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Project Title:	Mission Rock Energy Center
TN #:	221497
Document Title:	Ventura County APCD -- Preliminary Determination of Compliance
Description:	VCAPCD -- PDOC, 15-AFC-02
Filer:	Mike Monasmith
Organization:	California Energy Commission
Submitter Role:	Commission Staff
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Michael Villegas
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October 13, 2017

Mr. Mike Monasmith
Senior Project Manager, STEP Division
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

Subject: Notice of Preliminary Determination of Compliance (PDOC)
Mission Rock Energy Center, LLC (15-AFC-02)

Dear Mr. Monasmith:

Enclosed for your review and comment is the Ventura County Air Pollution Control District's (APCD) Preliminary Determination of Compliance (PDOC) for the Mission Rock Energy Center (Ventura County APCD Application No. 08308-100). This project proposes the installation of a nominal 275 MW natural gas-fired simple-cycle gas turbine power plant at 1025 Mission Rock Road near Santa Paula, California.

This PDOC is being issued pursuant to Rule 26.9, "New Source Review – Power Plants". This project is expected to meet the requirements of Rule 26, "New Source Review", and all other applicable Ventura County APCD rules and regulations, including applicable state and federal requirements that the Ventura County APCD enforces. However, the project does not currently meet the emission offset requirements of Section B.2.a of Rule 26.2, "New Source Review – Requirements". The project requires offsets for nitrogen oxides (NOx) at a tradeoff ratio of 1.3 to 1 that have not yet been identified. The PDOC includes conditions required to ensure compliance with all applicable requirements, including the NOx emission offset requirements of Rule 26.2.B. Pursuant to Rule 26.9.G, a Determination of Compliance shall confer the same rights and privileges as an Authority to Construct only when and if the California Energy Commission approves the Application for Certification 15-AFC-02.

Prior to the issuance of the Ventura County APCD Final Determination of Compliance (FDOC) for this project, Mission Rock Energy Center, LLC has stated that they will provide Emission Reduction Credits (ERCs) to comply with the emission offset requirements of Rule 26.2.B.2.a. As stated in this PDOC, NOx ERCs are required in the amount of (28.13 tons per year)*(1.3) = 36.57 tons per year. When NOx ERCs are provided that meet the requirements of Rule 26.2, the Ventura County APCD will provide a notification on the California Energy Commission Docket Log 15-AFC-02 for a minimum 45-day public review and comment period prior to the issuance of the Final Determination of Compliance.

Pursuant to Rules 26.9.F and 26.7.B.1, the notice of preliminary decision for this project will be published in the Ventura County Star and Santa Paula Times (in English) and the Vida Newspaper (in Spanish) by no later than 10 days from the date of this letter. This notice will also be posted on our website (www.vcapcd.org) in English, Spanish, and Mixtec. Written comments on this project are to be submitted within the 45-day period which begins on the latest date of the newspaper publications of the public notice.

If you have any questions, or wish to discuss this matter in further detail, please contact me at (805) 645-1421, or by email at kerby@vcapcd.org.

Sincerely,

Kerby E. Zozula, Manager
Engineering Division

Enclosures

Copies (via email): Barbara McBride, Calpine (Barbara.McBride@calpine.com)
Gerardo Rios, U.S. EPA Region IX (Rios.Gerardo@epa.gov)
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VENTURA COUNTY APCD
PRELIMINARY DETERMINATION OF COMPLIANCE

MISSION ROCK ENERGY CENTER
CEC APPLICATION FOR CERTIFICATION DOCKET NUMBER 15-AFC-02

Facility Name:	Mission Rock Energy Center
Mailing Address:	Mission Rock Energy Center, LLC 717 Texas Avenue, Suite 1000 Houston, TX 77002
Facility Address:	Mission Rock Energy Center, LLC 1025 Mission Rock Road Santa Paula, CA 93060
MREC Contact:	Barbara McBride Director Environmental Services 925-570-0849 Phone
VCAPCD Contact:	Kerby E. Zozula Engineering Division Manager Ventura County APCD 805-645-1421 Phone
Date PDOC Issued:	October 13, 2017
VCAPCD Application:	Rule 26.9 - DOC/Authority to Construct No. 08308-100
Application Submitted:	February 22, 2016
Deemed Complete:	April 14, 2016
Application Revised:	January 26, 2017

I. Project Proposal and Project Summary

The Mission Rock Energy Center (MREC), owned by Mission Rock Energy Center, LLC (MREC, LLC), requests a Determination of Compliance (DOC) from the Ventura County Air Pollution Control District (VCAPCD) for the installation of five GE LM6000-PG-Sprint simple-cycle natural gas fired combustion turbine generators (CTG) with a total combined nominal ISO rating of 275 MW, and a new emergency diesel engine powering a fire water pump with a rating of 220 BHP. The new turbines and the new emergency diesel fire water pump engine, along with other ancillary equipment, will be called the Mission Rock Energy Center (MREC). MREC will be located at a new facility near, and to the southwest of, the city of Santa Paula, CA.

This DOC is being issued pursuant to VCAPCD Rule 26.9, New Source Review - Power Plants. MREC is subject to the approval of the California Energy Commission (CEC) because the proposed power plant has a nominal rating greater than 50 MW. MREC filed an Application For Certification (AFC) with the CEC on December 31, 2015 (AFC Docket No. 15-AFC-02).

MREC will be a new major stationary source subject to VCAPCD Rule 33, Part 70 Permits, and a new acid rain source subject to VCAPCD Rule 34, Acid Deposition Control. As required by VCAPCD Rule 33.5, Part 70 Permits - Timeframes for Applications, Review and Issuance, prior to operation of the new CTG's and emergency diesel engine, MREC will submit an application for a Part 70 (Title V) Permit and Title IV Acid Rain Permit.

As shown in this DOC, if fully completed as proposed, the nitrogen oxides (NOx) emissions increase from this project has been calculated to be 28.13 tons per year. As required by Ventura County APCD Rule 26.2, New Source Review - Requirements, this NOx emission increase will be offset, at a tradeoff ratio of 1.3 to 1, with Emission Reduction Credits totaling 36.57 tons per year.

II. Applicable Rules and Regulations

Rule 26.2 - New Source Review – Requirements
Rule 26.6 - New Source Review – Calculations
Rule 26.7 - New Source Review - Notification
Rule 26.9 - New Source Review - Power Plants
Rule 26.11 - New Source Review – ERC Evaluation at Time of Use
Rule 26.12 - Federal Major Modifications
Rule 26.13 - New Source Review - Prevention of Significant Deterioration (PSD)
Rule 29 – Conditions on Permits
Rule 33.5 – Part 70 Permits – Timeframes for Applications, Review and Issuance
Rule 34 – Acid Deposition Control
Rule 50 – Opacity
Rule 51 - Nuisance
Rule 52 - Particulate Matter - Concentration (Grain Loading)

Pursuant to Sections B.1.f and B.1.g of Rule 52, the rule does not apply to the proposed gas turbine or internal combustion engine since the equipment will combust only gaseous or liquid fuels respectively and emit only combustion products.

Rule 53 - Particulate Matter - Process Weight

Pursuant to Sections B.1.f and B.1.g of Rule 53, the rule does not apply to the proposed gas turbine or internal combustion engine since the equipment will combust only gaseous or liquid fuels respectively and emit only combustion products.

Rule 54 - Sulfur Compounds

Rule 55 – Fugitive Dust

Rule 57.1 - Particulate Matter Emissions From Fuel Burning Equipment

Rule 64 - Sulfur Content of Fuels

Rule 68 Carbon Monoxide

Pursuant to Sections B.1.f and B.1.g of Rule 68, the rule does not apply to the gas turbine or the engine since the units combust only gaseous fuel and liquid fuel respectively and emit only combustion products.

Rule 74.9 - Stationary Internal Combustion Engines

Rule 74.23 - Stationary Gas Turbines

Rule 103 - Continuous Monitoring Systems

California Health & Safety Code 42301.6 - School Notice

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

Public Resources Code 21000-21177 - California Environmental Quality Act (CEQA) - California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387 CEQA Guidelines

40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

40 CFR Part 60, Subpart TTTT, Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

40 CFR Part 63, Subpart YYYY, National Emission Standard for Hazardous Air Pollutants (NESHAP) for Combustion Turbines

This rule applies to combustion turbines installed at major sources of hazardous air pollutants (HAPs). The turbines are not subject to the subpart because the stationary source is not a major source of HAPs. Section 63.6090 defines an affected source for Subpart YYYY as "any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions." The toxic emissions from the proposed stationary source has combined total HAPs (Hazardous Air Pollutants) emissions of less than 3 tons per year, which is significantly below the major source threshold for a single HAP of 10 tons per year or combined HAPs of 25 tons per year. Note that the Federal Clean Air Act does not define ammonia and sulfuric acid as HAPs. See Appendix H - Hazardous Air Pollutant Potential to Emit.

40 CFR Part 63 Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE)

40 CFR Part 64, Compliance Assurance Monitoring

40 CFR Part 68, List of Regulated Substances and Thresholds for Accidental Release Prevention
40CFR Part 75, Continuous Emission Monitoring (CEMS)

III. Project Location

The Mission Rock Energy Center (MREC) will be located at 1025 Mission Rock Road near Santa Paula, CA.

IV. Process Description

The Mission Rock Energy Center, LLC (MREC, LLC), requests a Determination of Compliance (DOC) from the Ventura County Air Pollution Control District (VCAPCD) for the installation of five (5) new GE LM6000 Class simple-cycle natural gas fired combustion turbine generators (CTG) and one new emergency diesel fire water pump engine. The new turbines and the new diesel engine along with other ancillary equipment will be called the Mission Rock Energy Center (MREC).

V. Equipment Listing

Five (5) New Combustion Turbine Generators (CTGs):
GE LM6000-PG-Sprint Combustion Turbine Generator (CTG) set, each rated at a nominal 55 MW, simple cycle, single annular combustor with water injection, a Selective Catalytic Reduction (SCR) system with aqueous ammonia injection for nitrogen oxides (NOx) control and an oxidation catalyst for reactive organic compounds (ROC) and carbon monoxide (CO) control.

The GE Sprint (SPRay INTercooling) option includes a combustion air cooling system to increase the power output of the gas turbine by cooling the combustion air, resulting in a higher mass flow through the turbine. MREC will also use an evaporative cooling tower system (also known as a wet surface air condenser / air chiller) to cool the inlet combustion air.

The turbines are simple-cycle turbines; there are no heat recovery steam generators or exhaust cooling towers in this project. The proposed units are GE Model LM6000-PG-Sprint combustion turbine generators. The turbines are designed to fire natural gas only. The net heat rate is 10,142 BTU/kWh (HHV). There are no bypass stacks. The single annular combustor and water injection system achieve lower NOx emissions by lowering the charge temperature with water injection. The exhaust is then sent through an oxidation catalyst and SCR system to further reduce emissions. The oxidation catalyst and SCR system will be sized so that the emissions from each turbine meet the permitted emission limits. The continuous emission monitoring systems, for NOx and CO, will monitor and record the exhaust emission concentrations from each turbine.

Continuous Emission Monitoring System:
A Continuous Emissions Monitoring System (CEMS) is proposed for monitoring and recording NOx and CO emissions from each turbine.

Emergency Internal Combustion Engine:
The project also includes an emergency internal combustion engine. The engine is diesel-fired and will power an emergency fire water pump. The proposed engine is a 220 BHP John Deere diesel engine, certified to meet U.S. EPA and California Air Resources Board emission standards for stationary direct-drive diesel fire pump engines. The engine will be used during emergency operations for the pumping of water for fire suppression or protection. The engine will be limited to a total of 50 hours per year for maintenance and readiness testing purposes.

Support Equipment:
The facility will have additional support equipment that is exempt from permit pursuant to Rule 23, Exemptions From Permit. This equipment includes inlet combustion air cooling towers, electric-powered fuel gas compressor, a nominal 100 MWhr (25 MW at 4 hours) battery storage system, water storage tanks, transformers, and one aqueous ammonia storage tank. A "black-start" emergency diesel electricity generating engine is not required because of the battery storage system. This support equipment is not subject to VCAPCD permit requirements, but is subject to general prohibitory rules such as Rule 50, Opacity, and Rule 51, Nuisance.

VI. Emission Control Technology Evaluation

The CTG's will use an evaporative water cooling tower system that reduces the inlet combustion air temperature. The CTG's will also be equipped with annular combustors and water injection. The demineralized water injection system will control the formation of pollutants by reducing the combustion temperatures. These combustors will achieve a NOx emission rate of 25 ppmvd @ 15% O2 using water injection (prior to add-on emissions control).

Each of the proposed CTG's also will be equipped with an oxidation catalyst for ROC and CO control, and a selective catalytic reduction (SCR) system for NOx control. The specific manufacturer(s) will be determined at a later date.

During normal operation, the exhaust from each of the CTGs is sent through the oxidation catalyst and SCR system. In the oxidation catalyst section, incompletely combusted organic compounds and carbon monoxide are further oxidized on the catalyst and converted primarily to carbon dioxide (CO_2) and water (H_2O). The oxidation catalyst units normally have minimum and maximum operating temperatures of 300 and 1,250 degrees Fahrenheit. The oxidation catalyst is located upstream of the SCR unit which is located just upstream of the exhaust stack.

The SCR system consists of ammonia injection in the CTG exhaust upstream of the catalyst and a catalyst bed. The ammonia mixes with the exhaust gas and reacts with NOx on the surface and interior of the catalyst to produce nitrogen gas (N_2) and water (H_2O). The SCR catalyst is a high temperature catalyst. The minimum and maximum operating temperatures for the SCR catalyst are 300 and 1,050 degrees Fahrenheit. Unreacted ammonia (ammonia slip) will be present in the CTG engine exhaust. Ammonia slip will be limited to 5 ppmvd @ 15% O2. The SCR system reduces the CTG NOx emissions by approximately 90% from 25 ppmvd to 2.5 ppmvd @ 15% O2.

The proposed emergency diesel internal combustion engine will be certified to meet U.S. EPA and California Air Resources Board emission standards for stationary direct-drive diesel fire pump engines.

VII. Emission Calculations

The emission calculations below are performed pursuant to the requirements of Rule 26.6, New Source Review - Calculations. Based on Rule 26, New Source Review; Rule 29, Conditions on Permits; and Rule 42, Permit Fees; the emissions of reactive organic compounds (ROC), nitrogen oxides (NOx), particulate matter (PM_{10}), sulfur oxides (SOx), carbon monoxide (CO), and ammonia (NH3) have been calculated in the units of tons per year and pounds per hour for the MREC CTG's and emergency diesel fire water pump engine.

Assumptions:

- Applicant has provided turbine manufacturer (GE) performance emission rates for the turbines (see Tables VII-1 & VII-2). These emission rates will be used to calculate total turbine emissions.

- The worst case hourly emissions will be based on turbine performance data (Run 1) of the manufacturer provided data. See Appendix A.

- The annual emissions will be based on the turbine performance data (Run 14) of the manufacturer provided data. See Appendix A.

- MREC will have an annual emission limit for all pollutants that is based on 2,500 total hours of operation for each of the 5 turbines.

- Annual per-turbine emissions = 150 startups (75 hours of operation) + 150 shutdowns (22.5 hours of operation) + 2,402.5 hours steady state (Run 14 emission factors) = 2,500 hours of operation per year per turbine.

- Startup and shutdown pounds per hour (lb/hr) are based on provided emission data (Application Appendix Table 5.1A-1) See Appendix B.

- Natural gas fuel sulfur limit = 0.75 grain per 100 scf, as BACT.

- Higher Heating Value (HHV) of natural gas fuel = 1,021 BTU/scf.

- Annual average operation = 2,804 MMBTU/Hr heat input for all 5 turbines combined (Run 14) = 560.8 MMBTU/Hr per turbine. See Appendix A.

- Worst-case hour heat input = 2,831 MMBTU/Hr for all 5 turbines combined (Run 1) = 566.2 MMBTU/Hr per turbine. See Appendix A.

- Worst-case hour is 30 minutes startup/30 minutes normal operation for NOx, PM10, SOx, CO, NH3. For ROC the worst case hour is 9 minutes shutdown/51 minutes normal operation.

- All ROC NOx, CO, PM10, NH3 emissions in pounds per hour (lbs/hr), emission factor, and ppmvd values are provided by the applicant and turbine manufacturer. Emission factors are calculated using location specific performance data. See Appendix A.

- NOx hourly emission limits are based on the assumption that for the turbines the hourly rate is based on the BACT limit of 2.5 ppmvd NOx. Based on manufacturer data, turbine emissions during steady-state normal ISO operations will be lower. Therefore, the applicant has proposed that annual NOx permitted emissions be calculated based on an average of 2.0 ppmvd NOx. NOx actual emissions in tons per year from the turbines will be tracked with a continuous emissions monitor to ensure that NOx annual permitted emissions are not exceeded.

- ROC lb/hr emissions limits are proposed by the applicant based on manufacturer performance data. The lb/hr limit is equal to approximately 1 ppmvd ROC. This is below the BACT limit of 2 ppmvd ROC.

- SOx emissions are based on the fuel sulfur content. As a BACT limit, 0.75 grains /100 scf will be used in calculating the SOx emissions. The calculation is shown below.

  SOx calculation:

  $$SOx = (0.75 \text{ gr}/100 \text{ scf}) \times (1 \text{ scf}/1{,}021 \text{ BTU}) \times (\text{lb}/7{,}000 \text{ gr}) \times (2 \text{ mol } SO_2/1 \text{ mol S}) \times (1{,}000{,}000 \text{ BTU/MMBtu})$$

  $$= 0.002098 \text{ lb SOx/MMBtu}$$

  SOx lb/hr are calculated by multiplying the turbine heat input by the calculated emission factor and are shown in Tables VII-1 & VII-2 below.

<u>**Rule 26.6 B – Potential to Emit**</u>

New Combustion Turbine Generators (CTG):
The CTG's have various states of operation: startup, shutdown, normal operation cold day, and normal operation average day. The CTG's have different emission factors associated with the various states of operation. MREC has provided manufacturer emissions data for each of the aforementioned states of operation see Tables VII-1 to VII-3 below.

Combustion Turbine Generator (CTG) Hourly Emission Calculations:
The turbine hourly emissions are calculated using the applicant/manufacturer provided performance data. The worst case hourly emissions occur on a cold day (Table VII-1). The annual emissions from the turbines are calculated using the emissions from the turbines during the average day (Table VII-2).

Table VII-1

Maximum Hourly Operation (cold day performance) - Per Turbine			
Pollutant	**Emission Factor**	**Emission Factor Basis**	**Pounds Per Hour (@ 566.2 MMBTU/Hr*)**
ROC	0.00126 lb/MMBTU	1.0 ppmvd (applicant proposed)	0.71
NO_x	0.00901 lb/MMBTU	2.5 ppmvd (BACT)	5.10
PM_{10}	2.00 lb/hr	2.0 lb/hr (applicant proposed)	2.00
SO_x	0.002098 lb/MMBTU	0.75 grain (BACT)	1.19
CO	0.00877 lb/MMBTU	4.0 ppmvd (applicant proposed)	4.97
NH_3	0.00667 lb/MMBTU	5.0 ppmvd (BACT)	3.78

*From Appendix A Turbine Performance Emissions Data Run 1 plant heat input 2,831 MMBtu/hr / 5 turbines = 566.2 MMBTU/Hr per turbine.

Table VII-2

Average Hourly Operation (ISO conditions performance) - Per Turbine			
Pollutant	**Emission Factor**	**Emission Factor Basis**	**Pounds Per Hour (@ 560.8 MMBTU/Hr*)**
ROC	0.0012558 lb/MMBTU	1.0 ppmvd (applicant proposed)	0.70
NO_x	0.0072 lb/MMBTU	2.0 ppmvd (applicant proposed)	4.04
PM_{10}	2.00 lb/hr	2.0 lb/hr (applicant proposed)	2.00
SO_x	0.002098 lb/MMBTU	0.75 grain (BACT)	1.18
CO	0.00877 lb/MMBTU	4.0 ppmvd (applicant proposed)	4.92
NH_3	0.00667 lb/MMBTU	5.0 ppmvd (BACT)	3.74

*From Appendix A Turbine Performance Emissions Data Run 14 plant heat input 2,804 MMBtu/hr / 5 turbines = 560.8 MMBTU/Hr per turbine.

The maximum startup and shutdown hourly emissions are calculated using the Appendix B startup/shutdown emissions and the remaining time in one hour as normal emissions from the cold day (Performance Run 1). Therefore, an hour when a startup occurs is 30 minutes startup emissions and 30 minutes normal operation. An hour when a shutdown occurs is 9 minutes of shutdown emissions and 51 minutes of normal emissions. These occurrences are shown in Table VII-3 below.

Table VII-3

Startup and Shutdown Hourly Emissions (pounds = lbs) Per Turbine						
Pollutant	**Startup Emissions**			**Shutdown Emissions**		
	Startup	**Normal Operation***	**Maximum Hourly Startup**	**Shutdown**	**Normal Operation***	**Maximum Hourly Shutdown**
Duration (min)	30	30	**60**	9	51	**60**
ROC	1.00	0.36	**1.36**	1.00	0.60	**1.60**
NOx	9.10	2.55	**11.65**	1.20	4.34	**5.54**
PM_{10}	1.00	1.00	**2.00**	0.30	1.70	**2.00**
SOx	0.595	0.595	**1.19**	0.18	1.01	**1.19**
CO	5.50	2.49	**7.99**	1.80	4.23	**6.03**
NH3	1.89	1.89	**3.78**	0.57	3.21	**3.78**

* Table VII-1 Max hourly operation lb/hr emissions divided by listed duration either 30 or 51 minutes, respectively

Maximum hourly emissions can be defined as occurring during any one hour time period where the turbine is in startup mode, the turbine is in shutdown mode, or the turbine is in normal operation. This occurs during a startup hour on a cold day for NOx, PM10, SOx, CO, and NH3. This occurs during shutdown for ROC. During startups and shutdowns the SCR system and the oxidation catalyst are not as effective at reducing NOx, ROC, and CO emissions as the exhaust temperature is not high enough for effective emissions control.

See the table below for the maximum hourly emissions for the turbines.

Table VII-4

Maximum Hourly Emissions (pounds = lbs)		
Pollutant	**Maximum Hourly Per Turbine**	**Maximum Hourly x 5 Turbines (lbs/hr)**
ROC	**1.60**	**8.00**
NOx	**11.65**	**58.25**
PM_{10}	**2.00**	**10.00**
SOx	**1.19**	**5.95**
CO	**7.99**	**39.95**
NH3	**3.78**	**18.90**

Combustion Turbine Generator (CTG) Annual Emission Calculations:

MREC has proposed operation limits for the facility on a per turbine basis of 150 startups (75 hours), 150 shutdowns (22.5 hours), and 2,402.5 hours of normal full load operation on an annual basis. Annual turbine emissions are calculated based on the average hourly operation lb/hr for 2,402.5 hours and the startup and shutdown emissions associated with 150 startups and 150 shutdowns per year. Each turbine is expected to have a maximum of 150 startups and 150 shutdowns per year, with the rest of the hours running normal operation.

Normal operations are expected to occur 2,402.5 hours per year. See emission factors, emission factor basis, and the pounds per hour emissions at the steady state normal operational load below.

Table VII-5

Normal Operation Emissions - Per Turbine				
Pollutant	**Emission Factor**	**Emission Factor Basis**	**Pounds Per Hour (@ 560.8 MMBtu/hr)**	**Tons Per Year (2402.5 hr/yr)**
ROC	0.0012558 lb/MMBTU	1 ppmvd (app proposed)	0.70	0.84
NOx	0.0072 lb/MMBTU	2.0 ppmvd (app proposed)	4.04	4.85
PM_{10}	2.00 lb/hr	2.0 lb/hr (app proposed)	2.00	2.40
SOx	0.002098 lb/MMBTU	0.75 grain, BACT	1.18	1.42
CO	0.00877 lb/MMBTU	4.0 ppmvd (app proposed)	4.92	5.91
NH3	0.00667 lb/MMBTU	5.0 ppmvd, BACT	3.74	4.49

Table VII-6

Startup and Shutdown Annual Emissions				
Pollutant	**Startup**		**Shutdown**	
	Pounds Per Startup	Tons Per Year (150 Startups/yr)	Pounds Per Shutdown	Tons Per Year (150 Shutdowns/yr)
ROC	1.00	0.075	1.00	0.075
NOx	9.10	0.68	1.20	0.09
PM_{10}	1.00	0.075	0.30	0.023
SOx	0.595	0.045	0.18	0.0135
CO	5.50	0.4125	1.80	0.135
NH3	1.89	0.14175	0.57	0.04275

Table VII-7

Maximum Annual Emissions					
Pollutant	**Annual Startups**	**Annual Shutdowns**	**Annual Normal Operation**	**Total Annual Turbine Operation**	**Annual x 5 Turbines**
	Tons Per Year	Tons Per Year	Tons Per Year	Tons Per Year	Tons Per Year
ROC	0.075	0.075	0.84	**0.99**	**4.95**
NOx	0.68	0.09	4.85	**5.62**	**28.10**
PM_{10}	0.075	0.023	2.40	**2.50**	**12.50**
SOx	0.045	0.0135	1.42	**1.48**	**7.40**
CO	0.4125	0.135	5.91	**6.46**	**32.30**
NH3	0.14175	0.04275	4.49	**4.67**	**23.35**

Maximum Annual is 150 startups (75 hours) + 150 shutdowns (22.5 hours) + 2402.5 hours normal operation = 2500 hours total usage.

Table VII-8

Maximum Turbine Emissions Hourly and Annual Operations				
Pollutant	Hourly	Hourly x 5 Turbines	Annual*	Annual x 5 Turbines
	lb/hr	lb/hr	Tons/yr	Tons/yr
ROC	1.60	8.00	0.99	**4.95**
NOx	11.65	58.25	5.62	**28.10**
PM_{10}	2.00	10.00	2.50	**12.50**
SOx	1.19	5.95	1.48	**7.40**
CO	7.99	39.95	6.46	**32.30**
NH3	3.78	18.90	4.67	**23.35**

* Annual is 150 startups (75 hours) + 150 shutdowns (22.5 hours) + 2402.5 hours normal operation

= 2500 hours total

Turbine Commissioning Emissions:

The turbines must go through a specific set of tests and steps before being certified as operational and available to provide power. The application includes information on the commissioning schedule for the turbines (see Appendix C). The SCR with ammonia injection and oxidation catalyst control systems will not be operable during all of the commissioning period as the control systems are going through a commissioning period as well. These systems do not alter the PM or SOx emissions; therefore, only the ROC, NOx, and CO emissions will be affected.

The turbines will have conditions placed on the permit which limits the facility to only having two turbines in the commissioning phase at any one time. Therefore, the worst case hourly commissioning emissions will be ROC = (2)(3.0) = 6.0 lbs/hr; NOx = (2)(68.0)= 136.0 lbs/hr; and CO = (2)(117.33)= 234.66 lbs/hr. The emissions from the commissioning process will be accounted for in the total annual emissions from the CTG. MREC will ensure that the total annual emissions from the facility do not exceed their annual permitted emissions including during the commissioning process.

Table VII-9

New Turbine Commissioning Emissions- Each Turbine		
Pollutant	**Maximum Commissioning Emissions (lbs/hr)***	**Total Commissioning Emissions (tpy)****
ROC	**3.0**	**0.82**
NOx	**68.0**	**10.33**
CO	**117.33**	**22.14**
SOx	**1.19**	**n/a**
PM10	**2.00**	**n/a**

* Only two turbines will be in the commissioning phase that produces the maximum hourly emission rates (lbs/hr).
**Total commissioning emissions in tons per year (tpy) is for all 5 turbines combined.

Emergency Diesel Fire Pump Engine Emission Calculations:

The permitted emissions for the 220 BHP John Deere emergency diesel fire water pump engine are based on full-load operation at a limit of 50 hours per year for maintenance and readiness testing. The engine will have a 50 hours per year limit for non-emergency usage. There will not be an hours per year limit for actual emergencies for the pumping of water for fire suppression or protection. The emission factors are based on the California ARB Airborne Toxic Control Measure (ATCM) for Stationary Internal Combustion Engines Table 2 standards for new direct-drive fire pump engines of Model Years 2009 and after. The NMHC+NOx standard of 3.0 g/bhp-hr is assumed to be 5% ROC and 95% NOx. The emission factors and permitted emissions are shown below:

Table VII-10

New 220 BHP Emergency Fire Pump Engine Emission Calculations				
Pollutant	**Emission Factor (g/bhp-hr)**	**Emission Factor Basis**	**Pounds Per Hour**	**Tons Per Year (50 hr/yr)**
ROC	0.2	Stationary Engine ATCM fire pump engine standards	0.10	0.00
NOx	2.8	Stationary Engine ATCM fire pump engine standards	1.36	0.03
PM_{10}	0.15	Stationary Engine ATCM fire pump engine standards	0.07	0.00
SOx	0.0051	Very low sulfur fuel (15 ppmw) mass balance see below	< 0.01	0.00
CO	2.6	Stationary Engine ATCM fire pump engine standards	1.26	0.03

$$\frac{0.000015\ lb-S}{lb-fuel}\times\frac{7.1\ lb-fuel}{gallon}\times\frac{2\ lb-SO_2}{1\ lb-S}\times\frac{1\ gal}{137{,}000\ Btu}\times\frac{1\ bhp\ input}{0.35\ bhp\ out}\times\frac{2{,}542.5\ Btu}{bhp-hr}\times\frac{453.6\ g}{lb}=\ 0.0051\ \frac{g-SO_x}{bhp-hr}$$

The facility is a new facility therefore the facility pre-project emissions are zero for all pollutants. The facility post-project emissions are shown below.

Table VII-11

Summary of Facility Post-Project Potential Permitted Emissions (Tons Per Year)						
	ROC	**NOx**	**PM_{10}**	**SOx**	**CO**	**NH_3**
Five New Turbines (CTGs)	4.95	28.10	12.50	7.40	32.30	23.35
New 220 BHP Emergency Engine	0.00	0.03	0.00	0.00	0.03	0
Post-Project Total Stationary Source	**4.95**	**28.13**	**12.50**	**7.40**	**32.33**	**23.35**
Rule 26.1: Major Source Thresholds	25	25	N/A	N/A	N/A	N/A

As shown above, post-project the facility is a major source for NOx only.

Rule 26.6 C – Actual Emissions:

Actual emissions are the emissions from existing equipment based on its actual operating history. MREC is a new facility. All of the equipment in this project is new. Therefore, the CTGs and emergency fire pump engine have no actual emissions.

Rule 26.6.D – Emission Increases:

Section D.1. of Rule 26.6 defines the emission increase for new emission units as the potential to emit of the new emission units. The CTGs and the emergency diesel fire pump engine are new emission units. Therefore, the emission increases are equal to the potential to emit of the new equipment and are shown in the table below.

Table VII-12

Summary of Facility Emission Increases (Tons Per Year)						
	ROC	**NOx**	**PM_{10}**	**SOx**	**CO**	**NH_3**
Five New Turbines (CTGs)	4.95	28.10	12.50	7.40	32.30	23.35
New 220 BHP Emergency Engine	0.00	0.03	0.00	0.00	0.03	0
Post-Project Total Stationary Source Emission Increase	**4.95**	**28.13**	**12.50**	**7.40**	**32.33**	**23.35**
Rule 26.1: Major Source Thresholds	25	25	N/A	N/A	N/A	N/A

Rule 26.1.18 defines a major source as "A stationary source which emits or has the potential emit 25 tons per year or more of nitrogen oxides (NOx) or reactive organic compounds (ROC)." There are not major source thresholds for PM10, SOx, CO, or NH3.

As shown above the facility will be a Rule 26 major source of NOx after the installation of the five CTGs and emergency fire water pump engine. The facility will not be a Rule 26 major source of ROC.

VIII. Rules Compliance

Rule 26.2 – Section A Best Available Control Technology (BACT)

Rule 26.2.A requires any application for new, replacement, modified, or relocated emissions units which have a potential to emit of any of the pollutants listed in Table 1 of Rule 26.2 shall install Best Available Control Technology for such pollutant. This rule has a zero threshold for BACT for ROC, NOx, PM-10, and SOx. BACT is not required for CO.

BACT is defined in Rule 26.1 as the most stringent emission limitation or control technology for an emission unit which a.) has been achieved in practice, or b.) is contained in an implementation plan approved by EPA, or c.) is contained in any applicable NSPS or NESHAP, or d.) any other limitation or control determined to be technologically feasible and cost effective.

1. **Combustion Turbine Generators (CTGs):**

BACT requirements apply for ROC, NOx, PM-10, and SOx. There are no BACT requirements for CO. Each of the five turbines is designed to be a simple cycle turbine, meaning it employs a "simple power cycle" and no waste heat is recovered for secondary steam production. There are no heat recovery steam generators (HRSGs). BACT databases for other air districts yield the following information:

US EPA RACT/BACT/LAER Clearinghouse: The US EPA has a collection of RACT/BACT/LAER determination guidelines for facilities from across the nation. A search of the database for simple cycle turbines over 25 MW showed the following recent BACT determinations.

Table VIII-1

EPA RACT/BACT/LAER Natural Gas Simple Cycle Turbine > 25MW				
Date	**Facility**	**NOx**	**ROC**	**PM**
10/14/15	Nacogdoches Power, LLC (232 MW turbine)	9.0 ppmvd @15% O2	2.0 ppmvd @15% O2	12.09 lb/Hr

10/27/15	Van Alstyne Energy Center (183 MW turbine)	9.0 ppmvd @15% O2	None	8.6 lb/Hr

SCAQMD: The South Coast Air Quality Management District (SCAQMD) separates out their BACT guidelines for major and non-major polluting facilities. Major source facilities BACT guidelines are evaluated on a case by case basis. The recent non-major guidelines have been reviewed as well. The non-major guidelines for gas turbines do not make any distinctions based on the type of turbine; however, there are distinctions for turbine size. The SCAQMD Non-Major BACT emission levels for >50MW gas turbine is shown below:

Table VIII-2

SCAQMD BACT >50 MW Turbine			
Date	**SCAQMD Gas Turbine**	**NOx**	**ROC**
10/20/00	Natural Gas Fired, > 50 MW	2.5 ppmvd @ 15% O2, 1 Hr rolling avg. **OR** 2.0 ppmvd @ 15% O2, 3 Hr rolling avg. x efficiency (%)	2.0 ppmvd as methane @ 15% oxygen, 1 hr avg. **OR** 0.0027 lb/MMBTU (HHV)

The SCAQMD provides the following site-specific BACT determinations in its major source BACT section for simple cycle turbines:

Table VIII-3

SCAQMD Site Specific Determinations					
Date	**Project Location**	**Equipment**	**NOx limit**	**ROC limit**	**Comments**
02/10/04	El Colton, LLC Colton, CA	1 – 48.7 MW GE LM6000	3.5 ppmvd (3-Hr avg.)	2.0 ppmvd (3-Hr avg.)	Hi temp SCR/oxidation catalyst
12/18/01	Indigo Energy Facility / Palm Springs, CA	3 – 45 MW GE LM 6000	5 ppmvd (1-Hr avg.)	2 ppmvd (1-Hr avg.)	High temp SCR/oxidation catalyst
02/27/08	Walnut Creek Energy Park/ City of Industry, CA	5 – 100 MW GE LMS100	2.5 ppmvd	2.0 ppmvd	High temp SCR/oxidation catalyst
12/01/10	CPV Sentinel, LLC	8 -100 MW GE LMS100	2.5 ppmvd	2.0 ppmvd	High temp SCR/oxidation catalyst

SJVAPCD: The San Joaquin Valley Air Pollution Control District (SJVAPCD) does not separate gas turbines by simple cycle or combined cycle. Instead they categorize the turbines either as with or without heat recovery. The BACT SJVAPCD Guidelines for turbines = or > 50 MW, Uniform Load, without heat recovery are:

Table VIII-4

SJVAPCD BACT Guideline 3.4.7			
Date	**SJVAPCD Gas Turbine**	**NOx**	**ROC**
10/01/02	= or >50 MW, Uniform Load, without Heat Recovery	<u>Achieved in practice:</u> 5.0 ppmvd @15% O_2, 3 Hr avg. (high temp SCR) <u>Technologically feasible:</u> 2.5 ppmvd @ 15% O_2 (high temp SCR or equal) 3.0 ppmvd @ 15% O_2 (high temp SCR or equal)	<u>Achieved in practice:</u> 2.0 ppmvd @15% O_2, 3 Hr avg. (oxidation catalyst) <u>Technologically feasible:</u> 0.6 ppmvd @15% O_2, 3 Hr avg. (oxidation catalyst) 1.3 ppmvd @15% O_2, 3 Hr avg. (oxidation catalyst)

SJVAPCD provides the following site-specific BACT determination:

Table VIII-5

SJVAPCD Site Specific BACT Determination					
Date	**Project/Location**	**Equipment**	**NOx limit**	**ROC limit**	**Comments**
12/19/07	Panoche Energy Center Firebaugh, CA	100 MW GE LMS100, Turbine	2.5 ppmvd (1-Hr avg.)	2.0 ppmvd (3-Hr avg.)	Water injection SCR/oxidation catalyst

BAAQMD: The Bay Area Air Quality Management District determines BACT requirements on a case by case basis. The latest revision to a turbine was done in April 2004. The resulting BACT database includes the following:

Table VIII-6

BAAQMD Simple Cycle >= 40 MW BACT Determination 89.1.3			
Date	**BAAQMD Gas Turbine**	**NOx**	**ROC**
07/18/03	$\geq$ 40 MW, simple cycle	2.5 ppmvd @ 15% O_2 (Hi temp SCR+ water or steam injection)	2.0 ppmvd @ 15% O_2 (oxidation catalyst)

CARB Guidance: California Air Resource Board BACT Clearinghouse does not have an entry for a Gas Turbine Simple Cycle > 50 MW. However, for smaller simple-cycle turbines there are the following guidance:

Table VIII-7

CARB BACT Simple Cycle >2MW <50 MW			
Date	**CARB Guidance**	**NOx**	**ROC**
09/2001	> 12 and < 50 MW	2.5 ppmvd @15% O2	2.0 ppmv @ 15% O2

BACT Discussion:

NOx:
As shown in the BACT guidelines listings above for gas fired turbines, emission levels of 2.5 ppmvd NOx @ 15% O2 have been achieved in practice for a simple cycle turbine at many facilities. These levels have been achieved using water injection into the combustors to limit NOx production and an SCR system for NOx control. There have been some facilities with combined cycle turbines that have been permitted at 2.0 ppmvd NOx @ 15% O2 using SCR. However, the VCAPCD is not aware of any simple cycle facilities demonstrating continuous compliance with a 2.0 ppmvd NOx limit. Alternative controls for NOx such as XONON combustors or EMx catalyst have not been demonstrated to be capable of reliably meeting a NOx limit lower than 2.5 ppmvd NOx @ 15% O2 for simple-cycle turbines of this size. No lower emission levels for NOx have been identified as being technologically feasible, contained in an implementation plan or in NSPS or NESHAP. Therefore, BACT for NOx is 2.5 ppmvd @15% O2 (1 hr average).

ROC:
As shown in the BACT guidelines listings above for gas fired turbines, emission levels of 2.0 ppmvd ROC @ 15% O2 have been achieved in practice for a simple cycle turbine. These levels have been achieved using an oxidation catalyst for ROC control. No lower emission levels for ROC are contained in an implementation plan or in NSPS or NESHAP. Therefore, BACT for ROC is 2.0 ppmvd @15% O2 (1 hr average).

PM10 and SOx
BACT for PM10 and SOx will be the use of PUC-regulated natural gas. This is accepted achieved-in-practice BACT by the SCAQMD, SJVUAPCD, and BAAQMD BACT Guidelines. No lower emission levels for natural gas fired turbines for PM10 and SOx have been identified as being technologically feasible, contained in implementation plans or in NSPS or NESHAP. Therefore, BACT for PM10 and SOx is use of PUC regulated natural gas.

In summary, BACT for the proposed simple-cycle GE LM600 gas combustion turbine generators is as follows:

Table VIII-8

BACT Simple Cycle GE LM6000 Gas Combustion Turbine Generators	
NOx	2.5 ppmvd @ 15% O_2, 1 Hr average, SCR
ROC	2.0 ppmvd @ 15% O_2 as methane, 1 Hr average, oxidation catalyst
PM_{10}	PUC-regulated natural gas only
SOx	PUC-regulated natural gas only

2. Emergency Diesel Fire Pump Engine:

Rule 26.2.A BACT requirements apply to ROC, NOx, PM-10, and SOx. Rule 26.2.A does not require BACT for CO emissions. The unit is a 220 BHP diesel-fired emergency fire water pump engine. The engine will have a 50 hours per year limit for non-emergency usage such as maintenance and readiness testing.

Since stationary emergency fire pump engines are regulated by U.S. EPA at the point of manufacture, BACT is considered to be compliance with Table 4 of 40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines". These engine emission standards are identical to the standards of the California Air Resources Board (CARB) Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines. This engine is subject to Table 2 of the ATCM as it is considered to be a new direct-drive fire pump engine. As a 220 BHP engine with a model year of 2011 it is subject to the following emission limits: NMHC+NOx = 3.0 g/bhp-hr, PM = 0.15 g/bhp-hr, and CO= 2.6 g/bhp-hr. ROC is assumed to be equivalent to NMHC. In addition, the ATCM also requires the use of CARB low-sulfur diesel fuel with a sulfur content of less than 0.0015% by weight.

Therefore, BACT for the 220 BHP John Deere emergency diesel fire water pump engine is as follows:

Table VIII-9

BACT Emergency Diesel Fire Water Pump Engine	
NOx	CARB Stationary Engine ATCM - NMHC+NOx = 3.0 g/bhp-hr
ROC	CARB Stationary Engine ATCM - NMHC+NOx = 3.0 g/bhp-hr
PM_{10}	CARB Stationary Engine ATCM - PM = 0.15 g/bhp-hr
SOx	Very low sulfur diesel fuel (15 ppmw sulfur or less)

Rule 26.2 – New Source Review Requirements, Section B – Offsets

Rule 26.2.B details the emission offset requirements for new, replacement, modified, or relocated emissions units. There are only offset requirements for ROC, NOx, PM10, and SOx. Emission offsets are not required for CO or NH3.

The offset thresholds are shown in Rule 26.2.B Table B-1.

Table VIII-10

Rule 26.2.B Table B-1 Offset Thresholds			
Pollutant	**Offset Threshold**	**Facility Post-Project Emissions**	**Offsets Triggered?**
ROC	5.0 ton/yr	4.95 ton/yr	No
NOx	5.0 ton/yr	28.13 ton/yr	Yes
PM_{10}	15.0 ton/yr	12.50 ton/yr	No
SOx	15.0 ton/yr	7.40 ton/yr	No

As shown in the table above, the offset thresholds of Rule 26.2 Table B-1 are exceeded for NOx only. Therefore, offsets will be required for any emission increases in NOx as calculated pursuant to Rule 26.6, New Source Review - Calculations. There are no offsets required for any ROC, PM_{10}, or SOx emission increases as the offset thresholds shown above will not be exceeded.

NOx Offset Requirements – Potential Emission Increases (Rule 26.6.D.1)
The increase in NOx emissions from the proposed five CTGs and emergency fire pump engine will be offset using Emission Reduction Credits (ERCs). The MREC facility is a new source. The emission increase from the new equipment is calculated as the potential to emit for the new emissions units. Therefore, the NOx emissions increase is equal to the post project potential permitted emissions.

The facility will be required to provide NOx offsets at a tradeoff ratio of 1.3 to 1 as per Rule 26.2.B.2.a. The quantity of offsets required is shown below.

NOx offsets required = increase in NOx emissions x 1.3 offset tradeoff ratio

= (5 new CTGs + new emergency engine) x 1.3 offset tradeoff ratio
= (28.10 tons + 0.03 tons) x 1.3 offset tradeoff ratio
= 28.13 tons NOx/yr x 1.3 offset tradeoff ratio
= 36.57 tons NOx/yr

Pursuant to Rule 26.2.B.2.d and Rule 26.11.C.6 the NOx offsets are not required to be surplus at the time of use since the most recent report of the Rule 26.11 Annual Equivalency Demonstration Program, dated April 1, 2017, shows a positive balance for NOx.

The actual ERC certificates will be identified prior to the issuance of the Final Determination of Compliance (FDOC). VCAPCD will not issue the FDOC until the ERC's have been identified and evaluated. In addition, the VCAPCD will provide a public notice of the proposed ERC's prior to the issuance of the FDOC. This public notice will specify a 45-day public comment period for the proposed ERCs.

Rule 26.2 B. 4 Offsets - ERC Quarterly Profile Check

As discussed above, the ERC Certificates will be identified prior to the FDOC being issued. VCAPCD will perform a quarterly profile check once the ERCs have been identified.

The applicant must provide the proposed quarterly profile of Mission Rock Energy Center to show that it meets the quarterly profile check of 80% as required by Rule 26.6.F.

Rule 26.2 Section C - Protection of Ambient Air Quality Standards and Ambient Air Increments

Rule 26.2.C requires the denial of any application for any new, replacement, modified, or relocated emissions unit that would cause the violation of any ambient air quality standard or the violation of any ambient air increment as defined in 40 CFR Part 51.166(c). Modeling of the MREC indicates that the project will not cause the violation of any ambient air quality standard or the violation of any ambient air increment as defined in 40 CFR Part 51.166(c). See Appendix G.

Rule 26.2 Section D - Certification of Statewide Compliance

The applicant must certify that all major sources, as defined in their specific nonattainment area, that are both located in California and owned or operated by the applicant, or by any entity controlling, controlled by or under common control with such applicant, are in compliance or on a schedule for compliance with all applicable emission limitations and standards. The applicant has provided a Certification of Statewide Compliance. See Appendix I.

Rule 26.2 Section E - Analysis of Alternatives

The applicant must provide an analysis of alternatives as required by Section 173(a)(5) of the federal Clean Air Act, of alternative sites, sizes, production processes, and environmental control techniques for the proposed source demonstrating that the benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification. The applicant has provided an analysis of alternatives. See Appendix J.

Rule 26.7 New Source Review – Notification

This Rule specifies the cases in which notification shall be provided of the Air Pollution Control Officer's preliminary decision to grant an Authority to Construct, or issue a Certificate of Emission Reduction Credit. In addition, this Rule specifies the process by which such notification shall be made. The MREC will result in an increase in NOx emissions over the 15.0 tons per year threshold and therefore a public notice will be required. The notification shall be published in a newspaper of general circulation in Ventura County. The notice period shall provide at least 30 days for the public to submit written comments regarding the decision. The VCAPCD shall consider all comments made during the comment period.

The VCAPCD shall also submit a copy of the notice and supporting data and analysis to the California Air Resources Board (ARB) and the U.S. Environmental Protection Agency (EPA) for comments.

The VCAPCD will provide written notification to any person or agency which submitted comments during the comment period.

Rule 26.9 New Source Review - Power Plants

This rule applies to MREC as an Application for Certification has been submitted to the California Energy Commission (Docket No. 15-AFC-02). The VCAPCD conducted a Determination of Compliance review (this document) as required by Rule 26.9. As required by Rule 26.9.F, a public notice and comment period shall be conducted as required by Rule 26.7. Compliance with Rule 26.9 is confirmed.

Rule 26.11 New Source Review – ERC Evaluation at Time of Use

This rule provides for the evaluation by the VCAPCD of emission reduction credits for reactive organic compounds (ROC) and nitrogen oxides (NOx) at the time that the Authority to Construct (in this case a Determination of Compliance) is issued. As MREC is required to provide NOx offsets as calculated above, the VCAPCD shall evaluate the proposed offsets pursuant to Rule 26.11 Section B.

Pursuant to Rule 26.2.B.2.d and Rule 26.11.C.6 these NOx offsets are <u>not</u> required to be surplus at the time of use since the most recent report of the Rule 26.11 Annual Equivalency Demonstration Program, dated April 1, 2017, shows a positive balance for NOx.

Rule 26.12 New Source Review – Federal Major Modifications

As shown in the Rule 26.6.D emission increase calculations, MREC results in being a new major source for NOx only. MREC is a <u>new</u> major source and not a <u>modified</u> source. As such the facility must comply with the requirements of Rule 26.2.E – Analysis of

Alternatives. See the Rule 26.2.E compliance section above and Appendix J (Analysis of Alternatives).

Rule 26.13 New Source Review – Prevention of Significant Deterioration

The post-project potentials to emit from all new units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is therefore 250 tons per year (tpy) for any regulated NSR pollutant.

Table VIII-11

PSD Major Source Determination: Potential to Emit (Tons Per Year)						
	NO2	**ROC**	**SO2**	**CO**	**PM**	**PM10**
Total PE from New and Modified Units	28.13	4.95	7.40	32.33	12.50	12.50
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	No	No	No	No	No	No

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore, Rule 26.13 is not applicable and no further PSD analysis is required.

Rule 29 Conditions On Permits

Section A of this rule requires the VCAPCD to apply conditions to permits which are necessary to assure that a stationary source and all emissions units at the stationary source will operate in compliance with applicable state and federal emission standards and with Ventura County APCD Rules, including permit conditions required by Rule 26, New Source Review.

Section B of this rule requires the VCAPCD to apply conditions to permits which will limit the amount of air contaminants a stationary source may emit. These emission limits are called permitted emissions and shall be expressed in pounds per hour and tons per year. In addition, conditions may include restrictions on production rates, fuel use rates, raw material use rates, hours of operation or other reasonable conditions to insure that the permitted emission limits are not exceeded.

This DOC contains conditions that both assure compliance with all applicable federal, state and Ventura County APCD rules and limit the stationary source permitted emissions in the units of tons per year and pounds per hour.

Rule 33.5 Part 70 Permits – Timeframes for Applications, Review and Issuance

Facilities that have a potential to emit that equals or exceeds the federal major source thresholds are subject to the requirements of Part 70 Permits (commonly called Title V sources) must submit timely applications to apply for their Part 70 Permit. In addition as discussed below, facilities that require a Title IV Acid Rain Permit are also required to obtain a Part 70 (Title V) Permit. MREC is a new facility that will be subject to the Part 70 permit requirements. Therefore, MREC will be required to submit a Part 70 permit application to the VCAPCD prior to operating the new turbines and emergency fire pump engine. A condition has been included in the DOC to ensure that the MREC submits a Part 70 permit application prior to operation of the new turbines and emergency fire pump engine.

Rule 34 Acid Deposition Control

This rule applies to any acid rain source, as defined in Title IV of the 1990 Federal Clean Air Act Amendments. A Title IV Acid Rain permit is required for the proposed turbines because they are new fossil fuel fired combustion devices used to generate electricity for sale with an electrical output of greater than 25 MW. The Title IV Acid Rain permit is required pursuant to 40 CFR Part 72, which is incorporated into VCAPCD Rule 34, Acid Deposition Control. The Determination of Compliance will require that MREC submit the Title IV Acid Rain permit application prior to operating the new turbines.

Rule 50 Opacity

Rule 50 limits visible emissions to an opacity of less than 20 percent (Ringelmann No. 1), as published by the United States Bureau of Mines. Visible emissions are not expected under normal operation from the turbines, emergency diesel fire pump engine, or ammonia tank.

Rule 51 Nuisance

Rule 51 requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The new equipment, including the turbines, emergency diesel fire water pump engine, and ammonia tank, are not expected to create nuisance problems, such as smoke or odors.

The VCAPCD has conducted a risk management review (RMR) under the Ventura County APCD Policy “Air Toxics Review of Permit Applications” dated July 10, 2002. The review can be found in Appendix G. The calculated maximum health risks are:

Table VIII-12

RMR Results				
Unit Description	**Cancer Risk**	**Hazard Index**		**Health Risk Reduction Plan Required?**
		Chronic	**Acute**	
Natural Gas Turbines	1.18×10^{-8}	1.66×10^{-5}	3.20×10^{-2}	No
Emergency Diesel Engine	6.76×10^{-6}	1.29×10^{-3}	---	No
Project Total	**6.77×10^{-6}**	**1.31×10^{-3}**	**3.20×10^{-2}**	**No**

The acute and chronic hazard indices are below 0.5 and the cancer risk factor associated with the project is less than 10 in a million. In accordance with VCAPCD's "Air Toxics Review of Permit Application" policy, the project is approved without the need to submit a Health Risk Reduction Plan.

Rule 54 Sulfur Compounds

Rule 54 requires compliance with sulfur dioxide (SO_2) emission limits of 300 ppmv and compliance with ground level concentration limits of SO_2 (0.25 ppmv averaged over 1 hour, 0.04 ppmv averaged over 24 hours, and 0.075 ppmv 1-hour average design value). The combustion of PUC natural gas only results in compliance with the 300 ppmv emission limit. Emissions from the project result in modeled ground level concentrations of 14.96 $\mu g/m^3$ (0.0114 ppmv) on a 1 hour average and 1.98 $\mu g/m^3$ (0.00151 ppmv) on a 24 hour average. See the air dispersion modeling results in Appendix G.

Rule 55 Fugitive Dust

The provisions of this rule shall apply to any operation, disturbed surface area, or man-made condition capable of generating fugitive dust, including bulk material handling, earth-moving, construction, demolition, storage piles, unpaved roads, track-out, or off-field agricultural operations. This rule places limits on visible dust, opacity, and track out from activities subject to the rule.

The applicant has proposed mitigation measures during the construction phase of MREC that will assure compliance with this rule. Compliance with this rule is expected during the routine operation of the MREC.

Rule 57.1 Particulate Matter Emissions From Fuel Burning Equipment

The rule requires that particulate matter emissions from the turbine not exceed 0.12 pounds per million BTU of fuel input. At the manufacturer's guaranteed particulate matter emission rate of 2.0 pounds per hour (which is greater than the EPA AP-42 emission factor) and the maximum fuel input rate of 566.2 MMBTU/Hr, the particulate matter emissions are 0.004 lb per MMBTU, which is significantly less than the Rule 57.1.B limit of 0.12 lb per MMBTU. Therefore, compliance with the rule is expected.

Rule 57.1 does not apply to internal combustion engines, pursuant to Section C.1 of the rule. Therefore, the rule does not apply to the new emergency fire pump engine.

Rule 64 Sulfur Content of Fuels

Rule 64.B.1 prohibits the combustion of gaseous fuels that contain sulfur compounds in excess of 50 grains per 100 cubic feet (788 ppmv), calculated as hydrogen sulfide at standard conditions. The turbine will be required to burn only Public Utilities Commission (PUC) regulated natural gas which meets this requirement. Rule 64.B.2 prohibits the combustion of liquid fuels that have a sulfur content in excess of 0.5 percent by weight. The emergency engine will only use ARB-certified diesel fuel that meets this limit. Section C.2 of the rule states that the monitoring and recordkeeping sections of the rule do not apply when PUC-regulated natural gas is or ARB-certified diesel is used. Therefore, compliance with this rule is expected.

Rule 74.9, Stationary Internal Combustion Engines

The facility is installing a 220 BHP John Deere emergency diesel fired internal combustion engine. The engine will provide emergency firewater capabilities for the protection of life and property. The facility has indicated that it will be operated less than or equal to 50 hours per year for non-emergency use such as engine maintenance and readiness testing. Pursuant to Section D.3 of Rule 74.9, the engine is exempt from the Section B (Requirements), Section C (Engine Operator Inspection Plan), and Section E (Recordkeeping) requirements of Rule 74.9 because it will be operated less than 50 hours per calendar year for non-emergency use. A non-resettable elapsed hour meter is required by Rule 74.9.D.3. The facility will submit the engine annual operating hours to the VCAPCD per Rule 74.9.F.2.

Rule 74.23 Stationary Gas Turbines

The proposed gas turbines are subject to the 9 x E/25 ppmvd @ 15% oxygen NOx limit of Rule 74.23.B.1. (E is the Unit Efficiency Percent and is not less than 25 percent as defined in the rule.) The NOx BACT limit of 2.5 ppmvd @ 15% oxygen is more stringent than the Rule 74.23 limit as described above. Rule 74.23 requires an annual source test to verify compliance with the NOx limit. The required NOx continuous emission monitor will also verify compliance with the NOx emission limit.

The turbines are also subject to the 20 ppmvd ammonia (NH_3) limit of Rule 74.23.B.4. The proposed ammonia limit of 5 ppmvd @ 15% oxygen is more stringent than the Rule 74.23 limit. Compliance with this ammonia limit will be verified by an annual source test.

Section C.1.e of Rule 74.23 exempts the turbines from the NOx and NH_3 emission concentration limits during start-up, planned shutdown, and unplanned load change periods. These exemption periods shall not exceed one (1) hour. For failed start-ups, each restart shall begin a new exemption period. The proposed conditions include limits on the durations of startup and shutdown consistent with these time periods.

Section D.1 requires records to be kept and available upon request for VCAPCD inspection for 2 years. However, VCAPCD Rule 103, Continuous Monitoring Systems, requires records to be kept for 5 years. The facility will be required to keep records for 5 years.

Section E requires the facility to provide the VCAPCD with reports and data identifying the annual usage (e.g., fuel consumptions, operating hours, etc.) of the turbines and the annual compliance verification source test.

Section F identifies specific test methods to be used to verify compliance. The facility will use these test methods for compliance.

Rule 103 Continuous Monitoring Systems

The application proposes that each of the new GE LM6000 Turbines will be equipped with NOx, CO, and O2 Continuous Emission Monitors (CEMs). Such CEMs will be required pursuant to Rule 103.A.1 for sources subject to federal regulations that require CEMs. The Determination of Compliance will require that the CEM system be operated in compliance with Rule 103. The requirements of Rule 103 include the installation, calibration, and maintenance of the system in accordance with the specifications for electric power generating units in 40 CFR, Part 75, Continuous Emission Monitoring, Subpart C, Operation and Maintenance Requirements, which includes by reference Appendix A to Part 75, Specifications and Test Procedures, and Appendix B to Part 75, Quality Assurance and Quality Control Procedures. Note that a CEMS is also required by 40 CFR Part 60, Subpart KKKK, “Standards of Performance for Stationary Combustion Turbines” as discussed below.

California Health & Safety Code 42301.6 (School Notice)

The VCAPCD has verified that the new turbines and the emergency diesel fire pump engine are not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

The proposed emergency engine is subject to this ATCM. The engine will be restricted to emergency usage and 50 hours per year for maintenance and testing purposes. The following requirements will apply to the new engine:

Title 17 CCR Section 93115 Requirements for New Emergency Direct-Drive Fire Pump Engines	Proposed Method of Compliance with Title 17 CCR Section 93115 Requirements
Emergency engine(s) must be fired on CARB diesel fuel, or an approved alternative diesel fuel.	The applicant has proposed the use of CARB certified diesel fuel. A permit condition will be included in the DOC requiring the use of CARB certified diesel fuel.
The engine(s) must meet the emission standards in Table 2 of the ATCM for the specific power rating and model year of the proposed engine.	The applicant has proposed the use of a diesel fire water pump engine that is certified to the latest EPA Tier Certification standards for the applicable horsepower range, guaranteeing compliance with the emission standards of the ATCM. Additionally, the proposed diesel PM emissions rate is less than or equal to 0.15 g/BHP-Hr.
The engine may not be operated more than 50 hours per year for maintenance and testing purposes.	A permit condition will be included in the DOC to require that the engine be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year.
A non-resettable hour meter with a minimum display capability of 9,999 hours shall be installed upon engine installation, unless the District determines on a case-by-case basis that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history.	A permit condition will be included in the DOC to require that the engine be equipped with a non-resettable hour meter with a minimum display capability of 9,999 hours.
An owner or operator shall maintain monthly records of the following: emergency use hours of operation; maintenance and testing hours of operation; hours of operation for emission testing; initial start-up testing hours; hours of operation for all other uses; and the type of fuel used. All records shall be retained for a minimum of 36 months.	Permit conditions enforcing these requirements will be included in the DOC.

Public Resources Code 21000-21177 - California Environmental Quality Act (CEQA) - California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387 CEQA Guidelines

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.

- Identify the ways that environmental damage can be avoided or significantly reduced.

- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.

- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The California Energy Commission (CEC) has the exclusive power to certify all thermal electric power plants greater than 50 MW in the State of California (Public Resources Code § 25500). While the CEC siting process is exempt from CEQA (14 CCR § 15251(k)), it is functionally equivalent to CEQA.

The VCAPCD holds no discretionary approval powers over this project; however the VCAPCD prepares a Determination of Compliance (DOC), this document as required by Rule 26.9, New Source Review - Power Plants. The DOC confers the rights and privileges of an Authority to Construct upon certification by the CEC, where the CEC certificate contains the conditions set forth in this DOC (20 CCR § 1744.5 and Rule 26.9). An Authority to Construct and Permit to Operate is required to be issued if the project receives a certificate from the CEC and the project is constructed in accordance with the conditions set forth in the DOC (Rule 26.9).

The VCAPCD makes the following findings regarding this project: the VCAPCD holds no discretionary approval powers over this project and the VCAPCD's actions are ministerial (CEQA Guidelines § 15369).

VCAPCD Rule 13.C.2 requires for projects requiring CEQA review for the VCAPCD to issue or deny an Authority to Construct (or in this case a DOC) within 180 days of the date the lead agency has approved the project. Since the DOC will be issued as a part of the lead agency's approval of the project (i.e. the CEC's issuance of a certificate), compliance with this requirement is confirmed.

40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines"

The proposed 220 BHP John Deere emergency diesel fire pump engine is subject to the Compression Ignition Internal Combustion Engine NSPS (Subpart IIII).

Sections 60.4201 through 60.4203 apply to engine manufacturers only. Section 60.4204 contains standards for non-emergency engines that do not apply to this engine since it is an emergency engine. Section 60.402(d) Table 4 applies to manufacturers of emergency fire pump engines.

Section 60.4205 contains emission standards for the engine. Section 60.4205(c) requires owners and operators of fire pump engines to comply with Section 60.402(d) Table 4 for manufacturers as discussed above. For engines in this power range (220 BHP) and 2011 model year, Table 4 requires the engine be certified to standards of 4.0, 3.5 and 0.20 g/kW-Hr (3.0, 2.6, 0.15 g/BHP-hr) for NMHC+NOx, CO and PM respectively. The proposed engine complies with these standards as shown in Appendix D – Diesel Engine Performance Data.

Section 60.4207 requires the use of low sulfur fuel. Proposed permit conditions require CARB diesel fuel, which satisfies the low sulfur fuel requirement.

Section 60.4209 requires that emergency engine be equipped with a non-resettable hour meter. Proposed permit conditions will require an hour meter which satisfies the requirement.

Section 60.4211 requires that the engine be certified and be operated and maintained according to the manufacturer's emission-related written instructions. The engine is an emergency fire pump engine under this rule, so is restricted to operating in certain scenarios. The engine may be operated for unlimited duration in emergency situations. Maintenance and testing is limited to up to 50 hours per year. Proposed permit conditions allow the emergency engine to operate in emergency situations and for up to 50 hours per year for maintenance and testing operations.

Section 60.4214 requires that the owner or operator maintain logs of engine operation including durations and reason for use. This requirement is specified in proposed permit conditions. No notifications or reports are required. The proposed permit conditions contain requirements to ensure compliance with the applicable portions of this subpart.

40 CFR Part 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines"

This subpart applies to all turbines with heat input in excess of 10 MMBTU/Hr that commence construction after February 18, 2005. The proposed GE LM6000-PG-Sprint gas turbines are subject to the subpart because the heat input for one turbine is 566.2

MMBTU/Hr. Each turbine is a simple cycle turbine without heat recovery. The turbines will be fired on only PUC regulated natural gas.

Section 60.4320 requires turbines to meet the applicable NOx standard in Table 1 of the subpart. The proposed natural gas fired turbines heat input are each 566.2 MMBTU/Hr, therefore the NOx limit as listed in Table 1 is 25 ppmvd at 15% O2 or 1.2 lb/MW-Hr when operating at or above 75% peak load and 96 ppmvd at 15% O2 or 4.7 lb/MW-hr when operating below 75% of peak load.

This Subpart KKKK NOx limit is less stringent than VCAPCD Rule 74.23 limit (9 ppmvd NOx) and the VCAPCD Rule 26.2.A NSR BACT limit of 2.5 ppmvd NOx for the turbines. Therefore, new turbines compliance with the VCAPCD NSR BACT requirements will comply with the Subpart KKKK.

Section 60.4330 requires the turbines to meet the SO_2 emission limits. The turbines will be fired on PUC regulated natural gas therefore the SO_2 emissions limits are either 0.90 lbs- SO_2/MWh discharge based on gross output (Section 60.4330 (a)(1)) or 0.060 lbs-SO_2/MMBTU potential in the fuel (Section 60.4330 (a)(2)). The natural gas sulfur content of the fuel will be limited to 0.75 grain per 100 scf (0.002098 lbs- SO_2/MMBTU). This sulfur content is lower than the fuel sulfur standard. Therefore, the new turbines will comply with this section.

Section 60.4333 is a general requirement that requires the operation and maintenance of the turbine in a manner of good air pollution control practices at all times. The facility will operate the turbines in this manner.

Section 60.4335 provides guidance on requirements when water or steam injection is being used to control NOx emissions. The section requires installation, certification, and maintaining of a continuous emission monitoring system (CEMS). The facility has proposed to install and operate a CEMS which will comply with this section.

Section 60.4345 contains requirements for the CEMS system. The CEMS may either be certified using either Performance Specification 2 (PS 2) of Appendix B of 40 CFR Part 60 (except 7-day drift test is based on unit operating days instead of calendar days), or according to the procedures of Appendix A of 40 CFR Part 75. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBTU basis. For each full unit operating hour, the NOx and diluent monitors must sample, analyze and record at least once each 15 minute quadrant for the hour to be valid. For partial unit operating hours, at least one valid point must be obtained for each quadrant of the hour the turbine operates. Only two valid points are needed for hours in which quality assurance or maintenance activities are conducted to validate the hour. All monitors including fuel flowmeters, watt meters, temperature sensors, etc. must be installed, calibrated, maintained and operated according to manufacturer's instructions. The facility must maintain a quality assurance (QA) plan for all continuous monitoring equipment.

Section 60.4350 contains requirements for using CEMS data to identify excess emissions. This includes that all CEMS data be reduced to hourly averages and recorded in units of ppm (uncorrected) or lb/MMBTU for each valid unit operating hour of data. For missing data, the owner or operator is not required to report data substituted using the missing data procedures of 40 CFR Part 75, and instead may report these periods as monitor downtime. All other monitored parameters must be reduced to hourly averages as well. For simple-cycle units, excess emissions are calculated on a 4-hour rolling average basis as required by Section 60.4350(g).

Sections 60.4360 and 60.4365 have requirements for monitoring sulfur content of fuel. Since only natural gas is combusted, sulfur content monitoring is not required per 60.4365(a) which specifies that, if a purchase contract, tariff sheet, or transportation contract lists sulfur content below 20 grains of sulfur per 100 standard cubic feet (scf) of gas, no monitoring is required. As discussed above, the natural gas sulfur content of the fuel will be limited to 0.75 grains of sulfur per 100 scf. MREC will be required to keep records of fuel gas sulfur content.

Section 60.3475 requires the submission of reports of excess emissions and monitor downtime (including startups, shutdowns and malfunctions).

Section 60.4380 specifies that periods of excess emissions to be reported are any time where the 4-hour NOx emission rate exceeds the applicable standard of 25 ppmvd at 15% O2 (or 96 ppmvd at 15% O2 when operating below 75% peak load as described above). The 4-hour average includes the unit operating hour and three unit operating hours immediately preceding the subject unit operating hour. An emission rate is calculated if a valid NOx rate is obtained for at least three out of four hours. Periods of monitor downtime to be reported include any hours the turbine was operating but valid readings were not obtained. For periods where multiple emission limits would apply (i.e. the 4-hour averaging period includes periods of operating both above and below 75% load), the applicable standard is the average of the applicable standards during each hour. For each hour where multiple emission standards apply, the higher emission standard during that hour applies.

Section 60.4395 requires that reports be submitted by the 30th day following the end of each semi-annual reporting period. This is specified in proposed permit conditions.

Sections 60.4400 and 60.4405 contain instructions for initial and periodic source testing. If testing is to be performed, EPA Method 7E or Method 20 may be used to measure NOx concentration along with EPA Methods 1 and 2 to determine stack gas flow rate or NOx and O2 may be measured using Method 20 or Methods 7E and 3A, and then converted to lb/MMBTU using EPA Method 19. Alternatively, if equipped with a CEMS, the initial performance test may be conducted as a RATA test. An additional requirement is that the test be conducted while the turbine is operating within +/- 25% of 100% peak load. This is specified in the proposed permit conditions.

Compliance with the requirements of 40 CFR Part 60 Subpart KKKK is expected.

40 CFR Part 60, Subpart TTTT, "Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units"

This subpart applies to stationary combustion turbines that commence construction after January 8, 2014.

Section 60.5520 (a) requires the turbine to meet the applicable standard for CO2 emissions as determined in either table 1 or 2 of the subpart. In this case the MREC turbines must meet the table 2 emission standard of 50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO2/MMBTU).

Table 2 of NSPS Subpart TTTT CO2 Emission Standards for Stationary Combustion Turbines	
Affected EGU	**CO2 Emission Standard**
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBTU).

"Design efficiency" is defined in the rule as "the rated overall net efficiency (e.g., electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions …."

"Potential electric output" is defined in the rule as "33 percent or the base load rating design efficiency at the maximum electric production rate …, whichever is greater, multiplied by the base load rating (expressed in MMBTU/h) of the EGU, multiplied by 106 BTU/ MMBTU, divided by 3,413 BTU/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr…" Based on the current ISO heat rate of 8,317 BTU/kWh (electrical) (LHV) and a conversion factor of 3412.1416 BTU/kWh (thermal), it takes 2.4375 kWh (thermal) input to produce 1 kWh (electrical) output (8317 BTU/kWh ÷ 3412.1416 BTU/kWh = 2.4375). The base load rating design efficiency for each turbine at MREC is therefore 1 kWh (electrical) / 2.4375 kWh (thermal) = 41%.

The percentage electric sales threshold that distinguishes base load and non-base load units is based on the specific turbine's design efficiency (commonly known as "the sliding-scale approach") and varies from 33 to 50 percent. Specifically, all units that have annual average electric sales (expressed as a capacity factor) greater than their net lower heating value (LHV) design efficiencies (as a percentage of potential electric output) are base load units. All units that have annual average electric sales (expressed as a capacity factor) less than or equal to their net LHV design efficiencies are non-base load units. As discussed above, it is expected that on an annual average basis each of the new MREC CTG's would supply less than one-third of its potential electric output to a utility power distribution system. Because this expected potential annual average electric sales rate is less than the 41% design efficiency, the new MREC CTG's would be non-base load units under the final CPS. As non-base load units, under the final CPS the potential electric output for each MREC turbine is calculated as follows:

Potential electric output =

$$= Design\ efficiency\ (\%) \times\ Heat\ Input\ Rate, \frac{MMBtu}{hr} \times \frac{10^6 Btu}{MMBtu} \times \frac{1\ kWh}{3412.1416\ Btu} \times \frac{1\ MWh}{1{,}000\ kWh} \times 8{,}760 hrs/yr$$

$$= 0.41 \times 2{,}831 \frac{MMBtu}{hr} \times \frac{10^6 Btu}{MMBtu} \times \frac{1\ kWh}{3412.1416\ Btu} \times \frac{1\ MWh}{1{,}000\ kWh} \times 8{,}760 hrs/yr$$

$$= 2{,}979{,}893 \text{ MW per year}$$

As long as the new MREC CTG's have net electric sales of less than 0.41 * 7,268,033 MW, or 2,979,893 MW per year, it will be subject to the 120 lb CO_2/MMBTU limit for non-base load gas turbines. The new MREC CTG is expected to operate with an annual capacity factor of approximately 29%. With a full load net nominal output of approximately 275 MW, the MREC units would supply a maximum of approximately 29% x 8760 hrs/year x 275 MW/Hr = 698,610 MW per year to a utility power distribution system. Since this output is less than the allowable level of 2,979,893 MW per year, MREC would be a non-base load unit under the final CPS and would be subject to the Best System of Emission Reduction (BSER) established for that subcategory.

Section 60.5525 and 60.5535 has the general requirements and monitoring for complying with the subpart. This turbine is limited to burning natural gas resulting in a consistent emission rate of 120 lb CO_2/MMBTU or less per section 60.5520(d)(1). Therefore, the facility will be required to maintain fuel purchase records of the natural gas.

Compliance with the requirements of 40 CFR Part 60, Subpart TTTT, "Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units", is expected.

40 CFR Part 63 Subpart ZZZZ – Reciprocating Internal Combustion Engines (RICE)

This NESHAP rule applies to the new emergency diesel fire pump engine. It applies to all reciprocating internal combustion engines (RICE) located at both major and area sources of HAPs. This rule is delegated to the Ventura County APCD for implementation by the EPA.

As discussed above, this site is not a major HAPs source. This rule has the following limited exemptions:

Section 40 CFR 63.6590(c)(1) lists new RICE at an area HAPS source complies with NESHAP Subpart ZZZZ by complying with the corresponding New Source Performance Standard - NSPS, 40 CFR 60 Subpart IIII for stationary compression ignition engines.

The proposed emergency engine will comply with NSPS IIII as discussed above and will therefore comply with NESHAPS ZZZZ.

40 CFR Part 64, "Compliance Assurance Monitoring"

The Compliance Assurance Monitoring (CAM) regulation applies to emission units at a major stationary source required to obtain a Title V permit, which use control equipment to achieve a specified emission limit. The section is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits. CAM is applicable to the turbine because the potential to emit for the stationary source exceeds the major source thresholds (25 tons per year for ROC or NOx, and 100 tons per year for PM, SOx, or CO) for NOx. The turbine will have a continuous emissions monitor (CEMs) installed which will comply with this requirement.

40 CFR Part 68, List of Regulated Substances and Thresholds for Accidental Release Prevention

This regulation addresses the risk management plan (RMP) requirements of section 112(r) of the federal Clean Air Act. 40 CFR Part 68 applies to regulated substances that are contained in a process at this facility that exceed the threshold quantity, as presented in 40 CFR Part 68.130. The Selective Catalytic Reduction (SCR) system for NOx control at the CTG uses aqueous ammonia with a concentration of less than 20% by weight. However, aqueous ammonia must be greater than or equal to 20% by weight ammonia in order to be one of the regulated toxic substances listed in 40 CFR Part 68.130. Therefore, facility is not subject to 40 CFR Part 68.

40 CFR Part 75 – Continuous Emission Monitoring (CEMS)

The new turbines combusts only natural gas, they are only required to monitor NOx and CO2 (or O2) and has the choice of monitoring SOx or may use fuel flow monitoring and default sulfur emission factors to calculate emissions. Additionally Subpart C of this part contains requirements for operating and maintaining the CEMS to ensure that accurate, valid data is collected. The CEMS is required to be initially certified and requires recertification if certain modifications are made. Required QA activities include linearity checks, 7-day calibration error tests, and relative accuracy test audits (RATA). Linearity and calibration error tests ensure that the monitors are measuring emissions accurately. RATA compare the CEMS readings to the results determined using a source test. The RATA must be conducted annually except in certain situations where the turbine does not operate for more than 168 hours per calendar quarter. Finally, this part contains requirements for substituting data in a conservative manner for any hour when the CEMS does not record valid data, and these requirements are specified in the proposed permit conditions. Additionally the facility is required to operate according to an approved CEMS protocol, which will contain the above requirements and specific procedures in detail.

IX. Recommendation

The Mission Rock Energy Center is expected to comply with all applicable VCAPCD, State, and Federal rules and regulations that the VCAPCD implements and enforces. Issue a Rule 26.9 Determination of Compliance for the Mission Rock Energy Center subject to the DOC Conditions presented in Appendix K.

Appendices:

Appendix A	Turbine Performance Emissions Data
Appendix B	Turbine Startup Emissions Data
Appendix C	Commissioning Schedule
Appendix D	Diesel Engine Performance Data
Appendix E	ERCs Identified For Use
Appendix F	ERC Profile Check
Appendix G	Air Quality Impact Analysis and Risk Management Review
Appendix H	Hazardous Air Pollutant Potential to Emit
Appendix I	Certification of Statewide Compliance
Appendix J	Analysis of Alternatives
Appendix K	DOC Conditions

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Appendix A

Turbine Performance Emissions Data

Applicant Provided Turbine Performance Data

		Run 1	Run 2	Run 3	Run 4	Run 5	Run 6
Ambient Data							
Dry Bulb	deg F	30.0	30.0	30.0	30.0	39.4	39.4
Relative Humidity	%	30.0	30.0	30.0	30.0	30.0	30.0
Elevation	feet	185.0	185.0	185.0	185.0	185.0	185.0
Fuel		Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Gas Turbine Load	%	100	75	50	25	100	75
Number of Gas Turbines		5	5	5	5	5	5
Net Plant Output	kW	281,125	209,848	138,477	67,024	278,746	208,046
Plant Heat Input	MMBtu/h HHV	2,831	2,201	1,633	1,102	2,815	2,192
Net Plant Heat Rate	Btu/kWh HHV	10,069	10,486	11,796	16,449	10,098	10,534
Stack Characteristics							
Number of CTGs		1	1	1	1	1	1
Stack Temperature	deg F	867	837	808	757	868	846
Stack Flow	lb/hr	1,197,006	1,013,213	842,286	683,703	1,198,275	1,007,085
Stack Volumetric Flow	ACFM	693,778	571,410	462,029	358,002	695,543	572,146
Stack Diameter	feet	12	12	12	12	12	12
Stack Velocity	feet/s	102.6	84.5	68.3	53.0	102.9	84.6
Stack Emissions (Total of 1 CTG)							
NOx	ppmvd@15%O2	2.5	2.5	2.5	2.5	2.5	2.5
	lb/h	5.10	3.96	2.93	1.98	5.07	3.94
	lb/MMBtu HHV	0.00901	0.00899	0.00898	0.00896	0.00900	0.00899
CO	ppmvd@15%O2	4.0	4.0	4.0	4.0	4.0	4.0
	lb/h	4.97	3.85	2.86	1.92	4.94	3.84
	lb/MMBtu HHV	0.00877	0.00876	0.00874	0.00873	0.00877	0.00876
VOC	ppmvd@15%O2	1.0	1.0	1.0	1.0	1.0	1.0
	lb/h	0.71	0.55	0.41	0.31	0.71	0.55
	lb/MMBtu HHV	0.00126	0.00125	0.00125	0.00139	0.00126	0.00125
NH3	ppmvd@15%O2	5.0	5.0	5.0	5.0	5.0	5.0
	lb/h	3.77	2.93	2.17	1.46	3.75	2.92
PM10	lb/MMBtu HHV	0.00667	0.00665	0.00665	0.00663	0.00667	0.00665
	lb/h	4.0	4.0	4.0	4.0	4.0	4.0
SOx	lb/hr	0.594					
	lb/MMBtu HHV	0.0010					

Run 7	Run 8	Run 9	Run 10	Run 11	Run 12	Run 13	Run 14	Run 15	Run 16	Run 17
39.4	39.4	59.0	59.0	59.0	59.0	59.0	61.0	61.0	61.0	61.0
30.0	30.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0
Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
50	25	100	100	75	50	25	100	100	75	50
5	5	5	5	5	5	5	5	5	5	5
137,284	66,426	276,676	271,789	202,844	133,784	64,675	276,438	270,514	201,860	133,143
1,630	1,100	2,805	2,754	2,157	1,609	1,090	2,804	2,742	2,147	1,604
11,871	16,560	10,138	10,134	10,634	12,023	16,852	10,142	10,136	10,635	12,049
1	1	1	1	1	1	1	1	1	1	1
826	774	869	867	863	861	812	870	868	862	865
829,660	673,537	1,195,857	1,186,022	993,607	801,365	651,055	1,195,430	1,182,387	993,311	797,936
461,727	357,837	696,775	690,079	572,987	459,718	357,342	697,007	688,467	572,215	459,133
12	12	12	12	12	12	12	12	12	12	12
68.3	52.9	103.1	102.1	84.8	68.0	52.9	103.1	101.8	84.6	67.9
2.5	2.5	2.0	2.5	2.5	2.5	2.5	2.0	2.5	2.5	2.5
2.93	1.97	4.04	4.96	3.88	2.89	1.95	4.04	4.94	3.86	2.88
0.00897	0.00896	0.00720	0.00900	0.00899	0.00897	0.00896	0.00720	0.00900	0.00899	0.00897
4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
2.85	1.92	4.92	4.83	3.78	2.81	1.90	4.92	4.81	3.76	2.81
0.00874	0.00873	0.00877	0.00877	0.00876	0.00874	0.00873	0.00877	0.00877	0.00876	0.00874
1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
0.41	0.31	0.70	0.69	0.54	0.40	0.30	0.70	0.69	0.54	0.40
0.00125	0.00139	0.00126	0.00126	0.00125	0.00125	0.00139	0.0012558	0.00126	0.00125	0.00125
5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2.17	1.46	3.74	3.67	2.87	2.14	1.45	3.74	3.66	2.86	2.13
0.00664	0.00663	0.00667	0.00667	0.00665	0.00664	0.00663	0.00667	0.00667	0.00666	0.00664
4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
		0.594								
		0.0011								

Run 18	Run 19	Run 20	Run 21	Run 22	Run 23	Run 24	Run 25	Run 26	Run 27	Run 28
61.0	79.2	79.2	79.2	79.2	79.2	76.0	76.0	76.0	76.0	76.0
60.0	43.2	43.2	43.2	43.2	43.2	50.0	50.0	50.0	50.0	50.0
185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0
Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
25	100	100	75	50	25	100	100	75	50	25
5	5	5	5	5	5	5	5	5	5	5
64,350	274,120	254,603	189,889	125,161	60,357	274,239	257,945	192,419	126,821	61,204
1,088	2,802	2,592	2,059	1,550	1,060	2,802	2,622	2,074	1,561	1,066
16,904	10,223	10,182	10,846	12,384	17,567	10,219	10,166	10,776	12,310	17,415
1	1	1	1	1	1	1	1	1	1	1
815	870	868	868	866	845	869	870	870	863	841
648,436	1,205,031	1,142,884	974,477	794,734	624,207	1,205,031	1,149,812	973,339	800,506	628,324
357,019	701,869	665,994	564,626	457,804	352,269	701,464	670,838	564,705	460,044	353,410
12	12	12	12	12	12	12	12	12	12	12
52.8	103.8	98.5	83.5	67.7	52.1	103.8	99.2	83.5	68.0	52.3
2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
1.95	5.05	4.67	3.70	2.78	1.90	5.05	4.72	3.73	2.80	1.91
0.00896	0.00900	0.00900	0.00899	0.00898	0.00896	0.00900	0.00900	0.00899	0.00898	0.00896
4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
1.90	4.92	4.55	3.61	2.71	1.85	4.92	4.60	3.63	2.73	1.86
0.00873	0.00877	0.00877	0.00876	0.00874	0.00873	0.00877	0.00877	0.00876	0.00874	0.00873
1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
0.30	0.70	0.65	0.52	0.39	0.30	0.70	0.66	0.52	0.39	0.30
0.00139	0.00126	0.00126	0.00125	0.00125	0.00139	0.00126	0.00126	0.00125	0.00125	0.00139
5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
1.44	3.74	3.46	2.74	2.06	1.41	3.74	3.50	2.76	2.07	1.41
0.00663	0.00667	0.00667	0.00666	0.00664	0.00663	0.00667	0.00667	0.00666	0.00665	0.00663
4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0

Run 29	Run 30	Run 31	Run 32	Run 33
96.0	96.0	96.0	96.0	96.0
30.0	30.0	30.0	30.0	30.0
185.0	185.0	185.0	185.0	185.0
Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
100	100	75	50	25
5	5	5	5	5
272,083	226,391	168,723	111,010	53,297
2,802	2,350	1,884	1,443	1,004
10,300	10,378	11,166	13,000	18,846
1	1	1	1	1
869	853	869	868	858
1,225,031	1,094,899	921,411	766,082	600,434
711,444	630,000	534,197	441,997	342,493
12	12	12	12	12
105.2	93.2	79.0	65.4	50.7
2.5	2.5	2.5	2.5	2.5
5.05	4.23	3.39	2.59	1.80
0.00900	0.00900	0.00899	0.00898	0.00896
4.0	4.0	4.0	4.0	4.0
4.92	4.12	3.30	2.52	1.75
0.00877	0.00877	0.00876	0.00874	0.00873
1.0	1.0	1.0	1.0	1.0
0.70	0.59	0.47	0.36	0.28
0.00126	0.00126	0.00125	0.00125	0.00139
5.0	5.0	5.0	5.0	5.0
3.74	3.13	2.51	1.92	1.33
0.00667	0.00667	0.00666	0.00665	0.00663
4.0	4.0	4.0	4.0	4.0

Appendix B
Turbine Startup Emissions Data

Table ***

Maximum Hourly, Daily, and Annual Emissions Calculations

Case #: LM6000 Peaking Units-Mission Rock

Number of Identical Engines: 5
Turbine Model: LM6000 PG Sprint

Input data per unit:	Max Operation hrs/day	Max Annual Op hrs	Avg # of Startups day			Startup Time hrs	Startup Time hrs		Shutdown Time hrs	Starts events/yr			Estimated Shutdowns yr	Max Estimated Shutdowns day		
	24	2500	2	0	0	0.5	0	0	0.15	150	0	0	150	2		
	Annual CF %:	29			SS Runtime	0.5	1	1	0.85							
	Startup Emissions lbs/event			**Shutdown Emissions lbs/event**	**Steady State Emissions** lbs/hr ***Case 14 An Avg Day***	**Emissions** lbs/hr ***Case 1 Cold Day***	**Worst Hr Emissions** lbs/hr ***SU Cold Day***	Total Start hrs/yr			Total Shutdown hrs/yr	Annual Steady State Non SU/SD hrs/yr	Total Annual Emissions Starts lbs/yr	lbs/yr	lbs/yr	Shutdowns lbs/yr
NOx	9.10	0.00	0.00	1.20	4.04	5.10	11.65	75			22.5	2402.5	1365.0	0.0	0.00	180.0
CO	5.50	0.00	0.00	1.80	4.92	4.97	7.99				Total SU-SD Hours/Yr:	97.5	825.0	0.0	0.00	270.0
VOC	1.00	0.00	0.00	1.00	0.70	0.70	1.60	1.36			Steady State Hour Breakdown		150.0	0.0	0.00	150.0
SOx	0.30	0.00	0.00	0.10	0.59	0.59	0.59					Hrs/yr	44.3	0.0	0.00	14.7
PM10	1.00	0.00	0.00	0.30	2.00	2.00	2.00					0	150.0	0.0	0.00	45.0
PM2.5	1.00	0.00	0.00	0.30	2.00	2.00	2.00		Base hours/yr:			2402.5	150.0	0.0	0.00	45.0
NH3	1.89	0.00	0.00	0.57	3.74	3.77	1.89						283.5	0.0	0.00	85.5
Cold start plus shutdown =			0.65	hrs					**Annual Fuel Use Values**		mmbtu/hr	hrs/yr		mmbtu/yr		
			0.15	hrs					Case 14 w/chiller		561.00	2500		1402500		
			0.15	hrs							0.00	0		0		
Shut down =			0.15	hrs					*includes SU/SD hours				Total =	1402500		

Maximum Estimated Annual Emissions		NOx lbs/yr	CO lbs/yr	VOC lbs/yr	SOx lbs/yr	PM10 lbs/yr	PM2.5 lbs/yr	NH3 lbs/yr	
Ops Scenario									
Cold Startups		1365.0	825.0	150.0	44.3	150.0	150.0		
		0.0	0.0	0.0	0.0	0.0	0.0		
		0.0	0.0	0.0	0.0	0.0	0.0		
Shutdowns		180.0	270.0	150.0	14.7	45.0	45.0		
Steady State		9706.1	11820.3	1691.4	1417.5	4805.0	4805.0	8985.4	
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Single Turbine, lbs/yr:	*11251.1*	*12915.3*	*1991.4*	*1476.4*	*5000.0*	*5000.0*	*8985.4*	
	Single Turbine, tons/yr:	5.63	6.46	1.00	0.74	2.50	2.50	4.49	
		NOx tpy	CO tpy	VOC tpy	SOx tpy	PM10 tpy	PM2.5 tpy	NH3 tpy	
	Total Tons/Yr All Units:	**28.13**	**32.29**	**4.98**	**3.69**	**12.50**	**12.50**	**22.46**	
EPA	PSD Program Trigger Levels, TPY:	250	250	250	250	250	250		
EPA	PSD Significant Emissions Rates, TPY:	40	100	40	40	15	10		
VCAPCD	Air Agency Offset Trigger Levels, TPY:	5	NA	5	15	15	NA	Ref: Rule 26.2	

(If PTE for ROC or NOX is > 25 tpy then the offset ration is 1.3:1. Offset ratio for PM10 or SOx is 1:1.)

Maximum Estimated Daily Emissions based on a 24 Hr Ops Cold Day

Max Daily Emissions Assumptions (Per turbine):

		Hours
starts per day =	2	1
	0	0
	0	0
shutdowns per day =	2	0.3
Steady state ops hrs/day =		22.7

	lbs/day	lbs/day all units
NOx	136.37	681.85
CO	127.42	637.10
VOC	19.98	99.90
SOx	14.18	70.90
PM10	48.00	240.00
PM2.5	48.00	240.00
NH3	90.50	452.50

Power Production Estimates

	All Units	
Case 14, Avg Day, 100% Load, Kw:	286605	Gross
Case 14, Avg Day, 100% Load, Kw:	276438	Net
MW	286.605	Gross
MW	276.438	Net
Annual MW	716513	Gross
Annual MW	691095	Net

Maximum Estimated Hourly Emissions

Max hourly emissions assumptions (Per turbine):	Hours
1. Startup, cold day	0.5
2. remainder of hour, cold day no DB, Case 1	0.5
3. NH3 is cold day data-steady state	

	lbs/hr	lbs/hr All Units	Case 1 used for remaining hour of start (lb/hr)
NOx	11.65	58.25	5.10
CO	7.99	39.93	4.97
VOC	1.35	6.76	0.71
SOx	0.59	2.95	0.26
PM10	2.00	10.00	1.00
PM2.5	2.00	10.00	1.00
NH3	3.77	18.85	3.77

GHG Emissions Estimates

Fuel:	Natural Gas				short		CO2e		
Btu/scf:	1021	HHV	*Emissions*	lbs/yr	tons/yr	IPCC SAR	short		
Heat Rate:	1402500	mmbtu/yr		1.64E+08	8.20E+04	Values	tons/yr		
Fuel Rate:	1373.6533	mmscf/yr		3.09E+03	1.55E+00	1	8.20E+04		
Emissions Factors				3.09E+02	1.55E-01	21	3.25E+01		
CO2	116.89	lbs/mmbtu				310	4.79E+01		
CH4	0.002205	lbs/mmbtu				Total CO2e:	82,050	short TPY	1 Engine
N2O	0.0002205	lbs/mmbtu				Total CO2e:	410,248	short TPY	All Engines
						Total CO2e:	74,590	metric TPY	1 Engine
						Total CO2e:	**372,952**	**metric TPY**	All Engines

Emissions Factors for GHG, 40 CFR 98, Subpart C, Tables C-1, C-2.

1 short ton = 2000 lbs, 1 metric ton = 2200 lbs.

Average CO2 Performance Estimate:

Gross MW:	1144.0	lbs CO2/Mw-hr
Net MW:	1186.1	lbs CO2/Mw-hr

Notes:

1. Turbine steady-state emissions based on the following:
   - NOx 2.5 ppm (1-hour) and 2.0 (annual)
   - CO 4.0 ppm
   - VOC <= 1 ppm
2. Startup data has no margin and assumed 30 minutes
3. Start event data is based on 30 minute start cycle to achieve compliance with BACT limits.
4. Short-term emissions based on 30 degree day (Case 1 cold day)
5. Annual emissions based on annual average day (Case 14)

Data References:

1. GE Base Load Performance Data as provided by the applicant.
2. GE LM6000 PG Sprint SU/SD data as provided by the applicant.
3. Proposed operational data as provided by the applicant.
4. *
5. *

Appendix C
Commissioning Schedule

Table 5.1A-7 Turbine Commissioning Schedule and Emissions Estimates

Ref: GE Energy, 9/3/15, Estimated Commissioning Schedule and Emissions

			Per Turbine Basis							
			Emissions, lbs/event				Emissions. Lbs/Hr			
Commisioning Phase	Phase #	Length, Hrs	NOx	CO	VOC	PM10	NOx	CO	VOC	PM10
Dry Fire GTG	1	12	0	0	0	0	0.00	0.00	0.00	0.00
First Fire and Shutdown	2	16	292	1137	20	48	18.25	71.06	1.25	3.00
Sync and Check E-stop	3	12	219	853	15	36	18.25	71.08	1.25	3.00
AVR, Sync to Grid	4	12	666	1000	18	36	55.50	83.33	1.50	3.00
Break In	5	8	444	667	12	24	55.50	83.38	1.50	3.00
Dynamic Commissioning 1	6	3	167	250	5	9	55.67	83.33	1.67	3.00
Dynamic Commissioning 2		3	204	218	4	9	68.00	72.67	1.33	3.00
Dynamic Commissioning 3		3	68	232	4	9	22.67	77.33	1.33	3.00
Dynamic Commissioning 4		3	80	267	5	9	26.67	89.00	1.67	3.00
Dynamic Commissioning 5		3	90	294	6	9	30.00	98.00	2.00	3.00
Dynamic Commissioning 6		3	102	311	6	9	34.00	103.67	2.00	3.00
Dynamic Commissioning 7		3	114	322	7	9	38.00	107.33	2.33	3.00
Dynamic Commissioning 8		3	126	330	8	9	42.00	110.00	2.67	3.00
Dynamic Commissioning 9		3	139	340	8	9	46.33	113.33	2.67	3.00
Dynamic Commissioning 10		3	154	352	9	9	51.33	117.33	3.00	3.00
Base Load AVR	7	12	615	1407	35	36	51.25	117.25	2.92	3.00
ECS Tuning-Break In	8	2	20	47	5	6	10.00	23.50	2.50	3.00
ECS Startup		4	24	78	5	12	6.00	19.50	1.25	3.00
ECS Tuning 1		1.5	6	21	2	6	4.00	14.00	1.33	4.00
ECS Tuning 2		1.5	17	25	2	6	11.33	16.67	1.33	4.00
ECS Tuning 3		1.5	20	22	2	6	13.33	14.67	1.33	4.00
ECS Tuning 4		1.5	7	23	2	6	4.67	15.33	1.33	4.00
ECS Tuning 5		1.5	8	27	2	6	5.33	18.00	1.33	4.00
ECS Tuning 6		1.5	9	29	2	6	6.00	19.33	1.33	4.00
ECS Tuning 7		1.5	10	31	2	6	6.67	20.67	1.33	4.00
ECS Tuning 8		1.5	11	32	3	6	7.33	21.33	2.00	4.00
ECS Tuning 9		1.5	13	33	3	6	8.67	22.00	2.00	4.00
ECS Tuning 10		1.5	14	34	3	6	9.33	22.67	2.00	4.00
ECS Tuning 11		1.5	15	35	4	6	10.00	23.33	2.67	4.00
Prelim Peformance Test	9	8	41	40	12	32	5.13	5.00	1.50	4.00
PPA Performance Test	10	8	41	40	12	32	5.13	5.00	1.50	4.00
Reliability Test	11	72	396	360	103	288	5.50	5.00	1.43	4.00
		Hrs	NOx, lbs	CO, lbs	VOC, lbs	PM10, lbs	PM2.5, lbs	(PM2.5 assumed equal to PM10)		
Firing Hours without Catalyst		125	3480	7980	162	270	270.00			
Firing hours with Catalyst		88	626	878	165	436	436.00			
Totals		213	4106	8858	327	706	706.00			
Period Avg, lbs/hr			*19.28*	*41.59*	*1.54*	*3.31*	*3.31*			

Appendix D
Diesel Engine Performance Data

Rating Specific Emissions Data - John Deere Power Systems

JOHN DEERE

Nameplate Rating Information

Clarke Model	JU6H-UFADP8
Power Rating (BHP / kW)	220 / 164
Certified Speed (RPM)	1760

Rating Data

Rating	6068HFC28A
Certified Power (kW)	177
Rated Speed	1760
Vehicle Model Number	Clarke Fire Pump

Units	g/kW-hr	g/hp-hr
NOx	3.6	2.7
HC	0.2	0.1
NOx + HC	3.8	2.8
Pm	0.13	0.10
CO	1.2	0.9

Certificate Data

Engine Model Year	2011
EPA Family Name	BJDXL06.8120
EPA JD Name	350HAK
EPA Certificate Number	JDX-NRCI-11-29
CARB Executive Order	Not Applicable
Parent of Family	6068HFG82A

Units	g/kW-hr
NOx	3.8
HC	0.1
NOx + HC	3.9
Pm	0.12
CO	1.2

* The emission data listed is measured from a laboratory test engine according to the test procedures of 40 CFR 89 or 40 CFR 1039, as applicable. The test engine is intended to represent nominal production hardware, and we do not guarantee that every production engine will have identical test results. The family parent data represents multiple ratings and this data may have been collected at a different engine speed and load. Emission results may vary due to engine manufacturing tolerances, engine operating conditions, fuels used, or other conditions beyond our control.

Appendix E
ERCs Identified for use

ERCs to be identified and included in FDOC

Appendix F
ERC Profile Check

Profile Check to be completed in FDOC

Appendix G

Air Quality Impact Analysis and Risk Management Review

Table of Contents

1. Purpose of this Document

This document serves as the Ambient Air Quality Analysis (AAQA) and Risk Management Review (RMR) for the proposed installation of five (5) new GE LM6000-PG-Sprint simple-cycle natural gas fired combustion turbine generators (CTG) and a new emergency diesel firewater pump engine for the Mission Rock Energy Center (MREC). This document describes the modeling performed to satisfy the requirements of Ventura County APCD Rule 26 (New Source Review) and Rule 51 (Nuisance).

2. Applicant

Project Site Location:
Mission Rock Energy Center
1025 Mission Rock Road
Santa Paula, CA 93060

Submitting Officials:
Alexandre B. Makler
Mission Rock Energy Center, LLC
717 Texas Avenue, Suite 1000
Houston, TX 77002

Barbara McBride
Calpine Corporation
4160 Dublin Boulevard, Suite 100
Dublin, CA 94568

Consultant:
Atmospheric Dynamics, Inc.
Torres Street 3 SW of Mountain View
Sundog
P.O. Box 5907
Carmel-by-the-Sea, CA 93921

Ventura County APCD Contact:
Kerby E. Zozula
Manager Engineering Division
Ventura County APCD
669 County Square Drive, 2nd Floor
Ventura, CA 93003

3. Project Location

The project is located at 1025 Mission Rock Road near Santa Paula, California within the Ventura County Air Pollution Control District (VCAPCD). It is located in a rural setting to the southwest of Santa Paula.

Figure 3-1 Project Location

4. Project Description

The Mission Rock Energy Center is proposing to construct and operate a 275 MW (nominal) natural gas-fired simple-cycle power plant. The MREC is planning to operate as a peaking power plant and is proposed to operate up to approximately 2,500 hours per year, with an expected facility capacity factor of up to 29 percent. The MREC will consist of the following:

- Five (5) GE LM6000-PG-Sprint gas turbines which will be operated in simple-cycle mode.
- A California Air Resources Board (CARB)-compliant diesel fire water pump engine
- Ancillary support systems and processes that are exempt from VCAPCD permit requirements pursuant to VCAPCD Rule 23.

The new CTGs will be fueled with pipeline quality natural gas and will be equipped with water injection, selective catalytic reduction (SCR) with catalyst, and an oxidation catalyst. The new diesel-fueled fire water pump engine will only be operated for up to 50 hours per year for maintenance and readiness testing purposes.

5. Ventura County APCD Rule 26 – New Source Review

Ambient Air Quality Standards (AAQS) are established to protect the public and the environment. An air quality standard defines the maximum amount of a pollutant that can be present in outdoor air without harm to public health, vegetation or wildlife. The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (40 CFR part 50) for pollutants considered harmful to public health and the environment. At present, EPA has set National Ambient Air Quality Standards for the following principal pollutants, which are called "criteria" pollutants:

- Ozone (O_3)
- Nitrogen Dioxide (NO_2)
- Sulfur Dioxide (SO_2)
- Respirable particulate matter having an aerodynamic diameter smaller than or equal to 10 microns (PM_{10})
- Fine particulate matter having an aerodynamic diameter smaller than or equal to 2.5 microns ($PM_{2.5}$)
- Carbon Monoxide (CO)
- Lead (Pb)

The National Ambient Air Quality Standards contain primary and secondary standards for each of the criteria pollutants. If a primary standard is exceeded, the public is considered at risk. If a secondary standard is exceeded, then crops, trees and buildings may be damaged. Air quality standards are based on a particular exposure period (averaging period) and concentration (average, maximum, or other statistical measure) during that period. A violation occurs if the observed concentration is greater than the standard during the specified averaging period.

The Clean Air Act also permits states to adopt additional or more protective air quality standards if needed. California law authorizes the Air Resources Board (ARB) to set ambient (outdoor) air pollution standards in consideration of public health, safety and welfare. California has set standards for certain pollutants, such as particulate matter and ozone, which are more protective of public health than respective federal standards. California has also set standards for some pollutants that are not addressed by federal standards, including the following:

- Visibility Reducing Particles
- Hydrogen Sulfide (H_2S)

- Vinyl Chloride

Both state and federal regulations require ambient air quality standards to be reviewed periodically, or whenever substantial new information becomes available.

Table 5-1. CAAQS/NAAQS Attainment Status for Ventura County

Pollutant		Attainment Status	
		Federal	State
Lead (Pb)		Attainment (Unclassified)	Attainment
Nitrogen Dioxide (NO_2)		Attainment (Unclassified)	Attainment
Sulfur Dioxide (SO_2)		Attainment (Unclassified)	Attainment
Carbon Monoxide (CO)		Attainment (Unclassified)	Attainment
Particulate Matter under 2.5 micrometers diameter ($PM_{2.5}$)		Attainment	Attainment
Particulate matter under 10 micrometers diameter (PM_{10})		Attainment	Nonattainment
Ozone	1-hour	N/A	Nonattainment
	8-Hour	Nonattainment	Nonattainment
Hydrogen Sulfide		N/A	Unclassified
Sulfates		N/A	Attainment
Visibility Reducing Particles		N/A	Unclassified
Vinyl Chloride		N/A	Attainment

VCAPCD Rule 26.2.C requires that:

> *The APCO shall deny an applicant an Authority to Construct for any new, replacement, modified or relocated emissions unit that would cause the violation of any ambient air quality standard or the violation of any ambient air increment as defined in 40 CFR 51.166(c). In making this determination the APCO shall take into account any offsets which were provided for the purpose of mitigating the emission increase*.

In order to insure that this project will not cause or contribute to a violation of State or Federal air quality standards, an Ambient Air Quality Analysis (AAQA) must be performed.

VCAPCD has determined that AAQAs performed for the purpose of complying with New Source Review use EPA's preferred air dispersion model along with 5 years of meteorological data to perform the air dispersion modeling. Information necessary to perform dispersion modeling includes the coordinates of the sources of emissions and the plant/facility boundary. Also required are the stack/modeling parameters for all emissions sources involved in the project.

The AAQA performed for this project was conducted using a progressive approach where any failure of preliminary analyses necessitates advancing to more refined approaches.

5.1 Project Criteria Pollutant Emissions

5.1.1 Natural Gas-Fired Combustion Turbine Generators (CTGs)

Emission rates for the CTGs are determined by the unit's operating state. The following operating states were considered for this evaluation:

- Commissioning. The period of time where the turbine is prepared for first operation, prior to the installation of the emissions control system. During this period NO_x and CO emissions are elevated.
- Startup. The period of time during which the turbine is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. During this period NO_x and CO emissions are elevated.
- Shutdown. The period of time during which the turbine is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. During this period NO_x and CO emissions are elevated.
- Normal Operations. The period of time during which the turbine is operating at optimal temperature and pressure. NO_x emissions reflect the application of water injection and SCR for NOx control. The CO emissions reflect the use of an oxidation catalyst.

For AAQA modeling the following worst-case scenarios were developed for the natural gas turbine emissions:

- Hourly emissions. Hourly emissions are based on the turbine performance data (Run 1) and of the manufacturer provided data (Appendix A) and the turbine startup emissions data (Appendix B) provided by the turbine manufacturer.
- Annual emissions. Annual emissions are from 150 startups (75 hours of operation), 150 shutdowns (22.5 hours of operation), plus 2,402.5 hours of normal steady state operation (total = 2,500 hours of operation per turbine).

5.1.2 Emergency Diesel Fire Water Pump Engine

For AAQA modeling the following worst-case scenarios were developed for the emergency diesel engine emissions:

- Hourly emissions. The emergency diesel engine will be operated for no more than 30 minutes in any rolling 1-hour period.
- Annual emissions. The emergency diesel engine will be operated a total of 50 hours per year for maintenance and readiness testing purposes.

5.1.3 AAQA Emissions Summary

Applicable project emissions are shown in Table 5-2 (provided by the permit engineer). Note that $PM_{2.5}$ emissions may be reported as both primary and secondary $PM_{2.5}$ emissions. If the project facility is a minor $PM_{2.5}$ source, only primary (directly emitted) $PM_{2.5}$ emissions are modeled. If the project facility is a major $PM_{2.5}$ source, both the primary and secondary $PM_{2.5}$ emissions are modeled. Since the project facility is a minor $PM_{2.5}$ source, only primary $PM_{2.5}$ emissions are required to be modeled.

Table 5-2. Emissions by Unit

Unit Description	Emissions (pounds = lbs)			
	SO_x	NO_x	CO	$PM_{10}/PM_{2.5}$
Commissioning – Maximum Hourly Emissions				
Natural Gas Turbine	1.19	68.00	117.33	2.00
Normal Operation – Maximum Hourly Emissions				
Natural Gas Turbine	1.19	11.65	7.99	2.00
Diesel Emergency Engine[1]	0.005	0.68	0.63	0.035
Total	1.20	12.33	8.62	2.04
Normal Operation – Maximum Annual Emissions				
Natural Gas Turbine	2,980	11,240	12,920	5,000
Diesel Emergency Engine	0.5	68	63	3.5
Total	2,981	11,308	12,983	5,004

[1] The diesel fire water pump engine cannot be operated for more than 30 minutes in any rolling 1-hour period for readiness testing and maintenance purposes.

5.2 Refined Analysis

The VCAPCD modeled the impact of the proposed project on the NAAQS and/or CAAQS using EPA's Guideline for Air Quality Modeling (Appendix W of 40 CFR Part 51) for guidance. The VCAPCD used a progressive three level approach to perform the AAQA. The first level (Level 1) uses a very conservative approach. If this analysis indicates a likely exceedance of an AAQS or SIL, the analysis proceeds to the second level (Level 2) which implements a more refined approach. For the 1-hour NO_2 standard, there are also third and fourth levels that can be implemented if the Level 2 analysis indicates a likely exceedance of an AAQS or SIL.

The modeling analyses included the maximum air quality impacts during commissioning, startup, shutdown and normal operations of the turbine and normal operation of the emergency engine using the appropriate emissions during each averaging period. Required model inputs for a refined AAQA include background ambient air quality data, land characteristics, meteorological inputs, a receptor grid, and source parameters including emissions. These inputs are described in the sections that follow.

5.2.1 Model Selection

VCAPCD required that the following regulatory models be used to analyze air quality impacts:

Table 5-3. Summary of Preferred Models

Model Name	Model Purpose	Model Version
AERMOD	Air dispersion modeling	16216r
AERMAP	Terrain processing	11103
AIRMET	Meteorological data processing	16216
AERSCREEN	Fumigation Modeling	16216

5.2.2 Background Ambient Air Quality

VCAPCD regulations require the air quality analysis to contain air quality monitoring data in the area for regulated pollutants for which there are NAAQS and/or CAAQS that may be affected by the source. For demonstrating compliance with the NAAQS and/or CAAQS, a background concentration is added to represent those sources not explicitly included in the modeling, as determined by the VCAPCD, so that the total concentration accounts for all contributions to current air quality.

Ambient air concentrations of CO, ozone (O_3), NO_2, PM_{10} and $PM_{2.5}$ are recorded at monitoring stations throughout the South Central Coast Air Basin. Monitoring stations may not measure all necessary pollutants, so background data may need to be collected from multiple sources. Table 5-4 displays monitors within close proximity to the project, as well as the pollutants measured.

Table 5-4. Monitoring Stations in Close Proximity to the Project Site

Site Criteria	Monitoring Site El Rio Rio Mesa School	 Santa Barbara UCSB	 Santa Barbara E Canon Perdido
Site ID	06-111-3001	06-083-1020	06-083-0011
Distance from Project (km)	7	72	55
Direction from Project	SW	NW	NW
Urban/Rural	Rural	Rural	Urban
Land Use	Ag / Mixed	Undeveloped Mixed	Mixed
Pollutants Monitored			
Ozone (O_3)	**X**		•
Nitrogen Dioxide (NO_2)	**X**		•
Respirable Particulate (PM_{10})	**X**		•
Fine Particulate ($PM_{2.5}$)	**X**		•
Carbon Monoxide (CO)			**X**
Sulfur Dioxide (SO_2)		**X**	

X = site selected for pollutant indicated; "•" = pollutant monitored at site

The area immediately surrounding the project site can be characterized as rural with land use being predominantly farmland/undeveloped.

The monitoring station closest to the project site is the El Rio – Rio Mesa School #2 station in Oxnard, located 7 kilometers to the southwest. This station measures O_3, NO_X/NO_2, PM_{10} and $PM_{2.5}$. This site is the most representative for these pollutants.

The Santa Barbara ─ The UCSB station is located 72 kilometers to the northwest of the project site. This is the closest station to the project site that monitors SOx, and was selected as having the most representative background value for this pollutant.

The Santa Barbara ─ The Canon Perdido station is located 55 kilometers to the northwest of the project site. This is the closest station to the project site that monitors CO, and was selected as having the most representative background value for this pollutant.

Table 5-5 below describes the maximum background concentrations, from the most recent available 3 year period of data collection, for which there are NAAQS and CAAQS that may be affected by the project's emissions.

Table 5-5. AAQS and Background Concentrations

Pollutant	Averaging Time	AAQS (µg/m³)		Background Concentration (µg/m³)[6]
		California	National (Primary)	
Respirable Particulate Matter (PM_{10})	24 Hour	50	150	105
	Annual Arithmetic Mean	20	--	27
Fine Particulate Matter ($PM_{2.5}$)	24 Hour[1]	--	35	22
	Annual Arithmetic Mean	12	15	10
Carbon Monoxide (CO)	1 Hour	23,000	40,000	4,684
	8 Hour	10,000	10,000	1,259
Nitrogen Dioxide (NO_2)	1 Hour Max	339	---	73
	1 Hour 98th Percentile[2]	---	188	56
	Annual Arithmetic Mean	57	100	12
Sulfur Dioxide (SO_2)[4]	1 Hour Max	655	---	10
	1 Hour 99th Percentile[3]	---	196	3
	3 Hour[5]	---	1,300	3
	24 Hour	105	365	3
	Annual Arithmetic Mean	--	79	1

[1] The $PM_{2.5}$ 24-hr value is the 98th percentile averaged over three years.
[2] The 1-hr value as the 98th percentile averaged over three years.
[3] The 1-hr value as the 99th percentile averaged over three years.
[4] The SO_2 annual standard is replaced by the more stringent SO_2 1-hour standard.
[5] No primary standard exist for SO_2 3-hour standard. Value used is for the secondary standard.
[6] Background reported as the maximum design value for the most recent 3-year period for which information is available (2014-2016).

5.2.3 Land Characteristics

Land characteristics are used in the AERMOD modeling system in three ways:

- via elevation within AERMOD to assess plume interaction with the ground;
- via a choice of rural versus urban algorithm within AERMOD; and
- via specific values of AERMET parameters that affect turbulence and dispersion. This aspect will be discussed in more detail in Section 5.2.4, Meteorological Inputs.

5.2.3.1 Elevation

Terrain elevations from United States Geological Survey (USGS) National Elevation Dataset (NED) data were used at a horizontal resolution of 10 meters, for receptor heights in AERMOD, which uses them to assess plume distance from the ground for each receptor. All coordinates were referenced to UTM World Geodetic System 1984 (WGS84). The AERMOD receptor elevations were interpolated among the NED nodes according to standard AERMAP procedure.

Table 5-6. Unit Location and Elevation Summary

Unit Description	Location			Elevation (m)
	UTM Zone	UTMN (m)	UTME (m)	
Natural Gas Turbine #1	11	306075.72	3798510.55	56.42
Natural Gas Turbine #2	11	306097.24	3798494.54	56.35
Natural Gas Turbine #3	11	306122.07	3798476.08	56.22
Natural Gas Turbine #4	11	306143.60	3798460.07	56.11
Natural Gas Turbine #5	11	306170.51	3798440.06	55.99
Emergency Diesel Engine	11	306209.23	3798371.10	55.57

5.2.3.2 Urban/Rural Classification

The classification of a site as urban or rural can be based on the Auer method specified in the EPA document Guideline on Air Quality Models (40 CFR Part 51, Appendix W). From the Auer's method, areas typically defined as Rural include:

- Residences with grass lawns and trees
- Large estates
- Metropolitan parks and golf courses
- Agricultural areas
- Undeveloped land
- Water surfaces

Auer defines an area as urban if it has less than 35% vegetation coverage or the area falls into one of the following use types:

Table 5-7. Land Use in Urban Classifications

Type	Use and Structures	Vegetation
I1	Heavy industrial	Less than 5%
I2	Light/moderate industrial	Less than 5%
C1	Commercial	Less than 15%
R2	Dense single / multi-family	Less than 30%
R3	Multi-family, two-story	Less than 35%

To determine if an area should be classified as urban or rural, evaluate land use within a 3 km radius from the center of the emissions source. If land use types

I1, I2, C1, R2, and R3 account for 50 % or more of the area within 3 km, then the area is classified as urban, otherwise the area is classified as Rural. For this project, it was determined that the source's land use classification is rural.

5.2.4 Meteorological Inputs

5.2.4.1 Surface Data

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. In order to select a meteorological site, the VCAPCD did a qualitative comparison of the following factors from EPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (Document EPA-454/R-99-005) recommended for consideration for siting:

- Proximity.
- Height of measurement.
- Aspects of the site's surface that affect turbulence and dispersion.

Table 5-8 provides the characteristics of the meteorological sites that are in close proximity to the project area, the type of data collected at each site, the met data processing parameters, and identifies the site selected.

Table 5-8. Surface Met Sites Near the Project Site

Site Criteria	Surface Met Sites			
	Oxnard Airport	Point Mugu Naval Air Station	Camarillo Airport	Santa Barbara Municipal Airport
Distance from Project (km)	15	21	15	68
Elevation	11	4	11	3
Direction from Project	SW	S	S	NW
Urban/Rural	Rural	Rural	Rural	Rural
Land Use	Ag/ Residential	Undeveloped Mixed	Ag/ Mixed	Mixed
Met Type	Station	Station	Station	Station
Station WBAN ID	93110	93111	23136	23190
Data Type	NCDC	NCDC	NCDC	NCDC
Years Available	2011-2015	2011-2015	2011-2015	2011-2015
U* Adjustment Applied	---	---	Yes	---
Site Selected			**X**	

[1]Met data was processed per the SJVAPCD's meteorological data processing guidance (http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm#modeling_guidance) in conjunction with VCAPCD's input. Lakes' Land Cover Data Tool was used to update National Land Cover Data (NLCD) used by AERSURFACE.

The VCAPCD believes that the chosen Camarillo Airport surface meteorological data is the most representative for the proposed project analysis for the following reasons:

- The project site and the meteorological site are in close proximity to each other.
- The land use and the location with respect to near-field terrain features are similar between both the selected surface meteorological site and the project site.
- The wind flow at the chosen meteorological site closely represents the wind flow expected in the project area.

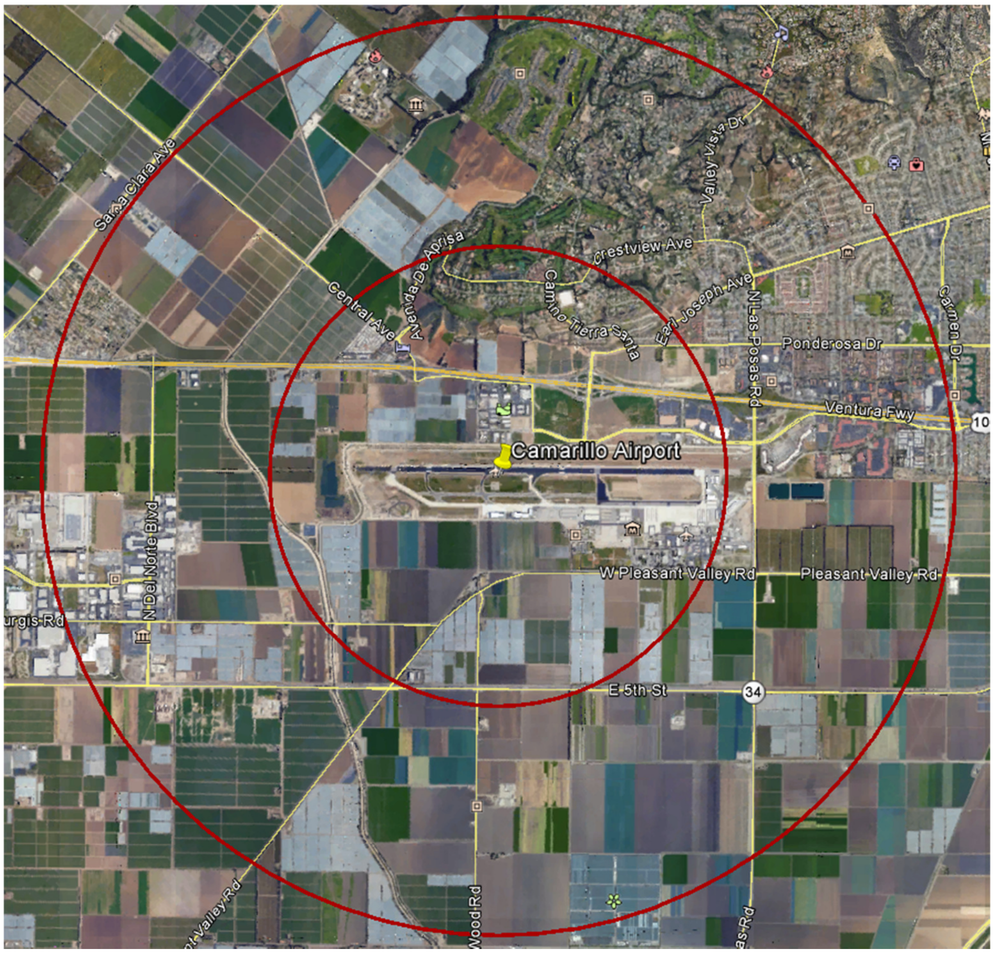


Figure 5-1 Camarillo Airport Met Site

5.2.4.2 Upper Air Data

The Point Mugu Naval Air Station (NAS) upper air met site is closest to the project site, but data completeness was not acceptable. Therefore, the VCAPCD selected upper air data from Vandenberg Air Force Base (AFB) as the most representative upper air site available that had acceptable data completeness.

Table 5-9. Upper Air Met Sites Near the Project Site

Site Criteria	Vandenberg AFB	Point Mugu NAS
Distance from Project (km)	142	21
Direction from Project	NW	SE
Station WBAN ID	93214	93111
Years Available	2011-2015	2011-2015
Site Selected	**X**	

5.2.5 Receptor Grid

Receptors in the model are geographic locations at which the model estimates concentrations. Receptors were placed such that they have good area coverage and so that the maximum model concentrations can be found. At greater distances from the emissions source, spacing between receptors may be greater since concentrations vary less with increasing distance. The spatial extent of the receptors is limited by the applicable range of the model (roughly 50 km for AERMOD), and possibly by knowledge of the distance at which impacts fall to negligible levels. Receptors need be placed only in ambient air, that is, locations to which the public has access, and that are not inside the project boundary.

The VCAPCD used a Cartesian coordinate receptor grid to provide adequate spatial coverage surrounding the project area, to identify the extent of significant impacts, and to identify the maximum impact location. In the analyses, the VCAPCD used a grid with 20 meter spacing telescoping from the facility fence line to 250 meter spacing out to a distance of 15 km.

After a preliminary modeling run was completed, subgrids of varying sizes, with 25 meter spacing were placed at the points of maximum impact for each averaging period in order to refine their impact values and locations.

5.2.6 Source Parameters

Screening modeling was performed to select worst-case CTG operating modes for each pollutant and averaging period. The modeling used emissions data based on an varying ambient temperatures (30°F, 39.4°F, 59°F, 61°F, 79.2°F, 76°F, and 96°F), and at nominal CTG operating load points of 25 percent, 50 percent, 75 percent, and 100 percent (percent loads based on gross MW output levels).

Table 5-10. Turbine Stack Parameter Screening Scenarios[1]

Scenario	Ambient Temp. (ºF)	Stack Exit Vel. (m/s)	Emissions (lbs/hr)			
			NOx	CO	$PM_{10}/PM_{2.5}$	SO_x
1	30	31.28	5.10	4.97	2	1.19
2	30	25.76	3.96	3.85	2	1.19
3	30	20.83	2.93	2.86	2	1.19
4	30	16.14	1.98	1.92	2	1.19
5	39.4	31.36	5.07	4.94	2	1.19
6	39.4	25.79	3.94	3.84	2	1.19
7	39.4	20.82	2.93	2.85	2	1.19
8	39.4	16.13	1.97	1.92	2	1.19
9	59	31.41	5.05	4.92	2	1.19
10	59	31.11	4.96	4.83	2	1.19
11	59	25.83	3.88	3.78	2	1.19
12	59	20.73	2.89	2.81	2	1.19
13	59	16.11	1.95	1.90	2	1.19
14	61	31.42	5.05	4.92	2	1.19
15	61	31.04	4.94	4.81	2	1.19
16	61	25.80	3.86	3.76	2	1.19
17	61	20.70	2.88	2.81	2	1.19
18	61	16.10	1.95	1.90	2	1.19
19	79.2	31.64	5.05	4.92	2	1.19
20	79.2	30.03	4.67	4.55	2	1.19
21	79.2	25.46	3.70	3.61	2	1.19
22	79.2	20.64	2.78	2.71	2	1.19
23	79.2	15.88	1.90	1.85	2	1.19
24	76	31.62	5.05	4.92	2	1.19
25	76	30.24	4.72	4.60	2	1.19
26	76	25.46	3.73	3.63	2	1.19
27	76	20.74	2.80	2.73	2	1.19
28	76	15.93	1.91	1.86	2	1.19
29	96	32.07	5.05	4.92	2	1.19
30	96	28.40	4.23	4.12	2	1.19
31	96	24.08	3.39	3.30	2	1.19
32	96	19.93	2.59	2.52	2	1.19
33	96	15.44	1.80	1.75	2	1.19

[1] Parameters based on manufacturer specifications provided by the project consultant.

Modeling was performed to obtain maximum 1-hour, 3-hour, 8-hour, 24-hour, and annual average concentrations of NO_x, CO, SO_x, and $PM_{10}/PM_{2.5}$. After evaluating modeled concentrations of each pollutant for each year in the five-year meteorological data set, it was determined that the parameters for Scenario

1 produced the highest impacts for NO_x and CO, while the parameters for Scenario 4 produced the highest impacts for and $SO_{x,}$ and $PM_{10}/PM_{2.5}$. Therefore, further refined modeling was performed using the source parameters in the tables below to conservatively estimate the project's impacts.

Table 5-11. Point Source Parameters

Unit Description	Release Height (m)	Temp. (°K)	Exit Velocity (m/sec)	Stack Diameter (m)
Natural Gas Turbine - Scenario 1[1] - Scenario 4[2]	 18.29 18.29	 736.9 676.1	 31.28 16.14	 3.6576 3.6576
Emergency Diesel Engine	7.62	803.2	44.3	0.127

[1]Scenario 1 parameters selected as producing the highest impacts for NO_x and CO.
[2]Scenario 4 parameters selected as producing the highest impacts for SO_x and $PM_{10}/PM_{2.5}$.

5.2.6.1 Good Engineering Practice (GEP) Analysis

The VCAPCD performed a Good Engineering Practice (GEP) stack height analysis, to ensure that:

- downwash is properly considered in the modeling, and
- stack heights used as inputs to the modeling are no greater than GEP height, so as to disallow artificial dispersion from the use of overly tall stacks.

The GEP analysis was performed with EPA's BPIP Prime (Building Profile Input Program) software, which uses building dimensions and stack heights as inputs.

There were no stacks present that exceeded GEP stack height of 65 meters. Therefore, actual stack heights were used to model emissions.

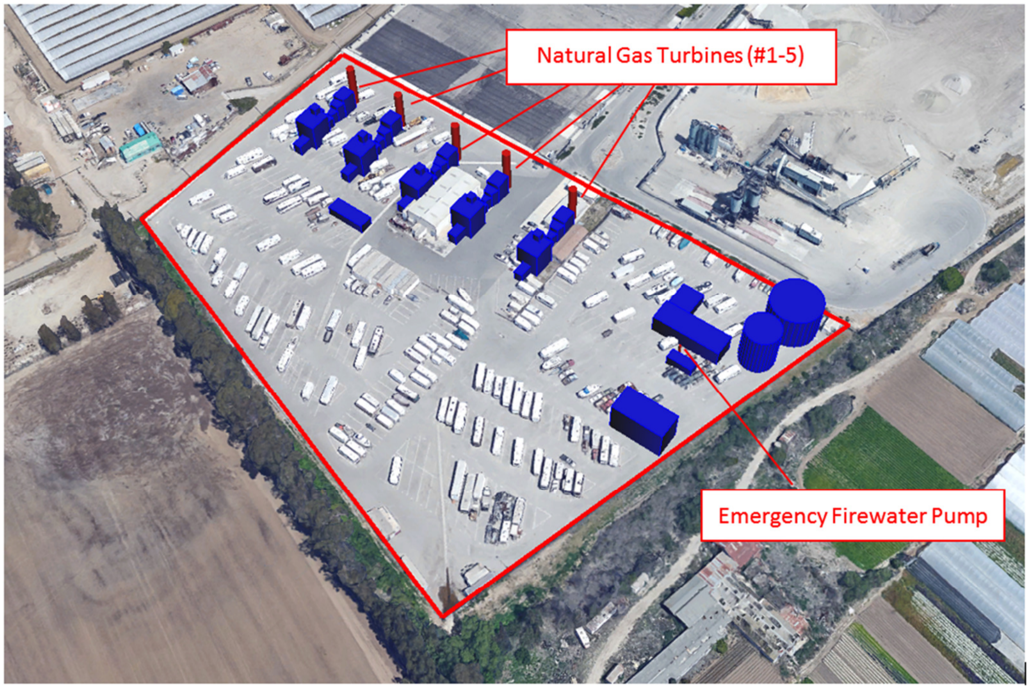


Figure 5-2. Onsite Structures (Blue Objects)

5.2.7 Ambient Air Quality Analysis (AAQA)

EPA and the State of California allow for the use of multi-tiered approaches for determining whether emissions will cause or contribute to the exceedance of an ambient air quality standard (AAQS). For each pollutant, the available tiers and options will vary, however, the first tier is always considered the most conservative and subsequent tiers further refine the analyses through the use of additional information or refined modeling techniques. In the first tier, for each averaging period, the maximum modeled concentration for each source and receptor combination is summed to produce a worst-case concentration. The sum of the maximum modeled concentration and maximum monitor value is compared to the national and state AAQS to determine whether or not an exceedance would be expected to occur. If an exceedance does occur, the maximum modeled concentrations are compared to their SILs to determine whether they exceed their *de minimus* value. If emissions of a pollutant are expected to cause an exceedance of both the standard and SIL, the next available tier of analysis will be performed until no further refinements are allowed. .

5.2.7.1 NO_2 (annual only), CO, SO_2, and PM_{10}/$PM_{2.5}$ Modeling

As previously noted, emissions of NO_2 (annual only), CO, SO_2, and PM_{10}/$PM_{2.5}$ were first evaluated using the first tier approach. After using that approach, it was determined that, for each applicable averaging period, none of these pollutants would cause or contribute to an exceedance of an ambient air quality standard, therefore there was no need to use any of the allowable refinements.

5.2.7.2 1-Hr NO_2 Modeling

While the new 1-hour NO_2 NAAQS is defined relative to ambient concentrations of NO_2, the majority of NO_x emissions from stationary sources are in the form of nitric oxide (NO) rather than NO_2. As noted in Appendix W the impact of an individual source on ambient NO_2 depends in part “on the chemical environment into which the source’s plume is to be emitted” (see Appendix W, Section 4.2.3.4). Because of the role NO_x chemistry plays in determining ambient impact levels of NO_2 based on modeled NO_x emissions, Section 4.2.3.4 of Appendix W recommends a tiered approach for NO_2 modeling. The tiered approach used for modeling NO_2 emissions is described below:

1) The first tier approach to evaluating 1-hr NO_2 involves modeling NO_2 emissions using the worst-case emission rate and the worst-case modeling parameters. This tier assumes that there is full conversion of NO to NO_2, regardless of chemistry. If, after performing this tier’s approach, the NO_2 emissions of are expected to cause an exceedance of both the standard and SIL, the next tier approach may be taken.
2) The second tier 1-hr NO_2 analysis involves using the ozone limiting method (OLM) or plume volume molar ratio method (PVMRM) with a single value background concentration of ozone (based on the most recent 5-yr average of maximum hourly ozone values) and NO_2 (based on the most recent 3-yr average of maximum hourly NO_2 values). If, after performing this tier’s approach, the NO_2 emissions of are expected to cause an exceedance of both the standard and SIL, the next tier approach may be taken.
3) The third tier 1-hr NO_2 analysis involves using the ozone limiting method (OLM) or plume volume molar ratio method (PVMRM) with the 8th highest Hr-of-Day background concentrations of ozone and NO_2. If, after performing this tier’s approach, the NO_2 emissions of are expected to cause an exceedance of both the standard and SIL, the next tier approach may be taken.
4) The fourth tier 1-hr NO_2 analysis involves using the ozone limiting method (OLM) or plume volume molar ratio method (PVMRM) with hourly background concentrations of ozone and NO_2 paired through space and time. If, after performing this tier’s approach, the NO_2 emissions of are expected to cause an exceedance of both the standard and SIL then the NO_2 emissions from this project are considered to contribute to an exceedance of the ambient air quality standard.

A summary of the AAQA results for turbine commissioning, and startup/shutdown/normal operation of the turbine plus operation of the emergency engine are provided in the following tables:

Table 5-12. AAQA Results: Turbine Commissioning

AAQS Pollutant & Averaging Time[1]	Modeled Impacts (μg/m³)	Back-ground (μg/m³)[2]	Total (μg/m³)	AAQS (μg/m³)		Significant Impact Level (SIL, μg/m³)	Project Impact Significant? [3]	
				National	State		AAQS	SIL
CO, 1-hour	403.69	4684	5,088	23,000	40,000	2000	No	No
CO, 8-hour	146.08	1259	1,405	10,000	10,000	500	No	No
NO_2, 1-hour (CAAQS)[4]	172.58	73	173	---	339	7.5	No	Yes
NO_2, 1-hour (NAAQS)[4]	172.58	56	173	188	---	7.5	No	Yes
SO_2, 1-hour (CAAQS)	6.16	10	16	---	655	7.8	No	No
SO_2, 1-hour(NAAQS)	6.16	3	9	196	---	7.8	No	No
SO_2, 3-hour	3.69	3	7	1,300	---	25	No	No
SO_2, 24-hour	0.85	3	4	365	105	5	No	No
PM_{10}, 24-hour	1.43	105	106	150	50	5	Yes	No
$PM_{2.5}$, 24-hour	1.43	22	23	35	---	1.3	No	Yes

[1]Per applicant, the emergency diesel fire pump engine will not operate during turbine commissioning. Only the new turbines were included in the evaluation. Per the applicant, two CTGs will be commissioned at a time. Therefore, the modeled impacts presented in the table represent the worst case modeled concentrations for any pair (two units) of the five CTGs.
[2]Background reported as the maximum design value for the most recent 3-year period for which information is available (2014-2016).
[3]If the project is expected to cause an exceedance of both the AAQS and SIL for any of the pollutant/averaging time categories, a more refined assessment would be performed for the project as is explained in Section 5.2.7.
[4]Modeled impacts are based on the usage of the third tier approach for evaluating 1-hr NO_2 described in Section 5.2.7.2. The sources were modeled together with the background; therefore, the modeled concentrations may be compared directly to the CAAQS and NAAQS without the need to add a separate background value.

As noted in the preceding table (Table 5-12), emissions of CO, NO_2, SO_2 and $PM_{2.5}$ during commissioning are not expected to cause an exceedance of any State or Federal ambient air quality standards. The 24-hour PM_{10} background concentration in Ventura County exceeds the State ambient air quality standard. However, the 24-hour PM_{10} emissions during commissioning are not expected to exceed the Federal SIL. Therefore, the project is not expected to contribute to an exceedance of the 24-hour PM_{10} State or Federal standards.

Table 5-13. AAQA Results: Turbine Startup/Shutdown/Normal Operations Plus Operation of the Emergency Diesel Engine

AAQS Pollutant & Averaging Time	Modeled Impacts (µg/m^3)	Back-ground (µg/m^3)[1]	Total (µg/m^3)	AAQS (µg/m^3)		Significant Impact Level (SIL, µg/m^3)	Project Impact Significant? [2]	
				National	State		AAQS	SIL
CO, 1-hour	116.96	4,684	4,801	23,000	40,000	2000	No	No
CO, 8-hour	84.21	1,259	1,344	10,000	10,000	500	No	No
NO_2, 1-hour (CAAQS)	126.24	73	200	---	339	7.5	No	Yes
NO_2, 1-hour (NAAQS)	126.24	56	183	188	---	7.5	No	Yes
NO_2, annual (CAAQS)	0.14	12	12	100	57	1	No	No
SO_2, 1-hour (CAAQS)	14.96	10	25	---	655	7.8	No	Yes
SO_2, 1-hour(NAAQS)	14.96	3	18	196	---	7.8	No	Yes
SO_2, 3-hour	9.01	3	12	1,300	---	25	No	No
SO_2, 24-hour	1.98	3	5	365	105	5	No	No
SO_2, annual	0.04	1	1	79	---	1	No	No
PM_{10}, 24-hour	3.33	105	108	150	50	5	Yes	No
PM_{10}, annual	0.07	27	27	---	20	1	Yes	No
$PM_{2.5}$, 24-hour	3.33	22	25	35	---	1.3	No	Yes
$PM_{2.5}$, annual	0.07	10	10	15	12	0.2	No	No

[1]Background reported as the maximum design value for the most recent 3-year period for which information is available (2014-2016).
[2]If the project is expected to cause an exceedance of both the AAQS and SIL for any of the pollutant/averaging time categories, a more refined assessment would be required for the project as is explained in Section 5.2.7. As shown above, no impacts are above both the AAQS and the SIL, therefore no further analysis is needed.

As noted in the preceding table (Table 5-13), emissions of CO, NO_2, SO_2, and $PM_{2.5}$ during normal operations are not expected to cause an exceedance of any State or Federal ambient air quality standard. The 24-hour PM_{10} background concentration in Ventura County exceeds the State ambient air quality standard, and the annual PM_{10} background concentration in Ventura County exceeds the State ambient air quality standard. However, the 24-hour and annual PM_{10} emissions during startup/shutdown/normal operations are not expected to exceed the Federal SILs. Therefore, the project is not expected to contribute to an exceedance of the 24-hour or annual PM_{10} State or Federal standards.

5.2.8 Fumigation Modeling

Fumigation occurs when a plume that was originally emitted into a stable layer is mixed rapidly to ground-level when unstable air below the plume reaches plume level. Fumigation can cause very high ground-level concentrations. One type of fumigation was analyzed for this project:

1. **Inversion breakup fumigation**. Inversion breakup fumigation occurs under low-wind conditions when a rising morning mixing height caps a stack and "fumigates" the air below.

Currently, AERSCREEN is the only regulatory model approved by EPA for shoreline fumigation and inversion breakup modeling. AERSCREEN calculates fumigation due to inversion break-up and shoreline fumigation for point sources with release heights (above ground level) of 10 m or more. The fumigation equations for AERSCREEN are taken from SCREEN3. Surface files were generated with the following parameters using AERSURFACE and a geoTIFF file from the 2011 National Land Cover Database (NLCD2011):

- Center latitude: 34.309040
- Center longitude: -119.107031
- Datum: NAD83
- Study radius (km) for surface roughness: 1.0
- Airport: N
- Continuous snow cover: N
- Surface moisture: average
- Arid region: N
- Month/season assignments: user-specified
- Late autumn after frost and harvest, or winter with no snow: 0
- Winter with continuous snow on ground: 0
- Transitional spring (partial green coverage, short annuals): 1, 2, 3, 4, 5, 6, 11, 12
- Midsummer with lush vegetation: 7, 8, 9, 10
- Autumn with unharvested cropland: 0
- Freq sect: monthly 3
    - Sector 1: 0-30
    - Sector 2: 30-60
    - Sector 3: 60-90
    - Sector 4: 90-120
    - Sector 5: 120-150
    - Sector 6: 150-180
    - Sector 7: 180-210
    - Sector 8: 210-240
    - Sector 9: 240-270

- Sector 10: 270-300
- Sector 11: 300-330
- Sector 12: 330-360

Meteorological data for AERSCREEN was then generated by MAKEMET using these surface files. Fumigation analyses were conducted for each of the 33 modeling scenarios presented by the applicant. For each modeling scenario, the maximum modeled fumigation impact was less than the maximum 1-hr concentration that was predicted to occur under normal dispersion conditions. Since this is the case, per EPA guidance (Section 4.5.3 of EPA-454/R-92-019), the effects of fumigation may be ignored. Therefore, no further analysis was performed.

6. Ventura County APCD Rule 51 – Nuisance (Risk Management Review)

The purpose of VCAPCD Rule 51 is to protect the health and safety of the public. This rule prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. The VCAPCD does not have a new source review rule for toxic air pollutants, but does have the VCAPCD policy "Air Toxic Review of Permit Applications" (revised 7/10/02) that is used to evaluate Rule 51 compliance for new permit applications. This policy defines how the VCAPCD will determine if a new, modified, replacement or relocated emissions unit can operate in compliance with Rule 51. VCAPCD requires that for an increase in air toxic emissions associated with a new permit application, VCAPCD shall perform an analysis to determine the possible impact to the nearest resident or worksite. If a preliminary health risk prioritization analysis demonstrates that the new facility's total prioritization score is less than the VCAPCD's significance threshold, then generally no further analysis is required.

The significant prioritization score threshold is defined as being equal to or greater than 1.0. If a preliminary analysis demonstrates that the new facility's total prioritization score is greater than the threshold, a screening or a more refined assessment is required using VCAPCD approved methods including but not limited to VCAPCD screening assessment tools, comparison to similar health risk assessments, and EPA's AERMOD and CARB's HARP2 program. Required model inputs characterize the various emitting units, meteorology, and the land surface, and define a set of receptors (spatial locations at which to estimate concentrations, typically out to 2-5 km from the facility). Modeling is performed in accordance with VCAPCD, OEHHA, and EPA's Guideline on Air Quality Modeling, in Appendix W to 40 CFR Part 51 (GAQM or Appendix W).

If a refined health risk assessment results in a health risk of less than 10 in a million for carcinogenic impacts (Cancer Risk) and less than 1.0 for the Acute and Chronic hazard indices (Non-Carcinogenic) for the new facility, the health risk from the proposed application is considered less than significant. For projects that exceed a cancer risk of 10 in one million or an acute or chronic hazard index of 1.0, the applicant must develop and implement a Health Risk Reduction Plan as explained in Section 6.7.1 of this document.

Carcinogenic impacts greater than 10 in a million, or Acute or Chronic hazard indices greater than 1.0 are considered significant and may not be permitted. In special circumstances, the Air Pollution Control Officer may approve a project determined to have a significant health risk.

6.1 Toxic Emissions

Toxic emissions for the proposed natural gas turbine were calculated using hourly and annual rates of natural gas combustion calculated by the permit engineer and emission factors provided by the applicant. The following assumptions were used in deriving the hourly and annual rates of natural gas combustion:

- Each turbine was limited to 2500 hours of operation per year.
- The higher heating value (HHV) of the natural gas is 1,021 BTU/scf.
- A worst case hour heat input of 2,831 MMBTU/hr for all 5 turbines combined (based on Run #1). This is equivalent to 566.2 MMBTU/Hr per turbine.
- An annual average heat input of 560.8 MMBTU/hr per turbine (based on Run #14).
- The worst case annual heat input was determined based on a scenario that included 150 startups (75 hours), 150 shutdowns (22.5 hours), and 2402.5 normal operation hours (a total of 2500 hours of operation per year). The worst case hourly heat input of 566.2 MMBTU/hr was used to calculate emissions for the startup and shutdown (97.5 hrs) operations (55,204.5 MMBTU). The annual average heat input of 560.8 MMBTU/hr was used to calculate emissions for the remaining 2402.5 hours of normal operation (1,347,322 MMBTU). In all, the annual heat input was therefore 1,402,527 MMBTU/yr.

Toxic emission factors for the turbine were proposed by the applicant and compiled from two sources:

- US EPA's AP-42 Table 3.1-3 (4/00). Since the emission factors presented in AP-42 are uncontrolled, an 80% control efficiency was applied to account for the presence of the oxidation catalyst and selective catalytic reduction systems.
- The California Toxic Emission Factor (CATEF) database. Information from this database was used to supplement the toxic emissions profile by adding pollutants not included in AP-42's profile.

Toxic emissions for the proposed diesel emergency engine were calculated as the mass of diesel particulate matter (DPM), which is considered equal to its PM_{10} emissions.

Emissions unit process rates are summarized in the following table:

Table 6-1. Source Process Rates

Unit Description	Process Material	Process Units	Hourly Process Rate	Annual Process Rate
Natural Gas Turbine (per turbine)	Natural Gas	MMBTU[1,2]	566.2	1,402,527
Emergency Diesel Engine	Diesel Particulate Matter	Hours of operation	0.5[3]	50

[1]A natural gas heating value (HHV) of 1,021 Btu/scf was used to convert MMBTU to million standard cubic feet (mmscf).
[2]The annual process rate for the natural gas turbines are based on 97.5 hours per year of startups/shutdowns at 566.2 BTU/hr and 2402.5 hours per year of normal operation at 560.8 BTU/Hr for a total of 1,402,527 MMMTU/year.
[3]The diesel fire water pump engine cannot be operated for more than 30 minutes in any rolling 1-hr period for testing and maintenance purposes.

Toxics emissions are summarized in the following table:

Table 6-2. Source Process Rates

Pollutant ID	Pollutant Name	Max. Hourly Emissions (lbs)[1]	Annual Emissions (lbs)[2]	Emission Factor Origin
Natural Gas Turbine (per Turbine)				
75070	Acetaldehyde	4.53E-03	1.12E+01	EPA[4]
107028	Acrolein	7.25E-04	1.80E+00	EPA[4]
7664417	Ammonia	3.78E+00	9.34E+03	MFG
71432	Benzene	1.36E-03	3.37E+00	EPA[4]
106990	1,3-Butadiene	4.87E-05	1.21E-01	EPA[4]
100414	Ethylbenzene	3.62E-03	8.98E+00	EPA[4]
50000	Formaldehyde	6.03E-02	1.49E+02	EPA[4]
110543	Hexane	4.24E-02	1.05E+02	CATEF[3]
91203	Naphthalene	1.47E-04	3.65E-01	EPA[4]
1151	PAHs (BaP)	2.49E-04	6.17E-01	EPA[4]
115071	Propylene	2.22E-01	5.49E+02	CATEF[3]
75569	Propylene oxide	3.28E-03	8.13E+00	EPA[4]
108883	Toluene	1.47E-02	3.65E+01	EPA[4]
1330207	Xylene	7.24E-03	1.79E+01	EPA[4]

Diesel Emergency Fire Pump Engine				
9901	Diesel particulate matter	3.50E-02	3.50E+00	Engine Manufacturer

[1]The worst case hourly emissions will be based on turbine performance data (run #1) of the manufacturer provided data.
[2]The annual emissions will be based on the turbine performance data (run #14) of the manufacturer provided data.
[3]Toxic emission factors derived from the California Toxic Emission Factor (CATEF) database. The CATEF emission factors (maximum values) were converted to lb/mmscf from lb/MMBTU using the HHV of natural gas. HHV of natural gas = 1021 BTU/scf.
[4]Toxic emission factor derived from US EPA's AP-42 Table 3.1-3 (4/00). Since the emission factors presented in AP-42 are uncontrolled, an 80% control efficiency was applied to account for the presence of oxidation catalyst and selective catalytic reduction systems.

The VCAPCD compared the turbine's hourly and annual toxic emissions calculated using the applicant's toxics profile to hourly and annual emissions calculated using the default profile for uncontrolled toxic emissions from natural gas-fired turbines (AP-42 Table 3.1-3 (4/00)). The VCAPCD found that the proposed profile generated hourly and annual toxic emissions that resulted in cancer, chronic and acute risk values that were similar to those calculated from the default profile. Therefore, the VCAPCD determined that the toxic emissions calculated using the applicant's proposed profile represented a conservative estimate and were acceptable for this project.

6.2 Prioritization

The prioritization methodology used by the VCAPCD is the *Air Toxic "Hot Spots" Program Facility Prioritization Guidelines* prepared by the Air Toxics and Risk Management Committee (TARMAC) of the California Air Pollution Control Officers Association (CAPCOA) dated August 2016.

The prioritization methodology has two basic methods that can be used to determine a source's potential impact on nearby receptors. The first is the "Emissions and Potency" method which relies on the quantity of a specific pollutant and the pollutant's specific potency (tendency to cause harm) in conjunction with the distance a source is from a receptor to calculate a score or potential for exposure.

The second method, "Dispersion Adjustment", is similar to the first method except that the stack height is also included as a parameter in the calculations to derive the prioritization score. Both prioritization methodologies look at three aspects of exposure 1) Acute short term non-carcinogenic risk [1 to 24 hours], 2) Chronic long term non-carcinogenic risk [24 hours to 1 year], and 3) Carcinogenic risk over a 70 year period.

For the purpose of this assessment the word carcinogenic refers to those compounds that have been identified by the Office of Environmental Health hazard Assessment (OEHHA) as having the potential of cause cancer.

Since the applicant determined that a refined health risk assessment was required in their assessment, a prioritization calculation was not performed.

6.3 Screening and Refined Assessment

If modeling is required after implementing a screening technique, two modeling options may be available.

- The first option is a screening model that uses conservative modeling assumptions to estimate impacts, or it may be a spreadsheet that was derived from a screening/refined model using conservative assumptions.
- The second option is to use a refined model which will require more resources and time. This is due to the facility and source specific information required to perform a given run.

The determination of which option is used will mainly be based on the following:

- Is there a screening method available for the scenario under review?
- Is the conservative screening method acceptable to the reviewing agency?
- Is the meteorological data used to develop the screening method acceptable?
- Are the source parameters used in the screening method acceptable?

The VCAPCD does not have a screening method available for the gas turbines and emergency diesel fire pump engine included in this project. Therefore, a refined health risk assessment was required and conducted.

6.4 Refined Assessment

The impact of the project was assessed in accordance with VCAPCD, OEHHA, and CARB guidance. The modeling analyses included the maximum air quality impacts during commissioning, startup, shutdown and normal operations using maximum hourly emissions for the acute hazard index (HI), annual emissions for the chronic HI, and annual emissions for the cancer risk.

6.4.1 Model Selection

The VCAPCD requires that the following regulatory models be used to analyze health impacts in the project area:

Table 6-3. Summary of Preferred Models

Model Name	Model Purpose	Model Version
AERMOD	Air dispersion modeling	16216r
AERMAP	Terrain processing	11103
AIRMET	Meteorological data processing	16216
HARP2	Analysis of health impacts	17052

6.4.2 Land Characteristics

Land characteristics are used in the AERMOD modeling system in three ways:

- via elevation within AERMOD to assess plume interaction with the ground;
- via a choice of rural versus urban algorithm within AERMOD; and
- via specific values of AERMET parameters that affect turbulence and dispersion. This aspect applies to the meteorological inputs discussed in Section 6.4.3.

6.4.2.1 Elevation

Terrain elevations from United States Geological Survey (USGS) National Elevation Dataset (NED) data were used at a horizontal resolution of 10 meters, for receptor heights in AERMOD, which uses them to assess plume distance from the ground for each receptor. All coordinates were referenced to UTM World Geodetic System 1984 (WGS84). The AERMOD, receptor elevations were interpolated among the NED nodes according to standard AERMAP procedure.

Table 6-4. Unit Location and Elevation Summary

Unit Description	Location			Elevation (m)
	UTM Zone	UTMN (m)	UTME (m)	
Natural Gas Turbine #1	11	306075.72	3798510.55	56.42
Natural Gas Turbine #2	11	306097.24	3798494.54	56.35
Natural Gas Turbine #3	11	306122.07	3798476.08	56.22
Natural Gas Turbine #4	11	306143.60	3798460.07	56.11
Natural Gas Turbine #5	11	306170.51	3798440.06	55.99
Emergency Diesel Engine	11	306209.23	3798371.10	55.57

6.4.2.2 Urban/Rural Classification

The classification of a site as urban or rural can be based on the Auer method specified in the EPA document Guideline on Air Quality Models (40 CFR Part 51, Appendix W). From the Auer's method, areas typically defined as Rural include:

- Residences with grass lawns and trees

- Large estates
- Metropolitan parks and golf courses
- Agricultural areas
- Undeveloped land
- Water surfaces

Auer defines an area as urban if it has less than 35% vegetation coverage or the area falls into one of the following use types:

Table 6-5. Land Use in Urban Classifications

Type	Use and Structures	Vegetation
I1	Heavy industrial	Less than 5%
I2	Light/moderate industrial	Less than 5%
C1	Commercial	Less than 15%
R2	Dense single / multi-family	Less than 30%
R3	Multi-family, two-story	Less than 35%

To determine if an area should be classified as urban or rural, evaluate land use within a 3 km radius from the center of the emissions source. If land use types I1, I2, C1, R2, and R3 account for 50 % or more of the area within the circle, then the area is classified as urban, otherwise the area is classified as Rural.

For this project, it was determined that the source's land use classification is rural.

6.4.3 Meteorological Inputs

6.4.3.1 Surface Data

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. In order to select a meteorological site, the VCAPCD did a qualitative comparison of the following factors from EPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (Document EPA-454/R-99-005) recommended for consideration for siting:

- Proximity.
- Height of measurement.
- Aspects of the site's surface that affect turbulence and dispersion.

Table 6-6 provides the characteristics of the meteorological sites that are in close proximity to the project area, the type of data collected at each site, the met data processing parameters, and identifies the site selected.

Table 6-6. Surface Met Sites Near the Project Site

Site Criteria	Surface Met Sites			
	Oxnard Airport	**Point Mugu Naval Air Station**	**Camarillo Airport**	**Santa Barbara Municipal Airport**
Distance from Project (km)	15	21	15	68
Elevation	11	4	11	3
Direction from Project	SW	S	S	NW
Urban/Rural	Rural	Rural	Rural	Rural
Land Use	Ag/ Residential	Undeveloped Mixed	Ag/ Mixed	Mixed
Met Type	Station	Station	Station	Station
Station ID	93110	93111	23136	23190
Data Type	NCDC	NCDC	NCDC	NCDC
Years Available	2009-2013	2009-2013	2009-2013	2009-2013
U* Adjustment Applied	---	---	Yes	---
Site Selected			**X**	

[1]Met data was processed per the SJVAPCD's meteorological data processing guidance (http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm#modeling_guidance). Lakes' Land Cover Data Tool was used to update National Land Cover Data (NLCD) used by AERSURFACE.

The VCAPCD believes that the chosen Camarillo Airport surface meteorological data is the most representative for the proposed project analysis for the following reasons

- The project site and the meteorological site are in close proximity to each other.
- The land use and the location with respect to near-field terrain features are similar between both the selected surface meteorological site and the project site.
- The wind flow at the chosen meteorological site closely represents the wind flow expected in the project area.

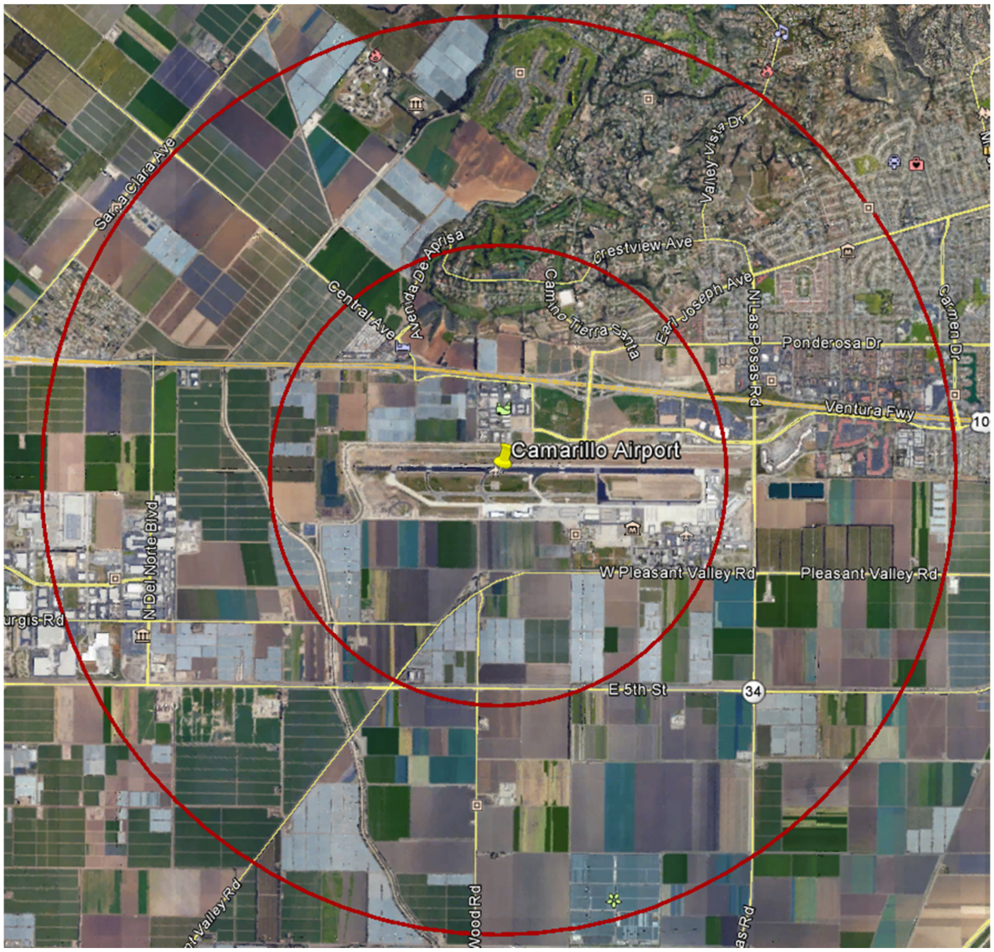


Figure 6-1 Camarillo Airport Met Site

6.4.3.2 Upper Air Data

The Point Mugu Naval Air Station (NAS) upper air met site is closest to the project site, but data completeness was not acceptable. Therefore, the VCAPCD selected upper air data from Vandenberg Air Force Base (AFB) as the most representative upper air site available that had acceptable data completeness.

Table 6-7. Upper Air Met Sites Near the Project Site

Site Criteria	Vandenberg AFB	Point Mugu NAS
Distance from Project (km)	142	21
Direction from Project	NW	SE
Station WBAN ID	93214	93111
Years Available	2011-2015	2011-2015
Site Selected	**X**	

6.4.4 Sensitive Receptors

Sensitive receptors are defined as infants and children, the elderly, the chronically ill, and any other members of the general population who are more susceptible to the effects of exposure to environmental contaminants than the population at large. Additionally, the VCAPCD includes in the definition of sensitive receptors locations occupied by groups of individuals that may be more susceptible than the general population to health risks from a chemical exposure and therefore include schools (public and private), day-care facilities, convalescent homes, parks, and hospitals.

The RMR approach treats all receptors as sensitive receptors. Long term health impacts (chronic and cancer) are evaluated for all sensitive receptors within the project area. In addition, short term health impacts (acute) are evaluated at all locations within the project area (beyond the facility fence line) at which an individual may be exposed for a period of one hour.

6.4.5 Source Parameters

Modeling was performed using the source parameters in the tables below to conservatively estimate the project's impacts.

Table 6-8. Point Source Parameters

Unit Description	Release Height (m)	Temp. (°K)	Exit Velocity (m/sec)	Stack Diameter (m)
Natural Gas Turbines				
- Scenario 1[1]	18.29	736.9	31.28	3.6576
- Scenario 4[2]	18.29	676.1	16.14	3.6576
Emergency Diesel Engine	7.62	803.2	44.3	0.127

[1]Scenario 1 parameters were determined to be the most appropriate for evaluating the Cancer and Chronic HI impacts from this project.
[2]Scenario 4 parameters were determined to be the most appropriate for evaluating the Acute HI impacts from this project.

6.5 Risk Management Review (RMR)

Adverse health effects are expressed in terms of cancer or non-cancer health risks. Cancer risk is typically reported as "lifetime cancer risk," which is the estimated maximum increase in the risk of developing cancer caused by long-term exposure to a pollutant identified as being a carcinogen by the OEHHA. The calculation of cancer risk conservatively assumes an individual is exposed continuously to the maximum pollutant concentrations 24 hours per day for 70 years. Although such continuous lifetime exposure to maximum Toxic Air Contaminants (TAC) levels is highly unlikely, the goal of the approach is to produce a conservative worst-case estimate of potential cancer risk.

Non-cancer risk is typically reported as a Hazard Index (HI). The HI is calculated for each target organ as a fraction of the maximum acceptable exposure level or REL for an individual pollutant. The REL is generally the level at (or below) which no adverse health effects are expected. The HI's are calculated for both short-term (acute) and long-term (chronic) exposures to non-carcinogenic substances by adding the ratios of predicted concentrations to RELs for all pollutants.

Both cancer and non-cancer risk estimates produced by the RMR represent incremental risks (i.e., risks due to the modeled sources only) and do not include potential health risks posed by existing background concentrations. The HARP model performs all of the necessary calculations to estimate the potential lifetime cancer risk, and the acute and chronic non-cancer HI's due to the project's TAC emissions. The following parameters were selected in the HARP model:

- Intake rate percentile
    - OEHHA derived method
- Exposure duration
    - Resident: 70 years
        - Fraction time at home adjustment: disabled
    - Worker: 25 years
- Site parameters
    - Inhalation pathway: enabled
    - Drinking water pathway: disabled
    - Fish water pathway: disabled
    - Beef/dairy (pasture) pathway: disabled
    - Home grown produce pathways: enabled (resident)
    - Pigs, chickens, and/or eggs pathways: disabled
    - Dermal pathway: enabled
    - Soil ingestion pathway: enabled
    - Mother's milk pathway: enabled (resident)
    - Deposition rate: 0.02 m/s

6.6 Risk Management Review Significance Thresholds

Project-related emissions are considered significant when the predicted increase in lifetime cancer risk exceeds 10 in 1 million (10×10^{-6}), and when either the non-carcinogenic acute hazard index or the non-carcinogenic chronic hazard index exceeds a value of 1.0.

6.7 Risk Management Review Results

The locations of the maximally exposed receptors for each type of adverse health impact are presented in Table 6-9.

Table 6-9. RMR Project Level Maximally Exposed Receptors

Unit Description	Health Impact	Receptor Type[1]	Receptor Location		
			UTM Zone	UTME (m)	UTMN (m)
Natural Gas Turbines	Cancer	Resident	11	306266	3798372
	Chronic	Resident	11	306266	3798372
	Acute	Resident	11	307000	3797400
Diesel Emergency Engine	Cancer	Resident	11	306266	3798372
	Chronic	Resident	11	306266	3798372
	Acute	--	---	---	---
Combined	Cancer	Resident	11	306266	3798372
	Chronic	Resident	11	306266	3798372
	Acute	Resident	11	307000	3797400

[1]In order to be conservative, all receptors were assumed to be residents regardless of whether they were residents, schools or workers.

The estimated cancer risk, and acute and chronic non-cancer hazard indexes for the project are summarized in Table 6-10.

Table 6-10. RMR Results

Unit Description	Cancer Risk	Hazard Index	
		Chronic	Acute
Natural Gas Turbine	1.18×10^{-8}	1.66×10^{-5}	3.20×10^{-2}
Diesel Emergency Engine	6.76×10^{-6}	1.29×10^{-3}	---
Project Total	6.77×10^{-6}	1.31×10^{-3}	3.20×10^{-2}

The acute and chronic hazard indices are below 0.5 and the cancer risk associated with the project is less than 10 in a million. In accordance with VCAPCD policy the VCAPCD policy "Air Toxic Review of Permit Applications" (revised 7/10/02), the project is approved as proposed.

6.7.1 Health Risk Reduction Plan

According to the VCAPCD policy noted above, if the health risk assessment indicates that the carcinogenic risk is greater than 1 in a million, or that the acute or chronic hazard indices are greater than 0.5, VCAPCD staff will work with the applicant to reduce the risk to an acceptable level. If after working with the applicant to reduce the risk, the health risk assessment still indicates that the additional carcinogenic risk is greater than 10 in a million, or the acute or chronic hazard indices are greater than 1, permit conditions will be placed on the permit requiring the applicant to develop and implement a Health Risk Reduction Plan.

The acute and chronic indices from the proposed Mission Rock Energy Center are below 1.0 and the cancer risk factor associated with the new facility is less than 10 in a million. Therefore, a Health Risk Reduction Plan is not be required for the project.

6.7.2 Rule 51 Permit Conditions

To ensure that health risks will not exceed VCAPCD allowable levels; the following permit conditions will be included for:

New Natural Gas-Fired Combustion Turbine Generators (CTGs)

- Each CTG shall be fired exclusively on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas.
- Each CTG shall be equipped with selective catalytic reduction (SCR) and oxidation catalyst systems.

<u>New Emergency Diesel Fire Water Pump Engine</u>

- The PM_{10} emissions rate shall be EPA-certified to not exceed 0.15 g/bhp-hr.
- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (a flapper type rain cap is allowed), roof overhang, or any other obstruction.
- Operation of the diesel fire water pump engine for maintenance and readiness testing shall not exceed 30 minutes in any rolling 1-hour period and a total of 50 hours per year.
- Only CARB-certified diesel fuel containing not more than 0.0015% sulfur by weight shall be used.

7. Report Summary

7.1 Ventura County APCD Rule 26 - New Source Review (NSR)

Ventura County APCD Rule 26.2.C requires that an Ambient Air Quality Analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an Air Quality Standard (AAQS). Therefore, the VCAPCD has performed an AAQA for this project.

As presented in Section 5 of this document, the proposed project will not cause or contribute significantly to a violation of the State or National Ambient Air Quality Standards (AAQS) for NO_x, CO, SO_x, PM_{10}, or $PM_{2.5}$.

7.2 Ventura County APCD Rule 51 – Nuisance

Rule 51 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of this operation provided the equipment is well maintained. Therefore, compliance with this rule is expected.

The VCAPCD policy "Air Toxic Review of Permit Applications" (revised 7/10/02) specifies that if the additional carcinogenic risk associated with new emission units subject to the application is less than 1 in a million, and that the acute and chronic hazard indices are less than 0.5, no further action is required. If the health risk assessment indicates that the additional carcinogenic risk is greater than 10 in a million, or acute or chronic hazard indices are greater than 1, then a health risk reduction plan will be required. Risk assessment results for this project are summarized in the table below.

Table 7-1. RMR Results

Unit Description	Cancer Risk	Hazard Index		Health Risk Reduction Plan Required?
		Chronic	Acute	
Natural Gas Turbines	1.18×10^{-8}	1.66×10^{-5}	3.20×10^{-2}	No
Diesel Emergency Engine	6.76×10^{-6}	1.29×10^{-3}	---	No
Project Total	6.77×10^{-6}	1.31×10^{-3}	3.20×10^{-2}	No

The acute and chronic indices are below 0.5 and the cancer risk factor associated with the project is less than 10 in a million. In accordance with VCAPCD's Air Toxics Review of Permit Applications policy, the project is approved without the need to submit a Health Risk Reduction Plan.

Appendix H
Hazardous Air Pollutant Potential to Emit

5.9.2.2 Construction Phase Effects

The construction phase of the MREC is expected to take approximately 23 months (followed by several months of startup and commissioning). No significant public health effects are expected during the construction phase. Strict construction practices that incorporate safety and compliance with applicable LORS will be followed (see Section 5.9.5). In addition, mitigation measures to reduce air emissions from construction effects will be implemented as described in Section 5.1, Air Quality, and Appendix 5.1E.

Temporary emissions from construction-related activities are discussed in Section 5.1, Air Quality and Appendix 5.1E. Construction-related emissions are temporary and localized, resulting in no long-term effects to the public.

Small quantities of hazardous waste may be generated during the construction phase of the MREC. Hazardous waste management plans will be in place so the potential for public exposure is minimal. Refer to the Waste Management, for more information. No acutely hazardous materials will be used or stored on-site during construction (see the Hazardous Materials Handling section). To ensure worker safety during construction, safe work practices will be followed (see the Worker Safety section).

5.9.2.3 Operational Phase Effects

Environmental consequences potentially associated with the operation of the MREC are potential human exposure to chemical substances emitted to the air. The human health risks potentially associated with these chemical substances were evaluated in a HRA. The chemical substances potentially emitted to the air from the MREC turbines, and IC engine are listed in Table 5.9-3.

Table 5.9-3 Chemical Substances Potentially Emitted to the Air from the MREC

Criteria Pollutants
PM
CO
SOx
NOx
VOC
Lead
Noncriteria Pollutants (Toxic Pollutants)
Ammonia, Arsenic, Acetaldehyde, Acrolein
Benzene, Beryllium
Cadmium, Chromium, Copper
1-3 Butadiene
Ethylbenzene
Formaldehyde
Hexane (n-Hexane)
Lead
Nickel, Naphthalene
Manganese, Mercury
PAHs, Propylene, Propylene Oxide
Selenium, Silica
Toluene
Vanadium
Xylene

Table 5.9-3 Chemical Substances Potentially Emitted to the Air from the MREC

Criteria Pollutants
Diesel Particulate Matter

PAH = polynuclear (or polycyclic) aromatic hydrocarbon

Tables 5.9-4 and 5.9-5 present the estimated toxic pollutant emissions from the facility processes.

Table 5.9-4 Toxic Pollutant Emissions Estimates (lbs/hr)

Pollutant/Device	Each Turbine	5 Turbines	Fire Pump
Ammonia	3.77	18.9	-
Total PAHs (BaP)	0.0000267	0.000134	-
Acetaldehyde	0.00452	0.0226	-
Acrolein	0.000721	0.0036	-
Benzene	0.00136	0.00679	-
1-3 Butadiene	0.0000487	0.000243	-
Ethylbenzene	0.00363	0.0181	-
Formaldehyde	0.201	1.0	-
Hexane	0.0287	0.144	-
Naphthalene	0.000147	0.00074	-
Propylene	0.0855	0.428	-
Propylene Oxide	0.00328	0.0164	-
Toluene	0.0147	0.0736	-
Xylene	0.00725	0.0362	-
Diesel PM	-	-	0.07

Table 5.9-5 Toxic Pollutant Emissions Estimates (lbs/year)

Pollutant/Device	Each Turbine	5 Turbines	Fire Pump
Ammonia	9430	47150	-
Total PAHs (BaP)	0.0662	0.331	-
Acetaldehyde	11.2	56	-
Acrolein	1.79	8.93	-
Benzene	3.37	16.8	-
1-3 Butadiene	0.121	0.603	-
Ethylbenzene	8.98	44.9	-
Formaldehyde	498	2490	-
Hexane	71.2	356	-

Naphthalene	0.365	1.83	-
Propylene	212	1060	-
Propylene Oxide	8.13	40.7	-
Toluene	36.5	183	-
Xylene	18	90	-
Diesel PM	-	-	3.78

Table 5.9-5 (continued) Wet SAC Toxic Pollutant Emissions Estimates

Substance	Lbs/Hr/Cell	Lbs/Yr/Cell
Arsenic	3.47E-8	8.68E-5
Beryllium	3.43E-9	8.57E-6
Cadmium	4.90E-9	1.22E-5
Total Chromium	5.34E-9	1.34E-5
Copper	1.25E-7	3.12E-4
Lead	1.56E-8	3.89E-5
Manganese	1.16E-3	2.89E+0
Mercury	1.47E-10	3.67E-7
Nickel	4.01E-8	1.00E-4
Selenium	4.72E-7	1.18E-3
Silica	3.20E-4	8.01E-1
Vanadium	2.67E-8	6.68E-5

Emissions of criteria pollutants will adhere to NAAQS and CAAQS as discussed in Section 5.1, Air Quality. The MREC also will include emission control technologies necessary to meet the required emission standards specified for criteria pollutants under VCAPCD rules. Offsets will be required because the MREC will be a major source under the Districts NSR rule. Finally, air dispersion modeling results (presented in Section 5.1, Air Quality) show that emissions will not result in concentrations of criteria pollutants in air that exceed ambient air quality standards (either NAAQS or CAAQS). These standards are intended to protect the general public with a wide margin of safety. Therefore, the MREC is not anticipated to have a significant effect on public health from emissions of criteria pollutants.

Potential effects associated with emissions of toxic pollutants to the air from the MREC are summarized in Appendix 5.1D. The HRA was prepared using guidelines developed by OEHHA and CARB, as implemented in the latest version of the Hotspots Analysis and Reporting Program (HARP) model (Version 2.0.3, ADMRT #16217).

5.9.2.4 Public Health Effect Study Methods

Emissions of toxic pollutants potentially associated with the MREC were estimated using emission factors approved by CARB and EPA. Concentrations of these pollutants in air potentially associated with MREC emissions were estimated using the HARP dispersion modeling module. Modeling allows the estimation of both short-term and long-term average concentrations in air for use in an HRA, accounting for site-specific terrain and meteorological conditions. Health risks potentially associated with the

Appendix I

Certification of Statewide Compliance

VENTURA COUNTY AIR POLLUTION CONTROL DISTRICT
669 County Square Drive, Ventura CA 93003 805/ 645-1401 FAX 805/ 645-1444 www.vcapcd.org

CERTIFICATION OF STATEWIDE COMPLIANCE

I certify that all major sources, as defined in their specific nonattainment area, which are located in California and which are owned or operated by the applicant, or by any entity controlling, controlled by, or under common control with such applicant, are in compliance or on a schedule for compliance with all applicable emission limitations and standards.

Signature of responsible official, partner, or sole proprietor (not a consultant or contractor) Original Signature Required/No Photocopies	
Print Name	Alexandre B. Makler
Organization or Company Name	Mission Rock Energy Center, LLC
Date	January 7, 2016

PLEASE NOTE: This form is required to be submitted with the application for an Authority to Construct any new, replacement, modified or relocated emission unit at a stationary source in Ventura County where the sum of all emission increases during the last 5 years as detailed in Rule 26.2.D would be greater than or equal to the following limits:

ROC 25.0 tons per year

NOx 25.0 tons per year

Appendix J

Analysis of Alternatives

Alternatives

This section discusses alternatives to Mission Rock's proposed MREC. These include the "no project" alternative, power plant site alternatives, linear facility route alternatives, technology alternatives, and water supply alternatives. This discussion focuses on alternatives that could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the potential impacts.

The CEQA requires consideration of "a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives" (14 CCR 15126.6[a]).

Thus, the focus of an alternatives analysis should be on alternatives that "could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects" (14 CCR 15126.6[c]). The CEQA Guidelines further provide that "among the factors that may be used to eliminate alternatives from detailed consideration in an EIR are: (i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts."

The Energy Facilities Siting Regulations (Title 20, CCR, Appendix B) guidelines titled *Information Requirements for an Application* require:

> *A discussion of the range of reasonable alternatives to the project, including the no project alternative... which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and an evaluation of the comparative merits of the alternatives.*

The data adequacy regulations also require:

> *A discussion of the applicant's site selection criteria, any alternative sites considered for the project and the reasons why the applicant chose the proposed site.*

A range of reasonable alternatives are identified and evaluated in this section, including the "no project" alternative (that is, not developing a new power generation facility), alternative site locations for constructing and operating the MREC, alternative project design features (including linear routes and water supply source), and various technology alternatives. This section also describes the site selection criteria used in determining the proposed location of the MREC.

6.1 Project Objectives

The MREC's primary objective is to combine dispatchable, operationally flexible, and efficient energy generation with state-of-the-art energy storage technology, to meet the need for new local capacity in the Moorpark Subarea of the Big Creek/Ventura local reliability area of Southern California Edison's (SCE's) service territory. The same energy storage system that provides MREC with black start capability will also provide an additional 25 MW/100 MW hours of flexible, preferred resource capacity to the grid. The energy storage system will be used to store energy during times of over-generation, which may be caused by intermittent renewable generation, and delivered back to the grid when needed.

Operationally flexible resources are increasingly needed to assist with the integration of intermittent renewable resources, such as solar and wind facilities, for grid operation. Additionally, peaking capacity is needed to respond to increases in the local demand for electricity that typically occur in the afternoons of summer days. The MREC is expected to run intermittently and provide real-time energy and voltage support to the grid. The MREC will have the ability to start and achieve full capacity in 10 minutes. The MREC will have black start capability provided by the energy storage system, which allows the facility to come online and support the grid to recover from a complete outage.

The same energy storage battery system that provides the MREC with black start capability will also provide an additional 25 MW/100 MWh of flexible, preferred resource capacity to the grid. The energy storage system will be used to store energy during times of over-generation, which may be caused by intermittent renewable generation, and delivered back to the grid when needed.

MREC will thus provide a resource to balance the variability of renewable resources, to satisfy peak energy and capacity needs during high load events, and to support the electrical grid during outages of transmission lines and other generating facilities. The CAISO has identified a near-term need for new power facilities that can support easily dispatchable and flexible system operation. The MREC's objectives are consistent with this need as follows:

- Safely construct and operate a 275 MW, natural gas-fired, simple-cycle generating facility with energy storage capabilities to meet SCE's need for local capacity due to the retirements of the once-through cooling plants in the Moorpark sub-area of the Big Creek/Ventura local reliability area of Southern California.
- Site the project as near as possible to a SCE substation with available transmission capacity to serve the Moorpark Subarea.
- Site the project in an existing industrial area on a brownfield site, to minimize environmental impacts.

6.2 The "No Project" Alternative

If the project were not constructed, Mission Rock's basic project objectives would not be met, and the grid reliability, environmental, and policy benefits that this highly dispatchable and flexible peaking project offers would not be realized. MREC's wide range of operational capabilities offers crucial flexible capacity to support electrical system stability and reliability during periods of low wind and solar output and grid instability. Enhanced stability of the electrical grid will also allow for further integration of renewable resources, providing the state with a path forward towards achieving the 50 percent Renewables Portfolio Standard mandate set forth in Senate Bill 350. Further, the no project alternative does not meet California's environmental policy goals of encouraging development and deployment of preferred resources, such as the energy storage features of the MREC.

The no project alternative could result in greater fuel consumption, air pollution, and other environmental impacts in the state because older, less efficient plants with higher air emissions would continue to generate power instead of being replaced with cleaner, more efficient plants, such as MREC. Therefore, because the no project alternative would not satisfactorily meet the project objectives specified above, the no project alternative was rejected in favor of the proposed project.

6.3 Power Plant Site Alternatives

Several alternative site locations were assessed during initial screening for the MREC. This initial screening identified the MREC site and three alternatives. The alternative sites are shown in Figure 6.3-1. Although each of the alternative sites could feasibly attain most of the project's basic objectives, the MREC site clearly became the preferred alternative for a variety of reasons, including minimizing the required construction of transmission, gas supply, and water supply linear features, and minimizing the project's environmental impacts. The key screening criteria used to select the MREC site and alternative sites included the following:

- Location within SCE's service territory
- Ability to gain site control
- Availability of sufficient land area
- Proximity to existing transmission and distribution lines and to an existing substation with transmission capacity
- Location near a source of water supply of sufficient quantity and quality
- Consistency and compatibility with the Ventura County zoning ordinances and existing land uses
- The ability to avoid or minimize potentially significant impacts on the environment

6.3.1 Proposed Project Site

The MREC site is located in unincorporated Ventura County, west of the City of Santa Paula, at 1025 Mission Rock Road. The MREC site is a 9.79-acre parcel currently used for recreational vehicle and boat storage which is almost entirely paved with asphalt-concrete. The MREC site is located in the Santa Clara River Valley within an industrial park, an area zoned General Industrial (Ventura County M-3, with minimum lot size of 10,000 square feet) that is known as the Mission Rock Area. Adjacent land uses include the Granite Construction Company asphaltic concrete plant and asphalt recycling facility, several automobile dismantling facilities, vehicle storage for crushed cars, auto repair and salvage yards, an oil and gas well and processing equipment, and agricultural production.

MREC will interconnect to the SCE Santa Clara Substation via a new 6.6-mile, 230-kV transmission line located approximately 4.5 miles west of the MREC site, as described in Section 3.0, Electrical Transmission. The natural gas line interconnection for the proposed power plant entails constructing approximately 2.4 miles of new 16-inch pipeline directly southwest from the project site to the point of interconnection with SoCalGas's high-pressure natural gas transmission lines 404/406. More information regarding the natural gas supply can be found in Section 4.0, Natural Gas Supply.

Service water will be provided from a new 1.7-mile-long pipeline connecting to the Limoneira Company's recycled water pipeline southwest of the MREC site. Process wastewater will be discharged to an existing pipe in Shell Road, adjacent to the MREC site, for disposal by Green Compass.

The MREC site meets the project objectives well. It is a brownfield site with relatively easy access to the Santa Clara Substation at 230 kV, is zoned appropriately for heavy industry, has an available recycled water supply, and would not conflict with sensitive land uses or receptors.

6.3.2 Alternative 1: Chase Site

The Chase site is a rectangular 25-acre parcel located within the City of Oxnard, 7.4 miles south of the MREC project site. The site is bounded by Sturgis Road to the north, South Del Norte Boulevard to the west, agricultural fields to the east, and East Fifth Street (SR-34) to the south. The parcel's eastern and southern boundaries are at the Oxnard city limit. Southwest of the parcel are agricultural uses within the City of Oxnard Planning Area of Interest in unincorporated Ventura County. South and southeast of the parcel are an oil well utility yard and several oil wells.

Light industrial uses within the McInnis Ranch Business Park are located to the north and northwest. A recycling center is located to the west. Approximately half of the Chase site is in agricultural use (plant nursery) and half is occupied by a cement batch plant and storage/light industrial yard. The General Plan land use designation of the property is Light Industry and the zoning designation is Light Manufacturing/Planned development.

There are five substations in Ventura County with 230 kV capacity. Two of these (Mandalay and Ormond Beach) serve existing generating stations and so would not be likely to have capacity to carry significant additional load. Reaching the Casitas substation would involve obtaining right-of-way through dense urban areas and over mountains. This leaves the Moorpark and Santa Clara Substations as potential interconnection locations.

A generator tie-line running to SCE's Moorpark Substation would need to be more than 15 miles long (direct distance is approximately 14 miles), depending on the routing. For example, one 18-mile-long route to the Moorpark substation would run to the southeast of the parcel, avoiding densely developed areas in Camarillo to an existing transmission corridor that connects Moorpark Substation with the Ormond Beach Power Plant. A second routing of 15 miles or more would run northeast from the parcel running through agricultural areas to the north of Camarillo.

A generator tie-line routing to the Santa Clara substation avoiding the urban areas of Ventura would be approximately 12 miles long.

This site would interconnect with SoCalGas's high pressure gas transmission line via a new 0.9-mile-long pipeline west to the existing line in South Rice Avenue.

Tertiary-treated, recycled water is likely available for this site through the City of Oxnard's Advanced Water Purification Facility (AWPF). This facility was recently completed (2012) through an initial phase to produce 6.25 million gallons per day (mgd) of recycled water and the City has plans to increase production to 25 mgd (Vorissis, 2013), so it is likely that the facility would have capacity to serve the project. The AWPF is located near Oxnard's southern boundary and a recycled water pipeline from that location could follow a number of routes. Direct distance to the Chase site is 4.8 miles, but the most direct routing using the existing rail and street grid, would be approximately 7.3 miles.

6.3.3 Alternative 2: Vulcan Site

The Vulcan site is a 55.2-acre parcel located just south of the Santa Clara River in an unincorporated area of Ventura, south of the community of Saticoy. The parcel is currently occupied by a Vulcan Materials construction aggregates facility named Saticoy Recycled, at 6029 Vineyard Avenue. The site is bound by the Santa Clara River floodplain on the northwest, SR-118 (Los Angeles Avenue) to the northeast, SR-232 (East Vineyard Avenue) to the southeast, and an agricultural property to the southwest. Surrounding land uses are mostly agricultural to the south and east and suburban residential to the north and west. To the northeast is another construction aggregate business. The parcel's General Plan land use designation is Open Space and the zoning designation is Open Space.

A power plant at this site could connect with the SoCalGas's high pressure gas transmission line in Los Angeles Avenue, adjacent to the parcel. A generator tie-line running to SCE's Santa Clara Substation would be approximately 5.3 miles long.

The best option to obtain service water for the Vulcan site would be to connect with the Limoneira Company recycled water pipeline at the same location planned for the MREC project at the Mission Rock site. This would require a pipeline 1.7 miles long. Alternatively, service water could be obtained from the Ventura Water Reclamation Facility or the Oxnard AWPF, depending on availability. The Ventura facility is 7.2 miles west of the Vulcan site, and a pipeline route would be more than 8 miles. Direct distance to the Oxnard facility is 9.2 miles.

6.3.4 Alternative 3: Camino Real

The Camino Real site is a 27-acre parcel located within the Oxnard city limit. The site is currently in agricultural row-crop use (strawberries). The parcel is bordered on the east by the Edison Canal, and on the other three sides by agricultural fields. The southern and eastern boundaries of the parcel are also City of Oxnard boundaries. North Del Norte Boulevard is 700 feet to the west and Camino Avenue is 800 feet to the north and serves as a frontage road to U.S. Highway 101. An SCE 115-kV transmission line traverses the site diagonally, from the center of the northern boundary of the parcel, to its southwestern corner.

Surrounding uses are agricultural for at least one half-mile, except for the small business park the Camino Real Industrial Plaza, approximately 250 feet north of the northern boundary. Uses in the business park include a health care outlet, an industrial hose supplier, a power machinery outlet, and church.

The General Plan land use designation of the property is Light Industry and the zoning designation is Light Manufacturing/Planned development.

A generator tie-line running to SCE's Moorpark Substation from the Camino Real site would be approximately 15 miles long. A routing to the Santa Clara substation avoiding the urban areas of Ventura would be approximately 10.4 miles long.

This site would interconnect with SoCaGas's high pressure gas transmission line via a new 1.1-mile-long pipeline west to the existing line in North Rice Avenue.

Tertiary treated, recycled water is likely available for this site through the City of Ventura's Water Reclamation Facility, which is located approximately 9 miles west of the Camino Real site. A pipeline route to Limoneira Company's recycled water pipeline would be approximately 6.6 miles long.

6.3.5 Alternative 4: Petrochem Refinery

The USA Petroleum/Petrochem Refinery site (Petrochem site) is a 98-acre parcel located along State Route 33 at Crooked Palm Drive, north of Ventura. The site is a former fertilizer plant and oil refinery that has been shut down since 1984. The property is bordered by open space to the north and south, the Ventura River Trail/Ojai Valley Trail bicycle and pedestrian path and Ventura River to the west and, across State Route 33, residential and agricultural uses to the east. Some of the former refinery equipment has been removed and some remains, and the owner is under a regulatory requirement to remove the remainder of the equipment.

The General Plan Land Use Designation is Existing Community/Urban Reserve and the zoning designation is M3 – General Industrial.

A generator tie-line to the Santa Clara Substation would be 7.2 or more miles long, depending on routing. A generator tie-line to the Casitas Substation would be about 3.5 miles long. A SoCalGas high-pressure gas distribution line is available immediately to the east of the site. Obtaining recycled water from the City of Ventura Water Treatment facility, if it were available, would require an 8.5-mile-long pipeline.

6.4 Comparative Evaluation of Alternative Sites

In the discussion that follows, the sites are compared in terms of each of the 16 topic areas required in the AFC. The following topics are of particular interest:

- **Land Use Compatibility**—Is the parcel zoned appropriately for industrial use and compatible with local land use policies?
- **Routing and Length of Linear Facilities**—Can linear facilities be routed to the site along existing transmission lines, pipelines, and roads? Will linear facilities be significantly shorter for a given site?
- **Visual Resources**—Are there significant differences between the sites in their potential for impact on significant or protected viewsheds?

- **Biological Resources**—Would there be significant impacts on wetlands or threatened or endangered species?
- **Noise**—Is the site sufficiently near a sensitive receptor area such that it would be difficult to mitigate potential noise impacts below the level of significance?
- **Use of Previously Disturbed Areas**—Has the site been previously disturbed? Does the site minimize the need for clearing vegetation and otherwise present low potential for impact on biological and cultural resources?

6.4.1 Project Development Constraints

As indicated in the introductory descriptions of each of the alternative sites, the basic needs of power plant siting for land and access to electrical transmission, gas supply, and water are met with the MREC using a relatively short generator tie-line and gas and water supply pipelines.

The Chase site would require a generator tie-line of 12 to 18 miles, depending on the route and destination chosen, assuming a tie-line that connects to either the Moorpark or Santa Clara substation. This site would require a process water pipeline of approximately 7.3 miles. These distances are significantly longer than those required for the MREC site. The gas supply line to the Chase site would be 0.9 miles, somewhat shorter than for MREC.

The Vulcan site would require offsite linears to connect to gas, transmission, and water equivalent to or shorter than those required for the MREC site. A generator tie-line route to the Santa Clara Substation would be approximately 5.3 miles long, a process water supply line to Limoneira Company's recycled water supply pipeline would be 1.7 miles long, and natural gas is available at high pressure adjacent to the site in Los Angeles Avenue.

The Camino Real site would require a generator tie-line of 12 to 15 miles, and a water supply line of 6 to 9 miles. The distance to a high pressure natural gas line from this site is 1.1 miles.

The Petrochem site would require a generator tie line of more than 7 miles to the Santa Clara substation or a 3.5-mile-long generator tie line to the Casitas substation. Natural gas is available adjacent to the site. Recycled water is likely available from the City of Ventura, via an 8.5-mile-long pipeline route.

6.4.2 Air Quality

The plant's configuration and operation would be essentially the same from an air quality perspective at each location. These sites are all in the same air district (VCAPCD) and offsets acquired by MREC would be equally appropriate for each site. The type and quantity of air emissions from the alternative sites would be identical. The impacts on the human population and the environment may differ slightly because of the location of residences and other human uses in the project vicinity. The MREC site is located 941 feet from the nearest residence, but there are only a handful of residences within 1 mile of the site. The Chase site also has few residences within 1 mile as it is surrounded by agricultural and industrial uses including oil fields. The Vulcan site is approximately 2,200 feet from the nearest residence, but this residence is part of a suburban neighborhood of Ventura/Saticoy, and there is a large number of residences with 1 mile of the Vulcan site, on the order of several hundred. The Camino Real site is approximately 1,600 feet to the nearest residence, an isolated farmstead, and is 0.4 miles from dense residential development. A medical facility, considered a sensitive land use because of the potential concentration of elderly people and those with medical conditions, is very close to this site at approximately 250 feet from its northern boundary. The Petrochem site is 500 feet or less from several isolated residences and 800 feet or less from two large areas of dense residential development.

6.4.3 Biological Resources

Special-status species recorded, or potentially occurring in the region, are generally the same for all sites. Four of the five are currently developed sites that would not destroy or damage wildlife habitat, although the Chase site has agricultural and open lot areas that could be used by wildlife. The Camino Real site is in agriculture. The MREC site is entirely paved and the Vulcan site is occupied by aggregate storage piles and processing equipment. In terms of adjacent habitat, the MREC and Vulcan sites are similar in that they are near to the Santa Clara River floodplain, and important wildlife habitat area and corridor. The Petrochem site is adjacent to the Ventura River riparian corridor and floodplain.

Generator tie-line routes for each site include mostly developed or agricultural areas and some undeveloped area that is hilly, grazing land, covered in chaparral or coastal sage scrub. One of the Chase site generator tie-line options that would interconnect with the Moorpark Substation would involve more than 8 miles of routes in undeveloped areas, with resulting impacts to natural habitats. An alternate route would mostly avoid these areas. The Petrochem generator tie-line route to the Santa Clara substation would also cross undeveloped areas. Each of the sites could involve construction across and through coastal sage scrub and riparian habitats, but would not have a permanent surface footprint in these areas (other than transmission tower bases).

Generally speaking, the largest potential for impacts to biological resources appears to be the potential for construction and operation to disrupt the nesting of listed birds in the Santa Clara and Ventura River floodways, such as the least Bell's vireo and Southwest willow flycatcher. This potential impact applies to the MREC, Vulcan, and Petrochem sites, but not the Chase or Camino Real sites, which are not located adjacent to a floodplain. The Chase and Petrochem sites currently provide habitat for the burrowing owl, however, unlike the other sites.

6.4.4 Cultural Resources

There are no known significant cultural resources at the MREC site. Resources of the other three sites are unknown. The MREC, Vulcan, and Petrochem sites have moderate to high sensitivity because of their location adjacent to the Santa Clara River. Sensitivity of the Chase and Camino Real sites are somewhat less as they are located in the Oxnard Plain and not near key drainages or other landforms that would be attractive to prehistoric settlement. The MREC, Vulcan, and Camino Real site generator tie-line routes that extend to the Santa Clara substation would run through a locally designated (Ventura County) historical district, the Santa Clara Valley of Ventura County Historic District. Although this district has been found to meet the criteria for listing in the NRHP, it has not been formally listed in the register. Properties that contribute to the district include agricultural parcels, mostly in orchard and row crops, and farmsteads and utility structures building between 1860 and 1945. The district includes several thousand acres of contributing parcels and 220 contributing buildings and encompasses most of the Santa Clara Valley between Santa Paula and Saticoy/Ventura. The potential effects of the generator tie-line routes from the Vulcan and Camino Real sites on the district have not been determined, but it is reasonable to assume that the lines would be able to avoid direct effects to the contributing properties.

6.4.5 Geological Resources and Hazards

There are no significant differences in terms of geological hazards present at each site. The Vulcan site is designated by county zoning overlay as a Mineral Resource Protection area, as it serves as a source of construction aggregates.

6.4.6 Hazardous Materials Handling

There would be no significant difference between the site locations in terms of hazardous materials handling. The uses of hazardous materials would be the same for any of the sites.

6.4.7 Land Use and Agriculture

The three sites are all located within Ventura County. The MREC, Vulcan, and Petrochem sites are in unincorporated areas and the Chase and Camino Real sites are within the City of Oxnard. The General Plan land use designation, zoning designation, and current land use of the sites are shown in Table 6.4-1.

Table 6.4-1 Land Use Designations and Uses

Site	General Plan Land Use Designation	Zoning District	Current Land Use
MREC	Mission Rock Road Existing Community	M3-General Industrial, 10,000 square feet minimum lot	RV and boat vehicle storage
Chase	Light Industry	M1-Light Manufacturing/ Planned Development	Plant nursery and cement batch plant
Vulcan	Open Space	OS – Open Space /MRP – mineral resources protection overlay, 80-acre minimum lot	Aggregate building materials processing and storage
Camino Real	Light Industry	M1-Light Manufacturing/ Planned Development	Agricultural row crops (strawberries)
Petrochem	Existing Community/Urban reserve	M3-General Industrial, 10,000 square feet minimum lot	Unused, former industrial site

MREC—The MREC zoning designation allows for power generation, although the Ventura County Zoning Ordinance table of permitted uses does not mention power generation (other than renewable sources). The zoning ordinances states:

> *The M3 Zone, as the heaviest manufacturing zone, is intended to provide for uses involving the kinds of processes, activities and elements which are specifically excluded from the M1 Zone* (Ventura County Ordinance Code, Division 8, Chapter 1, Section 8104-5.3).

There is no specified height limit for this zone unless the property is less than 100 feet from a residential zone, which the MREC site is not.

Chase Site—The Chase site is located in the City of Oxnard's Light Industrial land use designation area and is zoned M1 (Light Manufacturing). Power generation is not among the list of permitted uses for this zone in the City's zoning code, although "Electrical transmission and distribution substations" is a permitted use. Power generation is not explicitly prohibited in this zone. It is, however, mentioned in the zoning code as a permitted use in the City's M2 (Heavy Manufacturing) zone, as "Steam electric generating stations operated by gas or fuel oil." This wording would appear to exclude simple-cycle gas-fired power plants lacking a steam turbine generator, but this may simply reflect a time period when simple-cycle peaking plants were uncommon for utility use. All developments in the M1 zone require a Special Use Permit. There is a height limit of 55 feet, which would require that a variance be granted for the project, which has a stack height of 80 feet.

Vulcan Site—The Vulcan site is currently operated as a construction aggregates processing and supply business. The site is located adjacent to the Santa Clara River floodplain and has a General Plan land use designation of Open Space and a zoning designation of Open Space with a Mineral Resources Protection overlay. This refers to the mining of sand and gravel for construction aggregates. The Ventura County code includes the following description of this zoning designation:

The **Open Space** designation encompasses … any parcel or area of land or water which is essentially unimproved and devoted to an open-space use as defined in this section …

- *Open space used for the managed production of resources, including but not limited to, forest lands, rangeland, agricultural lands not designated agricultural; areas required for recharge of groundwater basins; bays, estuaries, marshes, rivers and streams which are important for the management of commercial fisheries; and* ***areas containing major mineral deposits*** *(emphasis added), including those in short supply* (Ventura County Ordinance Code, Division 8, Chapter 1, Section 8104-5.3, emphasis added).

Power generation does not appear to be a permitted use in the Open Space zone. The use of the Vulcan parcel for a power plant may conflict with its designation as a Mineral Resource Protection area as well, although the Vulcan parcel is 55 acres in size, and could possibly accommodate both power plant and construction aggregates processing uses. In addition, under the terms of the County's Save Open Space and Agricultural Resources (SOAR) initiative, siting a power plant in Open Space zone would require a popular vote.

Camino Real Site—The Camino Real site is located in the City of Oxnard's Light Industrial land use designation area and is zoned M1 (Light Manufacturing). As stated for the Chase site, power generation is not among the list of permitted uses for this zone in the city's zoning code, although "Electrical transmission and distribution substations" is a permitted use. Also as with the Chase site, there is a height limit of 55 feet, which would require a zoning standard variance be granted for the project, which has a stack height of 80 feet.

Petrochem—The Petrochem site is also in the Ventura County M3 (General Industrial) zone. The site is more than 100 feet from a residential zone, so the height limit would not apply

Agricultural Land Conversion—The MREC site and the southern half of the Chase site are classified as urban land and the Vulcan site is classed as other land (not agricultural or urban). The northern half of the Chase site and all of the Camino Real site are classified as Farmland of Statewide importance. The Chase and Camino Real sites would therefore involve conversion of agricultural land, although within the urban limit line of the City of Oxnard and in a location planned and zoned for light industry.

6.4.8 Noise

The MREC is located approximately 940 feet from the nearest residence and approximately 1,125 feet from a second residence.

At the Chase site, the nearest residences are approximately 600 and 800 feet, respectively, from the northern boundary of the site. From the southern half of the site, the nearest residences are 995 and 1,100 feet, respectively, from the parcel. The Chase parcel covers 25 acres, thus a 10-acre project could be sited on the northern or southern half of the parcel.

Residential uses border the Vulcan parcel to the southeast with the nearest residence approximately 100 feet from the parcel boundary. This property covers 55 acres, thus it is possible the power plant could be sited within this parcel at its northern end, approximately 2,000 feet from the nearest residence. Dense suburban residential development is located across the Santa Clara River floodplain, approximately 2,000 feet to the north and west.

There is an isolated rural residence approximately 1,600 feet from the Camino Real site. A dense suburban residential area is approximately 0.4 miles to the northwest. The area is on the opposite side of the US 101 Freeway, such that the noise from the project may not contribute much to the already high ambient noise near this roadway. It is more problematic that a medical facility and church, which are noise-sensitive land uses, are located only 350 and 500 feet to the north, respectively, in the Camino

Real Industrial Plaza. Siting the facility in the southeastern corner of the parcel could help in this regard to increase the distance from the power plant equipment that produces the most noise.

The Petrochem site is close to a number of residential uses. Isolated rural residences are located across State Route 33 at distances of 380, 520, and 530 feet, respectively. Dense residential developments are located to the southeast at 800 feet and northeast at 580 feet. These close distances would be problematic, but could be mitigated to some extent by positioning the power plant on the western portion of this large parcel. Doing so could increase the possibility of land use conflicts with the recreational trail and riparian corridor to the west of the site, however.

6.4.9 Paleontology

There would be no significant difference among the sites in terms of potential effects on paleontological resources. The probability of encountering significant fossils is approximately the same at each site.

6.4.10 Public Health

As discussed in Section 6.4.2, Air Quality, the plant's configuration and operation would be essentially the same from an air quality perspective at each location. The project and the alternative sites would not likely cause significant adverse long-term health impacts (either cancer or non-cancer) from exposure to toxic emissions, regardless of the site chosen.

6.4.11 Socioeconomics

All three sites are located in Ventura County. The number of workers, construction costs, payroll, and property tax revenues would be nearly the same for the project at each site. Most of the workers would come from Ventura County and would commute daily or weekly to the plant site. Some may move temporarily to the local area during construction, thus causing site-specific impacts on schools, utilities, and emergency services. These impacts would be temporary. As discussed in Section 6.4.2, Air Quality, and Section 6.4.10, Public Health, the project and the alternative sites would not have any potentially significant human health effects.

6.4.12 Soils

Neither the use of the MREC, Vulcan, or Petrochem sites would involve the conversion of agricultural land to utility uses. The Chase (northern half) and Camino Real sites are classified as Farmland of Statewide Importance and so would involve the conversion of important farmland. Both sites are within the City of Oxnard, however, on land zoned for industrial purposes.

Differences in soil erosion would be inconsequential, given proper use of BMPs during construction and operation.

6.4.13 Traffic and Transportation

None of the sites are underserved by transportation facilities. Therefore, the construction and operations traffic and transportation considerations are not a major consideration in evaluating or comparing the sites.

6.4.14 Visual Resources

The potential for visual resource impacts associated with each site varies depending on the relative visibility of the sites from roads and residences and the length and potential visibility of any new transmission lines that the power plant would require. Visual impacts are also a function of the surrounding facilities.

The MREC will be visible from within the Mission Rock Industrial area. It will also be visible from SR-126, which has a relatively high volume of traffic, but at a distance of approximately half a mile, will not be prominent in the view. There are few residential or recreational viewers near the site. Four residences are within or near the industrial area, but they are non-conforming uses in this area and their views of the MREC site are blocked by high fences that surround the individual businesses in the industrial park. There is open space in the Santa Clara River floodplain area to the southeast. Much of this area is owned by TNC and is managed for conservation, not recreation. Although guided tours are held a few times a year, the number of viewers is low and the MREC would be barely visible over the tops of the existing row of trees where there is a line of sight from the floodplain trails.

The Chase site is located relatively near rural residences along Sturgis Road and East Fifth Street, but these are few in number. The nearest densely developed residential area is 1.6 miles away and, at this distance, the facility would not be dominant in the viewshed. Surrounding uses include light industrial and warehousing.

The project at the Vulcan site would be somewhat prominent in views from residential areas. Dense suburban residential areas in Ventura are located approximately 2,100 feet to the northwest. Siting the CTGs and stacks on the property would not reduce this distance, though siting further north on the property would increase the distance to the nearest residences and apartment complexes. Siting further north would also shorten the distance to another set of receptors, travelers on State Route 118/232 (Los Angeles Avenue) as they enter or exit the Saticoy area of Ventura. There are also rural residences in the parcel adjacent to the south. Recreational viewers would include users of the linear park between the Santa Clara River floodplain and the residential areas, which begins approximately 3,600 feet from the nearest part of the Vulcan parcel. These are considered sensitive viewers.

The Camino Real site is located relatively near rural residences along West Ventura Road. The nearest densely developed residential area is the community of Nyeland Acres, approximately 2,200 feet to the northwest. The project facilities would be visible from the US 101 frontage road by residents leaving the community in this direction, but the facility would not be dominant in the viewshed at this distance and there would be some blockage by the elevated freeway overpass. Users of the Camino Real Industrial Plaza would have a relatively unobstructed view of the facility, from 250 to 750 feet away, but a business park/industrial park is not considered a sensitive land use from a visual resources point of view.

The Petrochem site is located on the floodplain of a relatively narrow canyon of the Ventura River in a location where viewshed quality is relatively high. A power generation facility at this site would be very visible from SR-33, which is the main artery from Ventura north to the Ojai area, from isolated residences and dense residential communities to the east of the site, and to users of the Ventura River/Ojai Valley bicycle/pedestrian trail, which runs adjacent to and borders the site to the west. In this setting, the power plant could potentially have an adverse impact to visual resources, from the point of view of residential and recreational viewers, who are considered sensitive viewing populations. If a power plant at this site were to interconnect with the Casitas substation, the route would extend north along the Ventura River riparian corridor and would likely raise objections in terms of visual resources impacts.

6.4.15 Water Resources

Similar to the proposed MREC site, each alternative site would require the same amount of water for process use, fire protection, and potable water uses (such as drinking water and safety showers). As stated above, tertiary treated water would likely be available at the Chase site through a relatively long (7.3 mile) pipeline and recycled water would be available at the Vulcan site from the same source as proposed for the MREC site, through a relatively short (1.7 mile) pipeline, and at the Camino Real site via a 6.6 mile pipeline to the same source as MREC. For the Petrochem site, an 8.5-mile-long pipeline would be necessary.

6.4.16 Waste Management

The same quantity of waste will be generated at the proposed site as at all alternative sites. The environmental impact of waste disposal would not differ significantly among the alternative sites.

6.4.17 Summary and Comparison

Although each of the alternative sites is feasible and could likely meet most of the basic project objectives, the MREC site is the preferred alternative for a variety of reasons.

The Chase site would be a suitable site except that it is not clear whether the City of Oxnard would agree that power generation is a permitted use in the Light Manufacturing zoning district. If not, a rezone would be required. Also, the distance necessary for a generator tie-line from the Chase site to the nearest 230 kV-capable substation would be an obstacle for this site because feasibility of routing is uncertain, and a long routing may be cost prohibitive.

The Vulcan site is also a brownfield site, and would not require long linears. However, the Open Space zoning and Mineral Resource Protection zoning overlay would clearly not permit a power plant to be sited there without both zoning and overlay changes. In addition, this site is located relatively near (0.5 mile) dense suburban residential areas and the project as viewed from the linear park along the Santa Clara River might be considered to cause a significant visual impact.

The Camino Real site is a greenfield site, but is in an area zoned for industry. As with the Chase site, the Camino Real site is zoned for light industry and it is not clear from the Oxnard zoning ordinance whether or not power generation is a permitted use in this zone. This site is near to sensitive uses, including a medical center and church in one direction, and is surrounded by agricultural areas in the other three directions.

The Petrochem site is a brownfield site, and is in an area zoned for industry and would require relatively long linears. This site is very near to dense residential developments and a regional recreational trail. In addition, the site and surrounding area have been the focus of previous unsuccessful development efforts. Since there appears to be no consensus as to the type of development preferred, if any, the success of a power generating facility development at this location seemed unlikely.

Taken all together, the MREC site best meets the basic project objectives without resulting in any adverse environmental impacts as compared to the other sites. Table 6.4-2 compares the MREC and alternative sites in light of the key project objectives and environmental factors.

Table 6.4-2 Comparison of the Proposed Site and Alternative Site Locations

Characteristic	MREC	Alternative 1 Chase	Alternative 2 Vulcan	Alternative 3 Camino Real	Alternative 4 Petrochem
Ability to gain site control	Yes	Unknown	Unknown	Unknown	Unknown
Availability of sufficient land area	Yes	Yes	Yes	Yes	Yes
Proximity to existing 230 kV substation	6.6 miles	12 miles	4.4 miles	10.5 miles	7/3.5 miles
Distance to recycled water supply source	1.8 miles	1.7 miles	2.0 miles	6.6 miles	8.5 miles
Distance to natural gas supply	2.4 miles	0.9 mile	0.1 mile	1.1 miles	0.1 mile
Land use consistent with County/City General Plans and Zoning	Yes	Unknown	No	Unknown	Yes

Table 6.4-2 Comparison of the Proposed Site and Alternative Site Locations

Characteristic	MREC	Alternative 1 Chase	Alternative 2 Vulcan	Alternative 3 Camino Real	Alternative 4 Petrochem
Proximity to nearest residence	940 feet	575 feet	100 feet	1,625 feet	380
Potential presence of Threatened and Endangered Species and Habitat	Moderate	Low	Moderate	Low	Moderate
Potential for buried archaeological resources	High	Low	High	Low	High
Potential noise impacts	Moderate	Moderate	Moderate	Moderate/High	High
Potential visual impacts	Low	Low	Moderate/High	Moderate	High
Potential soils/agricultural impacts	Low	Moderate (dependent on micro-siting)	Low	High	Low

6.5 Alternative Project Design Features

This subsection addresses alternatives to some of the MREC design features, such as the linear facility routing, interconnection location, and water supply source.

6.5.1 Alternative Linear Facility Routing

This subsection addresses alternative linear facility routing for the proposed natural gas supply pipeline, electrical transmission line, and water supply pipeline.

6.5.1.1 Natural Gas Supply Pipeline Route Alternatives

The MREC facility will connect to SoCalGas's existing high-pressure natural gas pipeline 404/406 through a new pipeline extending approximately 2.4 miles from the site extending south along Shell Road and west to the Southern Pacific Railroad tracks and then south again along the railroad right-of-way to the interconnection point. An alternative routing would be for the pipeline to exit the Mission Rock industrial area via Mission Rock and Pinkerton Roads, then turn northwest onto Briggs Road, then turn southeast onto Telegraph Road, following Telegraph Road to an intersection point at North Saticoy Avenue, for a total distance of 6.1 miles. This route requires a crossing of U.S. Highway 101. The railroad route is preferred because of the much shorter distance and much lower construction cost. This route would also avoid disrupting local traffic on Biggs and Telegraph roads during construction.

6.5.1.2 Electrical Transmission Line Route Alternatives

The facility will connect to SCE's 230-kV Santa Clara Substation via a new approximately 6.6-mile-long transmission line. The route chosen appears to be the most feasible to connect with the Santa Clara Substation. Other routes are possible, but would involve approximately the same combinations of agricultural land and undeveloped upland. More direct routes to the substation would be more than 6 miles long and would involve routing having the potential to disrupt agricultural operations, or routing along major roadways such as Foothill Road, or routings adjacent to suburban residential areas. For these reasons, the proposed route is preferred. The approach to the Santa Clara Substation from the north is necessitated by the need to connect with the substation's 230 kV bus and also to avoid crossing existing transmission lines approaching the substation.

Routing to the nearest alternative substation with 230 kV capability, the Moorpark Substation is also possible. A generator tie-line to the Moorpark Substation would run south from the MREC site and over the adjacent range of hills and from there along SR-118 to Moorpark and would be more than 14 miles long. To avoid TNC's nature preserve, which encompasses the adjacent hills, would likely require an even longer line. A route around the hills to Moorpark would extend to the southwest to SR-118 (Los Angeles Avenue) and would follow this roadway to Moorpark Substation, for a distance of 17.6 miles. This route runs mostly through agricultural areas, but passes near some developed, urban areas in Saticoy, Somis, and Moorpark.

6.5.1.3 Water Supply Pipeline Route Alternatives

The facility will connect via a new 1.7-mile water supply line from the Limoneira Company's existing recycled water pipeline which currently serves orchard irrigation. The proposed water supply line runs directly to the interconnection point across agricultural fields, and is co-located along most of the line with the route of the generator tie-line. A route co-located with the natural gas supply pipeline would also be feasible and would extend for approximately 2.2 miles to the Limoneira Company pipeline. The proposed route is the shortest and least expensive available.

6.5.2 Interconnection Alternatives

Two interconnection options near the MREC site were considered. The proposed interconnection location is SCE's 230-kV Santa Clara Substation, located approximately a direct distance of 4.4 miles west of the MREC site. Alternate interconnection options for 230 kV interconnection include the Moorpark and Casitas substations. As stated above, a routing to Moorpark would need to be 14 to 18 miles long. The Casitas Substation is an additional 8.2 miles in direct distance beyond the Santa Clara Substation, over almost entirely rugged terrain. A feasible generator tie-line route to this location from MREC would need to be more than 14 miles long.

The two remaining substations with 230-kV capability are located at existing power plants. It is assumed the substations located there are scaled to fit the input power and would not have capacity to accept additional power. One of these is the Mandalay Substation, which is approximately 11 miles direct distance from the MREC. The Ormond Beach Substation is nearly 13 miles from MREC, but a generator tie-line to that location would be a few miles longer.

Each of the alternate interconnection alternatives would thus require construction of significantly longer tie-in transmission lines, with greater potential environmental impacts based on greater length and additional terrain crossed. Therefore, the proposed interconnection at Santa Clara Substation is preferred to minimize potential environmental impacts and achieve the basic project objectives for the MREC.

6.5.3 Water Supply Source Alternatives

The MREC has incorporated cost-effective water conservation features into the project design to minimize the use of water and has arranged with Limoneira Company to purchase recycled water from its treatment plant for power plant process use.

Alternatively, recycled water could be procured from the City of Santa Paula's Water Recycling Facility, which uses a membrane bioreactor-based design and is capable of producing 3.4 mgd (expandable to 4.2 mgd) of recycled water. Availability of this water is currently unknown. A pipeline to the city's recycled water facility would be approximately 2.5 miles long, and cross agricultural areas and the Mission Rock industrial area.

6.6 Technology Alternatives

6.6.1 Generation Technology Alternatives

Selection of the power generation technology focused on those technologies that are optimized for peaking power generation and to use natural gas readily available from the existing distribution system. The following is a discussion of the suitability of such technologies for application to the MREC.

6.6.1.1 GE LM6000

The GE LM6000 PG combustion turbine technology was selected primarily because it is proven, reliable equipment that also provides operational flexibility. The configuration of five LM6000 PG units provides a well proven technology that is flexible in operation, efficient, cost effective, and easily dispatchable. The factors considered in selecting four LM6000 units included the following:

- High reliability/availability – The LM6000 gas generator has an overall reliability of 99.42 percent and package availability of 98.36 percent, based on GE data.
- Low equivalent forced outage rate – The LM6000 had an equivalent forced outage rate of 1.43 percent from November 2004 to July 2007.
- Mission Rock's parent company, Calpine, owns and operates a fleet of 20 LM6000s, including 15 LM6000 units in peaking service in California. Operation and maintenance advantages will accrue to the MREC by maintaining consistency with Calpine's fleet of LM6000 units.
- The LM6000 configured at 275 MW has the significant advantage of shaft redundancy. Because there will be five CTGs, the plant can ramp up to full load with minimal air emissions by successfully starting the CTGs and ramping them up to full load quickly. The units can also be shut down successively to follow reduced load.

6.6.1.2 GE LMS100

The GE LMS100 combustion turbine technology was also considered for MREC. Based on the nominal 100 MW output of these units, either 200 MW (two units) or 300 MW (three units) configurations would be feasible to achieve the desired output for MREC. Using the LMS100 turbines, however, would reduce the ability to operate at varying low loads at the optimal full-load heat rate for each unit. Partial loading of larger turbines would decrease operating efficiency and increasing emissions of GHGs per MW of generation. With the proposed LM6000 configuration, MREC will have five optimal operating points between 0 and 275 MW rather than only two or three with an LMS100 configuration. In addition, because it uses intercooler technology, the LMS100 would require significantly more water to operate, and a large cooling tower or air-cooled condenser structure.

6.6.1.3 Large Frame Industrial Turbines

Mission Rock considered choosing a large frame industrial turbine for the MREC. Several models are available in the 250 to 300 MW range with 10 or 12 minute startup times. This power output is achieved by using a single-turbine shaft, however, so that the LM6000 advantages of multiple-shaft ramping operation, shaft-redundancy, increased efficiency, and reduced GHG emissions would not be realized. Large frame industrial turbine technology is more appropriate for applications where potential future conversion to combined cycle is a consideration, than for peaking, load-following, and grid support operations. In addition, stack heights for this technology routinely approach 200 feet.

6.6.1.4 Conclusion

The GE LM6000 PG combustion turbine technology is proven, reliable, efficient, cost effective, provides operational flexibility and shaft redundancy while minimizing air emissions, GHGs, and water use. This technology clearly out-performs the others considered in meeting the project's objectives.

6.6.2 Fuel Technology Alternatives

Technologies based on fuels other than natural gas were eliminated from consideration because they do not meet the project objective of providing operationally flexible, dispatchable, quick start, and reliable power. Some of these alternative fuels have potential for additional air quality and public health impacts. Others, like certain biofuels, are not available in commercial quantities or are not available via pipeline or other reliable delivery system. Additional factors rendering alternative fuel technologies unsuitable for the proposed project are as follows:

- Biomass fuel facilities do not provide quick start capabilities and have additional environmental impacts related to air emissions and solid waste generation. Additionally, biomass facilities would require additional acreage, taller structures, and larger quantities of water.
- Coal, fuel oil, and other similar fuels emit more air pollutants and GHGs than technologies utilizing natural gas.

The availability of the natural gas resource provided by SoCalGas, as well as the environmental and operational advantages of natural gas technologies, makes natural gas the logical choice for the MREC.

6.6.3 Cooling Alternatives

MREC is a simple-cycle power plant that does not generate steam that would require a large cooling tower or air-cooled condenser. Therefore, cooling requirements are limited to CTG lubricating oil systems and inlet air cooling. The inlet cooling system and cooling material is discussed in detail in the following subsections. The remainder of this subsection will address the lubricating oil system cooling technology.

The lubricating oil system uses a fin-fan cooler to reduce the temperature of the lubricating oil. This system functions similar to an automobile radiator where the oil is passed through a "radiator" as air is passed through the cooling fins. Heat is removed from the oil and is released to the atmosphere. None of the oil is entrained in the air and no contaminants are released from a fin-fan cooler. Additionally, this type of cooling system does not use water.

6.6.4 Inlet Cooling Alternatives

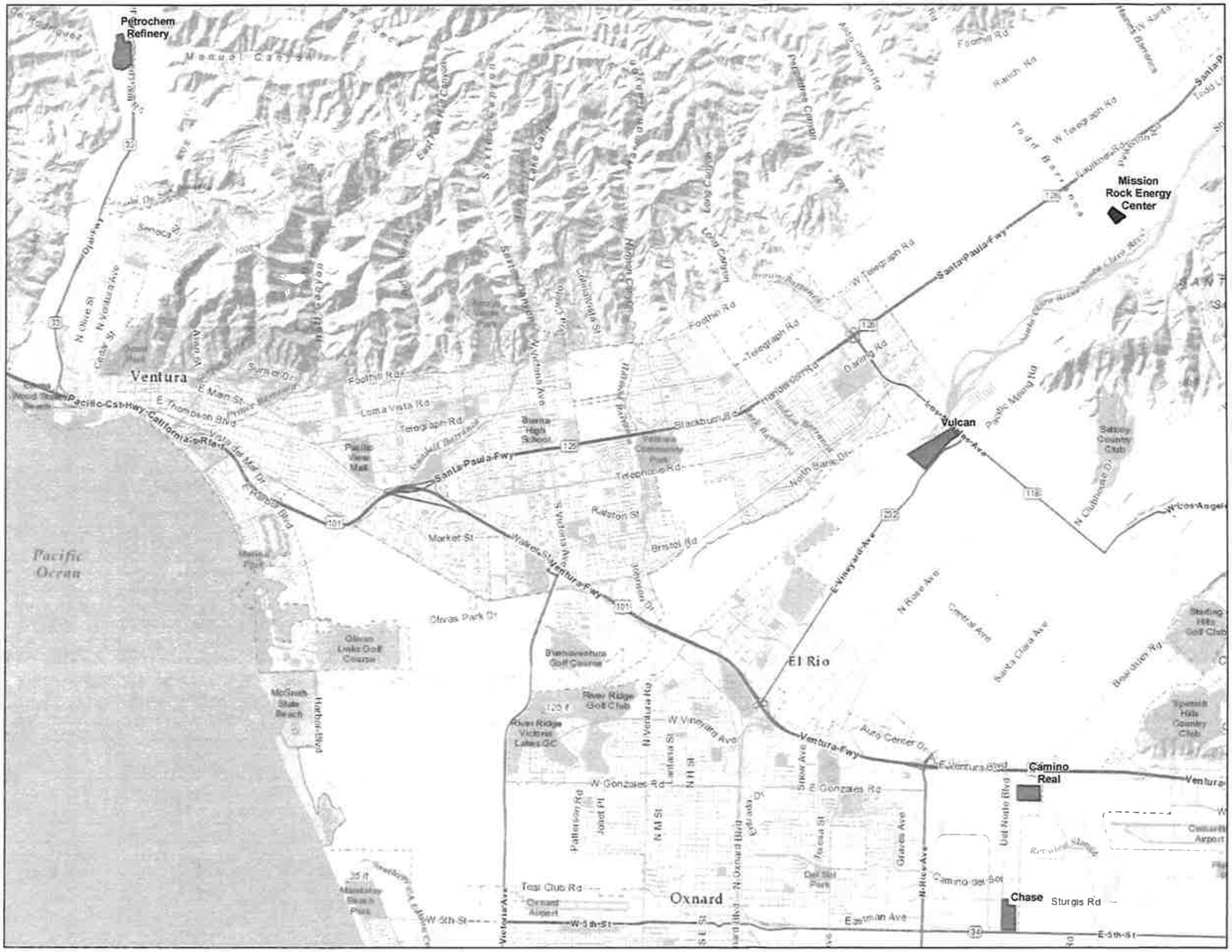
The CTG inlet air cooling can be accomplished using evaporative coolers, foggers, or mechanical chillers. The evaporative cooling system and foggers use water to decrease the inlet air temperature and increase CTG efficiency and electrical generation during warm ambient conditions. An evaporative cooling system uses water evaporation to cool the inlet CTG air. Water is applied to a porous media in the CTG air inlet and as the air passes through the media, water is evaporated, which results in cooling of the air. This system is similar to a residential evaporative (swamp) cooler. A fogger system is similar in principle to the evaporative cooling system, but this system sprays a fine mist of water into the CTG air inlet to result in cooling.

Mechanical chillers use a refrigerant in cooling coils located in the CTG air inlet to cool the air. This system is similar in principle to a residential or commercial comfort cooling system. The refrigerant is reused in the system and advances in refrigerant technology result in very low leak rates for refrigerant systems. Furthermore, most refrigerants are not considered air pollutants. Typical refrigerants include anhydrous ammonia and R134a. While anhydrous ammonia systems have a higher efficiency, they require the use of gaseous phase ammonia.

Water cooling uses less parasitic load and, therefore increases the cycle efficiency, compared with mechanical chillers. Although the quantities of water needed for an LM6000 inlet air cooling system are low, a mechanical chiller system is proposed for MREC to minimize water use. The mechanical chiller will use R134a refrigerant to avoid the use and storage of anhydrous ammonia onsite.

6.7 References

City of Oxnard. 2011. *General Plan 2030. Goals & Policies*. City of Oxnard Development Services Planning Division. Adopted October 2011.



LEGEND
Project Site
Altnerative Sites

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Miles

Figure 6.3-1
Alternative Sites
Mission Rock Energy Center
Ventura County, California

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Appendix K

DOC Conditions

Mission Rock Energy Center

Five (5) GE LM6000-PG-Sprint Combustion Turbine Generators (CTGs)
Total = 275 MW Nominal

Each CTG is simultaneously subject to the emission limits, monitoring requirements, source testing requirements, and recordkeeping and reporting requirements of the following rules and regulations:

Rule 26.2, New Source Review - Requirements

Rule 29, Conditions On Permits

Rule 64, Sulfur Content of Fuels

Rule 74.23, Stationary Gas Turbines

Rule 101, Sampling and Testing Facilities

Rule 102, Source Tests

Rule 103, Continuous Monitoring Systems

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS)

40 CFR Part 60, Subpart A, General Provisions

40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

40 CFR Part 75, Continuous Emissions Monitoring

The following conditions describe and streamline the most stringent requirements of the above rules and regulations. The Ventura County APCD has been delegated authority for 40 CFR Part 60 Subpart KKKK and is considered to be the Administrator.

The Rule 26 BACT NO_x emission limit (2.5 ppmvd at 15% O2) is the most stringent in comparison to the Rule 74.23 NO_x emission limit (9 ppmvd at 15% O2) and the NSPS Subpart KKKK NO_x emission limit (25 ppmvd at 15% O2) at loads above 75% of peak load; therefore the Rule 74.23 and NSPS emission limits are subsumed. However, there are no startup, shutdown, or load change exemption periods from the NSPS Subpart KKKK NO_x concentration limit; therefore, the permittee will need to monitor compliance with the NSPS limit with a 4-hour rolling average NO_x emission rate.

Compliance with the terms of the conditions below for each Mission Rock Energy Center CTG assures compliance with all individual requirements applicable to the

CTG which have been addressed above and below.

1. Prior to completion of construction, the permittee shall submit an application for a Title V Part 70 Permit for the Mission Rock Energy Center. The application shall also include the Title IV Acid Rain Permit application, VCAPCD Permit to Operate application, and all applicable supplementary forms and filing fees. (Rules 10, 33, 34)

2. Prior to operation of the new CTG's, permittee shall surrender NOx Emission Reduction Credits (ERCs) in the amount of 36.57 tons per year. (Rule 26.2)

3. Permittee shall identify the ERC Certificates to be used to satisfy the NOx emission offset requirements above prior to the issuance of the Final Determination of Compliance (FDOC). These NOx ERC Certificates shall comply with the quarterly profile check of Rule 26.2.B.4 and Rule 26.6.F. (Rules 26.2 and 26.6)

4. The combustion turbine generator (CTG) lube oil vents and the electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents to no greater than 5% opacity, except for no more than three minutes in any one hour. (Rule 26.2)

5. Each CTG shall be operated with a continuously recording fuel gas flowmeter. The flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, a gas fuel flowmeter that meets the installation, certification, and quality assurance requirements of Appendix D to 40 CFR Part 75 is acceptable for use. (Rules 26.2 and 74.23, 40 CFR Part 60 Subpart KKKK and 40 CFR Part 75)

6. Each CTG exhaust after the SCR (selective catalytic reduction) unit shall be equipped with continuously recording emissions monitors (CEM) for NOx, CO, and O2. Continuous emissions monitors shall meet the requirements of Rule 74.23, Rule 103, 40 CFR Part 60, Appendices B and F, 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75, Appendices A and B, as applicable, and shall be capable of monitoring emissions during startups, shutdowns, and unplanned load changes as well as normal operating conditions. (Rules 74.23 and 103, 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75)

7. CEM cycling times shall be those specified in 40 CFR Part 60, Subpart KKKK and 40 CFR, Part 51, Appendix P, Sections 3.4, 3.4.1 and 3.4.2, or shall meet equivalent specifications established by mutual agreement of the VCAPCD, the ARB and the EPA. For NOx monitoring for 40 CFR Part 60 Subpart KKKK, during each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NOx emission rate for the hour. (Rule 103 and 40 CFR Part 60 Subpart

KKKK)

8. The exhaust stack of each CTG shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during VCAPCD inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. (Rules 74.23, 101, and 102)

9. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR Part 60, Subpart KKKK, 40 CFR Part 75 Appendix F, and 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the VCAPCD, the ARB, and the EPA. (Rule 103, 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75)

10. In accordance with the applicable sections of 40 CFR Part 60 Appendix F, the CO CEMS shall be audited at least once each calendar quarter by conducting cylinder gas audits (CGA) or relative accuracy audits (RAA). CGA or RAA may be conducted during three of four calendar quarters, but no more than three calendar quarters in succession. The NOx and O2 CEMS shall be audited in accordance with the applicable requirements of 40 CFR Part 75. The VCAPCD shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the VCAPCD upon request. (Rule 103, 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75)

11. For the CO CEMS, the permittee shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F at least once every four calendar quarters. For the NOx and O2 CEMS, the permittee shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 75, Appendix B at least once every two calendar quarters unless the permittee achieves 7.5% or below relative accuracy. If the permittee meets the incentive of 7.5% or better relative accuracy, then the permittee shall perform a RATA once every four calendar quarters. For the CO CEMS, the permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. (Rule 103, 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75)

12. The permittee shall report any violation of the NOx and CO emissions limits of this permit, as measured by the CEMS, in writing to the VCAPCD within 96 hours of each occurrence. (Rule 103)

13. The permittee shall maintain permanent continuous monitoring records, in a form suitable for inspection, for a period of at least five (5) years. Such records shall be made available to the Air Resources Board or the VCAPCD upon request. The report shall include the following:

    Time intervals of report,

The date, time and duration of any startup, shutdown or malfunction in the operation of the gas turbines and CEMS,

The results of performance testing, evaluations, calibrations, checks, adjustments, and maintenance of the CEMS,

Emission Measurements,

Net megawatt-hours produced, and

Calculated NOx emission limit of 40 CFR Part 60, Subpart KKKK. (Rule 103)

14. Upon written request of the APCO, the permittee shall submit a written CEM report for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following:

Time intervals of report,

The date, time, duration and magnitude of excess emissions of NOx and/or CO, the nature and cause of the excess (if known), the corrective actions taken, and the preventive measures adopted,

The averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard,

The date, time and duration of each period during which the CEMS was inoperative, except for zero and span checks, and a description of the system repairs and adjustments undertaken during each period, and,

A negative declaration when no excess emissions occurred. (Rule 103)

15. For the purposes of 40 CFR Part 60, Subpart KKKK, excess emissions shall be defined as any unit operating period in which the 4-hour rolling average NOx concentration exceeds the applicable concentration limit, or alternatively as elected by the permittee, the 4-hour rolling average NOx emission rate exceeds the applicable lb/MWh emissions rate limit, as defined in Part 60.4320, Table 1. The 4-hour rolling average NOx concentration limit for any operating hour is determined by the arithmetic average of 25 ppmvd at 15% O2 for each hour in which the unit operated above 75% of peak load for the entire hour, and 96 ppmvd at 15% O2 for each hour in which it did not. The 4-hour rolling NOx lb/MWh emission limit for any operating hour is determined by the arithmetic average of 1.2 lb/MWh for each hour in which the unit operated above 75% of peak load for the entire hour, and 4.7 lb/MWh for each hour in which it did not. The 4-hour rolling average is the arithmetic average of the average NOx concentration in ppm measured by the CEMS for a given hour (corrected to 15 percent O2) or lb/MWh if elected by the permittee, and the average NOx concentrations or lb/MWh emission rates during the three unit operating hours immediately preceding that unit operating hour. A period of monitor downtime shall be

any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx or O2. (40 CFR Part 60 Subpart KKKK)

16. For the purposes of 40 CFR Part 60, Subpart KKKK, the permittee shall submit reports of NOx excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c) on a semi-annual basis. In addition, permittee shall submit the results of the initial and annual source tests for NOx. All semi-annual reports of excess emissions and monitor downtime shall be postmarked by the 30th day following the end of each six-month period, or by the close of business on the 60th day following the completion of the source test. (40 CFR Part 60 Subpart KKKK)

17. For the purposes of 40 CFR Part 60, Subpart KKKK, if the total duration of NOx excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CEMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form in 40 CFR Part 60.7(d) shall be submitted and the excess emission report described in 40 CFR Part 60.7(c) need not be submitted unless requested by the EPA or the VCAPCD. (40 CFR Part 60 Subpart KKKK)

18. Each ammonia injection grid shall be equipped with operational ammonia flowmeter and injection pressure indicator. All data shall be reduced to hourly averages. (Rule 74.23 and 40 CFR Part 60 Subpart KKKK)

19. Permittee shall monitor and record exhaust gas temperature at the oxidation catalyst inlet and the selective catalytic reduction (SCR) catalyst inlet. All data shall be reduced to hourly averages. (Rule 74.23 and 40 CFR Part 60 Subpart KKKK)

20. Each CTG shall be fired exclusively on natural gas, consisting primarily of methane and ethane, with sulfur content no greater than 0.75 grains of sulfur compounds (as sulfur) per 100 dry scf of natural gas. (Rules 26.2 and 64, 40 CFR Part 60 Subpart KKKK)

21. The natural gas sulfur content shall be: (i) documented in a valid purchase contract, supplier certification, tariff sheet or transportation contract <u>or</u> (ii) monitored weekly using ASTM Methods D4084, D5504, D6228, or Gas Processors Association Standard 2377, or verified using an alternative method approved by the VCAPCD. If the natural gas sulfur content is less than 0.75 gr/100 scf for 8 consecutive weeks, then the Monitoring frequency shall be once every six (6) months. If any six (6) month monitoring shows an exceedance, weekly monitoring shall resume. (Rules 26.2 and 64 and 40 CFR Part 60 Subpart KKKK)

22. <u>Startup</u> is defined as the period beginning with turbine initial firing and ending when the turbine meets the pounds per hour and ppmvd emission limits in Condition No. 29 below for normal operation. <u>Shutdown</u> is defined by the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. <u>Unplanned load change</u> is defined as the automatic release of power from the turbine and the subsequent restart. For an unplanned load change, the loss of power during the release must exceed forty (40) percent of the turbine rating. Startup,

shutdown, and unplanned load change durations shall not exceed 60 minutes (1 hour) for a startup, 60 minutes (1 hour) for a shutdown, and 60 minutes (1 hour) for an unplanned load change, per occurrence. For failed start-ups, each restart shall begin a new exemption period. (Rules 26.2, 29, and 74.23)

23. The CTGs, air pollution control equipment, and monitoring equipment shall be operated in a manner consistent with good air pollution control practice for minimizing emissions at all times including during startup, shutdown, and malfunction. (40 CFR Part 60 Subpart KKKK)

24. The permittee shall submit to the VCAPCD information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the VCAPCD to determine compliance with the NOx emission limits of this permit when the CEMS is not operating properly. (Rules 26.2, 29, and 74.23)

25. The HHV (higher heating value) and LHV (lower heating value) of the natural gas combusted shall be determined upon request using ASTM D3588, ASTM 1826, or ASTM 1945. (Rules 26.2, 29, and 74.23)

26. When a CTG is operating, ammonia shall be injected when the selective catalytic reduction system catalyst temperature exceeds 300 degrees F. Permittee shall monitor and record catalyst temperature during periods of startup. (Rules 26.2 and 74.23)

27. During <u>startup</u> of a CTG, emissions (in pounds = lbs) from each CTG in any one hour shall not exceed any of the following limits:

    ROC = 1.36 lbs,
    NOx (as NO_2) = 11.65 lbs,
    PM10 = 2.00 lbs,
    SOx (as SO_2) = 1.19 lbs, and
    CO = 7.99 lbs

    For the purpose of this condition, all PM10 emissions are assumed to be PM2.5 emissions.

    If the CTG is in startup mode during any portion of a clock hour, the facility will be subject to the aforementioned limits during that clock hour.

    Compliance with the ROC and PM10 emission limits shall be verified by CTG manufacturer's emission data. Compliance with the SOx emission limit shall be verified by complying with the natural gas sulfur content limit of this permit. Compliance with the NOx and CO emission limits shall be verified by continuous emissions monitors (CEMS) as required by this permit. If the CEMS is not operating properly, as required below, the CEMS missing data procedures required by Permit Condition No. 55 shall be implemented. (Rules 26.2, 29, and 74.23)

28. During shutdown of a CTG, emissions (in pounds = lbs) from each CTG in any one hour shall not exceed any of the following limits:

ROC = 1.60 lbs,
NOx (as NO2) = 5.54 lbs,
PM10 = 2.00 lbs,
SOx (as SO2) = 1.19 lbs, and
CO = 6.03 lbs

For the purpose of this condition, all PM10 emissions are assumed to be PM2.5 emissions.

If the CTG is in shutdown mode during any portion of a clock hour, the facility will be subject to the aforementioned limits during that clock hour.

Compliance with the ROC and PM10 emission limits shall be verified by CTG manufacturer's emission data. Compliance with the SOx emission limit shall be verified by complying with the natural gas sulfur content limit of this permit. Compliance with the NOx and CO emission limits shall be verified by continuous emissions monitors (CEMS) as required by this permit. If the CEMS is not operating properly, as required below, the CEMS missing data procedures required by Permit Condition No. 55 shall be implemented. (Rules 26.2, 29, and 74.23)

29. During normal operation of a CTG, emission concentrations and emission rates from each CTG, except during startup, shutdown, and/or unplanned load change, shall not exceed any of the following limits:

ROC = 0.71 pounds per hour and 1.0 ppmvd @ 15% O2,
NOx (as NO2) = 5.10 pounds per hour and 2.5 ppmvd @ 15% O2,
PM10 = 2.00 pounds per hour,
SOx (as SO2) = 1.19 pounds per hour,
CO = 4.97 pounds per hour and 4 ppmvd @ 15% O2,
Ammonia (NH3) = 3.78 pounds per hour and 5 ppmvd @ 15%O2.

For the purpose of this condition, all PM10 emissions are assumed to be PM2.5 emissions.

ROC and NOx (as NO2) ppmvd and pounds per hour limits are expressed as a one-hour rolling average limit. All other ppmvd and pounds per hour limits are three-hour rolling averages. If the CTG is in either startup or shutdown mode during any portion of a clock hour, the CTG shall not be subject to these limits during that clock hour. Startup limits and shutdown limits are listed in the above conditions.

Compliance with the ROC, NOx, PM10, CO, and NH3 emission limits shall be verified by initial and annual source testing as required below. Compliance with the SOx emission limit shall be verified by complying with the natural gas sulfur content limit of this permit. Compliance with the NH3 limits shall also be verified by monitoring the ammonia injection rate as required below. In addition, compliance with the NOx and

CO emission limits shall be verified by continuous emissions monitors (CEMS) as required by this permit. If the CEMS is not operating properly, as required below, the CEMS missing data procedures required by Permit Condition No. 55 below shall be implemented. (Rules 26.2, 29, and 74.23)

30. Emissions rates from each CTG during the commissioning period shall not exceed the following limits in pounds per hour:

    ROC = 3.0 pounds per hour per turbine,
    NOx (as NO2) = 68.0 pounds per hour per turbine, and
    CO = 117.33 pounds per hour per turbine.

    No more than two (2) CTGs shall be operated simultaneously during the commissioning period.

    Emissions rates from all of the CTGs combined during the commissioning period shall not exceed the following limits in tons per year. A year is defined as any twelve (12) month consecutive period.

    ROC = 0.82 tons per year,
    NOx (as NO2) = 10.33 tons per year, and
    CO = 22.14 tons per year.

    The commissioning period is the period of time commencing with the initial startup of the turbine and ending after 213 hours of turbine operation, or the date the permittee notifies the VCAPCD the commissioning period has ended. For purposes of this condition, the number of hours of turbine operation is defined as the total unit operating minutes during the commissioning period divided by 60.

    Compliance with the ROC, NOx and CO emission limits shall be verified by CTG manufacturer's emission data combined with records of commissioning hours. In addition, compliance with the NOx and CO emission limits shall be verified by continuous emissions monitors (CEMS) as required by this permit. If the CEMS is not operating properly, as required below, the permittee shall provide documentation, including a certified source test, correlating the control system operating parameters to the associated measured NOx and CO emissions. (Rules 26.2, 29, and 74.23)

31. Annual emissions from each CTG shall not exceed the following limits in tons per year. A year is defined as any twelve (12) month consecutive period.

    ROC = 0.99 tons per year,
    NOx (as NO2) = 5.62 tons per year,
    PM10 = 2.50 tons per year,
    SOx (as SO2) = 1.48 tons per year, and
    CO = 6.46 tons per year.

    For the purpose of this condition, all PM10 emissions are assumed to be PM2.5 emissions.

These tons per year limits include normal operation, startups, shutdowns, unplanned load changes, and the commissioning period.

Compliance with the NOx and CO emission limits shall be verified with the CEMS. In addition, compliance with the NOx and CO emission limits shall be verified with initial and annual source testing combined with compliance with the CTG's annual operating limit in hours per year.

Compliance with the ROC and PM10 emission limits shall be verified with initial and annual source testing combined with compliance with the CTG's annual operating limit in hours per year.

Compliance with the SOx emission limit shall be verified by complying with the natural gas sulfur content limit of this permit combined with compliance with the CTG's annual operating limit in hours per year. (Rules 26.2 and 29)

32. Each one-hour period in a one-hour rolling average, three-hour rolling average, or four-hour rolling average shall commence on the hour. (Rules 26.2 and 29)

33. Each calendar month in a twelve (12) consecutive calendar month rolling emissions calculation will commence at the beginning of the first day of the month. The twelve consecutive calendar month rolling emissions total to determine compliance with the annual tons per year emissions limits shall be compiled for each and every twelve consecutive calendar month rolling period. (Rules 26.2 and 29)

34. The ammonia (NH3) slip emission concentration limit shall be verified by initial and annual source testing as required below, and by the continuous recording of the ammonia injection rate to the SCR system. The correlation between the gas turbine heat input rate, the SCR system ammonia injection rate, and the corresponding ammonia (NH3) slip emission concentration shall be determined in accordance with required initial and annual ammonia source testing. Alternatively, the permittee may utilize a continuous in-stack ammonia (NH3) slip monitor, acceptable to the VCAPCD, to monitor compliance. At least 60 days prior to using an ammonia (NH3) slip continuous in-stack monitor, the permittee shall submit a monitoring plan to the VCAPCD for review and approval. (Rules 26.2, 74.23 and 103)

35. Within 90 days after the completion of the commissioning period for each combustion turbine, the permittee shall conduct an Initial Emissions Source Test at the exhaust of each turbine to determine the ammonia (NH_3) emission concentration to demonstrate compliance with the ammonia concentration and mass emission rate limits of this DOC. After the initial source test, the NH_3 emissions source test shall be conducted on an annual basis (no less than once every 12 months).

    The source test shall determine the correlation between the heat input rate of the gas turbine, SCR system ammonia injection rate, and the corresponding NH_3 emission concentration at the unit exhaust. NOx emissions at the CEM shall also be recorded during the test. The source test shall be conducted over the expected operating range of the turbine (including, but not limited to, minimum and full load modes) to establish the range of ammonia injection rates necessary to achieve NOx emission reductions while maintaining ammonia slip levels. The permittee shall repeat the source testing on an annual basis thereafter. Ongoing compliance with the ammonia emission concentration limit shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. The permittee shall submit the source test results to the VCAPCD within 45 days of conducting tests. (Rules 26.2, 29, and 74.23)

36. Within 90 days after the completion of the commissioning period for each combustion turbine, the permittee shall conduct an Initial Emissions Source Test at the exhaust of each turbine to demonstrate compliance with the ROC, NOx, PM10, and CO emission limits of Condition No. 29 of this DOC. The source test shall be conducted over the expected operating range of the turbine including, but not limited to, minimum and full load modes. This source test shall demonstrate compliance with the following short term emission limits during normal operation: ROC = 1.0 ppmvd @ 15% O2 and 0.71 pounds per hour, NOx = 2.5 ppmvd @ 15% O2 and 5.10 pounds per hour, PM10 = 2.0 pounds per hour, and CO = 4 ppmvd @ 15% O2 and 4.97 pounds per hour. The permittee shall submit the source test results to the VCAPCD within 45 days of conducting tests.

    After the initial source test, the ROC, NOx, PM10, and CO emissions source testing shall be conducted on an annual basis (no less than once every 12 months). (Rules 26.2, 29, and 74.23)

37. The VCAPCD must be notified 30 days prior to any source test, and a source test plan must be submitted for approval no later than 30 days prior to testing. Unless otherwise specified in this permit or authorized in writing by the VCAPCD, within 45 days after completion of a source test or RATA performed by an independent source test contractor, a final test report shall be submitted to the VCAPCD for review and approval. (Rule 102)

38. The following source test methods shall be used for the initial and annual compliance verification:

    ROC: EPA Methods 18 or 25,
    NOx: EPA Methods 7E or 20,
    PM10: EPA Method 5 (front half and back half) or EPA Method 201A and 202,
    CO: EPA Methods 10 or 10B,
    O2: EPA Methods 3, 3A, or 20,
    Ammonia (NH3): BAAQMD ST-1B.

    For the purpose of this condition, all PM10 emissions are assumed to be PM2.5 emissions.

    EPA approved alternative test methods as approved by the VCAPCD may also be used to address the source testing requirements of this permit. (Rules 26, 29, and 74.23 and 40 CFR Part 60 Subpart KKKK)

39. An initial and annual source test and a periodic NOx and CO Relative Accuracy Test Audit (RATA) shall be conducted on each CTG and its CEMS to demonstrate compliance with the NOx and CO emission limits of this permit and applicable relative accuracy requirements for the CEMS systems using VCAPCD approved methods. The annual source test and the NOx CEMS RATAs shall be conducted in accordance with the applicable RATA frequency requirements of 40 CFR Part 75, Appendix B, Sections 2.3.1 and 2.3.3. The annual source test and the CO CEMS RATAs shall be conducted in accordance with the applicable RATA frequency requirements of 40 CFR Part 60, Appendices B and F. The initial and annual RATA may be conducted during the initial and annual emission source tests required above and shall be conducted in accordance with a protocol complying with all the applicable requirements of an approved source test protocol. (Rule 74.23 and 103, 40 CFR Part 60, and 40 CFR Part 75)

40. Relative Accuracy Test Audits (RATAs) and all other required certification tests shall be performed and completed on the NOx CEMS in accordance with applicable provisions of 40 CFR Part 75 Appendix A and B and 40 CFR Part 60 Subpart KKKK; and on the CO CEMS in accordance with applicable provisions of 40 CFR Part 60 Appendix B and F. (Rules 74.23 and 103, 40 CFR Part 60 Subpart KKKK, 40 CFR Part 60, and 40 CFR Part 75)

41. The permittee shall maintain hourly records of NOx, CO, and NH_3 emission concentrations in ppmvd @15% oxygen. NOx and CO concentrations are measured by the CEM; NH3 emission concentrations are determined and demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of the ammonia injection rate as required above and below. The permittee shall maintain records of NOx and CO emissions in pounds per hour, tons per month, and tons per rolling twelve (12) month periods. (Rules 26.2 and 29)

42. The permittee shall maintain records that contain the following: the occurrence and duration of any start-up, shutdown, unplanned load change or malfunction, performance testing, evaluations, calibrations, checks, adjustments, any periods during which a continuous monitoring system or monitoring device is inoperative, maintenance of any CEM system that has been installed pursuant to VCAPCD Rule 103, and emission measurements. (Rules 74.23 and 103)

43. The APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the monitoring devices required by this permit to ensure that such devices are functioning properly. (Rule 103)

44. The permittee shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, amount of natural gas consumed, and duration of each start-up, each shutdown, and each unplanned load change time period. (Rules 26 and 74.23)

45. All records required to be maintained by this permit shall be maintained for a period of

five years and shall be made readily available for VCAPCD inspection upon request. (Rules 33 and 103)

46. For purposes of determining compliance with emission limits based on source testing, the average of three subtests shall be used. For purposes of determining compliance with emission limits based on a Continuous Emission Monitoring System (CEMS), data collected in accordance with the CEMS protocol shall be used and the averages for averaging periods specified herein shall be calculated as specified in the CEMS protocol. (Rules 26.2 and 74.23)

47. For purposes of determining compliance with emission limits based on CEMS data, all CEMS calculations, averages, and aggregates shall be performed in accordance with the CEMS protocol approved in writing by the VCAPCD. (Rules 26, 74.23, and 103)

48. The number of annual operating hours (including startup and shutdown hours) for each CTG shall not exceed 2,500 hours per year. This limit also includes commissioning hours for each turbine. A year is defined as any twelve (12) month consecutive period.

    In addition to the limit above, the number of startup periods occurring shall not exceed 150 startups per year per turbine and the duration of the startup periods shall not exceed 75 hours per year per turbine. The number of shutdown periods occurring shall not exceed 150 shutdowns per year per turbine and the duration of the shutdown periods shall not exceed 22.5 hours per year per turbine. The limits on startups and shutdowns per year do not include startups and shutdowns during commissioning as the commissioning period has separate and independent emission limits.

    Each CTG shall be equipped with an operating, non-resettable, elapsed hour meter. The permittee shall maintain a log that differentiates normal operation from startup operation, shutdown operation, and commissioning operation. These hours of operation records shall be compiled into a monthly total. The monthly operating hour records shall be summed for the previous twelve (12) months and reported to the VCAPCD on an annual basis. (Rules 26 and 74.23)

49. Not later than 90 calendar days prior to the installation of the selective catalytic reduction (SCR) / oxidation catalyst emission control systems, the permittee shall submit to the VCAPCD the final selection, design parameters and details of the SCR and oxidation catalyst emission control systems for each CTG including, but not limited to, the minimum ammonia injection temperature for the SCR; the catalyst dimensions and volume, catalyst material, catalyst manufacturer, space velocity and area velocity at full load; and control efficiencies of the SCR and the oxidation catalyst at temperatures between 100 ºF and 1000 ºF at space velocities corresponding to 100% and 25% load. (Rules 26.2 and 74.23)

50. Continuous monitors shall be installed on the SCR systems prior to their initial operation to monitor or calculate, and record the ammonia solution injection rate in pounds per hour and the SCR catalyst temperature in degrees Fahrenheit for each unit operating minute. The monitors shall be installed, calibrated and maintained in

accordance with a VCAPCD approved protocol, which may be part of the CEMS protocol. This protocol, which shall include the calculation methodology, shall be submitted to the VCAPCD for written approval at least 90 days prior to initial startup of the gas turbines with the SCR system. The monitors shall be in full operation at all times when a turbine is in operation. (Rules 26 and 103)

51. Except during periods when the ammonia injection system is being tuned or one or more ammonia injection systems is in manual control for compliance with applicable permit conditions, the automatic ammonia injection system serving the SCR system shall be in operation in accordance with manufacturer's specifications at all times when ammonia is being injected into the SCR system. Manufacturer specifications shall be maintained on site and made available to VCAPCD personnel upon request. (Rules 26 and 74.23)

52. The concentration of ammonia solution used in the SCR ammonia injection system shall be less than 20% ammonia by weight. Records of ammonia solution concentration shall be maintained on site and made available to VCAPCD personnel upon request. (40 CFR Part 68)

53. A continuous emission monitoring system (CEMS) shall be installed and operated on each CTG and properly maintained and calibrated to measure, calculate, and record the following, in accordance with the VCAPCD approved CEMS protocol:

    a. Hourly average concentration of oxides of nitrogen (NOx) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the NOx limits of this permit;
    b. Hourly average concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the CO limits of this permit;
    c. Percent oxygen (O2) in the exhaust gas averaged over each operating hour;
    d. Hourly mass emissions of oxides of nitrogen (NOx) calculated as NO2, in pounds;
    e. Cumulative mass emissions of oxides of nitrogen (NOx) calculated as NO2 in each startup and shutdown period, in pounds;
    f. Daily mass emissions of oxides of nitrogen (NOx) calculated as NO2, in pounds;
    g. Calendar monthly mass emissions of oxides of nitrogen (NOx) calculated as NO2, in pounds;
    h. Rolling 1-hour average and rolling 4-hour concentration of oxides of nitrogen (NOx) corrected to 15% oxygen, in parts per million (ppmvd);
    i. Rolling 1-hour average and rolling 4-hour average of oxides of nitrogen (NOx) calculated as NO2 emission rate, in pounds per megawatt-hour (MWh);
    j. Calendar month, calendar year, and rolling twelve (12) calendar-month period mass emissions of oxides of nitrogen (NOx), in tons;
    k. Hourly mass emissions of carbon monoxide (CO), in pounds;
    l. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds;
    m. Daily mass emissions of carbon monoxide (CO), in pounds;
    n. Calendar monthly mass emissions of carbon monoxide (CO), in pounds;
    o. Calendar month, calendar year, and rolling twelve (12) calendar-month

period mass emissions of carbon monoxide (CO), in tons;

p. Average concentration of oxides of nitrogen (NOx) and carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), averaged over each unit operating hour;
q. Average emission rate in pounds per hour of oxides of nitrogen (NOx) calculated as NO2 and pounds per hour of carbon monoxide (CO) during each unit operating hour.

(Rules 26, 29, 74.23, 103 and 40 CFR Part 60, Subpart KKKK)

54. No later than 90 calendar days prior to initial startup of the CTGs, the permittee shall submit a CEMS protocol to the VCAPCD, for written approval that shows how the CEMS will be able to meet all of the monitoring requirements of this permit. (Rules 74.23 and 103)

55. When the NOx CEMS is not recording data and the CTG is operating, hourly NOx emissions for purposes of rolling twelve (12) calendar-month period emission calculations shall be determined in accordance with 40 CFR Part 75 Subpart C. Additionally, when the CO CEMS is not recording data and the CTG is operating, hourly CO emissions for purposes of rolling twelve (12) calendar-month period emission calculations shall be determined using CO emission factors to be determined from source test emission factors and hourly fuel consumption data. Emission calculations used to determine hourly emission rates shall be reviewed and approved by the VCAPCD, in writing, before the hourly emission rates are incorporated into the CEMS emissions data. (Rules 26.2 and 29 and 40 CFR Part 75)

56. Each CTG shall be equipped with continuous monitors to measure, calculate, and record unit operating days and hours and the following operational characteristics and operating parameters (Rule 74.23):

a. Date and time;
b. Natural gas flow rate to the CTG during each unit operating minute, in standard cubic feet per hour;
c. Total heat input to the combustion turbine based on the natural gas higher heating value (HHV) during each unit operating minute, in Million British Thermal Units Per Hour (MMBTU/Hr);
d. Higher heating value (HHV) of the fuel on an hourly basis, in Million British Thermal Units Per Standard Cubic Foot (MMBTU/SCF);
e. Stack exhaust gas temperature during each unit operating minute, in degrees Fahrenheit;
f. Combustion turbine energy output during each unit operating minute in megawatts hours (MWh)

57. The values of the above operational characteristics and parameters shall be reduced to hourly averages. The monitors shall be installed, calibrated, and maintained in accordance with a turbine operation monitoring protocol, which may be part of the CEMS protocol, approved by the VCAPCD, which shall include any relevant calculation methodologies. The monitors shall be in full operation at all times when the combustion turbine is in operation. Calibration records for the continuous monitors shall be

maintained on site and made available to the VCAPCD upon request. (Rule 74.23)

58. At least 90 calendar days prior to initial startup of the CTGs, the permittee shall submit a CTG operating parameter monitoring protocol to the VCAPCD for written approval. This may be part of the CEMS protocol. (Rule 74.23)

59. Within thirty (30) calendar days after the end of the commissioning period for the CTGs, the permittee shall submit a written report to the VCAPCD. This report shall include, a minimum, the date the commissioning period ended, the startup and shutdown periods, the emissions of NOx and CO during startup and shutdown periods, and the emissions of NOx and CO during steady state operation. This report shall also detail any CTG or emission control equipment malfunction, upset, repairs, maintenance, modifications, or replacements affecting emissions of air contaminants that occurred during the commissioning period. All of the following continuous monitoring information shall be reported and averaged over each hour of operation, except for cumulative mass emissions. (Rules 26.2 and 29):

    a. Concentration of oxides of nitrogen (NOx) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);
    b. Concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);
    c. Percent oxygen (O_2) in the exhaust gas;
    d. Mass emissions of oxides of nitrogen (NOx) calculated as NO_2, in pounds and tons;
    e. Cumulative mass emissions of oxides of nitrogen (NOx) calculated as NO_2 in each startup and shutdown period, in pounds and tons;
    f. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds and tons;
    g. Mass emissions of carbon monoxide (CO), in pounds and tons;
    h. Total heat input to the combustion turbine based on the fuel's higher heating value, in Million British Thermal Units Per Hour (MMBTU/Hr);
    i. Higher Heating Value (HHV) of the natural gas fuel on an hourly basis, in Million British Thermal Units Per Standard Cubic Foot (MMBTU/SCF);
    j. Gross electrical power output of each CTG, in megawatts hours (MWh) for each hour;
    k. SCR catalyst temperature, in degrees Fahrenheit.

60. Upon request of the APCO, the hourly average information required by this permit shall be submitted in writing and /or in an electronic format approved by the VCAPCD. Upon request of the APCO, the minute-by-minute information required by this permit shall be submitted in an electronic format approved by the VCAPCD. (Rules 26.2, 74.23, and 103)

61. The CTGs shall comply with 40 CFR Part 60, Subpart TTTT, Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units. As defined by the annual hours of operation limits, and the natural gas fuel only requirements, of this permit, the CTG is subject to a CO_2 emission standard of 120 lb CO_2 per MMBTU, averaged over a twelve (12)

operating month rolling average.

To verify compliance with this condition, as required above by this permit, the permittee shall record and maintain written monthly records of the CTG natural gas consumption and the CTG net electrical sales supplied to the utility grid.

Mission Rock Energy Center - 220 BHP John Deere Emergency Diesel Engine

The Emergency Diesel Fire Pump Engine is simultaneously subject to the emission limits, monitoring requirements, and recordkeeping and reporting requirements of the following rules and regulations:

Rule 26.2, New Source Review – Requirements

Rule 50, Opacity

Rule 51, Nuisance

Rule 74.9, Stationary Internal Combustion Engines

Title 17, California Code of Regulations, Section 93115, Airborne Toxic Control Measure For Stationary Compression Ignition (CI) Engines (ATCM)

40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (NSPS IIII)

The following conditions describe and streamline the most stringent requirements of the above rules and regulations. The Ventura County APCD has been delegated authority for 40 CFR Part 60 Subpart IIII and is considered to be the Administrator.

Compliance with the terms of the streamlined conditions below for the Mission Rock Energy Center 220 BHP John Deere Emergency Diesel Fire Pump Engine assures compliance with all individual requirements applicable to the Emergency Diesel Fire Pump Engine which have been addressed above and below.

1. The annual hours of operation for maintenance and readiness testing of the Emergency Diesel Fire Pump Engine shall not exceed 50 hours per year. A year is defined as any twelve (12) month consecutive period. In addition, the Emergency Diesel Fire Pump Engine shall not be operated for more than 30 minutes in any rolling one (1) hour period during maintenance and readiness testing. Operation of the engine for maintenance and readiness testing shall not occur during the turbines' commissioning period. These limits do not include emergency operation for the pumping of water for fire suppression or protection. When not being operated for maintenance or readiness testing, the emergency engine shall only be used for the emergency pumping of water for fire suppression or protection.

   The engine shall be equipped with an operating, non-resettable, elapsed hour meter with a minimum display capacity of 9,999.9 hours. The permittee shall maintain a daily log to record the time of day and the duration of operation in hours and minutes. The daily log shall differentiate operation during maintenance and readiness testing from operation during emergency pumping of water for fire suppression or protection. These hours of operation records shall be compiled into a monthly total. The monthly operating hour records shall be summed for the previous twelve (12) months and reported to the VCAPCD after every calendar year by February 15. (Rule 26.2, Rule

74.9 and ATCM)

2. Only CARB-certified diesel fuel containing not more than 0.0015% sulfur by weight shall be used to fuel the Emergency Diesel Fire Pump Engine. Permittee shall maintain records of diesel fuel purchases to document compliance with this condition. (ATCM)

3. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which are as dark or darker in shade as that designated as No. 1 on the Ringelmann Chart as published by the United States Bureau of Mines, or 20% opacity. (Rule 50)

4. The emergency engine shall be EPA-certified to the applicable emissions requirements for emergency fire pump engines of 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines and the California ARB Airborne Toxic Control Measure For Stationary Compression Ignition (CI) Engines, based on the power rating of the engine and the engine model year. The ROC, NOx, and PM10 emission limits below have been applied as BACT pursuant to Rule 26.2. (Rule 26.2, NSPS IIII, and ATCM)

5. ROC and NOx emissions from the engine shall not exceed the Emission Standard for NMHC+NOx of 3.0 g/bhp-hr. The permittee shall maintain documentation certifying that the emergency diesel fire pump engine meets this emission standard. (Rule 26.2, NSPS IIII, and ATCM)

6. PM10 emissions from the engine shall not exceed shall not exceed the Emission Standard for PM of 0.15 g/hp-hr. The permittee shall maintain documentation certifying that the emergency diesel fire pump engine meets this emission standard. (Rules 26.2, NSPS IIII, and ATCM)

7. CO emissions from the engine shall not exceed shall not exceed the Emission Standard for CO of 2.6 g/bhp-hr. The permittee shall maintain documentation certifying that the emergency diesel fire pump engine meets this emission standard. (NSPS IIII and ATCM)

8. The exhaust stack of the Emergency Diesel Fire Pump Engine shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. A flapper type rain cap that is open while the engine is operating may be used. (Rule 51)

9. The Emergency Diesel Engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. (NSPS IIII and ATCM)

10. Permittee shall monitor the operational characteristics of the engine as recommended by the engine manufacturer or emissions control system supplier. (NSPS IIII and ATCM)