UTAH DIVISION OF AIR QUALITY NOTICE OF INTENT

Will-Power UT, LLC – Eagle Mountain, Utah

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1. EXECUTIVE SUMMARY

Will-Power UT, LLC (Will-Power) proposes to construct and operate a new power generation facility in Eagle Mountain, Utah (the facility). The facility is located at 1499 N Pony Express Parkway, Eagle Mountain, UT 84005 within an area of Utah County designated as a marginal nonattainment area of the National Ambient Air Quality Standards (NAAQS) for 2015 8-hour ozone; and, as a maintenance area of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}). Oxides of nitrogen (NO_X) and volatile organic compounds (VOCs) are considered precursors to ozone. This area of Utah County is in attainment for all other criteria pollutants.

This Notice of Intent (NOI) air permit application has been developed to request an Approval Order (AO) for the facility. Will-Power proposes to install 17 natural gas-fired simple cycle turbines (natural gas turbines), eight (8) ultra-low NO_X natural gas-fired line heaters (line heaters), two (2) natural gas-fired emergency generator engines (natural gas engines), and one (1) diesel-fired emergency fire pump engine (fire pump engine) and associated diesel belly tank. The proposed installation will provide primary power exclusively and directly to a nearby data center.

The proposed operations constitute a new minor source under New Source Review (NSR) permitting and a new Title V source. This NOI air permit application is submitted in accordance with the Utah Division of Air Quality (UDAQ) rules under Utah Administrative Code (UAC) R307-401 and includes all supporting documentation to obtain authorization for the proposed emissions units. Air dispersion modeling has been conducted for nitrogen dioxide (NO_2), PM_{10}, particulate with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), and carbon monoxide (CO) to demonstrate that the proposed operations will not cause or contribute to an exceedance of the applicable NAAQS. Additionally, air dispersion modeling has been conducted for formaldehyde to demonstrate that the proposed operations will not exceed the relevant Toxic Screening Level (TSL). Appendix B summarizes the emissions resulting from Will-Power’s operations.

2. GENERAL INFORMATION

2.1 Description of Facility

- Company Name: Will-Power UT, LLC
- Company Contact: Andrew Woerner, Senior Environmental Specialist
- Contact Number: (610)-412-8905
- Contact Email: Andrew.Woerner@Williams.com
- Address: 1499 N Pony Express Parkway, Eagle Mountain, UT 84005
- County: Utah County
- UTM Coordinates: 414,225.35 m Easting, 4,456,082.40 m Northing, UTM Zone 12
- Primary SIC Code: 4911 – Electric Services
- Area Designation: Marginal Nonattainment area of O_3
Maintenance area of PM_{10}
- Source Size Determination: Minor NSR Source and Title V Major Source for $PM_{2.5}$,PM_{10}, and CO
- Current AO: None

2.2 Source Size Determination

As presented in Appendix B, Table B-1, the annual potential to emit (PTE) for the proposed operations will remain below the Prevention of Significant Deterioration (PSD) major source thresholds (MSTs) for all applicable pollutants. The annual PTE for $PM_{2.5}$, PM_{10}, and CO all exceed the Title V MST.

The NO_X PTE exceeds the Nonattainment New Source Review (NNSR) MST for NO_X in a marginal ozone nonattainment area; however, the facility is proposing a federally enforceable, synthetic minor limit to ensure NO_X emissions remain below the NNSR MST. With the limit in place, the facility will be classified as a new synthetic minor[1] source under NSR.

2.3 Notice of Intent Forms

The following UDAQ forms are included in Appendix A of this application:

- Form 1 – Notice of Intent Application
- Form 2 – Company Information
- Form 3 – Process Information
- Form 5 – Emissions Information
- Form 17 – Diesel Powered Standby Generator
- Form 17a – Natural Gas Standby Generator
- Form 19 – Natural Gas Burners and Liquid Heaters (Gas Burner)
- Form 20 – Organic Liquid Storage Tank
- Form 22 – Combustion Turbine

[1] UAC R307-415-4(6)

2.4 Notice of Intent Fees

Will-Power will use the UDAQ Payment Portal to prepay the following UDAQ NOI air permit application fees associated with this submittal:

- "Application Filing Fee" for the "New Minor NSR Source or Minor Modification at Minor or Major Source" category = $750
- "Application Review Fee" for the "New Minor NSR Source or Minor Modification at Minor or Major Source" category in maintenance or non-attainment areas = $2,500
- Total UDAQ fees = $3,250

Will-Power understands that the total permit review fee is based on the total actual time spent by UDAQ staff processing this NOI air permit application. Upon issuance of the AO, if the total review time is more than the 20 standard hours, UDAQ will invoice Will-Power at $125 per hour for the additional time above 20 standard hours.

3. DESCRIPTION OF PROJECT AND PROCESS

3.1 Description of Project and Process

Will-Power is proposing to construct a power generation facility to provide primary power to a separately owned and operated nearby data center.

Air emissions from the facility will result from the operation of the equipment detailed below.

- Eleven (11) GE Vernova TM2500 34.8 MW ISO natural gas-fired turbines
- Six (6) Solar Titan 250 23.1 MW ISO natural gas-fired turbines
- Six (6) 11 MMBtu/hr ultra-low NO_X forced draft natural gas-fired line heaters
- Two (2) 3.4 MMBtu/hr ultra-low NOx forced draft natural gas-fired line heaters
- Two (2) CAT 3520, 3629 horsepower (hp) natural gas-fired emergency generator engines
- One (1) 325 hp diesel fired emergency fire pump engine
- One (1) 500 gallon (gal) diesel belly tank

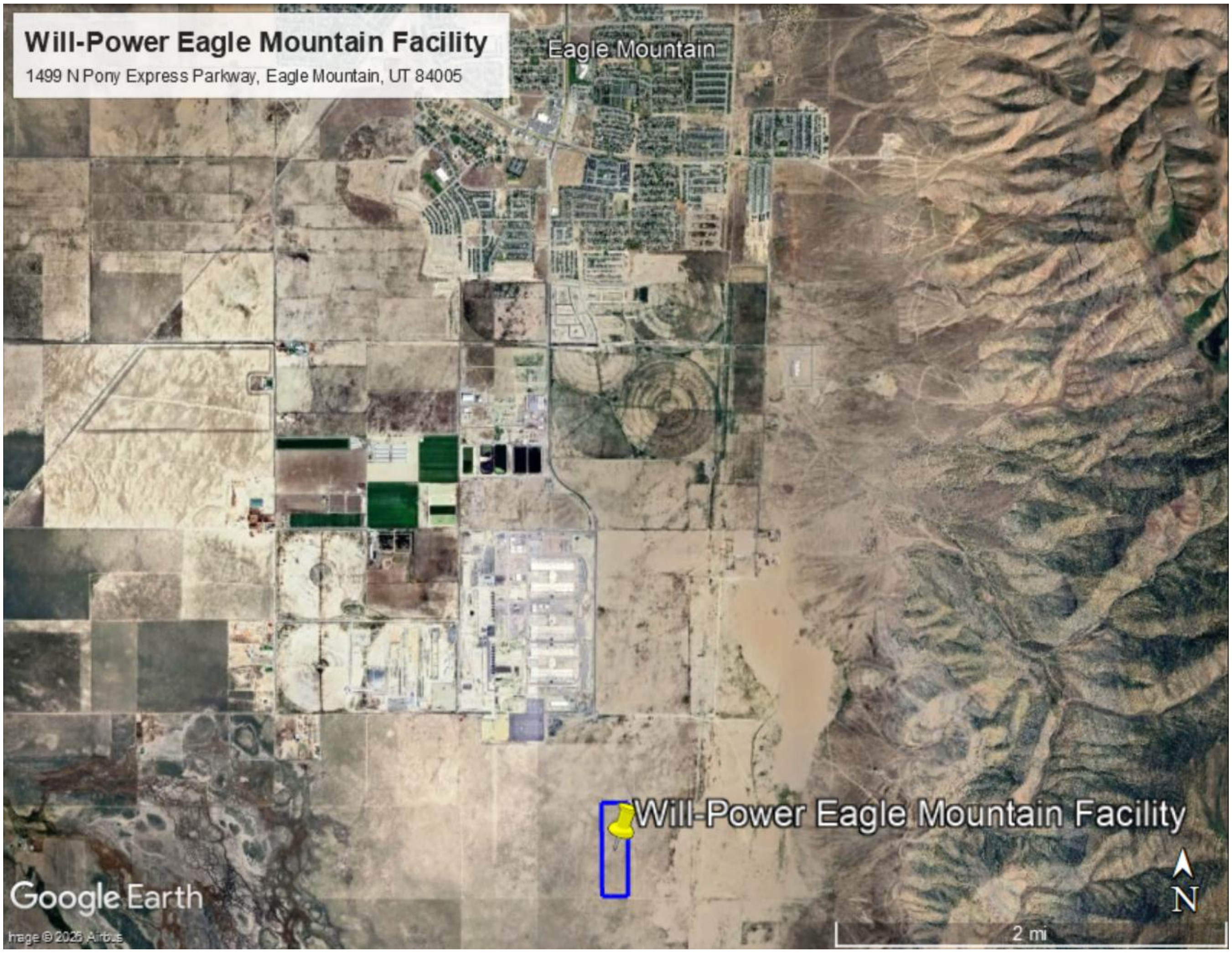
The natural gas turbines will operate year-round to provide primary power to a nearby data center. Due to the transient nature of data center power requirements, the electrical load required from the facility will vary. The PTE calculations provided with this application conservatively assume the continuous operation of all 17 natural gas turbines, 24 hours a day, 7 days a week, and 365 days a year, and utilize the maximum emission rates.

To ensure that the facility does not exceed the NNSR MSTs for NO_X, Will-Power proposes a federally enforceable limit of 95.39 tons of NO_X per rolling 12-month period for all natural gas turbines. Compliance with this limit will be demonstrated using a continuous emissions monitoring system (CEMS), which will be installed on all natural gas turbines. By imposing this federally enforceable limit, the facility will be a synthetic minor source under NSR.

3.2 Site Plan

The general location and property boundary of the facility is shown in Figure 3-1.

Figure 3-1. Facility Location and Boundary



4. EMISSIONS RELATED INFORMATION

This section details the methodology used to calculate controlled and uncontrolled emissions for criteria pollutants, greenhouse gases, and HAPs associated with each new unit and its associated fugitives as regulated by R307-401-5(2)(b). Detailed emissions calculation tables are included in Appendix B. Additionally, a comparison to major source thresholds is included.

4.1 Natural Gas Turbines

PTE calculations for each of the proposed natural gas turbines are based on emission factors and specifications provided by the manufacturer and control device supplier. The calculations performed account for the selective catalytic reduction (SCR) system, which activates after a warm-up period when the SCR reaches a threshold temperature. NH_3 emissions resulting from the SCR system are also accounted for in the emissions calculations. CO and VOC emissions are controlled by a catalytic oxidation system, which has a warm-up period before achieving full pollution reduction potential, but does not produce additional criteria pollutant emissions. Start up and shut down time is used to account for uncontrolled NO_X, CO, and VOC emissions. See Section 5 of this NOI air permit application for more detail regarding these control technologies.

PTE calculations for each of the proposed natural gas turbines are based on manufacturer and control device supplier data, with the natural gas turbine data reflecting various ambient temperatures and load conditions - i.e., for various operating scenarios. Emissions from potential operating scenarios are evaluated and the highest resulting emissions are taken as the maximum site-wide PTE. Consequently, the emissions calculations in Appendix B present multiple load conditions to enable verification that the highest possible emission rates have been properly accounted for in the site-wide PTE determination.

While there are two types of natural gas turbines, the type of data received and the calculation approach is the same for each type. The following methodology is carried out for each type; any references to specific data or natural gas turbine counts are with respect to the given turbine model.

4.1.1 Criteria Pollutants

NO_X, NH_3, CO, VOC, and formaldehyde emission factors are determined for each operating scenario by converting from emission values in parts per million volume dry (ppmvd) to pounds per million British thermal units (lb/MMBtu) using equation 19-1 of Environmental Protection Agency (EPA) Method 19 as follows:

$$\text{Controlled Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)=\left(\frac{\text{P}\times \text{C}_{@0\%\text{O2}}\times \text{MW}}{\text{R}\times \text{T}}\right)\left(\frac{\text{lb}}{\text{ft}^3}\right)\times \text{F}_\text{d}\left(\frac{\text{ft}^3}{\text{MMBtu}}\right)$$

Where:

P: Standard pressure = 14.7 psia
MW: Molecular weight of criteria pollutant (lb/lb-mol)
R: Ideal gas constant = 10.73 psi-ft^3/lbmol-˚R
T: Standard temperature = 527.67 ˚R
F_d: EPA Method 19 dry basis conversion factor[2] = 8710 ft^3/MMBtu
$C_{@0\%O2}$: Corrected criteria pollutant concentration at 0% O_2 ppmvd (lb-mol/lb-mol)

[2] EPA Method 19 Table 19-2.

$$C_{@0\%O2} = \left(C(\text{ppmvd}) \times \frac{1}{10^6}\right) \times \left(\frac{20.9 - 0}{20.9 - C_{O_2}(\%)}\right)$$

Where:

C = Concentration of criteria pollutant at reference oxygen concentration (ppmvd)

C_{O2}: Reference oxygen concentration (%) = 15 %

NO_X, NH_3, CO, VOC, and formaldehyde emission factors are converted from lb/MMBtu to pounds per hour (lb/hr) by multiplying the converted emission factor by the fuel consumption (MMBtu/hr) using the following equation:

$$\text{Controlled Emission Factor}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) \times \text{Fuel Consumption}\left(\frac{\text{MMBtu}}{\text{hr}}\right)$$

The fuel consumption is given by the manufacturer for a range of operating conditions.

NO_X, NH_3, CO, VOC, and formaldehyde annual PTEs in tons per year (tpy) are calculated using the following equation:

$$\begin{aligned}\text{Annual PTE(tpy)} \\ &= \left(\left(\text{Controlled Emission Factor}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Controlled Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right)\right)\right. \\ &\left. + \left(\text{Uncontrolled Emission Factor}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Uncontrolled Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right)\right)\right) \\ &\times \text{Number of Turbines} \times \frac{1\ \text{ton}}{2{,}000\ \text{Ibs}}\end{aligned}$$

Uncontrolled emission factors and startup/shutdown time (uncontrolled operation) are per the manufacturer and are the same for all operating conditions.

NH_3 emissions only occur when the SCR system is operating; therefore, NH_3 emissions are calculated excluding SCR warm up time.

SO_2 emissions are calculated using the grain/scf sulfur content and the higher heating value (HHV) of the natural gas that will be delivered to the site, per the Emission Factor Documentation for AP-42 Section 1.4 pages 3.8 and 3.4, respectively. The lb/hr emission factor is determined using the following equation:

$$\begin{aligned}\text{Emission Factor}\left(\frac{\text{lb}}{\text{hr}}\right) \\ &= \frac{\text{Sulfur Content of Natural Gas}\left(\frac{\text{grains}}{100\ \text{scf}}\right)}{\text{HHV of Natural Gas}\left(\frac{\text{Btu}}{\text{scf}}\right)} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} \times \frac{1\ \text{lb}}{7000\ \text{grains}} \\ &\times \text{Fuel Consumption}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times\end{aligned}$$

PM_{10} and $PM_{2.5}$ lb/hr emission factors are established by converting a lb/MMBtu emission factor from the EPA's Compilation of Air Pollutant Emission Factors from Stationary Sources (AP-42)[3] using the following equation:

$$\text{Emission Factor}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) \times \text{Fuel Consumption}\left(\frac{\text{MMBtu}}{\text{hr}}\right)$$

Emission factors for PM_{10} and $PM_{2.5}$ are conservatively assumed to be equivalent.

PM_{10}, $PM_{2.5}$, and SO_2 annual PTEs are calculated using the following equation:

$$\text{Annual PTE (tpy)} = \text{Emission Factor}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right) \times \text{Number of Turbines} \times \frac{1\text{ ton}}{2{,}000\text{ lbs}}$$

4.1.2 HAP Emissions

HAP emissions are conservatively determined using the maximum fuel consumption. Emission factors for HAPs are obtained from AP-42, Section 3.1, Table 3.1-3. and 3.4-4. HAP emissions are calculated using the following equation:[4]

$$\begin{aligned}&\text{Annual HAP PTE (tpy)}\\ &\quad= \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) \times \text{Maximum Fuel Consumption}\left(\frac{\text{MMBtu}}{\text{hr}}\right)\\ &\quad\times \text{Annual Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right) \times \frac{1\text{ ton}}{2{,}000\text{ lbs}}\end{aligned}$$

The potential emissions of non-hydrocarbon volatile organic HAPs are included in calculation of the VOC PTE(s).

4.1.3 GHG Emissions

GHG pollutants expected to be emitted from the natural gas turbines include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Standard emission factors for CO_2, CH_4, and N_2O for natural gas combustion are provided in 40 CFR Part 98, Subpart C, Table C-1 and Table C-2. CO_2 startup and shutdown emission factors are provided by the manufacturer. CO_2, CH_4, and N_2O emission rates are then weighted by their global warming potentials (GWPs) to obtain the CO_2 equivalent (CO_2e) emission rate. The global warming potential for each relevant pollutant is obtained from 40 CFR Part 98, Subpart A, Table A-1. Calculations for GHG pollutants are based on the emission factor for each GHG pollutant, relevant global warming potential, fuel consumption, and relevant conversion factors.

[3] U.S. EPA AP-42 Section 3.1 Table 3.1-2a

[4] U.S. EPA AP-42 Section 3.1 Table 3.1-3

$$\begin{aligned}
&\text{Annual } CO_2e \text{ PTE (tpy)} \\
&= \Bigg(\bigg(\Big(\text{Emission Factor } CH_4 \left(\frac{\text{kg}}{\text{MMBtu}}\right) \times \text{GWP } CH_4 \\
&+ \text{Emission Factor } N_2O \left(\frac{\text{kg}}{\text{MMBtu}}\right) \\
&\times \text{GWP } N_2O \Big) \times \text{Fuel Consumption} \left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \frac{2.2 \text{ lbs}}{1 \text{ kg}} \times \text{Operation Hours} \left(\frac{\text{hr}}{\text{yr}}\right)\bigg) \\
&+ \bigg(\Big(\text{Controlled Emission Factor } CO_2 \left(\frac{\text{kg}}{\text{MMBtu}}\right) \times \text{GWP } CO_2 \times \frac{2.2 \text{ lbs}}{1 \text{ kg}} \\
&\times \text{Controlled Operation Hours} \left(\frac{\text{hr}}{\text{yr}}\right)\Big) \\
&+ \Big(\text{Uncontrolled Emission Factor } CO_2 \left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Uncontrolled Operation Hours} \left(\frac{\text{hr}}{\text{yr}}\right)\Big)\bigg)\Bigg) \\
&\times \text{Number of Turbines} \times \frac{1 \text{ ton}}{2{,}000 \text{ lbs}}
\end{aligned}$$

4.2 Natural Gas Engines

The natural gas engines are equipped with a catalytic oxidizer emission control system to control CO and VOC emissions.

4.2.1 Criteria Pollutants

The CO and VOC PTE calculations are a product of uncontrolled emission factors, controlled emission factors and the maximum engine rating,[5] which are provided by the manufacturer. This data is used to calculate controlled emissions from all natural gas engines according to the following equation:

$$\begin{aligned}
&\text{Annual Criteria Pollutant PTE (tpy)} \\
&= \Bigg(\text{Uncontrolled Emission Factor} \left(\frac{\text{g}}{\text{bkW} - \text{hr}}\right) \times \text{Engine Rating (bkW)} \\
&\times \text{ Annual Uncontrolled Operation Hours} \left(\frac{\text{hr}}{\text{yr}}\right) \\
&+ \text{Controlled Emission Factor} \left(\frac{\text{g}}{\text{bkW} - \text{hr}}\right) \times \text{Engine Rating (bkW)} \\
&\times \text{ Annual Controlled Operation Hours} \left(\frac{\text{hr}}{\text{yr}}\right)\Bigg) \times \frac{0.0022 \text{ lb}}{\text{g}} \times \text{Number of Engines} \times \frac{1 \text{ ton}}{2{,}000 \text{ lbs}}
\end{aligned}$$

Emission factors and engine ratings are provided for a range of load conditions; the maximums out of the range are used for PTE calculations.

[5] Where engine specifications are provided for multiple load conditions, the maximum value is used.

NO_X calculations are a product of manufacturer-provided emission factors and the maximum engine rating as follows:

$$\text{Annual NO}_X\text{ PTE (tpy)} = \text{Emission Factor}\left(\frac{\text{g}}{\text{bkW}-\text{hr}}\right)\times\text{Engine Rating (bkW)}\times\text{ Annual Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right)\times\frac{0.0022\text{ lb}}{\text{g}}\times\text{Number of Engines}\times\frac{1\text{ ton}}{2{,}000\text{ Ibs}}$$

SO_2 and PM PTE calculations are based on fuel consumption, maximum engine rating, and emission factors from AP-42, Section 3.2, Table 3.2-2. SO_2 and PM emissions are calculated according to the following equation:

$$\text{Annual Criteria Pollutant PTE (tpy)} = \text{Emisison Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)\times\text{Fuel Consumption}\left(\frac{\text{MMBtu}}{\text{bhp}-\text{hr}}\right)\times\text{Engine Rating (bhp)}\times\text{ Annual Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right)\times\text{Number of Engines}\times\frac{1\text{ ton}}{2{,}000\text{ Ibs}}$$

4.2.2 HAPs

The PTE for each speciated HAP is determined using the fuel consumption, annual hours of operation, and emission factors for HAPs from AP-42, Chapter 3.2, Table 3.2-2, with the exception of formaldehyde, where the emission factor is provided by the manufacturer. Controlled individual HAP emissions are calculated using the equation listed below:

$$\text{Annual HAP PTE (tpy)} = \text{HAP Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)\times\text{Fuel Consumption}\left(\frac{\text{MMBtu}}{\text{bhp}-\text{hr}}\right)\times\text{Engine Rating (bhp)}\times\times\text{Annual Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right)\times\text{Number of Engines}\times\frac{1\text{ ton}}{2{,}000\text{ lbs}}$$

The potential emissions of non-hydrocarbon volatile organic HAPs are added to the VOC PTE(s).

4.2.3 GHGs

GHGs expected to be emitted include CO_2, CH_4, and N_2O. The CO_2e PTE for each natural gas engine is calculated by weighting each of these pollutants according to their GWP according to the equation below.

$$\text{Annual CO}_2\text{e PTE (tpy)} = \left(\text{CO}_2\text{ Emission Factor}\left(\frac{\text{kg}}{\text{MMBtu}}\right)\times\text{ GWP}_{\text{CO}_2}+\text{N}_2\text{O Emission Factor}\left(\frac{\text{kg}}{\text{MMBtu}}\right)\times\text{GWP}_{\text{N}_2\text{O}}+\text{CH}_4\text{ Emission Factor}\left(\frac{\text{kg}}{\text{MMBtu}}\right)\times\text{GWP}_{\text{CH}_4}\right)\times\text{Fuel Consumption}\left(\frac{\text{MMBtu}}{\text{bhp}-\text{hr}}\right)\times\text{Engine Rating (bhp)}\times\text{Annual Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right)\times\frac{2.2\text{ lb}}{1\text{ kg}}\times\text{Number of Engines}\times\frac{1\text{ ton}}{2{,}000\text{ Ibs}}$$

Emission factors for CO_2, CH_4 and N_2O are obtained from 40 CFR Part 98, Subpart C, Table C-1, and Table C-2. The GWP for each GHG is obtained from 40 CFR Part 98, Subpart A, Table A-1. The engine fuel consumption and engine rating are per manufacturer specification and the maximum is used.

4.3 Line Heaters

The type of data utilized, and the calculation approach is the same for both sizes of line heaters proposed. The following calculation methodology is carried out for each type.

4.3.1 Criteria Pollutants

The criteria pollutant PTE calculations for the line heaters are a product of emission factors, fuel consumption, and the annual hours of operation, as shown in the equation below.

$$\begin{aligned}&\text{Annual Criteria Pollutant PTE (tpy)}\\&= \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)\times\ \text{Fuel Consumption}\ \left(\frac{\text{MMBtu}}{\text{hr}}\right)\times\text{Annual Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right)\\&\times\frac{1\text{ ton}}{2{,}000\text{ Ibs}}\end{aligned}$$

Criteria pollutant emission factors are per manufacturer specifications. The line heaters are assumed to operate for 8760 hours per year.

4.3.2 HAPs

HAP PTE calculations for the line heaters are a product of emission factors, the fuel consumption, and the annual hours of operation, as shown in the equation below.

$$\begin{aligned}&\text{Annual HAP PTE (tpy)}\\&= \text{Emission Factor}\ \left(\frac{\text{lb}}{\text{MMscf}}\right)\times\ \text{Fuel Consumption}\ \left(\frac{\text{MMBtu}}{\text{hr}}\right)\times\frac{1}{\text{Natural Gas HHV}\ \left(\frac{\text{MMBtu}}{\text{MMscf}}\right)}\\&\times\text{Operation Hours}\ \left(\frac{\text{hr}}{\text{yr}}\right)\times\frac{1\text{ ton}}{2{,}000\text{ Ibs}}\end{aligned}$$

HAP emission factors are per AP-42 Chapter 1.4-2, Table 1.4-3 and 1.4-4. The natural gas HHV is per AP-42 Table 1.4-1, footnote a.

4.3.3 GHGs

GHGs expected to be emitted from the line heaters include CO_2, CH_4, and N_2O. The CO_2e PTE is calculated by weighting each of these pollutants according to their GWP as shown in the equation below.

$$\begin{aligned}&\text{Annual CO}_2\text{e PTE (tpy)}\\&= \left(\text{CO}_2\text{ Emission Factor}\left(\frac{\text{kg}}{\text{MMBtu}}\right)\times\ \text{GWP}_{\text{CO}_2} + \text{N}_2\text{O Emission Factor}\left(\frac{\text{kg}}{\text{MMBtu}}\right)\times\text{GWP}_{\text{N}_2\text{O}}\right.\\&\left.+\ \text{CH}_4\text{ Emission Factor}\left(\frac{\text{kg}}{\text{MMBtu}}\right)\times\text{GWP}_{\text{CH}_4}\right)\times\frac{2.2\text{ lb}}{1\text{ kg}}\times\text{Fuel Consumption}\ \left(\frac{\text{MMBtu}}{\text{hr}}\right)\\&\times\text{Annual Operation Hours}\ \left(\frac{\text{hr}}{\text{yr}}\right)\times\frac{1\text{ ton}}{2{,}000\text{ lbs}}\end{aligned}$$

Emission factors for CO_2, CH_4 and N_2O are obtained from 40 CFR Part 98, Subpart C, Table C-1, and Table C-2. The GWP for each GHG is obtained from 40 CFR Part 98, Subpart A, Table A-1.

4.4 Fire Pump Engine

Calculations for criteria pollutant emissions from the fire pump engine are based on the maximum power output of the fire pump engine and EPA's Tier III Nonroad Compression-Ignition Engine emission rates.[6]

4.4.1 Criteria Pollutants

Emission factors for PM_{10} and $PM_{2.5}$ are conservatively assumed to be equivalent to the PM emission factor. The VOC emission factor is assumed to be equal to 5% of the nonmethane hydrocarbon (NMHC) + NO_X emission factor with the NO_X emission factor accounting for the remaining 95%.[7] NO_X, PM_{10}, $PM_{2.5}$, VOC, and CO annual emission rates are calculated using the following equation:

$$\text{Annual PTE (tpy)} = \text{Emission Factor}\left(\frac{\text{grams}}{\text{kW-hr}}\right) \times \text{Engine Rating (kW)} \times \frac{0.0022\ \text{lbs}}{1\ \text{gram}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} \times \text{Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right)$$

SO_2 calculations are based on an emission factor from AP-42 Section 3.3, Table 3.3-1 and are calculated using the following equation.

$$\text{Annual } SO_2 \text{ PTE (tpy)} = \text{Emission Factor}\left(\frac{\text{lb}}{\text{hp-hr}}\right) \times \text{Engine Rating (hp)} \times \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} \times \text{Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right)$$

4.4.2 HAPs

HAP emissions are determined using the maximum fuel consumption and emission factors for HAPs from AP-42, Section 3.3, Table 3.3-2.

$$\text{Annual HAP PTE (tpy)} = \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) \times \text{Fuel Consumption}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right) \times \frac{1\ \text{ton}}{2000\ \text{lbs}}$$

4.4.3 GHGs

GHG pollutants expected to be emitted from the fire pump engine include CO_2, CH_4, and N_2O. The CO_2e PTE is calculated by weighting each of these pollutants according to their GWP as shown in the equation below. Standard emission factors for CO_2, CH_4, and N_2O are provided in 40 CFR Part 98, Subpart C, Table C-1, and Table C-2. The global warming potential for each relevant pollutant is obtained from 40 CFR Part 98, Subpart A, Table A-1.

[6] EPA Nonroad Compression-Ignition Engines: Exhaust Emission Standards (EPA-420-B-16-022), March 2016.

[7] Per CARB Emission Factors for CI Diesel Engines – Percent NO_X in Relation to NMHC + NO_X

$$\begin{aligned}&\text{Annual } CO_2\text{e PTE (tpy)}\\&= \left(\text{Emission Factor } CO_2\left(\frac{\text{kg}}{\text{MMBtu}}\right) \times \text{GWP } CO_2 + \text{Emission Factor } CH_4\left(\frac{\text{kg}}{\text{MMBtu}}\right) \times \text{GWP } CH_4\right.\\&\left. + \text{Emission Factor } N_2O\left(\frac{\text{kg}}{\text{MMBtu}}\right) \times \text{GWP } N_2O\right) \times \frac{2.2 \text{ lbs}}{\text{kg}} \times \text{Fuel Consumption}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times\\&\times \text{Operation Hours}\left(\frac{\text{hr}}{\text{yr}}\right) \times \frac{1 \text{ ton}}{2000 \text{ lbs}}\end{aligned}$$

4.5 Storage Tanks

The fire pump engine will be equipped with a diesel belly tank situated under the engine which is expected to emit VOCs and HAPs during fuel loading. Emissions from the tank are calculated per AP-42, Section 5.2 and are dependent on fuel throughput. A safety factor of two is applied to the emissions, resulting in a conservative estimate of the tank PTE.

4.5.1 VOC Emissions

Emissions from the filling of each belly tank are calculated per AP-42, Section 5.2: Transportation and Marketing of Petroleum Liquids. Specifically, equations contained in Section 5.2.2.1.1 (Loading Losses) are utilized.

$$L_L\left(\frac{\text{lb}}{10^3\text{gal}}\right) = 12.46\frac{\text{SPM}}{\text{T}}(\text{SF})$$

Where:

L_L = Loading loss (lb/10^3 gal of liquid loaded)
S = Saturation factor for "submerged loading: dedicated normal service" (Table 5.2-1)
P = True vapor pressure of diesel (psia) (Table 7.1-2)
M = Vapor molecular weight of diesel (Table 7.1-2)
T = Temperature of diesel (°R)
SF = Safety factor of 2

The loading loss emission factor is then multiplied by the belly tank diesel throughput in the following equation:

$$\text{Annual VOC PTE (tpy)} = L_L\left(\frac{\text{lb}}{10^3\text{gal}}\right) \times \text{Diesel Usage}\left(\frac{\text{gal}}{\text{yr}}\right) \times \frac{10^3 \text{ gal}}{1{,}000 \text{ gal}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lbs}}$$

4.5.2 HAP Emissions

HAP emissions from the diesel belly tanks are based on vapor weight percents of diesel fuel from TankESP. The weight percents are multiplied by the VOC loading loss as seen in the following equation:

$$\text{Annual HAP PTE (tpy)} = \text{Annual VOC PTE(tpy)} \times \text{HAP wt \%}$$

The HAP speciation provided by TankESP is detailed in Appendix B.

5. BACT ANALYSIS

Per UAC R307-401-5(2)(d), every facility, operation, or process that proposes any activity that emits an air contaminant must consider best available control technology (BACT) for a proposed new source or modification.[8]

Will-Power has followed EPA guidance in preparing this top-down BACT analysis. The first step in this approach is to determine the most stringent control available for a similar or identical source or source category for the emission unit in question. If it can be shown that this level of control is technically, environmentally, or economically infeasible or inappropriate on the basis of energy concerns for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This procedure continues until there are no remaining significant or exceptional technical, environmental, economic, or energy-related objections that can prevent the elimination of the BACT option(s) under review.

Presented below are the five basic steps of a top-down BACT review as identified by the EPA.[9]

5.1.1 Step 1 – Identify All Control Technologies

Available control technologies are identified for each emission unit in question. The following methods are used to identify potential technologies: (1) querying the RACT/BACT/LAER Clearinghouse (RBLC) database; (2) surveying regulatory agencies; (3) drawing from previous engineering experience; (4) surveying air pollution control equipment vendors; and (5) surveying available literature.

5.1.2 Step 2 – Eliminate Technically Infeasible Options

After the identification of control options, an analysis is conducted to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that prohibit the implementation of the control. Additionally, EPA's Draft New Source Review Workshop Manual states that "in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), the level of control (but not necessarily the technology) may be eliminated from further consideration."[10] Therefore, even if a permit lists a BACT or BACT emission limit, it is possible that the control technology (or limit) may not have been demonstrated in practice.

5.1.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Once technically infeasible options are removed from consideration, the remaining options are ranked based on their control effectiveness. If there is only one remaining option, or if all the remaining technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required.

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[8] UAC R307-401-4

[9] U.S. EPA. Draft New Source Review Workshop Manual, Chapter B. Research Triangle Park, North Carolina. October 1990.

[10] Ibid.

5.1.4 Step 4 - Evaluate Most Effective Controls and Document Results

Beginning with the most effective control option in the ranking, detailed economic, energy, and environmental impact evaluations are performed. If a control option is determined to be economically feasible without adverse energy or environmental impacts, it is not necessary to evaluate the remaining options with lower control effectiveness.

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the EPA's *OAQPS Control Cost Manual* (CCM) and other industry resources.[11] Note that the purpose of this analysis is not to determine whether controls are affordable for a particular company or industry, but whether the expenditure effectively allows the source to meet pre-established presumptive norms.

5.1.5 Step 5 - Select BACT

In the final step the lowest emission limitation is proposed as BACT along with any necessary control technologies or measures needed to achieve the cited emission limit. This proposal is based on the evaluations from the previous steps.

5.2 BACT Analyses

The top down BACT analysis is presented in Appendix C for each emission unit and respective pollutant. A summary of the BACT analysis is provided in the following subsections.

5.2.1 Natural Gas Turbines

The proposed natural gas turbines are compared against RBLC entries and other available databases for simple cycle natural gas turbines.

- Emission Units: Eleven (11) TM2500 natural gas turbines
- Pollutants: CO, SO_2, NO_X, $PM_{2.5}$, PM_{10}, and VOC

The proposed TM2500 natural gas turbines will use pipeline-quality gas and implement good combustion practices. Additionally, low emission rates will be achieved through the installation of SCR units and catalytic oxidizers. With this combination of controls, Will-Power is proposing maximum emission rates of 2.34 lb/hr of NO_X, 2.85 lb/hr of CO, 1.57 lb/hr of VOC, 0.18 lb/hr of SO_2, and 2.10 lb/hr of $PM_{2.5}$/PM_{10} for each TM2500 natural gas turbine. The NO_X, VOC, and CO maximum emission rates are based on concentrations of 2 ppm of NO_X, 3 ppm of hydrocarbon VOC, and 4 ppm of CO (all ppm values at 15% O2). Will-Power proposes the use of these technologies and their resulting emission rates, the use of pipeline quality (low-sulfur) natural gas, and the use of good combustion practices as BACT for these TM2500 natural gas turbines.

- Emission Units: Six (6) ST250 natural gas turbines
- Pollutants: CO, SO_2, NO_X, $PM_{2.5}$, PM_{10}, and VOC

The proposed natural gas turbines will use pipeline-quality gas and implement good combustion practices. Additionally, low emission rates will be achieved through the installation of SCR units and catalytic oxidizers.

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[11] Office of Air Quality Planning and Standards (OAQPS), *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA 452-02-001 (https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution), Daniel C. Mussatti & William M. Vatavuk, January 2002.

With this combination of controls, Will-Power is proposing maximum emission rates of 1.31 lb/hr of NO_X, 1.59 lb/hr of CO, 0.77 lb/hr of VOC, 0.10 lb/hr of SO_2, and 1.17 lb/hr of $PM_{2.5}/PM_{10}$ for each ST250 natural gas turbine. The NO_X, VOC, and CO maximum emission rates are based on concentrations of 2 ppm of NO_X, 3 ppm of hydrocarbon VOC, and 4 ppm of CO (all ppm values at 15% O2). Will-Power proposes the use of these technologies and their resulting emission rates, the use of pipeline quality (low-sulfur) natural gas, and the use of good combustion practices as BACT for these ST250 natural gas turbines.

5.2.2 Natural Gas Engines

The proposed natural gas engines are compared against RBLC entries and other available databases for natural gas-fired emergency engines > 500 hp.

- Emission Units: Two (2) G3520 2500 kW natural gas engines
- Pollutants: CO, SO_2, NO_X, PM_{10}, $PM_{2.5}$, and VOC

The proposed natural gas engines will use pipeline-quality gas and implement good combustion practices. Additionally, low emission rates will be achieved through the installation of catalytic oxidation units. With this combination of controls, Will-Power is proposing maximum emission rates of 7.99 lb/hr of NO_X, 6.0 lb/hr of CO, 2.25 lb/hr of VOC, 1.34E-2 lb/hr of SO_2, and 0.21 lb/hr of $PM_{2.5}/PM_{10}$ for each natural gas engine. Will-Power proposes the use of catalytic oxidation and the resulting emission rates, the use of pipeline quality (low-sulfur) natural gas, and the use of good combustion practices as BACT for these engines.

The use of SCR for reduction of NO_x was found to be economically infeasible, with a cost of $107,871 per ton of NO_X removed.

5.2.3 Line Heaters

The proposed heaters are compared against RBLC entries and other available databases for natural gas-fired line heaters < 100 MMBtu/hr.

- Emission Units: Six (6) 11 MMBtu/hr natural gas-fired line heaters
- Pollutants: CO, SO_2, NO_X, PM_{10}, $PM_{2.5}$ and VOC

The large line heaters proposed for the facility will use pipeline-quality gas and implement good combustion practices. Additionally, low emission rates will be achieved through the use of ultra-low NO_X burners. With this control, Will-Power is proposing a NO_X emission rate of 0.11 lb/hr, a CO emission rate of 0.40 lb/hr, a hydrocarbon VOC emission rate of 0.05 lb/hr, an SO_2 emission rate of 7.47E-3 lb/hr , and a $PM_{10}/PM_{2.5}$ emission rate of 0.08 lb/hr for each 11 MMBtu/hr line heater. Will-Power proposes the use of ultra-low NO_X burners, pipeline quality natural gas, and good combustion practices as BACT for this equipment.

- Emission Units: Two (2) 3.4 MMBtu/hr natural gas-fired line heaters
- Pollutants: CO, SO_2, NO_X, PM_{10}, $PM_{2.5}$ and VOC

The small line heaters proposed for the facility will use pipeline-quality gas and implement good combustion practices. Additionally, low emission rates will be achieved through the use of ultra-low NO_X burners. With this control, Will-Power is proposing a NO_X emission rate of 0.03 lb/hr, a CO emission rate of 0.13 lb/hr, a hydrocarbon VOC emission rate of 0.02 lb/hr, an SO_2 emission rate of 2.4E-3 lb/hr , and a $PM_{10}/PM_{2.5}$ emission rate of 0.03 lb/hr for each 3.4 MMBtu/hr line heater. Will-Power proposes the use of ultra-low NO_X burners, pipeline quality natural gas, and good combustion practices as BACT for this equipment.

5.2.4 Fire Pump Engine

Emission Unit: One (1) 325 hp fire pump engine
Pollutants: CO, SO_2, NO_X, PM_{10}, $PM_{2.5}$ and VOC

The proposed fire pump engine will use ULSD fuel and implement good combustion practices. Additionally, emissions will be minimized through compliance with applicable Tier III certification standards for nonroad engines, which are equivalent to NSPS Subpart IIII fire pump engine standards in this instance. With the combination of these controls, Will-Power is proposing a NO_X emission rate of 2.03 lb/hr, a CO emission rate of 1.87 lb/hr, a hydrocarbon VOC emission rate of 0.11 lb/hr, an SO_2 emission rate of 6.66E-01 lb/hr , and a PM_{10}/$PM_{2.5}$ emission rate of 0.11 lb/hr. Proposed BACT for the fire pump engine is the use of ULSD fuel, use of a Tier III certified engine, and implementation of good combustion practices.

5.2.5 Fire Pump Engine Belly Tank

Emission Unit: One (1) fire pump engine diesel belly tank
Pollutants: VOC

Will-Power is proposing that use of submerged filling is BACT for the fire pump engine belly tank. Use of this operating practice leads to the proposed VOC emission rate of 0.01 lb/10^3 gal of diesel loaded.

6. EMISSION IMPACT ANALYSIS

Table B-1 in Appendix B compares the facility's total PTE for each criteria pollutant to applicable modeling thresholds contained in R307-410-4. The emissions associated with the proposed operations are greater than the UDAQ modeling thresholds for PM_{10}, $PM_{2.5}$, NO_2, and CO.

Table B-2 in Appendix B compares the facility's total HAP PTE to applicable emission threshold values (ETVs). The proposed operations are greater than the ETV for formaldehyde.

Air dispersion modeling was conducted for PM_{10}, $PM_{2.5}$, NO_2, CO and formaldehyde and is detailed and submitted to UDAQ in a separate document with this application.

7. OFFSETTING REQUIREMENTS

7.1 UAC R307-403 Offsetting Requirements

R307-403 requires that emissions be offset according to nonattainment status for new and modified sources in nonattainment areas. To be subject to these requirements, a source must be above major source thresholds for new sources, or major modification thresholds for modifications to existing major sources. While the facility is located in a marginal ozone nonattainment area, it is not a new major source or major modification of ozone precursors, therefore, ozone offsets are not required per R307-403.

7.2 UAC R307-420 Offsetting Requirements

R307-420 requires offsets for new major sources and major modifications in Davis and Salt Lake County. This rule defines "Major Source" as a source with a PTE of greater than or equal to 50 tpy of VOCs or 100 tpy of NO_X. It also defines major modification as an increase of 25 tpy of VOCs and/or 40 tpy of NO_X. If proposed permitting action is classified as a new major source or major modification under these specific definitions, offsets are required. The facility is located in Utah County; therefore, the ozone offset requirements of R307-420 do not apply.

7.3 UAC R307-421 Offsetting Requirements

R307-421 requires offsets for new or modified sources in Salt Lake and Utah County that are proposing emissions increases greater than or equal to 25 tpy of NO_X or SO_2. For increases greater than or equal to 25 tpy but less than 50 tpy, emissions are required to be offset by a ratio of 1:1 per pollutant. For increases greater than or equal to 50 tpy, emissions are required to be offset by a ratio of 1.2 to 1 per pollutant. The facility is in Utah County and is proposing emissions of NO_X greater than 50 tpy. Will-Power will purchase 120 NO_X Emission Reduction Credits from the Utah County registry to satisfy the R307-421 PM_{10} offset requirement

8. REGULATORY REVIEW

This section summarizes the air permitting requirements and the key air quality regulations that apply to the Project. Specifically, applicability of PSD, Nonattainment New Source Review (NNSR), Title V of the 1990 Clean Air Act Amendments, New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and UDAQ regulations are addressed. Applicability to certain general provisions are not detailed in this narrative summary.

8.1 Federal Regulations

8.1.1 New Source Performance Standards

The NSPS are federal regulations found in Title 40 of the Code of Federal Regulations (40 CFR) Part 60. NSPS apply to certain types of equipment that are newly constructed, modified, or reconstructed after a given applicability date. Moreover, any source subject to NSPS is also subject to general provisions of 40 CFR Part 60 Subpart A (NSPS Subpart A), except as noted. The following section details the applicability of NSPS regulations to the facility.

8.1.1.1 Subpart A – General Provisions

All affected sources subject to source-specific NSPS are subject to the general provisions of NSPS Subpart A unless specifically excluded by the source specific NSPS. Subpart A requires initial notification, performance testing, recordkeeping, and monitoring, provides reference methods, and mandates general control device requirements for all other subparts.

8.1.1.2 Subpart IIII – Compression Ignition Internal Combustion Engines

NSPS Subpart IIII is applicable to stationary compression ignition internal combustion engines that commence construction, modification, or reconstruction after July 11, 2005, and that are manufactured after April 1, 2006. The proposed fire pump engine meets these applicability dates and is therefore subject to this subpart.

The fire pump engine must comply with the emission standards in Table 3 of this subpart for its model year and power rating. Compliance is achieved by installing a fire pump engine certified to the applicable standards and by operating and maintaining it according to the manufacturer’s instructions for the life of the unit. The fire pump engine must use diesel fuel that meets the required specifications, including a sulfur content of no more than 15 ppm.

The fire pump engine must be equipped with a non-resettable hour meter. It may operate for up to 100 hours per year for maintenance and readiness testing, and up to 50 hours per year in non-emergency situations, with no limit on operation during true emergencies. Will-Power will maintain all records required by Subpart IIII, including documentation showing that the fire pump engine is certified to the applicable emission standards.

8.1.1.3 Subpart JJJJ – Spark Ignition Internal Combustion Engines

NSPS Subpart JJJJ is applicable to stationary spark ignition internal combustion engines that commence construction, modification, or reconstruction after June 12, 2006, and that are manufactured after July 1,

2007. The proposed natural gas engines meet these applicability dates and are therefore subject to this subpart.

The natural gas engines must comply with the emission standards in Table 1 to Subpart JJJJ. Compliance is achieved by installing an engine certified to the applicable standards or by demonstrating compliance through performance testing and ongoing maintenance requirements. Certified engines must be operated and maintained according to the manufacturer's instructions for the life of the unit.

The natural gas engines will follow the NOx compliance requirements in Subpart JJJJ and Will-Power will maintain all records required by Subpart JJJJ, including documentation showing that the natural gas engines are certified to the applicable emission standards.

8.1.1.4 Subpart KKKKa New Source Performance Standards for Stationary Combustion Turbines and Stationary Gas Turbines

NSPS Subpart KKKKa is applicable to stationary gas turbines with base load rating equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr) and that commenced construction, modification, or reconstruction after December 13, 2024. The proposed natural gas turbines are subject to NSPS Subpart KKKKa. The turbines fall under the category "New combustion turbines, firing natural gas at utilization rates > 45 percent" and base load rating greater than or equal to 50 MMBtu/hr and less than 850 MMBtu/hr that fire natural gas. Under this rule, the applicable NO_X emission standard is 15 ppm at 15% O_2. Turbines that require post-combustion control to meet the applicable emission standard are required to install NO_X CEMS to demonstrate compliance. Turbines that meet the applicable emission standard without post-combustion control can demonstrate compliance with alternative methods. The SO_2 emission standards under Subpart KKKK remain unchanged in Subpart KKKKa and require the burning of low sulfur fuel. Will-Power will comply with this subpart by burning low sulfur fuel installing NO_X CEMS on all natural gas turbines.

8.1.1.5 Subpart TTTTa - Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

NSPS Subpart TTTTa is applicable to stationary combustion turbines with a base load rating greater than 260 gigajoules per hour (GJ/h) (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel) and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system. Since the proposed natural gas turbines are not capable of selling electricity to a utility power distribution system, the subpart does not apply.

8.1.2 National Emission Standards for Hazardous Air Pollutants

The NESHAP federal regulations found in 40 CFR Parts 61 and 63 are emission standards for HAPs. NESHAP are applicable to both major sources of HAPs (facilities that exceed the major source thresholds of 10 tpy of a single HAP or 25 tpy of any combination of HAPs from stationary sources) as well as non-major sources (i.e., emissions less than 10 tpy of a single HAP and less than 25 tpy of any combination of HAPs). NESHAP applies to sources in specifically regulated industrial source classifications (Clean Air Act Section 112(d)) or on a case-by-case basis (Clean Air Act Section 112(g)) for facilities not regulated as a specific industrial source type.

The facility is not a major source of HAPs, as total HAP emissions amount to less than 10 tons per year for an individual HAP and less than 25 tons per year of total HAPs.

8.1.2.1 Subpart A – General Provisions

NESHAP Subpart A, *General Provisions*, contains national emissions standards for HAPs defined in Section 112(b) of the Clean Air Act. All affected sources, which are subject to another NESHAP are subject to the general provisions of NESHAP Subpart A, unless specifically excluded by the source specific NEHSAP. Subpart A requires initial notification, performance testing, recordkeeping, and monitoring, provides reference methods, and mandates general control device requirements for all other subparts.

8.1.2.2 Subpart YYYY - Stationary Combustion Turbines

NESHAP Subpart YYYY, *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, applies to stationary combustion turbines located at a major source of HAPs. The facility is not a major source of HAPs, as total HAP emissions amount to less than 10 tons per year for any individual HAP and less than 25 tons per year of total HAPs.[12] Accordingly, Subpart YYYY does not apply.

8.1.2.3 Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines

NESHAP Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, applies to stationary reciprocating internal combustion engines located at both major and area sources of hazardous air pollutants (HAPs). Because the facility is an area source of HAPs; Subpart ZZZZ applies to the natural gas engines and the fire pump engine at the facility. Accordingly, the engines must comply with the applicable requirements for existing or new stationary spark-ignition (SI) RICE and compression-ignition (CI) RICE, as appropriate, based on their installation date and horsepower rating.

8.1.2.4 Subpart DDDDD - Industrial, Commercial, and Institutional Boilers and Process Heaters

NESHAP Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to owners or operators of industrial boilers or process heaters that are located at a major source of HAPs. Since the facility is not a major source of HAPs, Subpart DDDDD does not apply.

8.1.3 Permits Regulation – Acid Rain Program

40 CFR Part 72 establishes the permitting framework for the Acid Rain Program (ARP) under Title IV of the Clean Air Act. Part 72 defines the general provisions, applicability criteria, permitting procedures, designated representative requirements, and administrative processes governing affected sources and affected units. These regulations apply to fossil-fuel-fired electric generating units subject to mandatory SO_2 allowance requirements and, where applicable, NO_x emission limitations. The TM2500 natural gas turbines are considered “affected units” and are subject to the requirements of the ARP.

8.1.3.1 Applicability

Under the ARP, any fossil fuel-fired electric generating unit with a nameplate capacity greater than 25 MWe that sells electricity is classified as a “utility unit” and is therefore an affected unit under 40 CFR §72.6. All affected units must obtain and operate pursuant to an Acid Rain permit and comply with the standard requirements of Part 72.

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[12] 40 CFR 63.6085(b)

8.1.3.2 Emission Requirements

The ARP operates on a market of allowances. Each allowance permits a source to produce one ton of SO_2 a year. New sources must obtain allowances by purchasing them from other sources, or by attending EPA auctions for allowances. Allowances can be used the year they are purchased or banked for future years. Allowances must be surrendered annually in order to emit SO_2 in any quantity.

8.1.3.3 Monitoring, Reporting and Recordkeeping Requirements

Affected turbines must comply with the monitoring and reporting requirements of 40 CFR Part 75. This typically involves using either certified CEMS or EPA-approved fuel-based calculation methods to measure and report SO_2, NO_X, CO_2, flow, and heat input. Units must submit quarterly electronic emissions reports to EPA and retain supporting monitoring records for at least three years. Will-Power will install CEMS that will monitor NO_X on the TM2500 natural gas turbines and intends to apply for the alternative tracking and reporting methods for SO_2 and CO_2 to comply with these requirements.

8.2 UDAQ Air Quality Rules

Table 8-1. Evaluation of UDAQ Air Quality Rules

UAC	Regulation Name	Applicability	
		Yes	No
R307-101	General Requirements	X	
R307-102	General Requirements: Broadly Applicable Requirements	X	
R307-103	Administrative Procedures	X	
R307-104	Conflict of Interest		X
R307-105	General Requirements: Emergency controls	X	
R307-107	General Requirements: Breakdowns	X	
R307-110	General Requirements: State Implementation Plan	X	
R307-115	General Conformity	X	
R307-120	General Requirements: Tax Exemption for Air Pollution Control Equipment	X	
R307-121	General Requirements: Clean Air and Efficient Vehicle Tax Credit		X
R307-122	General Requirements: Heavy Duty Vehicle Tax Credit		X
R307-123	General Requirements: Clean Fuels and Vehicle Technology Grant and Loan Program		X
R307-124	General Requirements: Conversion to Alternative Fuel Grant Program		X
R307-125	Clean Air Retrofit, Replacement, and Off-Road Technology Program		X
R307-130	General Penalty Policy	X	

UAC	Regulation Name	Applicability	
		Yes	No
R307-135	Enforcement Policy for Asbestos Hazard Emergency Response Act		X
R307-150	Emission Inventories	X	
R307-165	Stack Testing	X	
R307-170	Continuous Emission Monitoring Program	X	
R307-201	Emission Standards: General Emission Standards		X
R307-202	Emission Standards: General Burning		X
R307-203	Emission Standards: Sulfur Content of Fuels		X
R307-204	Emission Standards: Smoke Management		X
R307-205	Emission Standards: Fugitive Emissions and Fugitive Dust		X
R307-206	Emission Standards: Abrasive Blasting		X
R307-207	Residential Fireplaces and Solid Fuel Burning Devices		X
R307-208	Outdoor Wood Boilers		X
R307-210	Standards of Performance for New Stationary Sources	X	
R307-214	National Emission Standards for Hazardous Air Pollutants	X	
R307-220	Emission Standards: Plan for Designated Facilities		X
R307-221	Emission Standards: Emission Controls for Existing Municipal Solid Waste Landfills		X
R307-222	Emission Standards: Existing incinerator for Hospital, Medical, Infectious Waste		X
R307-223	Emission Standards: Existing Small Municipal Waste Combustion Units		X
R307-224	Mercury Emission Standards: Coal Fired Electric Generating Units		X
R307-230	NO_X Emission Limits for Natural Gas-Fired Water Heaters		X
R307-250	Western Backstop Sulfur Dioxide Trading Program		X
R307-301	Utah and Weber Counties: Oxygenated Gasoline Program as a Contingency Measure		X
R307-302	Solid Fuel Burning Devices		X
R307-303	Commercial Cooking		X
R307-304	Solvent Cleaning		X

UAC	Regulation Name	Applicability	
		Yes	No
R307-305	Nonattainment and Maintenance Areas for PM_{10}: Emission Standards	X	
R307-306	PM_{10} Nonattainment and Maintenance Areas: Abrasive Blasting		X
R307-307	Road Salting and Sanding		X
R307-309	Nonattainment and Maintenance Areas for PM_{10} and $PM_{2.5}$: Fugitive Emissions and Fugitive Dust		X
R307-310	Salt Lake County: Trading of Emission Budgets for Transportation Conformity		X
R307-311	Utah County: Trading of Emission Budgets for Transportation Conformity		X
R307-312	Aggregate Processing Operations for $PM_{2.5}$ Nonattainment Areas		X
R307-320	Ozone Maintenance Areas and Ogden City: Employer Based Trip Reduction		X
R307-325	Ozone Nonattainment and Maintenance Areas: General Requirements	X	
R307-326	Ozone Nonattainment and Maintenance Areas: Control of Hydrocarbon Emissions in Petroleum Refineries		X
R307-327	Ozone Nonattainment and Maintenance Areas: Petroleum Liquid Storage		X
R307-328	Gasoline Transfer and Storage		X
R307-335	Degreasing		X
R307-341	Ozone Nonattainment and Maintenance Areas: Cutback Asphalt		X
R307-342	Adhesives and Sealants		X
R307-343	Wood Furniture Manufacturing Operations		X
R307-344	Paper, Film, and Foil Coatings		X
R307-345	Fabric and Vinyl Coatings		X
R307-346	Metal Furniture Surface Coatings		X
R307-347	Large Applicable Surface Coatings		X
R307-348	Magnet Wire Coatings		X
R307-349	Flat Wood Panel Coating		X
R307-350	Appliance Pilot Light		X
R307-351	Graphic Arts		X
R307-352	Metal Container, Closure, and Coil Coatings		X
R307-353	Plastic Parts Coatings		X

UAC	Regulation Name	Applicability	
		Yes	No
R307-354	Automotive Refinishing Coatings		X
R307-355	Aerospace Manufacture and Rework Facilities		X
R307-356	Appliance Pilot Light		X
R307-357	Consumer Products		X
R307-361	Architectural Coatings		X
R307-401	Permit: New and Modified Sources	X	
R307-403	Permits: New and Modified Sources in Nonattainment and Maintenance Areas	X	
R307-405	Permits: Major Sources in Attainment or Unclassified Areas (PSD)		X
R307-406	Visibility		X
R307-410	Permits: Emission Impact Analysis	X	
R307-414	Permits: Fees for Approval Orders	X	
R307-415	Permits: Operating Permit Requirements	X	
R307-417	Permits: Acid Rain Sources	X	
R307-420	Permits: Ozone Offset Requirements in Salt Lake County and Utah County		X
R307-421	Permits: PM_{10} Offset Requirements in Salt Lake County and Utah County	X	
R307-424	Permits: Mercury Requirements for Electric Generating Units		X
R307-501 to 511	Oil and Gas Industry		X
R307-801	Utah Asbestos Rule		X
R307-840	Lead-Based Paint Program Purpose, Applicability, and Definitions		X
R307-841	Residential Property and Child-Occupied Facility Renovation		X
R307-842	Lead-Based Paint Activities		X

8.2.1 R307-101 General Requirements

Chapter 19-2 and the rules adopted by the Air Quality Board constitute the basis for control of air pollution sources in the state. These rules apply and will be enforced throughout the state and are recommended for adoption in local jurisdictions where environmental specialists are available to cooperate in implementing rule requirements.

NAAQS, NSPS, PSD, and NESHAP apply throughout the nation and are legally enforceable in Utah.

Will-Power will comply and conform to the definitions, terms, abbreviations, and references used in the R307-101 and 40 CFR.

8.2.2 R307-107 General Requirements: Breakdowns

Will-Power will report breakdowns at the Eagle Mountain Data Center within 24 hours via telephone, electronic mail, fax, or other similar method and provide detailed written description within 14 days of the onset of the incident to UDAQ. Breakdown reports will include all reporting details outlined in R307-107-2, including, but not limited to, the cause and nature of the event, estimated quantity of emissions, and time of emissions.

8.2.3 R307-170 Continuous Emission Monitoring Program

Any source required to install a CEMS is subject to R307-170. The facility is required to install a CEMS under 40 CFR Part 75; therefore, R307-170 does apply. However, the facility is exempt from R307-170-6 and R307-170-9(7) due to stricter monitoring and reporting requirements set forth in 40 CFR Part 60 and R307-150, respectively.

8.2.4 R307-305 Nonattainment and Maintenance Areas for PM10: Emission Standards

The facility will not have any visible emissions of a shade or density darker than 20% opacity as set forth by R307-305-3(1) and will minimize visible and non-visible emissions during start-up or shutdown of a facility, installation, or operation through the use of adequate control technology and proper procedures as set forth in R307-305-3(4).

8.2.5 R307-410 Permits: Emission Impact Analysis

UAC R307-410 requires that Will-Power evaluate the emissions impact the facility may have on the air quality specifically in relation to the attainment status of the NAAQS. An emission impact analysis has been conducted for the facility. Please refer to Section 6 of this NOI air permit application for further discussion.

8.2.6 R307-415 Permits: Operating Permit Requirements

UAC R307-415 applies to facilities that have a potential to emit specific pollutants over certain thresholds, as listed below:

1. HAPs: The site-wide PTE exceeds 10 tpy or more of any individual HAP or 25 tpy or more of any combination of HAPs or
2. Criteria pollutants and GHGs: The site-wide PTE exceeds 100 tpy.

As shown in Appendix B, Table B-1, Title V thresholds are exceeded for $PM_{2.5}$, PM_{10}, and CO. Will-Power will submit a Title V operating permit application.

8.2.7 R307-417 Permits: Acid Rain Sources

Under R307-417, Utah adopted the federal Acid Rain Program (ARP), established under Title IV of the CAA. Under the ARP, any fossil fuel-fired electric generating unit with a nameplate capacity greater than 25 MWe that produces electricity for sale is classified as a utility unit and must obtain an Acid Rain permit.[13] As discussed in section 8.1.3, Will-Power is subject to the ARP and the requirements in R307-417.

8.2.8 R307-421 Permits: PM10 Offset Requirements in Salt Lake County and Utah County

R307-421 requires that Will-Power purchase NO_X offsets as discussed in section 7.1.3 of this NOI.

[13] 40 CFR Part 72 - 78

AIR QUALITY

Form 1
Notice of Intent (NOI) Application Checklist

Date February 2026

Company Will-Power UT, LLC

Utah Division of Air Quality
New Source Review Section

Source Identification Information [R307-401-5]

1. Company name, mailing address, physical address and telephone number ☑
2. Company contact (Name, mailing address, and telephone number) ☑
3. Name and contact of person submitting NOI application (if different than 2) ☑
4. Source Universal Transverse Mercator (UTM) coordinates ☑
5. Source Standard Industrial Classification (SIC) code ☑
6. Area designation (attainment, maintenance, or nonattainment) ☑
7. Federal/State requirement applicability (NAAQS, NSPS, MACT, SIP, etc.) ☑
8. Source size determination (Major, Minor, PSD) ☑
9. Current Approval Order(s) and/or Title V Permit numbers ☐

NOI Application Information: [R307-401]

1. Detailed description of the project and source process ☑
2. Discussion of fuels, raw materials, and products consumed/produced ☑
3. Description of equipment used in the process and operating schedule ☑
4. Description of changes to the process, production rates, etc. ☑
5. Site plan of source with building dimensions, stack parameters, etc. ☑

6. Best Available Control Technology (BACT) Analysis [R307-401-8]
   A. BACT analysis for all new and modified equipment ☑

7. Emissions Related Information: [R307-401-2(b)]
   A. Emission calculations for each new/modified unit and site-wide (Include PM_{10}, $PM_{2.5}$, NO_x, SO_2, CO, VOCs, HAPs, and GHGs) ☑
   B. References/assumptions, SDS, for each calculation and pollutant ☑
   C. All speciated HAP emissions (list in lbs/hr) ☑

8. Emissions Impact Analysis – Approved Modeling Protocol [R307-410]
   A. Composition and physical characteristics of effluent (emission rates, temperature, volume, pollutant types and concentrations) ☑

9. Nonattainment/Maintenance Areas – Major NSR/Minor (offsetting only) [R307-403]
   A. NAAQS demonstration, Lowest Achievable Emission Rate, Offset requirements ☐ N/A ■
   B. Alternative site analysis, Major source ownership compliance certification ☐ N/A ■

10. Major Sources in Attainment or Unclassified Areas (PSD) [R307-405, R307-406]
    A. Air quality analysis (air model, met data, background data, source impact analysis) ☐ N/A ■
    B. Visibility impact analysis, Class I area impact ☐ N/A ■
11. Signature on Application ☑

Note: The Division of Air Quality will not accept documents containing confidential information or data. Documents containing confidential information will be returned to the Source submitting the application.

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY

Form 2
Company Information/Notice of Intent (NOI)

Date January 2026

Utah Division of Air Quality
New Source Review Section

Application for: ☑ **Initial Approval Order** ☐ **Approval Order Modification**

General Owner and Source Information

1.Company name and mailing address:
Will-Power UT, LLC Eagle Mountain Site
1499 N Pony Express Parkway
Eagle Mountain, UT 84005
Phone No.: ( )
Fax No.: ( )

2. Company** contact for environmental matters:
Andrew Woerner
Phone no.: (610)-412-8905
Email: Andrew.Woerner@Williams.com
*** Company contact only; consultant or independent contractor contact information can be provided in a cover letter*

3. Source name and physical address (if different from above):
______
______
______
Phone no.: ( )
Fax no.: ( )

4. Source Property Universal Transverse Mercator coordinates (UTM), including System and Datum:
UTM: 12
X: 414,225.35 m Easting
Y: 4,456,082.40 m Northing

5. The Source is located in: Utah County

6. Standard Industrial Classification Code (SIC)
4911

7. If request for modification, AO# to be modified: DAQE #__________ DATED: ____/____/____

8. Brief (50 words or less) description of process.
Williams intends to construct a power generation facility to provide primary power to a private buyer for an adjacent data center. Equipment includes natural gas-fired turbines, natural gas-fired emergency generators, a diesel fire pump, and line heaters.

Electronic NOI
9. A complete and accurate electronic NOI submitted to DAQ Permitting Mangers Jon Black (*jlblack@utah.gov*) or Alan Humpherys (ahumpherys@utah.gov) can expedite review process. Please mark application type.

Hard Copy Submittal ☐ Electronic Copy Submittal ☑ Both ☐

Authorization/Signature

I hereby certify that the information and data submitted in and with this application is completely true, accurate and complete, based on reasonable inquiry made by me and to the best of my knowledge and belief.

Signature: Signed by: Nickolaus Munoz
57FD021F3426430...
Title: VP Power Innovation Operations

Nickolaus Munoz
Name (Type or print)

Telephone Number:
( )
Email: Nickolaus.Munoz@williams.com

Date:
1/30/2026 | 6:39 AM PST

docusign

Certificate Of Completion

Envelope Id: BE921B23-371D-4330-B4A2-54AF4A1EE482		Status: Completed
Subject: Complete with Docusign: Aquilla Signature Page.pdf		
Source Envelope:		
Document Pages: 1	Signatures: 1	Envelope Originator:
Certificate Pages: 1	Initials: 0	Sandra Bruce
AutoNav: Enabled		One Williams Center
EnvelopeId Stamping: Enabled		Tulsa, OK 74172
Time Zone: (UTC-08:00) Pacific Time (US & Canada)		Sandra.Bruce@Williams.com
		IP Address: 208.71.101.45

Record Tracking

Status: Original 1/29/2026 1:44:18 PM	Holder: Sandra Bruce Sandra.Bruce@Williams.com	Location: DocuSign

Signer Events	Signature	Timestamp
Nickolaus Munoz Nickolaus.Munoz@Williams.com Director of Operations - ORSH Security Level: Email, Account Authentication (None)	Signed by: Nickolaus Munoz 57FD021F3426430... Signature Adoption: Pre-selected Style Using IP Address: 151.142.232.179 Signed using mobile	Sent: 1/29/2026 1:48:13 PM Viewed: 1/30/2026 6:38:59 AM Signed: 1/30/2026 6:39:09 AM

Electronic Record and Signature Disclosure:
Not Offered via Docusign

In Person Signer Events	Signature	Timestamp

Editor Delivery Events	Status	Timestamp

Agent Delivery Events	Status	Timestamp

Intermediary Delivery Events	Status	Timestamp

Certified Delivery Events	Status	Timestamp

Carbon Copy Events	Status	Timestamp
Sandra Bruce Sandra.Bruce@Williams.com Accounts Payable Security Level: Email, Account Authentication (None)	COPIED	Sent: 1/29/2026 1:48:13 PM Resent: 1/30/2026 6:39:11 AM Viewed: 1/30/2026 6:40:20 AM

Electronic Record and Signature Disclosure:
Not Offered via Docusign

Witness Events	Signature	Timestamp

Notary Events	Signature	Timestamp

Envelope Summary Events	Status	Timestamps
Envelope Sent	Hashed/Encrypted	1/29/2026 1:48:13 PM
Certified Delivered	Security Checked	1/30/2026 6:38:59 AM
Signing Complete	Security Checked	1/30/2026 6:39:09 AM
Completed	Security Checked	1/30/2026 6:39:09 AM

Payment Events	Status	Timestamps

Form 3

Process Information

Utah Division of Air Quality
New Source Review Section

Company Will-Power UT, LLC

Site Eagle Mountain

Process Information - For New Permit ONLY	
1. Name of process: Power Generation	2. End product of this process: Electrical Power
3. Process Description*: Will-Power intends to construct a power generation facility with a total of 17 natural gas-fired turbines, 8 line heaters, 2 natural gas-fired emergency generators, and 1 diesel-fired emergency fire pump and its associated diesel belly tank to provide primary power to a co-located data center.	

Operating Data	
4. Maximum operating schedule: 24 hrs/day; 7 days/week; 52 weeks/year	5. Percent annual production by quarter: Winter -; Spring -; Summer -; Fall -
6. Maximum Hourly production (indicate units.): ______	7. Maximum annual production (indicate units): ______
8. Type of operation: Continuous ☑ Batch ☐ Intermittent ☐	9. If batch, indicate minutes per cycle ______ Minutes between cycles ______

10. Materials and quantities used in process.*

Material	Maximum Annual Quantity (indicate units)
See Appendix B	

11.Process-Emitting Units with pollution control equipment*

Emitting Unit(s)	Capacity(s)	Manufacture Date(s)
See Appendix B		

If additional space is required, please create a spreadsheet or Word processing document and attach to form.

Form 5
Emissions Information
Criteria/GHGs/ HAP's
Utah Division of Air Quality
New Source Review Section

AIR QUALITY

Company Will-Power UT, LLC
Site Eagle Mountain

Potential to Emit* Criteria Pollutants & GHGs			
Criteria Pollutants	**Permitted Emissions (tons/yr)**	**Emissions Increases (tons/yr)**	**Proposed Emissions (tons/yr)**
PM_{10} Total			
PM_{10} Fugitive			
$PM_{2.5}$			
NO_x	See Appendix B		
SO_2			
CO			
VOC			
VOC Fugitive			
NH_3			
Greenhouse Gases	**CO_2e**	**CO_2e**	**CO_2e**
CO_2			
CH_4			
N_2O			
HFCs	See Appendix B		
PFCs			
SF_6			
Total CO2e			

**Potential to emit to include pollution control equipment as defined by R307-401-2.*

Hazardous Air Pollutants** *(**Defined in Section 112(b) of the Clean Air Act)*				
Hazardous Air Pollutant***	**Permitted Emissions (tons/yr)**	**Emission Increase (tons/yr)**	**Proposed Emission (tons/yr)**	**Emission Increase (lbs/hr)**
	See Appendix B			
Total HAP				

**** Use additional sheets for pollutants if needed*

Utah Division of Air Quality
New Source Review Section

Form 17
Diesel Powered Standby Generator

Company: Will-Power UT, LLC
Site/Source: Eagle Mountain
Date: February 2026

Company Information

1. Company Name and Address:
Will-Power UT, LLC

1499 N Pony Express Parkway
Eagle Mountain, UT 84005
Phone Number: ______
Fax Number: ______

2. Company Contact:
Andrew Woerner
Andrew.Woerner@Williams.com

Phone Number: (610)-412-8905
Fax Number: ______

3. Installation Address:
Will-Power UT, LLC Eagle Mountain Site

1499 N Pony Express Parkway
Eagle Mountain, UT 84005
Phone Number: ______
Fax Number: ______

County where facility is located: Utah County

Latitude, Longitude and UTM Coordinates of Facility
414,225.35 m Easting, 4,456,082.40 m Northing
UTM Zone 12

Standby Generator Information

4. Engines:

Manufacturer	Model	Maximum Rated Horsepower or Kilowatts	Maximum Hours of Operation	Emission Rate Rate of NO_x grams/BHP-HR	Date the engine was constructed or reconstructed
See Appendix B					

Attach Manufacturer-supplied information

5. Calculated emissions for this equipment:

PM_{10} ______ Lbs/hr ______ Tons/yr $PM_{2.5}$ ______ Lbs/hr ______ Tons/yr
NO_x ______ Lbs/hr ______ Tons/yr SO_x ______ Lbs/hr ______ Tons/yr
CO ______ Lbs/hr ______ Tons/yr   VOC ______ Lbs/hr ______ Tons/yr
CO_2 ______ Tons/yr CH_4 ______ Tons/yr
N_2O ______ Tons/yr
HAPs ______ Lbs/hr (speciate) ______ Tons/yr (speciate)

See Appendix B.

Submit calculations as an appendix. If other pollutants are emitted, include the emissions in the appendix.

Utah Division of Air Quality
New Source Review Section

Form 17a
Natural Gas Standby Generator

Company: Will-Power UT, LLC
Site/Source: Eagle Mountain
Date: February 2026

Company Information

1. Company Name and Address:
Will-Power UT, LLC

1499 N Pony Express Parkway
Eagle Mountain, UT 84005
Phone Number: ____
Fax Number: ____

2. Company Contact:
Andrew Woerner
Andrew.Woerner@Williams.com

Phone Number: (610)-412-8905
Fax Number: ____

3. Installation Address:
Will-Power UT, LLC Eagle Mountain Site

1499 N Pony Express Parkway
Eagle Mountain, UT 84005
Phone Number: ____
Fax Number: ____

County where facility is located: Utah

Latitude & Longitude or UTM Coordinates of Facility
414,225.35 m Easting 4,456,082.40 m Northing
UTM Zone 12

Standby Generator Information

4. Engines:

Manufacturer	Model	Maximum Rated Horsepower or Kilowatts	Maximum Hours of Operation	Emission Rate Rate of NO_x grams/BHP-HR	Date the Engine Was Constructed or Reconstructed
See Appendix B.					

Attach Manufacturer supplied information

5. Calculated emissions for this equipment:

See Appendix B

PM_{10} ____ Lbs/hr ____ Tons/yr $PM_{2.5}$ ____ Lbs/hr ____ Tons/yr
NO_x ____ Lbs/hr ____ Tons/yr SO_x ____ Lbs/hr ____ Tons/yr
CO ____ Lbs/hr ____ Tons/yr VOC ____ Lbs/hr ____ Tons/yr
CO_2 ____ Tons/yr CH_4 ____ Tons/yr
N_2O ____ Tons/yr
HAPs ____ Lbs/hr (speciate) ____ Tons/yr (speciate)

Submit calculations as an appendix. If other pollutants are emitted, include the emissions in the appendix.

Utah Division of Air Quality
New Source Review Section

Form 19
Natural Gas Boilers and Liquid Heaters

Company Will-Power UT, LLC
Site/Source Eagle Mountain
Date February 2026

Boiler Information

1. Boiler Manufacturer: ______
2. Model Number: ______ 3. Serial Number: ______
4. Boiler Rating: ______ (10^6 Btu per Hour)
5. Operating Schedule: ______ hours per day ______ days per week ______ weeks per year
6. Use: ☐ steam: psig ______ ☐ hot water ☐ other hot liquid: ______
7. Fuels: ☐ Natural Gas ☐ LPG ☐ Butane ☐ Methanol
   ☐ Process Gas - H_2S content in process gas ______ grain/100cu.ft.
   ☐ Fuel Oil - specify grade: ______ ☐ Other, specify: ______
   Sulfur content ______ % by weight Days per year during which unit is oil fired: ______
   Backup Fuel: ☐ Diesel ☐ Natural Gas ☐ LPG ☐ Butane ☐ Methanol ☐ Other ______
8. Is unit used to incinerate waste gas liquid stream? ☐ yes ■ no
   (Submit drawing of method of waste stream introduction to burners)

Gas Burner Information

9. Gas Burner Manufacturer: ______
10. No. of Burners: 6
11. Minimum rating per burner: 11260 cu. ft/hr
12. Average Load: ______%
13. Maximum rating per burner: ______ cu. ft/hr
14. Performance Guarantee (ppm dry corrected to 3% Oxygen):
    NO_x: 9 CO: 50 Hydrocarbons: 13
15. Gas burner mode of control: ☐ Manual ☐ Automatic on-off ☐ Automatic hi-low ☐ Automatic full modulation

Oil Burner Information

16. Oil burner manufacturer:
17. Model: ______ number of burners: ______ Size number: ______
18. Minimum rating per burner: ______ gal/hr
19. Maximum rating per burner: ______ gal/hr

Form 11 - Natural Gas Boiler and Liquid Heater
(Continued)

Modifications for Emissions Reduction

20. Type of modification: ■ Low NO_X Burner ☐ Flue Gas Recirculation (FGR)
☐ Oxygen Trim ☐ Other (specify) ______

For Low-NO_X Burners	
21. Burner Type: ☐ Staged air ☐ Staged fuel ☐ Internal flue gas recirculation ☐ Ceramic ☐ Other (specify): ______	
22. Manufacturer and Model Number: ______	
23. Rating: 10.68 10^6 BTU/HR	24. Combustion air blower horsepower: 15
For Flue Gas Recirculation (FGR)	
25. Type: ☐ Induced ☐ Forced Recirculation fan horsepower: ______	
26. FGR capacity at full load: ______ scfm ______%FGR	
27. FGR gas temperature or load at which FGR commences: ______ ^OF ______% load	
28. Where is recirculation flue gas reintroduced? ______	
For Oxygen Trim Systems	
29. Manufacturer and Model Number: ______	
30. Recorder: ☐ yes ☐ no Describe: ______	

Stack or Vent Data	
31. Inside stack diameter or dimensions ______ Stack height above the ground ______ Stack height above the building ______	32. Gas exit temperature: ______ ^OF
33. Stack serves: ☐ this equipment only, ☐ other equipment (submit type and rating of all other equipment exhausted through this stack or vent)	
34. Stack flow rate: ______ acfm Vertically restricted? ☐ Yes ☐ No	

See Modeling Report

Emissions Calculations (PTE)

35. Calculated emissions for this device

PM_{10} ______Lbs/hr______ Tons/yr $PM_{2.5}$ ______Lbs/hr______ Tons/yr
NO_x ______Lbs/hr______ Tons/yr SO_x ______Lbs/hr______ Tons/yr
CO ______Lbs/hr______ Tons/yr VOC ______Lbs/hr______Tons/yr
CO_2 ______ Tons/yr CH_4 ______Tons/yr
N_2O ______Tons/yr
HAPs______ Lbs/hr (speciate)______Tons/yr (speciate)

Submit calculations as an appendix. If other pollutants are emitted, include the emissions in the appendix.

See NOI Appendix B

Utah Division of Air Quality
New Source Review Section

Company Will-Power UT, LLC
Site/Source Eagle Mountain
Date February 2026

Form 19
Natural Gas Boilers and Liquid Heaters

Boiler Information

1. Boiler Manufacturer: ______
2. Model Number: ______ 3. Serial Number: ______
4. Boiler Rating: ______ (10^6 Btu per Hour)
5. Operating Schedule: ______ hours per day ______ days per week ______ weeks per year
6. Use: ☐ steam: psig ______ ☐ hot water ☐ other hot liquid: ______
7. Fuels: ☐ Natural Gas ☐ LPG ☐ Butane ☐ Methanol
   ☐ Process Gas - H_2S content in process gas ______ grain/100cu.ft.
   ☐ Fuel Oil - specify grade: ______ ☐ Other, specify: ______
   Sulfur content ______ % by weight Days per year during which unit is oil fired: ______
   Backup Fuel: ☐ Diesel ☐ Natural Gas ☐ LPG ☐ Butane ☐ Methanol ☐ Other ______
8. Is unit used to incinerate waste gas liquid stream? ☐ yes ■ no
   (Submit drawing of method of waste stream introduction to burners)

Gas Burner Information

9. Gas Burner Manufacturer: ______
10. No. of Burners: 2 11. Minimum rating per burner: 3630 cu. ft/hr
12. Average Load: ______% 13. Maximum rating per burner: ______ cu. ft/hr
14. Performance Guarantee (ppm dry corrected to 3% Oxygen):
    NO_x: 9 CO: 50 Hydrocarbons: 13
15. Gas burner mode of control: ☐ Manual ☐ Automatic on-off ☐ Automatic hi-low ☐ Automatic full modulation

Oil Burner Information

16. Oil burner manufacturer:
17. Model: ______ number of burners: ______ Size number: ______
18. Minimum rating per burner: ______ gal/hr 19. Maximum rating per burner: ______ gal/hr

Form 11 - Natural Gas Boiler and Liquid Heater
(Continued)

Modifications for Emissions Reduction

20. Type of modification: ■ Low NO_X Burner ☐ Flue Gas Recirculation (FGR)
☐ Oxygen Trim ☐ Other (specify) ____________________

For Low-NO_X Burners

21. Burner Type: ☐ Staged air ☐ Staged fuel ☐ Internal flue gas recirculation
☐ Ceramic ☐ Other (specify): ____________________

22. Manufacturer and Model Number: ____________________

23. Rating: 10.68 10^6 BTU/HR

24. Combustion air blower horsepower: 10

For Flue Gas Recirculation (FGR)

25. Type: ☐ Induced ☐ Forced Recirculation fan horsepower: ____________________

26. FGR capacity at full load: ________ scfm ________%FGR

27. FGR gas temperature or load at which FGR commences: ________ ^{O}F ________% load

28. Where is recirculation flue gas reintroduced? ____________________

For Oxygen Trim Systems

29. Manufacturer and Model Number: ____________________

30. Recorder: ☐ yes ☐ no Describe: ____________________

Stack or Vent Data

31. Inside stack diameter or dimensions ________
Stack height above the ground ________
Stack height above the building ________

32. Gas exit temperature: ________ ^{O}F

See Modeling Report

33. Stack serves: ☐ this equipment only, ☐ other equipment (submit type and rating of all other equipment exhausted through this stack or vent)

34. Stack flow rate: ________ acfm Vertically restricted? ☐ Yes ☐ No

Emissions Calculations (PTE)

35. Calculated emissions for this device

PM_{10} ________Lbs/hr________ Tons/yr $PM_{2.5}$ ________Lbs/hr________ Tons/yr
NO_x ________Lbs/hr________ Tons/yr SO_x ________Lbs/hr________ Tons/yr
CO ________Lbs/hr________ Tons/yr VOC ________Lbs/hr________ Tons/yr
CO_2 ________ Tons/yr CH_4 ________Tons/yr
N_2O ________Tons/yr
HAPs________ Lbs/hr (speciate)________Tons/yr (speciate)

See NOI Appendix B

Submit calculations as an appendix. If other pollutants are emitted, include the emissions in the appendix.

Utah Division of Air Quality
New Source Review Section

Company: Will-Power UT, LLC
Site/Source: Eagle Mountain
Date: February 2026

Form 20
Organic Liquid Storage Tank

Equipment

1. Tank manufacturer: ______	2. Identification number: ______
3. Installation date: ______	4. Volume: ______ gallons
5. Inside tank diameter: ______ feet	6. Tank height: ______ feet
7. True vapor pressure of liquid: ______ psia	8. Reid vapor pressure of liquid: ______ psi
9. Outside color of tank: ______	10. Maximum storage temperature: ______ ^{O}F
11. Average throughput: 1649 gallons per year	12. Turnovers/yearly ____ Monthly ____ Weekly ____
13. Average liquid height (feet): ______	14. Access hatch: ☐ Yes ☐ No Number ______
15. Type of Seals: a. Primary seals: ☐ Mechanical shoe ☐ Resilient filled ☐ Liquid filled ☐ Vapor mounted ☐ Liquid mounted ☐ Flexible wiper b. Secondary seal: Type: ______	16. Deck Fittings: Gauge float well ☐ Yes ☐ No Number_____ Gauge hatch/ sample well ☐ Yes ☐ No Number_____ Roof drains ☐ Yes ☐ No Number_____ Rim vents ☐ Yes ☐ No Number_____ Vacuum break ☐ Yes ☐ No Number_____ Roof leg ☐ Yes ☐ No Number_____ Ladder well ☐ Yes ☐ No Number_____ Column well ☐ Yes ☐ No Number_____ Other: ______
17. Shell Characteristics: Condition: ______ Breather Vent Settings: ______ Tank Construction: ______ Roof Type: ______ Deck Construction: ______ Deck Fitting Category: ______	18. Type of Construction: ☐ Vertical Fixed Roof ☐ Horizontal Fixed Roof ☐ Internal Floating Roof ☐ External Floating Roof ■ Other (please specify) Belly Tank

19. Additional Controls:

☐ Gas Blanket ☐ Venting ☐ Carbon Adsorption ☐ Thermal Oxidation ☐ Other: ______

20. Single Liquid Information

Liquid Name: Diesel Fuel Oil No. 2	Liquid Name: ______
CAS Number: 68476-30-2	CAS Number: ______
Avg. Temperature: Ambient	Avg. Temperature: ______
Vapor Pressure: ______	Vapor Pressure: ______
Liquid Molecular Weight: ______	Liquid Molecular Weight: ______

Form 20 - Organic Liquid Storage Tank
(Continued)

<table>
<tr><th colspan="2">21. Chemical Components Information</th></tr>
<tr><td>Chemical Name: ______________________________
Percent of Total Liquid Weight: ____________________
Molecular Weight: ____________________________
Avg. Liquid Temperature: ______________________
Vapor Pressure: ______________________________</td><td>Chemical Name: ______________________________
Percent of Total Liquid Weight: ____________________
Molecular Weight: ____________________________
Avg. Liquid Temperature: ______________________
Vapor Pressure: ______________________________</td></tr>
<tr><th colspan="2">Emissions Calculations (PTE)</th></tr>
<tr><td colspan="2">22. Calculated emissions for this device: See Appendix B
VOC _________Lbs/hr_____ Tons/yr
HAPs_________Lbs/hr (speciate)______Tons/yr (speciate)
Submit calculations as an appendix. Provide Material Safety Data Sheets for products being stored.</td></tr>
</table>

Instructions

Note: 1. **Submit this form in conjunction with Form 1 and Form 2.**
2. Call the Division of Air Quality (DAQ) at **(801) 536-4000** if you have problems or questions in filling out this form. Ask to speak with a New Source Review engineer. We will be glad to help!

1. Indicate the tank manufacturer's name.
2. Supply the equipment identification number that will appear on the tank.
3. Indicate the date of installation.
4. Indicate the capacity of the tank in gallons or barrels.
5. Specify the inside tank diameter in feet.
6. Specify the tank height in feet.
7. Indicate the true vapor pressure of the liquid (psia).
8. Indicate the Reid vapor pressure of the liquid (psi).
9. Indicate the outside color of the tank.
10. Supply the highest temperature the liquid will reach during storage (degrees Fahrenheit).
11. Indicate average annual throughput (gallons).
12. Specify how many times the tank will be emptied and refilled per year, month or week.
13. Specify the average liquid height (feet).
14. Indicate whether or not the tank has access hatches and the number.
15. Indicate what type of seals the tank has.
16. Indicate what types of deck fittings are installed.
17. Specify condition of the tank, also include the following:
    - Breather vent settings in (psig) for fixed roof tanks
    - Tank construction, welded or riveted
    - Roof type; pontoon, double deck, or self-supporting roof
    - Deck construction; bolted or welded, sheet or panel construction sizes and seam length
    - Deck fitting category; typical, controlled, or detail
18. Indicate the type of tank construction.
19. Indicate other types of additional controls which will be used.
20. Provide information on liquid being stored, add additional sheets as necessary.
21. Provide information on chemicals being stored, add additional sheets as necessary.
22. Supply calculations for all criteria pollutants and HAPs. Use AP-42 or manufacturers' data to complete your calculations.

Utah Division of Air Quality
New Source Review Section

Form 22
Combustion Turbines

Company Will-Power UT, LLC
Site/Source Eagle Mountain
Date February 2026

Equipment Information

1. Manufacturer: Solar Titan

   Model Number: 250-31900S GSC

2. Operating time of Emission Source:

	AVERAGE	MAXIMUM
Hours/day	24	24
Days/week	7	7
Weeks/year	52	52

3. Manufacturer's rated output at baseload, ISO: 23.1 ☒ MW or ☐ hp

   Proposed site operating range: ______ ☒ MW or ☐ hp

   Manufacturer's rated heat rate at baseload, ISO: ______ (BTU/kW-hr)

4. Percent of annual heat input:

   Dec-Feb _____% Mar-May _____% Jun-Aug _____% Sep-Nov _____%

Gas Firing

5. Origin of gas:

   ☒ Pipeline ☐ Distillate fuel oil gasification ☐ Other liquid fuel gasification ☐ Solid fuel gasification ☐ Byproduct, specify source: ______

6. Are you on an interruptible gas supply:

   ☐ Yes ☒ No

   If "yes", specify alternate fuel: ______

7. Annual consumption of fuel: ______ scf

*8. Heat content: ______ BTU/scf

*9. Sulfur content: ______ % by wt.

10. Maximum firing rate: ______ scf/hr

11. Average firing rate: ______ scf/hr

*If the gas fired is pipeline grade natural gas, these items need not be completed.

Oil Fired

12. Grade of oil, Number: ☐ 1 ☐ 2 ☐ 4 ☐ 5 ☐ 6 ☐ Other: specify ______

13. Annual consumption: ______ gallons

14. Heat content: ______ ☐ BTU/lb ☐ BTU/gal

15. Sulfur content: ______ % by wt.

16. Ash content ______ % by wt.

17. Direction of firing: ☐ horizontal ☐ tangential ☐ other: specify ______

18. Average firing rate: ______ gal/hr

19. Maximum firing rate: ______ gal/hr

Form 22 – Combustion Turbines

Operation

20. Application: ■ Electric generation
 x Base load ____Peaking
 ☐ Driving pump/compressor
 ☐ Exhaust heat recovery
 ☐ Other – Specify _______________

21. Cycle: ■ Simple cycle
 ☐ Regenerative cycle
 ☐ Cogeneration
 ☐ Combined cycle

22. Is turbine equipped with exhaust heat recovery equipment? ☐ Yes ■ No
 If yes, supply the size, flow rate, steam output capacity and temperature profile.

23. Is turbine equipped with duct burners? ■ Yes ☐ No
 If yes, provide burner description, fuel usage, combustion air input and location of the burners. Show all heat transfer surface locations with the waste heat boiler and temperature profile.

Emissions Data

24. Attach manufacturer's information showing emissions of NO_x, CO, VOC, SO_x, PM_{10} and $PM_{2.5}$ for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM_{10} and $PM_{2.5}$, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
☐ Lean premix combustors ■ Oxidation catalyst ☐ Water injection ☐ Other – Specify ____________
☐ Other low-NO_x combustor ■ SCR catalyst ☐ Steam injection ________________________

Additional Information

25. On separate sheets provide the following:
 A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.
 B. Exhaust parameter information on attached form.

Emissions Calculations (PTE)

26. Calculated emissions for this device

PM_{10} ___________Lbs/hr___________ Tons/yr $PM_{2.5}$ ___________Lbs/hr___________ Tons/yr
NO_x ___________Lbs/hr___________Tons/yr SO_x ___________Lbs/hr___________ Tons/yr
CO ___________Lbs/hr___________Tons/yr VOC ___________Lbs/hr___________ Tons/yr
CO_2 ___________Tons/yr CH_4 ___________Tons/yr
N_2O ___________Tons/yr
HAPs__________ Lbs/hr (speciate)___________Tons/yr (speciate)
Submit calculations as an appendix. If other pollutants are emitted, include the emissions in the appendix.

See Appendix B

Utah Division of Air Quality
New Source Review Section

Form 22
Combustion Turbines

Company Will-Power UT, LLC
Site/Source Eagle Mountain
Date February 2026

Equipment Information

1. Manufacturer: GE Vernova

   Model Number: TM2500

2. Operating time of Emission Source:

	AVERAGE	MAXIMUM
Hours/day	24	24
Days/week	7	7
Weeks/year	52	52

3. Manufacturer's rated output at baseload, ISO: 34.8 ☒ MW or ☐ hp

   Proposed site operating range: ______ ☐ MW or ☐ hp

   Manufacturer's rated heat rate at baseload, ISO: ______ (BTU/kW-hr)

4. Percent of annual heat input:

   Dec-Feb ____% Mar-May ____% Jun-Aug ____% Sep-Nov ____%

Gas Firing

5. Origin of gas:

   ☒ Pipeline ☐ Distillate fuel oil gasification ☐ Other liquid fuel gasification ☐ Solid fuel gasification ☐ Byproduct, specify source: ______

6. Are you on an interruptible gas supply:

   ☒ Yes ☐ No

   If "yes", specify alternate fuel: ______

7. Annual consumption of fuel: ______ scf

*8. Heat content: ______ BTU/scf

*9. Sulfur content: ______ % by wt.

10. Maximum firing rate: ______ scf/hr

11. Average firing rate: ______ scf/hr

*If the gas fired is pipeline grade natural gas, these items need not be completed.

Oil Fired

12. Grade of oil, Number: ☐ 1 ☐ 2 ☐ 4 ☐ 5 ☐ 6 ☐ Other: specify ______

13. Annual consumption: ______ gallons

14. Heat content: ______ ☐ BTU/lb ☐ BTU/gal

15. Sulfur content: ______ % by wt.

16. Ash content ______ % by wt.

17. Direction of firing: ☐ horizontal ☐ tangential ☐ other: specify ______

18. Average firing rate: ______ gal/hr

19. Maximum firing rate: ______ gal/hr

Form 22 – Combustion Turbines

Operation

20. Application: ■ Electric generation
X Base load ____Peaking
☐ Driving pump/compressor
☐ Exhaust heat recovery
☐ Other – Specify ________________

21. Cycle: ■ Simple cycle
☐ Regenerative cycle
☐ Cogeneration
■ Combined cycle

22. Is turbine equipped with exhaust heat recovery equipment? ☐ Yes ■ No
If yes, supply the size, flow rate, steam output capacity and temperature profile.

23. Is turbine equipped with duct burners? ■ Yes ☐ No
If yes, provide burner description, fuel usage, combustion air input and location of the burners. Show all heat transfer surface locations with the waste heat boiler and temperature profile.

Emissions Data

24. Attach manufacturer's information showing emissions of NO_x, CO, VOC, SO_x, PM_{10} and $PM_{2.5}$ for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM_{10} and $PM_{2.5}$, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:

☐ Lean premix combustors ■ Oxidation catalyst ☐ Water injection ☐ Other – Specify ____________
☐ Other low-NO_x combustor ■ SCR catalyst ☐ Steam injection ________________________

Additional Information

25. On separate sheets provide the following:
A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.
B. Exhaust parameter information on attached form.

Emissions Calculations (PTE)

26. Calculated emissions for this device

See Appendix B

PM_{10} ___________Lbs/hr___________ Tons/yr $PM_{2.5}$ ___________Lbs/hr___________ Tons/yr
NO_x ___________Lbs/hr___________ Tons/yr SO_2 ___________Lbs/hr___________ Tons/yr
CO ___________Lbs/hr___________ Tons/yr VOC ___________Lbs/hr___________ Tons/yr
CO_2 ___________Tons/yr CH_4 ___________Tons/yr
N_2O ___________Tons/yr
HAPs__________ Lbs/hr (speciate)___________Tons/yr (speciate)
Submit calculations as an appendix. If other pollutants are emitted, include the emissions in the appendix.

APPENDIX B. EMISSIONS CALCULATIONS

Table B-1. Will-Power PTE Summary Table

Units	Quantity	Annual PTE (tpy)									
		PM_{10}	$PM_{2.5}$	NO_X	NO_2	CO	SO_2	VOC	CO_2e	Max Single HAP	Total HAPs
TM2500 NG Turbine[1]	11	100.59	100.59	95.39	114.62	169.96	8.56	71.38	1,785,940	*See HAP Summary*	12.76
ST250 NG Turbine[1]	6	30.79	30.79		35.49	59.79	2.61	21.33	544,738		2.50
Large NG Line Heaters (10.68 MMBtu/hr)	6	2.10	2.10	2.81	2.81	10.38	0.20	1.42	32,855		0.52
Small NG Line Heaters (3.43 MMBtu/hr)	2	0.23	0.23	0.30	0.30	1.11	0.02	0.15	3,523		0.06
Cat G3520 NG Engines	2	0.02	0.02	0.80	0.80	0.16	0.00	0.10	267.42		0.04
Diesel Fire Pump Engine	1	5.34E-03	5.34E-03	1.02E-01	1.02E-01	9.35E-02	3.33E-02	3.33E-02	18.61		4.31E-04
Diesel Fire Pump Tank	1	--	--	--	--	--	--	1.84E-05	--		1.23E-05
Sitewide PTE		**133.73**	**133.73**	**99.40**	**154.12**	**241.51**	**11.42**	**94.42**	**2,367,343**	**8.97**	**15.88**
Major Source Threshold [2, 3, 4]		250	250	100	250	250	250	100	75,000	10	25
Major Source Threshold Exceeded? [5]		No	No	No	No	No	No	No	N/A	No	No
Modeling Threshold [6]		15	10	--	40	100	40	--	--	*See HAP Summary*	N/A
Modeling Threshold Exceeded?		**YES**	**YES**	--	**YES**	**YES**	No	--	--	--	--

1. The combined NO_X total for the Natural Gas Turbines is reflective of the proposed limit, with compliance through the use of CEMS.

2. Criteria pollutant major source thresholds are defined by 40 CFR Section 51.165(a)(1)(iv)(A) and 51.166(b)(1)(i)(B) and reflect the Marginal Ozone Nonattainment status for Utah County

3. HAP threshold per 40 CFR 70.2 "Major Source"

4. CO_2e threshold per EPA-457/B-11-001

5. A source cannot be a major source for CO_2e unless it is a PSD major source for a criteria pollutant, per EPA-457/B-11-001

6. Criteria pollutant modeling thresholds per UAC R307-410-4, Table 1

Table B-2. HAPs Summary Table

Pollutant	HAP PTE (lb/hr)	HAP PTE (tpy)	HAP PTE for ETV Comparison	UDAQ ETV (lb/hr)	Modeling Required?
1,1,2,2-Tetrachloroethane	1.02E-03	5.10E-05	--	1.36	No
1,1,2-Trichloroethane	8.11E-04	4.06E-05	--	10.80	No
1,3-Butadiene	8.86E-03	8.93E-03	1.96E-03	0.29	No
1,3-Dichloropropene	6.73E-04	3.37E-05	--	0.90	No
2,2,4-Trimethylpentane	6.38E-03	3.19E-04	--	-	No
2-Methylnaphthalene	8.48E-04	4.96E-05	1.67E-06	-	No
3-Methylchloranthrene	1.25E-07	5.48E-07	1.25E-07	-	No
7,12-Dimethylbenz(a)anthracene	1.11E-06	4.87E-06	1.11E-06	-	No
Acenaphthene	3.20E-05	2.14E-06	1.25E-07	-	No
Acenaphthylene	1.41E-04	7.60E-06	1.25E-07	-	No
Acetaldehyde	0.40	0.81	1.82E-01	6.94	No
Acrolein	0.16	0.13	2.92E-02	0.04	No
Anthracene	1.67E-07	7.31E-07	1.67E-07	-	No
Arsenic	1.39E-05	6.09E-05	1.39E-05	1.98E-03	No
Benz(a)anthracene	1.25E-07	5.48E-07	1.25E-07	-	No
Benzene	7.04E-02	2.41E-01	5.48E-02	0.32	No
Benzo(a)pyrene	8.34E-08	3.65E-07	8.34E-08	-	No
Benzo(b)fluoranthene	4.36E-06	7.60E-07	1.25E-07	-	No
Benzo(e)pyrene	1.06E-05	5.29E-07	--	-	No
Benzo(g,h,i)perylene	1.06E-05	8.93E-07	8.34E-08	-	No
Benzo(k)fluoranthene	1.25E-07	5.48E-07	1.25E-07	-	No
Beryllium	8.34E-07	3.65E-06	8.34E-07	9.90E-06	No
Biphenyl	5.41E-03	2.70E-04	--	0.25	No
Cadmium	7.65E-05	3.35E-04	7.65E-05	1.32E-04	No
Carbon Tetrachloride	9.36E-04	4.68E-05	--	2.08	No
Chlorobenzene	7.75E-04	3.88E-05	--	9.12	No
Chloroform	7.27E-04	3.63E-05	--	9.67	No
Chromium	9.74E-05	4.26E-04	9.74E-05	6.60E-04	No
Chrysene	1.78E-05	1.43E-06	1.25E-07	-	No
Cobalt	5.84E-06	2.56E-05	5.84E-06	3.96E-03	No
Dibenzo(a,h)anthracene	8.34E-08	3.65E-07	8.34E-08	-	No
Dichlorobenzene	8.34E-05	3.65E-04	8.34E-05	-	No
Ethylbenzene	0.15	0.64	1.46E-01	17.19	No
Ethylene Dibromide	1.13E-03	5.65E-05	--	-	No
Fluoranthene	2.85E-05	2.33E-06	2.09E-07	-	No
Fluorene	1.45E-04	8.08E-06	1.95E-07	-	No
Formaldehyde	2.16E+00	8.97E+00	2.08E-01	0.06	Yes
Hexane	0.13	0.55	1.25E-01	-	No
Indeno(1,2,3-cd)pyrene	1.25E-07	5.48E-07	1.25E-07	-	No
Lead	3.48E-05	1.52E-04	3.48E-05	-	No
Manganese	2.64E-05	1.16E-04	2.64E-05	0.04	No
Mercury	1.81E-05	7.92E-05	1.81E-05	1.98E-03	No
Methanol	6.38E-02	3.19E-03	--	55.13	No

Table B-2. HAPs Summary Table

Pollutant	HAP PTE (lb/hr)	HAP PTE (tpy)	HAP PTE for ETV Comparison	UDAQ ETV (lb/hr)	Modeling Required?
Methylene Chloride	5.10E-04	2.55E-05	--	34.39	No
Naphthalene	8.45E-03	2.62E-02	5.97E-03	10.38	No
n-Hexane	2.83E-02	1.42E-03	--	34.89	No
Nickel	1.46E-04	6.40E-04	1.46E-04	6.60E-03	No
PAH	1.07E-02	4.40E-02	1.00E-02	-	No
Perchloroethylene	6.33E-05	3.16E-06	--	33.57	No
Phenanthrene	2.66E-04	1.84E-05	1.18E-06	-	No
Phenol	6.12E-04	3.06E-05	--	3.81	No
Propylene Oxide	0.13	0.58	1.32E-01	0.94	No
Pyrene	3.50E-05	3.26E-06	3.48E-07	-	No
Selenium	1.67E-06	7.31E-06	1.67E-06	0.04	No
Styrene	6.02E-04	3.01E-05	--	8.44	No
Toluene	0.63	2.60	5.93E-01	14.92	No
Vinyl Chloride	3.80E-04	1.90E-05	--	0.17	No
Xylenes	0.36	1.28	2.92E-01	17.19	No
Max HAP:	**Formaldehyde**	**Formaldehyde**			
	2.16	**8.97**			
Total HAPs:	**4.32**	**15.88**			

Table B-3. Natural Gas Turbines - Input Parameters

Parameter	Model	Units	Value
Number of TM2500 Natural Gas Turbines	TM2500	#	11
Number of ST250 Natural Gas Turbines	250-31900S GSC	#	6
Hours of Operation		(hr/yr)	8,760

Table B-4. Natural Gas Turbines - Startup (SU) and Shutdown (SD) Parameters

Parameter	Units	SU	SD	Reference
Number of events per year per natural gas turbine	(events/yr)	52	52	-
Duration of event	(mins)	20	20	1
Pollutant	**Units**	**SU**	**SD**	**Reference**
NO_X	(lbs/event)	4	4	1
CO	(lbs/event)	64	52	1
VOC	(lbs/event)	8	6	1
CO_2	(lbs/event)	2,560	1,950	1

1. Startup/shutdown parameters based on manufacturer data for ST250 units, multiplied by a factor of 2 for margin

Table B-5. Natural Gas Turbine Emissions Data

Pollutant	Unit	Value	Reference
Controlled			
NO_X	(ppmvd)	2	1
CO	(ppmvd)	4	1
VOC	(ppmvd)	3	1
NH_3	(ppmvd)	5	1
PM	(lb/MMBtu) (HHV)	0.0066	2

1. Values post control by oxidation catalyst and SCR; PPMVD values are corrected to 15% O_2

2. AP-42 Section 3.1 Table 3.1-2a

Table B-6. TM2500 Natural Gas Turbine Emission Rates

	Unit	Value
Controlled NO_X	(ppmvd @15% O_2)	2.00
Controlled NH_3	(ppmvd @15% O_2)	5.00
Controlled CO	(ppmvd @15% O_2)	4.00
Controlled Formaldehyde[1]	(ppmvd @15% O_2)	0.215
Controlled VOC	(ppmvd @15% O_2)	3.00

1. Assumes oxidation catalyst control efficiency for formaldehyde equal to: 15%

Table B-7. TM2500 Natural Gas Turbine PPM Emission Factor Conversion

Operating Parameter	Unit	Scenario Data												Reference
Ambient Air Temperature	(F)	110.0			60.0			15.0			-10.0			1
Load Condition	(%)	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	1
Fuel Flow (HHV)	(MMBtu/hr)	224	183	161	284	229	185	318	266	207	310	252	252	1
Reference O_2	(% O_2)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	1
F_d Factor Natural Gas	(dscfm/MMBtu)	8,710	8,710	8,710	8,710	8,710	8,710	8,710	8,710	8,710	8,710	8,710	8,710	2
P standard	(psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	--
T standard	(˚R)	528	528	528	528	528	528	528	528	528	528	528	528	--
Molar volume of ideal gas at 68F and 1 atm	(ft^3/lb-mol)	385	385	385	385	385	385	385	385	385	385	385	385	3
Conversion from ppm to fraction	-	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	--
NO_X														
NO_X Concentration @ Ref O_2	(ppmvd)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	--
NO_X Molecular Weight (as NO_2)	(lb/lb-mol)	46.006	46.006	46.006	46.006	46.006	46.006	46.006	46.006	46.006	46.006	46.006	46.006	4
Emission Factor	(lb/hr)	1.65	1.35	1.18	2.09	1.69	1.37	2.34	1.96	1.53	2.29	1.86	1.86	--
Emission Factor	(lb/MMBtu)	7.37E-03	7.37E-03	7.37E-03	7.37E-03	7.37E-03	7.37E-03	7.37E-03	7.37E-03	7.37E-03	7.37E-03	7.37E-03	7.37E-03	--
NH_3														
NH_3 Concentration @ Ref O_2	(ppmvd)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	--
NH_3 Molecular weight	(lb/lb-mol)	17.031	17.031	17.031	17.031	17.031	17.031	17.031	17.031	17.031	17.031	17.031	17.031	4
Emission Factor	(lb/hr)	1.53	1.25	1.10	1.94	1.56	1.26	2.17	1.82	1.41	2.12	1.72	1.72	--
Emission Factor	(lb/MMBtu)	6.82E-03	6.82E-03	6.82E-03	6.82E-03	6.82E-03	6.82E-03	6.82E-03	6.82E-03	6.82E-03	6.82E-03	6.82E-03	6.82E-03	--
CO														
CO Concentration @ Ref O_2	(ppmvd)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	
CO Molecular weight	(lb/lb-mol)	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	4
Emission Factor	(lb/hr)	2.01	1.64	1.44	2.55	2.05	1.66	2.85	2.39	1.86	2.78	2.26	2.26	--
Emission Factor	(lb/MMBtu)	8.98E-03	8.98E-03	8.98E-03	8.98E-03	8.98E-03	8.98E-03	8.98E-03	8.98E-03	8.98E-03	8.98E-03	8.98E-03	8.98E-03	--
Formaldehyde														
Formaldehyde Concentration @ Ref O_2	(ppmvd)	0.215	0.215	0.215	0.215	0.215	0.215	0.215	0.215	0.215	0.215	0.215	0.215	--
Formaldehyde Molecular weight	(lb/lb-mol)	30.026	30.026	30.026	30.026	30.026	30.026	30.026	30.026	30.026	30.026	30.026	30.026	4
Emission Factor	(lb/hr)	0.12	0.09	0.08	0.15	0.12	0.10	0.16	0.14	0.11	0.16	0.13	0.13	--
Emission Factor	(lb/MMBtu)	5.17E-04	5.17E-04	5.17E-04	5.17E-04	5.17E-04	5.17E-04	5.17E-04	5.17E-04	5.17E-04	5.17E-04	5.17E-04	5.17E-04	--
VOC														
VOC Concentration @ Ref O_2	(ppmvd)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	--
VOC Molecular weight (as CH_4)	(lb/lb-mol)	16.043	16.043	16.043	16.043	16.043	16.043	16.043	16.043	16.043	16.043	16.043	16.043	4
Emission Factor	(lb/hr)	0.86	0.71	0.62	1.10	0.88	0.71	1.22	1.03	0.80	1.20	0.97	0.97	--
Emission Factor	(lb/MMBtu)	3.86E-03	3.86E-03	3.86E-03	3.86E-03	3.86E-03	3.86E-03	3.86E-03	3.86E-03	3.86E-03	3.86E-03	3.86E-03	3.86E-03	--

1. Operating parameters provided by manufacturer
2. F_d Factor for natural gas from EPA Method 19 Table 19-2
3. Molar volume determined using R = 10.73 psi-ft^3/lbmol-˚R
4. Molecular weight from PubChem

Table B-8. ST250 Natural Gas Turbine Emission Rate

	Unit	Value
Controlled NO_X	(ppmvd @15% O_2)	2.00
Controlled NH_3	(ppmvd @15% O_2)	5.00
Controlled CO	(ppmvd @15% O_2)	4.00
Controlled Formaldehyde	(ppmvd @15% O_2)	0.091
Controlled VOC Emission	(ppmvd @15% O_2)	3.00

Table B-9. ST250 Natural Gas PPM Emission Factor Conversion

Operating Parameter	Unit	Scenario Data									Reference
Ambient Air Temperature	(F)	110.0			60.0			-10.0			1
Load Condition	(%)	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	1
Fuel Flow (HHV)	(MMBtu/hr)	140.90	115.75	98.95	165.36	135.73	114.41	177.49	157.41	130.41	1
Reference O_2	(% O_2)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	1
F_d Factor Natural Gas	(dscfm/MMBtu)	8710	8710	8710	8710	8710	8710	8710	8710	8710	2
P standard	(psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	--
T standard	(˚R)	528	528	528	528	528	528	528	528	528	--
Molar volume of ideal gas at 68F and 1 atm	(ft^3/lb-mol)	385.16	385.16	385.16	385.16	385.16	385.16	385.16	385.16	385.16	3
Conversion from ppm to fraction	-	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	--
NO_X											
NO_X Concentration @ Ref O_2	(ppmvd)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	--
NO_X Molecular weight	(lb/lb-mol)	46.006	46.006	46.006	46.006	46.006	46.006	46.006	46.006	46.006	4
Emission Factor	(lb/hr)	1.04	0.85	0.73	1.22	1.00	0.84	1.31	1.16	0.96	--
Emission Factor	(lb/MMBtu)	0.00737	0.00737	0.00737	0.00737	0.00737	0.00737	0.00737	0.00737	0.00737	--
NH_3											
NH_3 Concentration @ Ref O_2	(ppmvd)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	--
NH_3 Molecular weight	(lb/lb-mol)	17.031	17.031	17.031	17.031	17.031	17.031	17.031	17.031	17.031	4
Emission Factor	(lb/hr)	0.96	0.79	0.67	1.13	0.93	0.78	1.21	1.07	0.89	--
Emission Factor	(lb/MMBtu)	0.00682	0.00682	0.00682	0.00682	0.00682	0.00682	0.00682	0.00682	0.00682	--
CO											
CO Concentration @ Ref O_2	(ppmvd)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	
CO Molecular weight	(lb/lb-mol)	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	4
Emission Factor	(lb/hr)	1.26	1.04	0.89	1.48	1.22	1.03	1.59	1.41	1.17	--
Emission Factor	(lb/MMBtu)	0.00898	0.00898	0.00898	0.00898	0.00898	0.00898	0.00898	0.00898	0.00898	--
Formaldehyde											
Formaldehyde Concentration @ Ref O_2	(ppmvd)	0.091	0.091	0.091	0.091	0.091	0.091	0.091	0.091	0.091	--
Formaldehyde Molecular weight	(lb/lb-mol)	30.026	30.026	30.026	30.026	30.026	30.026	30.026	30.026	30.026	4
Emission Factor	(lb/hr)	0.03	0.03	0.02	0.04	0.03	0.03	0.04	0.03	0.03	--
Emission Factor	(lb/MMBtu)	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	--
VOC											
VOC Concentration @ Ref O_2	(ppmvd)	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	--
VOC Molecular weight (as CH_4)	(lb/lb-mol)	16.043	16.043	16.043	16.043	16.043	16.043	16.043	16.043	16.043	4
Emission Factor	(lb/hr)	0.54	0.45	0.38	0.64	0.52	0.44	0.68	0.61	0.50	--
Emission Factor	(lb/MMBtu)	0.00386	0.00386	0.00386	0.00386	0.00386	0.00386	0.00386	0.00386	0.00386	--

1. Operating parameters provided by manufacturer
2. F_d Factor for natural gas from EPA Method 19 Table 19-2
3. Molar volume determined using R = 10.73 (psi-ft^3/lbmol-˚R)
4. Molecular weight from PubChem

Table B-10. TM2500 Natural Gas Turbine - Inputs

Parameter	Units	Value
Number of TM2500 Natural Gas Turbines	-	11
Hours of Operation	(hr/yr)	8,760

Table B-11.TM2500 Natural Gas Turbine - Operating Parameters

Parameter	Units													Reference
Ambient Air Temperature	(F)	110.0			60.0			15.0			-10.0			1
Load Condition	(%)	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	1
Fuel Flow (HHV)	(MMBtu/hr)	224.33	182.90	160.74	284.22	228.82	185.31	317.58	266.45	207.17	310.20	252.29	252.29	1

1. Operating parameters provided on by manufacturer

Table B-12. TM2500 Natural Gas Turbine - Normal Operation Emissions - Each Turbine (lb/hr)

Parameter	Units													Max	Reference
Ambient Air Temperature:	(F)	110.0			60.0			15.0			-10.0			15	1
Load Condition:	(%)	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	100	1
Pollutant	**Units**	**Controlled Emissions**													
NO_X	(lb/hr)	1.65	1.35	1.18	2.09	1.69	1.37	2.34	1.96	1.53	2.29	1.86	1.86	2.34	1
CO	(lb/hr)	2.01	1.64	1.44	2.55	2.05	1.66	2.85	2.39	1.86	2.78	2.26	2.26	2.85	1
VOC	(lb/hr)	0.86	0.71	0.62	1.10	0.88	0.71	1.22	1.03	0.80	1.20	0.97	0.97	1.55	1
PM_{10}	(lb/hr)	1.48	1.21	1.06	1.88	1.51	1.22	2.10	1.76	1.37	2.05	1.67	1.67	2.10	2
$PM_{2.5}$	(lb/hr)	1.48	1.21	1.06	1.88	1.51	1.22	2.10	1.76	1.37	2.05	1.67	1.67	2.10	2
SO_2	(lb/hr)	0.13	0.10	0.09	0.16	0.13	0.10	0.18	0.15	0.12	0.17	0.14	0.14	0.18	3
NH_3	(lb/hr)	1.53	1.25	1.10	1.94	1.56	1.26	2.17	1.82	1.41	2.12	1.72	1.72	2.17	1
CO_2	(lb/hr)	26,242	21,395	18,802	33,248	26,767	21,677	37,150	31,168	24,234	36,286	29,513	29,513	37,150	4
CH_4	(lb/hr)	0.49	0.40	0.35	0.63	0.50	0.41	0.70	0.59	0.46	0.68	0.56	0.56	0.70	4
N_2O	(lb/hr)	0.05	0.04	0.04	0.06	0.05	0.04	0.07	0.06	0.05	0.07	0.06	0.06	0.07	4
CO_2e	(lb/hr)	26,268	21,417	18,822	33,282	26,795	21,700	37,188	31,200	24,259	36,323	29,543	29,543	37,188	4
Formaldehyde	(lb/hr)	0.12	0.09	0.08	0.15	0.12	0.10	0.16	0.14	0.11	0.16	0.13	0.13	0.16	1

1. Emission rates post oxidation catalyst and SCR controls

2. AP 42 Total PM Emission Factor = 0.0066 (lb/MMBtu)

3. Sulfur emission factors are determined using the following and assume 100% conversion of fuel sulfur to SO_2:

Sulfur Content	0.2	grain	Emission Factor Documentation for AP-42 Section 1.4, page 3.8
Per volume of natural gas	100	dscf	
Sulfur MW	32.07	(lb/lb-mol)	
SO_2 MW	64.06	(lb/lb-mol)	
Natural Gas HHV	1020	(btu/scf)	Emission Factor Documentation for AP-42 Section 1.4, page 3.4

4. GHG emission factors are determined using the following:

a. Emission Rate (lb/hr) = 40 CFR 98 Table C-1 Emission Factor (kg/MMBtu) * Fuel Heat Input (MMBtu/hr) * Conversion (lb/kg)

CO_2 EF	53.06	(kg/MMBtu)
CH_4 EF	1.00E-03	(kg/MMBtu)
N_2O EF	1.00E-04	(kg/MMBtu)

b. CO_2e is the sum of GHG constituents multiplied by their respective global warming potential per 40 CFR 98 Table A-1

1	CO_2 GWP
28	CH_4 GWP
265	N_2O GWP

Table B-13. TM2500 Natural Gas Turbine - Normal Operation Emissions - All Turbines (tpy)

Operating Parameter	Unit														
Ambient Air Temperature	(F)	110.0			60.0			15.0			-10.0				
Load Condition	(%)	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00		
Pollutant	**Units**	**Controlled Emissions**												**Max Emissions**	**Reference**
NO_X	(tpy)	79.35	64.69	56.86	100.53	80.94	65.55	112.34	94.25	73.28	109.72	89.24	89.24	112.34	1
CO	(tpy)	96.62	78.78	69.23	122.42	98.56	79.82	136.79	114.76	89.23	133.60	108.67	108.67	136.79	1
VOC	(tpy)	41.51	33.84	29.74	52.59	42.34	34.29	58.76	49.30	38.33	57.39	46.68	46.68	67.38	1
PM_{10}	(tpy)	71.05	57.93	50.91	90.02	72.48	58.69	100.59	84.39	65.62	98.25	79.91	79.91	100.59	--
$PM_{2.5}$	(tpy)	71.05	57.93	50.91	90.02	72.48	58.69	100.59	84.39	65.62	98.25	79.91	79.91	100.59	--
SO_2	(tpy)	6.05	4.93	4.33	7.66	6.17	5.00	8.56	7.18	5.58	8.36	6.80	6.80	8.56	--
NH_3	(tpy)	73.58	59.99	52.72	93.23	75.06	60.78	104.17	87.40	67.95	101.75	82.75	82.75	104.17	1
CO_2	(tpy)	1,259,313	1,026,736	902,315	1,595,527	1,284,546	1,040,278	1,782,812	1,495,750	1,162,975	1,741,332	1,416,295	1,416,295	1,782,811.79	--
CH_4	(tpy)	23.83	19.43	17.07	30.19	24.31	19.68	33.73	28.30	22.01	32.95	26.80	26.80	33.73	--
N_2O	(tpy)	2.38	1.94	1.71	3.02	2.43	1.97	3.37	2.83	2.20	3.29	2.68	2.68	3.37	--
CO_2e	(tpy)	1,260,612	1,027,795	903,246	1,597,172	1,285,870	1,041,351	1,784,650	1,497,293	1,164,174	1,743,128	1,417,756	1,417,756	1,784,650.26	--
Formaldehyde	(tpy)	5.59	4.55	4.00	7.08	5.70	4.61	7.91	6.63	5.16	7.72	6.28	6.28	7.91	--

1. Number of SUSD events per year per turbine:

	SU:	52	(events/yr)
	SD:	52	(events/yr)
SUSD event duration:			
	SU:	0.33	(hrs)
	SD:	0.33	(hrs)
Annual controlled operating time:		8725.33	(hr/yr)

Table B-14. TM2500 Natural Gas Turbine - Startup and Shut Down Emissions - All Turbines (tpy)

Pollutant	Units	Emissions
NO_X	(tpy)	2.29
CO	(tpy)	33.18
VOC	(tpy)	4.00
CO_2e	(tpy)	1289.86

Table B-15. TM2500 Natural Gas Turbine - HAP PTE

Pollutant	Emission Factor	HAP Emissions per CTG	HAP Emissions per CTG	HAP Emissions All CTGs	HAP Emissions All CTGs	Also a VOC, not a HC?[3]	Reference
	(lb/MMBtu)	(lb/hr)	(tpy)	(lb/hr)	(tpy)		
1,3-Butadiene	4.30E-07	1.37E-04	5.98E-04	1.50E-03	6.58E-03	No	1
Acetaldehyde	4.00E-05	1.27E-02	5.56E-02	1.40E-01	6.12E-01	Yes	1
Acrolein	6.40E-06	2.03E-03	8.90E-03	2.24E-02	9.79E-02	Yes	1
Benzene	1.20E-05	3.81E-03	1.67E-02	4.19E-02	1.84E-01	No	1
Ethylbenzene	3.20E-05	1.02E-02	4.45E-02	1.12E-01	4.90E-01	No	1
Formaldehyde	-	-	-	1.64E-01	7.91E+00	Yes	2
Naphthalene	1.30E-06	4.13E-04	1.81E-03	4.54E-03	1.99E-02	No	1
PAH	2.20E-06	6.99E-04	3.06E-03	7.69E-03	3.37E-02	No	1
Propylene Oxide	2.90E-05	9.21E-03	4.03E-02	1.01E-01	4.44E-01	No	1
Toluene	1.30E-04	4.13E-02	1.81E-01	4.54E-01	1.99E+00	No	1
Xylenes	6.40E-05	2.03E-02	8.90E-02	2.24E-01	9.79E-01	No	1
			Max HAP	**0.45**	**7.91**		
			Total HAPs	**1.27**	**12.76**		

1. HAPs and corresponding emissions factors from AP-42 Table 3.1-3 unless otherwise specified

2. Formaldehyde emissions per manufacturer data

3. Non-hydrocarbon HAPs which are VOCs are included in the VOC total

Table B-16. ST250 Natural Gas Turbine - Inputs

Parameter	Units	Value
Number of ST250 Natural Gas Turbines	-	6
Hours of Operation	(hr/yr)	8,760

Table B-17.ST250 Natural Gas Turbine - Operating Parameters

Parameter	Units										Reference
Ambient Air Temperature	(F)	110.0			60.0			-10.0			1
Load Condition	(%)	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	1
Fuel Flow (HHV)	(MMBtu/hr)	140.90	115.75	98.95	165.36	135.73	114.41	177.49	157.41	130.41	1

1. Operating parameters provided by manufacturer

Table B-18. ST250 Natural Gas Turbine -Normal Operation Emissions - Each Turbine (lb/hr)

Parameter	Units										Max	
Ambient Air Temperature:	(F)	110.0			60.0			-10.0			-10	
Load Condition:	(%)	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00	100	
Pollutant	**Units**	**Controlled Emissions**										**Reference**
NO_X	(lb/hr)	1.04	0.85	0.73	1.22	1.00	0.84	1.31	1.16	0.96	1.31	1
CO	(lb/hr)	1.26	1.04	0.89	1.48	1.22	1.03	1.59	1.41	1.17	1.59	1
VOC	(lb/hr)	0.54	0.45	0.38	0.64	0.52	0.44	0.68	0.61	0.50	0.77	1
PM_{10}	(lb/hr)	0.93	0.76	0.65	1.09	0.90	0.76	1.17	1.04	0.86	1.17	2
$PM_{2.5}$	(lb/hr)	0.93	0.76	0.65	1.09	0.90	0.76	1.17	1.04	0.86	1.17	2
SO_2	(lb/hr)	0.08	0.06	0.06	0.09	0.08	0.06	0.10	0.09	0.07	0.10	3
NH_3	(lb/hr)	0.96	0.79	0.67	1.13	0.93	0.78	1.21	1.07	0.89	1.21	1
CO_2	(lb/hr)	16,482	13,540	11,575	19,343	15,877	13,383	20,762	18,413	15,255	20,762	4
CH_4	(lb/hr)	0.31	0.26	0.22	0.36	0.30	0.25	0.39	0.35	0.29	0.39	4
N_2O	(lb/hr)	0.03	0.03	0.02	0.04	0.03	0.03	0.04	0.03	0.03	0.04	4
CO_2e	(lb/hr)	16,499	13,554	11,587	19,363	15,894	13,397	20,784	18,432	15,271	20,784	4
Formaldehyde	(lb/hr)	0.03	0.03	0.02	0.04	0.03	0.03	0.04	0.03	0.03	0.04	--

1. Emission rates post oxidation catalyst and SCR controls

2. AP 42 Total PM Emission Factor = 0.0066 lb/MMBtu

3. Sulfur emission factors are determined using the following and assume 100% conversion of fuel sulfur to SO_2:

Sulfur Content	0.2	grain	Emission Factor Documentation for AP-42 Section 1.4, page 3.8
Per volume of natural gas	100	dscf	
Sulfur MW	32.07	(lb/lb-mol)	
SO_2 MW	64.06	(lb/lb-mol)	
Natural Gas HHV	1020	(btu/scf)	Emission Factor Documentation for AP-42 Section 1.4, page 3.4

4. GHG emission factors are determined using the following:

a. (lb/hr) =40 CFR 98 Table C-1 Emission Factor (kg/MMBtu) * Fuel Heat Input (MMBtu/hr) * Conversion (lb/kg)

CO_2	53.06	(kg/MMBtu)
CH_4	1.00E-03	(kg/MMBtu)
N_2O	1.00E-04	(kg/MMBtu)

b. CO_2e is the sum of GHG constituents multiplied by their respective global warming potential per 40 CFR 98 Table A-1

1 CO2 GWP

28 CH4 GWP

265 N2O GWP

Table B-19. ST250 Natural Gas Turbine - Normal Operation Emissions - All Turbines (tpy)

Operating Parameter	Unit											
Ambient Air Temperature	(F)	110.0			60.0			-10.0				
Load Condition	(%)	100.00	75.00	50.00	100.00	75.00	50.00	100.00	75.00	50.00		
Pollutant	**Units**	**Controlled Emissions**									**MAX Emissions**	**Reference**
NO_X	(tpy)	27.18	22.33	19.09	31.90	26.19	22.07	34.24	30.37	25.16	34.24	1
CO	(tpy)	33.10	27.19	23.25	38.85	31.89	26.88	41.70	36.98	30.64	41.70	1
VOC	(tpy)	14.22	11.68	9.99	16.69	13.70	11.55	17.91	15.89	13.16	19.15	1
PM_{10}	(tpy)	24.44	20.08	17.16	28.68	23.54	19.84	30.79	27.30	22.62	30.79	--
$PM_{2.5}$	(tpy)	24.44	20.08	17.16	28.68	23.54	19.84	30.79	27.30	22.62	30.79	--
SO_2	(tpy)	2.07	1.70	1.45	2.43	2.00	1.68	2.61	2.31	1.92	2.61	--
NH_3	(tpy)	25.21	20.71	17.70	29.59	24.28	20.47	31.76	28.16	23.33	31.76	1
CO_2	(tpy)	431,435	354,426	302,985	506,332	415,605	350,323	543,474	481,989	399,315	543473.88	--
CH_4	(tpy)	8.16	6.71	5.73	9.58	7.86	6.63	10.28	9.12	7.56	10.28	--
N_2O	(tpy)	0.82	0.67	0.57	0.96	0.79	0.66	1.03	0.91	0.76	1.03	--
CO_2e	(tpy)	431,880	354,792	303,297	506,854	416,033	350,684	544,034	482,486	399,727	544034.32	--
Formaldehyde	(tpy)	0.81	0.67	0.57	0.95	0.78	0.66	1.02	0.91	0.75	1.02	--

1. Number of SUSD events per year per turbine:

	SU:	52	(events/yr)
	SD:	52	(events/yr)
SUSD event duration:			
	SU:	0.33	(hrs)
	SD:	0.33	(hrs)
Annual controlled operating time:		8725.33	(hr/yr)

Table B-20. ST250 Natural Gas Turbine - Startup and Shut Down Emissions - All Turbines (tpy)

Pollutant	Units	Emissions
NO_X	(tpy)	1.25
CO	(tpy)	18.10
VOC	(tpy)	2.18
CO_2e	(tpy)	703.56

Table B-21. ST250 HAP PTE

Pollutant	Emission Factor	HAP Emissions per CTG	HAP Emissions per CTG	HAP Emissions All CTGs	HAP Emissions All CTGs	Also a VOC, not a HC?[3]	Reference
	(lb/MMBtu)	(lb/hr)	(tpy)	(lb/hr)	(tpy)		
1,3-Butadiene	4.30E-07	7.63E-05	3.34E-04	4.58E-04	2.01E-03	No	1
Acetaldehyde	4.00E-05	7.10E-03	3.11E-02	4.26E-02	1.87E-01	Yes	1
Acrolein	6.40E-06	1.14E-03	4.98E-03	6.82E-03	2.99E-02	Yes	1
Benzene	1.20E-05	2.13E-03	9.33E-03	1.28E-02	5.60E-02	No	1
Ethylbenzene	3.20E-05	5.68E-03	2.49E-02	3.41E-02	1.49E-01	No	1
Formaldehyde	-	-	-	3.88E-02	1.02E+00	Yes	2
Naphthalene	1.30E-06	2.31E-04	1.01E-03	1.38E-03	6.06E-03	No	1
PAH	2.20E-06	3.90E-04	1.71E-03	2.34E-03	1.03E-02	No	1
Propylene Oxide	2.90E-05	5.15E-03	2.25E-02	3.09E-02	1.35E-01	No	1
Toluene	1.30E-04	2.31E-02	1.01E-01	1.38E-01	6.06E-01	No	1
Xylenes	6.40E-05	1.14E-02	4.98E-02	6.82E-02	2.99E-01	No	1
			Max HAP	**0.14**	**1.02**		
			Total HAPs	**0.38**	**2.50**		

1. HAPs and corresponding emissions factors from AP-42 Table 3.1-3 unless otherwise specified

2. Formaldehyde emissions per manufacturer data

3. Non-hydrocarbon HAPs are VOCs are included in the VOC total

Table B-22. Fire Pump Engine - Parameters

Parameter	Unit	Value	Reference
Quantity	#	1	--
Annual Hours of Operation	(hr/yr)	100	--
Engine Maximum Power Output - 100% Standby Load	(hp)	325	1
	(kW)	242	1
Fuel Consumption	(MMBtu/hr)	2.28	2

1. Nominal (maximum expected) rating

2. Fuel consumption calculated using the following:

Diesel High Heating Value (HHV):	0.138	(MMBtu/gal)
Average Brake-Specific Fuel Consumption (AP-42 Section 3.3, Table 3.3-1 Footnote a):	7000	(Btu/hp-hr)

Table B-23. Fire Pump Engine - Emission Factors

Pollutant	Emission Factors		Reference
	Unit	Value	
Criteria Pollutant Emission Factors			
NO_X	(g/kW-hr)	3.80	1,2
CO	(g/kW-hr)	3.50	1
NMHC (VOC)	(g/kW-hr)	0.20	1,2,3
PM_{10}	(g/kW-hr)	0.20	1,4
$PM_{2.5}$	(g/kW-hr)	0.20	1,4
SO_2	(lb/hp-hr)	2.05E-03	5
GHG Emission Factors			
CO_2	(kg/MMBtu)	73.96	6
CH_4	(kg/MMBtu)	3.00E-03	6
N_2O	(kg/MMBtu)	6.00E-04	6
CO_2e	(kg/MMBtu)	74.20	7

1. EPA Nonroad Compression-Ignition Engines: Exhaust Emission Standards (EPA-420-B-16-022), March 2016

2. CARB Emission Factors for CI Diesel Engines – Percent NO_X: in Relation to NMHC + NO_X:

95%

3. It is conservatively assumed that NMHC = VOC

4. It is conservatively assumed that PM=PM_{10}=$PM_{2.5}$

5. AP-42 Section 3.3, Table 3.3-1

6. Emission factor for carbon dioxide is obtained from 40 CFR 98, Table C–1 to Subpart C for Distillate Fuel Oil No. 2. Emission factors for methane and nitrous oxide are obtained from 40 CFR 98, Table C–2 to Subpart C

7. CO_2e is the sum of GHG constituents multiplied by their respective global warming potential per 40 CFR 98 Table A-1

1 CO_2 GWP
28 CH_4 GWP
265 N_2O GWP

Table B-24. Fire Pump Engine - PTE

Pollutant	Emissions	
	(lb/hr)	(tpy)
Criteria Pollutant Emissions		
NO_X	2.03	0.10
CO	1.87	0.09
NMHC (VOC)	0.11	5.58E-03
PM_{10}	0.11	5.34E-03
$PM_{2.5}$	0.11	5.34E-03
SO_2	6.66E-01	3.33E-02
GHG Emissions		
CO_2e	372	18.61

Table B-25. Fire Pump Engine - HAP PTE

Pollutant[1]	Emission Factor	Emissions		VOC, but not a HC?[2]
	(lb/MMBtu)	(lb/hr)	(tpy)	
Benzene	9.33E-04	2.12E-03	1.06E-04	No
Toluene	4.09E-04	9.30E-04	4.65E-05	No
Xylenes	2.85E-04	6.48E-04	3.24E-05	No
1,3-Butadiene	3.91E-05	8.90E-05	4.45E-06	Yes
Formaldehyde	1.18E-03	2.68E-03	1.34E-04	Yes
Acetaldehyde	7.67E-04	1.74E-03	8.72E-05	Yes
Acrolein	9.25E-05	2.10E-04	1.05E-05	Yes
Naphthalene	8.48E-05	1.93E-04	9.65E-06	No
	Max HAP (Formaldehyde):	**2.68E-03**	**1.34E-04**	
	Total HAPs:	**8.62E-03**	**4.31E-04**	

1. HAP pollutant emission factors per AP-42, Section 3.3, Table 3.3-2

2. All HAPs that are also VOCs and are not hydrocarbons are being added to the VOC total for the diesel fire pump

Table B-26. Fire Pump Tank - Parameters

Parameter	Value	Unit	Reference
Diesel Throughput	2.28	(MMBtu/hr)	--
	16.49	(gal/hr)	1
	1,649	(gal/yr)	2
Hours of Operation	0.27	(hr/yr)	3

1. Diesel High Heating Value (HHV): 0.138 (MMBtu/gal)

2. Based on 100 hours of annual operation

3. Fueling rate (conservative assumption) 100 (gal/min)

Table B-27. Fire Pump Tank - VOC PTE

Parameter	Value	Unit	Reference
Loading loss emission factor	0.01	($lb/10^3$ gal)	1,2
Loading loss all tanks	0.04	(lb/yr)	1,3,4
Loading loss all tanks	1.84E-05	(tpy)	--
Average hourly total loading loss all tanks	0.13	(lb/hr)	5

1. Includes (1) vapors formed in the empty tank by evaporation of residual product from previous loads, (2) vapors transferred to the tank in vapor balance systems as product is being unloaded, and (3) vapors generated in the tank as the new product is being loaded.

2. AP 42 Section 5.2 Transportation and Marketing of Petroleum Liquids

$$L_L = 12.46 \frac{SPM}{T}\left(1 - \frac{eff}{100}\right)$$

Where,

L_L, loading loss (lb/[10^3 gal of liquid loaded]) =	0.01
S, saturation factor[a] =	0.60
P, true vapor pressure of diesel (psia)[b] =	6.00E-03
M, molecular weight of vapors of diesel (lb/lb-mol)[b] =	130
T, Temperature (R)[b] =	523
eff, overall reduction efficiency =	0.00

a) AP 42 Table 5.2-1, for submerged loading and dedicated normal service.

b) AP 42 Table 7.1-2

c) AP 42 Table 7.1-7 (F) 63.3

3. Conversion factors:

1000 gal/Mgal

4. Safety Factor 2

5. Fueling rate (conservative assumption) 100 (gpm)

Table B-28. Fire Pump Tank - HAP PTE

HAP	HAP Composition (wt%)	Emissions (lb/hr)	Emissions (tpy)
Benzene	1.6%	2.19E-03	3.01E-07
Ethylbenzene	2.3%	3.04E-03	4.17E-07
Hexane	0.3%	4.55E-04	6.25E-08
Naphthalene	0.3%	3.88E-04	5.33E-08
Toluene	18.2%	2.43E-02	3.34E-06
Xylenes	44.0%	0.06	8.08E-06
	Max HAP (Xylenes):	**0.06**	**8.08E-06**
	Total HAPs:	**0.09**	**1.23E-05**

1. Determined from TankESP HAPs speciation

Table B-29. Large Natural Gas Line Heater - Operating Parameters

Parameter	Unit	Value
Quantity	#	6
Hours of Operation	(hr/yr)	8,760
Burner Heat Release (HHV)	(MMBtu/hr)	10.68
Standard Heat Content [1]	(Btu/scf)	1,020

1. Natural gas heating value from emission factor documentation for AP-42 Section 1.4, page 3.4

Table B-30. Large Natural Gas Line Heater - Emission Factors

Pollutant	Emission Factor		Reference
	Unit	Value	
Criteria Pollutants Emission Factors			
NO_X	(lb/MMBtu)	1.00E-02	1
CO	(lb/MMBtu)	3.70E-02	1
VOC	(lb/MMBtu)	5.00E-03	1a
SO_2	(lb/MMBtu)	7.00E-04	1
PM_{10}	(lb/MMBtu)	7.50E-03	1,2
$PM_{2.5}$	(lb/MMBtu)	7.50E-03	1,2
GHG Emission Factors			
CO_2	(kg/MMBtu)	53.06	3
CH_4	(kg/MMBtu)	1.00E-03	3
N_2O	(kg/MMBtu)	1.00E-04	3
CO_2e	(kg/MMBtu)	53.11	4

1. Manufacturer specifications

a. Assuming Hydrogen/VOC factor

2.. Assuming $PM=PM_{10}=PM_{2.5}$

3. Emission factors for greenhouse gases provided in 40 CFR Part 98, Subpart C, Tables C-1 and C-2

4. Global Warming Potentials provided in 40 CFR Part 98, Subpart A, Table A-1:

	GWP
CO_2	1
CH_4	28
N_2O	265

Table B-31. Large Natural Gas Line Heater - Criteria Pollutant and GHG PTE

Pollutant	Emissions			
	Per Natural Gas Line Heater		All Natural Gas Line Heaters	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Criteria Pollutant Emissions				
NO_X	0.11	0.47	0.64	2.81
CO	0.40	1.73	2.37	10.38
VOC	0.05	0.24	0.33	1.42
SO_2	7.47E-03	0.03	0.04	0.20
PM_{10}	0.08	0.35	0.48	2.10
$PM_{2.5}$	0.08	0.35	0.48	2.10
GHG Emissions				
CO_2e	1,250	5,476	7,501	32,855

Table B-32. Large Natural Gas Line Heater - HAP PTE

Pollutant	Emission Factors[1]		Emissions				VOC, but not a HC?[2]
			Per Natural Gas Line Heater		All Natural Gas Line Heaters		
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	
2-Methylnaphthalene	2.40E-05	(lb/MMscf)	2.51E-07	1.10E-06	1.51E-06	6.60E-06	No
3-Methylchloranthrene	1.80E-06	(lb/MMscf)	1.88E-08	8.25E-08	1.13E-07	4.95E-07	Yes
7,12-Dimethylbenz(a)anthracene	1.60E-05	(lb/MMscf)	1.67E-07	7.34E-07	1.00E-06	4.40E-06	No
Acenaphthene	1.80E-06	(lb/MMscf)	1.88E-08	8.25E-08	1.13E-07	4.95E-07	No
Acenaphthylene	1.80E-06	(lb/MMscf)	1.88E-08	8.25E-08	1.13E-07	4.95E-07	No
Anthracene	2.40E-06	(lb/MMscf)	2.51E-08	1.10E-07	1.51E-07	6.60E-07	No
Benz(a)anthracene	1.80E-06	(lb/MMscf)	1.88E-08	8.25E-08	1.13E-07	4.95E-07	No
Benzene	2.10E-03	(lb/MMscf)	2.20E-05	9.63E-05	1.32E-04	5.78E-04	No
Benzo(a)pyrene	1.20E-06	(lb/MMscf)	1.26E-08	5.50E-08	7.54E-08	3.30E-07	No
Benzo(b)fluoranthene	1.80E-06	(lb/MMscf)	1.88E-08	8.25E-08	1.13E-07	4.95E-07	No
Benzo(g,h,i)perylene	1.20E-06	(lb/MMscf)	1.26E-08	5.50E-08	7.54E-08	3.30E-07	No
Benzo(k)fluoranthene	1.80E-06	(lb/MMscf)	1.88E-08	8.25E-08	1.13E-07	4.95E-07	No
Chrysene	1.80E-06	(lb/MMscf)	1.88E-08	8.25E-08	1.13E-07	4.95E-07	No
Dibenzo(a,h)anthracene	1.20E-06	(lb/MMscf)	1.26E-08	5.50E-08	7.54E-08	3.30E-07	No
Dichlorobenzene	1.20E-03	(lb/MMscf)	1.26E-05	5.50E-05	7.54E-05	3.30E-04	Yes
Fluoranthene	3.00E-06	(lb/MMscf)	3.14E-08	1.38E-07	1.88E-07	8.25E-07	No
Fluorene	2.80E-06	(lb/MMscf)	2.93E-08	1.28E-07	1.76E-07	7.70E-07	No
Formaldehyde	7.50E-02	(lb/MMscf)	7.85E-04	3.44E-03	4.71E-03	2.06E-02	Yes
Hexane	1.80	(lb/MMscf)	1.88E-02	8.25E-02	1.13E-01	4.95E-01	No
Indeno(1,2,3-cd)pyrene	1.80E-06	(lb/MMscf)	1.88E-08	8.25E-08	1.13E-07	4.95E-07	No
Naphthalene	6.10E-04	(lb/MMscf)	6.39E-06	2.80E-05	3.83E-05	1.68E-04	No
Phenanthrene	1.70E-05	(lb/MMscf)	1.78E-07	7.79E-07	1.07E-06	4.68E-06	No
Pyrene	5.00E-06	(lb/MMscf)	5.23E-08	2.29E-07	3.14E-07	1.38E-06	No
Toluene	3.40E-03	(lb/MMscf)	3.56E-05	1.56E-04	2.14E-04	9.35E-04	No
Arsenic	2.00E-04	(lb/MMscf)	2.09E-06	9.17E-06	1.26E-05	5.50E-05	No
Beryllium	1.20E-05	(lb/MMscf)	1.26E-07	5.50E-07	7.54E-07	3.30E-06	No
Cadmium	1.10E-03	(lb/MMscf)	1.15E-05	5.04E-05	6.91E-05	3.03E-04	No
Chromium	1.40E-03	(lb/MMscf)	1.47E-05	6.42E-05	8.79E-05	3.85E-04	No
Cobalt	8.40E-05	(lb/MMscf)	8.79E-07	3.85E-06	5.28E-06	2.31E-05	No
Lead	5.00E-04	(lb/MMscf)	5.23E-06	2.29E-05	3.14E-05	1.38E-04	No
Manganese	3.80E-04	(lb/MMscf)	3.98E-06	1.74E-05	2.39E-05	1.05E-04	No
Mercury	2.60E-04	(lb/MMscf)	2.72E-06	1.19E-05	1.63E-05	7.15E-05	No
Nickel	2.10E-03	(lb/MMscf)	2.20E-05	9.63E-05	1.32E-04	5.78E-04	No
Selenium	2.40E-05	(lb/MMscf)	2.51E-07	1.10E-06	1.51E-06	6.60E-06	No
		Max HAP (Hexane):	**0.02**	**0.08**	**0.11**	**0.50**	
		Total HAPs:	**0.02**	**0.09**	**0.12**	**0.52**	

1. Natural gas HAPs factors from AP-42, Tables 1.4-3 and 1.4-4. Lead factor from Table 1.4-2

2. All HAPs that are also VOCs and are not hydrocarbons are being added to the VOC total for the natural gas line heaters. Hydrocarbon VOCs are accounted for in the original VOC factor for the natural gas line heaters.

Table B-33. Small Natural Gas Line Heater - Operating Parameters

Parameter	Unit	Value
Quantity	#	2
Hours of Operation	(hr/yr)	8760
Heat Input	(MMBtu/hr)	3.43
Standard Heat Content [1]	(Btu/scf)	1020

1. Natural gas heating value from emission factor documentation for AP-42 Section 1.4, page 3.4

Table B-34. Small Natural Gas Line Heater - Emission Factors

Pollutant	Emission Factor		Reference
	Unit	Value	
Criteria Pollutants Emission Factors			
NO_X	(lb/MMBtu)	1.00E-02	1
CO	(lb/MMBtu)	3.70E-02	1
VOC	(lb/MMBtu)	5.00E-03	1a
SO_2	(lb/MMBtu)	7.00E-04	1
PM_{10}	(lb/MMBtu)	7.50E-03	1,2
$PM_{2.5}$	(lb/MMBtu)	7.50E-03	1,2
GHG Emission Factors			
CO_2	(kg/MMBtu)	53.06	3
CH_4	(kg/MMBtu)	1.00E-03	3
N_2O	(kg/MMBtu)	1.00E-04	3
CO_2e	(kg/MMBtu)	53.11	4

1. Manufacturer specifications

   a. Assuming Hydrogen/VOC factor

2.. Assuming $PM=PM_{10}=PM_{2.5}$

3. Emission factor for greenhouse gases provided in 40 CFR Part 98, Subpart C, Tables C-1 and C-2

4. Global Warming Potentials provided in 40 CFR Part 98, Subpart A, Table A-1:

	GWP
CO_2	1
CH_4	28
N_2O	265

Table B-35. Small Natural Gas Line Heater - Criteria Pollutant and GHG PTE

Pollutant	Emissions			
	Per Natural Gas Line Heater		All Natural Gas Line Heaters	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Criteria Pollutant Emissions				
NO_X	0.03	0.15	0.07	0.30
CO	0.13	0.56	0.25	1.11
VOC	0.02	0.08	0.03	0.15
SO_2	2.40E-03	0.01	0.00	0.02
PM_{10}	0.03	0.11	0.05	0.23
$PM_{2.5}$	0.03	0.11	0.05	0.23
GHG Emissions				
CO_2e	402	1,762	804	3,523

Table B-36. Small Natural Gas Line Heater - HAP PTE

Pollutant	Emission Factors[1]		Emissions				VOC, but not a HC?[2]
			Per Natural Gas Line Heater		All Natural Gas Line Heaters		
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	
2-Methylnaphthalene	2.40E-05	(lb/MMscf)	8.08E-08	3.54E-07	1.62E-07	7.08E-07	No
3-Methylchloranthrene	1.80E-06	(lb/MMscf)	6.06E-09	2.65E-08	1.21E-08	5.31E-08	Yes
7,12-Dimethylbenz(a)anthracene	1.60E-05	(lb/MMscf)	5.39E-08	2.36E-07	1.08E-07	4.72E-07	No
Acenaphthene	1.80E-06	(lb/MMscf)	6.06E-09	2.65E-08	1.21E-08	5.31E-08	No
Acenaphthylene	1.80E-06	(lb/MMscf)	6.06E-09	2.65E-08	1.21E-08	5.31E-08	No
Anthracene	2.40E-06	(lb/MMscf)	8.08E-09	3.54E-08	1.62E-08	7.08E-08	No
Benz(a)anthracene	1.80E-06	(lb/MMscf)	6.06E-09	2.65E-08	1.21E-08	5.31E-08	No
Benzene	2.10E-03	(lb/MMscf)	7.07E-06	3.10E-05	1.41E-05	6.19E-05	No
Benzo(a)pyrene	1.20E-06	(lb/MMscf)	4.04E-09	1.77E-08	8.08E-09	3.54E-08	No
Benzo(b)fluoranthene	1.80E-06	(lb/MMscf)	6.06E-09	2.65E-08	1.21E-08	5.31E-08	No
Benzo(g,h,i)perylene	1.20E-06	(lb/MMscf)	4.04E-09	1.77E-08	8.08E-09	3.54E-08	No
Benzo(k)fluoranthene	1.80E-06	(lb/MMscf)	6.06E-09	2.65E-08	1.21E-08	5.31E-08	No
Chrysene	1.80E-06	(lb/MMscf)	6.06E-09	2.65E-08	1.21E-08	5.31E-08	No
Dibenzo(a,h)anthracene	1.20E-06	(lb/MMscf)	4.04E-09	1.77E-08	8.08E-09	3.54E-08	No
Dichlorobenzene	1.20E-03	(lb/MMscf)	4.04E-06	1.77E-05	8.08E-06	3.54E-05	Yes
Fluoranthene	3.00E-06	(lb/MMscf)	1.01E-08	4.42E-08	2.02E-08	8.85E-08	No
Fluorene	2.80E-06	(lb/MMscf)	9.43E-09	4.13E-08	1.89E-08	8.26E-08	No
Formaldehyde	7.50E-02	(lb/MMscf)	2.53E-04	1.11E-03	5.05E-04	2.21E-03	Yes
Hexane	1.80	(lb/MMscf)	6.06E-03	2.65E-02	1.21E-02	5.31E-02	No
Indeno(1,2,3-cd)pyrene	1.80E-06	(lb/MMscf)	6.06E-09	2.65E-08	1.21E-08	5.31E-08	No
Naphthalene	6.10E-04	(lb/MMscf)	2.05E-06	9.00E-06	4.11E-06	1.80E-05	No
Phenanthrene	1.70E-05	(lb/MMscf)	5.72E-08	2.51E-07	1.14E-07	5.01E-07	No
Pyrene	5.00E-06	(lb/MMscf)	1.68E-08	7.37E-08	3.37E-08	1.47E-07	No
Toluene	3.40E-03	(lb/MMscf)	1.14E-05	5.01E-05	2.29E-05	1.00E-04	No
Arsenic	2.00E-04	(lb/MMscf)	6.73E-07	2.95E-06	1.35E-06	5.90E-06	No
Beryllium	1.20E-05	(lb/MMscf)	4.04E-08	1.77E-07	8.08E-08	3.54E-07	No
Cadmium	1.10E-03	(lb/MMscf)	3.70E-06	1.62E-05	7.41E-06	3.24E-05	No
Chromium	1.40E-03	(lb/MMscf)	4.71E-06	2.06E-05	9.43E-06	4.13E-05	No
Cobalt	8.40E-05	(lb/MMscf)	2.83E-07	1.24E-06	5.66E-07	2.48E-06	No
Lead	5.00E-04	(lb/MMscf)	1.68E-06	7.37E-06	3.37E-06	1.47E-05	No
Manganese	3.80E-04	(lb/MMscf)	1.28E-06	5.60E-06	2.56E-06	1.12E-05	No
Mercury	2.60E-04	(lb/MMscf)	8.76E-07	3.83E-06	1.75E-06	7.67E-06	No
Nickel	2.10E-03	(lb/MMscf)	7.07E-06	3.10E-05	1.41E-05	6.19E-05	No
Selenium	2.40E-05	(lb/MMscf)	8.08E-08	3.54E-07	1.62E-07	7.08E-07	No
		Max HAP (Hexane):	**0.01**	**0.03**	**0.01**	**0.05**	
		Total HAPs:	**0.01**	**0.03**	**0.01**	**0.06**	

1. Natural gas HAPs factors from AP-42, Tables 1.4-3 and 1.4-4. Lead factor from Table 1.4-2

2. All HAPs that are also VOCs and are not hydrocarbons are being added to the VOC total for the natural gas line heaters. Hydrocarbon VOCs are accounted for in the original VOC factor for the natural gas line heaters.

Table B-37. CAT G3520 Natural Gas Engine - Parameters

Parameter		Value	Reference
Number of CAT G3520 Natural Gas Engines	#	2	--
Hours of Operation	(hr/yr)	100	--
Uncontrolled Hours of Operation	(hr/yr)	8.00	--
Startup (SU) Duration	(min)	30	1
SU & SD Count per Engine	events/year	16	2
Controlled Hours of Operation	(hr/yr)	92.00	--

1. Maximum expected duration

2. Assumes 12 monthly tests, 1 annual test, 3 additional tests.

Table B-38. CAT G3520 Natural Gas Engine - Criteria Pollutant & GHG Emission Factors

	Unit	Value			Reference
Load Condition	(%)	100.00%	75.00%	50.00%	1
Engine Power	(bhp)	3,629	2,768	1,907	1
Engine Power	(bkW)	2,706	2,064	1,422	1
Engine Fuel Consumption	(Btu/bhp-hr)	6,293	6,432	6,687	1
Criteria Pollutant Emission Factors					
NO_X	(g/bkW-hr)	1.34	1.34	1.34	1
Uncontrolled CO	(g/bkW-hr)	1.88	1.88	1.88	1
Controlled CO	(g/bkW-hr)	0.13	0.13	0.13	1
Uncontrolled VOC	(g/bkW-hr)	0.28	0.28	0.28	1a
Controlled VOC	(g/bkW-hr)	0.08	0.08	0.08	1a
SO_2	(lb/MMBtu)	5.88E-04	5.88E-04	5.88E-04	2
PM_{10}	(lb/MMBtu)	9.18E-03	9.18E-03	9.18E-03	2
$PM_{2.5}$	(lb/MMBtu)	9.18E-03	9.18E-03	9.18E-03	2
GHG Emission Factors					
CO_2	(kg/MMBtu)	53.06	53.06	53.06	3
CH_4	(kg/MMBtu)	1.00E-03	1.00E-03	1.00E-03	3
N_2O	(kg/MMBtu)	1.00E-04	1.00E-04	1.00E-04	3
CO_2e	(kg/MMBtu)	53.11	53.11	53.11	4

1. Manufacturer specifications

   a. Assuming NMNEHC (VOCs) (mol. Wt. of 15.84)

2. AP-42 Section 3.2, Table 3.2-2

3. Emission factor for greenhouse gases calculated from 40 CFR Part 98, Subpart C, Tables C-1 and C-2

4. CO_2e is the sum of GHG constituents multiplied by their respective global warming potential per 40 CFR 98 Table A-1.

1 CO_2 GWP

28 CH_4 GWP

265 N_2O GWP

Table B-39. CAT G3520 Natural Gas Engine - Criteria Pollutant & GHG Emissions

Pollutant	Unit	Emissions		
		100% Load Emissions	75% Load Emissions	50% Load Emissions
Criteria Pollutant Hourly Emissions				
NO_X	(lb/hr)	7.99	6.10	4.20
Uncontrolled CO	(lb/hr)	11.22	8.56	5.89
Controlled CO	(lb/hr)	0.78	0.59	0.41
Uncontrolled VOC	(lb/hr)	1.67	1.27	0.88
Controlled VOC	(lb/hr)	0.48	0.36	0.25
SO_2	(lb/hr)	1.34E-02	1.05E-02	7.50E-03
PM_{10}	(lb/hr)	0.21	0.16	0.12
$PM_{2.5}$	(lb/hr)	0.21	0.16	0.12
GHG Hourly Emissions				
CO_2e	(lb/hr)	2674.19	2084.78	1493.24

Table B-40. CAT G3520 Natural Gas Engine - Criteria Pollutant & GHG PTE

Pollutant	Emissions			Reference
	Per Natural Gas Engine		All Natural Gas Engines	
	Maximum (lb/hr)	(tpy)	(tpy)	
Criteria Pollutant Emissions				
NO_X	7.99	0.40	0.80	--
CO	6.00	0.08	0.16	1
VOC	2.25	0.05	0.10	1
SO_2	1.34E-02	6.71E-04	1.34E-03	--
PM_{10}	0.21	1.05E-02	0.02	--
$PM_{2.5}$	0.21	1.05E-02	0.02	--
GHG Emissions				
CO_2e	2,674.19	133.71	267.42	--

1. Maximum CO and VOC lb/hr representative of 30 min uncontrolled SU period and 30 min normal controlled operation.

Table B-41. CAT G3520 Natural Gas Engine - HAP PTE

Pollutant[1,2]	Emission Factor	Emissions			VOC, but not a HC?[3]
		Per Natural Gas Engine		All Natural Gas Engines	
	(lb/MMBtu)	(lb/hr)	(tpy)	(tpy)	
1,1,2,2-Tetrachloroethane	4.00E-05	5.10E-04	2.55E-05	5.10E-05	Yes
1,1,2-Trichloroethane	3.18E-05	4.06E-04	2.03E-05	4.06E-05	Yes
1,3-Butadiene	2.67E-04	3.40E-03	1.70E-04	3.40E-04	No
1,3-Dichloropropene	2.64E-05	3.37E-04	1.68E-05	3.37E-05	Yes
2-Methylnaphthalene	3.32E-05	4.23E-04	2.12E-05	4.23E-05	No
2,2,4-Trimethylpentane	2.50E-04	3.19E-03	1.59E-04	3.19E-04	No
Acenaphthene	1.25E-06	1.59E-05	7.97E-07	1.59E-06	No
Acenaphthylene	5.53E-06	7.05E-05	3.53E-06	7.05E-06	No
Acetaldehyde	8.36E-03	1.07E-01	5.33E-03	1.07E-02	Yes
Acrolein	5.14E-03	6.55E-02	3.28E-03	6.55E-03	Yes
Benzene	4.40E-04	5.61E-03	2.81E-04	5.61E-04	No
Benzo(b)fluoranthene	1.66E-07	2.12E-06	1.06E-07	2.12E-07	No
Benzo(e)pyrene	4.15E-07	5.29E-06	2.65E-07	5.29E-07	No
Benzo(g,h,i)perylene	4.14E-07	5.28E-06	2.64E-07	5.28E-07	No
Biphenyl	2.12E-04	2.70E-03	1.35E-04	2.70E-04	No
Carbon Tetrachloride	3.67E-05	4.68E-04	2.34E-05	4.68E-05	Yes
Chlorobenzene	3.04E-05	3.88E-04	1.94E-05	3.88E-05	Yes
Chloroform	2.85E-05	3.63E-04	1.82E-05	3.63E-05	Yes
Chrysene	6.93E-07	8.84E-06	4.42E-07	8.84E-07	No
Ethylbenzene	3.97E-05	5.06E-04	2.53E-05	5.06E-05	No
Ethylene Dibromide	4.43E-05	5.65E-04	2.82E-05	5.65E-05	Yes
Fluoranthene	1.11E-06	1.42E-05	7.08E-07	1.42E-06	No
Fluorene	5.67E-06	7.23E-05	3.62E-06	7.23E-06	No
Formaldehyde	(See Footnote 2)	0.97	9.28E-03	1.86E-02	Yes
Methanol	2.50E-03	3.19E-02	1.59E-03	3.19E-03	Yes
Methylene Chloride	2.00E-05	2.55E-04	1.28E-05	2.55E-05	Yes
n-Hexane	1.11E-03	1.42E-02	7.08E-04	1.42E-03	No
Naphthalene	7.44E-05	9.49E-04	4.74E-05	9.49E-05	No
PAH	2.69E-05	3.43E-04	1.72E-05	3.43E-05	No
Phenanthrene	1.04E-05	1.33E-04	6.63E-06	1.33E-05	No
Phenol	2.40E-05	3.06E-04	1.53E-05	3.06E-05	Yes
Pyrene	1.36E-06	1.73E-05	8.67E-07	1.73E-06	No
Styrene	2.36E-05	3.01E-04	1.50E-05	3.01E-05	No
Perchloroethylene	2.48E-06	3.16E-05	1.58E-06	3.16E-06	Yes
Toluene	4.08E-04	5.20E-03	2.60E-04	5.20E-04	No
Vinyl Chloride	1.49E-05	1.90E-04	9.50E-06	1.90E-05	Yes
Xylenes	1.84E-04	2.35E-03	1.17E-04	2.35E-04	No
			Max HAP (Formaldehyde):	**0.02**	
			Total HAPs:	**0.04**	

1. HAPs and corresponding emissions factors from AP-42 Table 3.2-2

2. Formaldehyde emission factors from manufacturer specifications:

Uncontrolled:	0.32	(g/bkW-hr)
Controlled:	0.006	(g/bkW-hr)

3. All HAPs that are also VOCs and are not hydrocarbons are being added to the VOC total for the natural gas engines. Hydrocarbon VOCs are accounted for in the original VOC factor for the natural gas engines.

APPENDIX C. BACT ANALYSES SUMMARY TABLES

Table C-1. Natural Gas Turbine - NO_X BACT

Process	Pollutant
Simple Cycle Natural Gas Turbines (RBLC), >50 and <850 MMBtu/hr (KKKKa)	NO_X

Step Number	Description of Step Components		Selective Catalytic Reduction (SCR)	Good Combustion Practices (GCP)	Steam/Water Injection	Dry Low-NO_X Burner (DLNB)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	2-2.5 ppm	Variable	25 ppm	9 ppm
		Proposed limit based on NSPS Subpart KKKKa	15 ppm			
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	SCR systems introduce a liquid reducing agent such as ammonia into the flue gas stream which reacts with flue gas NO_X in the presence of a catalyst and oxygen to reduce NO_X into nitrogen and water vapor.	GCP require design, operation, and maintenance measures be followed to reduce NO_X production.	Water or steam injection into the flame area provides a heat sink that lowers the flame temperature and reduces thermal NO_X formation.	DLNB technology uses advanced burner design, such as staged air or fuel introduction, in order to reduce NO_X formation.
		Feasible or Infeasible?	Technically Feasible; SCR systems are proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.	Technically feasible but has lower reduction efficiency than other technology that is proposed for use; steam/water injection is not proposed for use	Technically feasible but has lower reduction efficiency than other technology that is proposed for use; DLNB is not proposed for use. However, the ST250 units are manufactured with DLNB technology.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A	N/A	N/A
Step 5	Select BACT		Will-Power is proposing SCR and Good Combustion Practices to achieve a NOX emission rate of 2 ppm as BACT for the TM2500 units. Will-Power is proposing SCR, DLNB, and Good Combustion Practices to achieve a NOX emission rate of 2 ppm as BACT for the ST250 units.			

Table C-2. Natural Gas Turbine - VOC BACT

Process	Pollutant
Simple Cycle Natural Gas Turbines (RBLC), >50 and <850 MMBtu/hr (KKKKa)	VOC

Step Number	Description of Step Components		Catalytic Oxidation	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	1-3 ppm	1.4-2 ppm
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Catalytic Oxidation involves flowing the flue gas stream over a catalyst to allow VOCs to complete oxidation and convert to CO_2 and water vapor. Platinum and palladium are used for VOC oxidation. Efficiency is dependent on exhaust flow rate and composition.	GCP requires design, operation, and maintenance measures be followed to reduce VOC production.
		Feasible or Infeasible?	Technically Feasible; Catalytic Oxidation technology is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Catalytic Oxidation and Good Combustion Practices to achieve a VOC emission rate of 3 ppm as BACT.	

Table C-3. Natural Gas Turbine - CO BACT

Process	Pollutant
Simple Cycle Natural Gas Turbines (RBLC), >50 and <850 MMBtu/hr (KKKKa)	CO

Step Number	Description of Step Components		Catalytic Oxidation	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	4-5 ppm	9 ppm
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Catalytic Oxidation involves flowing the flue gas stream over a catalyst to allow CO to complete oxidation and convert to CO_2 and water vapor. Platinum and palladium are used for CO oxidation. Efficiency is dependent on exhaust flow rate and composition.	GCP requires design, operation, and maintenance measures be followed to reduce CO production.
		Feasible or Infeasible?	Technically Feasible; Catalytic Oxidation technology is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Catalytic Oxidation and Good Combustion Practices to achieve a CO emission rate of 4 ppm as BACT.	

Table C-4. Natural Gas Turbine - SO_2 BACT

Process	Pollutant
Simple Cycle Natural Gas Turbines (RBLC), >50 and <850 MMBtu/hr (KKKKa)	SO_2

Step Number	Description of Step Components		Pipeline Quality Natural Gas/Low-Sulfur Fuel	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	0.6-0.77 lb/hr	0.6-0.77 lb/hr
		Proposed limit based on NSPS Subpart KKKKa	0.06 lb SO_2/MMBtu	
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Selection of a lower sulfur content fuel.	GCP requires design, operation, and maintenance measures be followed to reduce SO_X production.
		Feasible or Infeasible?	Technically Feasible; Low Sulfur Fuel is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Low Sulfur Fuel and Good Combustion Practices as BACT. Fuel contains 0.2 gr/100 cubic feet of sulfur.	

Table C-5. Natural Gas Turbine - PM BACT

Process	Pollutant
Simple Cycle Natural Gas Turbines (RBLC), >50 and <850 MMBtu/hr (KKKKa)	$PM_{10}/PM_{2.5}$

Step Number	Description of Step Components		Pipeline Quality Natural Gas/Low-Sulfur Fuel	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	3.65 lb/hr	3.65 lb/hr
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	The use of natural gas that is pipeline quality or low in sulfur concentration.	GCP requires design, operation, and maintenance measures be followed to reduce PM production.
		Feasible or Infeasible?	Technically Feasible; Pipeline Quality Natural Gas is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Pipeline Quality Natural Gas and Good Combustion Practices as BACT.	

Table C-6. Natural Gas Engine - NO_X BACT

Process	Pollutant
Emergency Natural Gas Engines > 500 hp	NO_X

Step Number	Description of Step Components		Selective Catalytic Reduction (SCR)	Selective Non-Catalytic Reduction (SNCR)	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	2.13 lb/hr - 8.82 lb/hr	Not found in RBLC or other databases.	2 g/bhp-hr
		Proposed limit based on NSPS Subpart JJJJ	160 ppm		
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	SCR systems introduce a liquid reducing agent such as ammonia into the flue gas stream which reacts with flue gas NO_X in the presence of a catalyst and oxygen to reduce NO_X into nitrogen and water vapor.	SNCR uses a reagent of either ammonia or a urea solution, which is injected into the gas stream, to reduce NO_X to diatomic nitrogen and water. Depending on the reagent used, the optimum temperature range of the flue gas is between 1,600 and 2,100 °F due to the lack of a catalyst to lower the activation energy of the reactions.	GCP require design, operation, and maintenance measures be followed to reduce NO_X production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible	Technically Infeasible; the engines at the power plant are lean engines not rich engines and therefore this method is infeasible since it requires fuel rich mixtures.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	Most effective of technically feasible technology.	N/A	Second most effective of technically feasible technology.
Step 4	Evaluate Most Effective Controls		Use of SCR is proposed to be economically infeasible given an annualized cost per ton of NO_X removed of $107,871/ton and is not proposed for use. Table C-7 contains the cost analysis.	N/A	N/A
Step 5	Select BACT		Will-Power is proposing use of Good Combustion Practices to achieve a NO_X emission rate of 7.99 lb/hr as BACT.		

Table C-7. Cost Evaluation of SCR on a Natural Gas-Fired Emergency Use Engine - General Information

Parameter	Unit	Value	Notes
Process Information			
Duty	(kW)	2706	Approximate conversion
Duty	(bhp)	3629	Provided by vender
Uncontrolled NO_X Emission Rate	(g/kWh)	1.34	Provided by vender
	(lb/hr)	7.99	Converted using bkw
	(tpy)	0.40	Assumes 100 hours of operation for testing and maintenance
Controlled NO_X Emission Rate	(g/kWh)	0.13	Provided by vender
	(lb/hr)	0.80	Converted using bkw
	(tpy)	0.04	Assumes 100 hours of operation for testing and maintenance.
Economic Factors			
SCR Life Expectancy	(yr)	15	Engineering estimate
Interest Rate	(%)	7.00%	OMB Circular A-4, https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/
Capital Investment			
Total Capital Investment (NPV)	($)	$340,000	Provided by vender
Capital Recovery Factor (CRF)	--	0.1098	U.S. EPA Cost Control Manual Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Equation 2.8a
Capital Recovery Cost (CRC)	($)	$37,330	U.S. EPA Cost Control Manual Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Equation 2.8
Annual Operating Costs			
Catalyst Replacement Cost	($)	$0	Assuming replacement every 16,000 hours, no replacement cost for life expectacy of engine.
Reagent Consumption	(gal/hr)	2.85	Provided by vender
Reagent Cost per Gallon	($/gal)	$1.70	Provided by vender
Reagent Cost per Year	($/yr)	$485	Based on 100 hours per year, conservatively
Maintenance and Administrative Factor	($/yr)	$500	Provided by vender
Inflation Factor	--	1.50	Based on U.S. Bureau of Labor Statistics CPI Inflation Calculator from January of 2010 to December of 2025. https://www.bls.gov/data/inflation_calculator.htm
Total Direct Annual Operating Costs	($)	$1,477	
Total Annual Cost	**($)**	**$38,807**	**Sum of Capital Recovery Cost, Total Direct Operating Costs, Insurance, Tax and Other Annual Costs**
NO_X Cost Per Ton Removed			
NO_X Removed	(tpy)	0.36	
Cost per Ton of NO_X Removed	**($/ton)**	**$107,871**	

Table C-8. Natural Gas Engine - VOC BACT

Process	Pollutant
Emergency Natural Gas Engines > 500 hp	VOC

Step Number	Description of Step Components		Catalytic Oxidation	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	0.5 -1 g/hp-hr	Variable
		Proposed limit based on NSPS Subpart JJJJ	1.0 g/hp-hr or 86 ppmvd at 15% O2	
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Catalytic Oxidation involves flowing the flue gas stream over a catalyst to allow VOCs to complete oxidation and convert to CO_2 and water vapor. Platinum and palladium are used for VOC oxidation. Efficiency is dependent on exhaust flow rate and composition.	GCP require design, operation, and maintenance measures be followed to reduce VOC production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible; Catalytic Oxidation technology is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Catalytic Oxidation and Good Combustion Practices to achieve a controlled VOC emission rate of 0.48 lb/hr (0.06 g/hp-hr) as BACT.	

Table C-9. Natural Gas Engine - CO BACT

Process	Pollutant
Emergency Natural Gas Engines > 500 hp	CO

Step Number	Description of Step Components		Catalytic Oxidation	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	0.3 - 0.8 g/hp-hr	4 g/hp-hr
		Proposed limit based on NSPS Subpart JJJJ	4.0 g/hp-hr or 540 ppmvd at 15% O2	
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Catalytic Oxidation involves flowing the flue gas stream over a catalyst to allow CO to complete oxidation and convert to CO_2 and water vapor. Platinum and palladium are used for CO oxidation. Efficiency is dependent on exhaust flow rate and composition.	GCP requires design, operation, and maintenance measures be followed to reduce CO production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible; Catalytic Oxidation technology is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Catalytic Oxidation and Good Combustion Practices to achieve a controlled CO emission rate of 0.78 lb/hr (0.09 g/hp-hr) as BACT.	

Table C-10. Natural Gas Engine - SO_2 BACT

Process	Pollutant
Emergency Natural Gas Engines > 500 hp	SO_2

Step Number	Description of Step Components		Pipeline Quality Natural Gas/Low-Sulfur Fuel	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	0.0029 lb/hr - 0.0235 lb/hr	
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Fuel selection of a lower sulfur content.	GCP requires design, operation, and maintenance measures be followed to reduce SO_2 production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible; Low Sulfur Fuel is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Low Sulfur Fuel and Good Combustion Practices as BACT. Fuel contains 0.2 gr/100 cubic feet of sulfur.	

Table C-11. Natural Gas Engine - PM BACT

Process	Pollutant
Emergency Natural Gas Engines > 500 hp	$PM_{10}/PM_{2.5}$

Step Number	Description of Step Components		Pipeline Quality Natural Gas/Low-Sulfur Fuel	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	0.13-2.37 lb/hr	4 lb/hr
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	The use of natural gas that is pipeline quality or low in sulfur concentration.	GCP requires design, operation, and maintenance measures be followed to reduce PM production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible; Pipeline Quality Natural Gas is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Pipeline Quality Natural Gas and Good Combustion Practices as BACT.	

Table C-12. Line Heaters - NO_X BACT

Process	Pollutant
Natural Gas Line Heater <100 MMBtu/hr	NO_X

Step Number	Description of Step Components		Ultra-Low NO_X Burner	Flue Gas Recirculation	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	0.011 lb/MMBtu or 9 ppm	0.011 lb/MMBtu or 9 ppm	Varies
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	- Ultra low NO_X burners limit NO_X formation by carefully controlling how fuel and air mix and burn. Through staged combustion, reduced flame temperature, and optimized burner geometry, they slow the chemical pathways that create thermal NO_X	Flue gas recirculation reduces NO_X formation by routing a controlled portion of cooled flue gas back into the combustion air stream. The diluted air–fuel mixture lowers peak flame temperature and slows combustion reactions, which suppresses thermal NO_X.	GCP requires design, operation, and maintenance measures be followed to reduce NO_X production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible; Ultra Low NO_X burners are proposed for use.	Technically Feasible; However, use of the the Ultra Low NO_X burner can acheive similar emission rates without FGR so it is not proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A	N/A
Step 5	Select BACT		Will-Power is proposing Ultra-Low NO_X Burners and Good Combustion Practices to achieve a controlled NO_X emission rate of 0.01 lb/MMBtu as BACT.		

Table C-13. Line Heaters - VOC BACT

Process	Pollutant		
Natural Gas Line Heater <100 MMBtu/hr	VOC		
Step Number	**Description of Step Components**		**Good Combustion Practices (GCP)**
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Variable
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	GCP requires design, operation, and maintenance measures be followed to reduce VOC production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A
Step 4	Evaluate Most Effective Controls		N/A
Step 5	Select BACT		Will-Power is proposing Good Combustion Practices as BACT.

Table C-14. Line Heaters - CO BACT

Process	Pollutant
Natural Gas Line Heater <100 MMBtu/hr	CO

Step Number	Description of Step Components		Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Variable
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	GCP requires design, operation, and maintenance measures be followed to reduce CO production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A
Step 4	Evaluate Most Effective Controls		N/A
Step 5	Select BACT		Will-Power is proposing Good Combustion Practices as BACT.

Table C-15. Line Heaters - SO_2 BACT

Process	Pollutant
Natural Gas Line Heater <100 MMBtu/hr	SO_2

Step Number	Description of Step Components		Pipeline Quality Natural Gas/Low-Sulfur Fuel	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Variable	Variable
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Fuel selection of a lower sulfur content.	GCP requires design, operation, and maintenance measures be followed to reduce SO_2 production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible; Low Sulfur Fuel is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Low Sulfur Fuel and Good Combustion Practices as BACT.	

Table C-16. Line Heaters - PM BACT

Process	Pollutant
Natural Gas Line Heater <100 MMBtu/hr	$PM_{10}/PM_{2.5}$

Step Number	Description of Step Components		Pipeline Quality Natural Gas/Low-Sulfur Fuel	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Variable	
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	The use of natural gas that is pipeline quality.	GCP requires design, operation, and maintenance measures be followed to reduce PM production.
	Feasibility Discussions	Feasible or Infeasible?	Technically Feasible; Pipeline Quality Natural Gas is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing Pipeline Quality Natural Gas and Good Combustion Practices as BACT.	

Table C-17. Fire Pump Engine - NO_X BACT

Process	Pollutant
Diesel Fired Emergency Fire Pump Engine <500 hp	NO_X

Step Number	Description of Step Components		Selective Catalytic Reduction (SCR)	NSPS Subpart IIII Compliance	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Not found in RBLC or other databases for application to a fire pump engine.	Variable; NO_X + NMHC = 3.0 g/hp-hr for engine size range	Variable; only used in conjunction with other control technology.
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	SCR systems introduce a liquid reducing agent such as ammonia or urea into the flue gas stream prior to a catalyst. The catalyst reduces the temperature needed to initiate the reaction between the reducing agent and NO_X to form nitrogen and water.	Certified to comply with Tier Emission Standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engine or stationary fire pump engines, per the maximum engine power and model year.	GCP requires design, operation, and maintenance measures be followed to reduce NO_X production.
	Feasibility Discussions	Feasible or Infeasible?	SCR is technically feasible on diesel engines, however not frequently utilized on fire pump engines of this size.	Technically feasible. Using an EPA Tier certified engine has been demonstrated in practice for emergency engines and is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A	N/A
Step 5	Select BACT		Will-Power is proposing that compliance with 40 CFR 60, Subpart IIII and use of Good Combustion Practices is BACT.		

Table C-18. Fire Pump Engine - VOC BACT

Process	Pollutant
Diesel Fired Emergency Fire Pump Engine <500 hp	VOC

Step Number	Description of Step Components		Diesel Oxidation Catalyst (DOC)	NSPS Subpart IIII Compliance	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Not found in RBLC, TCEQ BACT Guidelines, or other databases; the San Joaquin Valley Unified Air Pollution Control District emergency engine guidance (Guideline 3.1.1) specifically exempts firewater engines.	Variable; NOx + NMHC = 3.0 g/hp-hr for engine size range	Variable; only used in conjunction with other control technology.
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Catalytic oxidation allows oxidation to take place at a faster rate and at a lower temperature than is possible with thermal oxidation. VOC emissions can be controlled via catalytic oxidation. The oxidation is facilitated by the presence of the catalyst and carried out by the same basic chemical reaction as thermal oxidation.	Certified to comply with Tier Emission Standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engine or stationary fire pump engines, per the maximum engine power and model year.	GCP requires design, operation, and maintenance measures be followed to reduce CO production.
	Feasibility Discussions	Feasible or Infeasible?	DOC is technically feasible on diesel engines, however not frequently utilized for on fire pump engines of this size.	Technically Feasible; NSPS IIII compliance is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A	N/A
Step 5	Select BACT		Will-Power is proposing that compliance with 40 CFR 60, Subpart IIII and use of Good Combustion Practices is BACT.		

1. U.S. EPA's Technical Bulletin for Diesel Oxidation Catalyst Installation, Operation, and Maintenance, EPA-420-F-10-030 published in May 2010.

Table C-19. Fire Pump Engine - CO BACT

Process	Pollutant
Diesel Fired Emergency Fire Pump Engine <500 hp	CO

Step Number	Description of Step Components		Diesel Oxidation Catalyst (DOC)	NSPS Subpart IIII Compliance	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Not found in RBLC,TCEQ BACT Guidelines, or other databases; the San Joaquin Valley Unified Air Pollution Control District emergency engine guidance (Guideline 3.1.1) specifically exempts firewater engines.	Variable; CO = 2.6 g/hp-hr for engine size range	Variable; only used in conjunction with other control technology.
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Catalytic oxidation allows oxidation to take place at a faster rate and at a lower temperature than is possible with thermal oxidation. CO emissions can be controlled via catalytic oxidation. The oxidation is facilitated by the presence of the catalyst and carried out by the same basic chemical reaction as thermal oxidation.	Certified to comply with Tier Emission Standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engine or stationary fire pump engines, per the maximum engine power and model year.	GCP requires design, operation, and maintenance measures be followed to reduce CO production.
	Feasibility Discussions	Feasible or Infeasible?	DOC is technically feasible on diesel engines, however not frequently utilized on fire pump engines of this size.	Technically Feasible; NSPS IIII compliance is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A	N/A
Step 5	Select BACT		Will-Power is proposing that compliance with 40 CFR 60, Subpart IIII and use of Good Combustion Practices is BACT.		

Table C-20. Fire Pump Engine - SO_2 BACT

Process	Pollutant
Diesel Fired Emergency Fire Pump Engine <500 hp	SO_2

Step Number	Description of Step Components		Ultra-Low Sulfur Diesel	Good Combustion Practices (GCP)
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Variable	Variable; only used in conjunction with other control technology.
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Ultra-low sulfur diesel (ULSD) contains less than 0.0015% sulfur by weight. The reduced sulfur content reduces the potential for SO_2 emissions.	GCP requires design, operation, and maintenance measures be followed to reduce SO_2 production.
	Feasibility Discussions	Feasible or Infeasible?	Technically feasible; ULSD is proposed for use.	Technically Feasible; Good Combustion Practices are proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A
Step 4	Evaluate Most Effective Controls		N/A	N/A
Step 5	Select BACT		Will-Power is proposing that use of ULSD and Good Combustion Practices is BACT.	

Table C-21. Fire Pump Engine - PM BACT

Process	Pollutant
Diesel Fired Emergency Fire Pump Engine <500 hp	$PM_{10}/PM_{2.5}$

Step Number	Description of Step Components		Diesel Particulate Filter (DPF)	Diesel Oxidation Catalyst (DOC)	Ultra-Low Sulfur Diesel	NSPS Subpart IIII Compliance
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Not found in RBLC, TCEQ BACT Guidelines, or other databases.	0.4 g/hp-hr	Variable	Variable; PM = 0.15 g/hp-hr for engine size range
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	A DPF is placed in the exhaust pathway to prevent the release of VOC. A DPF uses a substrate or filter to trap VOC and remove it from the exhaust stream.	Catalytic oxidation allows oxidation to take place at a faster rate and at a lower temperature than is possible with thermal oxidation. PM emissions can be controlled via catalytic oxidation. The oxidation is facilitated by the presence of the catalyst and carried out by the same basic chemical reaction as thermal oxidation.	Ultra-low sulfur diesel (ULSD) contains less than 0.0015% sulfur by weight. The reduced sulfur content reduces the potential for aggregation of sulfur containing compounds and thus reduces PM emissions.	Certified to comply with Tier Emission Standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engine or stationary fire pump engines, per the maximum engine power and model year.
	Feasibility Discussions	Feasible or Infeasible?	DPF is technically feasible on diesel engines, however not frequently utilized on fire pump engines of this size.	Technically feasible. The use of DOC has been demonstrated in practice for engines but is not commonly used for fire pump engines based on a lack of database results. Additionally, the only instance of catalyst use in the RBLC achieves an emission rate of 0.4 g/hp-hr, which is a higher emission rate that Will-Power has achieved without it.	Technically feasible; ULSD is proposed for use.	Technically Feasible; NSPS IIII compliance is proposed for use.
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A	N/A	N/A	NA
Step 4	Evaluate Most Effective Controls		N/A	N/A	N/A	N/A
Step 5	Select BACT		Will-Power is proposing that use of ULSD, NSPS IIII Compliance, and Good Combustion Practices is BACT.			

Table C-22. Fire Pump Engine Belly Tank - VOC BACT

Process	Pollutant
Diesel Tank	VOCs

Step Number	Description of Step Components		Submerged Filling
Step 1	Identify Air Pollution Control Technologies	RBLC & Other Databases Emission Rate Range	Included in the RBLC database as a form of control for VOC emissions.
Step 2	Eliminate Technically Infeasible Control Options	Description of Technology	Submerged filling requires that when the tank is being filled, the filling nozzle rest below the liquid level to minimize splashing which causes turbulence and prompts the outflow of vapors.
	Feasibility Discussions	Feasible or Infeasible?	Technically feasible; Sumberged Filling is proposed for use
Step 3	Ranking Remaining Control Technologies	Overall Control Efficiency	N/A
Step 4	Economic Considerations		N/A
Step 5	Select BACT		Will-Power is proposing that use of submerged filling is BACT.