San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

NOV 06 2017

Doug Bryant
Maas Energy Works
1670 Market St Suite 256
Redding CA, 96001

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: C-9011
Project Number: C-1170083

Dear Mr. Bryant:

Enclosed for your review and comment is the District's analysis of Hanford Renewable Energy's application for an Authority to Construct for the installation of two 1,306 bhp biogas-fired IC engines each powering an 1,028 kW electrical generator, at 19765 13th Ave. Hanford, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Ms. Andrea Ogden of Permit Services at (559) 230-5886.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:ao

Enclosures

cc: Tung Le, CARB (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

Installation of two Digester Gas-Fired IC Engines

Facility Name:	Hanford Renewable Energy LLC	Date:	October 19, 2017
Mailing Address:	1670 Market St Suite 256 Redding, CA 96001	Engineer:	Andrea Ogden
		Lead Engineer:	Joven Refuerzo
Contact Person:	Doug Bryant		
Telephone:	(207) 691-8068		
Application #:	C-9011-2-0 and '-3-0		
Project #:	C-1170083		
Deemed Complete:	February 16, 2017		

I. Proposal

Hanford Renewable Energy LLC (Hanford Renewable Energy) has requested two Authority to Construct (ATC) permits for the installation of two 1,306 bhp digester gas-fired IC engines each powering an 1,028 kW electrical generator. The proposed engines will be equipped with a selective catalytic reduction (SCR) system and an oxidation catalyst for emissions controls.

The IC engines will use digester gas from the existing digester system permitted under Phillip Verwey Farms #2 (C-6817). The engines will be owned by an entity other than Philip Verwey Farms #2 that will sell its power to the utility grid. Hanford Renewable Energy LLC (C-9011) has provided information supporting that the dairy and the power generation facility will be separately owned and operated.

The following is a summary of some of the information provided by the applicant. The proposed IC engines at the site will be installed, operated, maintained, repaired, and replaced if necessary by Hanford Renewable Energy. The responsibility of Philip Verwey Farms #2 will be limited to providing the digester gas fuel from it's existing covered lagoon permitted as C-6817-10-0. Hanford Renewable Energy will not be involved at all in the dairy's primary activity, production of milk. The proposed digester gas-fired IC engines generator sets will be constructed on land leased from the dairy site and will be operated and maintained by Hanford Renewable Energy. Hanford Renewable Energy will be solely responsible for ensuring that the digester gas-fired IC engines comply with all applicable air quality regulations. Hanford Renewable Energy will sell all of the electricity generated to the utility grid and will not provide any electricity directly to Philip Verwey Farms #2 (C-6817). Because Philip Verwey Farms #2 and the proposed digester gas-fired IC engines powering an electrical generator at the site will have different two-digit Standard Industrial Classification (SIC) codes (Industry Group 24: Dairy Farms for Philip Verwey Farms #2 vs. Industry Group 49: Electric, Gas, And

Sanitary Services for the IC engine generator set), pursuant to Section 3.37 of District Rule 2201, the proposed digester gas-fired IC engines will not be part of the dairy agricultural stationary source. Therefore, Philip Verwey Farms #2 and Hanford Renewable Energy are separate stationary sources and the proposed IC engines will be permitted as a non-agricultural stationary source (C-9011-2-0 and '-3-0).

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (2/18/16)
Rule 2410 Prevention of Significant Deterioration (6/16/11)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
Rule 4001 New Source Performance Standards (4/14/99)
Rule 4002 National Emission Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4701 Stationary Internal Combustion Engines - Phase 1 (8/21/03)
Rule 4702 Stationary Internal Combustion Engines (11/14/13)
Rule 4801 Sulfur Compounds (12/17/92)
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
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

III. Project Location

The facility is located at 19765 13th Ave in Hanford, CA. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

The applicant is proposing to install two 1,306 bhp Caterpillar lean burn digester gas-fired IC engines. The engines will each be equipped with an SCR system and an oxidation catalyst for emissions control and each engine will power an 1,028 kW generator. The electricity generated by this operation will be sold to the utility grid. Each engine will be permitted to operate up to 7 hours per day and 120 hours per year during the commissioning period (the time allowed during initial startup of the engine to perform testing, adjustment, tuning, and calibration of the IC engine without full operation of the SCR system and/or oxidation catalyst) in the first year and up to 24 hours per day and 6,500 hours per year after the commissioning period.

V. Equipment Listing

C-9011-2-0: 1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT SELECTIVE CATALYTIC REDUCTION (SCR) WITH OXIDATION CATALYST SYSTEM POWERING AN ELECTRICAL GENERATOR

C-9011-3-0: 1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT SELECTIVE CATALYTIC REDUCTION (SCR) WITH OXIDATION CATALYST SYSTEM POWERING AN ELECTRICAL GENERATOR

VI. Emission Control Technology Evaluation

The proposed engines will be equipped with:

- Turbocharger
- Intercooler
- Positive Crankcase Ventilation (PCV)
- Air/Fuel Ratio or an O_2 Controller
- Lean Burn Technology
- Oxidation Catalyst
- Selective Catalytic Reduction (SCR)

The turbocharger reduces the NO_X emission rate from the engine by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X.

The PCV system reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize engine operation and catalyst function.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, are passed through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it is converted to ammonia. The ammonia is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

An oxidation catalyst which converts CO and VOC emissions to CO_2 and water will be included. Typically, these catalysts are located prior to the urea injection site since the oxidation catalyst would otherwise convert the excess ammonia into NOx.

Additionally, prior to being combusted in the engine, the digester gas will be treated in a gas conditioning system to reduce the H_2S such that the sulfur content will not exceed 40 ppmv as H_2S.

VII. General Calculations

A. Assumptions

- Higher Heating Value (HHV) for Digester Gas: 700 Btu/scf (proposed by the applicant, based on 70% methane content, also used in other similar District projects)
- Typical EPA F-factor for digester gas: 9,100 dscf/MMBtu (Dry, adjusted to 60 °F), (Estimated based on previous source tests and District practice)
- MMBtu/hr to bhp conversion: 392.75 bhp-hr/MMBtu (per AP-42, Appendix A)
- Average sulfur content of the scrubbed biogas: 40 ppmv as H_2S (per applicant)
- Molar Specific Volume = 379.5 scf/lb-mol (60°F)
- Molecular weights:
  NO_X (as NO_2) = 46 lb/lb-mol CO = 28 lb/lb-mol NH_3 = 17 lb/lb-mol
  VOC (as CH_4) = 16 lb/lb-mol SO_X (as SO_2) = 64.06 lb/lb-mol
- Efficiency of each engine = 30% (District practice)
- A commissioning period to perform testing, adjustment, tuning, and calibration of the IC engines without full operation of the SCR system will be allowed during initial startup of each engine. The duration of the commissioning period shall last no more than 120 hours of operation of each engine without the SCR system installed and operating at its maximum efficiency (per applicant)
- Each engine will be limited to operating for no more than 7 hours per day during the commissioning period (proposed by applicant)
- During normal operation, each engine will operate 24 hours/day and 6,500 hours per year (proposed by the applicant)
- These engines will be allowed to operate up to 120 hours during the initial installation and testing period for commissioning purposes only during the first year of operation
- Ammonia slip from SCR = 10 ppm (per applicant)

B. Emission Factors

Emission Factors during the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent its damage. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.[1] Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

Emission Factors for Each Digester Gas-Fired Engine (Commissioning Period)

Pollutant	g/bhp·hr	ppmvd (@ 15%O2)	Source
NO_X	1.0	--	Information from Engine Supplier (Caterpillar)
SO_X	0.04	40 ppmvd in fuel gas	BACT Requirement/Mass Balance Equation on Following Page
PM_{10}	0.08	--	AP-42, Table 2.4-4, October 2008, See Equation on Following Page
CO	4.4	--	Information from Engine Supplier (Caterpillar)
VOC	1.11	--	Information from Engine Supplier (Caterpillar)
NH_3	0.06	10 ppmvd	Proposed by the Applicant, See Conversion on the Following Page

[1] See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (http://www.epa.gov/ttn/atw/rice/20120717riceqaupdate.pdf)

Emission Factors during Normal Operation after the Commissioning Period:

The emission factors for NOx, CO, and VOC from each proposed engine during normal operation were proposed by the applicant and supported by information provided by the engine and catalyst supplier. The emission factors for NOx, CO, and VOC will be achieved with the use of the SCR and catalyst system. The emission factors for SOx, PM_{10}, and ammonia slip during normal operation are same as the emission factors presented previously for during the commissioning period. The unit conversions for the emission factors are also shown below.

Emission Factors for Each Digester Gas-Fired Engine (Normal Operation)			
Pollutant	**g/hp-hr**	**ppmvd (@ 15%O_2)**	**Source**
NOx	0.15	10 ppmvd	Proposed by the Applicant, See Equation Below
SOx	0.04	40 ppmvd in fuel gas	Proposed by the Applicant, See Equation Below
PM_{10}	0.08	--	AP-42, Table 2.4-4, October 2008, See Equation Below
CO	0.60	66 ppmvd	Proposed by the Applicant, See Equation Below
VOC	0.10	19 ppmvd	Proposed by the Applicant, See Equation Below
NH_3	0.06	10 ppmvd	Proposed by the Applicant, See Equation Below

NOx – 10 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{0.15\text{ g NOx}}{\text{bhp - hr}} \times \frac{\text{MMBtu}}{9{,}100\text{ dscf}} \times \frac{0.3\text{ Btu}_{out}}{\text{Btu}_{in}} \times \frac{1\text{ lb - mol}}{46\text{ lb}} \times \frac{20.9 - 15}{20.9} \times \frac{379.5\text{ dscf}}{1\text{ lb mol}} \times \frac{393.24\text{ bhp - hr}}{\text{MMBtu}} \times \frac{\text{lb}}{453.6\text{ g}} = 10\text{ ppmv @ }15\,\%\ O_2$$

SOx – 40 ppmvd H_2S in fuel gas

$$\frac{40\text{ ft}^3\ H_2S}{10^6\text{ ft}^3} \times \frac{32.06\text{ lb S}}{\text{lb - mole }H_2S} \times \frac{\text{lb - mole}}{379.5\text{ ft}^3} \times \frac{64.06\text{ lb }SO_x}{32.06\text{ lb S}} \times \frac{\text{ft}^3}{700\text{ Btu}} \times \frac{10^6\text{ Btu}}{\text{MMBtu}} = 0.00965\ \frac{\text{lb - }SO_x}{\text{MMBtu}}$$

$$\frac{0.00965\text{ lb }SO_x}{\text{MMBtu}} \times \frac{\text{MMBtu}}{393.24\text{ bhp - hr}} \times \frac{\text{Btu}_{in}}{0.3\text{ Btu}_{out}} \times \frac{453.6\text{ g}}{\text{lb}} = 0.04\ \frac{\text{g - SOx}}{\text{bhp - hr}}$$

PM_{10} – AP-42, Table 2.4-4: 15 lb/10^6 dscf

15 lb-PM_{10}/10^6 dscf x 1 scf/ 700 Btu = 0.021 lb/MMBtu

$$\frac{0.021\text{ lb }PM_{10}}{\text{MMBtu}} \times \frac{\text{MMBtu}}{10^6\text{ Btu}} \times \frac{\text{Btu}_{in}}{0.3\text{ Btu}_{out}} \times \frac{2{,}545\text{ Btu}}{\text{hp - hr}} \times \frac{453.6\text{ g}}{\text{lb}} = 0.08\ \frac{\text{g - }PM_{10}}{\text{bhp - hr}}$$

CO – 66 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{66\,ft^3\ CO}{10^6\ ft^3} \times \frac{9{,}100\,ft^3}{1MMBtu} \times \frac{28\,lb\,CO}{1\,lb-mole} \times \frac{20.9}{20.9-15} \times \frac{1\,lb-mole}{379.5\,ft^3} \times \frac{MMBtu}{392.75\,bhp-hr} \times \frac{453.6\,g}{lb} \times \frac{Btu_{in}}{0.30\,Btu_{out}} = 0.6\ \frac{g-CO}{bhp-hr}$$

VOC – 19 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{19\,ft^3\ VOC}{10^6\ ft^3} \times \frac{9{,}100\,ft^3}{1MMBtu} \times \frac{16\,lb\,VOC}{1\,lb-mole} \times \frac{20.9}{20.9-15} \times \frac{1\,lb-mole}{379.5\,ft^3} \times \frac{MMBtu}{392.75\,bhp-hr} \times \frac{453.6\,g}{lb} \times \frac{Btu_{in}}{0.30\,Btu_{out}} = 0.1\ \frac{g-VOC}{bhp-hr}$$

NH_3 – 10 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{10\,ft^3\ NH_3}{10^6\,ft^3} \times \frac{9{,}100\,ft^3}{MMBtu} \times \frac{17\,lb\,NH_3}{lb-mole} \times \frac{20.9}{20.9-15} \times \frac{1\,lb-mole}{379.5\,ft^3} \times \frac{MMBtu}{392.75\,bhp-hr} \times \frac{453.6\,g}{lb} \times \frac{Btu_{in}}{0.30\,Btu_{out}} = 0.06\ \frac{g-NH_3}{bhp-hr}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since each engine is a new emissions unit, PE1 = 0 for all pollutants.

2. Post Project Potential to Emit (PE2)

Daily PE2 for Each Engine during the Commissioning Period:

As discussed above, during the commissioning period the engine will be limited to operating for no more than 7 hours per day. Therefore, the daily PE for NO_X, CO and VOC during the commissioning period will be based on operation for 7 hours/day since these values are greater than the values for operation for 24 hour/day with the SCR and oxidation catalyst. Since the values for SO_X, PM_{10} and NH_3 for operation after the commissioning period are greater, they will be used for the PE.

PE2 (lb/day) = [EF (g/hp-hr) x Rating (bhp) x 7 (hr/day)] / 453.6 (g/lb)

Daily PE2 During the Commissioning Period (each engine)								
NO_X	1.0	(g/hp·hr) x	1,306	(bhp) x	7	(hr/day) ÷ 453.59 (g/lb) =	20.2	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,306	(bhp) x	7	(hr/day) ÷ 453.59 (g/lb) =	0.8	(lb/day)
PM_{10}	0.08	(g/hp·hr) x	1,306	(bhp) x	7	(hr/day) ÷ 453.59 (g/lb) =	1.6	(lb/day)
CO	4.4	(g/hp·hr) x	1,306	(bhp) x	7	(hr/day) ÷ 453.59 (g/lb) =	88.7	(lb/day)
VOC	1.11	(g/hp·hr) x	1,306	(bhp) x	7	(hr/day) ÷ 453.59 (g/lb) =	22.4	(lb/day)
NH_3	0.06	(g/hp·hr) x	1,306	(bhp) x	7	(hr/day) ÷ 453.59 (g/lb) =	1.2	(lb/day)

Daily PE2 for Each Engine after Completion of the Commissioning Period:

Daily PE for the proposed engines after completion of the commissioning period is calculated in the following table.

PE2 (lb/day) = [EF (g/hp-hr) x Rating (bhp) x 24 (hr/day)] / 453.6 (g/lb)

Daily PE2 After the Commissioning Period (Normal Operation) (each engine)								
NO_X	0.15	(g/hp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	10.4	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	2.8	(lb/day)
PM_{10}	0.08	(g/hp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	5.5	(lb/day)
CO	0.60	(g/hp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	41.5	(lb/day)
VOC	0.10	(g/hp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	6.9	(lb/day)
NH_3	0.06	(g/hp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	4.1	(lb/day)

Maximum Annual PE2 for Each Engine Including the Commissioning Period:

As discussed above, the proposed engines will be allowed to operate up to 120 hours for commissioning during the first year of operation. The maximum annual PE for each engine will calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

Annual PE2 During the Commissioning Period (Each Engine)								
NO_X	1.0	(g/hp-hr) x	1,306	(bhp) x	120	(hr/year) ÷ 453.59 (g/lb) =	346	(lb/year)
SO_X	0.04	(g/hp-hr) x	1,306	(bhp) x	120	(hr/year) ÷ 453.59 (g/lb) =	14	(lb/year)
PM_{10}	0.08	(g/hp-hr) x	1,306	(bhp) x	120	(hr/year) ÷ 453.59 (g/lb) =	28	(lb/year)
CO	4.4	(g/hp-hr) x	1,306	(bhp) x	120	(hr/year) ÷ 453.59 (g/lb) =	1,520	(lb/year)
VOC	1.11	(g/hp-hr) x	1,306	(bhp) x	120	(hr/year) ÷ 453.59 (g/lb) =	384	(lb/year)
NH_3	0.06	(g/hp-hr) x	1,306	(bhp) x	120	(hr/year) ÷ 453.59 (g/lb) =	21	(lb/year)

First Year Annual PE2 After the Commissioning Period (Each Engine)								
NO_X	0.15	(g/hp-hr) x	1,306	(bhp) x	6,380	(hr/year) ÷ 453.59 (g/lb) =	2,755	(lb/year)
SO_X	0.04	(g/hp-hr) x	1,306	(bhp) x	6,380	(hr/year) ÷ 453.59 (g/lb) =	735	(lb/year)
PM_{10}	0.08	(g/hp-hr) x	1,306	(bhp) x	6,380	(hr/year) ÷ 453.59 (g/lb) =	1,470	(lb/year)
CO	0.60	(g/hp-hr) x	1,306	(bhp) x	6,380	(hr/year) ÷ 453.59 (g/lb) =	11,022	(lb/year)
VOC	0.10	(g/hp-hr) x	1,306	(bhp) x	6,380	(hr/year) ÷ 453.59 (g/lb) =	1,837	(lb/year)
NH_3	0.06	(g/hp-hr) x	1,306	(bhp) x	6,380	(hr/year) ÷ 453.59 (g/lb) =	1,102	(lb/year)

Maximum Daily and Annual PE2 from Each Engine during First Year, Including Commissioning:

Maximum Post-Project Daily and Annual PE2 (Each Engine)				
Pollutant	**Daily (lb/day)**	**During Commissioning (lb/year)**	**After Commissioning (lb/year)**	**Total (lb/year)**
NO_X	20.2	346	2,755	3,101
SO_X	2.8	14	735	749
PM_{10}	5.5	28	1,470	1,498
CO	88.7	1,520	11,022	12,542
VOC	22.4	384	1,837	2,221
NH_3	4.1	21	1,102	1,123

Annual PE2 for Each Engine after Commissioning:

The annual PE2 for each engine following the commissioning period is calculated as follows:

Annual PE2 After Year 1 with no Commissioning (Normal Operation) (Each Engine)								
NO_X	0.15	(g/hp·hr) x	1,306	(bhp) x	6,500	(hr/year) ÷ 453.59 (g/lb) =	2,807	(lb/year)
SO_X	0.04	(g/hp·hr) x	1,306	(bhp) x	6,500	(hr/year) ÷ 453.59 (g/lb) =	749	(lb/year)
PM_{10}	0.08	(g/hp·hr) x	1,306	(bhp) x	6,500	(hr/year) ÷ 453.59 (g/lb) =	1,497	(lb/year)
CO	0.60	(g/hp·hr) x	1,306	(bhp) x	6,500	(hr/year) ÷ 453.59 (g/lb) =	11,229	(lb/year)
VOC	0.10	(g/hp·hr) x	1,306	(bhp) x	6,500	(hr/year) ÷ 453.59 (g/lb) =	1,872	(lb/year)
NH_3	0.06	(g/hp·hr) x	1,306	(bhp) x	6,500	(hr/year) ÷ 453.59 (g/lb) =	1,123	(lb/year)

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site.

An ATC for one digester engine has already been issued to this facility as part of project # C-1161386.

SSPE1 (lb/year)					
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**
ATC C-9011-1-0	4,290	993	2,173	16,468	2,871
SSPE1	**4,290**	**993**	**2,173**	**16,468**	**2,871**

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site. Since the operation, including commissioning, is higher than the normal operation emissions, the emissions associated with the year with commissioning will be used for NSR purposes.

SSPE2 (lb/year)					
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**
SSPE1	4,290	993	2,173	16,468	2,871
C-9011-2-0	3,101	749	1,498	12,542	2,221
C-9011-3-0	3,101	749	1,498	12,542	2,221
SSPE2	**10,492**	**2,491**	**5,169**	**41,552**	**7,313**

5. Major Source Determination

<u>Rule 2201 Major Source Determination</u>:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source,
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months),
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165.

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1	4,290	993	2,173	2,173	16,468	2,871
SSPE2	10,492	2,491	5,169	5,169	41,552	7,313
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No	No

Note: PM2.5 assumed to be equal to PM10

As seen in the table above, the facility is not an existing Major Source and is not becoming a Major Source as a result of this project.

Rule 2410 Major Source Determination:

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

PSD Major Source Determination (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Estimated Facility PE before Project Increase	2.1	1.4	<1.0	8.2	1.1	1.1
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source?	No	No	No	No	No	No

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,

- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

As shown in Section VII.C.5 above, the facility is not a Major Source for any pollutant.

Therefore BE = PE1.

Since the proposed engines are new emissions units, BE = PE1 = 0 for all pollutants.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a Major Source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification.

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO_2 (as a primary pollutant)
- SO_2 (as a primary pollutant)
- CO

- PM
- PM_{10}
- Hydrogen sulfide (H_2S)[2]
- Total reduced sulfur (including H_2S)[2]

I. Project Emissions Increase - New Major Source Determination

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

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

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO_2	**VOC**	**SO_2**	**CO**	**PM**	**PM_{10}**
Total PE from New and Modified Units	3.1	2.2	<1.0	12.5	1.5	1.5
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	No	No	No	No	No	No

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix E.

[2] Because the facility is not included in the specific source categories listed in 40 CFR 51.165, for PSD purposes only non-fugitive emissions from the engine exhaust stacks must be addressed for this project. Although the sulfur (primarily H_2S) in the fuel will be converted almost entirely to SO_X during combustion, the maximum possible amount of H_2S and total reduced sulfur compounds from the engine stacks can be calculated by assuming that all sulfur in the fuel is emitted as H_2S. Based on the fuel sulfur limit of 40 ppmv as H_2S, the maximum possible H_2S emission factor for the engines is calculated to be 0.037 g-H_2S/bhp, resulting in a total combined maximum of 0.42 tpy H_2S from the exhaust stacks of the engine. This is well below the applicable PSD threshold of 250 tpy.

VIII. Compliance Determination

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

* Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

The proposed engines will have a PE greater than 2.0 lb/day for NO_X, SO_X, PM_{10}, CO, and VOC. Therefore, BACT is triggered for NO_X, SO_X, PM_{10}, and VOC. However, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

The proposed engines will each have a PE greater than 2.0 lb/day for NH_3. However, NH_3 slip emissions result from operation of an emissions control device (SCR) and not the emissions unit; therefore, this project does not trigger BACT for NH_3 emissions.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered for relocation of an emissions unit.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore, BACT is not triggered for modification of a unit.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 and/or Federal Major Modification. Therefore BACT is not triggered for Major Modification purposes.

2. BACT Guideline

BACT Guideline 3.3.15 applies to the proposed digester gas-fired IC engines [Waste Gas-Fired IC Engines] (See Appendix B).

3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the Top-Down BACT Analysis (See Appendix C), BACT has been satisfied with the following:

NO_X: NO_X emissions ≤ 0.15 g/bhp-hr
SO_X: Fuel sulfur content ≤ 40 ppmv (as H_2S)
PM_{10}: Fuel sulfur content ≤ 40 ppmv (as H_2S)
VOC: VOC emissions ≤ 0.10 g/bhp-hr

The following conditions will be placed on the ATC of each engine to ensure compliance with the BACT requirements during normal operation:

- This engine shall be fired on digester gas fuel only. [District Rule 2201]
- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 0.60 g-CO/bhp-hr (equivalent to 66 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 19 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up

to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant-by-pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	**SO_X**	**PM_{10}**	**CO**	**VOC**
SSPE2	10,492	2,491	5,169	41,552	7,313
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed,
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. As seen in Section VII.C.2 above, this project does not include a new emissions unit which has daily emissions greater than 100 lb/day for any pollutant, therefore public noticing for PE greater than 100 lb/day purposes is not required.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	**SSPE1 (lb/year)**	**SSPE2 (lb/year)**	**Offset Threshold**	**Public Notice Required?**
NO_X	4,290	10,492	20,000 lb/year	No
SO_X	993	2,491	54,750 lb/year	No
PM_{10}	2,173	5,169	29,200 lb/year	No
CO	16,468	41,552	200,000 lb/year	No
VOC	2,871	7,313	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the table below.

SSIPE Public Notice Thresholds					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_x	10,492	4,290	6,202	20,000 lb/year	No
SO_x	2,491	993	1,498	20,000 lb/year	No
PM_{10}	5,169	2,173	2,996	20,000 lb/year	No
CO	41,552	16,468	25,084	20,000 lb/year	Yes
VOC	7,313	2,871	4,442	20,000 lb/year	No

As demonstrated above, the SSIPE for CO is greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating permit, this change is not a Title V significant modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required since the SSIPE for CO is greater than 20,000 lb/year. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATCs and contained in or enforced by the latest PTOs and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

<u>Proposed Rule 2201 (DEL) Conditions for Each Engine during Both Commissioning and Normal Operation</u>:

- This engine shall be fired on digester gas fuel only. [District Rule 2201]

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [3][District Rules 2201, 4102, 4702, and 4801]

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]

- Ammonia (NH_3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rule 2201 and 4702]

- All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For the proposed engines, the DELs for NO_X, PM_{10}, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr), the maximum engine horsepower rating (1,306 bhp), and maximum number of hours allowed for commissioning activities. The following conditions will be placed on the permits to ensure compliance.

- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]

- Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]

- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]

- During the commissioning period, this engine shall operate for no more than 7 hours on any day in which the SCR system and oxidation catalyst are not

[3] Due to variations in sulfur content of the digester gas, an averaging time cannot be established until the unit has operated in a steady-state manner.

installed and operating for the entire duration of engine operation for that day. The permittee shall record total operating time of the engine for each day during the commissioning period in which the SCR system and oxidation catalyst are not installed and operating for the entire duration of engine operation on that day. [District Rule 2201]

- The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]

- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

- The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]

- Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-PM_{10}/bhp-hr, 4.4 g-CO/bhp-hr, 1.11 g-VOC/bhp-hr. [District Rule 2201]

<u>Proposed Rule 2201 (DEL) Conditions during Normal Operation</u>:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 0.60 g-CO/bhp-hr (equivalent to, 66 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 19 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

- Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]

Additionally, to limit annual emissions, the following condition will be included on the ATCs:

- This engine shall not operate more than 6,500 hours per calendar year. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

In accordance with District Policy APR 1705, source testing for NO_X, CO and VOC emissions from the digester gas fired IC engines served by a catalyst control system (including SCR and an oxidation catalyst) shall be conducted initially and at least once every 24 months thereafter. In addition, in order to assure compliance with the ammonia slip limit from the SCR system, source testing of the ammonia emissions will also be required initially and at least once every 24 months thereafter.

For PM_{10} emissions, the applicant has proposed to use an emission factor from AP-42, Section 2.4, which is applicable to municipal solid waste landfills. The digester gas fired in these engines should have a similar makeup to that of gas generated by a landfill. However, in order to assure that the engines are able to demonstrate compliance with the proposed PM_{10} emission factor, initial source testing will be required.

The engines are not served by any control devices for PM_{10} emissions. Therefore, it is not expected that the PM_{10} emissions will change much over time as long as the quality of the gas combusted in this unit remains fairly consistent. The facility will be required to monitor the sulfur content of the digester gas combusted in these units at least once per quarter. The results of quarterly monitoring should demonstrate that the quality of the gas combusted is consistent. Therefore, ongoing periodic source testing for PM_{10} emissions will not be required.

The following conditions will be placed on the permits to ensure compliance:

- Source testing to measure NO_X, CO, VOC, PM10, and ammonia (NH_3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201, and 4702]

- Source testing to measure NOx, CO, VOC, and ammonia (NH_3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH_3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

2. Monitoring

The proposed digester gas-fired engines are subject to District Rule 4702 – Internal Combustion Engines. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District

Rule 4702 requires monitoring of NO_x emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. However, Section 6.5.3 of District Rule 4702 requires monthly monitoring for engines equipped with non-certified control devices in order to demonstrate compliance with the emission limits in District Rule 4702. Therefore, monthly monitoring of NO_x, CO, and O_2 concentrations in accordance pre-approved alternate monitoring plan "A" will be required. Since the engine will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

The following conditions will be placed on the permits to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]

- If the NOx, CO, or NH_3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the allowable emission concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 8 hours, the permittee shall notify the District within the following 1 hour, and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4702]

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. Because of the variable content of digester gas, additional monitoring of the fuel sulfur content will be required.

The following conditions will be placed on the permit to ensure compliance:

- Fuel sulfur analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rules 2201 and 4702]

- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rules 2201 and 4702]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

The following conditions will be listed on the permits:

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

- The permittee shall maintain records of: (1) the date and time of NO_x, CO, O2, and NH_3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH_3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

- Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]

- The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

- {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

4. Reporting

No reporting is required to demonstrate compliance with District Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to Appendix D of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_x, CO, and SO_x. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_x, CO, or SO_x.

The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM_{10} and $PM_{2.5}$.

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 4001 New Source Performance Standards

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR) and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

40 CFR 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of NO_x, SO_x, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

The proposed engines are 1,306 bhp SI IC engines that are constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engines are subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

Rule 4002 National Emission Standards for Hazardous Air Pollutants

This rule incorporates NESHAPs from Part 63, Chapter 1, Title 40, Code of Federal Regulations (CFR) and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 63.

40 CFR 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part.

As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the permit. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

Rule 4101 Visible Emissions

Rule 4101 states that no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

The following condition will be listed on each permit to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix D), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

HRA Summary		
Unit	**Cancer Risk**	**T-BACT Required**
C-9011-2-0	0.061 per million	No
C-9011-3-0	0.061 per million	No

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined by the HRA Summary in Appendix D of this report, the emissions increases for this project was determined to be less than significant. The following condition will be listed on each permit as a mechanism to ensure compliance with this requirement.

- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

$$0.08 \quad \frac{g}{hp \cdot hr} \times \frac{1 hp \cdot hr}{2{,}545 Btu} \times \frac{10^6 Btu}{9{,}100 dscf} \times \frac{0.33 Btu_{out}}{1 Btu_{in}} \times \frac{15.43 grain}{g} = \quad 0.02 \quad \frac{grain}{dscf}$$

Since 0.02 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be listed on each of the proposed permits to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4701 Internal Combustion Engines – Phase I

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion (IC) engines.

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engines are subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

Rule 4702 Internal Combustion Engines

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides (SO_X) from IC engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0.

The proposed engines are required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed (except for an operator with at least 12 existing engines at one stationary source); therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the proposed engines.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated greater than 50 bhp shall comply with all the applicable requirements of the rule and the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

5.2.2.1.1 NO_X, CO, and VOC emission limits pursuant to Table 2;
5.2.2.1.2 SO_X control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and
5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the NO_X emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. As shown below, the applicant is proposing to comply with the NOx emission limit requirement of Table 2 as required by Section 5.2.2.1.1; therefore, no further discussion is required.

Section 5.2.2.3 allows that in lieu of complying with the NOx, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. As shown below, the applicant is proposing to comply with the NOx, CO, and VOC emission limit requirements of Table 2; therefore, no further discussion is required.

Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations (Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5.)			
Engine Type	**NO_X Emission Limit (ppmv @ 15% O_2, dry)**	**CO Emission Limit (ppmv @ 15% O_2, dry)**	**VOC Emission Limit (ppmv @ 15% O_2, dry)**
1. a. Rich-Burn, Waste Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. b. Rich-Burn, Cyclic Loaded, Field Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. c. Rich-Burn, Limited Use	25 ppmv	2,000 ppmv	250 ppmv
1. d. Rich-Burn, Not Listed Above	11 ppmv	2,000 ppmv	250 ppmv
2. a. Lean-Burn, 2-Stroke, Gaseous Fueled, >50 bhp & <100 bhp	75 ppmv	2,000 ppmv	750 ppmv
2. b. Lean-Burn, Limited Use	65 ppmv	2,000 ppmv	750 ppmv
2. c. Lean-Burn Engine used for gas compression	65 ppmv or 93% reduction	2,000 ppmv	750 ppmv
2. d. Waste Gas Fueled	65 ppmv or 90% reduction	2,000 ppmv	750 ppmv
2. e. Lean-Burn, Not Listed Above	11 ppmv	2,000 ppmv	750 ppmv

The proposed engines will be operated as a stationary source separate from the dairy farm and the District has determined that the engines are non-agricultural IC engines. The proposed engines are waste (digester) gas-fired engines and are required to comply with the following emissions limits from Table 2, Row 2.e: 11 ppmvd NO_X, 2,000 ppmvd CO, and 750 ppmvd VOC (all corrected to 15% O_2).

Therefore, the following previously presented condition will be listed on the permits to ensure compliance:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 0.60 g-CO/bhp-hr (equivalent to, 66 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 19 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3 applies to spark-ignited engines used exclusively in agricultural operations. As stated above, the proposed engines will be operated as part of a separate non-agricultural stationary source; therefore, Section 5.2.3 does not apply to the proposed engines.

Section 5.2.4 applies to certified compression-ignited engines. The proposed engines are not compression-ignited engines; therefore, Section 5.2.4 does not apply to the proposed engines.

Section 5.2.5 applies to non-certified compression-ignited engines. The proposed engines are not compression-ignited engines; therefore, Section 5.2.5 does not apply to the proposed engines.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The proposed engines will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the NOx emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the engines under this project; therefore this section of the Rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the NOx emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the engines under this project; therefore this section of the Rule is not applicable.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The applicant has proposed that the engines comply with the applicable emission limits of Table 2 of District Rule 4702; therefore, payment of annual emissions fees for the engines are not required and this section of the Rule is not applicable.

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or
5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or
5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or
5.7.4 Use California Reformulated Diesel for compression-ignited engines; or
5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or
5.7.6 Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

To satisfy BACT, the average sulfur content of the digester gas fuel for the engines will be limited to 40 ppmv or 0.04 g/bhp-hr (approximately equal to 0.8 grains sulfur per 100 standard cubic feet[4]). The following condition will be listed on each engine's permit to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702, and 4801]

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Section 5.8.1 through Section 5.8.11:

Section 5.8.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for NO_X, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system

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$$0.04 \frac{g}{hp\cdot hr} \times \frac{39275 hp\cdot hr}{MMBtu} \times \frac{MMBtu}{9{,}100 dscf} \times \frac{0.363 Btu_{out}}{1 Btu_{in}} \times \frac{15.43 grain}{g} = 0.008 \frac{grain}{dscf}$$

(CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

5.8.1.1 Periodic NO_X and CO emission concentrations,
5.8.1.2 Engine exhaust oxygen concentration,
5.8.1.3 Air-to-fuel ratio,
5.8.1.4 Flow rate of reducing agents added to engine exhaust,
5.8.1.5 Catalyst inlet and exhaust temperature,
5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic monitoring of NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following condition will be placed on each engine's permit to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The proposed engines will be subject to Section 5.8.1; therefore this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The proposed engines include a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B

(Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The proposed engines will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the proposed engines include an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for each engine in this project. Therefore, the following condition will be placed on the permits to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the operator shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program for each engine with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.8 requires that for each engine, the operator shall collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program for each engine and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, the operator shall use a portable NO_X analyzer to take NO_X emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NO_X emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All NO_X emissions readings shall be reported to the APCO in a manner approved by the APCO. NO_X emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period.

Therefore, the following conditions will be placed on each permit to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions-related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The proposed permit for each engine includes a pre-approved alternate emissions monitoring plan that requires periodic NO_x, CO, and O_2 emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the proposed engines; therefore this section of the Rule is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The proposed engines are subject to the requirements of Section 5.8; therefore this section of the Rule is not applicable.

Section 5.10 specifies SOx Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,

5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and

5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

The following condition will be listed on each engine's permit to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The proposed engines are each required to have a District Permit to Operate; therefore this section of the Rule is not applicable.

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

6.1.1.2 Engines subject to Section 8.0;

6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;

6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for the engines:

6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
6.1.2.2 Engine manufacturer,
6.1.2.3 Model designation and engine serial number,
6.1.2.4 Rated brake horsepower,
6.1.2.5 Type of fuel and type of ignition,
6.1.2.6 Combustion type: rich-burn or lean-burn,
6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,
6.1.2.11 Applicable emission limits,
6.1.2.12 Documentation showing existing emissions of NO_x, VOC, and CO, and
6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engines are in compliance with the emission requirements of this rule.

Section 6.1.4 requires that, for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2.

The applicant has submitted all the required information for Section 6.1 in the applications for the engines evaluated under this project.

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating log shall include, on a monthly basis, the following information:

6.2.1.1 Total hours of operation,
6.2.1.2 Type of fuel used,
6.2.1.3 Maintenance or modifications performed,
6.2.1.4 Monitoring data,
6.2.1.5 Compliance source test results, and

6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

The following condition will be placed on each permit to ensure compliance:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following previously presented condition will be listed on each engine's permit to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. The applicant is not claiming an exemption for the proposed engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Section 6.3.2 through Section 6.3.4 shall apply to the following engines:

6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.3.1.2 Engines subject to Section 8.0;
6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.

6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.

6.3.2.3 A portable NOx analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

The following conditions will be included on each permit to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201, and 4702]

- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, NOx, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. For engines that comply with a percent reduction limit, the percent reduction of NOx emissions shall also be reported.

The following conditions will be included on each permit to ensure compliance:

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH_3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters shall be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The proposed engines will be fueled by digester gas; therefore this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for these engines; therefore this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

- 6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
- 6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
- 6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
- 6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
- 6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
- 6.4.6 SOx Test Methods

  - 6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.
  - 6.4.6.2 Determination of total sulfur as hydrogen sulfide (H_2S) content – EPA Method 11 or EPA Method 15, as appropriate.
  - 6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.
  - 6.4.6.4 The SOx emission control system efficiency shall be determined using the following:

    % Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$

    Where:

    $C_{SO2,\ inlet}$ = concentration of SOx (expressed as SO_2) at the inlet side of the SOx emission control system, in lb/Dscf

$C_{SO2,\ outlet}$ = concentration of SOx (expressed as SO_2) at the outlet side of the SOx emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (hhv) of the fuel shall be determined by one of the following test methods:

6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.
6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

The following conditions will be listed on each permit to ensure compliance:

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH_3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

- The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:

6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.5.1.2 Engines subject to Section 8.0;

6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.

6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

The proposed engines will be equipped with SCR systems for control of NO_x and oxidation catalysts for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engines.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_x, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_x, CO, VOC, or oxygen concentrations.

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engines will be operated and maintained per the manufacturer's specifications.

Section 6.5.7 requires procedures and a schedule for using a portable NO_x analyzer to take NO_x emission readings pursuant to Section 5.8.9.

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO.

<u>NO_X Emissions:</u>

In order to satisfy the I & M requirements for NOx emissions, the applicant has proposed to perform the following:

1. The applicant will take periodic NOx emission concentration measurements with a portable analyzer at least once every calendar quarter.

2. To ensure that NOx emissions concentrations are not being exceeded between periodic NOx portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and NOx emissions. The appropriate ranges for each operating load will be established during initial source testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on each engine's permit to ensure compliance:

- During initial performance testing, the SCR system reagent injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

- The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

- If the SCR system reagent injection rate is outside of the established acceptable range, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

- The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

CO and VOC Emissions:

In order to satisfy the I & M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. The applicant will take periodic CO emission concentration measurements with a portable analyzer at least once every calendar quarter. Per the catalyst manufacturer, if the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, quarterly emission concentration measurements with a portable analyzer for VOC emissions will not be required.

2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emission concentration measurements, the applicant is proposing to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure. The appropriate ranges for each operating load will be established during initial source testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on each engine's permit to ensure compliance:

- During initial performance testing, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). For each operating load, the established acceptable inlet temperature and back pressure ranges demonstrated during the initial performance test that result in compliance with the CO emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

- The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate [District Rule 4702]

- The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]

- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable ranges, the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time. The applicant has proposed to comply with the I&M plan modification requirements per this section of the Rule.

The following condition will be listed on each engine's permit to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECP) option of Section 8.0. The proposed engines will be required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP) to comply with the NOx emission requirements of Section 5.2 for a group of engines. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the proposed engines; therefore this section of the Rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the proposed engines is not currently being proposed; therefore this section of the Rule is not applicable at this time.

Conclusion

As shown above, the proposed engines will satisfy all the requirements of Rule 4702. Therefore, the engines will be in compliance as of the date of initial operation and the following conditions will be added to each engine's permit to ensure continued compliance.

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

Rule 4801 Sulfur Compounds

The purpose of this District Rule 4801 is to limit the emissions of sulfur compounds. The limit is that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume of SO_x as (SO_2) = (n x R x T) ÷ P

Where:

n = moles SO_x
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from the engine will be calculated using the maximum sulfur content allowed for the digester gas, which is 40 ppmv, equivalent to 0.00965 lb-SO_x/MMBtu.

$$0.00965 \frac{lb}{MMBtu} \times \frac{1\,MMBtu}{9{,}100 scf_{exhaust}} \times \frac{1 lb \cdot mol}{64 lb \cdot SO_2} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times 1{,}000{,}000\,ppm = 6.29 \text{ ppmv}$$

Since 6.29 ppmv is less than 2000 ppmv, each engine is expected to comply with Rule 4801. The following condition will be placed on each engine's permit to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is 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.

California Environmental Quality ACT (CEQA)

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The San Joaquin Valley Unified Air Pollution Control District (District) adopted its *Environmental Review Guidelines* (ERG) in 2001. 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.

Greenhouse Gas (GHG) Significance Determination

It is determined that another agency has prepared an environmental review document for the project. The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). As a Responsible Agency, the District is limited to mitigating or avoiding impacts for which it has statutory authority. The District does not have statutory authority for regulating greenhouse gas emissions. The District has determined that the applicant is responsible for implementing greenhouse gas mitigation measures, if any, imposed by the Lead Agency.

District CEQA Findings

The proposed project is located in Kings County and is thus, subject to the Kings County Planning Agency Site Plan Review Process. In 2002, Kings County amended their General Plan to include a Dairy Element. The Dairy Element was developed by the Kings County Planning Agency as a comprehensive set of goals, objectives, policies, and standards to guide development, expansion, and operation of milk cow (bovine) dairies and dairy replacement stock facilities within Kings County. The Dairy Element establishes a written process (Site Plan Review) by which subsequent dairy projects involving site-specific operations can be evaluated to determine whether the environmental effects of the operation were covered in the Program Environmental Impact Report (EIR). The Program EIR for the Dairy Element (State Clearinghouse Number 2000111133) was certified by the Kings County Board of Supervisors on July 20, 2002.

Kings County is the Agency which has the principal responsibility for approving this project. Consistent with procedures established within the Program EIR, the Kings County Planning Agency has approved the project through its Site Plan Review process. The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CCR §15381). Rule 2010 requires operators of emission sources to obtain an Authority to Construct (ATC) and Permit to Operate (PTO) from the District. Rule 2201 requires that new and modified stationary sources reduce their emissions using Best Available Control Technology (BACT) and for non-agricultural sources offsetting emissions when above certain thresholds (SB 700).

As a responsible agency the District complies with CEQA by considering the EIR prepared by the Lead Agency, and by reaching its own conclusion on whether and how to approve the project involved (CCR §15096). The District has reviewed the environmental review document prepared by the Lead Agency for the project and finds it to be adequate. To reduce project related impacts on air quality, the District has imposed air pollutant emission controls on the project as required by BACT and District Rule 2201. Offsets were considered, but determined not to be a feasible mitigation measure due to legal constraints (Health and Safety Code §42301.18(c)). Thus, the District has adopted all feasible mitigation measures to reduce air impacts associated with the project.

Pursuant to CCR §15096, prior to project approval and issuance of ATCs the District will prepare findings. Upon project approval the District will file a Notice of Determination with Kings County.

Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs C-9011-2-0 and C-9011-3-0 subject to the permit conditions on the attached draft ATCs in Appendix A.

X. Billing Information

Annual Permit Fees			
Permit Number	**Fee Schedule**	**Fee Description**	**Annual Fee**
C-9011-2-0	3020-10-F	1,306 bhp IC engine	$820.00
C-9011-3-0	3020-10-F	1,306 bhp IC engine	$820.00

Appendices

A: Draft ATCs
B: BACT Guideline
C: Top-Down BACT Analysis
D: HRA Summary
E: Quarterly Net Emissions Change
F: Engine Data

APPENDIX A
Draft ATCs

APPENDIX B
BACT Guideline

SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*

Last Update: 3/6/2013

Waste Gas-Fired IC Engine**

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO_X	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)		1. Fuel Cells (<0.05 lb/MW-hr) 2. Microturbines (<9 ppmv @ 15% O_2) 3. Gas Turbine (<9 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
SO_X	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S) (dry absorption, wet absorption, chemical H_2S reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance)		
PM_{10}	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)		
CO	2.0 g/bhp-hr		1. Fuel Cells (<0.10 lb/MW-hr) 2. Microturbines (<60 ppmv @ 15% O_2) 3. Gas Turbine (<60 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
VOC	0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent)		Fuel Cells (<0.02 lb-VOC/MW-hr as CH_4)

** *For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Pages**

APPENDIX C
Top-Down BACT Analysis

Top-Down BACT Analyses for the Digester Gas-Fired Engine

As stated above, the information from the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engine will be utilized for the BACT analysis for the proposed engines.

I. BACT Analysis for NO_X Emissions:

a. Step 1 - List all control technologies

1) NO_X emissions ≤ 0.15 g/bhp-hr (10 ppmv NO_X @ 15% O_2 [1]) (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

2) Fuel Cell (≤ 0.05 lb/MW-hr = 1.1 ppmv NOx @ 15% O_2)[2] (Alternate Basic Equipment)

3) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

4) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Description of Control Technologies

1) NO_X emissions ≤ 0.15 g/bhp-hr (9 - 11 ppmv NO_X @ 15% O_2) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

2) Fuel Cell (≤ 0.05 lb- NO_X/MW-hr) (Alternate Basic Equipment)

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell.

1

$$\frac{0.15\ \text{g NOx}}{\text{bhp - hr}} \times \frac{\text{MMBtu}}{9{,}100\ \text{dscf}} \times \frac{30\%}{1} \times \frac{1\ \text{lb - mol}}{46\ \text{lb}} \times \frac{20.9 - 15}{20.9} \times \frac{379.5\ \text{dscf}}{1\ \text{lb mol}} \times \frac{393.75\ \text{bhp - hr}}{\text{MMBtu}} \times \frac{\text{lb}}{453.6\ \text{g}} = 10\ \text{ppmv @ 15 \% O2}$$

2

$$\frac{0.05\ \text{lb NOx}}{\text{MW - hr}} \times \frac{\text{MW}}{1{,}341\ \text{bhp}} \times \frac{\text{MMBtu}}{9{,}100\ \text{dscf}} \times \frac{30\%}{1} \times \frac{1\ \text{lb - mol}}{46\ \text{lb}} \times \frac{20.9 - 15}{20.9} \times \frac{379.5\ \text{dscf}}{1\ \text{lb mol}} \times \frac{393.75\ \text{bhp - hr}}{\text{MMBtu}} = 1.1\ \text{ppmv @ 15 \% O2}$$

Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of CO_2 that is found biogas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for biogas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, biogas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas (e.g. landfill gas and brewery wastewater gas).

3) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest means of generating electricity. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, NO_X emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for biogas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, biogas-fired turbines used to produce electricity are expected to be available in the size range of 2 - 7 MW. According to Solar Turbines, the smaller biogas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

4) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 biogas-fired microturbines operating in California as of the year 2006.[3] Microturbines generally have electrical efficiencies of 25 - 30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30 - 33%. Microturbine manufacturers include Capstone Microturbines and FlexEnergy.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_X, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_X, or DLN) combustion technology. Microturbines manufacturers will generally guarantee NO_X emissions of 9 - 15 ppmv @ 15% O_2. However, several emission tests performed on biogas-fired microturbines have demonstrated even lower emissions. A small number of dairy digester gas-fired microturbines have been installed[4], including Twin Birch Dairy and New Hope Farm View dairy and Twin Birch Dairy in New York, and den Dulk Dairy in Michigan.

The proposed project is for a large waste gas to energy facility and, although larger microturbines have recently become available, several microturbines (at least 5) would still be required to replace each engine. The applicant states that when they investigated microturbines they found that there were difficulties related to the loss of power and efficiency because of heat de-rating in warmer climates and the very high pressure requirement and parasitic load, which increased overall costs. In addition, a different applicant for digester gas projects recently permitted by the District (Projects S-1143770 and S-1143771) indicated that when they investigated microturbines they found that they could not secure the necessary financing for a waste gas to energy project of this size using microturbines and that the major microturbines vendors were unable to secure the debt. Although

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[3] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)

[4] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles

microturbines may not currently be a practical option for this particular project, they will be considered in the cost analysis below.

b. Step 2 - Eliminate technologically infeasible options

Option 3 - Gas Turbine (≤ 9 ppmv NO_x @ 15% O_2) (Alternate Basic Equipment)

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (Solar Turbines, Allison, and General Electric) do not currently produce or market waste gas-fired gas turbines rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[5] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][6] (October 5, 2015) also supports that gas turbines rated approximately 3 MW are not generally available. The smallest turbine for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

The proposed project would require a gas turbine rated 1,028 kW as a replacement for each engine, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_x @ 15% O_2) (Alternate Basic Equipment)

2) Digester gas-fueled microturbines (Alternate Basic Equipment)

3) NO_x emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

[5] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies

[6] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

d. Step 4 - Cost Effectiveness Analysis

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The District has determined that the proposed digester gas-fueled IC engines are non-agricultural IC engines. These lean burn, digester gas-fired, engines are subject to the following emission limits for non-agricultural, lean burn, waste gas fueled IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2.e: 11 ppmvd NO_X (or 0.10 g/bhp-hr)[7], 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2). The proposed digester engines are also subject to the New Source Performance Standards (NSPS) for IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes a more stringent VOC emissions limit of 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane) for landfill and digester gas-fired IC engines. Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engines will be based on the emission limits contained in these applicable regulations.

<u>Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)</u>

Because fuel cells have reduced NO_X and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis will examine if the replacement of the proposed engine with a fuel cell is cost effective even when the additional operation costs of a fuel cell are not considered.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 700 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)

7

$$\frac{11\,\text{ft}^3\ \text{NOx}}{10^6\ \text{ft}^3} \times \frac{9{,}100\ \text{ft}^3}{1\,\text{MMBtu}} \times \frac{46\ \text{lb NOx}}{1\ \text{lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1\ \text{lb-mole}}{379.5\ \text{ft}^3} \times \frac{\text{MMBtu}}{392.75\ \text{bhp-hr}} \times \frac{453.6\ \text{g}}{\text{lb}} \times \frac{\text{Btu}_{\text{in}}}{0.30\ \text{Btu}_{\text{out}}} = 0.17\ \frac{\text{g-NOx}}{\text{bhp-hr}}$$

- Price for electricity: \$127.72/MW-hr (*based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)*[8] *beginning June 1, 2016*)
- MMBtu/hr to bhp conversion: 392.75 (per AP-42, Appendix A)
- Btu to kW-hr conversion: 3,413 Btu/kW-hr (per AP-42, Appendix A)
- The initial capital costs and the operation costs for the digester gas-fueled IC engine and fuel cell will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[5] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][6]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of digester gas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [6]

<u>Assumptions for Each Proposed Digester Gas-Fired IC Engine</u>

- The engine will operate at full load for 24 hours/day and 6,500 hours/year
- Typical thermal efficiencies for IC engines range from 30-35%. A worst case thermal efficiency of 30% will be used.
- The maximum total daily heating value of the digester gas used by the engine will be: 266.02 MMBtu/day (*1,306* bhp_{out}*/engine x 1* bhp_{in}*/0.30* bhp_{out} *x 1* $MMBtu_{in}$*/392.75* bph_{in}*-hr x 24 hr/day*)
- The maximum total annual heating value for of the digester gas used by the engine will be: 72,048 MMBtu/year (*1,306* bhp_{out}*/engine x 1* bhp_{in}*/0.30* bhp_{out} *x 1* $MMBtu_{in}$*/392.75* bph_{in}*-hr x 6,500 hr/year*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,028 kW without add-on air pollution control equipment: \$1,223/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies on page 2-15 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-33*)
- Additional capital investment for digester gas conditioning and cleanup for the engine: \$387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for digester-fueled IC engine rated 1,028 kW: \$1,610/kW

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[8] See: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/BioMAT/index.page, https://scebiomat.accionpower.com/biomat/home.asp, and http://www.sdge.com/procurement/bioenergy-market-adjusting-tariff-bio-mat)

- Estimated operation costs for CHP IC engine rated 1,028 kW without add-on air pollution control costs: \$0.028/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies on page 2-17 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-33*)
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for digester gas-fired IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engine must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in the engine, there will be no increase in operating costs related to cleaning the digester gas for use in the engines.
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu
- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% O_2 as CH_4 = 1.0193 lb/MMBtu
- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane)

Assumptions for Fuel Cell System

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 45% (*US EPA Combined Heat and Power Partnership Catalog of CHP Technologies gives efficiencies of 47% for a 300 kW MCFC and 42.5% for a 1,400 kW MCFC*)
- Size of fuel cell system needed to replace the proposed engine: 1,463 kW (estimated based on 266.02 MMBtu/day and 45% efficiency[9])
- Estimated Purchase and Installation Cost for Molten Carbonate Fuel Cell: \$4,474/kW (*Average of the two costs for largest Molten Carbonate Fuel Cells given in US EPA Combined Heat and Power Partnership document Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]; The U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 12-1-2014 and available at: http://www.wbdg.org/resources/fuelcell.php) states, "Installation costs of a fuel cell system can range from \$5,000/kW to \$10,000/kW." Therefore, this estimate may be actually too low based on the recently reported costs for fuel cell power plants, such as the "Bloom Box".*)

9 $\frac{266.02\text{ MMBtu}}{\text{day}} \times \frac{\text{kW - hr}}{3{,}410\text{ Btu}} \times \frac{10^6\text{ Btu}}{\text{MMBtu}} \times \frac{\text{day}}{24\text{ hrs}} \times 45\% = 1{,}463\text{ kW}$

- Additional capital investment for biogas conditioning and cleanup for the fuel cell: \$563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for digester gas-fueled fuel cells rated ≥ 1,200 kW: \$5,037/kW
- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: \$0.04/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional operational costs for biogas conditioning and cleanup for large fuel cells: \$0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Operation Cost for digester gas-fueled fuel cells rated ≥ 1,200 kW: \$0.19/kW-hr
- Fuel Cell NO_X emissions: 0.01 - 0.02 lb/MW-hr (Note: Fuel cells have been certified to the ARB Distributed Generation Certification level of 0.07 lb-NO_X/MW-hr but measured emissions from fuel cells are generally much lower)
- Fuel Cell VOC emissions: 0.02 lb-VOC/MW-hr (≤ 2.0 ppmv VOC @ 15% O_2 as CH_4 based on ARB Distributed Generation Certification level of 0.02 lb-VOC/MW-hr and emission tests on fuel cells)
- Unlike the proposed engines, a high-temperature fuel cell power plant must primarily operate at steady state conditions; there would not be the ability to store gas to generate more electricity during peak hours, which is the current business plan of the applicant. Because the price paid for electricity is greater during peak hours and less during other times, the price paid for electricity generated by a fuel cell power plant would be less. This would require the operator to alter their plans of operation and result in less revenue per kW-hr of electricity generated potentially offsetting the revenue from increased power generating capacity because of the higher efficiency of a fuel cell power plant. For more conservative analysis, the difference in the cost of peak and off-peak electricity was not considered in this comparison.

Capital Cost

The estimated increased incremental capital cost for replacement of each proposed engine with a fuel cell is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engine.

The incremental capital cost for replacement of each proposed IC engine with a fuel cell power plant is calculated as follows:

(1,463 kW x \$5,037/kW) - (1,028 kW x \$1,610/kW) = \$5,714,051

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^n]/[(I+1)^n-1]$$

Where:
- A = Annual Cost
- P = Present Value
- I = Interest Rate (10%)
- N = Equipment Life (10 years)

$$A = [\$5{,}714{,}051 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$931{,}390/year}$$

Annual Costs

Annual Operation and Maintenance Cost

The annual operation and maintenance costs for each option are calculated as follows:

Proposed 1,028 kW Generator with IC Engine

1,028 kW x 6,500 hr/yr x $0.028/kW-hr = $187,096/year

Fuel Cells (Alternate Equipment)

1,463 kW x 6,500 hr/yr x $0.19/kW-hr = $1,806,805/year

Annual Costs of Increased Maintenance

$1,806,805/yr - $187,096/yr = $1,619,709/year

Total Increased Annual Costs for Fuel Cell as an Alternative to the Proposed Engine

$931,390/year + $1,619,709/year = **$2,551,099/year**

Emission Reductions

NO_X and VOC Emission Factors

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the engines will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.2, Table 2, 2.e. The District Standard Emissions for VOC emissions from the engines will be based on the New Source Performance Standard (NSPS) VOC emission limit for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since this limit is more stringent than the applicable emission limit in District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions

0.165 lb-NO_X/MMBtu (11 ppmv NO_X @ 15% O_2)
0.111 lb-VOC/MMBtu (75 ppmv VOC @ 15% O_2)

Emissions from Fuel Cells as Alternative Equipment

0.016 lb-NO_X/MMBtu (0.05 lb-NO_X/MW-hr)
0.006 lb-VOC/MMBtu (0.02 lb-VOC/MW-hr)

Emission Reductions

Each Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO_X Emission Reductions (65 ppmv @ 15% O_2 → 0.01 lb-NO_X/MW-hr)

72,048 MMBtu/year x (0.165 lb-NO_X/MMBtu – 0.016 lb-NO_X/MMBtu)
= 10,735 lb-NO_X/year (5.4 ton-NO_X/year)

VOC Emission Reductions (1.0 g/bhp-hr → 0.02 lb-VOC/MW-hr)

72,048 MMBtu/year x (0.111 lb-VOC/MMBtu – 0.006 lb-VOC/MMBtu)
= 7,565 lb-VOC/year (3.8 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Thresholds (MCET) for NO_X and VOC Reductions based on District Standard Emission Reductions

(5.4 ton-NO_X/year x \$24,500/ton-NO_X) + (3.8 ton-VOC/year x \$17,500/ton-VOC)
= \$198,800/year

As shown above, the annualized capital cost of this alternate option ($2,551,099) exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO_x and VOC emission reductions ($198,800). Therefore, this option is not cost effective and is being removed from consideration.

Option 2 – Microturbine

Per District BACT Policy APR 1305, the cost effectiveness of an Alternate Basic Equipment control option shall be performed using the following equation:

$$\mathbf{CE_{alt} = (Cost_{Alt} - Cost_{Basic}) \div (Emission_{Basic} - Emission_{Alt})}$$

Where:

CE_{Alt} = the cost effectiveness of alternate basic equipment expressed as dollars per ton of emissions reduced
$Cost_{Alt}$ = the equivalent annual capital cost of the alternate basic equipment plus its annual operating cost
$Cost_{Basic}$ = the equivalent annual capital cost of the proposed basic equipment, without BACT, plus its annual operating cost
$Emission_{Basic}$ = the emissions from the proposed basic equipment, without BACT
$Emission_{Alt}$ = the emissions from the alternate basic equipment

$COST_{Alt}$:

Capital Cost:

The purchase and installation costs for a microturbine will be estimated using data from the Environmental Protection Agency's (EPA's) Catalog of Combined Heat and Power Technologies Catalog, Section 5, dated March 2015.

Using data from Table 5-2, the amount of heat input it takes to produce one kW of electricity for nominally rated natural gas fired microturbines is as follows:

1,000 kW unit = 12.155 MMBtu/hr => 0.0121 MMBtu/kW

The data in Table 5-2 only represents natural gas fired units. Due to the differences in the heating value of natural gas and digester gas, the 1,000 kW digester gas fired electrical generating unit proposed in this project would equate to the following size natural gas fired electrical generating unit, assuming the same total volume of fuel is used:

Heat Input_{DG} = Input (MMBtu/kW) x (1 scf / 1,000 Btu_{NG}) x (700 Btu_{DG} / 1 scf)
Heat Input_{DG} = 0.0121 MMBtu_{NG}/kW x 1 scf/1,000 Btu_{NG} x 700 Btu_{DG}/1 scf

Heat Input_{DG} = 0.00847 MMBtu/kW

The ratio of the heat input required to produce the same amount of electricity for digester gas compared to natural gas is as follows:

0.00847 MMBtu/kW / 0.0121 MMBtu/kW = 0.7

Therefore, for an identical volume of gas, you will generate more electricity with natural gas over digester gas. An equivalent natural gas generator to a 1,000 kW digester gas fired generator can be determined as follows:

1,000 kW = Generator_{NG} x 0.7
Generator_{NG} = 1,000 kW / 0.7

Generator_{NG} = 1,428 kW

Therefore, for the purposes of comparing similar units in this cost analysis to the units given in EPA's CHP catalog, it will be considered that the 1,000 kW digester gas fired generator would equate to a 1,428 kW natural gas fired generator.

Extrapolating the data from Table 5-2, the cost to purchase and install a 1,428 kW natural gas fired microturbine generator set can be determined as follows:

333 kW unit = $2,580/kW (total installed cost)
1,000 kW unit = $2,500/kW (total installed cost)

Extrapolating the data outside of the table results in the following:

1,428 kW unit = $2,449/kW (total installed cost)

Therefore, the total capital cost would be:

1,428 kW unit x $2,449 kW = 3,497,172

Pursuant to the District BACT Policy APR 1305, section X., the annualized capital cost of the microturbine will be calculated as follows. The capital cost will be spread over the expected life of the engine which is estimated at 10 years and using the capital recovery equation (Equation 1). A 10% interest rate is assumed in the equation and the assumption will be made that the equation has no salvage value at the end of the ten-year cycle.

Equation 1: $A = [P * i(I+1)^n]/[(I+1)^n-1]$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)

N = Equipment Life (10 years)

A = [$3,497,172 * 0.1 * $(1.1)^{10}$]/[$(1.1)^{10}$-1]
= **$569,149/year**

Operation and Maintenance Costs

The typical operation and maintenance costs for a microturbine was taken from EPA's Combined Heat and Power Technologies Catalog, Section 5, Table 5-5, dated March 2015. The average operation and maintenance costs of a microturbine is estimated as follows:

Total Operation and Maintenance Costs: $0.012/kW-hr

The rating of the proposed generator set is 1,000 kW. Therefore, the total annual operation and maintenance costs can be determined as follows:

Annual Op and Maint Costs = EF x Rating x Operation
Annual Op and Maint Costs = $0.012 / kW-hr x 1,000 kW x 6,500 hr/year

Op and Maint Costs = $102,000

$COST_{Basic}$ = Annualized Capital Cost + Annual Op and Maint Costs
$COST_{Basic}$ = $569,149 + $78,000

$COST_{Basic}$ = $647,149

Capital Cost:

The purchase and installation cost (total capital cost) of a 1,431 bhp IC engine was received from Daryl Maas of Maas Energy (consultant on proposed project) on September 11, 2015. The capital cost of that IC engine, without any controls, was estimated as follows:

Total Capital Cost: $771,381

Pursuant to the District BACT Policy APR 1305, section X. (Revised 4/18/95), the annual cost of installing and maintaining the engine will be calculated as follows. The installation cost will be spread over the expected life of the engine which is estimated at 10 years and using the capital recovery equation (Equation 1). A 10% interest rate is assumed in the equation and the assumption will be made that the equation has no salvage value at the end of the ten-year cycle.

Equation 1: $A = [P * i(I+1)^n]/[(I+1)^n-1]$

Where: A = Annual Cost

P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$A = [\$771,381 * 0.1 * (1.1)^{10}]/[(1.1)^{10}-1]$
= $125,539/year

Operation and Maintenance Costs

The typical operation and maintenance costs for an IC engine was taken from EPA's Catalog of Combined Heat and Power Technologies Catalog, Section 2, Table 2-6, dated March 2015. The average operation and maintenance costs of an IC engine, without any controls, is estimated as follows:

Total Operation and Maintenance Costs: $0.020/kW-hr

The rating of the proposed generator set is 1,000 kW. Therefore, the total annual operation and maintenance costs can be determined as follows:

Annual Op and Maint Costs = EF x Rating x Operation
Annual Op and Maint Costs = $0.020 / kW-hr x 1,000 kW x 6,500 hr/year
Op and Maint Costs = $170,000

$COST_{Basic}$ = Annualized Capital Cost + Annual Op and Maint Costs
$COST_{Basic}$ = $125,539 + $130,000

$COST_{Basic}$ = $255,539

$Emission_{Basic}$:

In accordance with information provided by the Dresser-Rand/Guascor, the engine manufacturer, the uncontrolled NO_X emission rate from the proposed digester gas fired IC engine, without the SCR system, is as follows:

Emission Factor = 1.0 grams/bhp-hr
Engine Rating = 1,306 bhp
Operating Hours = 6,500 hours/year

$Emissions_{Basic}$: (EF x bhp x Operation) / 453.6 grams/lb
$Emissions_{Basic}$: 1.0 grams/bhp-hr x 1,306 bhp x 6,500 hours/year x lb/453.6 grams

$Emissions_{Basic}$ = 18,715 lb/year

$Emissions_{Alt}$:

The emissions from microturbine(s) operating at 9 ppmvd NO_X @ 15% O_2 are as follows:

Emission Factor = 0.126 grams/hp-hr (9 ppmv @ 15% O_2)
Equivalent Microturbine Rating = 1,306 bhp
Operating Hours = 6,500 hours/year

$Emissions_{Basic}$: (EF x bhp x Operation) / 453.6 grams/lb
$Emissions_{Basic}$: 0.126 grams/bhp-hr x 1,306 bhp x 6,500 hours/year x lb/453.6 grams

$Emissions_{Alt}$ = 2,358 lb/year

Cost Effectiveness:

Therefore, the cost effectiveness of installing a microturbine operating with NO_X emissions of 9 ppmvd @ 15% O_2 can be determined as follows:

$CE_{Alt} = (Cost_{Alt} – Cost_{Basic}) \div (Emission_{Basic} – Emission_{Alt})$

CE_{Alt} = [($647,149/yr - $255,539/yr) ÷ (18,715 lb/yr – 2,358 lb/yr)] x 2,000 lb/ton

CE_{alt} = $47,883/ton

The cost of NO_X reduction utilizing a microturbine with an emission concentration of 9 ppmvd @ 15% O_2 would be greater than the $24,500/ton cost effectiveness threshold of the District BACT policy. The equipment is therefore not cost effective and is being removed from consideration at this time.

Option 3 – IC Engine with NOx Emissions ≤ 0.15 g/bhp-hr

The applicant is proposing the use of lean burn IC engine equipped with a Selective Catalytic Reduction (SCR) system with NO_X emissions of 0.15 grams/bhp-hr. Since the applicant is proposing to use a control technology that is equivalent to this control option, a cost effective analysis is not necessary and no further discussion is required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the Digester Gas-fired Engines must be satisfied with the following: NO_X emissions to 0.15 g/bhp-hr

The applicant has proposed to use an SCR system for the digester gas-fired lean burn IC engine to limit NO_x emissions to 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

2. **BACT Analysis for SO_x Emissions:**

a. Step 1 - Identify all control technologies

The following options were identified to reduce SO_x emissions from the proposed engine:

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice/Contained in SIP)

There are no options listed in the SJVUAPCD BACT Clearinghouse as alternate basic equipment.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

The control efficiency of each of the options above is estimated and the controls are ranked below based on the control effectiveness.

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for SO_x emissions from the proposed engine is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use addition of iron oxide chemicals to the digester, a biological sulfur removal system, and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to $\leq$ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_x are satisfied.

3. BACT Analysis for PM_{10} Emissions:

a. Step 1 - Identify all control technologies

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Dairy anaerobic digester gas is the planned fuel for the proposed IC engines. The anaerobic digester gas will be composed primarily of methane (approximately 60% molar composition) and CO_2 (approximately 40% molar composition) and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly H_2S) resulting in the formation of sulfur-containing particulate. Therefore, scrubbing of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce particulate matter emissions from combustion of the digester gas as fuel in the proposed engines:

1) Sulfur Content of fuel ≤ 40 ppmv as H_2S (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option is required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for PM_{10} emissions from the proposed engine is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use addition of iron oxide chemicals to the digester, a biological sulfur removal system, and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for PM_{10} are satisfied.

4. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) Lean burn and 90% efficient crankcase control device or equivalent (Achieved in Practice)
2) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)
2) VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as CH_4) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the NO_X and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

This has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engines is VOC emissions ≤ 0.10 g/bhp-hr. The applicant has proposed VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

APPENDIX D
HRA Analysis

APPENDIX E
Quarterly Net Emissions Change

Quarterly Net Emissions Change (QNEC)

The QNEC is entered into PAS database and subsequently reported to CARB. For seasonal sources, or where the emissions differ quarter to quarter, then evaluate each pollutant for each quarter separately. The QNEC is calculated for each pollutant, for each unit, as the difference between the post-project quarterly potential to emit (PE2) and the pre-project quarterly potential to emit (PE1).

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

$PE2_{quarterly}$ = $PE2_{annual}$ ÷ 4 quarters/year
= 3,101 lb/year ÷ 4 qtr/year
= 775.25 lb NO_x/qtr

$PE1_{quarterly}$ = $PE1_{annual}$ ÷ 4 quarters/year
= 0 lb/year ÷ 4 qtr/year
= 0 lb NO_x/qtr

Quarterly NEC [QNEC] (Each Engine)			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	775.25	0	775.25
SO_X	187.25	0	187.25
PM_{10}	374.5	0	374.5
CO	31.35	0	31.35
VOC	555.25	0	555.25

APPENDIX F
Engine Data

Engine Manufacturer's Performance Data and Emissions Factors for CO, NOx, and VOCs

G3516 — GAS ENGINE TECHNICAL DATA — CATERPILLAR®

Partial Load Data is an Estimate

ENGINE SPEED:	1200	FUEL:	SITE SPECIFIC
COMPRESSION RATIO:	11:1	FUEL SYSTEM:	DELTEC
AFTERCOOLER - MAX. INLET (°F):	130	WITH CUSTOMER SUPPLIED AIR FUEL RATIO CONTROL	
JACKET WATER - MAX. OUTLET (°F):	230	FUEL PRESS. RANGE (PSIG):	1.5 - 5.0
COOLING SYSTEM:	JW, OC+AC	MIN. METHANE NUMBER:	132
IGNITION SYSTEM:	EIS	RATED ALTITUDE (FT):	801
EXHAUST MANIFOLD:	DRY	AT AIR TO TURBO. TEMP. (°F):	109
COMBUSTION:	LOW EMISSION	NOx EMISSION LEVEL:	1.0 g/bhp-hr
		FUEL LHV (BTU/SCF):	812
		APPLICATION:	60 Hz GENSET

RATING AND EFFICIENCY		NOTES	LOAD	100%	75%	50%
ENGINE POWER	(WITHOUT FAN)	(1)	BHP	1306	980	653
GENERATOR POWER	(WITHOUT FAN)	(2)	EKW	924	693	462
ENGINE EFFICIENCY	(ISO 3046/1)	(3)	%	36.4	32.4	32.4
ENGINE EFFICIENCY	(NOMINAL)	(3)	%	35.7	34.2	31.8
THERMAL EFFICIENCY	(NOMINAL)	(4)	%	36.3	38.4	42.1
TOTAL EFFICIENCY	(NOMINAL)	(5)	%	72.0	72.6	73.9
ENGINE DATA						
FUEL CONSUMPTION	(ISO 3046/1)	(6)	BTU/bhp-hr	6987	7294	7847
FUEL CONSUMPTION	(NOMINAL)	(6)	BTU/bhp-hr	7122	7436	7999
AIR FLOW (77 °F, 14.7 psi)		(7)	SCFM	2797	2041	1406
AIR FLOW		(7)	lb/hr	12401	9046	6233
COMPRESSOR OUT PRESSURE			in. HG (abs)	83.2	70.2	54
COMPRESSOR OUT TEMPERATURE			°F	327	294	213
AFTERCOOLER AIR OUT TEMPERATURE			°F	135	124	114
INLET MAN. PRESSURE		(8)	in. HG (abs)	75.5	54.4	34.8
INLET MAN. TEMPERATURE	(MEASURED IN PLENUM)	(9)	°F	142	135	133
TIMING		(10)	°BTDC	24	24	24
EXHAUST STACK TEMPERATURE		(11)	°F	941	994	1005
EXHAUST GAS FLOW (@ stack temp.)		(12)	CFM	7868	5982	4165
EXHAUST MASS FLOW		(12)	lb/hr	13407	9834	6798
EMISSIONS DATA						
NOx (as NO2)		(13)	g/bhp-hr	1	1	1
CO		(14)	g/bhp-hr	4.4	4.41	5.55
THC (molecular weight of 15.84)		(14)	g/bhp-hr	7.39	8.18	8.43
NMHC (molecular weight of 15.84)		(14)	g/bhp-hr	1.11	1.23	1.27
NMNEHC		(14)	g/bhp-hr	0.739	0.818	0.843
EXHAUST O2		(15)	% DRY	6.3	5.5	5.2
LAMBDA		(15)		1.67	1.55	1.49
HEAT BALANCE DATA						
LHV INPUT		(16)	BTU/min	155041	121393	87066
HEAT REJECTION TO JACKET (JW)		(17)	BTU/min	20627	17992	16420
HEAT REJECTION TO ATMOSPHERE		(18)	BTU/min	6009	5008	4007
HEAT REJECTION TO LUBE OIL (OC)		(19) (22)	BTU/min	5201	4766	4247
HEAT REJECTION TO EXHAUST (LHV to 77°F)		(20)	BTU/min	55923	44055	30881
HEAT REJECTION TO EXHAUST (LHV to 350°F)		(20)	BTU/min	35596	28648	20224
HEAT REJECTION TO A/C (AC)		(21) (22)	BTU/min	10914	7051	2839
HEAT REJECTION TO ENGINE PUMPS			BTU/min	977.2	977.2	977.2

CONDITIONS AND DEFINITIONS

ENGINE RATING OBTAINED AND PRESENTED IN ACCORDANCE WITH ISO 3046/1STD. REF. CONDITIONS OF 77°F, 29.6 IN HG BAROMETRIC PRESSURE. 500 FT ALTITUDE). NO OVERLOAD PERMITTED AT RATING SHOWN. CONSULT ALTITUDE CHARTS FOR APPLICATIONS ABOVE MAXIMUM RATED ALTITUDE AND/OR TEMPERATURE.

EMISSION LEVELS ARE BASED ON THE ENGINE OPERATING AT STEADY STATE CONDITIONS AND ADJUSTED TO THE SPECIFIED NOx LEVEL AT 100% LOAD. EMISSION TOLERANCES SPECIFIED ARE DEPENDANT UPON FUEL QUALITY. METHANE NUMBER CANNOT VARY MORE THAN ± 3. PUBLISHED PART LOAD DATA REQUIRES CUSTOMER SUPPLIED AIR FUEL RATIO CONTROL.

ENGINE RATING IS WITH 2 ENGINE DRIVEN WATER PUMPS.

FOR NOTES INFORMATION CONSULT PAGE THREE.