VENTURA COUNTY APCD
FINAL DETERMINATION OF COMPLIANCE

PUENTE POWER PROJECT
CEC APPLICATION FOR CERTIFICATION DOCKET NUMBER 15-AFC-01

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I. Project Proposal and Project Summary

The Puente Power Project (P3), owned by NRG Energy Center Oxnard LLC (NRG), requests a Determination of Compliance (DOC) from the Ventura County Air Pollution Control District (VCAPCD) for the installation of a new H-Class simple-cycle natural gas fired combustion turbine generator (CTG) with a nominal net rating of 262 MW and a new emergency diesel electricity generator engine with a rating of 779 BHP. The new turbine and the new diesel engine, along with other ancillary equipment, will be called the Puente Power Project (P3). The Puente Power Project will be located at the existing Mandalay Generating Station (MGS). The current Mandalay Generating Station facility equipment list and permitted emissions are included in Appendix A – Current Permitted Emissions.

This DOC is being issued pursuant to VCAPCD Rule 26.9, "New Source Review - Power Plants". The Puente Power Project is subject to the approval of the California Energy Commission (CEC) because the proposed power plant has a nominal rating greater than 50 MW. The Puente Power Project filed an Application For Certification with the CEC on April 15, 2015 (AFC Docket No. 15-AFC-01).

The project consists of replacing MGS Unit 2 (1,990 MMBTU/Hr, 215 MW net, Babcock and Wilcox Steam Generator natural gas fired electric utility boiler), with a new natural gas fired General Electric H-Class simple-cycle CTG (Model GE 7HA.01, 262 MW net nominal). MGS Unit 2 will be permanently shut down prior to the start of the commissioning period for the proposed new gas combustion turbine generator. MGS Unit 1 may be operational after the new CTG is operational, but will be permanently shut down within 90 operating days, but no later than 180 calendar days, after the start of the commissioning period for the proposed new gas combustion turbine generator. Ultimately, the Puente Power Project is designed to replace both MGS Unit 1 and MGS Unit 2.

P3 will also be replacing the existing 201 BHP diesel emergency electricity generator engine with a new 779 BHP diesel emergency electricity generator engine. An existing 154 BHP diesel emergency fire water pump engine will also be shut down. The remainder of the NRG Mandalay Generating Station facility will remain unchanged: including the 2510 MMBTU/Hr (130 MW) natural gas-fired peaker combustion turbine (MGS Unit 3), and various ancillary facilities. The new P3 CTG will utilize existing natural gas fuel lines and existing electrical distribution lines.

The Mandalay Generating Station currently has a Part 70 (Title V) Permit No. 00013 and a Title IV Acid Rain Permit No. 00013. As required by VCAPCD Rule 33.5, Part 70 Permits - Timeframes for Applications, Review and Issuance, prior to operation of the new P3 CTG, NRG will submit an application to amend their Part 70 Permit and Title IV Acid Rain Permit to include the Puente Power Project if approved by the CEC.

The ultimate design of the Puente Power Project is proposed to "re-power" and replace two, older electrical steam generating units, each rated at 215 MW, with a single new combustion gas turbine, rated at 262 MW net nominal, that will operate as a peaking turbine to be used when needed. The current Title V permit for the Mandalay Generating Station allows MGS Unit 1 and MGS Unit 2 to each operate at a 100 percent capacity factor for 8,760 hours per year (24 hours per day over 365 days per year). The Puente Power Project CTG will be limited to operation of 2,150 hours per year, which equals a capacity factor of approximately 25 percent. If fully completed as proposed, the Puente Power Project will therefore result in an annual electrical generating capacity reduction from 3,766,800 MW-hrs per year to 563,300 MW-hrs per year, which equals a reduction of approximately 85 percent.

As shown in this DOC, if fully completed as proposed, the Puente Power Project will reduce the permitted NOx emissions of the Mandalay Generating Station from 222.74 tons per year to 78.61 tons per year, which equals a permitted NOx emission reduction of approximately 65 percent when both MGS Unit 1 and MGS Unit 2 will be permanently shut down by December 31, 2020. However, under Ventura County APCD rules, there will be an actual NOx emissions increase from the Puente Power Project of 29.93 tons per year calculated based on the post-project potential to emit for the new units minus the pre-project actual emissions for the existing units being replaced. 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 38.91 tons per year.

VCAPCD Rule 59, "Electrical Power Generating Equipment - Oxides of Nitrogen Emissions", currently limits NOx emissions from MGS Unit 1 and MGS Unit 2 to a rate of 0.10 pounds of NOx per megawatt-hour. The Puente Power Project turbine will emit NOx at a rate of 0.09 pounds of NOx per megawatt-hour as limited by this DOC and the best available control technology (BACT) requirements of VCAPCD Rule 26.2, New Source Review - Requirements. This equals a decrease in the allowable NOx emission rate of 10 percent during normal operations.

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)

The applicant has determined that PSD does not apply to the proposed Puente Power Project. Rule 26.13 implements the requirements of 40 CFR 52.21 – Prevention of Significant Deterioration (PSD). This rule has not been approved by U.S. EPA. As such, any implementation of PSD requirements, including applicability determinations and/or determination of compliance with PSD requirements can only be performed by U.S. EPA. The VCAPCD is not making a PSD applicability determination at this time as the VCAPCD does not have federal authority to do so. However, the lack of a PSD applicability determination in this Determination of Compliance does not necessarily mean the project is not required to obtain a PSD permit. It would be a violation of section 165 of the federal Clean Air Act to commence construction of a project subject to the PSD program without first obtaining a PSD permit. Since the applicant has stated that PSD does not apply, this DOC does not include a discussion or calculations of greenhouse gases (GHGs).

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 from New, Modified, and Reconstructed Stationary Sources: 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). This turbine is 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.” As shown in Appendix H - Hazardous Air Pollutant Stationary Source Potential to Emit, the HAP emissions from the proposed stationary source are less than the major source threshold for a single HAP of 10 tons per year and less than the major source threshold for combined HAPs of 25 tons per year. Note that ammonia and propylene are considered to be toxic air contaminants but are not defined as EPA HAPs.

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 Puente Power Project (P3) will be installed at a site within NRG's existing Mandalay Generating Station (MGS) located at 393 North Harbor Boulevard in Oxnard, California.

IV. Process Description

The Puente Power Project (P3), owned by NRG, requests a Determination of Compliance (DOC) from the Ventura County Air Pollution Control District (VCAPCD) for the installation of a new H-Class simple-cycle natural gas fired combustion turbine generator (CTG) and a new emergency diesel generator engine. The new turbine and the new diesel engine along with other ancillary equipment will be called the Puente Power Project (P3).

The project consists of replacing MGS Unit 2 (1,990 MMBTU/Hr, 215 MW net, Babcock and Wilcox Steam Generator natural gas fired electric utility boiler) with a new natural gas fired General Electric (GE) H-Class simple-cycle CTG (Model GE 7HA.01, 262 MW net nominal). MGS Unit 2 will be permanently shut down prior to the start of the commissioning period for the proposed gas turbine engine. MGS Unit 1 may be operational after the new CTG is operational, but will be permanently shut down within 90 operating days, but no later than 180 calendar days, after the start of the commissioning period for the proposed new gas combustion turbine generator. Even though MGS Unit 1 will eventually be shut down, this evaluation and all emission calculations assume MGS Unit 1 remains operational and the emissions associated with MGS Unit 1 are still accounted for in the stationary source emissions for this project.

P3 will also be replacing the existing 201 BHP diesel emergency generator engine with a new 779 BHP diesel emergency electricity generator unit. An existing 154 BHP diesel emergency fire water pump engine will also be shut down. The remainder of the NRG facility will remain unchanged: including the 2510 MMBTU/Hr (130 MW) natural gas-fired peaker combustion turbine (MGS Unit 3), and various ancillary facilities. The current facility permitted emissions are in Appendix A – Current Permitted Emissions.

V. Equipment Listing

<u>New Combustion Turbine Generator (CTG):</u>
General Electric (GE) 7HA.01 Combustion Turbine Generator (CTG) set, rated at 262 MW net nominal, Serial No. to be determined, simple cycle, equipped with dry low-NOx combustion, a Selective Catalytic Reduction (SCR) system with aqueous ammonia injection for NOx control and an oxidation catalyst for CO control

The turbine is a simple-cycle turbine; there is no heat recovery steam generator. The proposed unit is a GE 7HA.01 Model. The turbine is designed to fire natural gas only. The net heat rate is 9039 BTU/kWh (LHV). There is no bypass stack. The dry low NOx combustors achieve lower NOx emission through the design of the combustors and fuel injection nozzles. This design optimizes the mixing of combustion air and fuel at peak flame temperatures resulting in low NOx emissions. The exhaust is then sent through an oxidation catalyst and SCR system.

Oxidation Catalyst:
The proposed oxidation catalyst unit is a BASF Camet system with the following dimensions: 25'W x 100'H x 0.6'D. The minimum and maximum operating temperatures for the oxidation catalyst are 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.

SCR System:
The proposed SCR unit is a Cormetech Model CM21HT unit with the following exterior dimensions: 25'W x 100'H x 1'D. It is a high temperature catalyst that is designed to operate without turbine exhaust cooling. The minimum and maximum operating temperatures for the SCR catalyst are 300 and 1,050 degrees Fahrenheit.

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

Emergency Internal Combustion Engine:
The project also includes an emergency internal combustion engine. The engine is diesel fired and will power the auxiliary electricity generator equipment required to shut down the plant in the event that there is a power outage. The proposed unit is a 779 BHP Caterpillar engine that produces 500 KW of emergency electric power. The engine is required to be certified to meet U.S. EPA Tier 4-Final emission standards.

The engine will only be used during emergencies when there is no power available from the electrical grid. 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 an electric powered fuel gas compressor, a water demineralizer, water storage tank, transformers, and one aqueous ammonia storage tank. This 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 will be equipped with dry low NOx (DLN) combustors. DLN combustors achieve a NOx emission rate of 25 ppmvd @ 15% O_2 without the use of water or steam injection. The low NOx emission rate is accomplished by the design of the combustors and fuel injection nozzles which optimizes the mixing of combustion air and fuel at peak flame temperatures. This results in low NOx emissions.
The proposed CTG will be equipped with an oxidation catalyst for CO control, and a selective catalytic reduction (SCR) system for NOx control.

The proposed oxidation catalyst unit is a BASF Camet system with the following dimensions: 25'W x 100'H x 0.6'D. The minimum and maximum operating temperatures for the oxidation catalyst are 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 proposed SCR unit is a Cormetech Model CM21HT unit with the following exterior dimensions: 25'W x 100'H x 1'D. The SCR system consists of ammonia injection in the CTG exhaust upstream of the catalyst and a catalyst bed. The ammonia reduces NOx to N2 and O2 in the presence of the catalyst. 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 IC diesel engine will be certified to meet US EPA Tier 4 final emission requirements.

VII. Emission Calculations

The emission calculations below are performed pursuant to the requirements of Rule 26.6 "New Source Review – Calculations". Based on Rule 29, "Conditions on Permits", and Rule 42, "Permit Fees", the emissions of ROC, NOx, PM10, SOx, CO, and NH3 have been calculated in the units of tons per year and pounds per hour for the Puente Power Project CTG and emergency diesel engine. All PM10 emissions are assumed to be PM2.5 emissions.

Assumptions:

All PM_{10} emissions from the turbine are assumed to be $PM_{2.5}$
Natural gas fuel sulfur limit limited to 0.75 grain per 100 scf (0.0021375 lb SOx/MMBTU)
Natural gas HHV = 1018 BTU/scf (nominal value from AFC Table 4.1-15)
Combustion "F" factor of 8710 dscf/MMBTU for natural gas (EPA Method 19)
Molecular weight (ROC) = 16 lb/lb-mole for methane
Molecular weight (NOx) = 46 lb/lb-mole for nitrogen dioxide
Molecular weight (CO) = 28 lb/lb-mole
Molecular weight (NH3) = 17 lb/lb-mole

Worst case CTG hourly emissions are during startup/shutdown/restart hour
Fuel Usage Maximums = 2,572 MMBTU/Hr (2.53 MMscf/Hr)
Annual emissions based on 200 startups, 200 shutdowns, 1,750 hours normal operation
Startup = 1 hour
Shutdown = 1 hour
Worst case hour = 30 minutes startup +12 minutes shutdown + 18 minutes startup
Steady state emissions values per manufacturer guarantee (see GE letter) Appendix B
Emergency engine limited to 50 hrs/yr non-emergency use for maintenance and readiness testing, with no hours limit on actual emergency use.
Baseline period 2012-2013 – Based on Rule 26.6.C, this two consecutive year period was determined to be the most representative as it best reflects current electricity market.
The applicant has supplied manufacturer emission data for CTG startup and shutdown emissions in Appendix B.

Rule 26.6 B – Potential to Emit

New Combustion Turbine Generator (CTG):

The CTG has various states of operation: startup, shutdown, and normal operation. The CTG has different emission factors associated with the various states of operation. NRG has proposed operation limits for the facility based on 200 startups, 200 shutdowns, and 1,750 hours of normal full load operation on an annual basis. The worst case daily operations the CTG may have four startup/shutdown cycles with the rest of the day at full load operation. The worst hourly emissions would occur when there is a startup then shutdown then another startup all within the same hour. While this worst case scenario is possible, it would be infrequent. The manufacturer of the CTG, General Electric, has provided hourly emission rates for startup and shutdown operation, see below. During startups and shutdowns the SCR system and the oxidation catalyst are not effective at reducing NOx and CO emissions as the exhaust temperature is not high enough for effective emissions control.

The maximum hourly emissions for startup consist of a maximum of 30 minutes at the higher startup emission rate followed by the remaining 30 minutes at the normal operation emission rate. The maximum hourly emissions for shutdown consist of a maximum of 12 minutes at the shutdown emission rate preceded by 48 minutes at the normal operation emission rate. Table VII-1 below shows how the hourly startup and hourly shutdown emissions were calculated:

Table VII - 1

Startup and Shutdown Maximum Hourly Emissions (lbs)						
Pollutant	**Startup Emissions**			**Shutdown Emissions**		
	Startup +	Normal Operation =	**Maximum Hourly Startup**	Shutdown +	Normal Operation =	**Maximum Hourly Shutdown**
Duration (min)	30	30	**60**	12	48	**60**
ROC	17.00	3.30	**20.30**	25.00	5.28	**30.28**
NOx	87.00	11.87	**98.87**	4.00	18.98	**22.98**
PM_{10}	3.70	5.05	**8.75**	1.50	8.08	**9.58**
SOx	2.75	2.75	**5.50**	1.10	4.40	**5.50**
CO	167.00	11.55	**178.55**	145.00	18.48	**163.48**
NH3	N/A	8.77	**8.77**	N/A	14.02	**14.02**

The worst case startup/shutdown emissions would occur if the CTG undergoes a 30-minute startup, followed by a 12-minute shutdown, and then is restarted for the remaining 18 minutes. Table VII-2 below shows how the hourly startup/shutdown/restart emissions were calculated:

Table VII – 2

Startup/Shutdown/Restart Maximum Hourly Emissions (lbs)				
Pollutant	Startup +	Shutdown +	Restart (Startup) =	**Maximum Hourly Startup/ Shutdown/ Restart Emissions**
Duration (min)	30	12	18	**60**
ROC	17.00	25.00	10.20	**52.20**
NOx	87.00	4.00	52.20	**143.20**
PM_{10}	3.70	1.50	2.22	**7.42**
SOx	2.75	1.10	1.65	**5.50**
CO	167.00	145.00	100.20	**412.20**
NH3	N/A	N/A	N/A	**N/A**

The maximum startup and shutdown hourly emissions are summarized in Table VII-3 below:

Table VII – 3

Startup and Shutdown Maximum Hourly Emissions			
Pollutant	**Startup**	**Shutdown**	**Startup/Shutdown/ Restart**
	Pounds Per Hour	Pounds Per Hour	Pounds Per Hour
ROC	20.30	30.28	52.20
NOx	98.87	22.98	143.20
PM_{10}	8.75	9.58	7.42
SOx	5.50	5.50	5.50
CO	178.55	163.48	412.20
NH3	8.77	14.02	n/a

Table VII – 4

Startup and Shutdown Annual Emissions				
Pollutant	**Startup**		**Shutdown**	
	Pounds Per Hour	Tons Per Year (200 Startups/yr)	Pounds Per Hour	Tons Per Year (200 Shutdowns/yr)
ROC	20.30	2.03	30.28	3.03
NOx	98.87	9.89	22.98	2.30
PM_{10}	8.75	0.88	9.58	0.96
SOx	5.50	0.55	5.50	0.55
CO	178.55	17.86	163.48	16.35
NH3	8.77	0.88	14.02	1.40

During normal operation, the exhaust from the CTG 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 (CO2) and water (H2O). In the SCR section, aqueous ammonia (NH3) is introduced into the exhaust stream through lances inserted into the exhaust ducting. The ammonia mixes with the exhaust gas and reacts with NOx on the surface and interior of the catalyst to produce nitrogen gas (N2) and water (H2O). Some residual ammonia, also known as "ammonia slip", remains in the exhaust gas. Normal operations are expected to occur 1,750 hours per year. See emission factors, emission factor basis, and the calculated pounds per hour emissions at the steady state normal operational load below.

ROC, NOx, CO, and NH3 ppmvd emission factors are BACT requirements and / or proposed by the applicant. The PM_{10} emission factors are based on the turbine manufacturer's data and proposed by the applicant. The SOx emission factor limit is based on a fuel sulfur content of 0.75 gr S/100 scf as proposed by the applicant.

Table VII – 5

New Turbine Emission Calculations - Normal Operation				
Pollutant	**Emission Factor**	**Emission Factor Basis**	**Pounds Per Hour (@ 2.53 MMscf/hr)**	**Tons Per Year (1,750 hr/yr)**
ROC	2.61 lb/MMscf	2.0 ppmvd (BACT)	6.60	5.78
NOx	9.38 lb/MMscf	2.5 ppmvd (BACT)	23.73	20.76
PM_{10}	N/A	10.1 lb/hr per GE	10.10	8.84
SOx	0.0021375 lb/MMBtu	Applicant Proposed Limit equal to: 0.75 gr/100 scf	5.50	4.81
CO	9.13 lb/MMscf	4.0 ppmvd (Rule 29)	23.10	20.21
NH3	6.93 lb/MMscf	5 ppmvd (BACT)	17.53	15.34

The lb/MMscf emission factors for ROC, NOx, CO, and NH3 are calculated based on the following equation pursuant to EPA Method 19:

lb/MMscf = (F)(MW)(20.9/20.9-15)(lbmole/385 dscf)(ppmv@15%O2/10^6)(1018 MMBTU/MMscf)

where F= f-factor
MW = Molecular weight

Maximum hourly emissions occur when there is a startup/shutdown/restart sequence. This sequence is not planned for the facility but could happen. This up/down/up sequence represents the worst case maximum hourly emissions.

The maximum annual emissions will occur with 200 startup hours, 200 shutdown hours, and 1,750 hours steady state operation. The emissions are tabulated in Table VII-6 below:

Table VII - 6

New Turbine Emission Calculations – Maximum Permitted Emissions Hourly and Annual Operations		
Pollutant	**Hourly**	**Annual**
	Pounds Per Hour	Tons Per Year
ROC	52.20	10.84
NOx	143.20	32.95
PM_{10}	10.10	10.68
SOx	5.50	5.91
CO	412.20	54.42
NH3	17.53	17.62

CTG Commissioning Calculations

The application includes information on the commissioning of the turbine. The SCR with ammonia injection and oxidation catalyst control systems will not be operable during a portion 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. Some commissioning tests will result in uncontrolled ROC and NOx emissions and some tests result in partially controlled emissions. These emissions and the expected total for the commissioning process are shown in Table VII-7 below:

Table VII - 7

New Turbine Commissioning Emissions		
Pollutant	**Maximum Commissioning Emissions (lbs/hr)**	**Total Commissioning Emissions (tpy)**
ROC	164.10	3.52
NOx	246.30	11.70
CO	1973.00	31.74

NRG has provided an estimated commissioning schedule for the turbine. The schedule is in Appendix C. The emissions from the commissioning process will be accounted for in the total annual emissions from the CTG. NRG will ensure that the total annual emissions from the facility do not exceed their annual permitted emissions including during the commissioning process.

New Emergency Internal Combustion Engine:

The emissions for the 779 BHP Caterpillar are based on full load operation at 50 hours per year. The engine will have a 50 hour per year limit for non-emergency usage for maintenance and readiness testing. There will not be an hours per year usage limit for actual emergencies.

The emission factors are based on the Final Tier 4 standards for engines in service as a generator. The permitted emissions are shown in Table VII-8 below:

Table VII - 8

New 779 BHP Emergency Engine Emission Calculations				
Pollutant	**Emission Factor (g/bhp-hr)**	**Emission Factor Basis**	**Tons Per Year (50 hr/yr)**	**Pounds Per Hour**
ROC	0.14	EPA Tier 4 final non-road diesel standards	0.01	0.24
NOx	0.50	EPA Tier 4 final non-road diesel standards	0.02	0.86
PM_{10}	0.02	EPA Tier 4 final non-road diesel standards	0.00	0.03
SOx	0.0051	Very low sulfur fuel (15 ppmw) mass balance - see below	0.00	0.008
CO	2.6	EPA Tier 4 final non-road diesel standards	0.11	4.48

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

Existing Steam Boilers (MGS Unit 1 & MGS Unit 2):

There are two existing natural gas fired electric utility steam boilers at the NRG facility. They are both 1,990 MMBTU/Hr (215 MW) Babcock and Wilcox natural gas steam boilers. As previously discussed one steam boiler (MGS Unit 2) will be permanently shut down prior to the start of the new turbine commissioning period. The other boiler (MGS Unit 1) may be operational after the new CTG is operational, but will be permanently shut down within 90 operating days, but no later than 180 calendar days, after the start of the commissioning period for the proposed new gas combustion turbine generator.

The potential emissions from the existing MGS Unit 1 and Unit 2 are from the permitted emissions summary for the MGS (see Appendix A) and are shown in Table VII-9 below:

Table VII - 9

Permitted Emissions for Existing Natural Gas Fired Steam Boilers (MGS Unit 1 & MGS Unit 2 each)			
Pollutant	**Emission Factor (lb/MMscf)**	**Pounds Per Hour**	**Tons Per Year**
ROC	1.40	2.66	11.62
NOx	10.66	20.21	88.49
PM_{10}	2.50	4.74	20.76
SOx	0.60	1.14	4.98
CO	40.0	75.81	332.05

The existing CTG MGS Unit 3 will continue to be operated as a peaking turbine. It is connected to a different portion of the electrical grid as compared to existing MGS Unit 1 and Unit 2 and the proposed Puente Power Project CTG. The potential emissions from the existing CTG MGS Unit 3 are from the permitted emissions summary for this facility (see Appendix A) and are shown in Table VII-10 below. These permitted emissions represent a permit operational limit of approximately 83 hours per year.

Table VII - 10

Permitted Emissions for Existing Natural Gas Fired Turbine (MGS Unit 3)			
Pollutant	**Emission factor (lb/MMscf)**	**Pounds Per Hour**	**Tons Per Year**
ROC	7.56	18.07	0.75
NOx	462.00	1104.41	45.64
PM_{10}	20.30	48.53	2.01
SOx	0.60	1.43	0.06
CO	115.50	276.10	11.41

Existing Emergency IC Engines

The two existing emergency engines provide emergency electrical power and also emergency firewater for the facility. Both engines are limited to 20 hours per year of non-emergency operation for maintenance and testing. The potential emissions from the existing IC engines are from the permitted emissions summary for this facility (see Appendix A) and are shown in Tables VII-11 and VII-12 below:

Table VII - 11

Permitted Emissions for MGS Existing 154 BHP emergency engine		
Pollutant	**Pounds Per Hour**	**Tons Per Year**
ROC	0.04	0.00
NOx	0.51	0.05
PM_{10}	0.04	0.00
SOx	0.01	0.00
CO	0.11	0.01

Table VII - 12

Permitted Emissions for MGS Existing 201 BHP emergency engine		
Pollutant	**Pounds Per Hour**	**Tons Per Year**
ROC	0.05	0.00
NOx	0.67	0.07
PM_{10}	0.05	0.00
SOx	0.01	0.00
CO	0.15	0.01

The following Tables VII-13 and VII-14 summarize the current Mandalay Generating Station permitted emissions (pre-project) and the proposed Mandalay Generating Station permitted emissions if the Puente Power Project is implemented as proposed (post-project):

Table VII - 13

Summary of Facility Pre-Project Potential Permitted Emissions (Tons Per Year)						
	ROC	**NOx**	**PM_{10}**	**SOx**	CO	NH3
MGS Unit 1 Steam Boiler	11.62	88.49	20.76	4.98	332.05	39.02
MGS Unit 2 Steam Boiler	11.62	88.49	20.75	4.98	332.04	39.01
MGS Unit 3 CTG	0.75	45.64	2.01	0.06	11.41	0
MGS 154 BHP Emergency Engine	0	0.05	0	0	0.01	0
MGS 201 BHP Emergency Engine	0	0.07	0	0	0.01	0
P3 New 262 MW Turbine	0	0	0	0	0	0
P3 New 779 BHP Engine	0	0	0	0	0	0
Pre-Project Total Stationary Source	**23.99**	**222.74**	**43.52**	**10.02**	**675.52**	**78.03**
Rule 26.1: Major Source Thresholds	25	25	N/A	N/A	N/A	N/A

As seen in Table VII-13 above, pre-project the facility is a major source for NOx only.

Table VII - 14

Summary of Facility Post-Project Potential Permitted Emissions (Tons Per Year)						
	ROC	**NOx**	**PM_{10}**	**SOx**	**CO**	**NH_3**
MGS Unit 1 Steam Boiler	11.62	88.49	20.76	4.98	332.05	39.02
MGS Unit 2 Steam Boiler – to be removed	0	0	0	0	0	0
MGS Unit 3 CTG	0.75	45.64	2.01	0.06	11.41	0
MGS 154 BHP Emergency Engine– to be removed	0	0	0	0	0	0
MGS 201 BHP Emergency Engine– to be removed	0	0	0	0	0	0
P3 New 262 MW Turbine	10.84	32.95	10.68	5.91	54.42	17.62
P3 New 779 BHP Engine	0.01	0.02	0.00	0.00	0.11	0
Post-Project Total Stationary Source	**23.22**	**167.10**	**33.45**	**10.95**	**397.99**	**56.64**
Rule 26.1: Major Source Thresholds	25	25	N/A	N/A	N/A	N/A

As seen in Table VII-14 above, post project the facility is a major source for NOx only.

<u>Rule 26.6 C – Actual Emissions:</u>

The new CTG and new IC engine have no actual existing emissions as defined by Rule 26.6.C.

The actual emissions from the existing natural gas fired electrical steam boilers (MGS Unit 1 and Unit 2) and existing natural gas-fired peaker CTG (MGS Unit 3) are calculated from the permitted emission factors and their historical fuel use (see Tables VII-15 and VII-16). The NOx emissions for MGS Unit 1 and MGS Unit 2 are based on the NOx CEMs data from the facility. The emission factors are shown in Tables VII-15 and VII-16 below. The historical fuel use was determined from fuel records from the baseline period (2012-2013). Based on Rule 26.6.C, this two consecutive year period was determined to be the most representative as it best reflects current electricity market. The fuel records are attached in Appendix D – Historical Fuel Records.

Table VII - 15

Actual Emissions for Existing Natural Gas Fired Steam Boiler - MGS Unit 1			
Pollutant	**Emission factor (lb/MMscf)**	**Avg. Annual Fuel Use (MMscf)**	**Tons Per Year**
ROC	1.40	1,101.70	0.77
NOx	3.42	1,101.70	1.88
PM_{10}	2.50	1,101.70	1.38
SOx	0.60	1,101.70	0.33
CO	40.0	1,101.70	22.03

Table VII - 16

Actual Emissions for Existing Natural Gas Fired Steam Boiler – MGS Unit 2			
Pollutant	**Emission factor (lb/MMscf)**	**Avg. Annual Fuel Use (MMscf)**	**Tons Per Year**
ROC	1.40	1,297.75	0.91
NOx	4.68	1,297.75	3.04
PM_{10}	2.50	1,297.75	1.62
SOx	0.60	1,297.75	0.39
CO	40.0	1,297.75	25.96

The actual emissions from the existing natural gas fired CTG (MGS Unit 3) are calculated from the emission factors and its historical fuel use (see Table VII-17). The historical fuel use was determined from fuel records from the baseline period (2012-2013). The fuel records are attached in Appendix D – Historical Fuel Records.

Table VII - 17

Actual Emissions for Existing Natural Gas Fired Turbine – MGS Unit 3			
Pollutant	**Emission factor (lb/MMscf)**	**Avg. Annual Fuel Use (MMscf)**	**Tons Per Year**
ROC	7.56	88.55	0.33
NOx	462.0	88.55	20.46
PM_{10}	20.30	88.55	0.90
SOx	0.60	88.55	0.03
CO	115.50	88.55	5.11

The actual emissions from the existing emergency engines are calculated from the emission factors and their historical fuel use (see Tables VII-18 and VII-19). The historical fuel use was determined from fuel records from the baseline period (2012-2013). The fuel records are attached in Appendix D – Historical Fuel Records.

Table VII - 18

Actual Emissions for Existing 154 BHP Emergency Engine		
Pollutant	**Pounds Per Hour**	**Tons Per Year**
ROC	0.04	0.00
NOx	0.51	0.00
PM_{10}	0.04	0.00
SOx	0.01	0.00
CO	0.11	0.00

Table VII - 19

Actual Emissions for Existing 201 BHP Emergency Engine		
Pollutant	**Pounds Per Hour**	**Tons Per Year**
ROC	0.05	0.00
NOx	0.67	0.00
PM_{10}	0.05	0.00
SOx	0.01	0.00
CO	0.15	0.00

As shown above, the two existing emergency diesel engines have no actual existing emissions in the units of tons per year.

Rule 26.6 D – Emission Increases:

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, or CO.

As shown above the facility is currently a major source of NOx and will remain a major source of NOx after the installation of the new CTG and emergency IC engine. The facility is not currently a major source of ROC, and will not become a major source of ROC.

Rule 26.1.29 defines Replacement Emissions Unit as "An emissions unit which supplants another emissions unit where the replacement emissions unit serves the identical function as the emission unit being replaced." The new 262 MW gas turbine will be connected to the same Southern California Edison 220-KV switchyard that the two (2) existing 215 MW Babcock and Wilcox Steam Generator boilers (MGS Units 1 and 2) are connected to. Once operating, the new 262 MW gas turbine will provide dispatchable power to provide voltage support to the local reliability area in the same manner as the current two 215 MW Babcock and Wilcox Steam Generators. Prior to the start of the commissioning period for the new CTG, MGS Unit 2 will be permanently shut down. Therefore the new turbine is a replacement emissions unit for MGS Unit 2. As described above, eventually MGS Unit 1 will also be permanently shut down and the new CTG will serve as a replacement for both MGS Unit 1 and MGS Unit 2.

Additionally, the new 779 BHP emergency diesel generator is replacing two existing emergency diesel engines, one for an electrical generator and one for a fire water pump. The new engine is providing emergency backup power in the same manner as the existing engine. Therefore the new emergency diesel engine is a replacement emissions unit for the two existing emergency IC engines.

Pursuant to Rule 26.6.D.2, an emissions increase for a replacement project is calculated as the emissions unit's post-project potential to emit adjusted to reflect current BACT minus the emissions unit's pre-project potential to emit adjusted to reflect current BACT. However, pursuant to Rule 26.6.D.7 this potential-to-potential emission calculation does not apply to a major modification of ROC or NOx.

Therefore, the emissions increase for this project will be calculated on a potential-to-potential basis for ROC, PM10, and SOx (Rule 26.6.D.2). The emissions increase for NOx will be calculated on an actual-to-potential basis (Rule 26.6.D.7). Note that Rule 26.2 does not require emission offsets for CO or NH3.

For a major modification of ROC or NOx as defined in Rule 26.1.19, pursuant to Rule 26.6.D.7, an emissions increase is calculated as the post-project potential to emit minus the emissions unit's pre-project actual emissions. Actual emissions are defined in Rule 26.6.C and are based on an average of the most recent two years of operation, or as determined by the APCO, a more representative period of two consecutive years in the most recent five years of operation. The facility is a major source for NOx but not for ROC. Therefore, the project cannot be a major modification for ROC.

Therefore, the NOx emissions increase will be calculated based the post-project potential to emit minus the emissions unit's pre-project actual emissions. The NOx emission calculations are shown in the Table VII-20 below:

Table VII - 20

Actual to Potential NOx Emission Changes (Rule 26.6.D.7)	NOx Tons Per Year
New P3 262 MW Turbine Emissions – potential emissions	+32.95
New P3 779 BHP Engine Emissions – potential emissions	+0.02
Remove existing MGS Unit 2 – actual emissions	-3.04
Remove Existing MGS 154 BHP Engine - actual emissions	-0.00
Remove Existing MGS 201 BHP Engine - actual emissions	-0.00
NOx Emission Change	**+29.93**

As shown in Table VII-20 above, the NOx emission increase is greater than the Rule 26.1.19 definition of major modification threshold of 25 tons per year. Therefore the project is a major modification for NOx.

The emission change for ROC will be calculated based on the potential emissions, as the facility is not a major source for ROC. PM10 and SOx will be calculated based on the potential emissions both pre-project and post-project as these pollutants do not have major source thresholds. The ROC, PM10, SOx, and CO emission change calculations are shown in Table VII-21 below.

Table VII - 21

Potential to Potential Emission Changes (Rule 26.6.D.2)	**Tons Per Year**			
	ROC	**PM_{10}**	**SOx**	**CO**
New P3 262 MW Turbine - potential emissions	10.84	10.68	5.91	54.42
New P3 779 BHP Emergency Engine - potential emissions	0.01	0.00	0.00	0.11
Remove Existing MGS Unit 2 - potential emissions	-11.62	-20.75	-4.98	-332.04
Remove existing 154 BHP Emergency Engine - potential emissions	0.00	0.00	0.00	-0.01
Remove existing 201 BHP emergency engine - potential emissions	0.00	0.00	0.00	-0.01
Emission Change	**-0.77**	**-10.07**	**+0.93**	**-277.53**

VIII. Analysis of Compliance With Applicable Rules and Regulations

Rule 26.2 – Section A Best Available Control Technology

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 and Table 1 have a zero threshold for BACT for ROC, NOx, PM-10, and SOx. BACT is not required for CO.

1. **262 MW Nominal Combustion Gas Turbine:**

BACT requirements apply for ROC, NOx, PM-10, and SOx. The unit is a simple cycle cogeneration turbine, meaning it employs a “simple power cycle” and no secondary steam is produced. There is no heat recovery steam generator (HRSG). The proposed turbine has a dry low-NOx combustor and is not equipped with water or steam injection for NOx control. 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 (see Table VII-22).

Table VII - 22

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 in Table VII-23 below:

Table VII - 23

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 (see Table VII-24):

Table VII - 24

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

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 shown in Table VII-25:

Table VII - 25

SJVAPCD BACT Guideline 3.4.7			
Date	**SJVAPCD Gas Turbine**	**NOx**	**ROC**
10/01/02	= or >50 MW, Uniform Load, without Heat Recovery	Achieved in practice: 5.0 ppmvd @15% O2, 3 Hr avg. (high temp SCR) Technologically feasible: 2.5 ppmvd @ 15% O2 (high temp SCR or equal) 3.0 ppmvd @ 15% O2 (high temp SCR or equal)	Achieved in practice: 2.0 ppmvd @15% O2, 3 Hr avg. (oxidation catalyst) Technologically feasible: 0.6 ppmvd @15% O2, 3 Hr avg. (oxidation catalyst) 1.3 ppmvd @15% O2, 3 Hr avg. (oxidation catalyst)

SJVAPCD provides the following site-specific BACT determination shown in Table VII-26:

Table VII - 26

SJVAPCD Site Specific BACT Determination					
Date	**Project/Location**	**Equipment**	**NOx limit**	**ROC limit**	**Comments**
10/05/01	GWF Energy Tracy, CA	84.4 MW GE PG7121, Turbine	5.0 ppmvd (3-Hr avg.)	2.0 ppmvd (3-Hr avg.)	Dry low NOx combustors SCR/oxidation catalyst

BAAQMD: The Bay Area Air Quality Management District determines BACT requirements on a case by case basis. The latest BACT determination for a turbine was done in July 2003. The resulting BACT database includes the information in Table VII-27 below:

Table VII - 27

BAAQMD Simple Cycle >= 40 MW BACT Determination 89.1.3			
Date	**BAAQMD Gas Turbine**	**NOx**	**ROC**
07/18/03	≥ 40 MW, simple cycle	2.5 ppmvd @ 15% O2 (Hi temp SCR+ water or steam injection)	2.0 ppmvd @ 15% O2 (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 the following guidance is presented in Table VII-28:

Table VII - 28

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:
As shown in the BACT guidelines listings above for gas fired turbines, emission levels of 2.5 ppmvd NOx @ 15% O2 and 2.0 ppmvd ROC @ 15% O2 have been achieved in practice for a simple cycle turbine. These levels have been achieved using an SCR system for NOx control and an oxidation catalyst. No lower emission levels for NOx and ROC have been identified as being technologically feasible.

These emission levels and controls have been proposed by the applicant to satisfy BACT.

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 PM10 and SOx have been identified as being technologically feasible.

Therefore, BACT for the Puente Power Project GE 7HA.01 Gas Turbine is as follows in Table VII-29:

Table VII - 29

BACT Gas Turbine	
NOx	2.5 ppmvd @ 15% O_2, 1 Hr average, SCR
ROC	2.0 ppmvd @ 15% O_2 as methane, 1 Hr average
PM_{10}	PUC regulated natural gas only
SOx	PUC regulated natural gas only

2. 779 BHP Emergency Diesel Engine:

BACT requirements apply for ROC, NOx, PM-10, and SOx. The unit is a 779 diesel fired emergency engine. The engine has a 50 hours per year limit for non-emergency operation. The applicant has proposed a diesel engine that meets US EPA non-road Tier 4 final standards. BACT databases for other air districts yield the following information:

SCAQMD:
The SCAQMD BACT manual lists BACT AN:392542 for 764 BHP Emergency IC engine, compression ignition, as the engine meets the applicable US EPA non-road Tier engine standard. The engine is required to use fuel with sulfur content of <0.05%.

SJVAPCD:
The SJVAPCD BACT lists BACT 3.1.1 for emergency diesel IC engines as the engine meets the latest US EPA Tier certification for NOx, ROC. Very low sulfur diesel fuel (15 ppmw sulfur or less). PM10 emissions of 0.15 g/BHP-Hr or the latest US EPA Tier Certification, whichever is more stringent.

BAAQMD:
The BAAQMD BACT lists BACT 96.1.3 for IC engine, compression ignition, stationary emergency as the engine meets CARB ATCM standard for ROC and NOx. Very low sulfur diesel fuel (15 ppmw sulfur or less). PM10 emissions of 0.15 g/BHP-Hr.

No lower emission levels for NOx, ROC, PM10, or SOx have been identified as being technologically feasible.

BACT for the Emergency IC engine is presented in Table VII-30 below:

Table VII - 30

BACT Emergency IC Engine	
NOx	US EPA non-road Tier 4 final standard
ROC	US EPA non-road Tier 4 final standard
PM_{10}	US EPA non-road Tier 4 final standard
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.1 Table B-1 (Table VII-31 below):

Table VII-31

Rule 26.2.B Table B-1 Offset Thresholds			
Pollutant	**Offset Threshold**	**Facility Post-Project Emissions**	**Offsets Review Triggered?**
ROC	5.0 ton/yr	23.22 ton/yr	Yes
NOx	5.0 ton/yr	167.10 ton/yr	Yes
PM_{10}	15.0 ton/yr	33.45 ton/yr	Yes
SOx	15.0 ton/yr	10.95 ton/yr	No

As shown in the table above, the offset thresholds of Rule 26.2 Table B-1 are exceeded for ROC, NOx and PM10. Therefore, offsets will be required for any emission increases in ROC, NOx, and PM10 as calculated pursuant to Rule 26.6, "New Source Review – Calculations". There are no offsets required for any SOx emission increases as the offset threshold will not be exceeded.

NOx Offset Requirements – Actual to Potential Emission Increases (Rule 26.6.D.7)
The increase in NOx emissions from the proposed CTG and IC engine will be offset using Emission Reduction Credits (ERCs). The NRG MGS facility is a major source for NOx. Please note that NOx emissions offsets were not provided for the existing boilers (MGS Units 1 and 2) or the existing emergency engines when they were originally placed into service. Therefore, per Rule 26.6 Section D.7.a, the NOx emissions increase is equal to the post-project potential to emit minus the pre-project actual 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 ratio

= (new CTG replacing MGS Unit 2 +
new IC engine replacing two existing IC engines) x 1.3 offset ratio
= (32.95 tons - 3.04 tons + 0.02 tons - 0.00 tons) x 1.3 offset ratio
= 29.93 tons NOx/yr x 1.3 offset ratio
= 38.91 tons NOx/yr

The District has determined that the following NOx ERC Certificates proposed by the applicant are eligible for use as emission offsets for the Puente Power Project. NOx offsets will be provided from ERC Certificate Nos. 1078, 1079, 1080, 1083, 1085, 1091, 1092, 1094, 1097, 1104, and 1107 owned by the Southern California Edison Co. These ERC Certificates currently have a total NOx balance of 50.66 tons per year. Pursuant to Rule 26.4.D.3, there are no limitations on the use of these emission reduction credits and they may be used as proposed for the Puente Power Project. A digital copy of each of these ERC Certificates is included in Appendix E – ERCs Identified For Possible Use.

Pursuant to Rule 26.2.B.2.d and Rule 26.11.C.6 these 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 shows a positive balance for NOx.

All of these ERC Certificates were created by the Southern California Edison Co. in the early 1990's as a part of an electrification conversion program. Over eighty (80) natural gas-fired engines were replaced with electric motors. These engines were used to power equipment such as oil well rod pumping units, natural gas compressors, and water well pumps. These ERC Certificates have all been assigned a quarterly profile of 25%, 25%, 25%, 25%.

ROC Offset Requirements - Potential to Potential Emission Increases (Rule 26.6.D.2):
The NRG Mandalay Generating Station is not a major source for ROC.

The facility will be required to provide ROC offsets at a tradeoff ratio of 1.1 to 1 as per Rule 26.2.B.2.b.1 for any emission increase. The quantity of offsets required is shown below.

ROC offsets required = increase in ROC emissions x 1.1 offset ratio

= (new CTG replacing MGS Unit 2 +
new IC engine replacing two existing IC engines)
= (10.84 - 11.62) tons + (0.01-0.00-0.00) tons
= -0.77 tons ROC/yr

As shown above there is no increase in ROC emissions. Therefore, offsets are not required for ROC.

PM10 Offset Requirements - Potential to Potential Emission Changes (Rule 26.6.D.2):
The NRG Mandalay Generating Station is not a major source for PM10.

The facility will be required to provide PM10 offsets at a tradeoff ratio of 1.1 to 1 as per Rule 26.2.B.2.c for any emission increase. The quantity of offsets required is shown below.

PM10 offsets required = increase in PM10 emissions

= (new CTG replacing MGS Unit 2 +
new IC engine replacing two existing IC engines)
= (10.68 - 20.75) tons + (0.00-0.00-0.00) tons
= -10.07 tons PM10/yr

As shown above there is no increase in PM10 emissions. Therefore, offsets are not required for PM10.

Rule 26.2 B. 4 Offsets - ERC Quarterly Profile Check

As discussed above, the ERC Certificates that will be used for the Puente Power Project have all been assigned a quarterly profile of 25%, 25%, 25%, 25%. These proposed ERC Certificates are expected to meet the quarterly profile check of Rule 26.2.B.4 and Rule 26.6.F as shown in Appendix F – ERC Profile Check. Rule 26.6.F requires the profile check be equal to at least 80 percent. In a March 29, 2016 letter, the applicant has stated that the Puente Power Project is expected to operate in a manner similar to Mandalay Generating Station Unit Nos. 1 and 2 for the most recent calendar years 2013, 2014, and 2015. In this letter, these years meet the quarterly profile check of 80 percent based on a 3-year average gross electrical output (MW-Hr) combined for MGS Unit Nos. 1 and 2. In addition, Appendix F shows that the average quarterly profile for MGS Unit Nos. 1 and 2 combined at the Mandalay Generating Station for the years 2010, 2011, 2012, 2013, and 2014 also meet the quarterly profile check of 80% based on the actual natural gas consumption records.

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). Rule 26.2.C only requires modeling for the Puente Power Project and does not require modeling for any other existing emissions units. Modeling of the Puente Power Project 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 in Appendix J.

The VCAPCD has determined that the applicant’s analysis of alternatives complies with Rule 26.2.E with the understanding that the California Energy Commission (CEC) Application For Certification process includes its own “Alternatives” analysis in Section 4.2 of the Revised Preliminary Staff Assessment (PSA) for the Puente Power Project (15-AFC-01) dated June 2016. The CEC analysis of alternatives is governed by the California Environmental Quality Act (CEQA).

The CEC alternatives analysis includes a no project alternative, off-site alternative locations, and a reconfiguration of the Puente Power Project within the Mandalay Generating Station. The CEC analysis of alternatives included a review of socioeconomics, including environmental justice factors such as minority populations and poverty level.

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 Puente Power Project will result in an increase in NOx emissions over the 15.0 tons per year threshold and therefore, a public notification was conducted.

The VCAPCD provided a public notice for the Puente Power Project in English, Spanish, Mixteco, and Tagalog both in local newspapers (Ventura County Star in English on May 23, 2016 and Ventura County VIDA in Spanish on May 26, 2016) and on the VCAPCD website (in all four languages). In addition, the VCAPCD participated in the CEC Preliminary Staff Assessment (PSA) workshop that was conducted in Oxnard on July 21, 2016 that included a "real time" translation in Spanish. The public comment period lasted over 60 days and closed on July 29, 2016.

In response to the public notice, six (6) comment letters were received during the public comment period and are included in Appendix L. The VCAPCD responded to these comments in Appendix M.

The District also submitted 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 their review. No comments were received from ARB or EPA on the Puente Power Project.

Rule 26.9 New Source Review - Power Plants

This rule applies to the Puente Power Project as an Application for Certification has been submitted to the California Energy Commission (Docket No. 15-AFC-01). The District conducted a Determination of Compliance review (this document) as required by Rule 26.9. Compliance with this rule is confirmed.

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

This rule provides for the evaluation by the District 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 the Puente Power Project is required to provide NOx offsets as calculated above, the District shall evaluate the proposed offsets per Rule 26.11 Section B.

Pursuant to Rule 26.2.B.2.d and Rule 26.11.C.6 these NOx offsets are not required to be surplus at the time of use since the most recent report (April 1, 2016) of the Rule 26.11 Annual Equivalency Demonstration Program 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, the Puente Power Project results in a major modification for NOx only. Major modifications are also federal major modifications unless there is a less than significant emissions increase or no increase in an existing plant-wide applicability limit.

This project results in a significant emissions increase for NOx. Additionally the facility does not have an existing plant-wide applicability limit. Therefore, this project is a federal major modification for NOx. 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.

Rule 29 Conditions On Permits

Section A of this rule requires the District 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 District 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 are subject to the requirements of Part 70 permits (commonly called Title V sources) must submit timely applications to revise their Part 70 permit. The Puente Power Project is a significant modification to the existing Title V permit for the Mandalay Generating Station. Therefore, NRG will be required to submit a Part 70 application to the District prior to operating such source pursuant to the modification. A condition has been placed on the DOC to ensure the facility submits a Part 70 modification application prior to operation of the new equipment.

Rule 34 Acid Deposition Control

A Title IV Acid Rain permit is required for the proposed turbine because the unit is a new fossil fuel fired combustion device 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 rules by District Rule 34, Acid Deposition Control. The Determination of Compliance will require that NRG submit the Title IV Acid Rain permit application prior to operating the new turbine.

Rule 50 Opacity

Rule 50 limits visible emissions to an opacity of less than 20 percent (Ringlemann No. 1), as published by the United States Bureau of Mines. Visible emissions are not expected under normal operation from the turbine, emergency diesel 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 turbine, engine, and ammonia tank, are not expected to create nuisance problems, such as smoke or odors.

The District 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 risks are below:

RMR Results

Unit Description	Cancer Risk	Hazard Index		Health Risk Reduction Plan Required?
		Chronic	Acute	
Using Adjusted U* Option (Adj-U*)				
Natural Gas Turbine	3.81×10^{-8}	8.24×10^{-5}	2.08×10^{-2}	No
Diesel Emergency Engine	5.37×10^{-8}	1.66×10^{-5}	---	No
Project Total	8.48×10^{-8}	9.23×10^{-5}	2.08×10^{-2}	No
Not Using Adjusted U* Option				
Natural Gas Turbine	3.81×10^{-8}	8.24×10^{-5}	4.19×10^{-2}	No
Diesel Emergency Engine	4.22×10^{-8}	1.59×10^{-5}	--	No
Project Total	7.32×10^{-8}	9.12×10^{-5}	4.19×10^{-2}	No

These risks are well below the District's "no further action" thresholds of 1 in a million for excess cancer risk, 0.5 for the chronic hazard index, and 0.5 for the acute hazard index. Therefore, compliance with Rule 51 is expected.

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 maximum modeled ground level concentrations of 1.3 $\mu g/m^3$ (0.0004 ppmv) on a 1 hour average and 0.2 $\mu g/m^3$ (0.00008 ppmv) on a 24 hour average. These concentrations are below the limits of Rule 54. 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, earthmoving, 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 Puente Power Project that will assure compliance with this rule. Compliance with this rule is expected during the routine operation of the Puente Power Project.

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 10.1 pounds per hour (which is greater than the EPA AP-42 emission factor) and the maximum fuel input rate of 2,572 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 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 779 BHP Caterpillar emergency diesel fired internal combustion engine. The engine will provide emergency power when there is a grid electricity power failure. 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 District per Rule 74.9.F.2.

Rule 74.23 Stationary Gas Turbines

The proposed GE 7HA.01 gas turbine is 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 turbine is 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 turbine 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 District inspection for 2 years. However, District 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 District with reports and data identifying the annual usage (e.g., fuel consumptions, operating hours, etc.) of the turbine 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 the new GE 7HA.01 Turbine 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 District has verified that the new CTG and the emergency 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 IC Engines Powering Electrical Generators	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. The proposed permit condition, requiring the use of CARB certified diesel fuel, was included earlier in this evaluation.
The engine(s) must meet the emission standards in Table 1 of the ATCM for the specific power rating and model year of the proposed engine.	The applicant has proposed the use of 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.	The following condition will be included on the permit: • *This engine shall 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, or by no later than January 1, 2005, on all engines subject to all or part of the requirements of sections 93115.6, 93115.7, or 93115.8(a) 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.	The following condition will be included on the permit: • *This engine shall be equipped with a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District determines 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*.
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 were shown earlier in the evaluation.

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

District Rule 13 Section C.2 requires for projects requiring CEQA review for the District 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 779 BHP Caterpillar emergency diesel fired 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 60.4205 contains emission standards for the engine. The emergency engine is required to comply with the emission standards for non-road compression ignition engines in 40 CFR 89.112 and 89.113. For engines in this power range and model year, these standards require 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, which are known as "Tier 3" standards. The proposed engine is a "Tier 4" certified engine with emission levels below these values, therefore the engine meets this requirement.

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 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 7HA.01 gas turbine is subject to the subpart because the heat input for the turbine is 2,572 MMBTU/Hr. The turbine is a simple cycle turbine without heat recovery and does not utilize water or steam injection for emissions control. The turbine 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 turbine is over 850 MMBTU/Hr, therefore the NOx limit as listed in Table 1 is 15 ppmvd at 15% O2 or 0.43 lb/MW-Hr when operating at or above 75% of peak load and 96 ppmvd at 15% O2 or 4.7 lb/MWh when operating below 75% of peak load.

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

Section 60.4330 requires the turbine to meet the SO_2 emission limits. The turbine 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 (0.0021375 lbs- SO_2/MMBTU). This sulfur content is lower than the fuel sulfur standard. Therefore, the new turbine 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 be required to operate the turbine in this manner.

Section 60.4340 provides guidance on requirements when there is no water or steam injection being used to control NOx emissions. The section requires either annual source testing to show NOx compliance or installation of a continuous emission monitoring system (CEMS) as described in 60.4335(b) and 60.4345 be used. The facility has proposed to install and operate a CEMS which will comply with these sections.

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. The Puente Power Project will be required to keep records of fuel natural 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 15 ppmvd at 15% O2 (or 96 ppmvd at 15% O2 when operating below 75% of 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 From New, Modified, and Reconstructed Stationary Sources: Electric Utility 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 NRG P3 turbine 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 the P3 CTG 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 the new P3 CTG 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 P3 CTG would be a non-base load unit under the final CPS. As a non-base load unit, under the final CPS the potential electric output for P3 is calculated as follows:

Potential electric output =

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

$$= 0.41 \times 2{,}567.81 \frac{MMBtu}{hr} \times \frac{10^6 Btu}{MMBtu} \times \frac{1\ kWh}{3412.1416\ Btu} \times \frac{1\ MWh}{1{,}000\ kWh} \times 8{,}760 hrs/yr$$

$$= 2{,}702{,}862 \text{ MW per year}$$

As long as the P3 CTG has net electric sales of less than 0.41 * 2,702,862 MW, or 1,108,173 MW per year, it will be subject to the 120 lb CO_2/MMBTU limit for non-base load gas turbines. The new P3 CTG is expected to operate with an annual capacity factor of approximately 25%. With a full load net nominal output of approximately 262 MW, the P3 unit would supply a maximum of approximately 25% x 8760 hrs/year x 262 MW/Hr = 573,780 MW per year to a utility power distribution system. Since this output is less than the allowable level of 1,108,173 MW per year, the P3 CTG 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.

<u>40 CFR Part 63 Subpart ZZZZ – Reciprocating Internal Combustion Engines (RICE)</u>

This NESHAP rule applies to the new emergency diesel 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.

<u>40 CFR Part 64, "Compliance Assurance Monitoring"</u>

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 and CO. However, based on 40 CFR Part 64.2(b)(1)(vi), NOx and CO emission are exempt from CAM since the Part 70 permit for the turbine already requires a continuous compliance determination method for both NOx and CO. The turbine will have a CEM installed which will comply with this requirement.

<u>40 CFR Part 68, List of Regulated Substances and Thresholds for Accidental Release Prevention</u>

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, the facility is not subject to 40 CFR Part 68.

40CFR Part 75 – Continuous Emission Monitoring (CEMS)

The new turbine combusts only natural gas, it is 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 Puente Power Project is expected to comply with all applicable District, State, and Federal rules and regulations that the VCAPCD implements and enforces. Issue a Rule 26.9 Determination of Compliance for the Puente Power Project subject to the conditions presented in Appendix K.

Appendices:

Appendix A	Current Permitted Emissions
Appendix B	Emissions Data
Appendix C	Commissioning Schedule
Appendix D	Historical Fuel Records
Appendix E	ERCs Identified For Possible Use
Appendix F	ERC Profile Check
Appendix G	Ambient Air Quality Analysis and Risk Management Review
Appendix H	Hazardous Air Pollutant Stationary Source Potential to Emit
Appendix I	Certification of Statewide Compliance
Appendix J	Analysis of Alternatives
Appendix K	DOC Conditions
Appendix L	PDOC Comment Letters
Appendix M	Responses to PDOC Comment Letters