Edit: Application Tracking

Air Case ID: 13067 Permit Id: 4775

FIN No.: A2775

Company Name: STELA POWER ASSETS, LLC

HA Basin No: N/A

Increment Tracked ☐

Permit No: AP49115138 * Select a Permit No

Date App. Received: 06/22/2026 *

Permit Writer: Not Assigned (NA) *

Case Type: Class 1 New *

Default ODS Date: 08/21/2026 *

Actual ODS Date:

Date App. to be Closed: 08/21/2027 *

Stop Days: **Actual Date App. to be Closed:** 8/21/2027

App. Incomplete? ☐

Date App. Closed:

Fee Paid ($): 45000 *

Case Description:

Comments:

Flag (For Class 4) : None

Update Cancel

RECEIVED
JUN 22 2026
BAPC/BAQP

May 29, 2026

RECEIVED
JUN 22 2026
ENVIRONMENTAL PROTECTION

Bureau of Air Pollution Control
Nevada Division of Environmental Protection
901 South Stewart Street, Suite 4001
Carson City, NV 89701

RE: Application for Class I Operating Permit for Stella Power Assets, LLC

To Whom It May Concern,

Stella Power Assets, LLC. (Stella) is proposing to construct an electrical generating station (the Facility) near Fernley, Lyon County, Nevada. The Facility will consist of thirty-six (36) natural gas fired turbines but only twenty-nine (29) turbines will run at any one time. The Facility will also have a dew point heater running on natural gas and a diesel fired emergency fire pump.

Stella is submitting this Class I Operating Permit (OP) application package following the procedures stipulated under Nevada Administrative Code (NAC) Chapter 445B. Enclosed with this letter and application is the filing fee of $45,000 for a Class I Operating Permit with 21 – 50 units as required by NAC 445B.327.

If you have any questions or comments about the information presented in this letter or the enclosed OP application, please do not hesitate to call me at (262) 409-5273 or Matthew Tarnoff (Trinity Consultants) at (775) 242-3200.

Sincerely,

Tony Mente
Chief of Engineering & Technology
Stella Power Assets, LLC

Enclosures

cc: Matthew Tarnoff, Trinity Consultants, Inc.

APPLICATION FOR A CLASS I OPERATING PERMIT

Nevada Department of Environmental Protection

Stella Power Assets, LLC

Prepared By:

TRINITY CONSULTANTS
5401 Longley Lane, Suite 5
Reno, NV 89511

May 2026

Trinity Consultants

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

2. FACILITY AND PROJECT DESCRIPTION 2-1
   2.1 Facility Overview 2-1

3. EMISSIONS QUANTIFICATION 3-1
   3.1 Facility-Wide Emissions Information 3-1
   3.2 Emission Calculation Methodology 3-1
      3.2.1 Solar Titan 130-23001S Turbines 3-2
      3.2.2 Dew Point Heater 3-2
      3.2.3 Emergency Fire Pump 3-2

4. REGULATORY APPLICABILITY 4-1
   4.1 Federally Applicable Requirements 4-1
      4.1.1 Prevention of Significant Deterioration (PSD) Applicability 4-1
      4.1.2 New Source Performance Standards 4-1
      4.1.3 National Emission Standards for Hazardous Air Pollutants 4-3
      4.1.4 Compliance Assurance Monitoring 4-4
   4.2 Class I Operating Permit Program 4-4
   4.3 Nevada Administrative Code Air Quality Regulations (NAC 445B) 4-5

5. ENVIRONMENTAL EVALUATION 5-1
   5.1 NAAQS and NVAAQS Thresholds 5-1
      5.1.1 NAAQS and NVAAQS Analyses 5-2
      5.1.2 PSD Class II Increment Analysis 5-3
   5.2 Facility Location 5-3
   5.3 Dispersion Model 5-4
   5.4 Building Wake Effects 5-4
   5.5 Air Pollutants Modeled 5-5
      5.5.1 Significance Impact Analysis 5-5
      5.5.2 Cumulative NAAQS Impacts Analysis 5-5
      5.5.3 PSD Class II Increment Impacts Analysis 5-5
   5.6 Nitrogen Dioxide Chemistry 5-6
   5.7 Meteorological Data 5-6
   5.8 Project Datum 5-6
   5.9 Receptor Grid and Facility Boundary 5-7
   5.10 Terrain Data 5-7
   5.11 Source Characterization 5-7
   5.12 Operating Scenarios 5-8
      5.12.1 Contribution Analysis 5-8
      5.12.2 Annual Criteria Pollutant Emissions Modeling 5-9
      5.12.3 Short-Term Criteria Pollutant Emissions Modeling 5-9
   5.13 Background Concentrations 5-9
   5.14 Ozone Modeling 5-9
   5.15 Secondary PM2.5 Assessment 5-10
   5.16 Modeling Results 5-11
   5.17 Electronic Files 5-19

APPENDIX A. EMISSION CALCULATIONS A

APPENDIX B. EQUIPMENT SPECIFICATION B

APPENDIX C. NDEP FORMS C

APPENDIX D. SITE MAPS D

1. EXECUTIVE SUMMARY

Stella Power Assets, LLC. (Stella) is proposing to construct an electrical generating station (the Facility) near Fernley, Lyon County, Nevada. The proposed Facility will operate under the jurisdiction of the Nevada Division of Environmental Protection (NDEP). Based on the proposed emission levels, the proposed Facility is classified as a Class I source under Nevada Administrative Code (NAC) 445B.036. Therefore, Stella is hereby submitting this Class I Operating Permit (OP) application to NDEP for the proposed Facility.

The Facility will be located located in Lyon County, Hydrographic Area (HA) 076, also referred to as Basin HA076 or Fernley Area, which is designated as attainment/unclassifiable for all criteria pollutants with respect to the National Ambient Air Quality Standards (NAAQS).[1] The Facility will be considered a Class I major source as the nitrogen oxide (NOx), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter of less than 10 microns (PM10), particulate matter with an aerodynamic diameter of less than 2.5 microns (PM2.5) emissions are each greater than the 100 tons per year (tpy) threshold. The Facility will not be considered major for hazardous air pollutants (HAPs) as the single HAP emissions are less than 10 tpy and the combined HAP emissions are less than 25 tpy. The proposed Facility will not be considered a major source under the Prevention of Significant Deterioration (PSD) program as the emissions of any pollutants are less than 250 tpy and the Facility is not a categorical source. The baseline date for HA076 was triggered on October 26, 1982 for sulfur dioxide (SO2) and October 15, 2025 for PM2.5.[2,3] For all other pollutants (PM10 & NO2) the minor source baseline date for the increment has not yet been triggered.

Stella is submitting this Class I OP permit application to request authorization for the installation and operation of 36 new natural gas-fired stationary combustion turbines and associated support equipment.

This report discusses the applicability of air regulatory requirements for the Facility, including:

- PSD
- Minor New Source Review (NSR) permitting
- NAC Requirements
- New Source Performance Standards (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Compliance Assurance Monitoring (CAM)

Per NAC 445B.3361, an owner or operator of a new Class I stationary source should apply for and obtain an OP pursuant to NAC 445B.001 to 445B.390 requirements. This Class I OP permit application includes a detailed analysis of pertinent air quality and regulatory analysis associated with the proposed project and satisfies the requirements stipulated in NAC 445B.295 and 445B.3363. Applicable NDEP permitting forms are included in Appendix A. Additionally, per NAC 445B.327.1.(c) a check in the amount of $45,000 has been included with this application. Stella understands that, per NAC 445B.3395, the Class I OP will go through a 30-day public comment period.

[1] Lyon County attainment status per EPA Greenbook: https://www3.epa.gov/airquality/greenbook/anayo_nv.html. (accessed April 2026)

[2] Nevada PSD Triggered 107(d) Planning Areas, http://ndep.nv.gov/baqp/planmodeling/docs/westar_psd_trigger_areas.pdf

[3] Identified by Dr. Scott Speckart on April 21, 2026 via email.

Per NAC 445B.310, the proposed project requires an environmental evaluation because the proposed emissions of NO2, carbon monoxide (CO), PM10, PM2.5, and volatile organic compounds (VOC) are greater than 25 tons each. With this application, Stella is submitting an air quality dispersion modeling analysis demonstrating compliance with all the applicable NAAQS, Nevada Ambient Air Quality Standards (NVAAQS), and Class II PSD Increments

2. FACILITY AND PROJECT DESCRIPTION

2.1 Facility Overview

The Facility will be located in Lyon County, Nevada, approximately 3 miles north-east of Fernley. Proposed operations will be located in Hydrographic Area 076, also referred to as Basin HA076 or Fernley Area. This area is currently designated as unclassifiable and/or attainment for all criteria pollutants.[4]

The proposed Facility will consist of 36 Solar Titan 130-23001S natural gas turbines providing baseload power, but no more than 29 turbines will operate at any one time. As such, all turbines at the Facility are grouped under SIC Code 4911 "Electric Services" and NAICS code 221112 "fossil fuel powered electrical power generation facilities". The facility will also have a dew point heater running on natural gas and a diesel burning emergency fire pump. Process flow diagrams and Manufacturer's specification sheets are provided in Appendix B and site maps are provided in Appendix D.

Each natural gas turbine is rated for an electrical generating capacity of 11.20 MW for a total generating capacity for 29 turbines in operation at any one time of 324.66 MW. The units are proposed to operate 24 hours a day, 365 days per year (8,760 hours per year) and anticipated to have start up and shutdown (SUSD) events totaling 20.50 hours per year for each turbine.

With respect to SUSD events, this application demonstrates a number of scenarios that Stella should be allowed to utilize for ensuring uptime for the consumers of the power generated at this Facility. First, Stella has demonstrated through modeling that the Facility should be allowed to start up 15 turbines in 1 hour, while 0 turbines are operating (i.e., starting up from no turbines operating). Second, the Facility should be allowed to start up 9 additional turbines while 15 turbines are operating at steady state. Third, the Facility should be allowed to start up 3 additional turbines per hour until the Facility is at full operational capacity. This would mean that the facility can go from no turbines operating to all 29 turbines operating at steady state within 4 hours.

[4] Lyon County attainment status per EPA Greenbook: https://www3.epa.gov/airquality/greenbook/anayo_nv.html. (accessed April 2026)

3. EMISSIONS QUANTIFICATION

This section addresses the methodology used to quantify the emissions from the site and assesses federal NSR program applicability. Complete documentation of these calculations is provided in Appendix A.

3.1 Facility-Wide Emissions Information

NOx, CO , PM10, PM2.5, VOC, CO2, greenhouse gases (GHG), and HAP emissions are associated with the operation of the equipment and processes at the Facility. The following sections contain a detailed description of the methodology used to calculate emissions for the emission units and processes at the Facility. A summary of the Facility wide potential to emit (PTE) is provided in Table 3-1 and detailed calculations are provided in Appendix A.

Table 3-1 Facility-Wide Potential to Emit

Scenario	Annual Emissions (tpy)								
	NO_x	CO	VOC	PM/PM_{10}	$PM_{2.5}$	SO_2	Max Single HAP	HAPs	GHG
Turbines - Max. Annual Emissions (100% Load @ Annual Avg. Temp.)	116.86	71.13	45.65	99.46	99.46	56.40	8.18	11.69	1,941,455.65
Turbines - Total annual startup + shutdown events	1.78	44.59	10.70	0.59	0.59	0.18	0.02	0.03	4,543.36
Dewpoint Heater	4.13	3.47	0.23	0.31	0.31	0.02	0.07	0.08	5,128.90
Emergency Fire Pump	4.46	2.54	0.23	0.15	0.15	0.01	0.00	0.01	507.95
Proposed -Sitewide -Annual Emissions[1]	127.23	121.73	56.82	100.51	100.51	56.60	8.28	11.80	1,951,635.85
NDEP Class I Thresholds[2]	100.00	100.00	100.00	100.00	100.00	100.00	10.00	25.00	--
Emissions > NDEP Class I Thresholds?	Yes	Yes	No	Yes	Yes	No	No	No	No
Prevention of Significant Deterioration (PSD) Thresholds (tpy)[3,4]	250.00	250.00	250.00	250.00	250.00	250.00	--	--	75,000.00
Emissions > PSD Thresholds?	No	No	No	No	No	No	No	No	Yes

1. Proposed emissions encompass all anticipated emissions sources at the Greenfield Facility.

2. The Class I thresholds are defined in NAC 445B.036 [40CFR 52.21] as 100 tpy of any air contaminant and 10 tpy of any individual HAP or 25 tpy of combined HAP.

3. PSD threshold per 40 CFR 52.21(b)(1)(i). The Facility is not on the list of 28 categorical sources and therefore the thresholds are 250 tpy for any NSR pollutant.

4. The 75,000 metric ton threshold for GHG is only triggered when another criteria pollutant exceeds the PSD threshold.

3.2 Emission Calculation Methodology

This section summarizes the calculation methodologies for each of the emission units used to establish the Facility-wide PTE. System information is contained in Section 2 and detailed calculations of all emissions units are available in Appendix A.

3.2.1 Solar Titan 130-23001S Turbines

The proposed Facility will include 36 Solar Titan 130-23001S natural gas fired turbines, each rated for an electrical generating capacity of 11.20 MW for a total generating capacity of 324.66 MW. The units are proposed to operate 24 hours a day, 365 days per year (8,760 hours per year) and anticipated to have SUSD events totaling 20.50 hours per year for each turbine. Each start up event is considered to take 20 minutes, and each shutdown event is considered to take 10 minutes. The SUSD conditions and emission factors are per manufacturer specification included in Appendix B. The proposed Facility will operate a maximum of 29 turbines at any one time, with 7 turbines kept in reserve.

The turbines are each equipped with a selective catalytic reduction (SCR) system for control of NOx and an oxidation catalyst system for control of CO, VOC, and organic HAPs. Operational parameters of the turbines are given per manufacturer specifications included control efficiencies in Appendix B.

NOx, CO, VOC, PM10, and PM2.5 emission factors for steady state and SU/SD operations are per manufacturer guarantee included in Appendix D. The SO2 emission factor for steady state and SU/SD operations is given per AP-42 Chapter 3.1 Table 3.1-1 and Table 3.1-2a for natural gas-fired turbines. The HAP emission factors for steady state and SU/SD operations are given per AP-42 Chapter 3.1 Table 3.1-3 natural gas-fired turbines with a control factor applied for catalytic oxidation.

The GHG emission factor is per 40 CFR Part 98 Subpart C Table C-2 and C-1, and the global warming potentials (GWP) are per 40 CFR Part 98 Subpart A Table A-1.

3.2.2 Dew Point Heater

The proposed Facility will include one natural gas-powered dew point heater, with a fuel consumption rate of 0.01 MMscf/hr. The unit is proposed to operate up to 24 hours a day, 365 days per year (8,760 hours per year). The NOx, CO, VOC, PM10, PM2.5, and HAP emission factors for operations are given per AP-42 Chapter 1.4 Table 1.4-1, Table 1.4-2, Table 1.4-3, and Table 1.4-4 for natural gas combustion.

The GHG emission factor is per 40 CFR Part 98 Subpart C Table C-2 and C-1, and the global warming potentials (GWP) are per 40 CFR Part 98 Subpart A Table A-1.

3.2.3 Emergency Fire Pump

The proposed Facility will include one diesel fired emergency fire pump, rated at 1774 hp. The unit is proposed to operate up to 24 hours a day and 500 hours per year. The NOx, CO, VOC, PM/PM10, PM2.5 emission factors are given per Table 4 of 40 CFR 60 Part IIII. 95% of the NHMC + NOX emission factor is assumed to be NOX, and 5% is assumed to be VOC as defined in Table B-22 (NOx and NMHC Fraction Default Values for All Engines except TRUs) of the 2005 Carl Moyer Program Guidelines. The SOx emission factor is given AP-42 Table 3.4-1 and the HAP emission factors are given per AP-42 Chapter 3.3 Table 3.3-1 and Table 3.3-12 for gasoline and diesel industrial engines.

The GHG emission factor is per 40 CFR Part 98 Subpart C Table C-2 and C-1, and the global warming potentials (GWP) are per 40 CFR Part 98 Subpart A Table A-1.

4. REGULATORY APPLICABILITY

The Project is subject to certain federal and NDEP air quality regulations. This section of the application summarizes the air permitting requirements and key air quality regulations that will apply to the Project. Specifically, applicability of NSR, NSPS, NESHAP, Class I operating permit regulations, and NDEP specific regulations are addressed below.

4.1 Federally Applicable Requirements

4.1.1 Prevention of Significant Deterioration (PSD) Applicability

The proposed Facility will be located in Lyon County, which is designated by the U.S. EPA as "attainment" or "unclassifiable" with respect to the NAAQS for all criteria pollutants.[5] The Facility is potentially subject to PSD permitting requirements should the Facility exceed the emission thresholds. The PSD permitting rules in 40 CFR 52.21 are adopted by referenced in NAC 445B.221 and under these rules, the major source threshold is 250 tpy unless the facility is listed specifically in 40 CFR 52.21(b)(1)(iii) as having a lower 100 tpy threshold. Turbines such as the ones proposed at the Facility do not generate steam as part of the process, therefore, they are not considered "Fossil fuel-fired steam electric plants" per 40 CFR 52.21(b)(1)(iii). As the Facility is not on the list of 28 categories detailed in 40 CFR 52.21(b)(1)(iii) with a lower threshold of 100 tpy, the major source threshold is 250 tpy. The proposed Facility is not a PSD major source as none of the pollutants are in excess of 250 tpy. The GHG emissions are greater than the 75,000 tpy thresholds, however, a facility is not subject to PSD permitting for GHG alone.

4.1.2 New Source Performance Standards

NSPS require new, modified, or reconstructed sources to control emissions to the level achievable by the best demonstrated technology as specified in the applicable provisions. Moreover, any source subject to an NSPS is also subject to the general provisions of NSPS Subpart A, unless specifically excluded.

4.1.2.1 NSPS 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 as applicable. Stella will comply will all applicable requirements of NSPS Subpart A.

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

NSPS Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, applies to owners or operators of steam generating units for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

[5] Lyon County attainment status per EPA Greenbook: https://www3.epa.gov/airquality/greenbook/anayo_nv.html. (accessed May 2026)

40 CFR § 63.11237 defines boilers as "*an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler.*"

The dewpoint heater in this application utilizes an indirect heating method to increase the temperature of the gas to avoid condensation of water. Since there is no boiling of water to recover thermal energy in the form of steam and/or hot water, this unit is not considered a boiler. Therefore, NSPS Dc is not applicable.

4.1.2.3 NSPS Subpart GG – Standards of Performance for Stationary Combustion Turbines

NSPS Subpart GG, Standards of Performance for Stationary Combustion, applies to all stationary gas turbines with a heat input at peak load greater than or equal to 10 MMBtu per hour. The proposed turbines are subject to NSPS Subpart KKKKa and therefore based on 40 CFR 60.4305a(b), they are not subject to NSPS Subpart GG.

4.1.2.4 NSPS Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

NSPS Subpart KKKK, Standards of Performance for Stationary Combustion, applies to any owner or operator of a stationary combustion turbine with a heat input at peak load greater than or equal to 10 MMBtu per hour, on or after February 18, 2005. The proposed Solar Turbines are subject to NSPS Subpart KKKKa and therefore based on 40 CFR 60.4305a(b), they are not subject to NSPS Subpart KKKK.

4.1.2.5 NSPS Subpart KKKKa – Standards of Performance for Stationary Combustion Turbines

NSPS Subpart KKKKa, Standards of Performance for Stationary Combustion Turbines, applies to any owner or operator of a stationary combustion turbine with a heat input at peak load greater than or equal to 10 MMBtu per hour, on or after December 13, 2024. The proposed Solar Turbines are subject to NSPS Subpart KKKKa as they have a maximum heat input greater than 10 MMBtu/hr and will be constructed after December 13, 2024. Stella will follow all requirements for stationary combustion turbines as stipulated under NSPS Subpart KKKKa for the new turbines and will meet as required emission standards with the use of add-on control devices such as catalytic oxidation and SCR. Stella will conduct initial performance testing on the schedule required under 40 CFR 60.8(a) and subsequent performance testing on the schedule required under 40 CFR 60.4333a, with tests once every year. If performance testing results in NOx emissions less than 75% of the NOx emission limit, testing may be reduced to every two years.

Stella will comply with all requirements under NSPS Subpart KKKKa.

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

NSPS Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, applies to owners and operators of any stationary compression ignition (CI) internal combustion engine (ICE) that are modified, reconstructed or constructed after July 11, 2005. The diesel-fired emergency engine is considered a CI ICE with a construction date after July 11, 2005, and is therefore subject to requirements under NSPS Subpart IIII.

In accordance with 40 CFR 60.4205(c) the emergency engine will comply with Table 4 of this subpart for all pollutants. Additionally, Stella will use diesel fuel that meets the requirements set forth in 40 CFR 60.4207 and 40 CFR 1090.305 dictating a maximum sulfur content of 15ppm and will comply with all applicable requirements of 40 CFR 60.4211.

In addition, since the proposed emergency engine is considered an emergency stationary unit, the initial notification is not required per 40 CFR Part 60.4214(b). Stella will keep records of the operation of the engine in emergency and non-emergency service through the use of a non-resettable hour meter. These records will include the time of operation of the engine and the reason the engine was in operation during that time.

4.1.3 National Emission Standards for Hazardous Air Pollutants

NESHAPs have been established in 40 CFR Part 61 and Part 63 to control emissions of HAP from stationary sources. A HAP major source is defined as having potential emissions in excess of 25 tpy for total HAP and/or potential emissions in excess of 10 tpy for any individual HAP. An area source is a stationary source that is not a major source of HAPs. Based on proposed emissions from the Facility, the site will be classified as an area source of HAPs as no single HAP exceeds 10 tpy and the combination of HAP does not exceed 25 tpy.

4.1.3.1 NESHAP Subpart A – General Provisions

All "affected sources" subject to a NESHAP Subpart are also subject to the applicable General Provisions of NESHAP Subpart A unless specifically excluded by a specific NESHAP Subpart. Because the proposed Project will include an affected source subject to a specific NESHAP Subpart, the NESHAP Subpart A General Provisions will apply. Stella will conduct initial performance testing on the schedule required under 40 CFR 60.8(a), with initial performance testing within 60 days after achieving the maximum production rate at the facility, and not later than 180 days after initial startup of the facility.

4.1.3.2 NESHAP Subpart JJJJJJ- National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

NESHAP Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, applies to owners and operators of industrial, commercial, or institutional boilers located at area sources of HAPs. The Facility will be an area source of HAP as seen in Table 3-1 and Appendix A.

The dew point heater is an indirect-fired unit used to increase the temperature of the natural gas stream to avoid condensation of water in the line. The unit does not meet the definition of a boiler per 40 CFR 63.11237 "Boiler" which says,

> *Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler.*

As process heaters are specifically excluded from the definition of a boiler, the dew point heater is not subject to the requirements of NESHAP Subpart JJJJJJ.

4.1.3.3 NESHAP Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

NESHAP Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, applies to any new or existing stationary combustion turbine operated at a major source of HAP emissions. The natural gas-fired turbines are considered Stationary Combustion Turbines but the facility is not considered a major source for HAPs as seen in Table 3-1 and Appendix A.

Therefore, as the site is classified as an area source the facility is not subject to NESHAP Subpart YYYY.

4.1.3.4 NESHAP Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

NESHAP Subpart ZZZZ applies to any new or existing stationary reciprocating internal combustion engine (RICE) operated at a major or area source. The replacement diesel-fired engine proposed as part of the Project is a new stationary RICE. Per 40 CFR 63.6590(c)(1), a new or reconstructed stationary RICE located at an area source of HAPs does not have any further requirements under NESHAP Subpart ZZZZ if the RICE meets the requirements of NSPS Subpart IIII. As described under Section 4.2.1.2 of this report, Stella will comply with all requirements stipulated under NSPS Subpart IIII. As such, Stella will comply with NESHAP Subpart ZZZZ by meeting the requirements of NSPS Subpart IIII.

4.1.4 Compliance Assurance Monitoring

Compliance Assurance Monitoring (CAM) plans are required for major sources required to obtain Title V (Part 70 or 71) permits. The CAM rule was signed on October 3, 1997, and came into effect on November 21, 1997. The U.S. EPA developed the CAM rule to focus on monitoring of certain operating parameters to ensure compliance with emission limitations in-between scheduled source tests. CAM requirements apply to stationary sources that: (l) are equipped with post-process pollutant control devices; (2) have pre-control device emissions equal to or greater than 100% of the major source threshold for a pollutant; and (3) are subject to the Title V permit program.

As the natural gas turbines are equipped with post-process pollutant control devices used to demonstrate compliance with standards promulgated post 11/15/1990, on an individual basis each EU does not have pre-control device emissions greater than the major source thresholds, nor do they have post control emissions greater than the major source threshold as can be seen in Table A-17 Appendix A. The site will be classified as subject to the Title V permit program. Therefore, as 40 CFR 64.2(a)(3) is not met, CAM plans do not apply to the proposed Facility.

4.2 Class I Operating Permit Program

40 CFR 70 establishes the major source operating permit program. The major source thresholds with respect to the NDEP operating permit program for sources in attainment areas are 10 tons per year of a single HAP, 25 tpy of any combination of HAP, or 100 tpy of a criteria pollutant.

The proposed Facility is expected to have potential emissions of NOx, CO, PM10, PM2.5, and VOC exceeding the 100 tpy major source threshold. The proposed Facility is expected to be an area source of HAP emissions as emissions do not exceed the 10 tpy for a single HAP and 25 tpy combined HAPS major source thresholds. As a result, the facility will be considered a major source per NAC 445B.094. Stella is applying for a Class I OP as part of this submittal.

4.3 Nevada Administrative Code Air Quality Regulations (NAC 445B)

In addition to the federal air requirements described previously, NDEP establishes requirements applicable at the emission unit level and at the facility level. The regulations also contain requirements related to the need for construction and/or operating permits. The requirements potentially applicable to the Facility are detailed in the following sections.

NAC 445B.295 and NAC 445B.3363 outline requirements for content on applications for an operating permit/permit to construct. The regulatory text from NAC 445B.295 and NAC 445B.3363 is included in ***italic, bold*** text. This section also includes Stella's action to meet each requirement in plain text.

NAC 445B.295

1. Information to identify the applicant, including the name and address of the company or the name and address of the plant if different from that of the company, the name of the owner of the company and the owner's agent, and the name and telephone number of the manager of the plant or another appropriate person to contact;

Please refer to the Class I Operating Permit to Construct form in Appendix C for identifying information.

2. A description of the stationary source's processes and products by Standard Industrial Classification Code, including any processes and products associated with an alternative operating scenario identified by the owner or operator;

Please refer to Section 2 of the application for this information.

3. A description of the fuels, fuel use and raw materials to be used and the rates of production and operating schedules for each emission unit which is a part of the stationary source;

Please refer to Sections 2 and 3 of the application for this information.

4. An identification and a description of any equipment for the control of air pollution and any devices or activities for monitoring compliance with emission limitations;

As noted in Section 3, the turbines use SCR and oxidation catalyst for emission control. Stella is not proposing the use of CEMS for monitoring emissions and will comply with NDEP guidance and federal requirements for monitoring compliance.

5. Limitations on the operation of the stationary source or any standards for work practices which affect emissions for all regulated air pollutants at the stationary source;

Please refer to Section 2 and 3 of the application for this information.

6. An explanation of any proposed exemption from any applicable requirement;

There are no proposed exemptions from any applicable requirements.

7. The location of any records that the applicant must keep pursuant to the requirements of the operating permit, if the records are kept at a location other than the emitting facility; and

All compliance related records will be retained on-site.

8. Other specific information that the Director determines is necessary to carry out, enforce and determine the applicability of all legal requirements.

Stella will provide, as requested, any additional information requested by the NDEP to meet this requirement. Note that none of the proposed emission sources have associated control devices that would meet the Compliance Assurance Monitoring applicability criteria in 40 CFR Part 64.

NAC 445B.3363

1. Except as otherwise provided in NAC 445B.33637, in addition to the information required pursuant to NAC 445B.295, an application for a Class I operating permit to construct or for a revision of a Class I operating permit to construct must include:

(a) Descriptions of all emissions of any regulated pollutants for which the source is defined as a major source.

(b) A description of all emissions of regulated air pollutants from all emission units.

(c) An identification and a description of all points of emissions and all activities which may generate emissions of the regulated air pollutants described pursuant to paragraph (a) in sufficient detail to establish the basis for the applicability of standards and fees.

(d) The emission rates of all regulated air pollutants that are subject to an emissions limitation pursuant to an applicable requirement. The emission rates must be described in tons per year and in such terms as are necessary to establish compliance using the applicable standard reference test method.

(e) Any other information required by any applicable requirement.

(f) The calculations on which the information described in this subsection are based.

(g) Citations to and a description of all applicable requirements.

(h) A reference to any applicable test method used for determining compliance with each applicable requirement.

Please refer to Section 3, Section 5, Appendix A, and Appendix C for identifying information.

2. Except as otherwise provided in NAC 445B.33637, in addition to the information required pursuant to subsection 1, an application for a Class I operating permit to construct must contain:

(a) For a proposed new major stationary source, a proposed major modification to an existing stationary source or a major modification at an existing major stationary source:

(1) All information required pursuant to 40 C.F.R. § 52.21;

(2) A description of all emissions of each regulated pollutant:

(I) For which the source is a major stationary source; or

(II) That will, because of the major modification, result in a significant emissions increase or a significant net emissions increase in accordance with 40 C.F.R. § 52.21(a)(2);

(3) A description of all emissions of each regulated pollutant associated with the major modification;

(4) A description of each hydrographic area that may be triggered for increment consumption; and

(5) Any other information that the Director determines is necessary to process the application.

The Facility is not a new major stationary source as defined in NAC 445B.0945. As noted in Section 3, the facility-wide PTE is below the major stationary source thresholds defined in 40 CFR § 52.21(b)(1) and is not a Prevention of Significant Deterioration major source.

(b) For a proposed new major source or a proposed modification which is not a major modification:

(1) All information required by NAC 445B.308 to 445B.311, inclusive;

Please refer to the environmental evaluation provided in Section 6 that addresses and provides all information required by NAC 445B.308 to 445B.311.

(2) Any other information that the Director determines is necessary to process the application; and

In addition to the information provided as part of this application, Stella will readily provide NDEP with any additional information requested by NDEP.

(3) For stationary sources subject to the provisions regarding new source review set forth in 42 U.S.C. §§ 7501 to 7515, inclusive, all information required by 42 U.S.C. § 7503.

The Facility is located in an attainment area currently designated as unclassifiable and/or attainment for all regulated air pollutants.[6] Therefore the nonattainment previsions set forth in 42 U.S.C. §§ 7501 to 7515 do not apply.

(c) For a source, or proposed source, subject to the requirements of 40 C.F.R. §§ 63.40 to 63.44, inclusive:

(1) All information required by 40 C.F.R. § 63.43(e); and

(2) Any other information that the Director determines is necessary to process the application.

The Facility is not subject to the requirements of 40 CFR §§ 63.40 to 63.44 since all emission units are regulated under specific NESHAPs discussed in Section 4.

(d) For a source, or proposed source, subject to the requirements of 40 C.F.R. §§ 63.50 to 63.56, inclusive:

(1) All information required by 40 C.F.R. § 63.53; and

(2) Any other information that the Director determines is necessary to process the application.

The Facility is not subject to the requirements of 40 CFR §§ 63.50 to 63.56 since the emission sources are subject to applicable emission standards as noted in Section 5.2 and 5.3 and therefore does not meet the definition of an affected source per §63.51.

3. Except as otherwise provided in NAC 445B.33637, in addition to the information required pursuant to subsections 1 and 2, an application for a Class I operating permit to construct for a modification at an existing major stationary source that is not a major modification must contain:

(a) All applicable information required to determine whether the project or modification will result in a significant emissions increase or a significant net emissions increase in accordance with 40 C.F.R. § 52.21(a)(2);

(b) A description of the project or modification, including all emission units;

(c) A description of the applicable procedures used to determine that the project or modification is not a major modification pursuant to the provisions of 40 C.F.R. § 52.21(a)(2);

(d) All calculations associated with the procedures required to make the determinations pursuant to 40 C.F.R. § 52.21(a)(2), including detailed information for expected and highest projections of any business activities in accordance with 40 C.F.R. § 52.21(b)(41)(ii)(a);

(e) Calculations of emissions in accordance with 40 C.F.R. § 52.21(b)(41)(ii)(b); and

(f) Detailed information used to demonstrate that emissions increases associated with any increased utilization that an emission unit could have accommodated during the baseline emission period is unrelated to the proposed project or modification, including any increased utilization due to product demand growth, in accordance with 40 C.F.R. § 52.21(b)(41)(ii)(c). In lieu of paragraphs (d), (e) and (f), the application must contain information on the potential of the unit to emit in accordance with 40 C.F.R. § 52.21(b)(41)(ii)(d).

[6] EPA Green Book, accessed November 2025. http://www.epa.gov/airquality/greenbook/phistory_nv.html

The Facility is not a major stationary source as defined in NAC 445B.0945. As noted in Section 3, the facility-wide PTE is below the major stationary source thresholds defined in 40 CFR § 52.21(b)(1). Stella is submitting this Class I OP application for a greenfield electric generating station. Therefore, these requirements do not apply.

4. Except for a source, or proposed source, subject to the requirements of 40 C.F.R. §§ 63.40 to 63.44, inclusive, or 40 C.F.R. §§ 63.50 to 63.56, inclusive, in addition to the information required pursuant to subsections 1, 2 and 3, an application for an operating permit to construct must include an environmental evaluation pursuant to NAC 445B.308, 445B.310 and 445B.311.
An environmental evaluation, pursuant to NAC 445B.308, 445B.310 and 445B.311, has been provided in Section 6.

5. As used in this section, "project" has the meaning established in 40 C.F.R. § 52.21, as adopted by reference in NAC 445B.221.
The proposed project being referenced in this application has been defined as consistent with the meaning established in 40 C.F.R. § 52.21.

5. ENVIRONMENTAL EVALUATION

NAC 445B.310.1(a) requires that an environmental evaluation be provided if a stationary source has the potential to emit greater than 25 tpy of any regulated air pollutant. Regulated air pollutants include PM, PM10, PM2.5, SO2, NO2, CO, ozone (O3), VOCs, lead (Pb), and hydrogen sulfide (H2S). Per NAC 445B.311, when the applicant is required to provide an environmental evaluation under NAC 445B.310, all regulated air pollutants must be modeled. In addition, the applicant must model all sources of emissions, including those emissions from insignificant activities.

Emission calculations for the proposed Facility shown in Section 3 exceed a potential emission rate of 25 tpy for PM10, PM2.5, NO2, SO2, and CO. Therefore, as required by NAC 445B.311, Stella has provided an environmental evaluation for all regulated air pollutants emitted from the Facility. Facility wide potential emissions are below the PSD threshold of 250 tons/yr for all criteria pollutants; therefore, PSD modeling requirements do not apply to this project other than NDEP's guidance to perform Class II PSD Increment modeling for triggered pollutants in the hydrographic basin. While it is not required to submit Class II PSD Increment modeling, NDEP will perform the modeling as part of the permit application review process and therefore Stella has provided the modeling method and results in this application.

This air quality dispersion modeling analysis is being provided to demonstrate compliance of the proposed emissions with the applicable NAAQS, NVAAQS, and PSD Class II Increment Standards.

This modeling analysis has been performed using current EPA and NDEP Air Quality Modeling regulatory guidelines.[7,8] This section describes the methodology followed in conducting the air dispersion analyses.

5.1 NAAQS and NVAAQS Thresholds

Regulated air pollutants associated with the Facility are PM10, PM2.5, SO2, NO2, VOC, and CO. This modeling analysis evaluates whether revised emissions from the Facility will demonstrate compliance with applicable ambient air quality standards. Table 5-1 presents a summary of the NAAQS and NVAAQS pollutant concentrations which must be met for various averaging times.

[7] Code of Federal Regulations, Title 40-Protection of the Environment, Part 51, Appendix W.

[8] Nevada Bureau of Pollution Control General Air Dispersion Modeling Guidelines, September, 2008.

Table 5-1. Applicable NVAAQS and NAAQS

	Averaging Period	Nevada Ambient Air Quality Standard (µg/m³)	Form of Standard	NAAQS Standard (µg/m³)	Form of Standard
$PM_{2.5}$	Annual	12/9[9]	Averaged over modeled years	9	Averaged over modeled years
	24-hour	35	8th high, 98th percentile	35	98th Percentile, averaged over modeled years
PM_{10}	24-hour	150	1st high	150	Not to be exceeded more than once per year on average over modeled years
NO_2	Annual	100	1st high	100	Annual Mean
	1-hour	188 (100 ppb)	8th high, 98th percentile	188	98th percentile of daily maximum 1-hour concentrations, averaged over modeled years
SO_2	Annual	80	1st high	80	N/A
	24-hour	365	1st high	365	N/A
	3-hour	1,300	1st high	N/A	Not to be exceeded more than once per year
	1-hour	196 (75 ppb)	99th percentile of daily maximum 1-hour concentrations, averaged over modeled years	196	99th percentile of daily maximum 1-hour concentrations, averaged over modeled years
CO	8-hour	10,500[1]	1st high	10,000 (9 ppm)	Not to be exceeded more than once per year
	1-hour	40,500	1st high	40,000 (35 ppm)	Not to be exceeded more than once per year

Notes:

µg/m³ = micrograms per cubic meter

PM_{10} = Particulate matter with diameter less than or equal to 10 microns

$PM_{2.5}$ = Particulate matter with diameter less than or equal to 2.5 microns

NO_2 = Nitrogen dioxide

SO_2 = Sulfur dioxide

CO = Carbon monoxide

[1] 7,000 µg/m³ at areas equal to or greater than 5,000 feet above Mean Sea Level

5.1.1 NAAQS and NVAAQS Analyses

As part of the NAAQS and NVAAQS analyses, the modeled concentration of all Facility sources (as described in Section 5.5) plus the background concentrations and/or neighboring source impacts have been considered (as described in Section 5.5) for comparison with the NAAQS and NVAAQS. The form of the probabilistic standard is identified in Table 5-1. The modeled impacts for each pollutant when compared to the NAAQS have been reported according to the standard as identified in Table 5-1.

[9] The $PM_{2.5}$ standard reflects the revised NAAQS limit promulgated by EPA and effective May 6, 2024.

5.1.2 PSD Class II Increment Analysis

A PSD Increment is the maximum increase in ambient concentrations allowed to occur above a baseline concentration for a pollutant. The proposed Facility is located approximately 3 miles northeast of Fernley in Lyon County, Nevada. The Facility is in an area that is either in attainment or unclassifiable for all regulated air pollutants. However, the SO2 PSD Class II increment was triggered in 1995 and the PM2.5 PSD Class II increment was triggered on October 15, 2025. Per information from Dr. Scott Speckart, the only projects submitted post trigger are the Nevada Cement Company PSD application that in and of itself triggered the PM2.5 increment and this Project. Stella has evaluated the PSD Class II increment for SO2 and PM2.5 against the PSD Increment thresholds identified in Table 5-2.

Table 5-2. PSD Class II Increment Thresholds

Pollutant	Maximum allowable increase (micrograms per cubic meter)
Class I Area	
$PM_{2.5}$:	
Annual arithmetic mean	1
24-hr maximum	2
PM_{10}:	
Annual arithmetic mean	4
24-hr maximum	8
Sulfur dioxide:	
Annual arithmetic mean	2
24-hr maximum	5
3-hr maximum	25
Nitrogen dioxide:	
Annual arithmetic mean	2.5
Class II Area	
$PM_{2.5}$:	
Annual arithmetic mean	4
24-hr maximum	9
PM_{10}:	
Annual arithmetic mean	17
24-hr maximum	30
Sulfur dioxide:	
Annual arithmetic mean	20
24-hr maximum	91
3-hr maximum	512
Nitrogen dioxide:	
Annual arithmetic mean	25
Class III Area	
$PM_{2.5}$:	
Annual arithmetic mean	8
24-hr maximum	18
PM_{10}:	
Annual arithmetic mean	34
24-hr maximum	60
Sulfur dioxide:	
Annual arithmetic mean	40
24-hr maximum	182
3-hr maximum	700
Nitrogen dioxide:	
Annual arithmetic mean	50

5.2 Facility Location

The Facility is located in Lyon County, Nevada. The North American Datum of 1983 (NAD83) Zone 11 Universal Trans Mercator (UTM) coordinates for the Facility are as follows:

- 313,190.52m Easting;

- 4,390,040.94m Northing;

5.3 Dispersion Model

Dispersion modeling is completed using the American Meteorological Society/ EPA Regulatory Model Improvement Committee Dispersion Model named "AERMOD." AERMOD is the EPA regulatory model approved for use with industrial sources. AERMOD version 24142 is used for the current modeling analysis. The AERMOD modeling is completed using the regulatory default options including stack-tip downwash, buoyancy-induced dispersion, calms processing routines, upper-bound downwash concentrations for super-squat buildings, default wind speed profile exponents, vertical potential temperature gradients, and no use of gradual plume rise. This facility is classified as a rural area, so no consideration of population is required.

A summary of the air pollutant modeling evaluations completed in support of the permit application is given in Table 5-3.

Table 5-3 Modeling Evaluations Proposed for the Facility

Pollutant Modeled	Averaging Periods Evaluated	Modeling Method
$PM_{2.5}$	Annual	AERMOD
	24-hour	AERMOD
PM_{10}	24-hour	AERMOD
NO_2	Annual	AERMOD
	1-hour	AERMOD
SO_2	Annual	AERMOD
	24-hour	AERMOD
	3-hour	AERMOD
	1-hour	AERMOD
CO	8-hour	AERMOD
	1-hour	AERMOD
Ozone	8-hour	Scheffe Spreadsheet

5.4 Building Wake Effects

The modeling analysis includes evaluation of building dimensions at the Facility to assess potential downwash effects on stack emissions from nearby structures. Building specifications are included as part of Appendix A. Building locations and dimensions are determined based on the site layout. Building elevations are determined using AERMAP software (Version 24142). U.S. Geological Survey (USGS) National Elevation Data (NED) digital elevation data (30 meter) is used in AERMET to assign terrain elevations to the receptors. Model receptors are developed in the Universal Transverse Mercator (UTM), North American Datum (NAD83) coordinate system. Direction-specific downwash parameters are calculated using the building information and EPA's Building Profile Input Program PRIME (BPIPPRM) software. This software produces building dimension data that is used with the PRIME building downwash algorithms incorporated into AERMOD.

5.5 Air Pollutants Modeled

5.5.1 Significance Impact Analysis

Stella does not have any existing sources in the Facility area; thus, the significance modeling emission inventory is equivalent to the modeling emission inventory for the ambient impact analysis. The receptors in exceedance of the significant impact analysis for all pollutants and averaging periods were identified prior to performing a cumulative impact analysis inclusive of neighboring sources. However, for conservation, all receptors from the significant impact analysis were included in the cumulative impact analysis.

5.5.2 Cumulative NAAQS Impacts Analysis

The ambient impacts modeling included ambient air concentrations of criteria air pollutants [PM_{10}, $PM_{2.5}$, NO_x, SO_2, and CO] emitted from the Facility's sources, neighboring sources and insignificant activities as listed in NAC 445B.288. For comparison against the NAAQS and NVAAQS, the emissions of the regulated air pollutants were modeled to determine ambient air concentrations for the following regulatory averaging periods for the NAAQS and NVAAQS, consistent with 40 CFR Part 50:

- 24-hour for PM_{10};
- 24-hour and annual for $PM_{2.5}$;
- 1-hour and annual for NO_2;
- 1-hour, 3-hour, 24-hr, and annual for SO_2; and
- 1-hour and 8-hour for CO.

Per NDEP guidance on 11/6/2025, the Facility is considered adjacent to one other emission source (Nevada Cement). As such, this one off-site emission source was modeled together with the Facility, and the regional background concentrations in Table 5-4 are added to the results in order to compare against the applicable thresholds. To be conservative, all receptors for each pollutant and averaging period were modeled in the cumulative impact analysis.

All models other than annual SO2 receptors exceeded the respective SILs for at least one receptor. Therefore, a cumulative impact analysis was performed to demonstrate compliance with the 24-hr and annual PM2.5, and 24-hr PM10 1-hr and annual NO2, 1-hr, 3-hr, 24-hr SO2, and 1-hr and 3-hr CO NAAQS/NVAAQS for all receptors. As the black start turbines exceeded the SIL for 24-hr PM2.5 only, these emissions were conservatively used in the Scenario 1 and Scenario 2 SIL exceeding receptor analysis for the cumulative impact analysis.

For all pollutants and averaging periods, there were no exceedances of the cumulative modeling analyses for NAAQS/NVAAQS, as provided in Section 5.16.

5.5.3 PSD Class II Increment Impacts Analysis

The PSD Class II increment impacts analysis modeling included ambient air concentrations of triggered criteria air pollutants [$PM_{2.5}$ and SO_2] emitted from the Facility's sources and insignificant activities. For comparison against the PSD Class II increments, the emissions of the regulated air pollutants were modeled to determine ambient air concentrations for the following regulatory averaging periods for the PSD Class II increments with no fenceline receptors and an NDEP provided increment receptor grid, consistent with 40 CFR Part 50:

- 24-hour and annual for PM2.5; and
- 1-hour, 3-hour, 24-hr, and annual for SO2;

All models other than annual SO2 receptors exceeded the respective SILs for at least one receptor. Therefore, a cumulative PSD Class II Increment impact analysis was performed to demonstrate compliance with the 24-hr and annual PM2.5 and 1-hr and 3-hr SO2, for all receptors provided by NDEP.

Per guidance from Dr. Speckart on 4/22/206, the increment consumption could be conservatively modeled utilizing the model files provided by Dr. Speckart for Nevada Cement and the Facility's sources and insignificant activities.

For all pollutants and averaging periods, there were no exceedances of the cumulative modeling analyses for Class II PSD Increment, as provided in Section 5.16.

5.6 Nitrogen Dioxide Chemistry

Several options are available in AERMOD for calculating the conversion of NO_X emissions into NO_2. EPA has identified a tiered approach for addressing NO_2 conversion, with each tier requiring a more technical approach and typically resulting in a less conservative result. The three tiers identified by EPA are summarized below:

Tier 1: All of the NOx emissions released from the source are assumed to convert to NO2. This is the most conservative option and likely will result in an overestimate of NO2 concentrations in the ambient air.

Tier 2: Modeled NOx concentrations are converted to NO2 by multiplying by empirically derived scaling factors of 0.75 for annual averages. This method is referred to as the Ambient Ratio Method (ARM). A new Tier 2 option has been developed and is referred to as the ARM2 method. The ARM2 method is an additional Tier 2 method that can be used where a ratio is applied in the AERMOD program, as opposed to the post-processing requirement for ARM.

Tier 3: NO2 concentrations are calculated from NOx within AERMOD using screening algorithms that estimate the amount of NO2 conversion based on ambient ozone concentrations and other environmental factors. Two options are available in AERMOD, the Ozone Limiting Method (OLM) and the Plume Volume Molar Ratio Method (PVMRM). Both Tier 3 methods are generally acceptable for use in a regulatory context.

Modeled concentrations of NOx from Stella are converted to NO2 using the ARM2 method, which is contained within the AERMOD model.

5.7 Meteorological Data

Meteorological data was provided by NDEP for the Facility for the time period of 12/1/2000 through 11/30/2001. NDEP provided the meteorological data sets to Trinity with and without adjusted friction velocity (ADJ_U*). Stella utilized the non-ADJ_U* meteorological files for both the NAAQS/NVAAQS and Class II PSD Increment Analyses.

5.8 Project Datum

The Project datum was set in WGS84, Zone 11 UTM coordinates. All emission sources, buildings, receptors, fenceline, and elevation references are in WGS84, Zone 11 UTM coordinates.

5.9 Receptor Grid and Facility Boundary

NAAQS/NVAAQS modeling is completed using a receptor grid consistent with EPA Guidelines. Following EPA guidelines, receptor locations have been identified with enough density and spatial coverage to isolate the area with the highest impacts. Receptors consist of fenceline receptors located around the perimeter of the facility, and a dense Cartesian receptor grid beginning at the fenceline and extending outward.

For the purposes of establishing a dispersion model Facility boundary, consideration of adequate barriers to public access included the installation of fencing, posting signage, use of security cameras, construction of safety berms, and inclusion of natural terrain features that restrict public access.

The following tiered Cartesian receptor array was used for the analysis:

- "Boundary" receptors spaced at approximately 25-meter intervals along the boundary of the Facility.
- Cartesian grid receptors, spaced at 50-meter intervals, out to a distance of at least 1,000 meters from the boundary of the Facility;
- Cartesian grid receptors, spaced at 250-meter intervals, out to a distance of at least 5,000 meters from the boundary of the Facility;
- Cartesian grid receptors, spaced at 1000-meter intervals, out to a distance of at least 25,000 meters from the boundary of the Facility; and
- Receptors will not be generated within the Facility boundary.

Class II PSD Increment modeling utilized the receptor grid provided by NDEP that contains receptors for Hydrographic Basin 76. Per guidance from Dr. Speckart contained in an email on 5/1/2026, the Facility fence line does not need to be included in the Class II PSD Increment models.

5.10 Terrain Data

Elevations for all modeled receptors were electronically generated through the AERMOD terrain processor, AERMAP (Version 24142), and the applicable United States Geological Survey (USGS) 1/3 arc second resolution National Elevation Dataset (NED). AERMAP determines the elevation of each receptor by interpolation.

In addition to terrain elevation, an additional parameter called the hill height scale is required for each receptor to execute AERMOD's terrain modeling algorithms. The 1/3 arc second NED extending 50 km from Facility sources was used for calculating the hill height scales. Because the receptor domain only extends 25 km from the boundary, a 50 km NED extent is more than necessary to capture the 10% slope from every receptor in the modeling domain. AERMOD computes the impact at a receptor as a weighted interpolation between horizontal and terrain-following states using a critical dividing streamline approach. This scheme assumes that part of the plume mass will have enough energy to ascend and traverse over a terrain feature and the remainder will impinge and traverse around a terrain feature under certain meteorological conditions. The hill height scale is computed by the AERMAP terrain preprocessor for each receptor as a measure of the one terrain feature in the modeling domain that would have the greatest effect on plume behavior at that receptor.

5.11 Source Characterization

The sources at the Facility include natural gas turbines, a dewpoint heater, and an emergency fire pump. Emissions from all sources are modeled as individual point sources. Stack parameters for the point sources

were based on design parameters and provided by the manufacturer. The emission rates for all sources are provided in Appendix A.

5.12 Operating Scenarios

A modeling simulation was used to assess all facility impacts. The modeling analysis considered the maximum potential air dispersion impacts from the significant sources at the proposed Facility. Emissions from the proposed Facility will result from operations associated with an electrical generating station. Process equipment was modeled at maximum design capacity, taking into account potential SUSD emissions and their respective operating event periods.

While the proposed Project includes installing 36 turbines, only 29 turbines will run at any one time, with 7 in reserve. The short term modeling was performed to demonstrate compliance under the worst-case modeling conditions as identified in Scenario 1, Scenario 2, and Scenario 3 utilizing the contribution analysis in Section 5.12.1

- Alternate Operating Scenario (Scenario 1 - Initial Plant Start) – The 15 highest contributing turbines were modeled in SUSD while the remaining turbines are off.

- Alternate Operating Scenario (Scenario 2 - Continuing Plant start) – The 15 turbines from Scenario 1 were modeled in steady state while the next 9 most contributing turbines were modeled in SUSD and the remaining turbines are off.

- Standard Operating Scenario (Scenario 3 - Standard Plant Operation with optional SUSD) – The 3 most contributing turbines were modeled in SUSD while 26 turbines were modeled in steady state, and the 7 permanent reserve turbines are off. This scenario covers all steady state operations as well as any 3 turbines in SUSD while 26 other turbines are running.

5.12.1 Contribution Analysis

For NAAQS/NVAAQS models, a contribution analysis was performed to identify the 7 turbines with the lowest contribution to the highest impacted receptor and the 3, 15, and 24 turbines with the highest contribution to the highest impacted receptor. The analysis was performed for 1-hr NO2 utilizing SUSD emission rates and parameters for all turbines. The 7 identified lowest contributing turbines are considered the turbines in reserve and the emission rates were set to zero for the remainder of the modeling analysis. The 3, 15, or 24 most contributing turbines were selected to operate in SUSD mode for all short-term criteria pollutant models (for Scenarios 3, 1, and 2 respectively). The SUSD turbines operate at higher emission rates than the steady state turbines and were found to have higher contributions to the highest impacted receptors. For annual models, all 29 turbines were modeled for steady state operation, while the 7 reserve turbines were modeled with no emissions. Note that Scenario 1 and Scenario 2 only apply to short term, non-annual models.

For Class II PSD Increment models, a contribution analysis was performed to identify the 7 turbines with the lowest contribution to the highest impacted receptor and the 3, 15, and 24 turbines with the highest contribution to the highest impacted receptor. The analysis was performed for 24-hr PM2.5 utilizing SUSD emission rates and parameters for all turbines. The 7 identified lowest contributing turbines are considered the turbines in reserve for which the emission rates were set to zero for the remainder of the modeling analysis. The 3, 15, or 24 most contributing turbines were selected to operate in SUSD mode for all short-term criteria pollutant models (for Scenarios 3, 1, and 2 respectively). The SUSD turbines operate at higher

emission rates than the steady-state turbines, and were found to have higher contributions to the highest impacted receptors. Note that Scenario 1 and Scenario 2 only apply to short term, non-annual models.

5.12.2 Annual Criteria Pollutant Emissions Modeling

Annual emissions modeling is based on both steady-state emissions and SUSD events. Steady-state emission rates represent expected emissions under normal, continuous, operating conditions over the course of a year. As discussed in Section 2.1, Stella is proposing to limit SUSD events for each unit to 41 per year, resulting in a total of 20.50 hours of non-steady-state operation per unit annually. While steady-state emissions represent the majority of operating time and have a greater impact over an annual averaging period, the annual modeling uses steady-state plus SU/SD annual emission rates to be conservative.

5.12.3 Short-Term Criteria Pollutant Emissions Modeling

Short-term impacts (1-hour, 3-hour, 8-hour, and 24-hour averaging periods) are evaluated using the maximum daily pound-per-hour emission rates. For 1-hour modeling, emissions are calculated based on a worst-case scenario that includes 30 minutes of SUSD operation and 30 minutes of steady-state operation.

This approach outlined in 5.12 and 5.12.1 ensures that the worst-case SUSD impacts from the 3, 15, or 24 highest contributing turbines are evaluated for short-term averaging periods.

5.13 Background Concentrations

Pursuant to recommended NDEP guidance, background concentrations are considered negligible for gaseous pollutants and will therefore not be included for NO_2, SO_2, or CO modeling for comparison against the NAAQS or NVAAQS. The modeling for PM_{10} and $PM_{2.5}$ included regional background concentrations to determine compliance with the PM_{10} and $PM_{2.5}$ NVAAQS and NAAQS. Background concentrations for the following pollutants and averaging periods were added to the modeled concentration for the following averaging periods, as recommended by NDEP, are shown below in Table:

Table 5-4. Applicable NVAAQS and NAAQS Background Concentrations

Pollutant	Background Concentration ($\mu g/m^3$)
PM_{10}-24 hour	10.2
$PM_{2.5}$-24 hour	8
$PM_{2.5}$- Annual	2.3
NO_2	0
SO_2	0
CO	0

5.14 Ozone Modeling

O_3 is a secondary pollutant formed by photochemical reactions from O_3 precursor pollutants. While several pollutants may result in O_3 formation, VOC and NO_X are the two greatest contributors. Per NDEP's Modeling Guidelines, Stella has shown compliance with the 8-hour O_3 standard using the screening technique developed by the U.S. EPA entitled, *VOC/NO_x Point Source Screening Tables, by Richard D. Scheffe.*

The Scheffe method uses a screening method based on VOC and NO_X emissions to determine the expected model impact. Table 1 of the paper indicates the Rural based ozone increment (ppm) as a function of the non-methane hydrocarbon (NMOC) emissions and NMOC/NO_X ratios. Facility wide emission calculations are shown in Section 3. For this analysis, we are conservatively assuming that VOC emissions are equal to NMOC emissions. Table 5-5 shows the Facility is below relevant NAAQS and NVAAQS threshold levels; no further analysis is required.

Table 5-5. Facility Wide Ozone

NMOC (tpy)	NO_X (tpy)	NMOC/NO_X	Table 1 Ozone Increment	Ozone NAAQS/NVAAQS (8-hour averaging period)	Exceed Thresholds?
51.53	126.64	0.41 tons/ton	0.011 ppm	0.070 ppm	No

5.15 Secondary PM2.5 Assessment

Emissions of primary NO_X and SO_2 can undergo a transformation in the ambient atmosphere to form particulate matter, particularly $PM_{2.5}$. A similar case is true for ozone, of which NO_X and volatile organic compounds (VOC) are precursors. EPA released guidance[10] in 2019 (the MERPs guidance) describing a methodology for accounting for this secondary formation of $PM_{2.5}$ and ozone. Secondary formation of $PM_{2.5}$ and ozone are accounted for in this analysis according to the MERPs guidance.

Representative MERPs data in Churchill County, Nevada are obtained from the EPA View Qlik website.[11] MERPs use technically credible air quality modeling to relate precursor emissions and peak secondary pollutant impacts from hypothetical sources. In developing the MERPs, the EPA uses photochemical grid modeling (PGM) platforms for the hypothetical sources that use current state-of-the-science algorithms and equations to evaluate plume dispersion and chemical transformations. The EPA uses emission rates of 3,000 tpy, 1,000 tpy, and 500 tpy of NOx, SO2, or VOC, as well as stack heights of 10 meters (approximately 30 ft) and 90 meters (approximately 300 ft) for the PGM evaluations.

Pursuant to the EPA guidance, Stella uses the data available for the only Nevada hypothetical source in EPA's View Qlik website. The hypothetical source has a 500 tpy emission rate and 90 m and 10 m stack heights. The more conservative value was used between the two stack heights. Secondary $PM_{2.5}$ is based on preliminary estimates of annual site-wide potential primary NO_X, SO_2, and VOC emissions as represented in the table below. These MERP concentrations are added to modeled impacts of Facility-wide $PM_{2.5}$ sources.

[10] "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program" (04/30/2019, EPA-454-R-19-003)

[11] Obtained from EPA MERPS ViewQlik website on July 9, 2025 (https://www.epa.gov/scram/merps-view-qlik)

Table 5-6. Preliminary Estimates of Secondary Formation of $PM_{2.5}$ and Ozone

Precursor Pollutant	MERP Modeled Emissions (tpy)	MERP Value	
		$PM_{2.5}$ Daily ($\mu g/m^3$)	$PM_{2.5}$ Annual ($\mu g/m^3$)
NO_X	500	0.011	0.00046
SO_2	500	0.06	0.00097
VOC	500	--	--
	Total	0.072	0.0014

5.16 Modeling Results

The modeled SIL ground-level concentrations using the approach for the standard operating scenario (Scenario 3) described throughout this report are presented in Table 5-7. The modeled cumulative NAAQS/NVAAQS ground-level concentrations using the approach described throughout this report (Scenario 1, Scenario 2, and Scenario 3) are presented in Table 5-8, Table 5-10, and Table 5-12. Note the modeled concentration is reported in the form of the standard listed in Table 5-1. The Class II increment ground level concentration using the approach described throughout this report (Scenario 1, Scenario 2, and Scenario 3) are presented in Table 5-9, Table 5-11, and Table 5-13.

As shown in the tables below, the emission levels from the Facility and neighboring source demonstrate full compliance with the applicable standards for all pollutants and averaging periods.

Table 5-7. Significant Impacts Analysis Results for Scenario 3 (Standard Operation with Optional 3 SUSD Turbines)

Pollutant	Averaging Period	High Value in AERMOD[1]	Concentration		High Value< Class II SIL
			Model Impact	Class II SIL	
			(µg/m³)	(µg/m³)	
CO	1-hour	H1H	2,418.61	2,000	No
	8-hour	H1H	659.86	500	No
NO_2	1-hour	H1H	136.10	7.5	No
	Annual	Max. Avg.	6.58	1	No
$PM_{2.5}$	24-hour	H1H	21.66	1.2	No
	Annual	Max. Avg.	1.19	0.13	No
PM_{10}	24-hour	H1H	21.66	5	No
SO_2	1-hour	H1H	66.61	7.8	No
	3-hour	H1H	25.17	25	No
	24-hour	H1H	7.41	5	No
	Annual	Max.	0.63	1	Yes

Footnotes:

1. All Class II SILs are compared to the highest modeled concentration

Table 5-8. Cumulative NAAQS/NVAAQS Impacts Analysis Results for Scenario 3 (Standard Operation with Optional 3 SUSD Turbines)

Pollutant	Averaging Period	High Value in AERMOD	Concentration			NAAQS	NVAAQS	Total Impact < NAAQS or NVAAQS?
			Model Impact Including Neighboring Sources	Background	Total Impact	($\mu g/m^3$)	($\mu g/m^3$)	
			($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)			
CO	1-hour	H1H[1]	2,418.64	-	2,418.64	40,000	40,500	Yes
	8-hour	H1H[1]	660.88	-	660.88	10,000	10,500	Yes
NO_2	1-hour	H8H	90.33	-	90.33	188	188	Yes
	Annual	Max. Avg.	6.68	-	6.68	100	100	Yes
$PM_{2.5}$	24-hour	H8H	16.12	8.01[3]	24.12	35	35	Yes
	Annual	Max. Avg.	1.35	2.31[3]	3.65	9[2]	12	Yes
PM_{10}	24-hour	H1H[1]	21.82	10.20	32.02	-	150	Yes
SO_2	1-hour	H4H	36.09	-	36.09	196	196	Yes
	3-hour	H1H[1]	25.17	-	25.17	1,300	1,300	Yes
	24-hour	H2H	6.62	-		-	365	Yes
	Annual	Max.	-	-	-	-	80	Yes

Footnotes:

1. NAAQS for PM10 24-hr is H6H, and for CO and 3-hour SO_2 is H2H, but for NVAAQS the four mentioned averaging periods are evaluated at H1H, therefore only H1H results are presented for these averaging periods to conservatively demonstrate compliance with both standards.
2. The $PM_{2.5}$ standard reflects the revised NAAQS limit as revised by EPA effective May 6, 2024.
3. Background for $PM_{2.5}$ 24-hr and Annual averaging periods include the secondary $PM_{2.5}$ impacts as discussed in Section 5.17.

Table 5-9. Cumulative Class II PSD Increment Analysis Results for Scenario 3 (Standard Operation with Optional 3 SUSD Turbines)

Pollutant	Averaging Period	High Value in AERMOD[1]	Concentration		High Value< Class II Increment
			Model Impact Including Neighboring Sources	Class II PSD Increment	
			(µg/m³)	(µg/m³)	
$PM_{2.5}$	24-hour	H2H	8.42	9	Yes
	Annual	Max Avg.	1.65	4	Yes
SO_2	3-hour	H2H	154.48	512	Yes
	24-hour	H2H	43.43	91	Yes

Footnotes:

1. All short term Class II PSD increments are compared to the second highest modeled concentration other than annual which is compared to the max average annual concentration.

Table 5-10. Cumulative NAAQS/NVAAQS Impacts Analysis Results for Scenario 1 (Plant Initial Start with 15 SUSD Turbines)

Pollutant	Averaging Period	High Value in AERMOD	Concentration			NAAQS	NVAAQS	Total Impact < NAAQS or NVAAQS?
			Model Impact Including Neighboring Sources	Background	Total Impact	($\mu g/m^3$)	($\mu g/m^3$)	
			($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)			
CO	1-hour	H1H[1]	11,057.02	-	11,057.02	40,000	40,500	Yes
	8-hour	H1H[1]	2,347.10	-	2,347.10	10,000	10,500	Yes
NO_2	1-hour	H8H	137.98	-	137.98	188	188	Yes
	Annual	Max. Avg.	N/A – Short Term Only	-	N/A – Short Term Only	100	100	N/A – Short Term Only
$PM_{2.5}$	24-hour	H8H	18.81	8.01[3]	26.81	35	35	Yes
	Annual	Max. Avg.	N/A – Short Term Only	2.31[3]	N/A – Short Term Only	9[2]	12	N/A – Short Term Only
PM_{10}	24-hour	H1H[1]	25.54	10.20	35.74	-	150	Yes
SO_2	1-hour	H4H	38.27	-	38.27	196	196	Yes
	3-hour	H1H[1]	26.77	-	26.77	1,300	1,300	Yes
	24-hour	H2H	5.76	-	5.76	-	365	Yes
	Annual	Max.	N/A – Short Term Only	-	N/A – Short Term Only	-	80	N/A – Short Term Only

Footnotes:

4. NAAQS for PM10 24-hr is H6H, and for CO and 3-hour SO_2 is H2H, but for NVAAQS the four mentioned averaging periods are evaluated at H1H, therefore only H1H results are presented for these averaging periods to conservatively demonstrate compliance with both standards.
5. The $PM_{2.5}$ standard reflects the revised NAAQS limit as revised by EPA effective May 6, 2024.
6. Background for $PM_{2.5}$ 24-hr and Annual averaging periods include the secondary $PM_{2.5}$ impacts as discussed in Section 5.17.

Table 5-11. Cumulative Class II PSD Increment Analysis Results for Scenario 3 (Standard Operation with Optional 3 SUSD Turbines)

Pollutant	Averaging Period	High Value in AERMOD[1]	Concentration		High Value< Class II Increment
			Model Impact Including Neighboring Sources	Class II PSD Increment	
			($\mu g/m^3$)	($\mu g/m^3$)	
$PM_{2.5}$	24-hour	H2H	8.78	9	Yes
	Annual	Max Avg.	N/A – Short Term Only	4	N/A – Short Term Only
SO_2	3-hour	H2H	144.76	512	Yes
	24-hour	H2H	42.12	91	Yes

Footnotes:

2. All short term Class II PSD increments are compared to the second highest modeled concentration other than annual which is compared to the max average annual concentration.

Table 5-12. Cumulative NAAQS/NVAAQS Impacts Analysis Results for Scenario 2 (Plant Second Start with 15 SS + 9 SUSD Turbines)

Pollutant	Averaging Period	High Value in AERMOD	Concentration			NAAQS	NVAAQS	Total Impact < NAAQS or NVAAQS?
			Model Impact Including Neighboring Sources	Background	Total Impact	($\mu g/m^3$)	($\mu g/m^3$)	
			($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)			
CO	1-hour	H1H[1]	4,813.53	-	4,813.53	40,000	40,500	Yes
	8-hour	H1H[1]	1,311.52	-	1,311.52	10,000	10,500	Yes
NO_2	1-hour	H8H	118.89	-	118.89	188	188	Yes
	Annual	Max. Avg.	N/A – Short Term Only	-	N/A – Short Term Only	100	100	N/A – Short Term Only
$PM_{2.5}$	24-hour	H8H	15.57	8.01[3]	23.57	35	35	Yes
	Annual	Max. Avg.	N/A – Short Term Only	2.31[3]	N/A – Short Term Only	9[2]	12	N/A – Short Term Only
PM_{10}	24-hour	H1H[1]	21.79	10.20	31.99	-	150	Yes
SO_2	1-hour	H4H	33.51	-	33.51	196	196	Yes
	3-hour	H1H[1]	24.11	-	24.11	1,300	1,300	Yes
	24-hour	H2H	6.19	-	6.19	-	365	Yes
	Annual	Max.	N/A – Short Term Only	-	N/A – Short Term Only	-	80	N/A – Short Term Only

Footnotes:

7. NAAQS for PM10 24-hr is H6H, and for CO and 3-hour SO_2 is H2H, but for NVAAQS the four mentioned averaging periods are evaluated at H1H, therefore only H1H results are presented for these averaging periods to conservatively demonstrate compliance with both standards.
8. The $PM_{2.5}$ standard reflects the revised NAAQS limit as revised by EPA effective May 6, 2024.
9. Background for $PM_{2.5}$ 24-hr and Annual averaging periods include the secondary $PM_{2.5}$ impacts as discussed in Section 5.17.

Table 5-13. Cumulative Class II PSD Increment Analysis Results for Scenario 2 (Plant Second Start with 15 SS + 9 SUSD turbines)

Pollutant	Averaging Period	High Value in AERMOD[1]	Concentration		High Value< Class II Increment
			Model Impact Including Neighboring Sources	Class II PSD Increment	
			($\mu g/m^3$)	($\mu g/m^3$)	
$PM_{2.5}$	24-hour	H2H	8.93	9	Yes
	Annual	Max Avg.	N/A – Short Term Only	4	N/A – Short Term Only
SO_2	3-hour	H2H	151.05	512	Yes
	24-hour	H2H	42.93	91	Yes

Footnotes:

3. All short term Class II PSD increments are compared to the second highest modeled concentration other than annual which is compared to the max average annual concentration.

5.17 Electronic Files

The air dispersion modeling input and output electronic data files are provided to NDEP via a USB flash drive or email. The downwash files and terrain data files utilized in the analysis are also provided in electronic form on the USB flash drive or email. Each model folder contains an AERMOD input file and an AERMOD output file.

APPENDIX A. EMISSION CALCULATIONS

Table A-1. Annual Sitewide Emissions

Scenario	Annual Emissions (tpy)								
	NO_x	CO	VOC	PM/PM_{10}	$PM_{2.5}$	SO_2	Max Single HAP	HAPs	GHG
Turbines - Max. Annual Emissions (100% Load @ Annual Avg. Temp.)	116.86	71.13	45.65	99.46	99.46	56.40	8.18	11.69	1,941,455.65
Turbines - Total annual startup + shutdown events	1.78	44.59	10.70	0.59	0.59	0.18	0.02	0.03	4,543.36
Dewpoint Heater	4.13	3.47	0.23	0.31	0.31	0.02	0.07	0.08	5,128.90
Emergency Fire Pump	4.46	2.54	0.23	0.15	0.15	0.01	0.00	0.01	507.95
Proposed-Sitewide-Annual Emissions[1]	127.23	121.73	56.82	100.51	100.51	56.60	8.28	11.80	1,951,635.85
NDEP Class I Thresholds[2]	100.00	100.00	100.00	100.00	100.00	100.00	10.00	25.00	--
Emissions > NDEP Class I Thresholds?	Yes	Yes	No	Yes	Yes	No	No	No	No
Prevention of Significant Deterioration (PSD) Thresholds (tpy)[3,4]	250.00	250.00	250.00	250.00	250.00	250.00	--	--	75,000.00
Emissions > PSD Thresholds?	No	No	No	No	No	No	No	No	Yes

1. Proposed emissions encompass all anticipated emissions sources at the Greenfield Facility.

2. The Class I thresholds are defined in NAC 445B.036 [40CFR 52.21] as 100 tpy of any air contaminant and 10 tpy of any individual HAP or 25 tpy of combined HAP.

3. PSD threshold per 40 CFR 52.21(b)(1)(i). The Facility is not on the list of 28 categorical sources and therefore the thresholds are 250 tpy for any NSR pollutant.

4. The 75,000 metric ton threshold for GHG is only triggered when another criteria pollutant exceeds the PSD threshold.

Table A-2. Turbine Rating and Parameters

Parameter[1,2]	Value	Unit
Turbine Model[1]	Titan 130-23001S	--
Turbine Output Rating[1]	11,195.00	kW
Turbine Output Rating[1]	11.20	MW
Heat Rate[1]	7,308.00	btu/kWh
Turbine Heat Input[1]	130.53	MMBtu/hr, HHV
Turbine Fuel Consumption[1]	0.12	MMscf/hr, HHV
Number of Turbines[3]	29	Turbines
Steady State Hours of Operation[3]	8,760	hours per turbine
Startup and Shutdown Events per Turbine[3]	41	events per turbine
Startup and Shutdown Hours of Operation[1,3]	20.50	hours per turbine

1. Turbine parameters per manufacturer specifications.
2. Natural gas fuel consumption per client specifications of 1,060 Btu/scf
3. Operational parameters per client specifications.

Table A-3. Startup/Shutdown Emissions [1,2]

Unit	Duration (mins)	Start Up/Shut Down Emissions (lb/event[3])						
		NO_x	CO	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2	HAP	GHG
Start Up (cold)	20.00	1.50	36.00	9.00	0.50	0.22	0.03	5,095
Shut Down	10.00	1.50	39.00	9.00	0.50	0.07	0.02	2,547
Combined SU/SUD	30.00	3.00	75.00	18.00	1.00	0.30	0.05	7,642

1. Start up (SU) and Shut down (SD) emissions for all pollutants except SO_2, HAP and GHG per manufacturer specifications. All SU/SD events (Cold Start, Warm Start etc.) are considered identical for emissions.
2. Start up (SU) and Shut down (SD) emission rates for all pollutants except PM10/PM2.5, HAP and GHG include a 50% safety margin.
3. It is conservatively assumed that PM_{10}=$PM_{2.5}$ emissions.
4. Each start up event is considered to take 30 minutes to allow catalyst to reach operating temperature. Load can be taken off the turbine within 10 minutes and it is considered shut down.

Table A-4. Hourly Emission Rates in Startup, Shutdown, and Steady State Operation per Turbine

Scenario	Scenario Description	Turbine Emissions (lb/hr)							
		NO_x	CO	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2	MAX Single HAP	HAP	GHG
Hourly Emissions - 100% Load @ Annual Avg. Temp.[1,2]		0.92	0.56	0.36	0.78	0.44	0.06	0.09	15,285
Hourly Emissions SU/SD + Steady State Remaining[3] (For Modeling Only)		3.46	75.28	18.18	1.39	0.52	0.08	0.09	15,285

1. NOx, CO, VOC, SO_2 and PM steady state emission factors per the January 16, 2026 Titan 130-23001S Emission Sheet with SCR and Catalytic Oxidation. It is conservatively assumed that PM_{10}=$PM_{2.5}$ emissions. SCR reduction efficiency is given as 78% and Catalytic Oxidation reduction efficiencies is given as 80% for CO and 33% for VOC. The fuel sulfur content of 0.0034 lbm/MMBtu is given per the Emission Sheet.

2. Hourly Emissions SU/SD + Steady State Remaining is based on 40 minutes of SU/SU activities and 20 minutes of steady state operations.

Table A-5. Annual Emission Rates in Startup, Shutdown, and Steady State Operation for All Turbines

Scenario	Scenario Description	Emissions All Turbines (tpy)							
		NO_x	CO	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2	MAX Single HAP	HAP	GHG
Annual Emissions - 100% Load @ Annual Avg. Temp.[1]		116.86	71.13	45.65	99.46	56.40	8.18	11.69	1,941,455.65
Annual Emissions SU/SD + Steady State Remaining[2]		1.78	44.59	10.70	0.59	0.18	0.02	0.03	4,543.36

1. Annual Emissions All Turbines Steady State (tpy) = Turbines emissions (lb/hr) * number of Turbines * operational hours per year (steady state) /2000 (lb/ton)

2. Annual Emissions All Turbines SUSD (tpy) = Turbines emissions (lb/event) * number of Turbines * number of events /2000 (lb/ton)

Table A-6. Greenhouse Gas Emission Factor for Startup, Shutdown, and Steady State Operations

Pollutant	Global Warming Potential[1]	Emission Factor (kg/MMBtu)[2]	GHG equivalent (kg/MMBtu)[3]	GHG Equivalent (lb/MMBtu)[4]
CO_2	1	53.06	53.06	117.0
CH_4	28	1.00E-03	2.80E-02	0.1
N_2O	265	1.00E-04	2.65E-02	0.1
Total GHG equivalent (lb/MMBtu):				117.10

1. Global Warming Potentials (GWP) are obtained from Subpart A of 40 CFR 98, Table A–1 "Global Warming Potentials."

2. GHG emissions factors per 40 CFR Part 98 Subpart C Table C-1 and C-2 (natural gas usage).

3. GHG equivalent (CO_{2e}) (kg/MMBtu) = Emission Factor (kg/MMBtu) * Global Warming Potential.

4. GHG equivalent (CO2e) (lb/MMBtu) converted using 1kg = 2.205 lbs.

Table A-7. Hourly HAP Emission Rates in Startup, Shutdown, and Steady State Operations

Scenario	Emission Factor[1] (lb/MMbtu)	Emissions[2] (lb/hr)
1,3-Butadiene	4.30E-07	3.74E-05
Acetaldehyde	4.00E-05	3.48E-03
Acrolein	6.40E-06	5.57E-04
Benzene	1.20E-05	1.04E-03
Ethylbenzene	3.20E-05	2.78E-03
Formaldehyde	7.40E-04	6.44E-02
Naphthalene	1.30E-06	1.13E-04
PAH	2.20E-06	1.91E-04
Propylene Oxide	2.90E-05	2.52E-03
Toluene	1.30E-04	1.13E-02
Xylenes	6.40E-05	5.57E-03
Total HAP Emissions	**1.06E-03**	**0.09**

1. HAP emission factors provided in AP-42 Chapter 3.1, Table 3.1-3 (April, 2000)

Organic HAPS include 33.33% control given by the oxidation catalyst.

2. Potential to emit (lb/hr) = Emission Factor (lb/MMbtu)* Turbine heat input (MMbtu/hr) * (1- control efficiency)

Table A-8. Natural Gas Fired Dewpoint Heater Input Parameters

EU	Manufacturer	Fuel Fired	Quantity	Unit Heat Input (each) [1] (MMBtu/hr)	Natural Gas Heating Value [2] (MMBtu/MMscf)	Fuel Consumption Rate (total) [3] (MMscf/hr)
Dewpoint Heater	TBD	Natural Gas	1	10.00	1,060	0.01

1. Per manufacturer's specifications.
2. Natural gas average heating value per AP-42, Chapter 1.4, Natural Gas Combustion
3. Fuel Consumption Rate (MMscf/hr) = Total Heat Input (MMBtu/hr) / Natural Gas Heating Value (MMBtu/MMscf).

Table A-9. Natural Gas Fired Dewpoint Heater Emission Factors

Pollutant	Emission Factor	Unit
PM / PM_{10} / $PM_{2.5}$ [1,2]	7.60	(lb/MMscf)
SO_2 [1]	0.60	(lb/MMscf)
VOC [1]	5.50	(lb/MMscf)
CO [1]	84.00	(lb/MMscf)
NO_x [3]	100.00	(lb/MMscf)

1. Emission factors per AP-42 Chapter 1.4, *Natural Gas Combustion*, Tables 1.4-1 and 1.4-2.
2. It is conservatively assumed that emissions of PM = $PM_{2.5}$ = PM_{10}.

Table A-10. Dewpoint Heater Greenhouse Gas Emission Factor

Pollutant	Global Warming Potential[1]	Emission Factor (kg/MMBtu)[2]	GHG equivalent (kg/MMBtu)[3]	GHG Equivalent (lb/MMBtu)[4]
CO_2	1.00	53	53	117
CH_4	25	1.00E-03	2.50E-02	0.06
N_2O	298	1.00E-04	2.98E-02	0.07
Total GHG equivalent (lb/MMBtu):				117

1. Global Warming Potentials (GWP) are obtained from Subpart A of 40 CFR 98, Table A–1 "Global Warming Potentials."
2. GHG emissions factors for the Line Heaters are per 40 CFR Part 98 Subpart C Table C-1 and C-2 (natural gas usage).
3. GHG equivalent (CO_{2e}) (kg/MMBtu) = Emission Factor (kg/MMBtu) * Global Warming Potential.
4. GHG equivalent (CO2e) (lb/MMBtu) converted using 1kg = 2.205 lbs.

Table A-11. Dewpoint Heater Short-Term and Annual PTE for Criteria Pollutants and GHG

Pollutant	Short-Term Potential To Emit (lb/hr) [1,2,5]	Annual Potential to Emit (tpy) [3,4,5]
$PM/PM_{10}/PM_{2.5}$	0.07	0.31
SO_2	0.01	0.02
VOC	0.05	0.23
CO	0.79	3.47
NO_x	0.94	4.13
GHG	1,170.98	5,128.90

1. Emissions for $PM/PM_{10}/PM_{2.5}$, SO_2, CO, NO_x and VOC (lb/hr) = Emission Factor (lb/MMscf) * Total Fuel Consumption Rate (MMscf/hr).
2. Emissions for GHG (lb/hr) = Emission Factor (lb/MMBtu) * Total Heat Input (MMBtu/hr).
3. Emissions (tpy) = Short Term Potential to Emit (lb/hr) * 8,760 hours per year of operation / 2,000 lb/ton.
4. Assume continuous operation or 8,760 hours of operation per year and 2,000 lb/ton.
5. Values shown are for all natural gas fired heaters.

Table A-12. Natural Gas Fired Dewpoint Heater Short-Term and Annual HAP PTE

Pollutant	CAS Number	Emission Factor (lb/MMscf) [1,2]	Potential To Emit	
			(lb/hr) [3]	(tpy) [4]
2-Methylnaphthalene	91-57-6	2.40E-05	2.26E-07	9.92E-07
3-Methylcholanthrene	56-49-5	1.80E-06	1.70E-08	7.44E-08
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.51E-07	6.61E-07
Acenaphthene	83-32-9	1.80E-06	1.70E-08	7.44E-08
Acenaphthylene	203-96-8	1.80E-06	1.70E-08	7.44E-08
Anthracene	120-12-7	2.40E-06	2.26E-08	9.92E-08
Benz(a)anthracene	56-55-3	1.80E-06	1.70E-08	7.44E-08
Benzene	71-43-2	2.10E-03	1.98E-05	8.68E-05
Benzo(a)pyrene	50-32-8	1.20E-06	1.13E-08	4.96E-08
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.70E-08	7.44E-08
Benzo(g,h,i)perylene	191-24-2	1.20E-06	1.13E-08	4.96E-08
Benzo(k)fluoranthene	205-82-3	1.80E-06	1.70E-08	7.44E-08
Chrysene	218-01-9	1.80E-06	1.70E-08	7.44E-08
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	1.13E-08	4.96E-08
Dichlorobenzene	25321-22-6	1.20E-03	1.13E-05	4.96E-05
Fluoranthene	206-44-0	3.00E-06	2.83E-08	1.24E-07
Fluorene	86-73-7	2.80E-06	2.64E-08	1.16E-07
Formaldehyde	50-00-0	0.08	7.08E-04	3.10E-03
Hexane	110-54-3	1.80	1.70E-02	0.07
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.70E-08	7.44E-08
Naphthalene	91-20-3	6.10E-04	5.75E-06	2.52E-05
Phenanathrene	85-01-8	1.70E-05	1.60E-07	7.02E-07
Pyrene	129-00-0	5.00E-06	4.72E-08	2.07E-07
Toluene	108-88-3	3.40E-03	3.21E-05	1.40E-04
Arsenic	7440-38-2	2.00E-04	1.89E-06	8.26E-06
Beryllium	7440-41-7	1.20E-05	1.13E-07	4.96E-07
Cadmium	7440-43-9	1.10E-03	1.04E-05	4.55E-05
Chromium	7440-47-3	1.40E-03	1.32E-05	5.78E-05
Cobalt	7440-48-4	8.40E-05	7.92E-07	3.47E-06
Lead	7439-92-1	5.00E-04	4.72E-06	2.07E-05
Manganese	7439-96-5	3.80E-04	3.58E-06	1.57E-05
Mercury	7439-97-6	2.60E-04	2.45E-06	1.07E-05
Nickel	7440-02-0	2.10E-03	1.98E-05	8.68E-05
Selenium	7782-49-2	2.40E-05	2.26E-07	9.92E-07
Total HAP Emissions			**1.78E-02**	**0.08**

1. HAP emission factors are provided in AP-42, Section 1.4, Tables 1.4-3 and 1.4-4.
2. Lead emission factor was obtained from AP-42, Section 1.4, Table 1.4-2 .
3. Potential to emit (lb/hr) = Emission Factor (lb/MMscf)* Total Fuel Consumption Rate (MMscf/hr).

4. Potential to emit (tpy) = Potential to emit (lb/hr) * 8,760 operating hours per year / 2000 lb per ton.

Table A-13. Key Parameters/Constants for Diesel Fire Pump Emission Calculations

Parameter	Value	Unit
Engine Power[1]	12.42	MMBtu/hr
Engine Power[2]	1,774.29	hp
Engine Power	1,323.08	kW
Daily Hours	24	hrs/day
Annual Hours[3]	500	hrs/yr
Number of Engines	1	Engine

1. Engine Power per manufacturer specifications.

2. Average BSCF of 7,000 Btu / hp-hr taken from AP-42 Table 3.3-1 (10/96).

3. Emission calculations for the fire pump are performed with the annual hours of operation based on the memo "Calculating Potential to Emit (PTE) for Emergency Generators" from the Office of Air Quality Planning and Standards to the directors of Environmental Protection Agency (EPA) Air Divisions published September, 1995. (500 hours/year, inclusive of testing, maintenance, and emergency use which is limited to 100 hours/year).

Table A-14. Emission Factors and PTE for Diesel Fire Pump

Pollutant	Emission Factor	Unit	Hourly PTE[4]	Unit	Annual PTE[4]	Unit
VOC[1] (NMHC)	0.24	g/hp-hr	0.94	lb/hr	0.23	tpy
NO_x[1]	4.56	g/hp-hr	17.84	lb/hr	4.46	tpy
CO[1]	2.60	g/hp-hr	10.17	lb/hr	2.54	tpy
PM[1,2]	0.15	g/hp-hr	0.59	lb/hr	0.15	tpy
PM_{10}[1,2]	0.15	g/hp-hr	0.59	lb/hr	0.15	tpy
$PM_{2.5}$[1,2]	0.15	g/hp-hr	0.59	lb/hr	0.15	tpy
SO_x[3]	5.50E-03	g/hp-hr	2.15E-02	lb/hr	0.01	tpy

1. Emission factors for NOx, CO, VOC, PM/PM10 per Table 4 of 40 CFR 60 Part IIII. 95% of the NHMC + NOX emission factor is assumed to be NOX, and 5% is assumed to be VOC as defined in Table B-22 (NOx and NMHC Fraction Default Values for All Engines except TRUs) of the 2005 Carl Moyer Program Guidelines.

2. It is assumed that the fire pump PM/PM_{10} emission rate is equal to the $PM_{2.5}$ emission rate.

3. SOx emission factor calculated in accordance with AP-42 Table 3.4-1. The engine will use ultra low sulfur diesel fuel. The emission factor is based on a fuel sulfur content of 0.0015% for ultra low sulfur diesel fuel, as defined under 40 CFR 80, Subpart I, Section 80.510(c)(1)

4. Hourly PTE (lb/hr) = Emission factor (grams/hp-hr) * Engine power (hp) * 0.0022 grams/lb

5. Annual PTE (tons/year) = hourly PTE (lb/hr) * Annual Operating hours (hours/yr) /2000 (lb/ton)

Table A-15. Greenhouse Gas Potential to Emit for Diesel Fire Pump

Pollutant	Global Warming Potential[1]	Emission Factor (kg/MMBtu)[2]	CO_2e emissions	
			(lb/yr) [3]	(tpy)
CO_2	1.0	73.96	1,012,565	506.28
CH_4	28.0	3.00E-03	1,150	0.58
N_2O	265.0	6.00E-04	2,177	1.09
			Total CO_2e Emissions (tpy):	507.95

1. Global Warming Potentials are obtained from Subpart A of 40 CFR 98, Table A–1 "Global Warming Potentials."

2. 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.

3. CO2e Potential Emissions (lb/year) = GWP * Emission Factor (kg/MMBtu) * 1000 (g/kg) * 7,000 (Btu/hp-hr) / 1,000,000 (Btu/MMBtu) * Annual Hours (hr/year) * Engine Power (hp) / 453.592 (grams/lb)

4. Conversion from Btu to hp-hr: 1 hp-hr = 7000 Btu per AP-42 Chapter 3.3, Table 3.3-1 (10/96).

Table A-16. HAP Emissions for Diesel Fire Pump

Pollutant	Emission Factor (lb/MMBtu)[1]	Emission Factor (lb/hp-hr)[2]	Hourly PTE[3] (lb/hr)	Annual PTE (lb/yr)[4]	Annual PTE (tpy)
Benzene	9.33E-04	6.53E-06	1.16E-02	5.79	2.90E-03
Toluene	4.09E-04	2.86E-06	5.08E-03	2.54	1.27E-03
Xylenes	2.85E-04	2.00E-06	3.54E-03	1.77	8.85E-04
1,3 Butadiene	3.91E-05	2.74E-07	4.86E-04	0.24	1.21E-04
Formaldehyde	1.18E-03	8.26E-06	1.47E-02	7.33	3.66E-03
Acetaldehyde	7.67E-04	5.37E-06	9.53E-03	4.76	2.38E-03
Acrolein	9.25E-05	6.48E-07	1.15E-03	0.57	2.87E-04
Naphthalene	8.48E-05	5.94E-07	1.05E-03	0.53	2.63E-04
Acenaphthylene	5.06E-06	3.54E-08	6.28E-05	3.14E-02	1.57E-05
Acenaphthene	1.42E-06	9.94E-09	1.76E-05	8.82E-03	4.41E-06
Fluorene	2.92E-05	2.04E-07	3.63E-04	0.18	9.07E-05
Phenanthrene	2.94E-05	2.06E-07	3.65E-04	0.18	9.13E-05
Anthracene	1.87E-06	1.31E-08	2.32E-05	1.16E-02	5.81E-06
Fluoranthene	7.61E-06	5.33E-08	9.45E-05	0.05	2.36E-05
Pyrene	4.78E-06	3.35E-08	5.94E-05	2.97E-02	1.48E-05
Benzo(a)anthracene	1.68E-06	1.18E-08	2.09E-05	1.04E-02	5.22E-06
Chrysene	3.53E-07	2.47E-09	4.38E-06	2.19E-03	1.10E-06
Benzo(b)fluoranthene	9.91E-08	6.94E-10	1.23E-06	6.15E-04	3.08E-07
Benzo(k)fluoranthene	1.55E-07	1.09E-09	1.93E-06	9.63E-04	4.81E-07
Benzo(a)pyrene	1.88E-07	1.32E-09	2.33E-06	1.17E-03	5.84E-07
Indeno(1,2,3-cd)pyrene	3.75E-07	2.63E-09	4.66E-06	2.33E-03	1.16E-06
Dibenz(a,h)anthracene	5.83E-07	4.08E-09	7.24E-06	3.62E-03	1.81E-06
Benzo(g,h,l)perylene	4.89E-07	3.42E-09	6.07E-06	3.04E-03	1.52E-06
		Total HAPs:	**4.81E-02**	**24.06**	**1.20E-02**

1. HAP Emission Factors per AP-42 Chapter 3.3, Table 3.3-2 (10/96)
2. Conversion from MMBtu to hp-hr: 1 hp-hr = 0.007 MMBtu per AP-42 Chapter 3-3, Table 3.3-1 (10/96).
3. Hourly PTE (lbs/hr) = Emission Factor (lb/hp-hr) * Engine Power (hp)
4. Annual PTE (lbs/yr) = Emission Factor (lb/hp-hr) * Engine Power (hp) * Annual Hours (hrs/yr)

Table A-17. Key Parameters/Constants for Diesel Fire Pump Emission Calculations

NOx (assumes 78% reduction SCR)	ppm@15%O2	2.0
	Hours per Year	8760
	Controlled lbm/hr	0.920
	short tons/yr	4.03
	Hours per Year	8760
	Uncontrolled lbm/hr	4.182
	short tons/yr	18.32
	SUSD Hours	20.50
	SUSD Hourly LB/30 minutes	3.00
	Uncontrolled lbm/yr	30.75
	Uncontrolled tpy	0.02
	Total Uncontrolled tpy	**18.33**
CO (assumes 80% reduction CO catalyst)	ppm@15%O2	2.0
	Hours per Year	8760
	lbm/hr	0.560
	short tons/yr	2.5
	Hours per Year	8760
	Uncontrolled lbm/hr	4.600
	short tons/yr	20.15
	SUSD Hours	20.50
	SUSD Hourly LB/30 minutes	75.00
	Uncontrolled lbm/yr	768.75
	Uncontrolled tpy	0.38
	Total Uncontrolled tpy	**20.53**

1. Assumption on control efficiency is provided by manufacturer specifications

POINT SOURCES for NAAQS/NVAAQS Modeling - "NORMAL OPERATION"																	
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (meters)	Stack Height (meters)	Short Term Stack Temperature (K)	Short Term Exit Velocity (m/s)	Stack Diameter (meters)	Short-Term Modeled Emission Rates (lbs/hr)					Long-Term Modeled Emission Rates (tpy)		
									PM_{10}	$PM_{2.5}$	SO_2	CO	NO_X	$PM_{2.5}$	SO_2	NO_X
Engine Source Parameters									Modeling Inputs							
Turb1	RESERVE	313640.1	4390306.4	1248.03	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Turb2	Steady	313638.6	4390281.3	1248.06	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb3	Steady	313637.1	4390256.2	1247.87	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb4	Steady	313635.6	4390231.1	1247.89	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb5	RESERVE	313634.1	4390206.0	1247.96	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Turb6	RESERVE	313632.6	4390180.9	1247.96	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Turb7	Steady	313631.1	4390155.8	1248.04	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb8	RESERVE	313629.6	4390130.7	1248.07	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Turb9	RESERVE	313628.1	4390105.6	1248.41	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Turb10	RESERVE	313626.6	4390080.5	1248.77	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Turb11	RESERVE	313625.1	4390055.4	1249.00	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Turb12	Steady	313623.6	4390030.3	1248.96	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb13	Steady	313622.1	4390005.2	1248.59	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb14	Steady	313620.6	4389980.1	1248.02	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb15	Steady	313619.1	4389955.0	1247.72	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb16	Steady	313617.6	4389929.9	1247.87	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb17	Steady	313616.1	4389904.8	1248.31	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb18	Steady	313614.6	4389879.0	1248.22	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb19	SUSD	313202.3	4389838.7	1250.41	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46	3.45	1.95	4.09
Turb20	SUSD	313226.4	4389837.9	1250.21	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46	3.45	1.95	4.09
Turb21	SUSD	313250.4	4389837.2	1250.10	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46	3.45	1.95	4.09
Turb22	Steady	313274.5	4389836.4	1249.87	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb23	Steady	313298.6	4389835.6	1249.77	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb24	Steady	313322.6	4389834.9	1249.76	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb25	Steady	313346.7	4389834.1	1249.78	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb26	Steady	313370.8	4389833.3	1249.74	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb27	Steady	313394.8	4389832.6	1249.52	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb28	Steady	313418.9	4389831.8	1249.15	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb29	Steady	313443.0	4389831.1	1248.90	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb30	Steady	313467.0	4389830.3	1248.63	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb31	Steady	313491.1	4389829.5	1248.40	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb32	Steady	313515.2	4389828.8	1248.39	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb33	Steady	313539.2	4389828.0	1248.38	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb34	Steady	313563.3	4389827.2	1248.24	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb35	Steady	313587.4	4389826.5	1248.12	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
Turb36	Steady	313611.5	4389825.7	1248.15	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92	3.45	1.95	4.09
DHEAT	DewPoint Heater	313084.40	4389884.10	1251.48	12.0	366.5	0.62	0.4	0.07	0.07	0.01	0.79	0.94	0.31	0.02	4.13
EMERGE	Diesel Fire Pump	313685.00	4389861.10	1248.48	4.0	761.5	4.79	0.8	0.59	0.59	0.02	10.17	1.02	0.15	0.01	4.46

Buildings					
Buiding	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (meters)	Height (meters)
WH	WareHouse	312983.9	4389850.6	1252.0	12.2
CT	Control Building	313659.7	4389829.8	1248.1	12.2

POINT SOURCES for PSD Class II Increment Modeling- "NORMAL OPERATION"											
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (meters)	Stack Height (meters)	Short Term Stack Temperature (K)	Short Term Exit Velocity (m/s)	Stack Diameter (meters)	Short-Term Modeled Emission Rates (lbs/hr)		Long-Term Modeled Emission Rates (tpy)
									$PM_{2.5}$	SO_2	$PM_{2.5}$
Engine Source Parameters									Modeling Inputs		
Turb1	Steady	313640.1	4390306.4	1248.03	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb2	RESERVE	313638.6	4390281.3	1248.06	15.24	793.15	9.08	2.4	0.00	0.00	0.00
Turb3	RESERVE	313637.1	4390256.2	1247.87	15.24	793.15	9.08	2.4	0.00	0.00	0.00
Turb4	RESERVE	313635.6	4390231.1	1247.89	15.24	793.15	9.08	2.4	0.00	0.00	0.00
Turb5	RESERVE	313634.1	4390206.0	1247.96	15.24	793.15	9.08	2.4	0.00	0.00	0.00
Turb6	RESERVE	313632.6	4390180.9	1247.96	15.24	793.15	9.08	2.4	0.00	0.00	0.00
Turb7	RESERVE	313631.1	4390155.8	1248.04	15.24	793.15	9.08	2.4	0.00	0.00	0.00
Turb8	RESERVE	313629.6	4390130.7	1248.07	15.24	793.15	9.08	2.4	0.00	0.00	0.00
Turb9	Steady	313628.1	4390105.6	1248.41	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb10	Steady	313626.6	4390080.5	1248.77	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb11	Steady	313625.1	4390055.4	1249.00	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb12	Steady	313623.6	4390030.3	1248.96	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb13	Steady	313622.1	4390005.2	1248.59	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb14	Steady	313620.6	4389980.1	1248.02	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb15	Steady	313619.1	4389955.0	1247.72	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb16	Steady	313617.6	4389929.9	1247.87	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb17	Steady	313616.1	4389904.8	1248.31	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb18	Steady	313614.6	4389879.0	1248.22	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb19	Steady	313202.3	4389838.7	1250.41	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb20	Steady	313226.4	4389837.9	1250.21	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb21	Steady	313250.4	4389837.2	1250.10	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb22	Steady	313274.5	4389836.4	1249.87	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb23	Steady	313298.6	4389835.6	1249.77	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb24	Steady	313322.6	4389834.9	1249.76	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb25	Steady	313346.7	4389834.1	1249.78	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb26	SUSD	313370.8	4389833.3	1249.74	15.24	833.15	5.01	2.4	1.39	0.52	3.45
Turb27	SUSD	313394.8	4389832.6	1249.52	15.24	833.15	5.01	2.4	1.39	0.52	3.45
Turb28	SUSD	313418.9	4389831.8	1249.15	15.24	833.15	5.01	2.4	1.39	0.52	3.45
Turb29	Steady	313443.0	4389831.1	1248.90	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb30	Steady	313467.0	4389830.3	1248.63	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb31	Steady	313491.1	4389829.5	1248.40	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb32	Steady	313515.2	4389828.8	1248.39	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb33	Steady	313539.2	4389828.0	1248.38	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb34	Steady	313563.3	4389827.2	1248.24	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb35	Steady	313587.4	4389826.5	1248.12	15.24	793.15	9.08	2.4	0.78	0.44	3.45
Turb36	Steady	313611.5	4389825.7	1248.15	15.24	793.15	9.08	2.4	0.78	0.44	3.45
DHEAT	DewPoint Heater	313084.40	4389884.10	1251.48	12.0	366.5	0.62	0.4	0.07	0.01	0.31
EMERGE	Diesel Fire Pump	313685.00	4389861.10	1248.48	4.0	761.5	4.79	0.8	0.59	0.02	0.15

POINT SOURCES for PSD Class II Increment Modeling - "PLANT INITIAL START"										
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (meters)	Stack Height (meters)	Short Term Stack Temperature (K)	Short Term Exit Velocity (m/s)	Stack Diameter (meters)	Short-Term Modeled Emission Rates (lbs/hr)	
									$PM_{2.5}$	SO_2
Engine Source Parameters									Modeling Inputs	
Turb1	RESERVE	313640.1	4390306.4	1248.03	15.24	793.15	9.08	2.4	0.00	0.00
Turb2	RESERVE	313638.6	4390281.3	1248.06	15.24	793.15	9.08	2.4	0.00	0.00
Turb3	RESERVE	313637.1	4390256.2	1247.87	15.24	793.15	9.08	2.4	0.00	0.00
Turb4	RESERVE	313635.6	4390231.1	1247.89	15.24	793.15	9.08	2.4	0.00	0.00
Turb5	RESERVE	313634.1	4390206.0	1247.96	15.24	793.15	9.08	2.4	0.00	0.00
Turb6	RESERVE	313632.6	4390180.9	1247.96	15.24	793.15	9.08	2.4	0.00	0.00
Turb7	RESERVE	313631.1	4390155.8	1248.04	15.24	793.15	9.08	2.4	0.00	0.00
Turb8	RESERVE	313629.6	4390130.7	1248.07	15.24	793.15	9.08	2.4	0.00	0.00
Turb9	RESERVE	313628.1	4390105.6	1248.41	15.24	793.15	9.08	2.4	0.00	0.00
Turb10	RESERVE	313626.6	4390080.5	1248.77	15.24	793.15	9.08	2.4	0.00	0.00
Turb11	RESERVE	313625.1	4390055.4	1249.00	15.24	793.15	9.08	2.4	0.00	0.00
Turb12	RESERVE	313623.6	4390030.3	1248.96	15.24	793.15	9.08	2.4	0.00	0.00
Turb13	RESERVE	313622.1	4390005.2	1248.59	15.24	793.15	9.08	2.4	0.00	0.00
Turb14	RESERVE	313620.6	4389980.1	1248.02	15.24	793.15	9.08	2.4	0.00	0.00
Turb15	RESERVE	313619.1	4389955.0	1247.72	15.24	793.15	9.08	2.4	0.00	0.00
Turb16	SUSD	313617.6	4389929.9	1247.87	15.24	833.15	5.01	2.4	1.39	0.52
Turb17	SUSD	313616.1	4389904.8	1248.31	15.24	833.15	5.01	2.4	1.39	0.52
Turb18	SUSD	313614.6	4389879.0	1248.22	15.24	833.15	5.01	2.4	1.39	0.52
Turb19	SUSD	313202.3	4389838.7	1250.41	15.24	833.15	5.01	2.4	1.39	0.52
Turb20	SUSD	313226.4	4389837.9	1250.21	15.24	833.15	5.01	2.4	1.39	0.52
Turb21	SUSD	313250.4	4389837.2	1250.10	15.24	833.15	5.01	2.4	1.39	0.52
Turb22	SUSD	313274.5	4389836.4	1249.87	15.24	833.15	5.01	2.4	1.39	0.52
Turb23	SUSD	313298.6	4389835.6	1249.77	15.24	833.15	5.01	2.4	1.39	0.52
Turb24	SUSD	313322.6	4389834.9	1249.76	15.24	833.15	5.01	2.4	1.39	0.52
Turb25	SUSD	313346.7	4389834.1	1249.78	15.24	833.15	5.01	2.4	1.39	0.52
Turb26	SUSD	313370.8	4389833.3	1249.74	15.24	833.15	5.01	2.4	1.39	0.52
Turb27	SUSD	313394.8	4389832.6	1249.52	15.24	833.15	5.01	2.4	1.39	0.52
Turb28	SUSD	313418.9	4389831.8	1249.15	15.24	833.15	5.01	2.4	1.39	0.52
Turb29	SUSD	313443.0	4389831.1	1248.90	15.24	833.15	5.01	2.4	1.39	0.52
Turb30	SUSD	313467.0	4389830.3	1248.63	15.24	833.15	5.01	2.4	1.39	0.52
Turb31	RESERVE	313491.1	4389829.5	1248.40	15.24	793.15	9.08	2.4	0.00	0.00
Turb32	RESERVE	313515.2	4389828.8	1248.39	15.24	793.15	9.08	2.4	0.00	0.00
Turb33	RESERVE	313539.2	4389828.0	1248.38	15.24	793.15	9.08	2.4	0.00	0.00
Turb34	RESERVE	313563.3	4389827.2	1248.24	15.24	793.15	9.08	2.4	0.00	0.00
Turb35	RESERVE	313587.4	4389826.5	1248.12	15.24	793.15	9.08	2.4	0.00	0.00
Turb36	RESERVE	313611.5	4389825.7	1248.15	15.24	793.15	9.08	2.4	0.00	0.00
DHEAT	DewPoint Heater	313084.40	4389884.10	1251.48	12.0	366.5	0.62	0.4	0.07	0.01
EMERGE	Diesel Fire Pump	313685.00	4389861.10	1248.48	4.0	761.5	4.79	0.8	0.59	0.02

POINT SOURCES for PSD Class II Increment Modeling - "PLANT CONTINUING START"										
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (meters)	Stack Height (meters)	Short Term Stack Temperature (K)	Short Term Exit Velocity (m/s)	Stack Diameter (meters)	Short-Term Modeled Emission Rates (lbs/hr)	
									$PM_{2.5}$	SO_2
Engine Source Parameters									Modeling Inputs	
Turb1	RESERVE	313640.1	4390306.4	1248.03	15.24	793.15	9.08	2.4	0.00	0.00
Turb2	RESERVE	313638.6	4390281.3	1248.06	15.24	793.15	9.08	2.4	0.00	0.00
Turb3	RESERVE	313637.1	4390256.2	1247.87	15.24	793.15	9.08	2.4	0.00	0.00
Turb4	RESERVE	313635.6	4390231.1	1247.89	15.24	793.15	9.08	2.4	0.00	0.00
Turb5	RESERVE	313634.1	4390206.0	1247.96	15.24	793.15	9.08	2.4	0.00	0.00
Turb6	RESERVE	313632.6	4390180.9	1247.96	15.24	793.15	9.08	2.4	0.00	0.00
Turb7	RESERVE	313631.1	4390155.8	1248.04	15.24	793.15	9.08	2.4	0.00	0.00
Turb8	RESERVE	313629.6	4390130.7	1248.07	15.24	793.15	9.08	2.4	0.00	0.00
Turb9	RESERVE	313628.1	4390105.6	1248.41	15.24	793.15	9.08	2.4	0.00	0.00
Turb10	RESERVE	313626.6	4390080.5	1248.77	15.24	793.15	9.08	2.4	0.00	0.00
Turb11	RESERVE	313625.1	4390055.4	1249.00	15.24	793.15	9.08	2.4	0.00	0.00
Turb12	SUSD	313623.6	4390030.3	1248.96	15.24	833.15	5.01	2.4	1.39	0.52
Turb13	SUSD	313622.1	4390005.2	1248.59	15.24	833.15	5.01	2.4	1.39	0.52
Turb14	SUSD	313620.6	4389980.1	1248.02	15.24	833.15	5.01	2.4	1.39	0.52
Turb15	SUSD	313619.1	4389955.0	1247.72	15.24	833.15	5.01	2.4	1.39	0.52
Turb16	STEADY	313617.6	4389929.9	1247.87	15.24	793.15	9.08	2.4	0.78	0.44
Turb17	STEADY	313616.1	4389904.8	1248.31	15.24	793.15	9.08	2.4	0.78	0.44
Turb18	STEADY	313614.6	4389879.0	1248.22	15.24	793.15	9.08	2.4	0.78	0.44
Turb19	STEADY	313202.3	4389838.7	1250.41	15.24	793.15	9.08	2.4	0.78	0.44
Turb20	STEADY	313226.4	4389837.9	1250.21	15.24	793.15	9.08	2.4	0.78	0.44
Turb21	STEADY	313250.4	4389837.2	1250.10	15.24	793.15	9.08	2.4	0.78	0.44
Turb22	STEADY	313274.5	4389836.4	1249.87	15.24	793.15	9.08	2.4	0.78	0.44
Turb23	STEADY	313298.6	4389835.6	1249.77	15.24	793.15	9.08	2.4	0.78	0.44
Turb24	STEADY	313322.6	4389834.9	1249.76	15.24	793.15	9.08	2.4	0.78	0.44
Turb25	STEADY	313346.7	4389834.1	1249.78	15.24	793.15	9.08	2.4	0.78	0.44
Turb26	STEADY	313370.8	4389833.3	1249.74	15.24	793.15	9.08	2.4	0.78	0.44
Turb27	STEADY	313394.8	4389832.6	1249.52	15.24	793.15	9.08	2.4	0.78	0.44
Turb28	STEADY	313418.9	4389831.8	1249.15	15.24	793.15	9.08	2.4	0.78	0.44
Turb29	STEADY	313443.0	4389831.1	1248.90	15.24	793.15	9.08	2.4	0.78	0.44
Turb30	STEADY	313467.0	4389830.3	1248.63	15.24	793.15	9.08	2.4	0.78	0.44
Turb31	SUSD	313491.1	4389829.5	1248.40	15.24	833.15	5.01	2.4	1.39	0.52
Turb32	SUSD	313515.2	4389828.8	1248.39	15.24	833.15	5.01	2.4	1.39	0.52
Turb33	SUSD	313539.2	4389828.0	1248.38	15.24	833.15	5.01	2.4	1.39	0.52
Turb34	SUSD	313563.3	4389827.2	1248.24	15.24	833.15	5.01	2.4	1.39	0.52
Turb35	SUSD	313587.4	4389826.5	1248.12	15.24	833.15	5.01	2.4	1.39	0.52
Turb36	RESERVE	313611.5	4389825.7	1248.15	15.24	793.15	9.08	2.4	0.00	0.00
DHEAT	DewPoint Heater	313084.40	4389884.10	1251.48	12.0	366.5	0.62	0.4	0.07	0.01
EMERGE	Diesel Fire Pump	313685.00	4389861.10	1248.48	4.0	761.5	4.79	0.8	0.59	0.02

POINT SOURCES for NAAQS/NVAAQS Modeling "PLANT INITIAL START"														
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (meters)	Stack Height (meters)	Short Term Stack Temperature (K)	Short Term Exit Velocity (m/s)	Stack Diameter (meters)	Short-Term Modeled Emission Rates (lbs/hr)				
									PM_{10}	$PM_{2.5}$	SO_2	CO	NO_x
Engine Source Parameters									Modeling Inputs				
Turb1	RESERVE	313640.1	4390306.4	1248.03	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb2	RESERVE	313638.6	4390281.3	1248.06	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb3	RESERVE	313637.1	4390256.2	1247.87	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb4	RESERVE	313635.6	4390231.1	1247.89	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb5	RESERVE	313634.1	4390206.0	1247.96	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb6	RESERVE	313632.6	4390180.9	1247.96	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb7	RESERVE	313631.1	4390155.8	1248.04	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb8	RESERVE	313629.6	4390130.7	1248.07	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb9	RESERVE	313628.1	4390105.6	1248.41	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb10	RESERVE	313626.6	4390080.5	1248.77	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb11	RESERVE	313625.1	4390055.4	1249.00	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb12	RESERVE	313623.6	4390030.3	1248.96	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb13	RESERVE	313622.1	4390005.2	1248.59	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb14	RESERVE	313620.6	4389980.1	1248.02	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb15	RESERVE	313619.1	4389955.0	1247.72	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb16	RESERVE	313617.6	4389929.9	1247.87	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb17	RESERVE	313616.1	4389904.8	1248.31	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb18	RESERVE	313614.6	4389879.0	1248.22	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb19	SUSD	313202.3	4389838.7	1250.41	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb20	SUSD	313226.4	4389837.9	1250.21	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb21	SUSD	313250.4	4389837.2	1250.10	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb22	SUSD	313274.5	4389836.4	1249.87	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb23	SUSD	313298.6	4389835.6	1249.77	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb24	SUSD	313322.6	4389834.9	1249.76	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb25	SUSD	313346.7	4389834.1	1249.78	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb26	SUSD	313370.8	4389833.3	1249.74	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb27	SUSD	313394.8	4389832.6	1249.52	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb28	SUSD	313418.9	4389831.8	1249.15	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb29	SUSD	313443.0	4389831.1	1248.90	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb30	SUSD	313467.0	4389830.3	1248.63	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb31	SUSD	313491.1	4389829.5	1248.40	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb32	SUSD	313515.2	4389828.8	1248.39	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb33	SUSD	313539.2	4389828.0	1248.38	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb34	RESERVE	313563.3	4389827.2	1248.24	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb35	RESERVE	313587.4	4389826.5	1248.12	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb36	RESERVE	313611.5	4389825.7	1248.15	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
DPTHTR	DewPoint Heater	313084.40	4389884.10	1251.48	12.0	366.5	0.62	0.4	0.07	0.07	0.01	0.79	0.94
FP	Diesel Fire Pump	313685.00	4389861.10	1248.48	4.0	761.5	4.79	0.8	0.59	0.59	0.02	10.17	1.02

POINT SOURCES for NAAQS/NVAAQS Modeling "PLANT CONTINUING START"														
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (meters)	Stack Height (meters)	Short Term Stack Temperature (K)	Short Term Exit Velocity (m/s)	Stack Diameter (meters)	Short-Term Modeled Emission Rates (lbs/hr)				
									PM_{10}	$PM_{2.5}$	SO_2	CO	NO_x
Engine Source Parameters									Modeling Inputs				
Turb1	RESERVE	313640.1	4390306.4	1248.03	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb2	RESERVE	313638.6	4390281.3	1248.06	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb3	SUSD	313637.1	4390256.2	1247.87	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb4	RESERVE	313635.6	4390231.1	1247.89	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb5	RESERVE	313634.1	4390206.0	1247.96	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb6	RESERVE	313632.6	4390180.9	1247.96	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb7	RESERVE	313631.1	4390155.8	1248.04	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb8	RESERVE	313629.6	4390130.7	1248.07	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb9	RESERVE	313628.1	4390105.6	1248.41	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb10	RESERVE	313626.6	4390080.5	1248.77	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb11	RESERVE	313625.1	4390055.4	1249.00	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb12	SUSD	313623.6	4390030.3	1248.96	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb13	SUSD	313622.1	4390005.2	1248.59	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb14	SUSD	313620.6	4389980.1	1248.02	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb15	SUSD	313619.1	4389955.0	1247.72	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb16	RESERVE	313617.6	4389929.9	1247.87	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb17	SUSD	313616.1	4389904.8	1248.31	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb18	SUSD	313614.6	4389879.0	1248.22	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb19	Steady	313202.3	4389838.7	1250.41	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb20	Steady	313226.4	4389837.9	1250.21	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb21	Steady	313250.4	4389837.2	1250.10	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb22	Steady	313274.5	4389836.4	1249.87	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb23	Steady	313298.6	4389835.6	1249.77	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb24	Steady	313322.6	4389834.9	1249.76	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb25	Steady	313346.7	4389834.1	1249.78	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb26	Steady	313370.8	4389833.3	1249.74	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb27	Steady	313394.8	4389832.6	1249.52	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb28	Steady	313418.9	4389831.8	1249.15	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb29	Steady	313443.0	4389831.1	1248.90	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb30	Steady	313467.0	4389830.3	1248.63	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb31	Steady	313491.1	4389829.5	1248.40	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb32	Steady	313515.2	4389828.8	1248.39	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb33	Steady	313539.2	4389828.0	1248.38	15.24	793.2	9.08	2.4	0.78	0.78	0.44	0.56	0.92
Turb34	SUSD	313563.3	4389827.2	1248.24	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
Turb35	RESERVE	313587.4	4389826.5	1248.12	15.24	793.2	9.08	2.4	0.00	0.00	0.00	0.00	0.00
Turb36	SUSD	313611.5	4389825.7	1248.15	15.24	833.2	5.01	2.4	1.39	1.39	0.52	75.28	3.46
DPTHTR	DewPoint Heater	313084.40	4389884.10	1251.48	12.0	366.5	0.62	0.4	0.07	0.07	0.01	0.79	0.94
FP	Diesel Fire Pump	313685.00	4389861.10	1248.48	4.0	761.5	4.79	0.8	0.59	0.59	0.02	10.17	1.02

APPENDIX B. EQUIPMENT SPECIFICATION

Cogeneration Plant Estimated Performance Summary

Stella Power

March 17, 2026

Performance listed below is estimated, not guaranteed.

Gas Turbine: (1) Titan 130-23001S Axial with SCR and CO Catalyst Emission Control System	
KW Gross Output @ ISO Conditions:	16,520 KW
Site Ambient Temperature for Performance Analysis:	105 °F
Site Elevation for Performance Analysis:	4,200 feet
Site Ambient Relative Humidity for Performance Analysis:	60 %
Turbine Inlet Pressure Loss:	4.0 "H2O
Turbine Outlet Pressure Loss:	7.0 "H2O
Turbine Fuel Consumption @ specified site conditions (LHV):	117.7 MMBtu/hr
KW Gross Output @ specified site conditions:	11,195 KW
Gas Compressor Power:	0 kW
Turbine Auxiliary Power:	51 KW
Total Auxiliary Power Consumption:	51 KW
Net Gas Turbine Power Production:	11,144 KW

Cycle Performance (lower heating value basis):	
Net Turbine Electrical Heat Rate:	10,560 Btu/kWHR
Gross Plant Heat Rate (Process steam or Tons converted to equivalent KW):	10,560 Btu/kWHR
Overall Cycle Efficiency (LHV):	32.3 %

STEPP Version 2507

Fuel Information:			
HHV/LHV	1.109	Wobbe	1215.2
Btu/lbm, (HHV)	22,866	Btu/SCF, (HHV)	1041.8
Btu/lbm, (LHV)	20,610	Btu/SCF, (LHV)	939.0
Molecular Weight	43.73	lbs of CO2/MMBtu	118.3

Caterpillar Confidential: Do not disclose without Solar's approval

Estimated Power Island Emissions

Stella Power

Estimated using data available as of March 17, 2026

(1) Titan 130-23001S Axial with SCR and CO Catalyst Emission Control System		Plant Total
Ambient Temperature	°F	105.0
Gross Power Output	kW	11,195
Fuel Type	Natural Gas	
Assumed Fuel Sulfur Content	lbm/MMBtu*	0.0034
Gas Turbine Exhaust Flow	lbm/hr	332,800
Stack Exhaust Flow	lbm/hr	332,800
Flue Gas Temperature Leaving Gas Turbine	°F	968
Flue Gas Temperature At Stack	°F	968
Heat Input to Gas Turbine	MMBtu/hr*	131.0
PM10/PM2.5 Particulates from Gas Turbine	lbm/MMBtu*	0.01
Turbine Exhaust Gas Analysis		
H2O, assumes 60% relative humidity	% vol	11.1%
N_2	% vol	71.7%
CO_2	% vol	2.9%
O_2	% vol	13.4%
SO_2	% vol	0.0%
Argon	% vol	0.9%
Gas Turbine Exhaust Emissions		
NOx	ppm@15%O2	9
	lbm/hr	4.28
CO	ppm@15%O2	15
	lbm/hr	4.34
UHC	ppm@15%O2	15
	lbm/hr	2.48
$PM_{10}/PM_{2.5}$	lbm/hr	1.31
SO_2	lbm/hr	0.444
CO_2	lbm/hr	15,300
Exhaust Emissions At Stack		
NOx (assumes 78% reduction SCR)	ppm@15%O2	2.0
	lbm/MMBtu*	0.00728
	lbm/hr	0.95
	short tons/yr	4.16
CO (assumes 80% reduction CO catalyst)	ppm@15%O2	3.0
	lbm/MMBtu*	0.00665
	lbm/hr	0.869
	short tons/yr	3.8
UHC	ppm@15%O2	15.0
	lbm/MMBtu*	0.019
	lbm/hr	2.48
	short tons/yr	10.9
VOC	ppm@15%O2	2.0
	lbm/MMBtu*	0.00114
	lbm/hr	0.149
	short tons/yr	0.652
$PM_{10}/PM_{2.5}$	lbm/hr	1.31
	lbm/MMBtu*	0.01
	short tons/yr	5.72
SO_2	lbm/hr	0.444
	lbm/MMBtu*	0.0034
	short tons/yr	1.94
SCR Ammonia Slip	ppm@15%O2	5
SCR Reduction Efficiency	%	78%
CO Catalyst Reduction Efficiency	%	80%
VOC Catalyst Reduction Efficiency	%	0%
CO_2	lbm/MMBtu*	118
	lbm/hr	15,400
	short tons/yr	67,600
	tonne/year	61,400

(1) Titan 130-23001S Axial with SCR and CO Catalyst Emission Control System	**Plant Total**

*HHV

(1) Titan 130-23001S Axial with SCR and CO Catalyst Emission Control System	**Plant Total**

Emissions Notes:

1. This document is for initial emissions estimates only. For air permit applications, Solar can provide appropriate site-specific turbine emissions documentation.

2. Fuels must comply with Solar specification ES 9-98. Actual emissions may vary due to site fuel characteristics. Zero fuel bound nitrogen is assumed for gaseous fuels, and less than 0.02% for liquid fuels.

3. Turbine "ppm" values are applicable for operation at ambient temperatures between 0 and 120°F.

4. The table below gives the load ranges to which the turbine ppm emissions listed above apply. Mass based estimates are valid at ambient temperature and operating load noted.

Pollutant	Load Range
NOx	50 to 100%
CO	50 to 100%
UHC	50 to 100%

5. SO2 emissions depend upon the fuel's sulfur content. The SO2 estimate is based upon EPA's AP-42 document (Tables 3.1-2a. and 3.1-2b. April 2000).

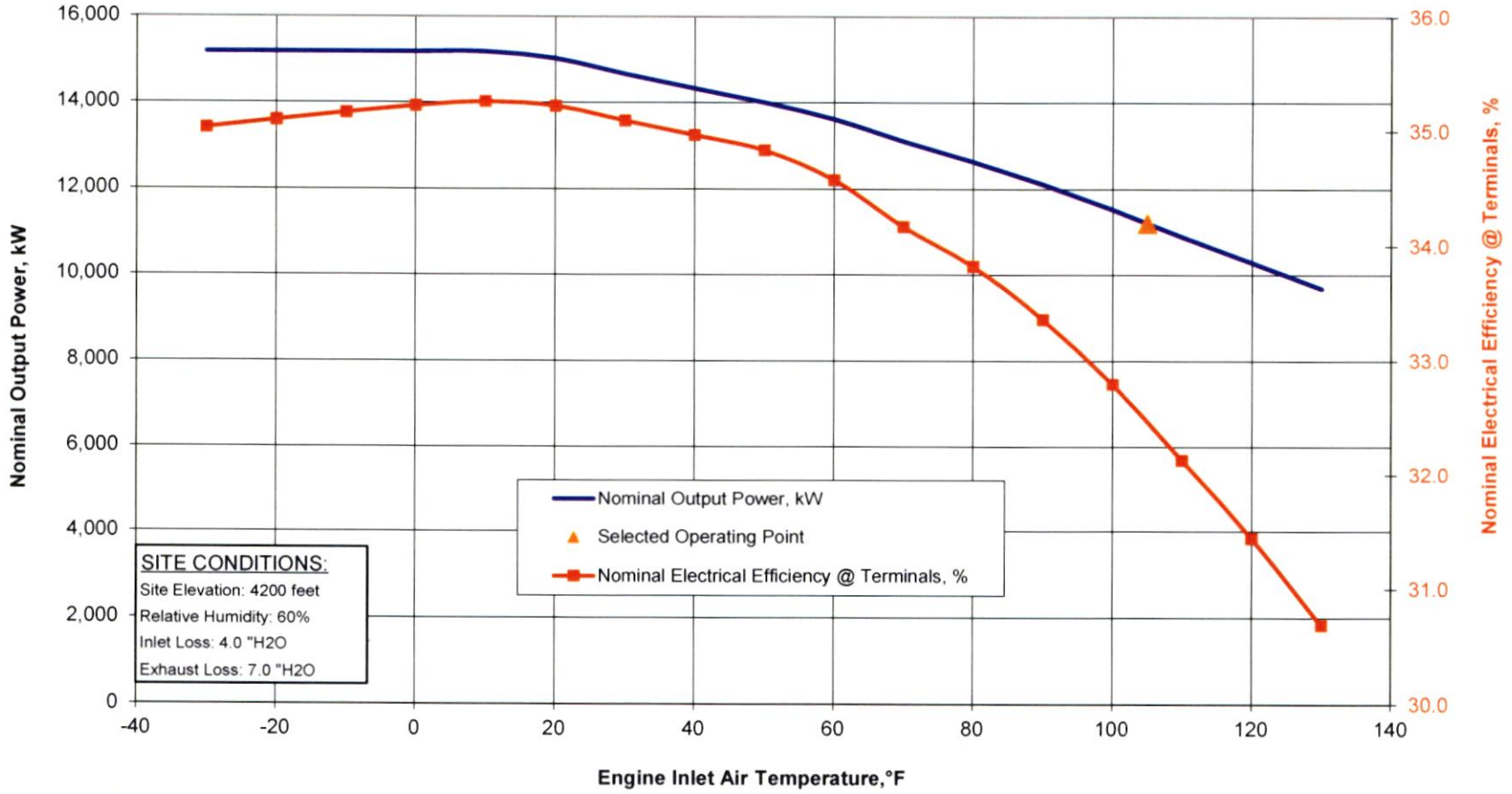
6. Annual estimates shown above assume 8760 hours/year operation.

For more information contact: , ,

Caterpillar Confidential: Do not disclose without Solar's approval

Titan 130-23001S Axial (Natural Gas)

FULL LOAD PERFORMANCE



Caterpillar Confidential: Do not disclose without Solar's approval STEPP Version 2507

RE: List of Inputs Needed

Reply | Reply All | Forward | ...

Thu 2/12/2026 11:30 AM

TM Tony Mente <tony.mente@stellapowerco.com>
To Casey Elliott
Cc Matthew Tarnoff; Andrew Reese; Nash Whitney; Nasiol Saro

Hey Casey,

Adding to the below. I got a response back from Solar on some of the pending points.

1. Stack temperature and flow rate are:
   Max operating exhaust gas temperature: 1040°F SoLoNox engine, @104°F ambient temperature and 50% load.
   Max exhaust gas flow: 478623 lb/h @ -4°F ambient temperature and 100% load.
   Gas temperature at max flow: 869°F @-4°F ambient temperature and 100% load.
2. Emissions
   Values in the table are ok.
   For the PM, start and stop are both <0.5 lb/event.
   Do not take any permitted limits on SUSD. The data is estimated only. Our SUSD lb/event data is estimate only and is intended to be used with PTE calculations not explicit emissions limits for the permit. There is no way to accurately measure emissions during SUSD even though some states may blindingly push this concept it should never be assented to.

Tony Mente
Stella Power Co.
+1 262.409.5273

APPENDIX C. NDEP FORMS

Class I

Air Quality Operating Permit (AQOP), Operating Permit to Construct (OPTC), and Prevention of Significant Deterioration (PSD)
Application Form

Facility Name: Stella Power Assets, LLC
Existing Facility ID: AN/A
Existing Class I AQOP/OPTC: AP N/A
Type of Facility: Electrical Generating Station
Number of Units (including IA's) in Facility: 38
Number of Units (including IA's) Affected in Action: 38

Application Type:

- ☒ New AQOP
- ☐ Minor Revision of Existing AQOP
- ☐ Significant Revision of Existing AQOP
- ☐ Renewal of Existing AQOP
- ☐ New OPTC
- ☐ Revision of OPTC
- ☐ Rollover OPTC to a New AQOP
- ☐ Rollover OPTC to Existing AQOP
- ☐ Administrative Revision of Existing AQOP
- ☐ New PSD AQOP
- ☐ Major PSD Revision of AQOP
- ☐ New PSD OPTC
- ☐ Major PSD Revision of OPTC

NDEP

Please Submit Application to:
Nevada Division of Environmental Protection
Bureau of Air Pollution Control, Class I Permitting Branch
901 South Stewart Street, Suite 4001
Carson City, Nevada 89701-5249
Phone (775) 687-9349

September 2024
(Ver. 5)

IMPORTANT INFORMATION

- The Application packet contains:
  - General Company Information Form
  - Industrial Process Application Form
  - Combustion Equipment Application Form
  - Storage Silo Application Form
  - Liquid Storage Tanks Application Form
  - Facility-Wide Potential to Emit Table
  - Surface Area Disturbance Form
  - Plant Boundary Coordinates Form
  - Plant Building Parameters Forms
  - Application Certification Document with Required Attachments

- Please see the Guidance Document located at https://ndep.nv.gov/air/permitting/download-permit-forms for additional instructions on how to complete the application.
- The application is available from the Nevada Division of Environmental Protection – Bureau of Air Pollution Control (BAPC) in a Microsoft Word file, or on the internet at https://ndep.nv.gov/air/permitting/download-permit-forms. A printed copy of the application must be submitted (mailed or hand delivered), along with an electronic version.
- The application filing fee required by Nevada Administrative Code (NAC) 445B.327 must be submitted with the completed application. Checks must be made payable to the "Nevada State Treasurer, Environmental Protection" with "BAPC" noted in the memo line. Fees may also be submitted electronically at https://epayments.ndep.nv.gov/.
- This application shall be used for a new, renewal, and revision of Class I sources, including AQOP, OPTC, rollover OPTC, and PSD actions.
- An application for a Class I AQOP, OPTC, and PSD must be signed by the Responsible Official, as defined in NAC 445B.156. The certification document (signature page) is the last page of the application and the original "wet" signature must be provided.
- All items in the application must be addressed. If an item does not apply "N/A" or similar notation must be entered in the appropriate blank. All other information must be provided. Incomplete applications will be returned to the Responsible Official within:
  - 45 days for a new or revision of Class I OPTC. (NAC 445B.3364(1))
  - 30 days for sources subject to permitting requirements set forth in 40 CFR 52.21 applying for a new or revision of Class I PSD OPTC. (NAC 445B.3364(2))
  - 60 days for a new, significant revision, or renewal of Class I AQOP. (NAC 445B.3395(1), NAC 445B.3443(3))
  - 10 working days for a minor revision of Class I AQOP. (NAC 445B.3395(5))
  - 30 days for sources subject to permitting requirements set forth in 40 CFR 52.21 applying for a new of Class I PSD. (NAC 445B.3395(2))
  - 45 days for an administrative revision of Class I OPTC. (NAC 445B.3441(2) and NAC 445B.3364(1))

IMPORTANT INFORMATION (continued)

- For the renewal of a Class I Operating Permit, a **complete** application and corresponding processing fee must be submitted in accordance with NAC 445B.3443(2) at least 240 days prior to the expiration date of the current permit but not earlier than 18 months. The BAPC suggests that the application be submitted well in advance of the timeline outlined in NAC 445B.3443 to ensure the application is deemed complete. The BAPC has 60 days to deem the application complete or incomplete. As stated above, incomplete applications will be returned within 60 days of the receipt of the application. Therefore, the BAPC recommends the application be submitted at least 300 days prior to expiration of the current permit.
- For stationary sources subject to the provisions regarding new source review set forth in United States Code (U.S.C.) Title 42 7501 through 7515, inclusive (nonattainment areas), include all information required by U.S.C. Title 42 7503 pursuant to NAC 445B.3363(2)(b)(3).
- For a proposed new major source or a proposed major modification to an existing stationary source that is subject to the provisions of 40 CFR 52.21, include all information required by 40 CFR 52.21 pursuant to NAC 445B.3368(3)(a).
- For a proposed new major source, or a proposed significant revision to an existing stationary source which is not subject to the provisions of 40 CFR 52.21, include all information as required by NAC 445B.308 through 445B.313, inclusive, pursuant to NAC 445B.3368(3)(b).
- For a proposed new major source or a proposed significant revision to an existing stationary source which is subject to the requirements of U.S.C. Title 42 7412 regarding hazardous air pollutants, include all information required by NAC 445B.308 through 445B.313, inclusive, pursuant to NAC 445B.3368(3)(c).

GENERAL COMPANY INFORMATION FORM

1. **Briefly describe the permitted facility's process and include the Standard Industrial Classification (SIC) number and North American Industry Classification System (NAICS). Add details in the attached Process Narrative.**

   Stella Power Co. (Stella) is proposing to construct an electrical generating station consisting of natural gas turbines. SIC Code 4911 "Electric Services" and NAICS code 221112 "fossil fuel powered electrical power generation facilities"

2. **Company Name and Address that are to appear on the operating permit [NAC 445B.295(1)]:**

   Name: Stella Power Assets, LLC
   Address: TBD Innovation Drive
   City: Fernley
   State: Nevada Zip Code: 89408

3. **Owner's Name and Address [NAC 445B.295(1)]:**

   Name: Stella Power Assets, LLC
   Address: 600 Cleveland Ave, Suite 304
   City: Clearwater
   State: Florida Zip Code: 33755

4. **Facility Name and Physical Address, if different from #2 [NAC 445B.295(1)]:**

   Name: N/A
   Address:
   City:
   State: Zip Code:

5. **If records required under the operating permit will be kept at a location other than the facility, specify that location [NAC 445B.295(7)]:**

   Name: N/A
   Address:
   City:
   State: Zip Code:

GENERAL COMPANY INFORMATION FORM (continued)

6. Responsible Official Name, Title and Mailing Address [NAC 445B.295(1)]:

Name:	Tony Mente
Title:	Chief of Engineering & Technology
Address:	600 Cleveland Ave, Suite 304
City:	Clearwater
State:	Florida Zip Code: 89032
Phone Number:	702.643.4940
Fax Number:	
E-mail Address:	Tony.Mente@StellaPowerCo.com

Is this a new Responsible Official? ☒ Yes ☐ No

If yes, and the Responsible Official (RO) does not meet the definition under NAC 445B.156 then please fill out the "Responsible Official Identification/Designation/Change Request Form" and mail it in. (https://ndep.nv.gov/air/permitting/download-permit-forms)

7. Plant Manager or other appropriate Contact Name, Title and Address [NAC 445B.295(1)]:

Name:	Tony Mente
Title:	Chief of Engineering & Technology
Address:	600 Cleveland Ave, Suite 304
City:	Clearwater
State:	Florida Zip Code: 89032
Phone Number:	702.643.4940
Fax Number:	
E-mail Address:	Tony.Mente@StellaPowerCo.com

8. Location and Driving Directions to the Facility (For Example: From Elko, Nevada, 4 miles south of I-80 at xx Interchange) [NAC 445B.295(8)]:

Hydrographic Basin (HA) Number: HA 076
HA Basin Name: Fernley Area

Township(s): 21N N; Range(s): 25E E; Section(s): 33

UTM Coordinates for the Front Gate of the Facility (NAD 83, Zone 11):
4,390,040.94 m North; 313,190.52 m East;

Nearest City: Fernley
County: Lyon

Driving Directions from nearest city to the Facility:
From Fernley, drive east on Highway 80 until Exit 50 to Nevada Pacific Parkway. Take a right until Duffy Road. Take a left at Duffy Road After ~1 mile, the Facility will be on the right.

GENERAL COMPANY INFORMATION FORM (continued)

9. Emission Cap Requested [NAC 445B.070, NAC 445B.296(2), NAC 445B.296(3)]:

☐ Yes ☒ No (If yes, provide details in the attached Process Narrative)

10. **Important note** for completing the Industrial Process, Combustion Equipment, Storage Silo, and Liquid Storage Tank Application Forms: forms need to be included for all permitted emission units and insignificant activities. Provide additional forms as needed. All items in the application must be addressed. If an item does not apply, then "N/A" or similar notation (TDB, unknown, etc.) must be entered in the appropriate blank.

11. Check one that applies:

☐ Major Stationary Source [40 CFR 52.21]

☐ Minor Source [40 CFR 71.2]

☐ New Source Review (NSR) Synthetic Minor Source [40 CFR 49.167]

12. Is the Facility subject to 40 CFR 51.307 and 52.21(p) (i.e., located within 100 km of a Class I Federal Area within Nevada and any adjacent states, for example Jarbidge Wilderness Area) protected by the Regional Haze Program (40 CFR Part 81)?

☐ Yes ☒ No

13. Check any of the following that apply to this application:

☐ Involve significant changes to the existing requirements for monitoring, reporting, or recordkeeping.

☐ Require or change a determination of an emission limitation or other standard on a case-by-case basis.

☒ Require or change a visibility or increment analysis.

☐ Require or change a determination of ambient impact for any temporary source.

☐ Establish or change a condition of the operating permit for which there is no a federally enforceable emissions cap and/or an alternative emission limitation pursuant to U.S.C. Title 42 7412(i)(5).

☐ Result in an increase in allowable emissions that exceeds any of the following specified thresholds: Carbon monoxide, 100 tons per year; Nitrogen oxides, 40 tons per year; Sulfur dioxide (SO_2), 40 tons per year; Particulate Matter less than or equal to 10 microns in diameter (PM_{10}), 15 tons per year; Ozone (O_3), 40 tons per year of volatile organic compounds (VOC); Sulfuric acid mist, 7 tons per year; and Hydrogen sulfide (H_2S), 10 tons per year.

☐ Modification pursuant to any provision of U.S.C. Title 42 7401 to 7515, inclusive, or a major modification at an existing major stationary source.

If any of the boxes were checked above, a minor revision may not be made to the Class I Operating Permit pursuant to NAC 445B.3425.

14. Will the Facility be constructed in more than one phase [NAC 445B.3395(17)]?

☐ Yes ☒ No (If yes, provide details in the attached Process Narrative)

GENERAL COMPANY INFORMATION FORM (continued)

15. Will the facility violate any "Applicable requirement" pursuant to NAC 445B.019?
☐ Yes ☒ No

16. Verify facility's compliance status for the following regulations and describe the reason for exemption if applicable:

FEDERALLY ENFORCEABLE REQUIREMENTS			
NAC 445B.225	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.315(3)(h)	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.315(3)(i)	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.315(3)(k)	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
40 CFR 52.21(r)(4)	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.252	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.22067	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.22093	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.22037	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.227	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
40 CFR Parts 60.1-60.19, 61.01-61.19, 61.140-61.157, 63.1-63.15, and 70	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
40 CFR Part 82	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.230	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.22017	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*

STATE REQUIREMENTS			
NRS 445B.470	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.22013	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.326(1)	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 445B.22087	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*
NAC 459.952-459.95528	☒ Compliant	☐ Not Compliant	☐ Exempt, *Reason for Exemption*

17. Has the facility provided modeling for each non-combustion baghouse individually? (See Testing Determination System for Baghouses Guidance Document)
☐ **Yes** ☒ No

COMBUSTION EQUIPMENT APPLICATION FORM
CLASS I OPERATING PERMIT

System Number and Name: **System 1 – Natural Gas Turbines**

Emission Unit Description: **36 Natural Gas Fired Turbines**

Alternative Operating Scenario: ☐ **Yes** ☒ **No**

Insignificant Activity: ☐ **Yes** ☒ **No** If yes, identify exemption regulation: _____

Description			Data
Equipment Description	BAPC Emission Unit ID *Applicable for Renewal or Revision*	eg. Unit ID: S2.001	S2.001 – S2.036
	Source Classification Code (SCC)	e.g. *3-03-024-04 for Conveyors*	20100201
	Manufacturer		Solar Turbines
	Date Manufactured		TBD
	Model and Serial Number		MN: Titan 130 23001S, SN: TBD
	Emissions Released Inside building?	yes/no	no
For Reciprocating Internal Combustion Engines (RICE) Only	Type of Engine Code (See Notes*)		N/A
	Date Constructed	month/day/yr	N/A
	Cylinder Displacement	liter/cylinder	N/A
	EPA Tier #		N/A
Location of Emission Source	UTM Northing (NAD 83, Zone 11)	m	Various - See modeling report
	UTM Easting (NAD 83, Zone 11)	m	Various - See modeling report
Operating Parameters /Fuel Usage	Fuel Type		Pipeline quality natural gas
	Fuel Flow Meter Installed?	yes/no/NA	Yes
	Sulfur Content	%	0.0005
	Heat Content	Btu/*unit*	1,060 btu/scf
	Start Time *if operating less than 24 hours/day*	hour:minute	N/A
	End Time *if operating less than 24 hours/day*	hour:minute	N/A
Control Equipment	Manufacturer		SCR and Oxidation Catalyst
	Manufacturer's Guarantee Included? *If "yes", attach manufacturer's sheets immediately after these forms.*	yes/N/A	Yes
Stack Parameters	Stack Height	feet	50
	Stack Inside Diameter	feet	8
	Stack Temperature	°F	Steady State – 968, SUSD - 1040
	Stack Exit Velocity	feet/second	Steady State – 29.76, SUSD – 16.45
	Actual Gas Volume Flow Rate	acfm	
	Dry Gas Volume Flow Rate *If not included in detailed calculations.*	dscfm	Steady State – 89,831, SUSD – 49,607
	Stack Release Type		☒ vertical ☐ capped ☐ horizontal

Notes*

Code	Description	Code	Description
LU	Limited Use	E-SI	Emergency Spark Ignition
LDG	Landfill/Digester Gas	SI4SRB	Spark Ignition 4-Stroke Rich Burn
NECI	Non-Emergency Compression Ignition	SI4SLB	Spark Ignition 4-Stroke Lean Burn
ECI	Emergency Compression Ignition	SI2SLB	Spark Ignition 2-Stroke Lean Burn

COMBUSTION EQUIPMENT APPLICATION FORM
CLASS I OPERATING PERMIT (continued)

Emission Unit Description: **Natural Gas Fired Turbine**

1. Subject to a Federal Regulation specific to the emission unit (e.g. 40 CFR Part 60, 61, 63, 64, 76, or other): ☒ **Yes** ☐ **No** If yes, identify regulation and applicability and include required analysis or plans (e.g. siting analysis or Continuous Assurance Monitoring (CAM) plans).
   NSPS Subpart KKKKa- Stationary Combustion Turbines

2. Subject to a State Regulation specific to the emission unit (e.g. NAC 445B.2203, NAC 445B.22047, NAC 445B.22017): ☒ **Yes** ☐ **No** If yes, identify regulation and applicability.
   Subject to NAC 445B.2203, 22047, and 22017 for opacity, particulate emissions, and sulfur emissions for fuel-burning equipment.

3. Identify standards for work practices which affect emissions for all regulated air pollutants (e.g. At all times, including startup, shutdown and malfunction).
   At all times, including startup, shutdown and malfunction, the emission unit will be operated in a manner consistent with good air pollution control practices. NRI qualified technicians and/or the third party preferred vendors conduct periodic preventive/ predictive maintenance on a weekly, monthly, quarterly, and annual basis to meet or exceed manufactured recommendations

4. Identify and describe compliance and performance testing with reference to any applicable test methods, monitoring devices, compliance plan, or other activities required to determine compliance with an applicable requirement (e.g. Emissions from this unit will be monitored by CEMS and/or COMS for the specific pollutant(s) (NO_X, CO, etc.)).
   Performance testing will be conducted on various turbines at various points in time to confirm emission profile compliance.

5. How will fuel consumption be monitored for this emission unit? (e.g. maximum fuel consumption rate supplied by manufacturer, fuel flow meter).
   Fuel flow meter

6. Does this unit have the capability to bypass air pollution controls in an emergency situation as defined under NAC 445B.056?:
   ☐ **Yes** ☒ **No**

COMBUSTION EQUIPMENT APPLICATION FORM
CLASS I OPERATING PERMIT

System Number and Name: **System 2 – Natural Gas Fired Dewpoint Heater**

Emission Unit Description: **1 Natural Gas Fired Dewpoint Heater**

Alternative Operating Scenario: ☐ **Yes** ☒ **No**

Insignificant Activity: ☐ **Yes** ☒ **No** If yes, identify exemption regulation: _____

Description			Data
Equipment Description	BAPC Emission Unit ID *Applicable for Renewal or Revision*	eg. Unit ID: S2.001	S2.037
	Source Classification Code (SCC)	e.g. *3-03-024-04 for Conveyors*	10200602
	Manufacturer		TBD
	Date Manufactured		TBD
	Model and Serial Number		MN: TBD, SN: TBD
	Emissions Released Inside building?	yes/no	no
For Reciprocating Internal Combustion Engines (RICE) Only	Type of Engine Code (See Notes*)		N/A
	Date Constructed	month/day/yr	N/A
	Cylinder Displacement	liter/cylinder	N/A
	EPA Tier #		N/A
Location of Emission Source	UTM Northing (NAD 83, Zone 11)	m	4,390,240.60
	UTM Easting (NAD 83, Zone 11)	m	313,378.60
Operating Parameters /Fuel Usage	Fuel Type		Pipeline quality natural gas
	Fuel Flow Meter Installed?	yes/no/NA	Yes
	Sulfur Content	%	0.0005
	Heat Content	Btu/*unit*	1,060 btu/scf
	Start Time *if operating less than 24 hours/day*	hour:minute	N/A
	End Time *if operating less than 24 hours/day*	hour:minute	N/A
Control Equipment	Manufacturer		N/A
	Manufacturer's Guarantee Included? *If "yes", attach manufacturer's sheets immediately after these forms.*	yes/N/A	N/A
Stack Parameters	Stack Height	feet	39.3
	Stack Inside Diameter	feet	1.17
	Stack Temperature	°F	200
	Stack Exit Velocity	feet/second	2.03
	Actual Gas Volume Flow Rate	acfm	
	Dry Gas Volume Flow Rate *If not included in detailed calculations.*	dscfm	1,229
	Stack Release Type		☒ vertical ☐ capped ☐ horizontal

Notes*

Code	Description	Code	Description
LU	Limited Use	E-SI	Emergency Spark Ignition
LDG	Landfill/Digester Gas	SI4SRB	Spark Ignition 4-Stroke Rich Burn
NECI	Non-Emergency Compression Ignition	SI4SLB	Spark Ignition 4-Stroke Lean Burn
ECI	Emergency Compression Ignition	SI2SLB	Spark Ignition 2-Stroke Lean Burn

COMBUSTION EQUIPMENT APPLICATION FORM
CLASS I OPERATING PERMIT (continued)

Emission Unit Description: **Natural Gas Fired Dewpoint Heater**

1. Subject to a Federal Regulation specific to the emission unit (e.g. 40 CFR Part 60, 61, 63, 64, 76, or other): ☐ **Yes** ☒ **No** If yes, identify regulation and applicability and include required analysis or plans (e.g. siting analysis or Continuous Assurance Monitoring (CAM) plans).

2. Subject to a State Regulation specific to the emission unit (e.g. NAC 445B.2203, NAC 445B.22047, NAC 445B.22017): ☒ **Yes** ☐ **No** If yes, identify regulation and applicability.
   Subject to NAC 445B.2203, 22047, and 22017 for opacity, particulate emissions, and sulfur emissions for fuel-burning equipment.

3. Identify standards for work practices which affect emissions for all regulated air pollutants (e.g. At all times, including startup, shutdown and malfunction).
   At all times, including startup, shutdown and malfunction, the emission unit will be operated in a manner consistent with good air pollution control practices. NRI qualified technicians and/or the third party preferred vendors conduct periodic preventive/ predictive maintenance on a weekly, monthly, quarterly, and annual basis to meet or exceed manufactured recommendations

4. Identify and describe compliance and performance testing with reference to any applicable test methods, monitoring devices, compliance plan, or other activities required to determine compliance with an applicable requirement (e.g. Emissions from this unit will be monitored by CEMS and/or COMS for the specific pollutant(s) (NO_X, CO, etc.)).
   N/A

5. How will fuel consumption be monitored for this emission unit? (e.g. maximum fuel consumption rate supplied by manufacturer, fuel flow meter).
   Fuel flow meter

6. Does this unit have the capability to bypass air pollution controls in an emergency situation as defined under NAC 445B.056?:
   ☐ **Yes** ☒ **No**

COMBUSTION EQUIPMENT APPLICATION FORM
CLASS I OPERATING PERMIT

System Number and Name: **System 3 – Diesel Fired Emergency Fire Pump**

Emission Unit Description: **1 Diesel Gas Fired Emergency Fire Pump**

Alternative Operating Scenario: ☐ **Yes** ☒ **No**

Insignificant Activity: ☐ **Yes** ☒ **No** If yes, identify exemption regulation: _____

Description			Data
Equipment Description	BAPC Emission Unit ID *Applicable for Renewal or Revision*	eg. Unit ID: S2.001	S2.038
	Source Classification Code (SCC)	e.g. *3-03-024-04 for Conveyors*	2102004002
	Manufacturer		TBD
	Date Manufactured		TBD
	Model and Serial Number		MN: TBD, SN: TBD
	Emissions Released Inside building?	yes/no	no
For Reciprocating Internal Combustion Engines (RICE) Only	Type of Engine Code (See Notes*)		N/A
	Date Constructed	month/day/yr	N/A
	Cylinder Displacement	liter/cylinder	N/A
	EPA Tier #		N/A
Location of Emission Source	UTM Northing (NAD 83, Zone 11)	m	4,389,827.0
	UTM Easting (NAD 83, Zone 11)	m	313,653.5
Operating Parameters /Fuel Usage	Fuel Type		ULSD
	Fuel Flow Meter Installed?	yes/no/NA	Yes
	Sulfur Content	%	0.0015%
	Heat Content	Btu/*unit*	7,000 btu/hp-hr
	Start Time *if operating less than 24 hours/day*	hour:minute	N/A
	End Time *if operating less than 24 hours/day*	hour:minute	N/A
Control Equipment	Manufacturer		N/A
	Manufacturer's Guarantee Included? *If "yes", attach manufacturer's sheets immediately after these forms.*	yes/N/A	N/A
Stack Parameters	Stack Height	feet	13.1
	Stack Inside Diameter	feet	2.62
	Stack Temperature	°F	911
	Stack Exit Velocity	feet/second	4.79 m/s
	Actual Gas Volume Flow Rate	acfm	
	Dry Gas Volume Flow Rate *If not included in detailed calculations.*	dscfm	1964
	Stack Release Type		☒ vertical ☐ capped ☐ horizontal

Notes*

Code	Description	Code	Description
LU	Limited Use	E-SI	Emergency Spark Ignition
LDG	Landfill/Digester Gas	SI4SRB	Spark Ignition 4-Stroke Rich Burn
NECI	Non-Emergency Compression Ignition	SI4SLB	Spark Ignition 4-Stroke Lean Burn
ECI	Emergency Compression Ignition	SI2SLB	Spark Ignition 2-Stroke Lean Burn

COMBUSTION EQUIPMENT APPLICATION FORM
CLASS I OPERATING PERMIT (continued)

Emission Unit Description: **Diesel Gas Fired Emergency Fire Pump**

1. Subject to a Federal Regulation specific to the emission unit (e.g. 40 CFR Part 60, 61, 63, 64, 76, or other):
☒ **Yes** ☐ **No** If yes, identify regulation and applicability and include required analysis or plans (e.g. siting analysis or Continuous Assurance Monitoring (CAM) plans).
NSPS Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
NESHAP Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

2. Subject to a State Regulation specific to the emission unit (e.g. NAC 445B.2203, NAC 445B.22047, NAC 445B.22017):
☒ **Yes** ☐ **No** If yes, identify regulation and applicability.
Subject to NAC 445B.2203, 22047, and 22017 for opacity, particulate emissions, and sulfur emissions for fuel-burning equipment.

3. Identify standards for work practices which affect emissions for all regulated air pollutants (e.g. At all times, including startup, shutdown and malfunction).
At all times, including startup, shutdown and malfunction, the emission unit will be operated in a manner consistent with good air pollution control practices. NRI qualified technicians and/or the third party preferred vendors conduct periodic preventive/ predictive maintenance on a weekly, monthly, quarterly, and annual basis to meet or exceed manufactured recommendations

4. Identify and describe compliance and performance testing with reference to any applicable test methods, monitoring devices, compliance plan, or other activities required to determine compliance with an applicable requirement (e.g. Emissions from this unit will be monitored by CEMS and/or COMS for the specific pollutant(s) (NO_X, CO, etc.)).
N/A

5. How will fuel consumption be monitored for this emission unit? (e.g. maximum fuel consumption rate supplied by manufacturer, fuel flow meter).
Fuel flow meter

6. Does this unit have the capability to bypass air pollution controls in an emergency situation as defined under NAC 445B.056?:
☐ **Yes** ☒ **No**

INDUSTRIAL PROCESS AND STORAGE SILO DETAILED CALCULATIONS

Unit No.	Unit Description	Operating Hours		Throughput			Controls		Emissions					References
		Daily	Annual	Hourly	Annual	Units	Type	Efficiency or Dry Volume Flow Rate	Pollutant	Factor	Unit	Hourly Rate (lbs/hr)	Yearly Rate (tons/yr)	
System No. & Name:									**Uncontrolled**					
See Detailed Emission Calculations									PM					
									PM_{10}					
									$PM_{2.5}$					
									Controlled					
									PM					
									PM_{10}					
									$PM_{2.5}$					
System No. & Name:									**Uncontrolled**					
									PM					
									PM_{10}					
									$PM_{2.5}$					
									Controlled					
									PM					
									PM_{10}					
									$PM_{2.5}$					
System No. & Name:									**Uncontrolled**					
									PM					
									PM_{10}					
									$PM_{2.5}$					
									Controlled					
									PM					
									PM_{10}					
									$PM_{2.5}$					
System No. & Name:									**Uncontrolled**					
									PM					
									PM_{10}					
									$PM_{2.5}$					
									Controlled					
									PM					
									PM_{10}					
									$PM_{2.5}$					
System No. & Name:									**Uncontrolled**					
									PM					
									PM_{10}					
									$PM_{2.5}$					
									Controlled					
									PM					
									PM_{10}					
									$PM_{2.5}$					

*Exact format may be changed, but requested information is still required.

COMBUSTION EQUIPMENT DETAILED CALCULATIONS

Unit No.	Unit Description	Operating Hours		Heat Input (MMBtu)		Fuel Usage			Power Output		Controls		Emissions					References
		Daily	Annual	Hourly	Annual	Hourly	Annual	Units	Amount	Units	Type	Efficiency or Dry Volume Flow Rate	Pollutant	Factor	Unit	Hourly Rate (lbs/hr)	Yearly Rate (tons/yr)	
System No. & Name:													**Uncontrolled**					
													PM					
													PM_{10}					
													$PM_{2.5}$					
													SO_2					
													NO_X					
													CO					
													VOC					
													Pb					
													Hg					
													H_2S					
													Controlled					
													PM					
													PM_{10}					
													$PM_{2.5}$					
													SO_2					
													NO_X					
													CO					
													VOC					
													Pb					
													Hg					
													H_2S					
System No. & Name:													**Uncontrolled**					
													PM					
													PM_{10}					
													$PM_{2.5}$					
													SO_2					
													NO_X					
													CO					
													VOC					
													Pb					
													Hg					
													H_2S					
													Controlled					
													PM					
													PM_{10}					
													$PM_{2.5}$					
													SO_2					
													NO_X					
													CO					
													VOC					
													Pb					
													Hg					
													H_2S					

See Detailed Emission Calculations

*Exact format may be changed, but requested information is still required.

GREENHOUSE GASES (GHG) DETAILED CALCULATIONS

Unit No.	Unit Description	Operating Hours		Heat Input (MMBtu)		Fuel Usage			Controls		Emissions					References
		Daily	Annual	Hourly	Annual	Hourly	Annual	Units	Type	Efficiency or Dry Volume Flow Rate	Pollutant	Factor	Unit	Hourly Rate (lbs/hr)	Yearly Rate (tons/yr)	
	System No. & Name:															
	See Detailed Emission Calculations															
	System No. & Name:															
											CO_2					
											CH_4					
											N_2O					
	System No. & Name:															
											CO_2					
											CH_4					
											N_2O					
	System No. & Name:															
											CO_2					
											CH_4					
											N_2O					
	System No. & Name:															
											CO_2					
											CH_4					
											N_2O					
	System No. & Name:															
											CO_2					
											CH_4					
											N_2O					
	System No. & Name:															
											CO_2					
											CH_4					
											N_2O					
	System No. & Name:															
											CO_2					
											CH_4					
											N_2O					
	System No. & Name:															
											CO_2					
											CH_4					
											N_2O					
	System No. & Name:															
											CO_2					
											CH_4					
											N_2O					

*Exact format may be changed, but requested information is still required.

HAZARDOUS AIR POLLUTANTS (HAPS) DETAILED CALCULATIONS

Unit No.	Unit Description	Operating Hours		Heat Input (MMBtu)		Fuel Usage			Controls		Emissions					References
		Daily	Annual	Hourly	Annual	Hourly	Annual	Units	Type	Efficiency or Dry Volume Flow Rate	Pollutant	Factor	Unit	Hourly Rate (lbs/hr)	Yearly Rate (tons/yr)	
	System No. & Name:															
See Detailed Emission Calculations																

*Exact format may be changed, but requested information is still required.

FACILITY-WIDE POTENTIAL TO EMIT TABLE
(FOR ALL SOURCES INCLUDING INSIGNIFICANT ACTIVITIES)
(POUND/HOUR AND TON/YEAR)

Pollutant	Facility-Wide Potential to Emit (pound/hour)	Facility-Wide Potential to Emit (ton/year)
Total Particulate Matter (PM)	22.91	100.33
Total PM_{10}	22.91	100.33
Total $PM_{2.5}$	22.91	100.33
Total Sulfur Dioxide (SO_2)	12.92	56.58
Total Carbon Monoxide (CO)	22.72	99.52
Total Oxides of Nitrogen (NO_X)	28.88	126.48
Total Volatile Organic Compounds (VOC)	11.76	51.52
Total Lead (Pb)	--	--
Total Hydrogen Sulfide (H_2S)	--	--
Total Sulfuric Acid Mist (H_2SO_4)	--	--
Total Hazardous Air Pollutants (HAPs)	2.70	11.80
Total Greenhouse Gases (CO_{2e})	445,578.96	1,951,635.85
Other Regulated Pollutants (Specify)	--	--
Formaldehyde	2.26	8.18

REVISION TABLE

Please complete the table below if this application is for a Minor/Significant **Revision** of an existing Class I Air Quality Operating Permit. Add more columns if needed for any other applicable regulated pollutants. All Potential To Emit (PTE) values must be in tons per year (TPY) [NAC 445B.3425 and NAC 445B.344]

Description	Pollutants									
	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	CO	VOC	HAPs	CO_{2e}	Other
Permitted Facility-Wide PTE (TPY)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Proposed Facility-Wide PTE (TPY)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Change in Facility-Wide PTE (TPY)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

SURFACE AREA DISTURBANCE FORM

1. Total Acres of the Facility Site: 92.4
2. Total Acres Disturbed: 92.4
3. Add Surface Area Disturbance location as Township(s), Range(s) and Section
   Section 33 Township 21 North, Range 25 East
4. NAC 445B.22037 requires fugitive dust to be controlled (regardless of the size or amount of acreage disturbed), and requires an ongoing program, using best practical methods, to prevent particulate matter from becoming airborne. All activities which have the potential to adversely affect the local air quality must implement all appropriate measures to limit controllable emissions. Appropriate measures for dust control may consist of a phased approach to acreage disturbance rather than disturbing the entire area all at once; using wet suppression through such application methods as water trucks or water spray systems to control wind-blown dust; the application of soil binding agents or chemical surfactant to roadways and areas of disturbed soil; as well as the use of wind-break or wind limiting fencing designed to limit wind erosion soils.
5. If the Surface Area Disturbance is greater than 5 acres, please check each box that applies for Best Management Practices (BMPs) used for controlling dust on project's disturbed areas:

   ☒ Water trucks

   ☐ Graveling/paving of roadway storage areas and staging areas

   ☐ Dust palliatives

   ☒ Posting and limiting vehicle speeds to 10-15 miles per hour

   ☐ Ceasing operations during high wind events

   ☐ Fencing or berming to prevent unauthorized access to disturbed areas

   ☒ Application of water sprays on material storage piles on a regular basis

   ☐ Covering material storage piles with tarpaulin or geo-textiles; tenting

   ☐ Use of overhead water spray racks or water hoses

   ☐ Track-out controls (graveled entranced, exit area, and street sweeping)

   ☐ Landscape preservation and impact avoidance

   ☒ Wind fence

   ☐ Pre-watering of areas to be disturbed (including all unpaved onsite roads and staging areas)

   ☐ Inform all subcontractors (including truck drivers) of their responsibilities for the control of fugitive dust while they are on the project site

   ☐ Training of equipment operators to recognize fugitive dust generation and having the authority to shut down operations until water truck arrives and sprays water on the disturbed areas

   ☐ Other Applicable BMPs: Click or tap here to enter text.

   ☐ Other Applicable BMPs: Click or tap here to enter text.

   ☒ If using water trucks, list how many water trucks are used and their capacity in gallons: Unknown & Unknown

PLANT BOUNDARY COORDINATES FORM

Corner Number	UTM Easting	UTM Northing
See Modeling Report		

PLANT BUILDING PARAMETERS FORM

Building Parameters
Building Name: See Modeling Report **Building Tier :** _____
Roof Height (ft): _____ **Building Diameter (ft):** _____

Building UTM Coordinates

UTM Easting	UTM Northing	UTM Easting	UTM Northing

Building Parameters
Building Name: _____ **Building Tier :** _____
Roof Height (ft): _____ **Building Diameter[4] (ft):** _____

Building UTM Coordinates

UTM Easting	UTM Northing	UTM Easting	UTM Northing

APPLICATION CERTIFICATION DOCUMENT

(With Required Attachments)

Please check all applicable boxes below to indicate the information provided in your application submittal:

- ☒ Cover Page
- ☒ General Company Information Form
- ☐ Compliance Plan
- ☐ Industrial Process Application Form(s)
- ☒ Combustion Equipment Application Form(s)
- ☐ Storage Silo Application Form(s)
- ☐ Liquid Storage Tank Application Form(s)
- ☒ Manufacturer's Guarantee
- ☒ Facility-Wide Potential to Emit Table
- ☐ Revision Table
- ☒ Surface Area Disturbance Form
- ☐ Plant Boundary Coordinates Form (See modeling report provided)
- ☐ Plant Building Parameters Form (See modeling report provided)
- ☒ Detailed Emission Calculations (for all emission units including IA units)
- ☐ Source Testing Data (if referenced in calculations)
- ☒ Process Narrative (revision applications must include a description of the revision)
- ☒ Process Flow Diagram(s)
- ☒ Site Plan(s) showing the locations (UTM coordinates), dimensions, and heights of buildings on the site
- ☒ Maps:
  - ☒ Vicinity Map of where the facility is located in the State
  - ☒ Area Map of the Facility (including location of all emission units, building locations (with UTMs), location of front gate, and fence line/site boundary (with UTMs))
- ☒ Environmental Evaluation (AERMOD Air Dispersion Modeling Report and Electronic Input Files) (NAC 445B.310, NAC 445B.311)
- ☒ Manufacturer's Guarantee *if applicable*
- ☒ Equipment Specifications *if applicable*
- ☐ TANKs Modeling Output *if applicable*
- ☒ Application Fee Attached or Electronically Submitted
- ☐ Digital Copy of Application on CD or Thumb Drive
- ☒ Application Certification Document with Original Responsible Official Signature

APPLICATION CERTIFICATION DOCUMENT (CONTINUED)

(With Required Attachments)

PLEASE NOTE THE FOLLOWING REQUIREMENTS WHICH APPLY TO PERMIT APPLICANTS DURING THE APPLICATION PROCESS:

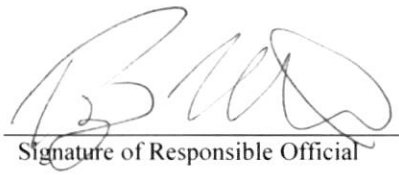
A. A permit applicant must submit supplementary facts or corrected information upon discovery. (NAC 445B.297(1)(b))

B. A permit applicant is required to provide any additional information which the Director requests in writing within the time specified in the Director's request. (NAC 445B.297(1)(c))

C. Submission of fraudulent data or other information may result in prosecution for an alleged criminal offense. (NRS 445B.470)

CERTIFICATION:

I certify that, based on information and belief formed after reasonable inquiry, the statements and information contained in this application are true, accurate and complete.



Signature of Responsible Official

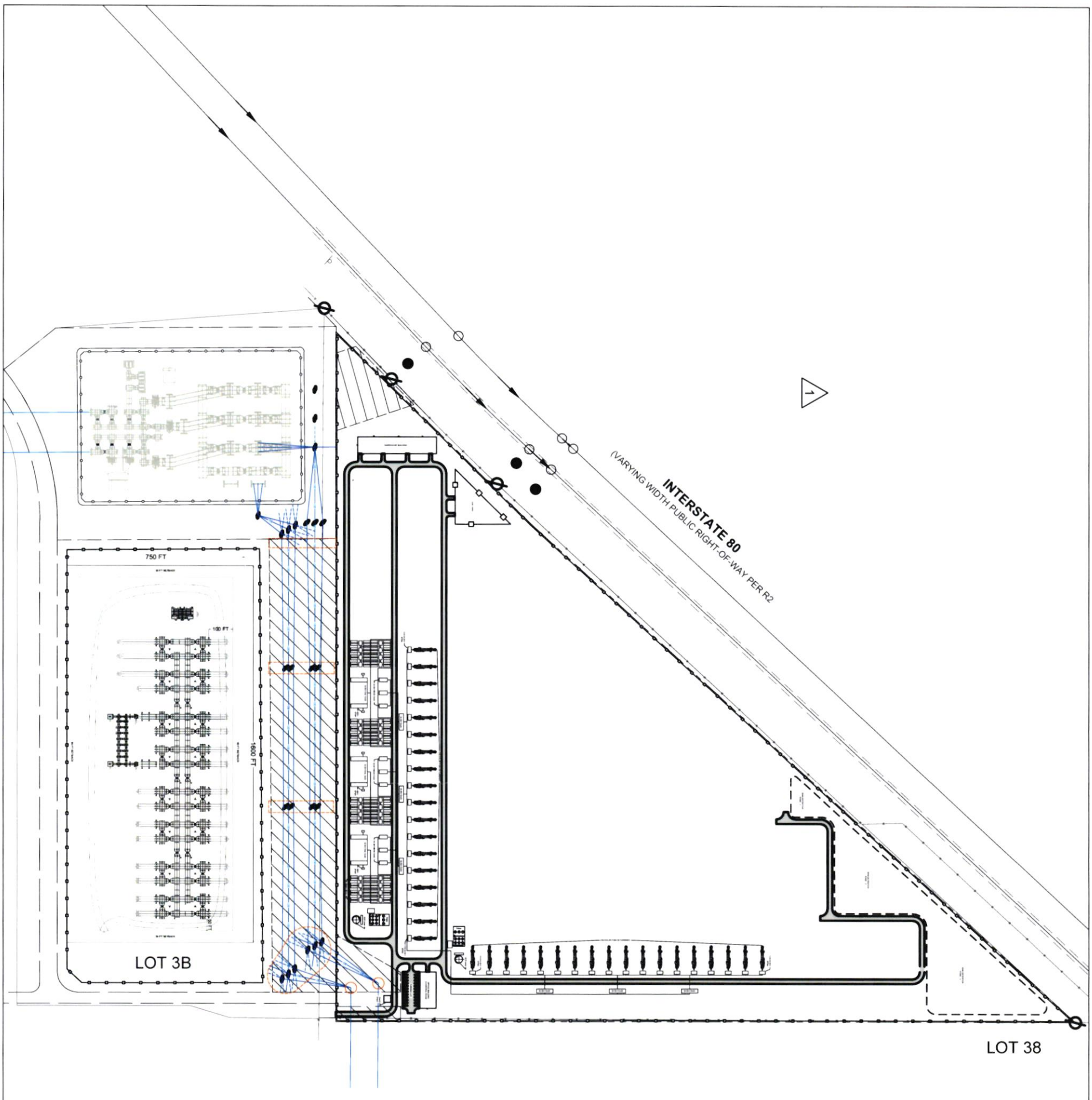
Tony Mente, Chief of Engineering & Technology

Print or Type Name and Title

6/2/2026

Date

APPENDIX D. SITE MAPS



NOTES:

1. THE BASE MAP HAS BEEN CREATED USING AVAILABLE AERIAL PHOTOGRAPHY PROVIDED BY AUTOCAD CIVIL3D.
2. PROPERTY LINES AND CONTOURS CREATED FROM "BOUNDARY AND TOPOGRAPHIC SURVEY" BY TLMOS & ASSOCIATES, INC., DATED 12-19-2025.
3. THIS PLAN IS IN THE NEVADA STATE PLANE WEST ZONE (US FOOT), NORTH AMERICAN DATUM 1983 (NAD 83) COORDINATE SYSTEM

The drawings, its contents, and each component of this drawing are the property of Stella Power Co. and shall not be reproduced or used in any manner except for the purposes identified on the Title Block and only by or on behalf of this client for the identified project unless otherwise authorized by the express, written consent of Stella Power Co.

Sheet 01 / 03

drawing title: 324MW POWER PLANT - OVERALL SITE PLAN

project title: FERNLEY POWER DISTRICT (FPD) MARK IV CAPITAL

CITY OF FERNLEY, LYON COUNTY, NEVADA

designed	AJR	scale	1" = 200'
checked	AJR	date	04/2026
drawn	AJR	project no.	2025.001.01

graphic scale: 0 200 400 600 SCALE IN FEET

No.	Revision	Date	By

REVIEW ONLY
NOT FOR
CONSTRUCTION

STELLA POWER CO
800 CLEVELAND ST
CLEARWATER, FL 33755
(888) 588-4773

STELLA POWER

Path: R:\26\2901\0031\ArcGISPro\Lot38Maps\Lot38Maps.aprx: Vicinity

Date: 5/14/2026 User: naydin



T21N, R25E, a Portion of Section 33,
Lyon County, Nevada
Projection: NAD 1983 UTM Zone 11N
Data Source: ESRI World Topographic Map as accessed on 05/14/2026

Legend

Project Location

N

0 10 20 Miles

0 20 40 Kilometers

Trinity

STELLA POWER COMPANY

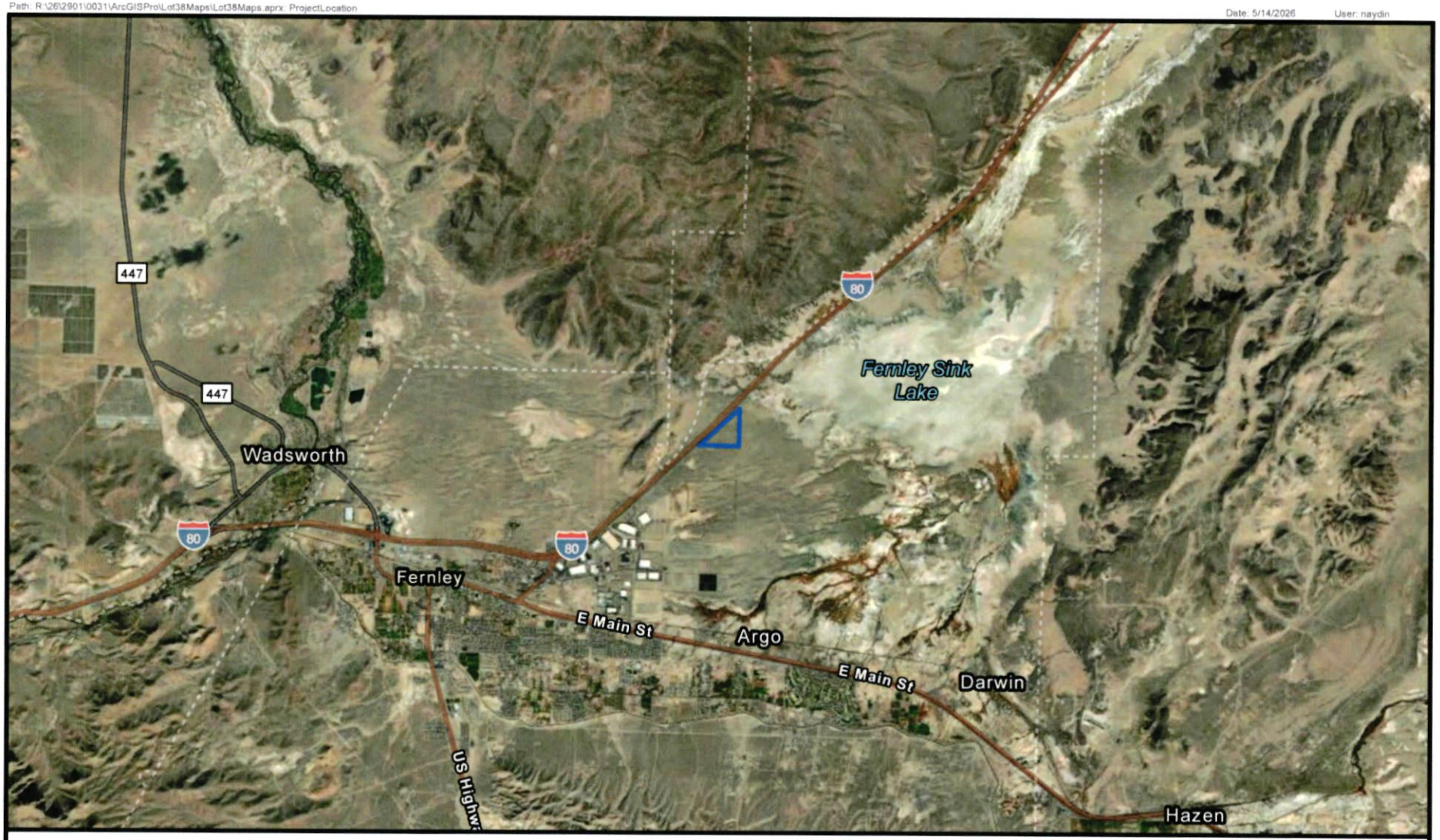
Air Permit Application

VICINITY

Figure 1

Path: R:\26\2901\0031\ArcGISPro\Lot38Maps\Lot38Maps.aprx: ProjectLocation

Date: 5/14/2026 User: naydin



T21N, R25E, a Portion of Section 33,
Lyon County, Nevada
Projection: NAD 1983 UTM Zone 11N
Image Source: Vantor 5/01/2025

Legend

Project Area

N

0 1 2 Miles

0 2 4 Kilometers

Trinity Consultants

STELLA POWER COMPANY
Air Permit Application

PROJECT LOCATION
Figure 2

Solar Turbines
A Caterpillar Company

PIL 170
Product Information Letter

Emission Estimates at Start-up, Shutdown, and Commissioning for SoLoNOx™ Combustion Products

Leslie Witherspoon

PURPOSE

The purpose of this Product Information Letter (PIL) is to provide emission estimates for start-up and shutdown events for Solar® gas turbines with SoLoNOx™ dry low emissions combustion systems.[1] For start-up and shutdown emissions estimates for conventional combustion turbines, landfill gas, digester gas, or other alternative fuel applications, contact Solar's Environmental Programs team.

INTRODUCTION

The information presented in this document is representative for both generator sets (GS) and compressor set/mechanical drives (CS/MD) SoLoNOx combustion turbine applications. Operation of duct burners and/or any add-on control equipment is not accounted for in the emissions estimates. Emissions estimates related to the start-up, shutdown, and commissioning of combustion turbines will not be warranted. The estimates in this document are based on limited engine testing and analysis. The engine testing was conducted at idle and other non-SoLoNOx mode load points. An actual start-up/shutdown event was not measured.

The start-up and shutdown estimates are most commonly used for potential to emit calculations to determine air permitting status. **Solar discourages customers from accepting the estimates in this document as permit limits, with or without source testing requirements.** Accurately measuring emissions during a – non-steady state – start-up or shutdown event with steady state source test methods may prove to be very challenging. In the event customers take permit limits and accept compliance testing permit conditions, Solar recommends adding significant margin to the estimates in this document.

START-UP PROCESS

The duration of a nominal start-up is the same for a cold start, warm start, or hot start (e.g., a Solar Turbine is programmed to start-up in "x" minutes whether it's a cold, warm, or hot start).

The start-up and shutdown time for a Solar turbine in a simple-cycle or combine heat and power application is the same. Heat recovery steam generator (HRSG) steam pressure is usually 250 psig or less. At 250 psig or less, thermal stress within the HRSG is minimized and, therefore, firing ramp-up/ramp-down is not limited. However, some combined heat and power plant applications will desire or dictate longer start-up/shutdown times due to external requirements.

The start-up sequence and attaining SoLoNOx combustion mode takes three steps:

1. Purge-crank
2. Ignition and acceleration to idle
3. Loading/thermal stabilization

[1]Start-up and shutdown emissions for the Mercury™50 engine are found in PIL 205

Caterpillar Confidential Green: Information contained herein is to be treated as Confidential and Proprietary to Caterpillar

During the "purge-crank" step, rotation of the turbine shaft is accomplished with a starter motor to remove any residual fuel gas in the engine flow path and exhaust. During "ignition and acceleration to idle," fuel is introduced into the combustor and ignited in a diffusion flame mode and the engine rotor is accelerated to idle speed.

The third step consists of applying up to 50% load[2] while allowing the combustion flame to transition and stabilize. Once 50% load is achieved, the turbine transitions to SoLoNOx combustion mode and the engine control system begins to maintain the combustion primary zone temperature and limit pilot fuel to achieve the targeted nitrogen oxides (NOx), carbon monoxide (CO), and unburned hydrocarbons (UHC) emission levels.

SHUTDOWN PROCESS

Normal, planned cool down/shutdown duration varies by engine model. Once the shutdown process starts the engine unloads and moves into a cooldown mode.

START-UP AND SHUTDOWN EMISSIONS ESTIMATES

Tables 1 through 5 summarize the estimated pounds of emissions per start-up and shutdown event for SoLoNOx products. The mass emissions estimates are calculated using exhaust characteristics at ISO conditions in conjunction with ppm emissions estimates at various load points. The estimates in Tables 1 and 2 are representative of new production units ordered from 2006 up until the implementation of Enhanced Emissions Control (EEC). Tables 3 and 4 summarize emissions estimates for turbine models and ratings equipped with EEC. Enhanced Emission Control is a control regime that will result in lower CO and UHC values at lower loads thus reducing the estimated emissions per start-up and shutdown sequence. The Titan™ 250 and the Titan 130 23001/23502 (and 22401/22402) ratings have always been equipped with EEC. As testing is completed and other models/ratings are qualified and able to be equipped with the updated controls PIL170 will be updated. Reference PIL 220 for additional information about Enhanced Emission Control. Table 5 summarizes start-up and shutdown emissions estimates for liquid fuel applications.

Please contact Solar Environmental Programs Anthony Pocengal (858.505.8554) for support.

COMMISSIONING EMISSIONS

Commissioning generally takes place over a two-week period. Static testing, where no combustion occurs, usually requires one week and no emissions are expected. Dynamic testing, where combustion will occur, typically includes a number of engine start and shutdown cycles and a variety of loads will be placed on the system. It is impossible to predict how long the turbine will run and in what combustion/emissions mode it will be running. The dynamic testing period is generally followed by one to two days of final commissioning during which the turbine is running at various loads.

[2]40% load for the Titan 250 Engine on natural gas. 65% load for all engines on liquid fuel (except 80% load for the Centaur™ 40).

Caterpillar Confidential Green: Information contained herein is to be treated as Confidential and Proprietary to Caterpillar

Table 1: Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set Applications
Nominal Start-up and Shutdown, Natural Gas Fuel
Production Units from 2006 and without Enhanced Emissions Control
Emissions estimates will NOT be warranted.

Engine	Total Emissions Per Start (lbs)					Total Emissions Per Shutdown (lbs)				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Centaur 40 4701S	1	66	62	12	247	1	67	67	13	228
Centaur 50 6201S	1	67	84	17	333	1	67	88	18	316
Taurus™ 60 7901S	1	86	110	22	338	1	89	119	24	311
Taurus 65 8701S	1	74	67	13	376	1	75	74	15	347
Taurus 70 10801S	1	78	67	13	544	1	58	52	10	411
Mars™ 90 13000S GSC	1	84	41	8	640	1	80	44	9	605
Mars 100 15000S/16000S GSC	1	81	39	8	669	1	76	42	8	616
Titan 130 20501S	3	172	138	28	832	3	174	151	30	768

Assumes ISO conditions: 59°F, 60% RH, sea level, no losses.

Assumes unit is operating at >50% load prior to shutdown.

Assumes natural gas fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Caterpillar Confidential Green: Information contained herein is to be treated as Confidential and Proprietary to Caterpillar

Table 2: Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx CS/MD Applications
Nominal Start-up and Shutdown, Natural Gas Fuel
Production Units from 2006 and without Enhanced Emissions Control
Emissions estimates will NOT be warranted.

Engine	Total Emissions Per Start (lbs)					Total Emissions Per Shutdown (lbs)				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Centaur 40 4702S	1	21	17	3	188	1	19	18	4	194
Centaur 50 6102S	1	21	17	3	184	1	20	19	4	169
Taurus 60 7802S	1	22	17	3	180	1	20	18	4	161
Taurus 70 10802S	1	88	88	18	381	1	78	83	17	295
Mars 90 13000S CS/MD	1	45	20	4	437	1	56	28	6	590
Mars 100 15000S/16000S CS/MD	1	46	20	4	385	1	58	28	6	490
Titan 130 20502S	1	55	37	7	662	1	61	43	9	751

Assumes ISO conditions: 59°F, 60% RH, sea level, no losses.

Assumes unit is operating at >50% load prior to shutdown.

Assumes natural gas fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Caterpillar Confidential Green: Information contained herein is to be treated as Confidential and Proprietary to Caterpillar

Table 3: Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set Applications
Nominal Start-up and Shutdown, Natural Gas Fuel
Production Units with Enhanced Emissions Control
Emissions estimates will NOT be warranted.

Engine	Total Emissions Per Start (lbs)					Total Emissions Per Shutdown (lbs)				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Taurus 60 7901S GSC (Post 9/2020 Orders)	1	42	24	5	368	1	50	28	6	345
Taurus 70 10801S GSC (Post 2/2018 Orders)	1	21	26	5	552	1	16	21	4	419
Taurus 70 11101S GSC (Post 2/2018 Orders)	1	21	27	5	563	1	17	22	4	427
Mars 90 13000S GSC (Post 9/2020 Orders)	1	23	20	4	727	1	25	20	4	682
Mars 100 15000S GSC (Post 9/2020 Orders)	1	40	34	7	760	1	44	36	7	710
Mars 100 16000S GSC (Post 8/2017 Orders)	1	32	26	5	789	1	35	27	5	733
Titan 130 19501S (Post 9/2020 Orders)	1	15	17	3	842	1	15	17	3	795
Titan 130 20501S (Post 2/2018 Orders)	1	18	21	4	839	1	19	22	4	782
Titan 130 23001S (All Units)	1	24	28	6	943	1	26	30	6	885
Titan 250 30000S GSC (All Units)	2	42	22	4	1502	2	33	17	3	1159
Titan 250 31900S GSC (All Units)	2	32	18	4	1280	2	26	14	3	975

Assumes ISO conditions: 59°F, 60% RH, sea level, no losses.

Assumes unit is operating at >50% load prior to shutdown.

Assumes natural gas fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Caterpillar Confidential Green: Information contained herein is to be treated as Confidential and Proprietary to Caterpillar

Table 4: Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx CS/MD Applications

Nominal Start-up and Shutdown, Natural Gas Fuel

Production Units with Enhanced Emissions Control

Emissions estimates will NOT be warranted.

Engine	Total Emissions Per Start (lbs)					Total Emissions Per Shutdown (lbs)				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Taurus 60 7802S (Post 9/2020 Orders)	1	6	5	1	247	1	7	6	1	235
Taurus 70 10802S (Post 2/2018 Orders)	1	20	28	6	381	1	19	27	5	295
Mars 90 13000S CS/MD (Post 9/2020 Orders)	1	17	12	2	437	1	24	18	4	564
Mars 100 15000S CS/MD (Post 9/2020 Orders)	1	20	13	3	474	1	30	18	4	612
Mars 100 16000S CS/MD (Post 8/2017 Orders)	1	19	13	3	496	1	28	19	4	642
Titan 130 20502S (Post 9/2020 Orders)	1	11	6	1	682	1	14	8	2	762
Titan 130 22402S (All Units)	1	13	15	3	690	1	15	17	3	775
Titan 130 23502S (All Units)	1	17	19	4	767	1	20	23	5	869
Titan 250 30000S CS/MD (All Units)	2	33	13	3	1172	2	28	11	2	1036
Titan 250 31900S CS/MD (All Units)	1	21	8	2	987	1	18	7	1	880

Assumes ISO conditions: 59°F, 60% RH, sea level, no losses.

Assumes unit is operating at >50% load prior to shutdown.

Assumes natural gas fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Caterpillar Confidential Green: Information contained herein is to be treated as Confidential and Proprietary to Caterpillar

Table 5: Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set Applications
Nominal Start-up and Shutdown, Liquid Fuel (Diesel #2)
Emissions estimates will NOT be warranted.

Engine	Total Emissions per Start (lbs)					Total Emissions per Shutdown (lbs)				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Centaur 40 4701S	1	11	1	1	420	1	12	1	1	388
Centaur 50 6201S	1	15	1	1	471	1	17	1	1	439
Taurus 60 7901S	1	14	1	1	510	1	16	1	1	467
Taurus 70 10801S	2	27	2	2	754	1	22	1	1	568
Mars 100 16000S GSC	2	19	1	1	821	2	25	2	2	804
Titan 130 20501S	2	32	2	2	1189	2	35	2	2	1106
Titan 130 23001S	2	27	2	2	1231	2	29	2	2	1132
Titan 250 30000S GSC	5	7	1	1	2188	4	6	1	1	1656
Titan 250 31900S GSC	4	5	1	1	2172	3	4	1	0	1643

Assumes ISO conditions: 59°F, 60% RH, sea level, no losses.

Assumes unit is operating at >50% load prior to shutdown.

Assumes natural gas fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Neither Solar Turbines Incorporated nor its affiliates shall be held liable for any improper, unauthorized, or incorrect use of the information described and/or contained herein and assumes no responsibility for anyone's use of the information contained herein. No warranty, express or implied, is made regarding accuracy, adequacy, completeness, legality, reliability or usefulness of any information. Solar Turbines Incorporated provides this information on an "as is" basis. Any and all warranties of any kind, express or implied, including but not limited to the implied warranties of merchantability, fitness for a particular purpose, and non-infringement of proprietary rights are disclaimed.

Caterpillar is a registered trademark of Caterpillar Inc. Solar, Titan, Mars, Taurus, Mercury, Centaur, Saturn, SoLoNox, InSight Platform and Turbotronic are trademarks of Solar Turbines Incorporated. All other trademarks are the intellectual property of their respective companies.

© 2025 Solar Turbines Incorporated. Specifications subject to change without notice. All rights reserved.

Caterpillar Confidential Green: Information contained herein is to be treated as Confidential and Proprietary to Caterpillar

Solar® Turbines
A Caterpillar Company

PIL 171
Product Information Letter

Particulate Matter Emissions

Travis Domingo and Anthony Pocengal

PURPOSE

This Product Information Letter (PIL) provides guidance and background related to particulate matter (PM) emissions and the test methodologies to quantify PM emissions. This PIL includes Solar's recommended $PM_{10/2.5}$ emissions factors for air permitting.

PARTICULATE MATTER BACKGROUND

The Environmental Protection Agency (EPA) defines PM_{10} and $PM_{2.5}$ as particles with aerodynamic diameter smaller than 10/2.5 micrometers respectively. The EPA has designated National Ambient Air Quality Standards (NAAQS) for $PM_{10/2.5}$ to which States have implementation plans to meet the standards (i.e. be in "attainment").

Nearly all particulate matter from gas turbines exhaust is less than one micrometer (micron) in diameter. Therefore, the emission rates of PM_{10} and $PM_{2.5}$ from gas turbines are theoretically equivalent.

TESTING FOR PARTICULATE MATTER

The turbine combustion process has little effect on the particulate matter generated and measured. The largest contributor to particulate matter emissions for gas and liquid fired combustion turbines is measurement technique and error. Other, minor contributing, sources of particulate matter emissions include carbon, ash, fuel-bonded sulfur, artifact sulfate formation, compressor/lubricating oils, and inlet air.

Historical customer particulate matter source test data show that there is significant variability from test to test. The source test results support the common industry argument that particulate matter from natural gas fired combustion sources is difficult to measure accurately. The reference test methods for particulate matter were developed primarily for measuring emissions from coal-fired power plants and other major emitters of particulates. Generally, current turbines are much more efficient and the fuels they combust are subject to strict quality requirements. The test methods were not developed for these cleaner fuels or verified for low emission levels. There are interferences, insignificant at higher exhaust particulate matter concentrations that result in emissions greater than the actual emissions from gas turbines.

Due to measurement and procedural errors, the measured results may be significantly higher and not representative of actual particulate matter emitted. There are many potential error sources in measuring particulate matter. Most of these have to do with contamination of the samples, material from the sampling apparatus getting into the samples, and human error in samples and analysis. Source test firms are gaining experience in measuring particulate matter and are deploying best practices which has lessened the historical variability from test to test and the emissions levels measured have decreased.

RECOMMENDED PARTICULATE MATTER EMISSION FACTORS

When necessary to support the air permitting process Solar recommends the following $PM_{10/2.5}$ emission factors for all models and ratings except for the Mercury™ 50. Please refer to PIL 205 for the Mercury 50. The emission factors below are intended to include both the front half (filterable) and the back half (condensable).

Caterpillar Non-Confidential

- Pipeline Natural Gas* and Natural Gas/Hydrogen Blends&: 0.006 lb/MMBtu fuel input (HHV)
- Landfill/Digester Gas+: 0.02 lb/MMBtu fuel input (HHV)
- Liquid Fuel#: 0.01 lb/MMBtu fuel input (HHV)

*Pipeline natural gas emissions factor assumes <1 grains of Sulfur per 100 standard cubic feet.
&Natural Gas/Hydrogen Blends can utilize the same emission factors as 100% natural gas.
+Landfill/digester gas emissions factor assumes <.15lb SO2/MMBtu heat input
#Liquid fuel emission factor assumes fuel Sulfur content is <500 ppm and ash content is <0.005% by wt.

Contact Solar's Environmental Programs group for particulate matter emissions estimates for fuels not listed above.

The conversion of particulate matter emissions request from mg/Nm^3 to lb/MMBtu (HHV) units involves several specific turbine parameters. Please contact Solar if you need the calculation performed.

TEST METHOD RECOMMENDATION

Solar recommends utilizing the preferred reference test method(s) required by applicable regulatory agency. When U.S. EPA reference test methods are specified for use, Solar recommends the below:

- EPA Method 201/201A to measure the "front half". The "Front half" represents filterable PM
- EPA Method 202[2] (with Nitrogen purge and field blanks) should be used to measure the "back half." "Back half" measurements represent the condensable portion of particulate matter.
    - Solar highly recommends utilizing EPA's recommended best practices[4] until more representative test methods are accepted for widespread use by EPA, State/Local regulatory authorities, or any other applicable regulatory authority.
    - In addition to the best practices for Method 202, Other Test Method (OTM) 59, Method for the Correction of Residual Ammonia in Condensable particulate Matter Samples Collected according to Method 202[4] must be followed to minimize additional biases from the presence of ammonia or sulfur dioxide
- EPA Method 5[5], which measures the front and back halves may be substituted (e.g. where exhaust temperatures do not allow the use of Method 202).

The turbine shall have a minimum of 300 operating hours prior to conducting particulate matter source testing. The turbine shall be running for 3-4 hours prior to conducting a particulate matter source test so that the turbine and auxiliary equipment is in a sustained "typical" operating mode prior to gathering samples.

Testing shall include a minimum of three 4-hour test runs.

ALTERNATE TEST METHODS FOR PM QUANTIFICATION

In addition to the EPA and EU standard reference test methods, there are alternate testing methodologies[6] available which measure PM emissions to higher accuracy levels. These methodologies utilize dilution sampling techniques that may lead to PM emissions ~10x lower than the current EPA reference test method. This method uses specialized equipment and experience in properly conducting these alternate test methods may not be as widespread. Moreover, utilization of these alternate methodologies requires prior approval from air permitting authorities. Contact Solar's Environmental Strategy Team for more information on these alternate methodologies.

Caterpillar Non-Confidential

REFERENCES

[1]EPA Method 201, Determination of PM10 Emissions, Exhaust Gas Recycle Procedure. EPA Method 201A. Determination of PM10 Emissions, Constant Sampling Rate Procedure, 40 CFR 60, Part 60, Appendix A.
[2]EPA Method 202, Determination of Condensable Particulate Emissions from Station Sources, 40 CFR 60, Part 60. Appendix A.
[3]EPA Method 202 Best Practices Handbook, January 2016
[4]OTM 59, Method for the Correction of Residual Ammonia in Condensable particulate Matter Samples Collected according to Method 202
[5]EPA Method 5, Determination of Particulate Emissions from Station Sources, 40 CFR 60, Part 60, Appendix A.
[6]EPA Other Test Method (OTM) 37, Measurement of Direct PM2.5 and PM10 Emissions at Low Concentrations by Dilution Sampling (Constant Sampling Rate Procedure). Conditional Test Method (CTM) 39, Measurement of PM2.5 and PM10 Emissions By Dilution Sampling (Constant Sampling Rate Procedures)

Neither Solar Turbines Incorporated nor its affiliates shall be held liable for any improper, unauthorized, or incorrect use of the information described and/or contained herein and assumes no responsibility for anyone's use of the information contained herein. No warranty, express or implied, is made regarding accuracy, adequacy, completeness, legality, reliability or usefulness of any information. Solar Turbines Incorporated provides this information on an "as is" basis. Any and all warranties of any kind, express or implied, including but not limited to the implied warranties of merchantability, fitness for a particular purpose, and non-infringement of proprietary rights are disclaimed.

Caterpillar is a registered trademark of Caterpillar Inc. Solar, Titan, Mars, Taurus, Mercury, Centaur, Saturn, SoLoNOx, InSight Platform and Turbotronic are trademarks of Solar Turbines Incorporated. All other trademarks are the intellectual property of their respective companies.

© 2025 Solar Turbines Incorporated. Specifications subject to change without notice. All rights reserved.