low-bleed pneumatic controllers; a 95 percent reduction in VOC and CH_4 emissions from pneumatic pumps (only if an emission control device is already on site); and the implementation of a periodic leak detection and repair program. The facility will comply with the applicable provisions of Subpart OOOOa if and when it becomes final.

[14] Affected facilities covered by proposed §60.5365a(a), §60.5365a(d) (2), §60.5365a(f), §60.5365a(g), §60.5365a(h) (1), and §60.5365a(i) are omitted from this summary because they are specific to well sites, i.e., hydraulically fractured or refractured wells, and/or natural gas processing plants.

4.2.10 Non-Applicability of Other NSPS

NSPS are developed for particular industrial source categories. The applicability of a particular NSPS to a facility can be readily ascertained based on the industrial source category covered. Other than the above-listed Subparts specifically identified as applicable, other NSPS are categorically not applicable to the facility.

4.3 National Emission Standards for HAP

National Emissions Standards for Hazardous Air Pollutants (NESHAP), codified in 40 CFR 61 and 63, regulate HAP emissions from various affected sources. South Carolina has incorporated by reference the NESHAP from 40 CFR 61 and 40 CFR 63 at SC R. 61-62.61 and SC R. 61-62.63, respectively. Based on the type of operations at the proposed facility and the type of HAP that will be emitted, no applicable 40 CFR 61 regulations apply to the project. This section identifies and discusses the NESHAP codified in 40 CFR Part 63 that potentially apply to the project.

Note that the proposed facility will be an area source (i.e., not a major source) of HAP as defined in 40 CFR 63.2. Potential emissions of each individual HAP will be less than 10 tons/yr and total HAP emissions will be less than 25 tons/yr.

4.3.1 40 CFR Part 63, Subpart A – NESHAP General Provisions

Due to its operation of equipment subject to an individual NESHAP, the facility is subject to the applicable requirements of 40 CFR Part 63 Subpart A, *General Provisions*.

4.3.2 40 CFR Part 63, Subpart HH – NESHAP for Oil and Natural Gas Production Facilities

40 CFR Part 63, Subpart HH (Subpart HH) applies to dehydration units located at natural gas production facilities that are major or area sources of HAP as defined in §63.761. The proposed facility is not a natural gas production facility nor will it operate dehydration units; therefore, Subpart HH does not apply.

4.3.3 40 CFR Part 63, Subpart HHH – NESHAP for Natural Gas Transmission and Storage Facilities

The provisions of 40 CFR Part 63, Subpart HHH (Subpart HHH) apply to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of HAP emissions as defined in §63.1271. Specifically, Subpart HHH applies to glycol dehydration units at natural gas transmission and storage facilities. The proposed facility meets the definition of "facility" under Subpart HHH. However, Subpart HHH is not applicable given that the facility will be a minor source of HAP. Additionally, glycol dehydration units are not proposed to be installed as a part of this project.

4.3.4 40 CFR Part 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines

40 CFR Part 63, Subpart YYYY (Subpart YYYY) applies to stationary combustion turbines located at major sources of HAP constructed after January 14, 2003. Subpart YYYY will not apply to the project because the proposed facility will be a minor source of HAP.

4.3.5 40 CFR Part 63, Subpart ZZZZ – NESHAP for Reciprocating Internal Combustion Engines

40 CFR Part 63, Subpart ZZZZ (RICE MACT) establishes emission and operating limitations for HAP emitted from stationary RICE located at major and area sources of HAP as well as establishes requirements to demonstrate compliance with the applicable emissions limitations. The RICE MACT was published in the Federal Register on June 15, 2004 with an effective date of June 12, 2006. It has been revised and/or updated several times since June 15, 2004, with the latest final rule being issued on January 1, 2013. Additionally, on September 5, 2013, EPA announced further reconsideration of certain issues addressed in the RICE MACT. The issues to be reconsidered were primarily related to emergency engines. However, on August 15, 2014, EPA published a notice in the Federal Register announcing it would not propose any changes at that time.[15] On May 1, 2015, the US Court of Appeals for the DC Circuit reversed certain

[15] 79 FR 48072.

portions of the RICE MACT and remanded them to EPA for further consideration.[16] The regulatory analysis presented in this section uses the RICE MACT Final Rule published on January 1, 2013 as its basis.

The proposed emergency generator, IA-EG1, is considered an affected source under the RICE MACT. Because IA-EG1 will be constructed after June 12, 2006 and be located at an area source of HAP, it is considered a new RICE. As such, compliance with the RICE MACT is demonstrated by complying with the applicable provisions of Subpart JJJJ, per §63.6590(c).

4.3.6 40 CFR Part 63, Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

40 CFR Part 63, Subpart DDDDD (Subpart DDDDD) applies to industrial, commercial, and institutional boilers and process heaters of various sizes and fuel types that are located at major sources of HAP. The proposed facility is an area source of HAP and the only heaters at the facility will be used for space heating. Units used for comfort heat or space heat are specifically excluded from the definition of process heaters under §63.7575; therefore, Subpart DDDDD does not apply.

4.3.7 40 CFR Part 63, Subpart JJJJJJ – NESHAP for Industrial, Commercial, and Institutional Boilers at Area Sources

40 CFR Part 63, Subpart JJJJJJ (Subpart JJJJJJ) applies to boilers of various sizes that are located at area sources. The proposed facility will operate two catalytic heaters and one HVAC unit, all of which will fire natural gas. None of these units meet the definition of industrial, commercial, or institutional boilers;[17] therefore Subpart JJJJJJ does not apply.

4.3.8 Non-Applicability of Other NESHAP

As with NSPS standards, NESHAP are developed for particular industrial source categories. Therefore, the applicability of a particular NESHAP can be readily

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[16] *Delaware Department of Natural Resources and Environmental Control v. Environmental Protection Agency et al* decided May 1, 2015. http://www.cadc.uscourts.gov/internet/opinions.nsf/2E87E0199203E71B85257E3800500091/$file/13-1093-1550129.pdf

[17] 40 CFR §63.11193.

ascertained based on the industrial source category covered. All NESHAP regulations in 40 CFR 61 and 40 CFR 63, excluding those identified as applicable above, are not applicable to the facility.

4.4 South Carolina Regulations

In addition to Federal air regulations, SC R. 61-62 establishes regulations applicable at the emission unit level (source specific) and at the facility level. The rules also contain requirements related to the need for construction and/or operating permits. Potentially applicable standards under SC R. 61-62 are discussed below. Generally applicable facility provisions (e.g., restrictions on open burning) have been excluded from this discussion.

4.4.1 Standard No. 1 – Fuel Burning Operations

Regulation 61-62.5, Standard No. 1 regulates emissions of PM, SO_2, and opacity from fuel burning operations. Fuel burning operations are defined in Regulation 61-62.1 as:

> *Use of furnace, boiler, device or mechanism used principally but not exclusively, to burn any fuel for the purpose of indirect heating in which the material being heated is not contacted by and adds no substance to the products of combustion.*

There are no processes proposed as a part of this project that meet the definition of fuel burning operations.

4.4.2 Standard No. 2 – Ambient Air Quality Standards

As a source of criteria pollutants, the proposed facility is subject to the ambient air quality standards established under SC R. 61-62.5, Standard No. 2 (Standard 2). Compliance with Standard 2 is typically demonstrated using an air dispersion modeling analysis. According to Section 1.2.B of SCDHEC published guidance entitled "Standard 2 and 7 Modeling Exemption and Deferral Guidelines"[18], dated 25 September 2015, emissions from the proposed emergency generator, comfort heater, and catalytic heaters are not subject to Standard 2 and Standard 7 modeling

[18]https://www.scdhec.gov/environment/docs/Standard2and7ModelingExemptionandDeferralGuidelines.pdf

requirements for all pollutants. Per Section 1.2.C of these guidelines, emissions of PM, PM_{10}, $PM_{2.5}$, and SO_2 are exempt from Standard 2 and Standard 7 modeling requirements because the total estimated potential emission rate from each unit for each of these pollutants is less than 1.14 pounds per hour (lbs/hr). A demonstration of compliance with Standard 2 using air dispersion modeling is required when emissions of NO_2 and CO exceed 1.14 lbs/hr and 10 lbs/hr, respectively, which is the case for the proposed facility.

An air dispersion modeling analysis has been performed for NO_2 and CO emissions from the proposed combustion turbines, the only pollutants and emission units not exempt from Standard 2 and Standard 7 modeling requirements. The revised compliance demonstration was performed using the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD). The air dispersion modeling analysis is discussed in Section 5 of this application.

4.4.3 Standard No. 3 – Waste Combustion and Reduction

SC R. 61-62.5, Standard No. 3 generally regulates all sources that burn any waste other than virgin fuel for any purpose. Fuel burning sources at the proposed facility will only burn virgin fuel; therefore, this standard will not apply.

4.4.4 Standard No. 4 – Emissions from Process Industries

The proposed combustion turbines D-1 through D-3 will be subject to the visible emissions standard outlined in SC R. 61-62.5, Standard No. 4, Section IX, which requires that emissions not exhibit opacity greater than 20 percent for those facilities constructed after December 31, 1985. The proposed combustion turbines will demonstrate compliance with this standard by exclusively firing natural gas.

4.4.5 Standard No. 5 – Volatile Organic Compounds

SC R. 61-62.5, Standard No. 5 regulates VOC emissions from certain processes. However, the proposed facility will not include any of the regulated processes. Thus, this standard does not apply.

4.4.6 Standard No. 5.2 – Control of Oxides of Nitrogen Emissions

SC R. 61-62.5 Standard No. 5.2 (Standard 5.2) applies to any source that has not undergone a NO_x BACT analysis in accordance with SC R. 61-62.5, Standard No. 7, and meets one or more of the following criteria as outlined in Section I(a)(1)-(3) of Standard 5.2:

- Any new source that is constructed after June 25, 2004;
- Any existing source where a burner assembly is replaced with another burner assembly[19] after the effective date of this regulation, regardless of size or age of the burner assembly to be replaced; or,
- Any existing source that is removed from its presently permitted facility and moved to another permitted facility after the effective date of this regulation except process equipment and commercial or industrial boilers that are transferred between facilities within the state under common ownership.

The combustion turbines that will be installed at the facility were constructed before June 25, 2004 and are therefore considered existing sources under Standard 5.2. As a part of this project, these existing sources (D-1, D-2, and D-3) will be transferred between facilities within the state under common ownership. As such, they are exempt from this standard, per Section I(a)(3) of Standard 5.2.

4.4.7 Standard No. 7 – Prevention of Significant Deterioration

As previously discussed, PSD review is not required for the proposed facility as it will not be considered a major source under the PSD Program. Nevertheless, SCDHEC requires minor sources to perform increment modeling for pollutants after a Minor Source Baseline Date has been established for that pollutant for the county in which the facility is located.

The minor source baseline dates for PM_{10}, SO_2, and NO_2 have been triggered in Dorchester County[20], which is a Class II area under Standard 7. However, as previously

[19] The replacement of individual components of the burner (e.g., burner heads, nozzles, or windboxes) does not trigger the applicability of this regulation.

[20] SCDHEC, *SC Minor Source Baseline Dates*, dated 28 March 2012, accessed, 24 January 2014.

mentioned, the proposed combustion turbines are exempt from Standard 7 air dispersion modeling requirements for PM_{10} and SO_2 since potential emissions of PM_{10} and SO_2 from each are less than 1.14 lb/hr.

A Standard 7 compliance demonstration has been performed to include NO_2 emissions from proposed combustion turbines D-1, D-2, and D-3, the only pollutant and emission units not exempt from Standard 7 modeling requirements. The compliance demonstration was performed using AERMOD. The air dispersion modeling analysis is discussed in Section 5 of this application.

4.4.8 Standard No. 8 – Toxic Air Pollutants

SC R. 61-62.5, Standard No. 8 (Standard 8) applies to sources that have the potential to emit toxic air pollutants (TAP), but does not apply to fuel burning sources that only burn virgin fuel, per Section I of Standard 8. Given that the only sources of TAP emissions associated with the project are virgin fuel (natural gas) combustion sources, Standard 8 does not apply to the proposed project.

4.4.9 61-62.7 – Good Engineering Practice Stack Height

Regulation 61-62.7, *Good Engineering Practice Stack Height*, addresses Good Engineering Practice (GEP) stack height as it pertains to compliance with the Standard 2 and Standard 7. As discussed in Section 5, a GEP stack height analysis was performed as part of the Standard 2 and Standard 7 compliance demonstration for the facility.

5. AIR DISPERSION MODELING

An air dispersion modeling analysis has been conducted to demonstrate compliance with SC R. 61-62.5, Standard 2 and Standard 7. As previously mentioned, the compliance demonstration is limited to CO and NO_2 for Standard 2 and NO_2 for Standard 7. The methods used in this modeling analysis are consistent with current EPA and SCDHEC procedures and follow the procedures outlined in the SCDHEC Air Quality Modeling Guidelines and AERMOD Guidelines.[21,22,23] Details of the modeling analysis, dispersion model techniques, and modeling results are provided in the following sections.

5.1 Model Selection

The air dispersion modeling analysis was conducted using the latest version of AERMOD, version 15181 of AERMOD to estimate maximum ground-level concentrations. AERMOD is a steady-state plume model that incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of surface and elevated sources, as well as simple and complex terrain. Air dispersion modeling was performed using the AERMOD regulatory default options, including the default Ambient Ratio Method (ARM) options for NO_x to NO_2 conversion. The default ARM options assume a 0.75 NO_x to NO_2 conversation ratio for 1-hour NO_2 modeling and a 0.80 NO_x to NO_2 ratio for annual NO_2 modeling.

5.2 Geographic Coordinate System

In this modeling analysis, the location of emission sources, structures, and receptors were represented using the Universal Transverse Mercator (UTM) geographic coordinate system. One UTM zone is present within the State of South Carolina, Zone 17. The location of the facility is approximately 544,461 meters (m) East and 3,676,724 m North in Zone 17. This modeling analysis uses the World Geodetic System of 1984

[21] 40 CFR 51, Appendix W, *Guideline on Air Quality Models.*

[22] South Carolina Department of Health and Environmental Control, *Air Quality Modeling Guidelines*, July 2001.

[23] https://www.scdhec.gov/environment/docs/AERMOD_Guidelines.pdf\

(WGS84[24]), as the geodetic reference system from which the locational data was obtained.

5.3 Meteorological Data

AERMOD utilizes upper air and surface profile data obtained from publicly-available National Weather System (NWS) data (or similar), processed via AERMOD's meteorological data pre-processor, AERMET. Per South Carolina modeling guidelines, the dispersion modeling analysis was performed using 2002 through 2006 preprocessed meteorological data available from the SCDHEC website.[25] As recommended by SCDHEC, surface and upper-air data from the Charleston International Airport (CHS) meteorological station (Station Number 13880) were used, with a surface station base elevation of 46 feet (14.02 meters).[26]

5.4 Receptor Grids

Ground-level concentrations were estimated at receptors placed along the property line and within one Cartesian receptor grid. The property line grid receptors were spaced 50 meters apart and the grid receptors extending beyond the facility boundary to 1,500 meters were spaced 100 meters apart in all directions per SCDHEC guidance. The resultant maximum concentration occurs well within this distance at a receptor located on the property line.

5.5 Terrain

AERMOD uses advanced terrain characterization to account for the effects of terrain features on plume dispersion and travel. AERMOD's terrain pre-processor, AERMAP (latest version 11103), imports digital terrain data and computes a height scale for each receptor from National Elevation Dataset (NED) data files. A height scale is assigned to each individual receptor and is used by AERMOD to determine whether the plume will go over or around a hill.

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[24] As stated in AERMAP User Guide, the WGS84 and the North American Datum of 1983 (NAD83) datum are considered the same for all practical purposes.

[25] https://www.scdhec.gov/Environment/AirQuality/ComplianceandReporting/AirDispersionModeling/ModelingData/

[26] https://www.scdhec.gov/environment/docs/SC02-06_Met_Data-Station_Elevations.pdf

The receptor terrain elevations that were estimated by AERMAP are the highest elevations extracted from USGS 1:24,000 scale (7.5-minute series) NED data for the area in the vicinity of the facility. For each receptor, AERMAP assigns the maximum possible elevation within a box centered on the receptor of concern and extending halfway to each adjacent receptor. Base elevations were assigned to structures and stacks in a similar fashion. This is a conservative technique for estimating terrain elevations as it ensures that the highest terrain elevations are accounted for in the analysis.

5.6 Building Downwash Analysis

Federal regulations at 40 CFR 51, Appendix W (*Guideline on Air Quality Models*) restrict the use of stack heights in excess of GEP stack height in air dispersion modeling analyses. The GEP height of a stack is the greater of: 1) 65 meters (measured from the base elevation of the stack), or 2) the value resulting from applying the following equation:[27]

$$H_g = H + 1.5 * (L)$$

Where:

H_g = GEP stack height
H = height of nearby structure
L = lesser dimension, height or projected width, of nearby structure

Aerodynamic downwash has the potential to increase ground-level concentrations from stack sources above the concentrations that would be predicted in the absence of these effects. Under 40 CFR 51, Appendix W, the portion of a stack that is in excess of the GEP stack height is generally not creditable when modeling to determine source impacts, preventing the use of excessively tall stacks to reduce ground-level pollutant concentrations.

Downwash is handled in air quality models through the use of arrays of direction-specific building dimensions, determined through the use of EPA's Building Profile Input Program Plume Rise Model Enhancement (BPIP-PRIME) algorithm. BPIP-PRIME generates direction-specific building heights and widths for a given stack.

[27] 40 CFR Part 51, Section 100, Paragraph (ii).

BPIP-PRIME also calculates a GEP stack height above which the downwash from buildings does not have any impact on the emissions from the stack. A BPIP-PRIME analysis was performed for each modeled stack.

Stacks that have a release height lower than their GEP value are modeled at their actual release height. Based on the GEP formula above, BPIP-PRIME calculated a GEP height of approximately 40 feet for S-1 through S-3. The actual height of each stack will be approximately 26 feet, below the estimated GEP stack height value. As such, the stacks were modeled at their actual release height.

The input and output files used in the BPIP-PRIME downwash analysis are provided in Appendix E of this application. The output file lists: the names and dimensions of the structures considered; the emissions unit location and height; a summary of the dominant structure for each emissions unit (considering all wind directions); and the actual building height and projected widths for all wind directions. Each building processed using BPIP-PRIME was assigned a unique numerical identification in the model, which corresponds to BPIP-PRIME files. Buildings included in the BPIP-PRIME analysis are listed in Table 5-1 below and illustrated on Figure 2.

Table 5-1: Building Summary

Model Building ID	Building Description	UTM Easting (m)[a]	UTM Northing (m)[a]	Height (ft)[b]	Length (ft)[b]	Width (ft)[b]
OBLD	Operations Center	544,472.32	3,676,722.92	16	28	28
BLDA	Compressor Building A [c]	544,484.28	3,676,697.08	16	50	35
BLDB	Compressor Building B	544,472.56	3,676,672.31	16	50	35

a. Location represents the southwest corner of the building.
b. Obtained from civil site plans.

5.7 Land Use Analysis

Varying land use will produce different environmental responses to heating, cooling, albedo, etc., which have an effect on the vertical stability and subsequent behavior of pollutant dispersion. As stated in the July 2001 SCDHEC *Air Quality Modeling*

Guidelines[28] (Modeling Guidelines) document, with few exceptions, all of South Carolina is considered to be rural. Typically only areas in the large metropolitan areas of the State (i.e., Greenville/Spartanburg, Columbia, and Charleston) are considered urban.

In accordance with the Modeling Guidelines and *August Auer, 1978*[29] guidance, a 3-km radius domain centered at the proposed facility was considered for the land-use analysis. ArcGIS (Version 10.3) was used for extraction of the land-use values in the domain. The original land-use map for this extraction was obtained from the publically-available USGS 1992 National Land Cover Dataset, as provided in the Modeling Guidelines. The data has 30-meter grid resolution and 21 land-use categories. Commercial/Industrial/Transportation and High Intensity Residential were considered urban while other categories were considered rural. The frequency of the 21 categories were used to determine the total frequency of rural and urban land-use (as a percentage), which was then evaluated according to the Modeling Guidelines in terms of overall dispersion classification as urban or rural. The procedures provided in the Modeling Guidelines classify areas as rural when the frequency of rural land-use categories is 50% or greater.

Figure 3 shows the 3-km radius centered at the proposed facility, overlain on a land-use map. The resulting land-use count and percentages are summarized in Table 5-2. More than 99 percent of the domain surrounding the facility comprises rural land features.

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[28] SCDHEC's *Air Quality Modeling Guidelines*, dated July 2001 (http://www.scdhec.gov/environment/docs/modguide.pdf).

[29] August H. Auer Jr., 1978: *Correlation of Land Use and Cover with Meteorological Anomalies*. Journal of Applied Meteorology, Volume 17, p. 636–643.

Table 5-2: Land Use Analysis

Category	Land Use Category Description	Number of Grid Cells	Frequency (%)	Dispersion Class
11	Open Water	5	0.016	Rural
21	Low Intensity Residential	76	0.243	Rural
22	High Intensity Residential	29	0.093	Urban
23	Commercial/Industrial/Transportation	1	0.003	Urban
31	Bare Rock/Sand/Clay	1	0.003	Rural
33	Transitional	812	2.597	Rural
41	Deciduous Forest	2,925	9.355	Rural
42	Evergreen Forest	6,965	22.275	Rural
43	Mixed Forest	3,169	10.135	Rural
81	Pasture/Hay	1,566	5.008	Rural
82	Row Crops	6,506	20.807	Rural
91	Woody Wetlands	8818	28.201	Rural
92	Emergent Herbaceous Wetlands	395	1.263	Rural
	Total	31,268		
	Rural		99.904	
	Urban		0.096	

5.8 Source Characterization

The AERMOD dispersion model allows for emissions units to be represented as point, area, or volume sources. For point sources with unobstructed vertical releases, it is appropriate to use actual stack parameters (i.e., height, diameter, exhaust gas temperature, and gas exit velocity) in this modeling analysis. The emission units were modeled as point sources using actual stack parameters as presented in Table 5-3.

Table 5-3: Point Source Parameters

Stack ID	Unit ID	UTM Easting (m)	UTM Northing (m)	Stack Height (ft)	Exhaust Temp. (°F)	Exit Flow (ACFM)	Velocity (ft/s)	Stack Diameter (ft)	Raincap (Y/N)	NOx (lbs/hr)	CO (lbs/hr)
S-1	D-1	544501.456	3676703.048	26	832	27,388	141.04	2.03	N	8.34	14.71
S-2	D-2	544497.527	3676694.700	26	832	27,388	141.04	2.03	N	8.34	14.71
S-3	D-3	544489.677	3676678.283	26	832	27,388	141.04	2.03	N	8.34	14.71

5.9 Background Concentrations and Ambient Standards

SCDHEC provides background concentrations for each criteria pollutant and averaging period for which there is an ambient standard, which are to be incorporated into AAQS compliance demonstrations. The air dispersion modeling analysis performed for this project utilized background concentration data from 2011-2013 monitoring at the Jenkins Avenue Fire Station site in Charleston County, SC for NO_2 and at the Parklane site in Richland County, SC for CO. Background concentrations were added to the modeled concentrations for the purpose of comparing estimated cumulative ambient impacts to the AAQS. Applicable AAQS and background concentrations used in this modeling analysis are presented in Table 5-4 below.

5.10 Modeling Results

For Standards Nos. 2 and 7, the maximum modeled impacts for NO_2 and CO for the meteorological dataset were compared to the applicable standards for each averaging period. The results of this analysis are presented in Table 5-4 and demonstrate the proposed facility, including the units D-1, D-2, and D-3, will be in compliance with Standard 2 and Standard 7 for modeled pollutants. The AERMOD input and output modeling files for each modeled pollutant, along with the AERMAP input and output files are included in electronic format in Appendix E.

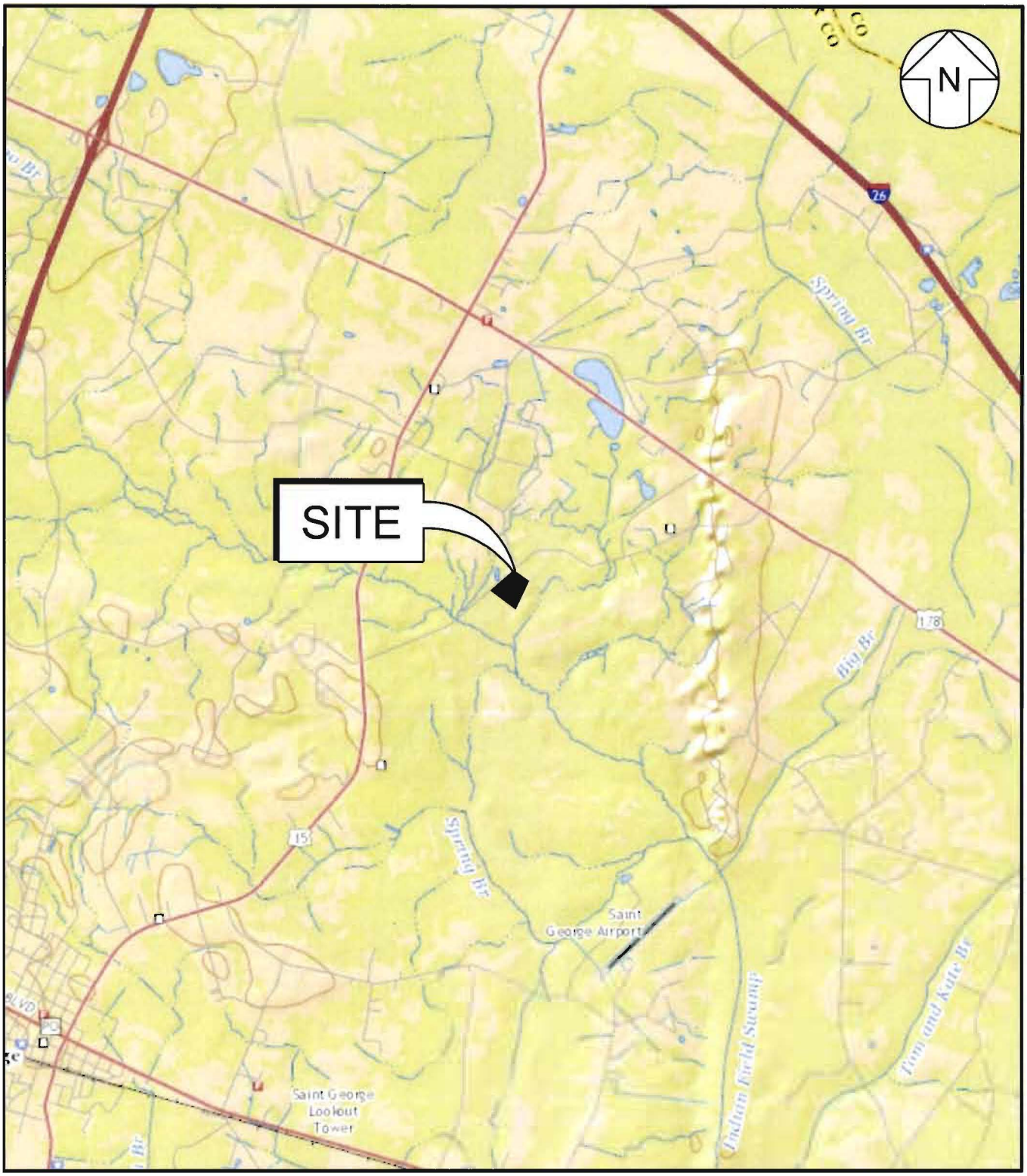
Table 5-4: Model Results in Comparison with Ambient Standards

Pollutant	Averaging Period	Maximum Modeled Results (µg/m³)	AAQS[30] (µg/m³)	Percent of Standard	Background Concentration (µg/m³)	Total Concentration (µg/m³)	Percent of Standard (Total)	Shows Compliance? (Yes/No)
Standard 2								
NO_2	Annual[a]	1.75	100	1.75%	12.40	14.15	14%	Yes
	1-hour[b]	63.59	188	33.82%	72.10	135.69	72%	Yes
CO	1-hour[c]	213.65	40,000	0.53 %	1,450	1,664	4%	Yes
	8-hour[c]	103.29	10,000	1.03 %	916	1,019	10%	Yes
Standard 7								
NO_2	Annual	1.75	25	7.0%	-	1.75	7%	Yes

a. The high first high value is shown for annual NO2
b. The 8th-highest maximum of daily 1-hour results averaged over five years is shown for 1-hour NO2
c. The high second high value is shown for 1-hour and 8-hour CO.

[30] SC R. 61-62.5, Standard 2

FIGURES



SOURCE: ESRI ARCGIS 10.2.1, USGS NATIONAL MAP

LOCATION MAP

SCALE: 1"=5,000'

0 5,000'

SCALE IN FEET

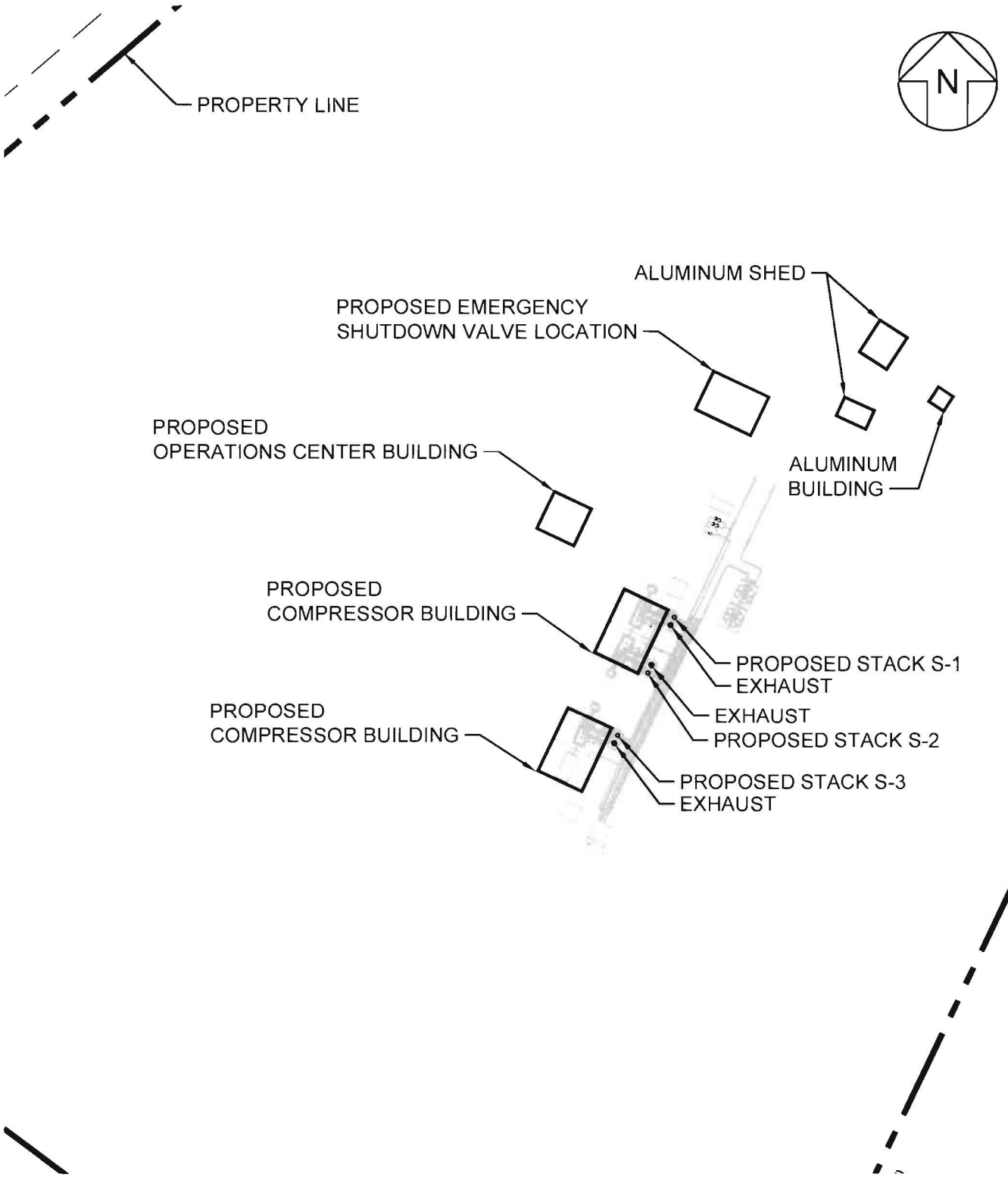
DOMINION CAROLINA GAS TRANSMISSION, LLC
TOPOGRAPHIC SITE LOCATION MAP
DORCHESTER COMPRESSOR STATION
ST. GEORGE, SC
AIR QUALITY CONSTRUCTION PERMIT APPLICATION

Geosyntec consultants

FIGURE 1

PROJECT NO: GSC5940 | DECEMBER 2015

M:\D\DCG-DORCHESTER-GSC5940\FIGURES\5940F001



0 100'
SCALE IN FEET

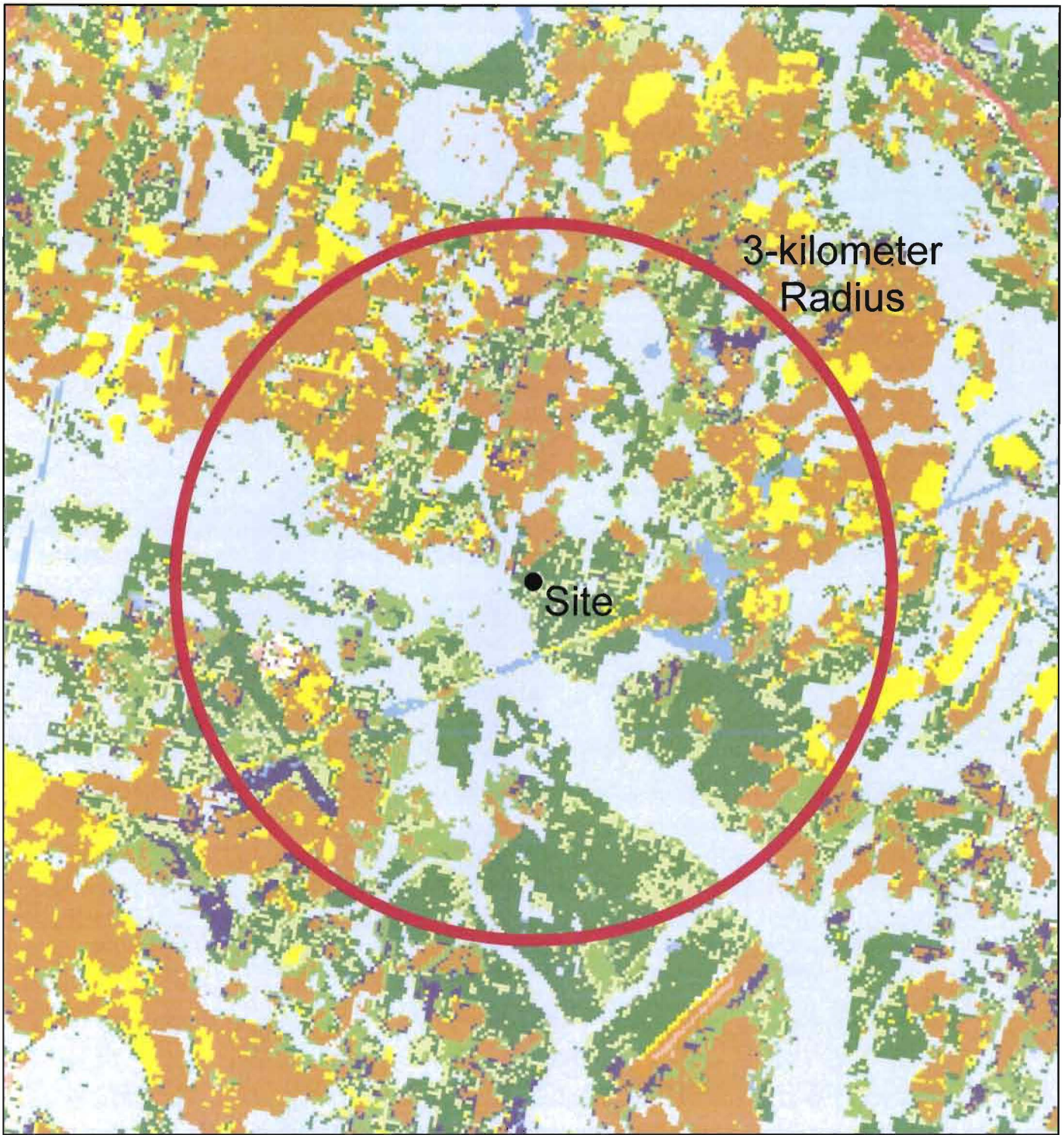
DOMINION CAROLINA GAS TRANSMISSION, LLC
FACILITY LAYOUT
DORCHESTER COMPRESSOR STATION
ST. GEORGE, SC
AIR QUALITY CONSTRUCTION PERMIT
APPLICATION

Geosyntec consultants

FIGURE
2

PROJECT NO: GSC5940 | DECEMBER 2015

M:\D\DCG-DORCHESTER-GSC5940\FIGURES\DORCHESTER COMPRESSOR SITE_20151118



Legend

- Open Water
- Low Intensity Residential
- High Intensity Residential
- Commercial/Industrial/Transportation
- Bare Rock/Sand/Clay
- Quarries/Strip Mines/Gravel Pits
- Transitional
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Pasture/Hay
- Row Crops
- Urban/Recreational Grasses
- Woody Wetlands
- Emergent Herbaceous Wetlands

4,000 2,000 0 4,000 Feet

Note:
Land use data from the National Land Cover Dataset 1992. Vogelmann, J.E., S.M. Howard, L. Yang, C. R. Larson, B. K. Wylie, and J. N. Van Driel, 2001. Completion of the 1990's National Land Cover Data Set for the conterminous United States, Photogrammetric Engineering and Remote Sensing 67 650-662

Land Use
DCG Dorchester Compressor Station
County Road S-18-37
St. George, South Carolina

Geosyntec consultants

Columbia, South Carolina | DECEMBER 2015

Figure 3

P:\PRJ1\AirModeling\DCG\T2C_GIS\MXD\T2C-Dorchester_Land_Use.mxd

APPENDIX A

SCDHEC Air Quality Construction Permit Application Forms

D H E C
South Carolina Department of Health and Environmental Control

Bureau of Air Quality
Construction Permit Application
Facility Information

RECEIVED
DEC 21 2015
BUREAU OF AIR QUALITY

FACILITY IDENTIFICATION	
SC Air Permit Number (8-digits only) *(Leave blank if one has never been assigned)* -	Application Date December 2015
Facility Name *(This should be the name used to identify the facility at the physical address listed below)* Dorchester Compressor Station	Facility Federal Tax Identification Number *(Established by the U.S. Internal Revenue Service to identify a business entity)* 57-0655473

FACILITY PHYSICAL ADDRESS		
Physical Address: County Road S-18-37		County: Dorchester
City: St. George	State: SC	Zip Code: 29477
Facility Coordinates *(Facility coordinates should be based at the front door or main entrance of the facility.)*		
Latitude: 33°13'42.72"N	Longitude: 80°31'22.17"W	☐ NAD27 *(North American Datum of 1927)* Or ☒ NAD83 *(North American Datum of 1983)*

CO-LOCATION DETERMINATION
Are there other facilities in close proximity that could be considered co-located? ☒ No ☐ Yes*
List potential co-located facilities, including air permit numbers if applicable:

If yes, please submit co-location applicability determination details in an attachment to this application.

COMMUNITY OUTREACH
What are the potential air issues and community concerns? Please provide a brief description of potential air issues and community concerns about the entire facility and/or specific project. Include how these issues and concerns are being addressed, if the community has been informed of the proposed construction project, and if so, how they have been informed. N/A

FACILITY'S PRODUCTS / SERVICES	
Primary Products / Services *(List the primary product and/or service)* Natural Gas Transmission	
Primary SIC Code *(Standard Industrial Classification Codes)* 4922	Primary NAICS Code *(North American Industry Classification System)* 486210
Other Products / Services *(List any other products and/or services)* N/A	
Other SIC Code(s): N/A	Other NAICS Code(s): N/A

AIR PERMIT FACILITY CONTACT *(Person at the facility who can answer technical questions about the facility and permit application.)*			
Title/Position: Env. Program Manager	Salutation: Mr.	First Name: Rick	Last Name: Kopec
Mailing Address: 220 Operation Way, MC J48			
City: Cayce		State: SC	Zip Code: 29033
E-mail Address: richard.l.kopec@dom.com		Phone No.: 803.726.3707	Cell No.: 803.391.1077
One hard copy of the signed permit will be mailed to the designated Air Permit Contact. If additional individuals need electronic copies of the permit, please provide their names and e-mail addresses.			
Name		**E-mail Address**	
Brandon Mogan, PE		BMogan@geosyntec.com	

COPY

D H E C

South Carolina Department of Health and Environmental Control

Bureau of Air Quality
Construction Permit Application
Facility Information

CONFIDENTIAL INFORMATION / DATA
Does this application contain confidential information or data? ☒ No ☐ Yes*

**If yes, include a sanitized version of the application for public review and ONLY ONE COPY OF CONFIDENTIAL INFORMATION SHOULD BE SUBMITTED*

LIST OF FORMS INCLUDED (Identify all forms included in the application package)	
Form Name	**Included (Y/N)**
Expedited Review Request (DHEC Form 2212)	☐ Yes ☒ No
Equipment/Processes (DHEC Form 2567)	☒ Yes
Emissions (DHEC Form 2569)	☒ Yes
Regulatory Review (DHEC Form 2570)	☒ Yes
Emissions Point Information (DHEC Form 2573)	☒ Yes ☐ No (If No, Explain)

OWNER OR OPERATOR			
Title/Position: General Manager	Salutation: Mr.	First Name: Keith	Last Name: Windle
Mailing Address: 220 Operations Way, MC J48			
City: Cayce		State: SC	Zip Code: 29033
E-mail Address: keith.windle@dom.com		Phone No.: 803.726.3715	Cell No.: 804.836.5353

OWNER OR OPERATOR SIGNATURE

I certify, to the best of my knowledge and belief, that no applicable standards and/or regulations will be contravened or violated. I certify that any application form, report, or compliance certification submitted in this permit application is true, accurate, and complete based on information and belief formed after reasonable inquiry. I understand that any statements and/or descriptions, which are found to be incorrect, may result in the immediate revocation of any permit issued for this application.

K-W 2 — 12/4/15

Signature of Owner or Operator — Date

PERSON AND/OR FIRM THAT PREPARED THIS APPLICATION (If not the same person as the Professional Engineer who has reviewed and signed this application.)			
Consulting Firm Name: Geosyntec Consultants, Inc.			
Title/Position: Senior Engineer	Salutation: Mr.	First Name: Brandon	Last Name: Mogan
Mailing Address: 1331 Elmwood Avenue, Suite 310			
City: Columbia		State: SC	Zip Code: 29201
E-mail Address: BMogan@geosyntec.com		Phone No.: 803.724.3263	Cell No.: 803.422.5251
SC Professional Engineer License/Registration No. (if applicable): 30362			

PROFESSIONAL ENGINEER INFORMATION			
Consulting Firm Name: Geosyntec Constultants, Inc.			
Title/Position: Senior Engineer	Salutation: Mr.	First Name: Brandon	Last Name: Mogan
Mailing Address: 1331 Elmwood Avenue, Suite 310			
City: Columbia		State: SC	Zip Code: 29201
E-mail Address: BMogan@geosyntec.com		Phone No.: 803.724.3263	Cell No.: 803.422.5251
SC License/Registration No.: 30362			

PROFESSIONAL ENGINEER SIGNATURE

I have placed my signature and seal on the engineering documents submitted, signifying that I have reviewed this construction permit application as it pertains to the requirements of *South Carolina Regulation 61-62, Air Pollution Control Regulations and Standards.*

12/7/15

Signature of Professional Engineer — Date

No. 30362 — BRANDON A. MOGAN — LICENSED PROFESSIONAL ENGINEER — SOUTH CAROLINA

SOUTH CAROLINA — GEOSYNTEC CONSULTANTS, INC. — No. 773 — CERTIFICATE OF AUTHORIZATION

D H E C

South Carolina Department of Health and Environmental Control

Bureau of Air Quality
Construction Permit Application
Equipment / Processes

APPLICATION IDENTIFICATION		
(Please ensure that the information list in this table is the same on all of the forms and required information submitted in this construction permit application package.)		
Facility Name *(This should be the name used to identify the facility)* Dorchester Compressor Station	SC Air Permit Number (8-digits only) *(Leave blank if one has never been assigned)* -	Application Date December 2015

PROJECT DESCRIPTION
Brief Project Description (What, why, how, etc.): The purpose of this application is to obtain a permit to construct a proposed natural gas compressor station in Dorchester, SC. The primary emission sources at the facility will be three natural gas-fired combustion turbine compressor sets. The facility will also include several exempt emission sources.

ATTACHMENTS	
☒ Process Flow Diagram	Location in Application: Appendix C
☒ Detailed Project Description	Location in Application: Refer to report narrative

EQUIPMENT / PROCESS INFORMATION

Equipment ID Process ID	Action	Equipment / Process Description	Maximum Design Capacity (Units)	Control Device ID(s)	Pollutants Controlled (Include CAS#)	Capture System Efficiency and Description	Emission Point ID(s)
D-1	☒ Add ☐ Remove ☐ Modify ☐ Other	13.92 MMBtu/hr Simple-Cycle Natural Gas-Fired Combustion Turbine	13.92 MMBtu/hr	N/A	N/A	N/A	S-1
D-2	☒ Add ☐ Remove ☐ Modify ☐ Other	13.92 MMBtu/hr Simple-Cycle Natural Gas-Fired Combustion Turbine	13.92 MMBtu/hr	N/A	N/A	N/A	S-2
D-3	☒ Add ☐ Remove ☐ Modify ☐ Other	13.92 MMBtu/hr Simple-Cycle Natural Gas-Fired Combustion Turbine	13.92 MMBtu/hr	N/A	N/A	N/A	S-3
	☐ Add ☐ Remove ☐ Modify ☐ Other						
	☐ Add ☐ Remove ☐ Modify ☐ Other						

CONTROL DEVICE INFORMATION					
Control Device ID	Action	Control Device Description	Maximum Design Capacity (Units)	Inherent/Required/Voluntary (Explain)	Destruction/Removal Efficiency Determination
	☐ Add ☐ Remove ☐ Modify ☐ Other				
	☐ Add ☐ Remove ☐ Modify ☐ Other				
	☐ Add ☐ Remove ☐ Modify ☐ Other				
	☐ Add ☐ Remove ☐ Modify ☐ Other				
	☐ Add ☐ Remove ☐ Modify ☐ Other				

N/A

RAW MATERIAL AND PRODUCT INFORMATION			
Equipment ID Process ID Control Device ID	Raw Material(s)	Product(s)	Fuels Combusted
D-1	Natural Gas	Natural Gas	Natural Gas
D-2	Natural Gas	Natural Gas	Natural Gas
D-3	Natural Gas	Natural Gas	Natural Gas

MONITORING AND REPORTING INFORMATION					
Equipment ID Process ID Control Device ID	**Pollutant(s)/Parameter(s) Monitored**	**Monitoring Frequency**	**Reporting Frequency**	**Monitoring/Reporting Basis**	**Averaging Period(s)**
D-1	N/A	N/A	N/A	N/A	N/A
D-2	N/A	N/A	N/A	N/A	N/A
D-3	N/A	N/A	N/A	N/A	N/A

D H E C

PROMOTE PROTECT PROSPER

South Carolina Department of Health and Environmental Control

Bureau of Air Quality
Construction Permit Application
Emissions

APPLICATION IDENTIFICATION *(Please ensure that the information list in this table is the same on all of the forms and required information submitted in this construction permit application package.)*		
Facility Name *(This should be the name used to identify the facility)* Dorchester Compressor Station	SC Air Permit Number (8-digits only) *(Leave blank if one has never been assigned)* -	Application Date December 2015

ATTACHMENTS *(Check all the appropriate checkboxes if included as an attachment)*	
☒ Sample Calculations, Emission Factors Used, etc.	☒ Detailed Explanation of Assumptions, Bottlenecks, etc.
☒ Supporting Information: Manufacturer's Data, etc.	☐ Source Test Information
☐ Details on Limits Being Taken for Limited Emissions	☐ NSR Analysis

SUMMARY OF PROJECTED CHANGE IN FACILITY WIDE POTENTIAL EMISSIONS
(Calculated at maximum design capacity.)

Pollutants	Emission Rates Prior to Construction / Modification (tons/year)			Emission Rates After Construction / Modification (tons/year)		
	Uncontrolled	Controlled	Limited	Uncontrolled	Controlled	Limited
Particulate Matter (PM)	N/A			1.1	No Controls	No Limits
Particulate Matter <10 Microns (PM_{10})				1.1		
Particulate Matter <2.5 Microns ($PM_{2.5}$)				1.1		
Sulfur Dioxide (SO_2)				5.7E-01		
Nitrogen Oxides (NO_x)				109.8		
Carbon Monoxide (CO)				178.6		
Volatile Organic Compounds (VOC)				13.5		
Lead (Pb)				-		
Highest HAP Prior to Construction (CAS #:)				-		
Highest HAP After Construction (CAS #: 110-54-3)				0.32		
Total HAP Emissions*				0.53		

Include emissions from exempt equipment and emission increases from process changes that were exempt from construction permits.
(*All HAP emitted from the various equipment or processes must be listed in the appropriate "Potential Emission Rates at Maximum Design Capacity" Table)

POTENTIAL EMISSION RATES AT MAXIMUM DESIGN CAPACITY									
Equipment ID / Process ID	Emission Point ID	Pollutants (Include CAS #)	Calculation Methods / Limits Taken / Other Comments	Uncontrolled		Controlled		Limited	
				lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
			See Appendix B						

D H E C

South Carolina Department of Health and Environmental Control

Bureau of Air Quality
Construction Permit Application
Regulatory Review

APPLICATION IDENTIFICATION *(Please ensure that the information list in this table is the same on all of the forms and required information submitted in this construction permit application package.)*		
Facility Name *(This should be the name used to identify the facility)* Dorchester Compressor Station	SC Air Permit Number (8-digits only) *(Leave blank if one has never been assigned)* -	Application Date December 2015

STATE AND FEDERAL AIR POLLUTION CONTROL REGULATIONS AND STANDARDS
(If not listed below add any additional regulations that are triggered.)

Regulation	Applicable		Include all limits, work practices, monitoring, record keeping, etc.		
	Yes	No	Explain Applicability Determination	List the specific limitations and/or requirements that apply.	How will compliance be demonstrated?
Regulation 61-62.1, Section II(E) Synthetic Minor Construction Permits	☐	☒	Major Source	N/A	N/A
Regulation 61-62.1, Section II(G) Conditional Major Operating Permits	☐	☒	Major Source	N/A	N/A
Regulation 61-62.5, Standard No. 1 Emissions from Fuel Burning Operations	☐	☒	No sources in this applicable category. See Report Section 4.4.1	N/A	N/A
Regulation 61-62.5, Standard No. 2 Ambient Air Quality Standards	☒	☐	See Report Section 4.4.2	See Report Section 4.4.2	See Report Section 4.4.2
Regulation 61-62.5, Standard No. 3 Waste Combustion and Reduction	☐	☒	Project does not contain any waste combustion. See section 4.4.3	N/A	N/A
Regulation 61-62.5, Standard No. 4 Emissions from Process Industries	☒	☐	See Report Section 4.4.4	Opacity < =20%	See Report Section 4.4.4
Regulation 61-62.5, Standard No. 5 Volatile Organic Compounds	☐	☒	Project does not contain applicable source category. See Report Section 4.4.5	N/A	N/A
Regulation 61-62.5, Standard No. 5.2 Control of Oxides of Nitrogen	☐	☒	See Report Section 4.4.6	N/A	N/A
Regulation 61-62.5, Standard No. 7 Prevention of Significant Deterioration*	☒	☐	See Report Section 4.4.7	See Report Section 4.4.7	See Report Section 4.4.7
Regulation 61-62.5, Standard No. 7.1 Nonattainment New Source Review*	☐	☒	Not in nonattainment area.	N/A	N/A
Regulation 61-62.5, Standard No. 8 Toxic Air Pollutants	☐	☒	See Report Section 4.4.8	See Report Section 4.4.8	See Report Section 4.4.8
Regulation 61-62.70 Title V Operating Permit Program	☒	☐	Facility-wide emissions are greater than major source thresholds for two pollutants: CO and NOx	See Report Section 4.1.3	See Report Section 4.1.3

STATE AND FEDERAL AIR POLLUTION CONTROL REGULATIONS AND STANDARDS *(If not listed below add any additional regulations that are triggered.)*					
Regulation	**Applicable**		**Include all limits, work practices, monitoring, record keeping, etc.**		
	Yes	**No**	**Explain Applicability Determination**	**List the specific limitations and/or requirements that apply.**	**How will compliance be demonstrated?**
Regulation 61-62.72 Acid Rain	☐	☒	No sources in this applicable category.	N/A	N/A
Regulation 61-62.96 Nitrogen Oxides Budget Trading Program	☐	☒	No sources in this applicable category.	N/A	N/A
Regulation 61-62.99 Nitrogen Oxides Budget Program Requirements for Stationary Sources Not In the Trading Program	☐	☒	No sources in this applicable category.	N/A	N/A
40 CFR Part 64 - Compliance Assurance Monitoring (CAM)	☐	☒	No sources in this applicable category.	N/A	N/A
40 CFR 60 Subpart A - General Provisions	☒	☐	See Report Section 4.2.1	N/A	N/A
40 CFR 60 Subparts D, Db, and Dc – NSPS for Steam Generating Units	☐	☒	See Report Section 4.2.2	N/A	N/A
40 CFR 60 Subpart K, Ka, and Kb – NSPS for Volatile Organic Liquid Storage Vessels	☐	☒	See Report Section 4.2.3	N/A	N/A
40 CFR Part 60, Subpart GG – NSPS for Stationary Gas Turbines	☐	☒	See Report Section 4.2.4	N/A	N/A
40 CFR Part 60, Subpart IIII – Stationary Compression Ignition Engines	☐	☒	See Report Section 4.2.5	N/A	N/A
40 CFR 60 Subpart JJJJ – Stationary Spark Ignition Combustion Engines	☒	☐	See Report Section 4.2.6	See Report Section 4.2.6	See Report Section 4.2.6
40 CFR 60 Subpart KKKK – Stationary Gas Turbines	☐	☒	See Report Section 4.2.7	N/A	N/A
40 CFR 60 Subpart OOOO – NSPS for Crude Oil and Natural Gas Production, and Transmission and Distribution	☐	☒	See Report Section 4.2.8	N/A	N/A
Other 40 CFR Part 60 Subparts	☐	☒	See Report Section 4.2.9	N/A	N/A
40 CFR 61 Subpart A - General Provisions	☐	☒	No pollutant-specific standards are applicable at the facility	N/A	N/A
40 CFR 63 Subpart A - General Provisions	☒	☐	See Report Section 4.3.1	See Report Section 4.3.1	See Report Section 4.3.1
40 CFR Part 63, Subpart HH – NESHAP for Oil and Natural Gas Production Facilities	☐	☒	See Report Section 4.3.2	N/A	N/A

STATE AND FEDERAL AIR POLLUTION CONTROL REGULATIONS AND STANDARDS *(If not listed below add any additional regulations that are triggered.)*					
Regulation	**Applicable**		**Include all limits, work practices, monitoring, record keeping, etc.**		
	Yes	**No**	**Explain Applicability Determination**	**List the specific limitations and/or requirements that apply.**	**How will compliance be demonstrated?**
40 CFR Part 63, Subpart HHH – NESHAP for Natural Gas Transmission and Storage Facilities	☐	☒	See Report Section 4.3.3	N/A	N/A
40 CFR Part 63, Subpart EEEE – Organic Liquids Distribution (non-gasoline)	☐	☒	N/A	N/A	N/A
40 CFR Part 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines	☐	☒	See Report Section 4.3.4	N/A	N/A
40 CFR Part 63, Subpart ZZZZ – Reciprocating Internal Combustion Engines	☒	☐	See Report Section 4.3.5	See Report Section 4.3.5	See Report Section 4.3.5
40 CFR Part 63, Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	☐	☒	See Report Section 4.3.6	N/A	N/A
40 CFR Part 63, Subpart JJJJJJ – NESHAP for Industrial, Commercial, and Institutional Boilers at Area Sources	☐	☒	See Report Section 4.3.7	N/A	N/A
Other 40 CFR 63 Subparts	☐	☒	See Report 4.3.8	N/A	N/A

* Green House Gas emissions must be quantified if these regulations are triggered.

South Carolina Department of Health and Environmental Control

Bureau of Air Quality
Emission Point Information

A. APPLICATION IDENTIFICATION	
1. Facility Name: Dorchester Compressor Station	
2. SC Air Permit Number (if known; 8-digits only): -	3. Application Date: December 2015
4. Project Description: The purpose of this application is to obtain a permit to construct a proposed natural gas compressor station in St. George, SC. The primary emission sources at the facility will be three Saturn 10 simple-cycle natural gas-fired combustion turbine compressor sets.	

B. FACILITY INFORMATION	
1. Is your company a Small Business? ☐ Yes ☒ No	2. If a Small Business or small government facility, is Bureau assistance being requested? ☐ Yes ☒ No
3. Are other facilities collocated for air compliance? ☐ Yes ☒ No	4. If Yes, provide permit numbers of collocated facilities:

C. AIR CONTACT			
Consulting Firm Name (if applicable): Geosyntec Consultants, Inc.			
Title/Position: Senior Engineer	Salutation: Mr.	First Name: Brandon	Last Name: Mogan
Mailing Address: 1331 Elmwood Avenue, Suite 310			
City: Columbia		State: SC	Zip Code: 29201
E-mail Address: BMogan@geosyntec.com		Phone No.: 803.724.3263	Cell No.: 803.422.5251

D. EMISSION POINT DISPERSION PARAMETERS
Source data requirements are based on the appropriate source classification. Each emission point is classified as a point, area, volume, or flare source. Contact the Bureau of Air Quality for clarification of data requirements. Include sources on a scaled site map. Also, a picture of area or volume sources would be helpful but is not required. A user generated document or spreadsheet may be substituted in lieu of this form provided all of the required emission point parameters are submitted in the same order, units, etc. as presented in these tables.
Abbreviations / Units of Measure: UTM = Universal Transverse Mercator; °N = Degrees North; °W = Degrees West; m = meters; AGL = Above Ground Level; ft = feet; ft/s = feet per second; ° = Degrees; °F = Degrees Fahrenheit

E. POINT SOURCE DATA

(Point sources such as stacks, chimneys, exhaust fans, and vents.)

Emission Point ID	Description/Name	Point Source Coordinates Projection: NAD83				Release Height AGL (ft)	Temp. (°F)	Exit Velocity (ft/s)	Inside Diameter (ft)	Discharge Orientation	Rain Cap? (Y/N)	Distance To Nearest Property Boundary (ft)	Building		
		UTM E (m)	UTM N (m)	Lat (°N)	Long (°W)								Height (ft)	Length (ft)	Width (ft)
S-1	Turbine D-1 (Stack S-1)	544,501	3,676,703			26	832	141.04	2.03	Vertical	N	See Modeling Files	See Modeling Files	See Modeling Files	See Modeling Files
S-2	Turbine D-2 (Stack S-2)	544,498	3,676,695			26	832	141.04	2.03	Vertical	N	See Modeling Files	See Modeling Files	See Modeling Files	See Modeling Files
S-3	Turbine D-3 (Stack S-3)	544,490	3,676,678			26	832	141.04	2.03	Vertical	N	See Modeling Files	See Modeling Files	See Modeling Files	See Modeling Files

F. AREA SOURCE DATA

(Area sources such as storage piles, and other sources that have low level or ground level releases with no plumes.)

Emission Point ID	Description/Name	Area Source Coordinates Projection:				Release Height AGL (ft)	Easterly Length (ft)	Northerly Length (ft)	Angle From North (°)	Distance To Nearest Property Boundary (ft)
		UTM E (m)	UTM N (m)	Lat (°N)	Long (° W)					
	N/A									

G. VOLUME SOURCE DATA

(Volume sources such as building fugitives that have initial dispersion vertical depth prior to release.)

Emission Point ID	Description/Name	Volume Source Coordinates Projection:				Release Height AGL (ft)	Initial Horizontal Dimension (ft)	Initial Vertical Dimension (ft)	Distance To Nearest Property Boundary (ft)
		UTM E (m)	UTM N (m)	Lat (°N)	Long (° W)				
	N/A								

H. FLARE SOURCE DATA

(Point sources where the combustion takes place at the tip of the stack.)

Emission Point ID	Description/Name	Flare Source Coordinates Projection:				Release Height AGL (ft)	Heat Release Rate (BTU/hr)	Distance To Nearest Property Boundary (ft)	Building		
		UTM E (m)	UTM N (m)	Lat (°N)	Long (° W)				Height (ft)	Length (ft)	Width (ft)
N/A											

I. AREA CIRCULAR SOURCE DATA

Emission Point ID	Description/Name	Area Circular Source Coordinates Projection:				Release Height AGL (ft)	Radius of Area (ft)	Distance To Nearest Property Boundary (ft)
		UTM E (m)	UTM N (m)	Lat (°N)	Long (° W)			
N/A								

J. AREA POLY SOURCE DATA

Emission Point ID	Description/Name	Area Poly Source Coordinates Projection:		Release Height AGL (ft)	Number of Vertices
		UTM E (m)	UTM N (m)		
N/A					

K. OPEN PIT SOURCE DATA

Emission Point ID	Description/Name	Open Pit Source Coordinates Projection:		Release Height AGL (ft)	Easterly Length (ft)	Northerly Length (ft)	Volume (ft^3)	Angle From North (°)
		UTM E (m)	UTM N (m)					
N/A								

L. EMISSION RATES

Emission Point ID	Pollutant Name	CAS #	Emission Rate (lb/hr)	Same as Permitted (1)	Controlled or Uncontrolled	Averaging Period
S-1	NOx	N/A	8.34	☒ Yes ☐ No	Uncontrolled	1-hr, Annual
S-1	CO	630-08-0	14.71	☒ Yes ☐ No	Uncontrolled	1-hr, 8-hr
S-2	NOx	N/A	8.34	☒ Yes ☐ No	Uncontrolled	1-hr, Annual
S-2	CO	630-08-0	14.71	☒ Yes ☐ No	Uncontrolled	1-hr, 8-hr
S-3	NOx	N/A	8.34	☒ Yes ☐ No	Uncontrolled	1-hr, Annual
S-3	CO	630-08-0	14.71	☒ Yes ☐ No	Uncontrolled	1-hr, 8-hr
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		

(1) Any difference between the rates used for permitting and the air compliance demonstration must be explained in the application report.

APPENDIX B

Emissions Calculations

Equipment ID	D-1		D-2		D-3		IA-EG1		IA-ST1		IA-ST2		IA-ST3		IA-ST4		IA-FBC		IA-PD		IA-WSD		IA-BD		IA-EL		Facility-wide Total	
Emission Unit Description	Combustion Turbine		Combustion Turbine		Combustion Turbine		Emergency Generator		Lube Oil Storage Tank		Underground Oily Water Storage Tank		Condensate Storage Tank		Parts Washer		Catalytic Heaters, Comfort Heater		Pneumatic Devices		Wet Seal Degassing		Equipment Blowdowns		Equipment Leaks			
Model Number	Saturn 10-T1000		Saturn 10-T1000		Saturn 10-T1000																							
Fuel	Natural gas		Natural gas		Natural gas		Natural Gas										Natural gas		Natural Gas		N/A		N/A		N/A			
Stack ID	S-1		S-2		S-3		Not Assigned		Not Assigned		Not Assigned		Not Assigned		Not Assigned		Not Assigned		Not Assigned		Not Assigned		Not Assigned		Not Assigned			
Capacity	13.92	MMBtu/hr	13.92	MMBtu/hr	13.92	MMBtu/hr	125	kW	165	gallons	1,000	gallon	500	gallon	20	gallon	0.045, 0.075	MMBtu/hr	N/A		N/A		N/A		N/A			
Pollutants	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr) [1]	(tons/yr)	(lb/hr) [1]	(tons/yr)	(lb/hr) [1]	(tons/yr)	(lb/hr) [1]	(tons/yr)	(lb/hr)	(tons/yr)
NOx	8.34	36.5	8.34	36.5	8.34	36.5	0.55	1.4E-01									1.6E-02	7.1E-02									25.59	109.8
CO	14.71	59.4	14.71	59.4	14.71	59.4	1.10	0.3									1.4E-02	6.0E-02									45.23	178.6
SO_2	4.36E-02	1.9E-01	4.36E-02	1.9E-01	4.36E-02	1.9E-01	1.18E-03	3.0E-04									9.7E-05	4.3E-04									0.13	5.7E-01
VOC	0.48	1.7	0.48	1.7	0.48	1.7	2.01	5.0E-01	4.59E-03	2.0E-02	4.25E-03	1.9E-02	8.48E-03	3.7E-02	0.03	0.1	8.9E-04	3.9E-03	0.23	1.0	0.11	0.5	0.30	1.3	1.11	4.9	5.27	13.5
PM	0.08	0.4	0.08	0.4	0.08	0.4	2.01E-02	5.0E-03									1.2E-03	5.4E-03									0.28	1.1
PM_{10}	0.08	0.4	0.08	0.4	0.08	0.4	2.01E-02	5.0E-03									1.2E-03	5.4E-03									0.28	1.1
$PM_{2.5}$	0.08	0.4	0.08	0.4	0.08	0.4	2.01E-02	5.0E-03									1.2E-03	5.4E-03									0.28	1.1
CO_2	1,491	6,529	1,491	6,529	1,491	6,529	221.27	55.3									19.41	85.0	0.12	0.5	5.98E-02	0.3	1.56E-01	0.7	5.82E-01	2.5	4,713	19,730
CH_4	0.03	0.1	0.03	0.1	0.03	0.1	2.51	0.6									3.7E-04	1.6E-03	3.61	15.8	1.75	7.7	4.57	20.0	17.07	74.7	29.60	119.3
N_2O	2.81E-03	1.2E-02	2.81E-03	1.2E-02	2.81E-03	1.2E-02											3.6E-04	1.6E-03									8.78E-03	3.8E-02
GHG (mass)	1,491	6,529	1,491	6,529	1,491	6,529	223.78	55.9									19.41	85.0	3.74	16.4	1.81	7.9	4.73	20.7	17.65	77.3	4,743	19,850
GHG (CO_2e)	1,492	6,535	1,492	6,535	1,492	6,535	284.13	71.0									19.53	85.5	90.46	396	43.9	192.2	114.43	501.2	427.22	1,871.2	5,456	22,724
Hexane [2]																	1.2E-05	5.3E-05	0.01	0.04	4.74E-03	0.02	0.01	0.05	0.05	0.20	0.07	0.32
Total HAP	1.3E-02	5.8E-02	1.3E-02	5.8E-02	1.3E-02	5.8E-02	1.45E-01	3.6E-02									3.1E-04	1.3E-03	0.01	0.04	4.74E-03	0.02	0.01	0.05	0.05	0.20	0.26	0.53

Notes

1. lb/hr = tons/yr * 2,000 lb/ton / 8,760 hr/yr
2. Hexane is the highest single HAP on a facility-wide basis. However, it may not be the highest single HAP on an emission unit level.

Solar Saturn 10-T1000 Combustion Turbine
Potential to Emit Calculations

Source Designation:	D-1
Manufacturer:	Solar Turbines
Model:	Saturn 10-T1000
Fuel Used:	Natural Gas
Control Device:	None
Emission Point Name:	S-1

Manufacturer Performance Data:

Lower Heating Value (LHV) (Btu/scf):	939.2	[1]
Lower Heating Value (LHV) (Btu/lbm):	20,612	[1]
Fuel Flow (lbm/hr):	676	[1]
Fuel Flow (scfm):	247.09	[1]
Fuel Flow (scf/hr):	14,825	[1]
Heat Input (LHV) (MMBtu/hr):	13.92	[1]
Emission Rate Data, Full Load		
NOx Emission Rate (lbs/hr):	8.34	[1]
CO Emission Rate (lbs/hr):	13.54	[1]
UHC Emission Rate (lbs/hr):	1.94	[1]
Emission Rate Data, Startup		
NOx Emissions (lb/event):	0.8	[2]
CO Emissions (lb/event):	1.7	[2]
UHC Emissions (lb/event):	0.3	[2]
Emission Rate Data, Shutdown		
NOx Emissions (lb/event):	0.8	[2]
CO Emissions (lb/event):	2.4	[2]
UHC Emissions (lb/event):	0.6	[2]

Notes:

[1] Performance data based on Solar Turbines Emission and Performance Data Estimates for Solar Saturn 10-1200 at 30°F.

[2] Startup/shutdown emissions data provided in 27 October 2015 e-mail from Trevor Miller, Solar Turbines, to DCG.

Operational Parameters:

Total Annual Hours of Operation (hr/yr):	8,760	-
Annual Number of Startups:	180	[1]
Approximate Duration of Startup (mins):	10	[2]
Annual Number of Shutdowns:	180	[1]
Approximate Duration of Shutdown (mins):	3	[3]

Notes:

[1] DCG-estimated annual number of unit startup/shutdowns.

[2] Approximate startup duration based on 27 October 2015 e-mail from Trevor Miller, Solar Turbines, to DCG.

[3] Approximate shutdown duration set at the conservative end of the typical range based on DCG experience.

Continued on next page

Criteria Pollutant & Greenhouse Gas Emissions Estimates

Pollutant	Emission Factors[1],[2] (lb/MMBtu)	Hourly Emission Rate, Excluding SU/SD[3],[4] (lb/hr)	Hourly Emission Rate, Including SU/SD[3],[5],[6] (lb/hr)	Maximum Hourly Emission Rate[7] (lb/hr)	Annual PTE, Excluding SU/SD[8] (tons/yr)	Annual PTE, Including SU/SD[6],[9] (tons/yr)	Maximum Annual PTE[10] (tons/yr)
NO_x	-	8.34	8.13	8.34	36.53	36.51	36.53
CO	-	13.54	14.71	14.71	59.31	59.41	59.41
SO_2	0.003	0.044	-	0.044	0.191	-	0.191
VOC	-	0.39	0.48	0.48	1.70	1.71	1.71
PM (Filterable + Condensable)	6.08E-03	8.46E-02	-	8.46E-02	0.37	-	0.37
PM_{10} (Filterable + Condensable)	6.08E-03	8.46E-02	-	8.46E-02	0.37	-	0.37
$PM_{2.5}$ (Filterable + Condensable)	6.08E-03	8.46E-02	-	8.46E-02	0.37	-	0.37
CO_2	107.08	1,491	-	1,491	6,529	-	6,529
CH_4	2.02E-03	2.81E-02	-	2.81E-02	0.12	-	0.12
N_2O	2.02E-04	2.81E-03	-	2.81E-03	0.012	-	0.012
Total GHG (mass basis) [11]	-	-	-	1,491	-	-	6,529
Total GHG (CO2e basis) [12]	-	-	-	1,492	-	-	6,535

Notes:

[1] SO2, PM, PM10, and PM2.5 emission factors from AP-42, 5th ed., Seciton 3.1: Stationary Gas Turbines, Table 3.1-2a (April 2000). Conservatively assume that PM = PM10 = PM2.5. Emission factors are adjusted to be based on LHV for consistency with manufacturer data by multiplying by a factor of LHV/HHV. Default emission factor for SO2 from footnote h of Table 3.1-2a.

Natural Gas HHV from AP-42, 5th ed., Section 3.1 = 1,020 Btu/scf

[2] CO2, CH4, and N2O emission factors from 40 CFR Part 98 Subpart C, Table C-1: Default CO2 Emission Factors and High Heat Values for Various Types of Fuel, for natural gas combustion, converted from kg/MMBtu to lb/MMBtu. Emission factors are adjusted to be based on LHV for consistency with manufacturer data by multiplying by a factor of LHV/HHV.

Natural Gas HHV from 40 CFR Part 98 Subpart C, Table C-1 = 1,026 Btu/scf

[3] Hourly emission rates for NOx, CO, and UHC provided by manufacturer, based on full-load operation at 30°F. VOC emissions assoumed to be 20% of UHC emissions.

[4] Hourly emission rates for SO2, particulates, CO2, CH4, and N2O calculated using emission factors and unit heat input, i.e., Hourly Emission Rate (lb/hr) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr).

[5] Hourly Emission Rate, including SU/SD, estimated assuming that the unit is started and stopped in the same hour and that the unit runs at full-load for the remainder of the hour. Example calculation:
Hourly Emission Rate, Including SU/SD = Startup Emissions (lb/event) * 1 event/hr + Shutdown Emission (lb/event) * 1 event/hr + Hourly Emission Rate (lb/hr) * (60 - (Approx. Startup Duration + Approx. Shutdown Duration))/60.

[6] Startup/shutdown emissions data for SO2, particulates, CO2, CH4, and N2O are not available.

[7] The maximum hourly emission rate is the worst-case value between the Hourly Emission Rate, Excluding SU/SD, and the Hourly Emission Rate, Including SU/SD.

[8] Annual PTE, Excluding SU/SD (tons/yr) = Hourly Emission Rate, Excluding SU/SD (lb/hr) * 8,760 hrs/yr * 1 ton/2000 lbs.

[9] Annual PTE, Including SU/SD, estimated based on the anticipated annual number of unit startups and shutdowns, the approximate duration of each startup and shutdown, and assuming that the unit runs at full-load for the remainder of the year.

[10] Maximum Annual PTE is the worst-case value between the Annual PTE, Excluding SU/SD, and the Annual PTE, Including SU/SD.

[11] Total GHG (mass basis) = CO2 + CH4 + N2O

[12] Total GHG (CO2e basis) = CO2 + CH4 * CH4 Global Warming Potential (GWP) + N2O * N2O GWP. GWP for CH4 and N2O from 40 CFR Part 98, Subpart A, Table A-1: GWP CH4 = 25, GWP N2O = 298.

Continued on next page

Hazardous Air Pollutant Emission Factors and Potential Emission Calculations:

HAP	Emission Factor (LHV)[1] (lb/MMBtu)	Hourly Emission Rate[2] (lb/hr)	Annual PTE[3] (tons/yr)
1,3-Butadiene	3.96E-07	5.51E-06	2.41E-05
Acetaldehyde	3.68E-05	5.13E-04	2.25E-03
Acrolein	5.89E-06	8.20E-05	3.59E-04
Benzene	1.10E-05	1.54E-04	6.74E-04
Ethylbenzene	2.95E-05	4.10E-04	1.80E-03
Formaldehyde	6.54E-04	9.10E-03	3.99E-02
Naphthalene	1.20E-06	1.67E-05	7.30E-05
PAH	2.03E-06	2.82E-05	1.24E-04
Propylene Oxide	2.67E-05	3.72E-04	1.63E-03
Toluene	1.20E-04	1.67E-03	7.30E-03
Xylene	5.89E-05	8.20E-04	3.59E-03
	Total HAP	0.01	0.06

Notes:

1 AP-42, 5th ed., Section 3.1: Stationary Gas Turbines, Table 3.1-3 (April 2000). Emission factors are adjusted to be based on LHV by multiplying by a factor of LHV/HHV.

Natural Gas HHV from AP-42, 5th ed., Section 3.1 = 1,020 Btu/scf

2 Hourly Emission Rate (lb/hr) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr).

3 Potential Emissions (tons/yr) = Potential Emissions (lb/hr) × 8,760 hrs/yr × 1 ton/2,000 lb.

Solar Saturn 10-T1000 Combustion Turbine
Potential to Emit Calculations

Source Designation:	D-2
Manufacturer:	Solar Turbines
Model:	Saturn 10-T1000
Fuel Used:	Natural Gas
Control Device:	None
Emission Point Name:	S-2

Manufacturer Performance Data:

Lower Heating Value (LHV) (Btu/scf):	939.2	[1]
Lower Heating Value (LHV) (Btu/lbm):	20,612	[1]
Fuel Flow (lbm/hr):	676	[1]
Fuel Flow (scfm):	247.09	[1]
Fuel Flow (scf/hr):	14,825	[1]
Heat Input (LHV) (MMBtu/hr):	13.92	[1]
Emission Rate Data, Full Load		
NOx Emission Rate (lbs/hr):	8.34	[1]
CO Emission Rate (lbs/hr):	13.54	[1]
UHC Emission Rate (lbs/hr):	1.94	[1]
Emission Rate Data, Startup		
NOx Emissions (lb/event):	0.8	[2]
CO Emissions (lb/event):	1.7	[2]
UHC Emissions (lb/event):	0.3	[2]
Emission Rate Data, Shutdown		
NOx Emissions (lb/event):	0.8	[2]
CO Emissions (lb/event):	2.4	[2]
UHC Emissions (lb/event):	0.6	[2]

Notes:

[1] Performance data based on Solar Turbines Emission and Performance Data Estimates for Solar Saturn 10-1200 at 30°F.

[2] Startup/shutdown emissions data provided in 27 October 2015 e-mail from Trevor Miller, Solar Turbines, to DCG.

Operational Parameters:

Total Annual Hours of Operation (hr/yr):	8,760	-
Annual Number of Startups:	180	[1]
Approximate Duration of Startup (mins):	10	[2]
Annual Number of Shutdowns:	180	[1]
Approximate Duration of Shutdown (mins):	3	[3]

Notes:

[1] DCG-estimated annual number of unit startup/shutdowns.

[2] Approximate startup duration based on 27 October 2015 e-mail from Trevor Miller, Solar Turbines, to DCG.

[3] Approximate shutdown duration set at the conservative end of the typical range based on DCG experience.

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Criteria Pollutant & Greenhouse Gas Emissions Estimates

Pollutant	Emission Factors[1],[2] (lb/MMBtu)	Hourly Emission Rate, Excluding SU/SD[3],[4] (lb/hr)	Hourly Emission Rate, Including SU/SD[3],[5],[6] (lb/hr)	Maximum Hourly Emission Rate[7] (lb/hr)	Annual PTE, Excluding SU/SD[8] (tons/yr)	Annual PTE, Including SU/SD[6],[9] (tons/yr)	Maximum Annual PTE[10] (tons/yr)
NO_x	-	8.34	8.13	8.34	36.53	36.51	36.53
CO	-	13.54	14.71	14.71	59.31	59.41	59.41
SO_2	0.003	0.044	-	0.044	0.191	-	0.191
VOC	-	0.39	0.48	0.48	1.70	1.71	1.71
PM (Filterable + Condensable)	6.08E-03	8.46E-02	-	8.46E-02	0.37	-	0.37
PM_{10} (Filterable + Condensable)	6.08E-03	8.46E-02	-	8.46E-02	0.37	-	0.37
$PM_{2.5}$ (Filterable + Condensable)	6.08E-03	8.46E-02	-	8.46E-02	0.37	-	0.37
CO_2	107.08	1,491	-	1,491	6,529	-	6,529
CH_4	2.02E-03	2.81E-02	-	2.81E-02	0.12	-	0.12
N_2O	2.02E-04	2.81E-03	-	2.81E-03	0.012	-	0.012
Total GHG (mass basis) [11]	-	-	-	1,491	-	-	6,529
Total GHG (CO2e basis) [12]	-	-	-	1,492	-	-	6,535

Notes:

[1] SO2, PM, PM10, and PM2.5 emission factors from AP-42, 5th ed., Seciton 3.1: Stationary Gas Turbines, Table 3.1-2a (April 2000). Conservatively assume that PM = PM10 = PM2.5. Emission factors are adjusted to be based on LHV for consistency with manufacturer data by multiplying by a factor of LHV/HHV. Default emission factor for SO2 from footnote h of Table 3.1-2a.

Natural Gas HHV from AP-42, 5th ed., Section 3.1 = 1,020 Btu/scf

[2] CO2, CH4, and N2O emission factors from 40 CFR Part 98 Subpart C, Table C-1: Default CO2 Emission Factors and High Heat Values for Various Types of Fuel, for natural gas combustion, converted from kg/MMBtu to lb/MMBtu. Emission factors are adjusted to be based on LHV for consistency with manufacturer data by multiplying by a factor of LHV/HHV.

Natural Gas HHV from 40 CFR Part 98 Subpart C, Table C-1 = 1,026 Btu/scf

[3] Hourly emission rates for NOx, CO, and UHC provided by manufacturer, based on full-load operation at 30°F. VOC emissions assoumed to be 20% of UHC emissions.

[4] Hourly emission rates for SO2, particulates, CO2, CH4, and N2O calculated using emission factors and unit heat input, i.e., Hourly Emission Rate (lb/hr) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr).

[5] Hourly Emission Rate, including SU/SD, estimated assuming that the unit is started and stopped in the same hour and that the unit runs at full-load for the remainder of the hour. Example calculation:
Hourly Emission Rate, Including SU/SD = Startup Emissions (lb/event) * 1 event/hr + Shutdown Emission (lb/event) * 1 event/hr + Hourly Emission Rate (lb/hr) * (60 - (Approx. Startup Duration + Approx. Shutdown Duration))/60.

[6] Startup/shutdown emissions data for SO2, particulates, CO2, CH4, and N2O are not available.

[7] The maximum hourly emission rate is the worst-case value between the Hourly Emission Rate, Excluding SU/SD, and the Hourly Emission Rate, Including SU/SD.

[8] Annual PTE, Excluding SU/SD (tons/yr) = Hourly Emission Rate, Excluding SU/SD (lb/hr) * 8,760 hrs/yr * 1 ton/2000 lbs.

[9] Annual PTE, Including SU/SD, estimated based on the anticipated annual number of unit startups and shutdowns, the approximate duration of each startup and shutdown, and assuming that the unit runs at full-load for the remainder of the year.

[10] Maximum Annual PTE is the worst-case value between the Annual PTE, Excluding SU/SD, and the Annual PTE, Including SU/SD.

[11] Total GHG (mass basis) = CO2 + CH4 + N2O

[12] Total GHG (CO2e basis) = CO2 + CH4 * CH4 Global Warming Potential (GWP) + N2O * N2O GWP. GWP for CH4 and N2O from 40 CFR Part 98, Subpart A, Table A-1: GWP CH4 = 25, GWP N2O = 298.

Continued on next page

Hazardous Air Pollutant Emission Factors and Potential Emission Calculations:

HAP	Emission Factor (LHV)[1] (lb/MMBtu)	Hourly Emission Rate[2] (lb/hr)	Annual PTE[3] (tons/yr)
1,3-Butadiene	3.96E-07	5.51E-06	2.41E-05
Acetaldehyde	3.68E-05	5.13E-04	2.25E-03
Acrolein	5.89E-06	8.20E-05	3.59E-04
Benzene	1.10E-05	1.54E-04	6.74E-04
Ethylbenzene	2.95E-05	4.10E-04	1.80E-03
Formaldehyde	6.54E-04	9.10E-03	3.99E-02
Naphthalene	1.20E-06	1.67E-05	7.30E-05
PAH	2.03E-06	2.82E-05	1.24E-04
Propylene Oxide	2.67E-05	3.72E-04	1.63E-03
Toluene	1.20E-04	1.67E-03	7.30E-03
Xylene	5.89E-05	8.20E-04	3.59E-03
	Total HAP	0.01	0.06

Notes:

1 AP-42, 5th ed., Section 3.1: Stationary Gas Turbines, Table 3.1-3 (April 2000). Emission factors are adjusted to be based on LHV by multiplying by a factor of LHV/HHV.

Natural Gas HHV from AP-42, 5th ed., Section 3.1 = 1,020 Btu/scf

2 Hourly Emission Rate (lb/hr) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr).

3 Potential Emissions (tons/yr) = Potential Emissions (lb/hr) × 8,760 hrs/yr × 1 ton/2,000 lb.

Solar Saturn 10-T1000 Combustion Turbine

Potential to Emit Calculations

Source Designation:	D-3
Manufacturer:	Solar Turbines
Model:	Saturn 10-T1000
Fuel Used:	Natural Gas
Control Device:	None
Emission Point Name:	S-3

Manufacturer Performance Data:

Lower Heating Value (LHV) (Btu/scf):	939.2	[1]
Lower Heating Value (LHV) (Btu/lbm):	20,612	[1]
Fuel Flow (lbm/hr):	676	[1]
Fuel Flow (scfm):	247.09	[1]
Fuel Flow (scf/hr):	14,825	[1]
Heat Input (LHV) (MMBtu/hr):	13.92	[1]
Emission Rate Data, Full Load		
NOx Emission Rate (lbs/hr):	8.34	[1]
CO Emission Rate (lbs/hr):	13.54	[1]
UHC Emission Rate (lbs/hr):	1.94	[1]
Emission Rate Data, Startup		
NOx Emissions (lb/event):	0.8	[2]
CO Emissions (lb/event):	1.7	[2]
UHC Emissions (lb/event):	0.3	[2]
Emission Rate Data, Shutdown		
NOx Emissions (lb/event):	0.8	[2]
CO Emissions (lb/event):	2.4	[2]
UHC Emissions (lb/event):	0.6	[2]

Notes:

[1] Performance data based on Solar Turbines Emission and Performance Data Estimates for Solar Saturn 10-1200 at 30°F.

[2] Startup/shutdown emissions data provided in 27 October 2015 e-mail from Trevor Miller, Solar Turbines, to DCG.

Operational Parameters:

Total Annual Hours of Operation (hr/yr):	8,760	-
Annual Number of Startups:	180	[1]
Approximate Duration of Startup (mins):	10	[2]
Annual Number of Shutdowns:	180	[1]
Approximate Duration of Shutdown (mins):	3	[3]

Notes:

[1] DCG-estimated annual number of unit startup/shutdowns.

[2] Approximate startup duration based on 27 October 2015 e-mail from Trevor Miller, Solar Turbines, to DCG.

[3] Approximate shutdown duration set at the conservative end of the typical range based on DCG experience.

Continued on next page

Criteria Pollutant & Greenhouse Gas Emissions Estimates

Pollutant	Emission Factors[1],[2] (lb/MMBtu)	Hourly Emission Rate, Excluding SU/SD[3],[4] (lb/hr)	Hourly Emission Rate, Including SU/SD[3],[5],[6] (lb/hr)	Maximum Hourly Emission Rate[7] (lb/hr)	Annual PTE, Excluding SU/SD[8] (tons/yr)	Annual PTE, Including SU/SD[6],[9] (tons/yr)	Maximum Annual PTE[10] (tons/yr)
NO_x	-	8.34	8.13	8.34	36.53	36.51	36.53
CO	-	13.54	14.71	14.71	59.31	59.41	59.41
SO_2	0.003	0.044	-	0.044	0.191	-	0.191
VOC	-	0.39	0.48	0.48	1.70	1.71	1.71
PM (Filterable + Condensable)	6.08E-03	8.46E-02	-	8.46E-02	0.37	-	0.37
PM_{10} (Filterable + Condensable)	6.08E-03	8.46E-02	-	8.46E-02	0.37	-	0.37
$PM_{2.5}$ (Filterable + Condensable)	6.08E-03	8.46E-02	-	8.46E-02	0.37	-	0.37
CO_2	107.08	1,491	-	1,491	6,529	-	6,529
CH_4	2.02E-03	2.81E-02	-	2.81E-02	0.12	-	0.12
N_2O	2.02E-04	2.81E-03	-	2.81E-03	0.012	-	0.012
Total GHG (mass basis) [11]	-	-	-	1,491	-	-	6,529
Total GHG (CO2e basis) [12]	-	-	-	1,492	-	-	6,535

Notes:

[1] SO2, PM, PM10, and PM2.5 emission factors from AP-42, 5th ed., Seciton 3.1: Stationary Gas Turbines, Table 3.1-2a (April 2000). Conservatively assume that PM = PM10 = PM2.5. Emission factors are adjusted to be based on LHV for consistency with manufacturer data by multiplying by a factor of LHV/HHV. Default emission factor for SO2 from footnote h of Table 3.1-2a.

Natural Gas HHV from AP-42, 5th ed., Section 3.1 = 1,020 Btu/scf

[2] CO2, CH4, and N2O emission factors from 40 CFR Part 98 Subpart C, Table C-1: Default CO2 Emission Factors and High Heat Values for Various Types of Fuel, for natural gas combustion, converted from kg/MMBtu to lb/MMBtu. Emission factors are adjusted to be based on LHV for consistency with manufacturer data by multiplying by a factor of LHV/HHV.

Natural Gas HHV from 40 CFR Part 98 Subpart C, Table C-1 = 1,026 Btu/scf

[3] Hourly emission rates for NOx, CO, and UHC provided by manufacturer, based on full-load operation at 30°F. VOC emissions assoumed to be 20% of UHC emissions.

[4] Hourly emission rates for SO2, particulates, CO2, CH4, and N20 calculated using emission factors and unit heat input, i.e., Hourly Emission Rate (lb/hr) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr).

[5] Hourly Emission Rate, including SU/SD, estimated assuming that the unit is started and stopped in the same hour and that the unit runs at full-load for the remainder of the hour. Example calculation:
Hourly Emission Rate, Including SU/SD = Startup Emissions (lb/event) * 1 event/hr + Shutdown Emission (lb/event) * 1 event/hr + Hourly Emission Rate (lb/hr) * (60 - (Approx. Startup Duration + Approx. Shutdown Duration))/60.

[6] Startup/shutdown emissions data for SO2, particulates, CO2, CH4, and N2O are not available.

[7] The maximum hourly emission rate is the worst-case value between the Hourly Emission Rate, Excluding SU/SD, and the Hourly Emission Rate, Including SU/SD.

[8] Annual PTE, Excluding SU/SD (tons/yr) = Hourly Emission Rate, Excluding SU/SD (lb/hr) * 8,760 hrs/yr * 1 ton/2000 lbs.

[9] Annual PTE, Including SU/SD, estimated based on the anticipated annual number of unit startups and shutdowns, the approximate duration of each startup and shutdown, and assuming that the unit runs at full-load for the remainder of the year.

[10] Maximum Annual PTE is the worst-case value between the Annual PTE, Excluding SU/SD, and the Annual PTE, Including SU/SD.

[11] Total GHG (mass basis) = CO2 + CH4 + N2O

[12] Total GHG (CO2e basis) = CO2 + CH4 * CH4 Global Warming Potential (GWP) + N2O * N2O GWP. GWP for CH4 and N2O from 40 CFR Part 98, Subpart A, Table A-1: GWP CH4 = 25, GWP N2O = 298.

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Hazardous Air Pollutant Emission Factors and Potential Emission Calculations:

HAP	Emission Factor (LHV)[1] (lb/MMBtu)	Hourly Emission Rate[2] (lb/hr)	Annual PTE[3] (tons/yr)
1,3-Butadiene	3.96E-07	5.51E-06	2.41E-05
Acetaldehyde	3.68E-05	5.13E-04	2.25E-03
Acrolein	5.89E-06	8.20E-05	3.59E-04
Benzene	1.10E-05	1.54E-04	6.74E-04
Ethylbenzene	2.95E-05	4.10E-04	1.80E-03
Formaldehyde	6.54E-04	9.10E-03	3.99E-02
Naphthalene	1.20E-06	1.67E-05	7.30E-05
PAH	2.03E-06	2.82E-05	1.24E-04
Propylene Oxide	2.67E-05	3.72E-04	1.63E-03
Toluene	1.20E-04	1.67E-03	7.30E-03
Xylene	5.89E-05	8.20E-04	3.59E-03
	Total HAP	0.01	0.06

Notes:

1 AP-42, Sth ed., Section 3.1: Stationary Gas Turbines, Table 3.1-3 (April 2000). Emission factors are adjusted to be based on LHV by multiplying by a factor of LHV/HHV.

Natural Gas HHV from AP-42, Sth ed., Section 3.1 = 1,020 Btu/scf

2 Hourly Emission Rate (lb/hr) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr).

3 Potential Emissions (tons/yr) = Potential Emissions (lb/hr) × 8,760 hrs/yr × 1 ton/2,000 lb.

REQUIRED

Estimate emissions from the proposed 125 kW natural gas-fired emergency standby generator (IA-EG1).

GIVEN

The assumptions and parameters used for estimating emissions from the emission source are provided below.

Emission Source IDs =	IA-EG1		
Description =	Natural gas-fired emergency standby generator		
Rated Capacity =	125	kW	
=	168	hp	*(125 kW * 1.34102209 hp/1 kw)*
Brake Specific Fuel Consumption =	12,000	Btu/hp-hr	*(Conservative assumption)*
Size =	2.01	MMBtu/hr	*(12,000Btu/hp-hr * 1 MMBtu/ 10^6 Btu * 168 hp)*
Total Max Hours of Operation =	500	hr/yr	*(1995 EPA memo, Calculating Potential to Emit (PTE) for Emergency Generators)*
Higher Heating Value (HHV) of Fuel =	1,020	Btu/scf	
Fuel Flow =	1,972	scf/hr	*(2.01 * 10^6 Btu/hr / 1,020Btu/scf)*
CO_2 GWP =	1		*(40 CFR 98, Table A-1)*
CH_4 GWP =	25		*(40 CFR 98, Table A-1)*

SOLUTION

Criteria Pollutant Emissions & Greenhouse Gases (GHG)

Pollutants	Emission Factor[1,2]		Estimated Potential Emissions	
			(lb/hr)[3,4]	(tons/yr)
NOx	2	g/kW-hr	0.55	0.1
CO	4	g/kW-hr	1.10	0.3
PM[5]	9.99E-03	lb/MMBtu	2.01E-02	5.0E-03
PM_{10}	9.99E-03	lb/MMBtu	2.01E-02	5.0E-03
$PM_{2.5}$	9.99E-03	lb/MMBtu	2.01E-02	5.0E-03
SO_2	5.88E-04	lb/MMBtu	1.18E-03	3.0E-04
VOC	1	lb/MMBtu	2.01	0.5
CO_2	110	lb/MMBtu	221.27	55.3
CH_4	1.25	lb/MMBtu	2.51	0.6
GHG (mass)[6]	-	-	223.78	55.9
GHG (CO_2e)[7]	-	-	284.13	71.0

Notes:

1) Emission factors for NOx, CO, and VOC from 40 CFR Part 60, Subpart JJJJ, Table 1

2) Emission factors for PM, SO_2, VOC, CO_2, and CH_4 from AP-42 Chapter 3, Section 2, Table 3.2-2.

3) Emissions (lb/hr) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr)

4) Emissions (lb/hr) = Emission Factor (g/kW-hr) * Rated Capacity (kW) * [1 lb / 453.592 grams]

5) Conservatively assume PM is the sum of condensable PM and filterable PM10/2.5, and that PM = PM_{10} = $PM_{2.5}$

6) GHG (mass) = CO_2 + CH_4

7) GHG (CO_2e) = CO_2 * CO_2 GWP + CH_4 * CH_4 GWP

Continued on next page

HAP Emissions				
	Pollutant	Emission Factor	Estimated Potential Emissions	
Pollutant	Type	lb/MMBtu	(lb/hr)	(tons/yr)
1,1,2,2-Tetrachloroethane	HAP	4.00E-05	8.05E-05	2.0E-05
1,1,2-Trichloroethane	HAP	3.18E-05	6.40E-05	1.6E-05
1,3-Butadiene	HAP	2.67E-04	5.37E-04	1.3E-04
1,3-Dichloropropene	HAP	2.64E-05	5.31E-05	1.3E-05
2-Methylnaphthalene	POM	3.32E-05	6.68E-05	1.7E-05
2,2,4-Trimethylpentane	HAP	2.50E-04	5.03E-04	1.3E-04
Acenaphthene	POM	1.25E-06	2.51E-06	6.3E-07
Acenaphthylene	POM	5.53E-06	1.11E-05	2.8E-06
Acetaldehyde	HAP	8.36E-03	1.68E-02	4.2E-03
Acrolein	HAP	5.14E-03	1.03E-02	2.6E-03
Benzene	HAP	4.40E-04	8.85E-04	2.2E-04
Benzo(b)fluoranthene	POM	1.66E-07	3.34E-07	8.3E-08
Benzo(e)pyrene	POM	4.15E-07	8.35E-07	2.1E-07
Benzo(g,h,i)perylene	POM	4.14E-07	8.33E-07	2.1E-07
Biphenyl	HAP	2.12E-04	4.26E-04	1.1E-04
Carbon Tetrachloride	HAP	3.67E-05	7.38E-05	1.8E-05
Chlorobenzene	HAP	3.04E-05	6.12E-05	1.5E-05
Chloroform	HAP	2.85E-05	5.73E-05	1.4E-05
Chrysene	POM	6.93E-07	1.39E-06	3.5E-07
Ethylbenzene	HAP	3.97E-05	7.99E-05	2.0E-05
Ethylene Dibromide	HAP	4.43E-05	8.91E-05	2.2E-05
Fluoranthene	POM	1.11E-06	2.23E-06	5.6E-07
Fluorene	POM	5.67E-06	1.14E-05	2.9E-06
Formaldehyde	HAP	5.28E-02	1.06E-01	2.7E-02
Methanol	HAP	2.50E-03	5.03E-03	1.3E-03
Methylene Chloride	HAP	2.00E-05	4.02E-05	1.0E-05
n-Hexane	HAP	1.11E-03	2.23E-03	5.6E-04
Naphthalene	HAP	7.44E-05	1.50E-04	3.7E-05
PAH	POM	2.69E-05	5.41E-05	1.4E-05
Phenanthrene	POM	1.04E-05	2.09E-05	5.2E-06
Phenol	HAP	2.40E-05	4.83E-05	1.2E-05
Pyrene	POM	1.36E-06	2.74E-06	6.8E-07
Styrene	HAP	2.36E-05	4.75E-05	1.2E-05
Tetrachloroethane	HAP	2.48E-06	4.99E-06	1.2E-06
Toluene	HAP	4.08E-04	8.21E-04	2.1E-04
Vinyl Chloride	HAP	1.49E-05	3.00E-05	7.5E-06
Xylene	HAP	1.84E-04	3.70E-04	9.3E-05
Total POM	HAP	8.71E-05	1.75E-04	4.4E-05
Highest Single HAP	Formaldehyde	5.28E-02	1.06E-01	2.7E-02
Total HAP	-	7.22E-02	1.45E-01	3.6E-02

Notes:

- Emission factors from AP-42 Chapter 3, Section 2, Table 3.2-2.
- Emissions = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr)
- Total POM calculation conservatively includes individual constituents considered to be POM as well as PAH, a subset of POM.

REQUIRED

Estimate emissions from the proposed 165 gallon lube oil storage tank (IA-ST1).

GIVEN

Turnovers per year =	2		*(Provided via email dated November 9, 2015)*
Tank size =	165	gallons	
Throughput =	330	gallons	*(165 gallons * 2 turnovers per year)*

SOLUTION

Actual Emissions:

Actual losses =	15.46	lb/yr	*(Actual emissions from TANKS 4.0.9d, conservatively assume all losses are VOC)*
Safety factor =	2.6		*(From Initial Title V Permit Application for similar facility)*

Scaled Up Potential Emissions:

Total VOC emissions =	40.2	lb/yr	*(15.46 lb/yr * 2.6)*
	4.59E-03	lb/hr	
	2.0E-02	ton/yr	

REQUIRED

Estimate emissions from the proposed 1,000 underground oily water storage tank (IA-ST2).

GIVEN

Turnovers per year =	5		*(Provided via email dated November 9, 2015)*
Tank size =	1,000	gallons	
Throughput =	5,000	gallons	*(1000 gallons * 5 turnovers per year)*

SOLUTION

Actual Emissions:

Actual losses =	14.31	lb/yr	*(Actual emissions from TANKS 4.0.9d, conservatively assume all losses ore VOC)*
Safety factor =	2.6	safety factor	*(From Initial Title V Permit Application far similar facility)*

Scaled Up Potential Emissions:

Total VOC emissions =	37.2	lb/yr	*(14.31 lb/yr * 2.6)*
	4.25E-03	lb/hr	
	1.9E-02	ton/yr	

REQUIRED

Estimate emissions from the proposed 500 gallon aboveground condensate storage tank (IA-ST3).

GIVEN

Turnovers per year =	2		*(Assumed based an number of turnovers for a similar tank at a comparable DCG facility)*
Tank size =	500	gallons	
Throughput =	1,000	gallons	*(500 gallons * 2 turnovers per year)*

SOLUTION

Actual Emissions:

Actual losses =	28.57	lb/yr	*(Actual emissions from TANKS 4.0.9d, conservatively assume all losses are VOC)*
Safety factor =	2.6	safety factor	*(From Initial Title V Permit Application for similar facility)*

Scaled Up Potential Emissions:

Total VOC emissions =	74.3	lb/yr	*(28.57 lb/yr * 2.6)*
	8.48E-03	lb/hr	
	3.7E-02	ton/yr	

REQUIRED

Estimate emissions from the proposed 20 gallon Safety-Kleen parts washer (IA-ST4).

GIVEN *(Assumed based on Safety-Kleen Model 30)*

Depth (front to back)	26	inches
Width	36	inches
Sink Depth	8	inches
Max Fill	15	gallons
Surface Area	6.5	ft^2

SOLUTION

Usage Data

Max Fill	15	gallons/turnover-yr	
Maximum Turnovers	5	turnovers/yr	*(Conservative assumption)*
Maximum Purchased	75	gallons	*(15 gallons/turnover-yr * 5 turnovers/yr)*

Solvent Data:

% VOC	100%		
Solvent Density	7.9	lbs/gallon	*(Assumption based on MSDS for Safety-Kleen Immersion Cleaner and Cold Parts Cleaner: http://safety-kleen.com/File%20Library/msds/82411-rev-10-12.pdf)*

Emission Calculation:

(Solvent purchased - solvent disposed) x (Solvent density) x (%VOC in solvent) = VOC emissions

Solvent purchased	75.00	gallons	
Solvent disposed	50%		*(Conservative assumption)*
Solvent disposed	37.50	gallons/yr	

VOC Emissions =	296.25	lbs/yr
=	0.03	lb/hr
=	0.15	ton/yr

REQUIRED

Estimate potential emissions from the proposed exempt fuel combustion sources.

GIVEN

Fuel =	Natural Gas		
Maximum Run Hours =	8,760	hours/yr	
Equipment Description	2 Natural Gas fired catalytic heater (0.045 MMBTU/hr) and 1 Natural Gas fired HVAC unit (0.075 MMBtu/hr)		
No. of Catalytic Heaters =	2		
Catalytic Heaters Size =	0.045	MMBtu/hr	
No. of Comfort Heaters =	1		
Comfort Heater Size =	0.075	MMBtu/hr	
Total Fuel Combustion Heat Input Rating =	0.165	MMBtu/hr	
Higher Heating Value (HHV) of Fuel =	1,020	MMBtu/MMscf	
Max Hours of Operation =	8,760	hr/yr	
Max Natural Gas Usage =	1.62E-04	MMscf/hr	*(0.165 MMBtu/hr / 1,020 MMBtu/MMscf)*
Annual Fuel Use =	1.417	MMscf/yr	*(1.62E-04 MMscf/hr * 8,760 hr/yr)*
CO_2 GWP =	1		*(40 CFR 98 Table A-1)*
CH_4 GWP =	25		*(40 CFR 98 Table A-1)*
N_2O GWP =	298		*(40 CFR 98 Table A-1)*
Emission Factors			
NOx EF =	100	lb/MMscf	*(Emission Factors from EPA AP-42, Chapter 1, Section 4, Table 1.4-1, uncontrolled small boilers (<100 MMBtu/hr))*
CO EF =	84	lb/MMscf	*(Emission Factors from EPA AP-42, Chapter 1, Section 4, Table 1.4-1, uncontrolled small boilers (<100 MMBtu/hr))*
SO_2 EF =	0.6	lb/MMscf	*(Emission Factors from EPA AP-42, Chapter 1, Section 4, Table 1.4-2)*
VOC EF =	5.5	lb/MMscf	*(Emission Factors from EPA AP-42, Chapter 1, Section 4, Table 1.4-2)*
PM =	7.6	lb/MMscf	*(Emission Factors from EPA AP-42, Chapter 1, Section 4, Table 1.4-2)*
PM_{10} =	7.6	lb/MMscf	*(Conservatively assume PM = PM_{10} = $PM_{2.5}$)*
$PM_{2.5}$ =	7.6	lb/MMscf	*(Conservatively assume PM = PM_{10} = $PM_{2.5}$)*
CO_2 EF =	120,000	lb/MMscf	*(Emission Factors from EPA AP-42, Chapter 1, Section 4, Table 1.4-2)*
CH_4 EF =	2.3	lb/MMscf	*(Emission Factors from EPA AP-42, Chapter 1, Section 4, Table 1.4-2)*
N_2O EF =	2.2	lb/MMscf	*(Emission Factors from EPA AP-42, Chapter 1, Section 4, Table 1.4-2)*

SOLUTION

Emission Calculations = Fuel use (MMscf/hr) x EF (lb/MMscf) x Number of Units = lb Pollutant/hr

NOx =	1.62E-02	lb/hr	7.1E-02	tpy
CO =	1.36E-02	lb/hr	6.0E-02	tpy
SO_2 =	9.71E-05	lb/hr	4.3E-04	tpy
VOC =	8.90E-04	lb/hr	3.9E-03	tpy
PM =	1.23E-03	lb/hr	5.4E-03	tpy
PM_{10} =	1.23E-03	lb/hr	5.4E-03	tpy
$PM_{2.5}$ =	1.23E-03	lb/hr	5.4E-03	tpy
CO_2 =	1.94E+01	lb/hr	85.0	tpy
CH_4 =	3.72E-04	lb/hr	1.6E-03	tpy
N_2O =	3.56E-04	lb/hr	1.6E-03	tpy

GHG Emissions (Mass) = CO_2 Emissions + CH_4 Emissions + N_2O Emissions
= 19.412 lb/hr + 3.72E-04 lb/hr + 3.56E-04 lb/hr
= 19.41 lb/hr
= 85.0 tons/yr

GHG Emissions (CO2e) = CO_2 Emissions * CO_2 GWP + CH_4 Emissions * CH_4 GWP
+ N_2O Emissions * N_2O GWP
= 19.412 lb/hr * 1 + 3.72E-04 lb/hr * 25 + 3.56E-04 lb/hr * 298
= 19.53 lb/hr
= 85.5 tons/yr

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HAP Emissions				
		Emission Factor*	Estimated Potential Emissions	
Pollutants	Pollutant Type	lb/MMscf	(lb/hr)	(tons/yr)
2-Methylnaphthalene	POM	2.4E-05	3.9E-09	1.7E-08
3-Methylchloranthrene	POM	1.8E-06	2.9E-10	1.3E-09
7,12-Dimethylbenz(a)anthracene	POM	1.6E-05	2.6E-09	1.1E-08
Acenaphthene	POM	1.8E-06	2.9E-10	1.3E-09
Acenaphthylene	POM	1.8E-06	2.9E-10	1.3E-09
Anthracene	POM	2.4E-06	3.9E-10	1.7E-09
Benz(a)anthracene	POM	1.8E-06	2.9E-10	1.3E-09
Benzene	HAP	2.1E-03	3.4E-07	1.5E-06
Benzo(a)pyrene	POM	1.2E-06	1.9E-10	8.5E-10
Benzo(b)fluoranthene	POM	1.8E-06	2.9E-10	1.3E-09
Benzo(g,h,i)perylene	POM	1.2E-06	1.9E-10	8.5E-10
Benzo(k)fluoranthene	POM	1.8E-06	2.9E-10	1.3E-09
Chrysene	POM	1.8E-06	2.9E-10	1.3E-09
Dibenzo(a,h)anthracene	POM	1.2E-06	1.9E-10	8.5E-10
Dichlorobenzene	HAP	1.2E-03	1.9E-07	8.5E-07
Fluoranthene	POM	3.0E-06	4.9E-10	2.1E-09
Fluorene	POM	2.8E-06	4.5E-10	2.0E-09
Formaldehyde	HAP	7.5E-02	1.2E-05	5.3E-05
Hexane	HAP	1.80	2.9E-04	1.3E-03
Indeno(1,2,3-cd)pyrene	POM	1.8E-06	2.9E-10	1.3E-09
Naphthalene	HAP	6.1E-04	9.9E-08	4.3E-07
Phenanathrene	POM	1.7E-05	2.8E-09	1.2E-08
Pyrene	POM	5.0E-06	8.1E-10	3.5E-09
Toluene	HAP	3.4E-03	5.5E-07	2.4E-06
Arsenic	HAP	2.0E-04	3.2E-08	1.4E-07
Beryllium	HAP	1.2E-05	1.9E-09	8.5E-09
Cadmium	HAP	1.1E-03	1.8E-07	7.8E-07
Chromium	HAP	1.4E-03	2.3E-07	9.9E-07
Cobalt	HAP	8.4E-05	1.4E-08	6.0E-08
Manganese	HAP	3.8E-04	6.1E-08	2.7E-07
Mercury	HAP	2.6E-04	4.2E-08	1.8E-07
Nickel	HAP	2.1E-03	3.4E-07	1.5E-06
Selenium	HAP	2.4E-05	3.9E-09	1.7E-08
Total POM	HAP	8.8E-05	1.4E-08	6.2E-08
Highest Single HAP	Hexane	1.80	2.9E-04	1.3E-03
Total HAP	-	1.89	3.1E-04	1.3E-03

*Emission factors from EPA AP-42, Chapter 1, Section 4, Table 1.4-3 (Organic Compounds) and Table 1.4-4 (Metals)

REQUIRED

Estimate potential emissions from venting natural gas (NG) powered intermittent bleed (IB) pneumatic devices (PD) at the proposed compressor station.

GIVEN

IB PD Emission Factor (IB PD EF) =	2.35	scf NG/hr-PD	*(40 CFR Part 98, Subpart W, Table W-3)*
No. of IB PD at Dorchester (IB PD Count) =	38	PD	*(Provided via email dated November 9, 2015)*
% CH_4 =	95.6%		*(Average from DCG Gas Quality Report, 2013-2014)*
% CO_2 =	1.2%		*(Average from DCG Gas Quality Report, 2013-2014)*
% VOC =	0.2%		*(Average from DCG Gas Quality Report, 2013-2014)*
% HAP =	0.01%		*(Hexane+, Average from DCG Gas Quality Report, 2013-2014)*
Assumed Leakage Time =	8760	hr/yr	*(24 hr/day * 365 days/yr)*
Specific Gravity of NG =	0.58		*(Average SG from DCG Gas Quality Report, 2013-2014)*
ρ_{air} =	0.0346	kg/cf	*(@ 60°F & 14 psia)*
ρ_{NG} =	0.0202	kg/cf	*(0.58 * 0.0346 kg/cf)*
ρ_{CH4} =	0.0192	kg/cf	*(40 CFR Part 98, Subpart W, 98.233(v), eq W-36 @60°F & 14 psia)*
ρ_{CO2} =	0.0526	kg/cf	*(40 CFR Part 98, Subport W, 98.233(v), eq W-36 @60°F & 14 psia)*
CH_4 GWP =	25	tons CO2e/ton CH4	*(40 CFR Port 98, Subpart A, Table A-1)*
CO_2 GWP =	1	tons CO_2e/ton CO_2	*(40 CFR Part 98, Subpart A, Table A-1)*

SOLUTION

Estimate potential emissions of CH_4, CO_2, and VOC from the PDs at the facility generally following the methodology outlined in 40 CFR Part 98, Subpart W related to PDs (98.233(a)). The methodology in Subpart W has been modified to accommodate the estimation of VOC and HAP emissions from the PDs at the facility and to use 2013-2014 average gas composition data from the DCG Gas Quality Report.

IB PDs

1) Estimate the potential volume of NG vented from the IB PDs at the proposed facility.

IB PD Vol NG Emissions (V_{NG}) = IB PD Count * IB PD EF * 8760 hr/yr
= 38 PD * 2.35 scf NG/hr-PD * 8760 hr/yr
= 782,268 scf NG/yr

2) Estimate the potential volume of CH_4, CO_2, VOC, and HAP vented from the IB PDs at the proposed facility.

IB PD Vol CH4 Emissions (V_{CH4}) = V_{NG} * % CH4
= 782,268 scf NG/yr * 95.6%
= 747,848 scf CH4/yr

IB PD Vol CO2 Emissions (V_{CO2}) = V_{NG} * % CO2
= 782,268 scf NG/yr * 1.2%
= 9,309 scf CO2/yr

IB PD Vol VOC Emissions (V_{VOC}) = V_{NG} * % VOC
= 782,268 scf NG/yr * 0.2%
= 1,877 scf VOC/yr

IB PD Vol HAP Emissions (V_{HAP}) = V_{NG} * % HAP
= 782,268 scf NG/yr * 0.01%
= 78 scf HAP/yr

3) Given the density of NG, CH_4, and CO_2 along with the volumetric emissions of NG, CH_4, CO_2, and VOC, estimate the density of VOCs.

ρ_{VOC} = [(ρ_{NG} * V_{NG}) - (ρ_{CH4} * V_{CH4}) - (ρ_{CO2} * V_{CO2})] / V_{VOC}
= [(0.0202 kg/cf * 782,268 scf NG/yr) - (0.0192 kg/cf * 747,848 scf CH4/yr) - (0.0526 kg/cf * 9,309 scf CO2/yr)] / 1,877 scf VOC/yr
= 0.4963 kg/cf

ρ_{HAP} = 0.4963 kg/cf *(Assumed to be the same as ρ_{VOC})*

Continued on next page

4) Use the density of CH_4, CO_2, VOC, and HAP to estimate potential mass emissions of CH_4, CO_2, VOC, and HAP from IB PDs at the facility.

IB PD Mass CH4 Emissions (M_{CH4}) = V_{CH4} * ρ_{CH4} * 1 ton/907.2 kg
= 747,848 scf CH4/yr * 0.0192 kg/cf * 1 ton/907.2 kg
= 15.8 tons CH4/yr

IB PD Mass CO2 Emissions (M_{CO2}) = V_{CO2} * ρ_{CO2} * 1 ton/907.2 kg
= 9,309 scf CO2/yr * 0.0526 kg/cf * 1 ton/907.2 kg
= 0.5 tons CO2/yr

IB PD Mass VOC Emissions (M_{VOC}) = V_{VOC} * ρ_{VOC} * 1 ton/907.2 kg
= 1,877 scf VOC/yr * 0.4963 kg/cf * 1 ton/907.2 kg
= 1.0 tons VOC/yr

IB PD Mass HAP Emissions (M_{HAP}) = V_{HAP} * ρ_{HAP} * 1 ton/907.2 kg
= 78 scf HAP/yr * 0.4963 kg/cf * 1 ton/907.2 kg
= 0.04 tons VOC/yr

5) Calculate potential GHG emissions from IB PDs at the facility on a CO_2 equivalent basis.

IB PD GHG CO_2e Emissions = M_{CH4} * CH_4 GWP + M_{CO2} * CO_2 GWP
= 15.8 tons CH4/yr * 25 tons CO2e/ton CH4 + 0.54 tons CO2/yr * 1 tons CO2e/ton CO2
= 396.2 tons CO_2e/yr

SUMMARY

Pollutant	IB PDs (tons/yr)	Total PDs (tons/yr)
CH_4	15.8	15.8
CO_2	0.5	0.5
GHG (mass basis)	16.4	16.4
GHG (CO_2e basis)	396.2	396.2
VOC	1.0	1.0
HAP	0.04	0.04

Note:

1) HAP emissions are based on the cumulative volume fraction of hydrocarbons that contain six or more carbon atoms (hexane+), thus they are a conservative estimate of HAP emissions.

REQUIRED

Estimate potential emissions from wet seal degassing (WSD) at the proposed compressor station.

GIVEN

EPA Screening Tool Data

Number of Compressors =	3	units	*(Dorchester Compressor Station)*
Single Centrifugal Compressor Venting Emissions =	5,791	m tons CO_2e/yr	*(EPA Screening Tool for NG Transmission for 1 units)*
Centrifugal Compressor Venting Emissions =	17,373	m tons CO_2e/yr	*(5,791 m tons CO2e/yr * 3 units)*
CH_4-CO2e Conversion Factor =	0.000479	m tons CO_2e/cf CH_4	*(EPA Screening Tool for NG Transmission; Guidance & Sources tab)*
Centrifugal Compressor Venting Emissions =	36,269,311	cf CH_4/yr	*(17,373 m tons CO2e/yr / 0.000479 m tons CO2e/cf CH4)*

Recovery Efficiency

Assumed Recovery Efficiency =	99%		*(EPA Presentation: http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/smith.pdf)*

Standard Data

% CH_4 =	95.6%		*(Average from DCG Gas Quality Report, 2013-2014)*
% CO_2 =	1.2%		*(Average from DCG Gas Quality Report, 2013-2014)*
% VOC =	0.2%		*(Average from DCG Gas Quality Report, 2013-2014)*
% HAP =	0.01%		*(Hexane+, Average from DCG Gas Quality Report, 2013-2014)*
ρ_{CH4} =	0.0192	kg/cf	*(40 CFR Part 98, Subpart W, 98.233(v), eq W-36)*
ρ_{CH4} =	2.12E-05	ton/cf	*(0.0192 kg/cf * 2.205-lb/kg /2000 lb/ton)*
ρ_{CO2} =	0.0526	kg/cf	*(40 CFR Part 98, Subpart W, 98.233(v), eq W-36)*
ρ_{CO2} =	5.80E-05	ton/cf	*(0.0526 kg/cf * 2.205-lb/kg /2000 lb/ton)*
ρ_{VOC} =	0.4963	kg/cf	*(See Pneumatic Device Emissions Calculations)*
ρ_{VOC} =	5.47E-04	ton/cf	*(0.4963 kg/cf * 2.205-lb/kg /2000 lb/ton)*
ρ_{HAP} =	0.4963	kg/cf	*(See Pneumatic Device Emissions Calculations)*
ρ_{HAP} =	5.47E-04	ton/cf	*(0.4963 kg/cf * 2.205-lb/kg /2000 lb/ton)*
CH_4 GWP =	25	tons CO_2e/ton CH_4	*(40 CFR Part 98, Subpart A, Table A-1)*
CO_2 GWP =	1	tons CO_2e/ton CO_2	*(40 CFR Part 98, Subpart A, Table A-1)*

SOLUTION

Unrecovered NG Venting

Unrecovered NG Venting = Centrifugal Compressor Venting Emissions / Volume Fraction CH4
= 36,269,311 cf CH4/yr / 0.956
= 37,938,610 cf NG/yr

Unrecovered CH_4, CO_2, VOC, and HAP Venting

Uncontrolled CH_4 Emissions = Unrecovered NG Venting * ρCH_4 * % CH_4
= 37,938,610 cf NG/yr * 2.12E-05 ton/cf * 95.6%
= 768 tons/yr

Unrecovered CO_2 Emissions = Unrecovered NG Venting * ρCO_2 * % CO_2
= 37,938,610 cf NG/yr * 5.80E-05 ton/cf * 1.2%
= 26 tons/yr

Unrecovered VOC Emissions = Unrecovered NG Venting * ρVOC* % VOC
= 37,938,610 cf NG/yr * 5.47E-04 ton/cf * 0.2%
= 50 tons/yr

Unrecovered HAP Emissions = Unrecovered NG Venting * ρHAP* % HAP
= 37,938,610 cf NG/yr * 5.47E-04 ton/cf * 0.01%
= 2.1 tons/yr

Potential Emissions

Potential CH_4 Emissions = Unrecovered CH_4 Emissions * (1 - Assumed Recovery Efficiency)
= 768 tons/yr * (1 - 0.99)
= 7.7 tons/yr

Potential CO_2 Emissions = Unrecovered CO_2 Emissions * (1 - Assumed Recovery Efficiency)
= 26 tons/yr * (1 - 0.99)
= 0.3 tons/yr

Continued on next page

Potential VOC Emissions = Unrecovered VOC Emissions * (1 - Assumed Recovery Efficiency)
= 50 tons/yr * (1 - 0.99)
= 0.5 tons/yr

Potential HAP Emissions = Unrecovered HAP Emissions * (1 - Assumed Recovery Efficiency)
= 2.1 tons/yr * (1 - 0.99)
= 0.02 tons/yr

GHG Summary

WSD GHG CO2e Emissions = Potential CH_4 Emissions * CH_4 GWP + Potential CO_2 Emissions * CO_2 GWP
= 7.68 tons/yr * 25 tons CO2e/ton CH4 + 0.26 tons/yr * 1 tons CO2e/ton CO2
= 192.2 tons CO2e/yr

SUMMARY

Pollutant	WSD Emissions (tons/yr)
CH_4	7.7
CO_2	0.3
GHG (mass basis)	7.9
GHG (CO_2e basis)	192.2
VOC	0.5
HAP	0.02

Note:

1) HAP emissions are based on the cumulative volume fraction of hydrocarbons that contain six or more carbon atoms (hexane+), thus they are a conservative estimate of HAP emissions.

REQUIRED

Estimate potential emissions from venting natural gas (NG) to the atmosphere during equipment blowdowns at the proposed compressor station.

GIVEN

Compressor Blowdown Data

Number of Compressors =	3	units	*(Dorchester Compressor Station)*
Number of Shutdown Events per compressor =	180	events/unit-yr	*(Provided via email dated November 9, 2015)*
Number of Shutdown Events (N_{comp}) =	540	events/yr	*(180 events/unit-yr * 3 units)*
Vol. between isolation valves (V_{comp}) =	17.45	cf/unit	*(DCG estimate)*
Max. Pressure (P_{comp}) =	1,200	psia	*(Worst-case scenario assumption)*
Temp @ P_{comp} (T_{comp}) =	200	Deg F	*(DCG estimate)*

Fuel Supply System Blowdown Data

Vol. of NG emitted during blowdown =	3,000	scf/event	*(DCG estimated value @ 150 psi and 150 deg F for similar Compressor Station)*
No. blowdowns (N_{fs}) =	3	events/yr	*(Worst-case scenario assumption)*
Annual volume of NG emitted (Vol NG_{FS}) =	9,000	scf/yr	*(3 events/yr * 3,000 scf/event)*

ESD Blowdown Data

Vol. of NG emitted during blowdown =	128,000	scf/event	*(DCG estimated value @ 900 psi and 90 deg F for similar Compressor Station)*
No. blowdowns (N_{ESD}) =	3	events/yr	*(Worst-case scenario assumption)*
Annual volume of NG emitted (Vol NG_{ESD}) =	384,000	scf/yr	*(3 events/yr * 128,000 scf/event)*

Standard Data

Standard Temperature (T_s) =	60	deg F	*(definition of 'standard', 40 CFR Part 98, Subpart A)*
Standard Pressure (P_s) =	14.7	psia	*(definition of 'standard', 40 CFR Part 98, Subpart A)*
% CH_4 =	95.6%		*(Average from DCG Gas Quality Report, 2013-2014)*
% CO_2 =	1.2%		*(Average from DCG Gas Quality Report, 2013-2014)*
% VOC =	0.2%		*(Average from DCG Gas Quality Report, 2013-2014)*
% HAP =	0.01%		*(Hexane+, Average from DCG Gas Quality Report, 2013-2014)*
ρ_{CH4} =	0.0192	kg/cf	*(40 CFR Part 98, Subpart W, 98.233(v), eq W-36)*
ρ_{CO2} =	0.0526	kg/cf	*(40 CFR Part 98, Subpart W, 98.233(v), eq W-36)*
ρ_{VOC} =	0.4963	kg/cf	*(See Pneumatic Device Emissions Calculations)*
ρ_{HAP} =	0.4963	kg/cf	*(See Pneumatic Device Emissions Calculations)*
CH_4 GWP =	25	tons CO_2e/ton CH_4	*(40 CFR Part 98, Subpart A, Table A-1)*
CO_2 GWP =	1	tons CO_2e/ton CO_2	*(40 CFR Part 98, Subpart A, Table A-1)*
Purge Factor (C) =	1		*(40 CFR Part 98, Subpart W, Eq W-14a, not purged)*

SOLUTION

Estimate potential emissions of CH_4, CO_2, VOC, and HAP from equipment blowdowns at the facility generally following the methodology outlined in 40 CFR Part 98, Subpart W related to equipment blowdowns (98.233(v)). The methodologies in Subpart W have been modified to accommodate the estimation of VOC and HAP emissions from equipment blowdowns at the facility and to use 2013-2014 average gas composition data from the DCG Gas Quality Report.

1) Estimate the potential amount of NG vented to the atmosphere due to compressor shutdowns at the facility.

$$\text{Vol } NG_{comp} = N_{comp} * [V_{comp} * (((459.67 + T_s)*P_{comp}) / ((459.67+ T_{comp}) * P_s)) - V_{comp} * C]$$

(40 CFR Part 98, Subpart W, Eq W-14A)

$$= 540 * [17.45 * (((459.67 + 60) * 1200) / ((459.67 + 200) * 14.7)) - 17.45 * 1]$$

$$= 596{,}551 \text{ scf/yr}$$

2) Estimate total amount of NG vented to the atmosphere due to equipment blowdowns by adding the DCG-estimated values for fuel supply and ESD blowdowns to the above-calculated value.

$$\text{Vol } NG_{Total} = \text{Vol } NG_{FS} + \text{Vol } NG_{ESD} + \text{Vol } NG_{Comp}$$

$$= 9{,}000 \text{ scf/yr} + 384{,}000 \text{ scf/yr} + 596{,}551 \text{ scf/yr}$$

$$= 989{,}551 \text{ scf/yr}$$

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3) Estimate the potential volume of CH_4, CO_2, VOC, and HAP vented during equipment blowdowns at the facility.

Vol CH_4 Emissions (V_{CH4}) = Vol NG_{Total} * % CH4
= 989,551 scf/yr * 95.6%
= 946,011 scf/yr

Vol CO_2 Emissions (V_{CO2}) = Vol NG_{Total} * % CO2
= 989,551 scf/yr * 1.2%
= 11,776 scf/yr

Vol VOC Emissions (V_{VOC}) = Vol NG_{Total} * % VOC
= 989,551 scf/yr * 0.2%
= 2,375 scf/yr

Vol HAP Emissions (V_{HAP}) = Vol NG_{Total} * % HAP
= 989,551 scf/yr * 0.01%
= 99 scf/yr

4) Estimate potential mass emissions of CH_4, CO_2, VOC, and HAP from equipment blowdowns at the facility.

Mass CH_4 Emissions (M_{CH4}) = V_{CH4} * ρ_{CH4} * 1 ton/907.2 kg
= 946,011 scf/yr * 0.0192 kg/cf * 1 ton/907.2 kg
= 20.0 tons CH4/yr

Mass CO_2 Emissions (M_{CO2}) = V_{CO2} * ρ_{CO2} * 1 ton/907.2 kg
= 11,776 scf/yr * 0.0526 kg/cf * 1 ton/907.2 kg
= 0.7 tons CO2/yr

Mass VOC Emissions (M_{VOC}) = V_{VOC} * ρ_{VOC} * 1 ton/907.2 kg
= 2,375 scf/yr * 0.4963 kg/cf * 1 ton/907.2 kg
= 1.3 tons VOC/yr

Mass HAP Emissions (M_{HAP}) = V_{HAP} * ρ_{HAP} * 1 ton/907.2 kg
= 99 scf/yr * 0.4963 kg/cf * 1 ton/907.2 kg
= 0.05 tons HAP/yr

5) Calculate potential GHG emissions from equipment blowdowns at the proposed on a CO_2 equivalent basis.

CHB PD GHG CO_2e Emissions = M_{CH4} * CH4 GWP + M_{CO2} * CO2 GWP
= 20.0 tons CH4/yr * 25 tons CO2e/ton CH4 + 0.7 tons CO2/yr * 1 tons CO2e/ton CO2
501.2 tons CO_2e/yr

SUMMARY

Pollutant	Equipment Blowdown Emissions (tons/yr)
CH_4	20.0
CO_2	0.7
GHG (mass basis)	20.7
GHG (CO_2e basis)	501.2
VOC	1.3
HAP	0.05

Note:

1) HAP emissions are based on the cumulative volume fraction of hydrocarbons that contain six or more carbon atoms (hexane+), thus they are a conservative estimate of HAP emissions.

REQUIRED

Estimate potential emissions from venting natural gas (NG) to the atmosphere due to leaky equipment at the proposed compressor station.

GIVEN

Assumed Leakage Time (T_{Valve}) =	8760	hr/yr	
VOL % CH_4 =	95.6%		*(Average from DCG Gas Quality Report, 2013-2014)*
VOL % CO_2 =	1.2%		*(Average from DCG Gas Quality Report, 2013-2014)*
VOL % VOC =	0.2%		*(Average from DCG Gas Quality Report, 2013-2014)*
VOL % HAP =	0.01%		*(Hexane+, Average from DCG Gas Quality Report, 2013-2014)*
ρ_{CH4} =	0.0192	kg/cf	*(40 CFR Part 98, Subpart W, 98.233(v), eq W-36)*
ρ_{CO2} =	0.0526	kg/cf	*(40 CFR Part 98, Subpart W, 98.233(v), eq W-36)*
ρ_{VOC} =	0.4963	kg/cf	*(See Pneumatic Device Emissions Calculations)*
ρ_{HAP} =	0.4963	kg/cf	*(See Pneumatic Device Emissions Calculations)*
CH_4 GWP =	25	tons CO_2e/ton CH_4	
CO_2 GWP =	1	tons CO_2e/ton CO_2	
Contingency Factor =	1.2		*(Conservative Assumption)*

SOLUTION

Estimate potential emissions of CH4, CO2, and VOC from equipment leaks at the facility generally following the methods outlined in 40 CFR Part 98, Subpart W related to equipment leaks (98.233(q),(r),&(v)). The methodologies in Subpart W have been modified to accommodate the estimation of VOC and HAP emissions from equipment leaks at the facility and to use 2013-2014 average gas composition data from the DCG Gas Quality Report.

Component Type [1]	Number of Leaks [2]	EF (scf/hr-component) [1]	NG Volume (scf/yr) [3]	Mass Emissions (tons/yr) [4]				GHG CO_2e[6]
				CH_4	CO_2	VOC	HAP[5]	
Compressor Components, Gas Service - Connector	15	5.59	734,526	17.8	0.6	1.2	0.0	446
Compressor Components, Gas Service - Meter	0	19.33	-	-	-	-	-	-
Compressor Components, Gas Service - Open Ended Line	2	17.27	302,570	7.3	0.3	0.5	0.02	183.9
Compressor Components, Gas Service - Pressure Relief Valve	0	39.66	-	-	-	-	-	0.0
Compressor Components, Gas Service - Valve	7	14.84	909,989	22.1	0.8	1.4	0.1	553.1
Non-compressor Components, Gas Service - Connector	17	5.71	850,333	20.6	0.7	1.3	0.1	516.8
Non-compressor Components, Gas Service - Meter	0	2.93	-	-	-	-	-	0.0
Non-compressor Components, Gas Service - Open Ended Line	0	11.27	-	-	-	-	-	0.0
Non-compressor Components, Gas Service - Pressure Relief Valve	0	2.01	-	-	-	-	-	0.0
Non-compressor Components, Gas Service - Valve	5	6.42	281,196	6.8	0.2	0.4	0.02	170.9
Total			**3,078,614**	**74.7**	**2.5**	**4.9**	**0.2**	**1,871.2**

Notes:

1) 40 CFR Part 98, Subpart W, Table W-3.

2) Maximum number of Leaks detected during five DCG compressor station monitoring events.

3) NG Volume (scf/yr) = Number of Leaks (components) * NG EF (scf/hr/component) * 8,760 hr/yr.

4) Mass Emissions (tons/yr) = NG Volume (scf/yr) * $VOL_{pollutant}$ * $\rho_{pollutant}$ * / 907.2 kg/ton * Contingency Factor

5) Based on the cumulative volume fraction of hydrocarbons that contain six or more carbon atoms (hexane+), thus a conservative estimate of HAP.

6) GHG CO2e emissions = Mass $Emissions_{CH4}$ * GWP_{CH4} + Mass $Emissions_{CO2}$ * GWP_{CO2}

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

Identification

User Identification	DCS - IAST1
City:	St. George
State:	South Carolina
Company:	DCG - Dorchester
Type of Tank:	Horizontal Tank
Description	165 gal lube oil storage tank (2 turnovers)

Tank Dimensions

Shell Length (ft):		5 00
Diameter (ft):		3.00
Volume (gallons):		165 00
Turnovers:		2 00
Net Throughput(gal/yr):		330 00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n)	N	

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0 03
Pressure Settings (psig)	0 03

Meterological Data used in Emissions Calculations Charleston C.O., South Carolina (Avg Atmospheric Pressure = 14 75 psia)

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

DCS - IAST1 - Horizontal Tank
St. George, South Carolina

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
Crude oil (RVP 5)	All	68.08	63.81	72.34	66.12	3.3642	3.0996	3.6466	50.0000			207.00	Option 4: RVP=5

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

Emissions Report for: Annual

DCS - IAST1 - Horizontal Tank
St. George, South Carolina

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	0.99	14.47	15.46

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

Identification

User Identification:	DCS - IAST2
City:	St. George
State:	South Carolina
Company	DCG - Dorchester
Type of Tank	Horizontal Tank
Description	1000 gal underground oily water storage tank (5 turnovers)

Tank Dimensions

Shell Length (ft):		6.17
Diameter (ft):		5.33
Volume (gallons):		1,000.00
Turnovers:		5.00
Net Throughput(gal/yr):		5,000.00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	Y	

Paint Characteristics

Shell Color/Shade.
Shell Condition

Breather Vent Settings

Vacuum Settings (psig):	-0 03
Pressure Settings (psig)	0 03

Meterological Data used in Emissions Calculations Charleston C O , South Carolina (Avg Atmospheric Pressure = 14.75 psia)

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

DCS - IAST2 - Horizontal Tank
St. George, South Carolina

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
Crude oil (RVP 5)	All	65.54	65.54	65.54	65.10	3.2052	3.2052	3.2052	50.0000			207.00	Option 4: RVP=5

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

Emissions Report for: Annual

DCS - IAST2 - Horizontal Tank
St. George, South Carolina

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	14.31	0.00	14.31

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

Identification

User Identification.	DCS - IAST3
City	St. George
State:	South Carolina
Company	DCG - Dorchester
Type of Tank:	Horizontal Tank
Description	500 gal condensate storage tank (2 turnovers) Crude oil used as a surrogate

Tank Dimensions

Shell Length (ft):		5.32
Diameter (ft):		4.00
Volume (gallons).		500.00
Turnovers:		2.00
Net Throughput(gal/yr):		1,000 00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	N	

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good

Breather Vent Settings

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

Meterological Data used in Emissions Calculations: Charleston C.O., South Carolina (Avg Atmospheric Pressure = 14.75 psia)

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

DCS - IAST3 - Horizontal Tank
St. George, South Carolina

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
Crude oil (RVP 5)	All	68.08	63.81	72.34	66.12	3.3642	3.0996	3.6466	50.0000			207.00	Option 4: RVP=5

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

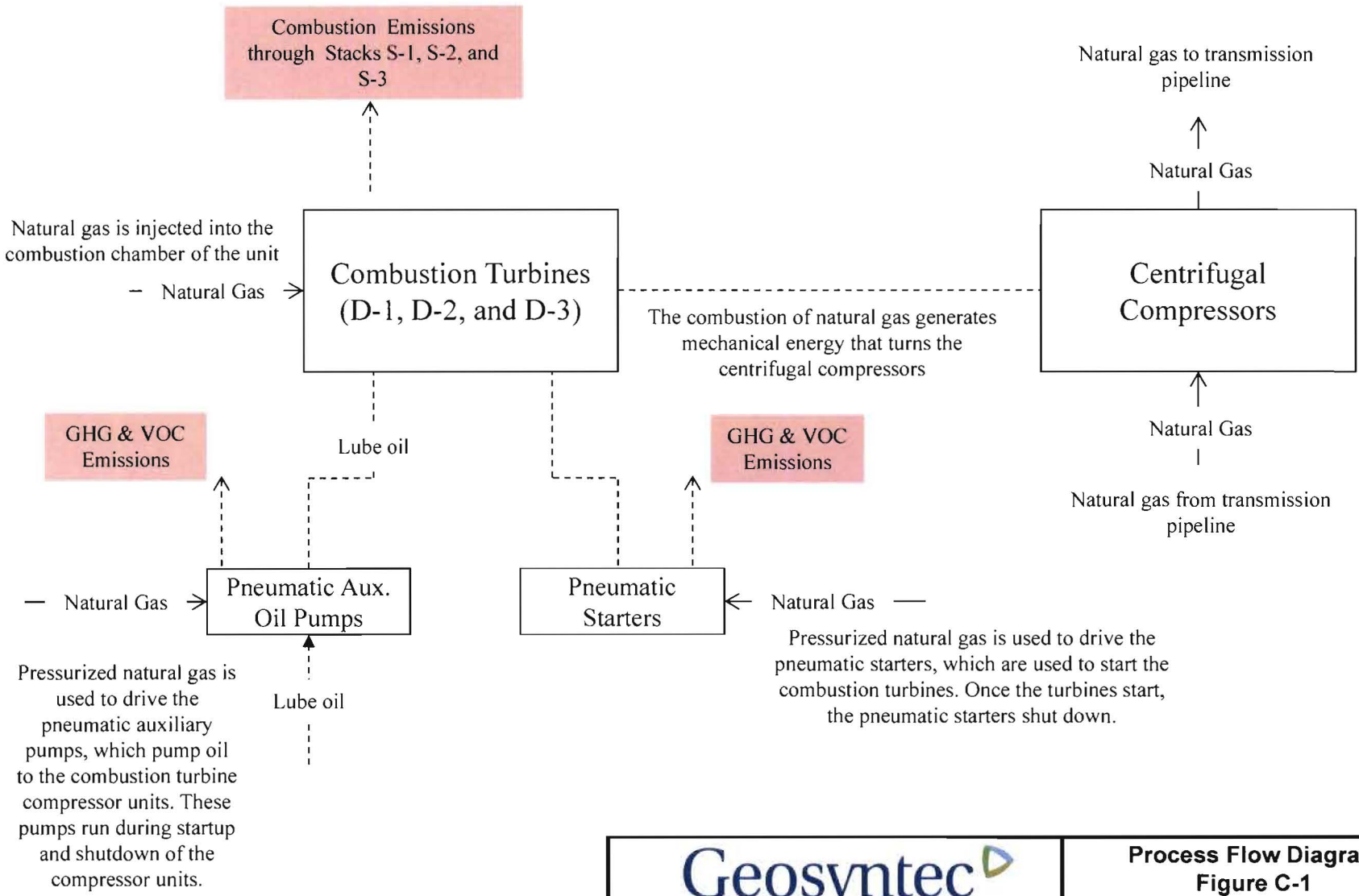
Emissions Report for: Annual

DCS - IAST3 - Horizontal Tank
St. George, South Carolina

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	3.00	25.57	28.57

APPENDIX C

Process Flow Diagram



Geosyntec consultants

Process Flow Diagram
Figure C-1

Dorchester Compressor Station
St. George, Dorchester County, SC

APPENDIX D

Supporting Documentation for Emissions Calculations

From: Kennie W Mckenzie (Energy - 2T) [mailto:Kennie.W.Mckenzie@dom.com]
Sent: Monday, November 2, 2015 8:10 AM
To: Brandon Mogan <BMogan@Geosyntec.com>; Jeffrey Barwick <JBarwick@Geosyntec.com>
Cc: Richard L Kopec (Energy - 2) <Richard.L.Kopec@dom.com>
Subject: Fwd: T2C Air Permitting Data Needs

See below.
Thanks
Kennie

Sent from my iPhone

Begin forwarded message:
From: "Trevor S. Miller" <Miller_Trevor_S@solarturbines.com>
Date: October 30, 2015 at 2:19:56 PM EDT
To: "Kennie W Mckenzie (Energy - 2T)" <Kennie.W.Mckenzie@dom.com>
Subject: Re: Fwd: T2C Air Permitting Data Needs
Kennie,

As highlighted below, proposed units D-1 through D-3 will be Saturn 10-T1000 units despited being labeled Saturn 10-T1200 in the following manufacturer data.

Attached is the predicted emissions for Dorchester. Per my last email, the current engine configuration at Southern are Saturn 10 - T1000. Solar has not manufactured a true T1000 since the 1980s. When a customer orders an overhaul T1000 we build a T1200 and adjust the nozzles accordingly. With that said emissions predictions are the same for T1000 and T1200. Our predicted emissions tool only has emissions predictions option for a T1200, that's why the heading has ST1200.

Attached are the predicted exhaust flows for a Saturn 10 1400 and Saturn 10 1200

Please let me know if you need anything else

Trevor S. Miller
Customer Service Account Manager
Solar Turbines Inc.
Email: Miller_Trevor_S@solarturbines.com
Office: 504-734-8241
Cell: 630-258-1972

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Kristina Izett

From: Jeffrey Barwick
Sent: Tuesday, October 27, 2015 5:02 PM
To: Kristina Izett
Subject: FW: T2C Air Permitting Data Needs
Attachments: Predicted Emissions Saturn 10 T1200.pdf

See attached. Please place this in the file for Dorchester.

Jeffrey Barwick, PE | Geosyntec Consultants, Inc
O: 864.478.1170 | C: 803.983.3119 | jbarwick@geosyntec.com

From: Kennie W Mckenzie (Energy - 2T) [mailto:Kennie.W.Mckenzie@dom.com]
Sent: Tuesday, October 27, 2015 4:43 PM
To: Brandon Mogan <BMogan@Geosyntec.com>
Cc: Richard L Kopec (Energy - 2) <Richard.L.Kopec@dom.com>; Jeffrey Barwick <JBarwick@Geosyntec.com>
Subject: Fwd: T2C Air Permitting Data Needs

Sent from my iPhone

Begin forwarded message:

From: "Trevor S. Miller" <Miller_Trevor_S@solarturbines.com>
Date: October 27, 2015 at 12:20:13 AM EDT
To: "Kennie W Mckenzie (Energy - 2T)" <Kennie.W.Mckenzie@dom.com>
Subject: Re: T2C Air Permitting Data Needs

Kennie,

Attached is the predicted emissions for Saturn 10 - 1200

Saturn 10 - T1200 SU/SD estimates:

Assumes 10 minute start-up

SU
NOx 0.8 lbs/event
CO 1.7 lbs/event
UHC 0.3 lbs/event

SD
NOx 0.8 lbs/event
CO 2.4 lbs/event
UHC 0.6 lbs/event

Please let me know if you need anything else.

Trevor S. Miller
Customer Service Account Manager

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer: Carolina Gas Transmission	Engine Model: SATURN 10-1200 CS/MD STANDARD — *Units are 10-T1000 per note above
Job ID: NO14-03616	
Inquiry Number: NO14-03616	Fuel Type: SD NATURAL GAS — Water Injection: NO
Run By: Trevor S Miller — Date Run: 13-Nov-15	Engine Emissions Data: REV. 0.0

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 1259 HP 100.0% Load — Elev. 90 ft — Rel. Humidity 60.0% — Temperature 30.0 Deg. F			
PPMvd at 15% O2	150.00	400.00	100.00
ton/yr	36.54	59.32	8.49
lbm/MMBtu (Fuel LHV)	0.599	0.973	0.139
lbm/(MW-hr)	8.89	14.42	2.07
(gas turbine shaft pwr) lbm/hr	8.34	13.54	1.94
2 — 1239 HP 100.0% Load — Elev. 90 ft — Rel. Humidity 60.0% — Temperature 40.0 Deg. F			
PPMvd at 15% O2	150.00	400.00	100.00
ton/yr	36.03	58.50	8.38
lbm/MMBtu (Fuel LHV)	0.599	0.972	0.139
lbm/(MW-hr)	8.90	14.45	2.07
(gas turbine shaft pwr) lbm/hr	8.23	13.36	1.91
3 — 1218 HP 100.0% Load — Elev. 90 ft — Rel. Humidity 60.0% — Temperature 50.0 Deg. F			
PPMvd at 15% O2	150.00	400.00	100.00
ton/yr	35.50	57.64	8.25
lbm/MMBtu (Fuel LHV)	0.598	0.970	0.139
lbm/(MW-hr)	8.92	14.48	2.07
(gas turbine shaft pwr) lbm/hr	8.11	13.16	1.88

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg C, and between 50% and 100% load for gas, fuel, and between 65% and 100% load for liquid fuel (except f or the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg C and betwee
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer **Carolina Gas Transmission**	Engine Model **SATURN 10-1200 CS/MD STANDARD**
Job ID **NO14-03616**	
Inquiry Number **NO14-03616**	Fuel Type: **SD NATURAL GAS** Water Injection: **NO**
Run By: **Trevor S Miller** Date Run: **13-Nov-15**	Engine Emissions Data **REV. 0.0**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
4 — 1197 HP 100.0% Load — Elev. 90 ft — Rel. Humidity 60.0% — Temperature 60.0 Deg. F			
PPMvd at 15% O2	150.00	400.00	100.00
ton/yr	34.95	56.74	8.12
lbm/MMBtu (Fuel LHV)	0.597	0.968	0.139
lbm/(MW-hr)	8.94	14.51	2.08
(gas turbine shaft pwr) lbm/hr	7.98	12.95	1.85
5 — 1171 HP 100.0% Load — Elev. 90 ft — Rel. Humidity 60.0% — Temperature 70.0 Deg. F			
PPMvd at 15% O2	150.00	400.00	100.00
ton/yr	34.35	55.77	7.99
lbm/MMBtu (Fuel LHV)	0.595	0.966	0.138
lbm/(MW-hr)	8.98	14.59	2.09
(gas turbine shaft pwr) lbm/hr	7.84	12.73	1.82
6 — 1133 HP 100.0% Load — Elev. 90 ft — Rel. Humidity 60.0% — Temperature 80.0 Deg. F			
PPMvd at 15% O2	150.00	400.00	100.00
ton/yr	33.48	54.35	7.78
lbm/MMBtu (Fuel LHV)	0.593	0.962	0.138
lbm/(MW-hr)	9.05	14.69	2.10
(gas turbine shaft pwr) lbm/hr	7.64	12.41	1.78

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg C, and between 50% and 100% load for gas, fuel, and between 65% and 100% load for liquid fuel (except f or the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg C and betwee
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer: Carolina Gas Transmission	Model: SATURN 10-1200 *Units are 10-T1000 per note above
Job ID: NO14-03616	Package Type: CS/MD
Run By: Trevor S Miller; Date Run: 13-Nov-15	Match: STANDARD
Engine Performance Code: REV. 4.16.1.18.10; Engine Performance Data: REV. 0.0	Fuel System: GAS
	Fuel Type: SD NATURAL GAS

DATA FOR NOMINAL PERFORMANCE

Elevation	feet	90
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	4.0
Accessory on GP Shaft	HP	27.0

		1	2	3	4	5	6
Engine Inlet Temperature	deg F	30.0	40.0	50.0	60.0	70.0	80.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	22300	22300	22300	22300	22300	22300
Specified Load	HP	FULL	FULL	FULL	FULL	FULL	FULL
Net Output Power	HP	1259	1239	1218	1197	1171	1133
Fuel Flow	mmBtu/hr	13.92	13.74	13.56	13.38	13.18	12.90
Heat Rate	Btu/HP-hr	11058	11089	11130	11173	11262	11383
Therm Eff	%	23.010	22.945	22.862	22.773	22.593	22.352
Engine Exhaust Flow	lbm/hr	51554	50815	50043	49276	48362	47304
PT Exit Temperature	deg F	832	844	856	869	881	890
Exhaust Temperature	deg F	832	844	856	869	881	890

Fuel Gas Composition (Volume Percent)

Methane (CH4)	92.79
Ethane (C2H6)	4.16
Propane (C3H8)	0.84
N-Butane (C4H10)	0.18
N-Pentane (C5H12)	0.04
Hexane (C6H14)	0.04
Carbon Dioxide (CO2)	0.44
Hydrogen Sulfide (H2S)	0.0001
Nitrogen (N2)	1.51

Fuel Gas Properties

LHV (Btu/Scf)	939.2	Specific Gravity	0.5970	Wobbe Index at 60F	1215.6

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

SOLAR TURBINES INCORPORATED
ENGINE PERFORMANCE CODE REV. 4.16.1.18.10
CUSTOMER: Carolina Gas Transmission
JOB ID: NO14-03616

DATE RUN: 13-Nov-15
RUN BY: Trevor S Miller

--- SUMMARY OF ENGINE EXHAUST ANALYSIS ---
POINT NUMBER 1

HP= 1259, %Full Load=100.0, Elev= 90ft, %RH= 60.0, Temperature= 30.0F

GENERAL INPUT SPECIFICATIONS

ENGINE FUEL: SD NATURAL GAS

29.83	in Hg	AMBIENT PRESSURE
60.0	percent	RELATIVE HUMIDITY
0.0021	---	SP. HUMIDITY (LBM H2O/LBM DRY AIR)

FUEL GAS COMPOSITION (VOLUME PERCENT)
LHV (Btu/Scf) = 939.2 SG = 0.5970 W.I. @60F (Btu/Scf) = 1215.6

Methane (CH4)	=	92.7899
Ethane (C2H6)	=	4.1600
Propane (C3H8)	=	0.8400
N-Butane (C4H10)	=	0.1800
N-Pentane (C5H12)	=	0.0400
Hexane (C6H14)	=	0.0400
Carbon Dioxide (CO2)	=	0.4400
Hydrogen Sulfide (H2S)	=	0.0001
Nitrogen (N2)	=	1.5100

STANDARD CONDITIONS FOR GAS VOLUMES: Temperature: 60 deg F Pressure: 29.92 in Hg
NORMAL CONDITIONS FOR GAS VOLUMES: Temperature: 32 deg F Pressure: 29.92 in Hg

GENERAL OUTPUT DATA

676.	lbm/hr	FUEL FLOW
247.09	Scfm	FUEL FLOW
20612.	Btu/lbm	LOWER HEATING VALUE
939.	Btu/Scf	LOWER HEATING VALUE
11382.	Scfm	EXHAUST FLOW @ 14.7 PSIA & 60F
28373.	Acfm	ACTUAL EXHAUST FLOW CFm
51554.	lbm/hr	EXHAUST GAS FLOW
28.65	---	MOLECULAR WEIGHT OF EXHAUST GAS
75.45	---	AIR/FUEL RATIO

EXHAUST GAS ANALYSIS

ARGON	CO2	H2O	N2	O2	
0.91	2.31	4.72	76.11	15.95	VOLUME PERCENT WET
0.96	2.42	0.00	79.88	16.74	VOLUME PERCENT DRY
654.	1826.	1529.	38360.	9182.	lbm/hr
0.97	2.70	2.26	56.79	13.59	g/(g FUEL)

SOLAR TURBINES INCORPORATED
ENGINE PERFORMANCE CODE REV. 4.16.1.18.10
CUSTOMER: Carolina Gas Transmission
JOB ID: NO14-03616

DATE RUN: 13-Nov-15
RUN BY: Trevor S Miller

--- SUMMARY OF ENGINE EXHAUST ANALYSIS ---
POINT NUMBER 2

HP= 1239, %Full Load=100.0, Elev= 90ft, %RH= 60.0, Temperature= 40.0F

GENERAL INPUT SPECIFICATIONS

ENGINE FUEL: SD NATURAL GAS

29.83	in Hg	AMBIENT PRESSURE
60.0	percent	RELATIVE HUMIDITY
0.0032	---	SP. HUMIDITY (LBM H2O/LBM DRY AIR)

FUEL GAS COMPOSITION (VOLUME PERCENT)
LHV (Btu/Scf) = 939.2 SG = 0.5970 W.I. @60F (Btu/Scf) = 1215.6

Methane (CH4)	=	92.7899
Ethane (C2H6)	=	4.1600
Propane (C3H8)	=	0.8400
N-Butane (C4H10)	=	0.1800
N-Pentane (C5H12)	=	0.0400
Hexane (C6H14)	=	0.0400
Carbon Dioxide (CO2)	=	0.4400
Hydrogen Sulfide (H2S)	=	0.0001
Nitrogen (N2)	=	1.5100

STANDARD CONDITIONS FOR GAS VOLUMES: Temperature: 60 deg F Pressure: 29.92 in Hg
NORMAL CONDITIONS FOR GAS VOLUMES: Temperature: 32 deg F Pressure: 29.92 in Hg

GENERAL OUTPUT DATA

667.	lbm/hr	FUEL FLOW
243.89	Scfm	FUEL FLOW
20612.	Btu/lbm	LOWER HEATING VALUE
939.	Btu/Scf	LOWER HEATING VALUE
11225.	Scfm	EXHAUST FLOW @ 14.7 PSIA & 60F
28244.	Acfm	ACTUAL EXHAUST FLOW CFm
50815.	lbm/hr	EXHAUST GAS FLOW
28.64	---	MOLECULAR WEIGHT OF EXHAUST GAS
75.34	---	AIR/FUEL RATIO

EXHAUST GAS ANALYSIS

ARGON	CO2	H2O	N2	O2	
0.91	2.31	4.88	75.99	15.92	VOLUME PERCENT WET
0.96	2.42	0.00	79.88	16.73	VOLUME PERCENT DRY
644.	1801.	1560.	37771.	9038.	lbm/hr
0.97	2.70	2.34	56.65	13.55	g/(g FUEL)

SOLAR TURBINES INCORPORATED
ENGINE PERFORMANCE CODE REV. 4.16.1.18.10
CUSTOMER: Carolina Gas Transmission
JOB ID: NO14-03616

DATE RUN: 13-Nov-15
RUN BY: Trevor S Miller

--- SUMMARY OF ENGINE EXHAUST ANALYSIS ---
POINT NUMBER 3

HP= 1218, %Full Load=100.0, Elev= 90ft, %RH= 60.0, Temperature= 50.0F

GENERAL INPUT SPECIFICATIONS

ENGINE FUEL: SD NATURAL GAS

29.83	in Hg	AMBIENT PRESSURE
60.0	percent	RELATIVE HUMIDITY
0.0046	---	SP. HUMIDITY (LBM H2O/LBM DRY AIR)

FUEL GAS COMPOSITION (VOLUME PERCENT)
LHV (Btu/Scf) = 939.2 SG = 0.5970 W.I. @60F (Btu/Scf) = 1215.6

Methane (CH4)	=	92.7899
Ethane (C2H6)	=	4.1600
Propane (C3H8)	=	0.8400
N-Butane (C4H10)	=	0.1800
N-Pentane (C5H12)	=	0.0400
Hexane (C6H14)	=	0.0400
Carbon Dioxide (CO2)	=	0.4400
Hydrogen Sulfide (H2S)	=	0.0001
Nitrogen (N2)	=	1.5100

STANDARD CONDITIONS FOR GAS VOLUMES: Temperature: 60 deg F Pressure: 29.92 in Hg
NORMAL CONDITIONS FOR GAS VOLUMES: Temperature: 32 deg F Pressure: 29.92 in Hg

GENERAL OUTPUT DATA

658.	lbm/hr	FUEL FLOW
240.65	Scfm	FUEL FLOW
20612.	Btu/lbm	LOWER HEATING VALUE
939.	Btu/Scf	LOWER HEATING VALUE
11064.	Scfm	EXHAUST FLOW @ 14.7 PSIA & 60F
28108.	Acfm	ACTUAL EXHAUST FLOW CFm
50043.	lbm/hr	EXHAUST GAS FLOW
28.61	---	MOLECULAR WEIGHT OF EXHAUST GAS
75.20	---	AIR/FUEL RATIO

EXHAUST GAS ANALYSIS

ARGON	CO2	H2O	N2	O2	
0.91	2.31	5.11	75.81	15.87	VOLUME PERCENT WET
0.96	2.43	0.00	79.89	16.72	VOLUME PERCENT DRY
633.	1774.	1609.	37143.	8883.	lbm/hr
0.96	2.70	2.45	56.46	13.50	g/(g FUEL)

SOLAR TURBINES INCORPORATED
ENGINE PERFORMANCE CODE REV. 4.16.1.18.10
CUSTOMER: Carolina Gas Transmission
JOB ID: NO14-03616

DATE RUN: 13-Nov-15
RUN BY: Trevor S Miller

--- SUMMARY OF ENGINE EXHAUST ANALYSIS ---
POINT NUMBER 4

HP= 1197, %Full Load=100.0, Elev= 90ft, %RH= 60.0, Temperature= 60.0F

GENERAL INPUT SPECIFICATIONS

ENGINE FUEL: SD NATURAL GAS

29.83	in Hg	AMBIENT PRESSURE
60.0	percent	RELATIVE HUMIDITY
0.0067	---	SP. HUMIDITY (LBM H2O/LBM DRY AIR)

FUEL GAS COMPOSITION (VOLUME PERCENT)
LHV (Btu/Scf) = 939.2 SG = 0.5970 W.I. @60F (Btu/Scf) = 1215.6

Methane (CH4)	=	92.7899
Ethane (C2H6)	=	4.1600
Propane (C3H8)	=	0.8400
N-Butane (C4H10)	=	0.1800
N-Pentane (C5H12)	=	0.0400
Hexane (C6H14)	=	0.0400
Carbon Dioxide (CO2)	=	0.4400
Hydrogen Sulfide (H2S)	=	0.0001
Nitrogen (N2)	=	1.5100

STANDARD CONDITIONS FOR GAS VOLUMES: Temperature: 60 deg F Pressure: 29.92 in Hg
NORMAL CONDITIONS FOR GAS VOLUMES: Temperature: 32 deg F Pressure: 29.92 in Hg

GENERAL OUTPUT DATA

649.	lbm/hr	FUEL FLOW
237.37	Scfm	FUEL FLOW
20612.	Btu/lbm	LOWER HEATING VALUE
939.	Btu/Scf	LOWER HEATING VALUE
10908.	Scfm	EXHAUST FLOW @ 14.7 PSIA & 60F
27970.	Acfm	ACTUAL EXHAUST FLOW CFm
49276.	lbm/hr	EXHAUST GAS FLOW
28.58	---	MOLECULAR WEIGHT OF EXHAUST GAS
75.07	---	AIR/FUEL RATIO

EXHAUST GAS ANALYSIS

ARGON	CO2	H2O	N2	O2	
0.90	2.30	5.42	75.56	15.81	VOLUME PERCENT WET
0.96	2.43	0.00	79.89	16.72	VOLUME PERCENT DRY
622.	1747.	1682.	36500.	8724.	lbm/hr
0.96	2.69	2.59	56.25	13.44	g/(g FUEL)

SOLAR TURBINES INCORPORATED
ENGINE PERFORMANCE CODE REV. 4.16.1.18.10
CUSTOMER: Carolina Gas Transmission
JOB ID: NO14-03616

DATE RUN: 13-Nov-15
RUN BY: Trevor S Miller

--- SUMMARY OF ENGINE EXHAUST ANALYSIS ---
POINT NUMBER 5

HP= 1171, %Full Load=100.0, Elev= 90ft, %RH= 60.0, Temperature= 70.0F

GENERAL INPUT SPECIFICATIONS

ENGINE FUEL: SD NATURAL GAS

29.83	in Hg	AMBIENT PRESSURE
60.0	percent	RELATIVE HUMIDITY
0.0095	---	SP. HUMIDITY (LBM H2O/LBM DRY AIR)

FUEL GAS COMPOSITION (VOLUME PERCENT)
LHV (Btu/Scf) = 939.2 SG = 0.5970 W.I. @60F (Btu/Scf) = 1215.6

Methane (CH4)	=	92.7899
Ethane (C2H6)	=	4.1600
Propane (C3H8)	=	0.8400
N-Butane (C4H10)	=	0.1800
N-Pentane (C5H12)	=	0.0400
Hexane (C6H14)	=	0.0400
Carbon Dioxide (CO2)	=	0.4400
Hydrogen Sulfide (H2S)	=	0.0001
Nitrogen (N2)	=	1.5100

STANDARD CONDITIONS FOR GAS VOLUMES: Temperature: 60 deg F Pressure: 29.92 in Hg
NORMAL CONDITIONS FOR GAS VOLUMES: Temperature: 32 deg F Pressure: 29.92 in Hg

GENERAL OUTPUT DATA

640.	lbm/hr	FUEL FLOW
233.95	Scfm	FUEL FLOW
20612.	Btu/lbm	LOWER HEATING VALUE
939.	Btu/Scf	LOWER HEATING VALUE
10723.	Scfm	EXHAUST FLOW @ 14.7 PSIA & 60F
27747.	Acfm	ACTUAL EXHAUST FLOW CFm
48362.	lbm/hr	EXHAUST GAS FLOW
28.53	---	MOLECULAR WEIGHT OF EXHAUST GAS
74.75	---	AIR/FUEL RATIO

EXHAUST GAS ANALYSIS

ARGON	CO2	H2O	N2	O2	
0.90	2.30	5.85	75.23	15.72	VOLUME PERCENT WET
0.96	2.44	0.00	79.90	16.70	VOLUME PERCENT DRY
609.	1717.	1785.	35722.	8528.	lbm/hr
0.95	2.68	2.79	55.85	13.33	g/(g FUEL)

SOLAR TURBINES INCORPORATED
ENGINE PERFORMANCE CODE REV. 4.16.1.18.10
CUSTOMER: Carolina Gas Transmission
JOB ID: NO14-03616

DATE RUN: 13-Nov-15
RUN BY: Trevor S Miller

--- SUMMARY OF ENGINE EXHAUST ANALYSIS ---
POINT NUMBER 6

HP= 1133, %Full Load=100.0, Elev= 90ft, %RH= 60.0, Temperature= 80.0F

GENERAL INPUT SPECIFICATIONS

ENGINE FUEL: SD NATURAL GAS

29.83	in Hg	AMBIENT PRESSURE
60.0	percent	RELATIVE HUMIDITY
0.0133	---	SP. HUMIDITY (LBM H2O/LBM DRY AIR)

FUEL GAS COMPOSITION (VOLUME PERCENT)
LHV (Btu/Scf) = 939.2 SG = 0.5970 W.I. @60F (Btu/Scf) = 1215.6

Methane (CH4)	=	92.7899
Ethane (C2H6)	=	4.1600
Propane (C3H8)	=	0.8400
N-Butane (C4H10)	=	0.1800
N-Pentane (C5H12)	=	0.0400
Hexane (C6H14)	=	0.0400
Carbon Dioxide (CO2)	=	0.4400
Hydrogen Sulfide (H2S)	=	0.0001
Nitrogen (N2)	=	1.5100

STANDARD CONDITIONS FOR GAS VOLUMES: Temperature: 60 deg F Pressure: 29.92 in Hg
NORMAL CONDITIONS FOR GAS VOLUMES: Temperature: 32 deg F Pressure: 29.92 in Hg

GENERAL OUTPUT DATA

626.	lbm/hr	FUEL FLOW
228.86	Scfm	FUEL FLOW
20612.	Btu/lbm	LOWER HEATING VALUE
939.	Btu/Scf	LOWER HEATING VALUE
10512.	Scfm	EXHAUST FLOW @ 14.7 PSIA & 60F
27388.	Acfm	ACTUAL EXHAUST FLOW CFm
47304.	lbm/hr	EXHAUST GAS FLOW
28.47	---	MOLECULAR WEIGHT OF EXHAUST GAS
74.74	---	AIR/FUEL RATIO

EXHAUST GAS ANALYSIS

ARGON	CO2	H2O	N2	O2	
0.89	2.29	6.40	74.78	15.63	VOLUME PERCENT WET
0.96	2.44	0.00	79.90	16.70	VOLUME PERCENT DRY
594.	1673.	1917.	34810.	8310.	lbm/hr
0.95	2.67	3.06	55.63	13.28	g/(g FUEL)

SOLAR TURBINES INCORPORATED
ENGINE PERFORMANCE CODE REV. 4.16.1.18.10
CUSTOMER: Carolina Gas Transmission
JOB ID: NO14-03616

DATE RUN: 13-Nov-15
RUN BY: Trevor S Miller

SATURN 10-1200
CS/MD
STANDARD
GAS
TSB-2 REV. 0.0

DATA FOR NOMINAL PERFORMANCE

Fuel Type		SD NATURAL GAS					
Elevation	feet	90					
Inlet Loss	in H2O	4.0					
Exhaust Loss	in H2O	4.0					
Accessory on GP Shaft	HP	27.0					
Engine Inlet Temp.	deg F	30.0	40.0	50.0	60.0	70.0	80.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0
Elevation Loss	HP	4	4	4	4	4	4
Inlet Loss	HP	25	25	25	25	24	24
Exhaust Loss	HP	13	13	13	13	13	13
Off-Optimum NPT Loss	HP	0	0	0	0	0	0
Driven Equipment Speed	RPM	22300	22300	22300	22300	22300	22300
Optimum Equipment Speed	RPM	22679	22652	22625	22599	22531	22375
Gas Generator Speed	RPM	22300	22300	22300	22300	22300	22257
Specified Load	HP	FULL	FULL	FULL	FULL	FULL	FULL
Net Output Power	HP	1259	1239	1218	1197	1171	1133
Fuel Flow	mmBtu/hr	13.92	13.74	13.56	13.38	13.18	12.90
Heat Rate	Btu/HP-hr	11058	11089	11130	11173	11262	11383
Therm Eff	%	23.010	22.945	22.862	22.773	22.593	22.352
Inlet Air Flow	lbm/hr	50970	50239	49474	48715	47808	46763
Engine Exhaust Flow	lbm/hr	51554	50815	50043	49276	48362	47304
PCD	psiG	78.4	77.5	76.5	75.5	74.2	72.4
Compensated PTIT	deg F	1066	1073	1081	1089	1099	1105
PT Exit Temperature	deg F	832	844	856	869	881	890
Exhaust Temperature	deg F	832	844	856	869	881	890

FUEL GAS COMPOSITION (VOLUME PERCENT)
LHV (Btu/Scf) = 939.2 SG = 0.5970 W.I. @60F (Btu/Scf) = 1215.6

Methane (CH4)	=	92.7899
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Carbon Dioxide (CO2)	=	0.4400
Hydrogen Sulfide (H2S)	=	0.0001
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STANDARD CONDITIONS FOR GAS VOLUMES: Temperature: 60 deg F Pressure: 29.92 in Hg

NORMAL CONDITIONS FOR GAS VOLUMES: Temperature: 32 deg F Pressure: 29.92 in Hg

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

September 6, 1995

MEMORANDUM

SUBJECT: Calculating Potential to Emit (PTE) for Emergency Generators

FROM: John S. Seitz, Director
Office of Air Quality Planning and Standards (MD-10)

TO: Director, Air, Pesticides and Toxics Management Division, Regions I and IV
Director, Air and Waste Management Division, Region II
Director, Air, Radiation and Toxics Division, Region III
Director, Air and Radiation Division, Region V
Director, Air, Pesticides and Toxics Division, Region VI
Director, Air and Toxics Division, Regions VII, VIII, IX, and X

The purpose of this guidance is to address the determination of PTE for emergency electrical generators.

Background

In a memorandum dated January 25, 1995, the Environmental Protection Agency (EPA) addressed a number of issues related to the determination of a source's PTE under section 112 and title V of the Clean Air Act (Act). One of the issues discussed in the memorandum was the term "maximum capacity of a stationary source to emit under its physical and operational design," which is part of the definition of "potential to emit." The memorandum clarified that inherent physical limitations, and operational design features which restrict the potential emissions of individual emission units, can be taken into account. This clarification was intended to address facilities for which the theoretical use of equipment is much higher than could ever actually occur in practice. For such facilities, if their

physical limitations or operational design features are not taken

into account, the potential emissions could be overestimated and consequently the source owner could be subject to the Act requirements affecting major sources. Although such source owners could in most cases readily accept enforceable limitations restricting the operation to its designed level, EPA believes this administrative requirement for such sources to be unnecessary and burdensome.

On the topic of "physical and operational design," the January 25 memorandum provided a general discussion. In addition, EPA committed to providing technical assistance on the type of inherent physical and operational design features that may be considered acceptable in determining the potential to emit for certain individual small source categories. The EPA is currently conducting category-specific analyses in support of this effort, and hopes as a result of these analyses to generate more general guidance on this issue as well.

The purpose of this memorandum is to address the issue of PTE as it relates specifically to emergency generators. There is a significant level of interest in this source category because there are many thousands of locations for which an emergency generator is the only emitting source. Moreover, based on a review of this source category, there exists a readily identifiable constraint on the operational design of emergency generators. Hence, the EPA believes it would be useful to provide today's guidance before the entire effort is complete.

The policies set forth in this memorandum are intended solely as guidance, do not represent final Agency action, and cannot be relied upon to create any rights enforceable by any party.

Guidance for Emergency Generators

For purposes of today's guidance, an "emergency generator" means a generator whose sole function is to provide back-up power when electric power from the local utility is interrupted. The emission source for such generators is typically a gasoline or diesel-fired engine, but can in some cases include a small gas turbine. Emissions consist primarily of carbon monoxide and nitrogen oxides. Other criteria pollutants, and hazardous air pollutants, are also emitted, but at much lower levels. Emissions occur only during emergency situations (i.e., where electric power from the local utility is interrupted), and for a very short time to perform maintenance checks and operator training.

The EPA believes that generators devoted to emergency uses are clearly constrained in their operation, in the sense that, by definition and design, they are used only during periods where electric power from public utilities is unavailable. Two factors indicate that this constraint is in fact "inherent." First, while the combined period for such power outages during any one year will vary somewhat, an upper bound can be estimated which would never be expected to be exceeded absent extraordinary circumstances. Second, the duration of these outages are entirely beyond the control of the source, and when they do occur (except in the case of a major catastrophe) rarely last more than a day.

For emergency generators, EPA has determined that a reasonable and realistic "worst-case" estimate of the number of hours that power would be expected to be unavailable from the local utility may be considered in identifying the "maximum capacity" of such generators for the purpose of estimating their PTE. Consequently, EPA does not recommend the use of 8760 hours per year (i.e., full-year operation) for calculating the PTE for emergency generators. Instead, EPA recommends that the potential to emit be determined based upon an estimate of the maximum amount of hours the generator could operate, taking into account (1) the number of hours power would be expected to be unavailable and (2) the number of hours for maintenance activities.

The EPA believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions. Alternative estimates can be made on a case-by-case basis where justified by the source owner or permitting authority (for example, if historical data on local power outages indicate that a larger or smaller number would be appropriate). Using the 500 hour default assumption, EPA has performed a number of calculations for some typically-sized emergency generators. These calculations indicate that these generators, in and of themselves, rarely emit at major source levels. (Of course, there may be unusual circumstances where these calculations would not be representative, for example where many generators are present that could operate simultaneously).

Cautions

Today's guidance is only meant to address emergency generators as described. Specifically, the guidance does not address: (1) peaking units at electric utilities; (2) generators at industrial facilities that typically operate at low rates, but are not confined to emergency purposes; and (3) any standby

generator that is used during time periods when power is available from the utility. This guidance is also not intended to discourage permitting authorities from establishing operational limitations in construction permits when such limitations are deemed appropriate or necessary. Additionally, this memorandum is not intended to be used as the basis to rescind any such restrictions already in place.

Distribution/Further Information

The Regional Offices should send this memorandum to States within their jurisdiction. Questions concerning specific issues and cases should be directed to the appropriate Regional Office. Regional Office staff may contact Tim Smith of the Integrated Implementation Group at 919-541-4718. The document is also available on the technology transfer network (TTN) bulletin board, under "Clean Air Act" - "Title V" - "Policy Guidance Memos". (Readers unfamiliar with this bulletin board may obtain access by calling the TTN help line at 919-541-5384).

cc: Air Branch Chief, Region I-X
Regional Air Counsels, Region I-X
Adan Schwartz (2344)
Tim Smith (MD-12)

Onshore Natural Gas Transmission

11/29/2013

INSTRUCTIONS:

Data Collection Year 2014 and later - This tool has been updated from previous versions to account for a change in the global warming potential (GWP) of methane (CH4) that is applicable in 2014 and later years. This tool should not be used for years 2011 to 2013. For years 2011 to 2013, use the version of the tool that is in the GHGRP Applicability Tool archive.

This sheet provides a simple tool for estimating equipment leak and vented emissions from natural gas transmission. Enter the required information into the "Input Data" field for each source of emissions at your facility. The tool will automatically sum emissions from each input and provide a total estimate of annual CO_2e equipment leak and vented emissions. Enter this total into the CO_2e emissions field for natural gas transmission in the applicability tool.

For screening purposes related to co-located industry segments, emissions from all applicable industry segments should be combined to determine whether the emissions from the facility with the co-located industry segments would exceed the 25,000 metric ton CO_2e reporting threshold.

Methane Emissions Source	Input Data	Units	Emissions (metric tons CO_2e/year)
Reciprocating compressor rod packing venting		number of compressor cylinders	0
		operating factor (decimal form)*	
Centrifugal compressor venting	1	number of compressors	5,791
	1	operating factor (decimal form)*	
Blowdown vent stacks (to atmosphere)		number of times the compressor starts annually	0
Equipment Leaks & Pneumatic Devices**	Not required *(see note below)*	None	1,583
		Transmission Total (metric tons CO_2e/year)	7,374

Please see the "Guidance & Sources" tab for further information on the calculation methodologies of the above emissions sources.

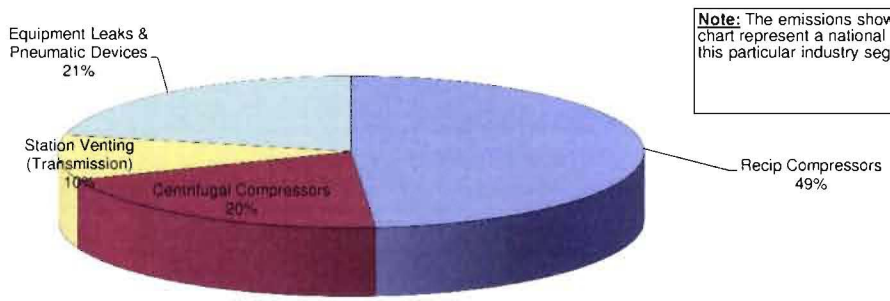
Notes:

The emissions factors and calculation methods used in this tool are based on publicly available sources including: the Technical Support Document for Subpart W; the U.S. GHG Inventory; and the 2009 API Compendium. More details can be found in the Guidance and Sources tab of this worksheet. This tool is only a guide to help companies determine their Subpart W applicability. The results of this tool are not legally binding. A reporter must make the final determination regarding their Subpart W applicability.

*This is defined as the fraction of time the process unit is operating in a calendar year. For example, a 90% operating factor would be entered as 0.9 because the unit is in operation for 90% of the year.

**"Equipment Leaks & Pneumatic Devices" are estimated in this tool as 21% of total natural gas transmission emissions. User input is not required to calculate emissions from these sources; they are estimated (based on the other emissions) using the percentages shown in the pie chart.

Estimate of natural gas transmission emissions. This pie chart is used to estimate emissions from selected sources in the tool.



Note: The emissions shown in this pie chart represent a national average for this particular industry segment.

Sources:

EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006. April 2008. epa.gov/climatechange/emissions/usgginv_archive.html

EPA. Background Technical Support Document (docket # EPA-HQ-OAR-2009-0923) for Subpart W. <www.regulations.gov>. EPA revised.

Applicability Tool Disclaimer

The content provided in the applicability tool is intended solely as compliance assistance for potential reporters to aid in assessing whether they are required to report under the Greenhouse Gas Mandatory Reporting Rule. Any variation between the rule and the information provided in this tool is unintentional, and, in the case of such variations, the requirements of the rule govern. The applicability tool and its contents do not constitute rulemaking or a decision by EPA and may not be relied upon to create a substantive or procedural right or benefit enforceable by law, or in equity, by any person. While this tool is designed to help potential reporters comply with the rule, compliance with all Federal, State, and Local laws and regulations remains the sole responsibility of each facility owner or operator subject to those laws and regulations. Use of this tool does not constitute an assessment by EPA of the applicability of the rule to any particular facility. In any particular case, EPA will make its assessment by applying the law and regulations to the specific facts of the case. No information entered by the user is maintained by EPA, and any results generated by the applicability tool, along with additional information entered by the user,

APPENDIX E

Electronic SCDHEC Application Forms and Electronic Modeling Files

(*On Compact Disc*)