San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

SEP 17 2018

Ray Brewer
California Dairy Energy 4, LLC
145 North N St, Ste A
Tulare, CA 93274

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: C-9070
Project Number: C-1162454

Dear Mr. Brewer:

Enclosed for your review and comment is the District's analysis of California Dairy Energy 4, LLC's application for an Authority to Construct for the installation of a dairy manure digester system with a 12.25 MMBtu/hour backup/emergency flare and three 1,609 brake horsepower digester gas-fired internal combustion engines powering electrical generators, at 11883 W Floral Ave, Fresno.

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 Mr. Jonah Aiyabei of Permit Services at (559) 230-5910.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:jka

Enclosures

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

Samir Sheikh
Executive Director/Air Pollution Control Officer

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San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

Digester System with Backup/Emergency Flare and IC Engines

Facility Name:	California Dairy Energy 4, LLC	Date:	August 28, 2018
Mailing Address:	145 North N St, Ste A Tulare, CA 93274	Engineer:	Jonah Aiyabei
		Lead Engineer:	Jerry Sandhu
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Application #s:	C-9070-1-0, 2-0, 3-0, and 4-0		
Project #:	C-1162454		
Deemed Complete:	February 24, 2017		

I. Proposal

California Dairy Energy 4, LLC (CDE 4) has requested Authority to Construct (ATC) permits for the installation of a dairy manure digester system with a 12.25 MMBtu/hour backup/emergency flare and three 1,609 brake horsepower digester gas-fired internal combustion engines powering electrical generators. The three IC engines will each have a maximum power rating of 1,609 bhp and will be equipped with an oxidation catalyst and a selective catalytic reduction (SCR) system. Each IC engine will power a 1,145 kW electrical generator to provide electricity to the utility grid. The draft ATCs are included in Appendix A.

The proposed power plant will be installed at Johann Dairy (facility C-5469), an existing permitted dairy operation in Fresno. The proposed power plant will be installed south of the existing lagoons and solid manure separator system within area of the existing dairy operation that is currently used for the handling and storage of solid manure.

Liquid manure will be sent directly from Johann Dairy to the CDE 4 anaerobic digester (ATC -1-0) for production of digester gas that will be used to power each of the three proposed IC engines (ATCs -2-0 through -4-0). The proposed backup/emergency flare is expected to operate only when the IC engines are down for maintenance or repair.

CDE 4 and Johann Dairy are separate companies that are not under common ownership or control. The applicant has provided the fuel supply and lease agreements between CDE 4 and Johann Dairy that support the dairy and power plant will not be under common ownership or control. Further, not more than 10% of the electricity produced by the digester gas-fired power plant may be sold to the dairy operation (per applicant). The majority of the electrical power

(≥90%) will be sold to the electric utility grid. Thus, the power plant (production of electricity) and the dairy operation (production of milk) are not part of the same industrial grouping. Since all of the criteria of Sections 3.39.1 through 3.39.3 of District Rule 2201 are not met, the power plant and dairy operation are not the same stationary source.

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 4311	Flares (6/16/09)
Rule 4701	Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702	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 project site is leased by CDE 4, LLC (lessee) from Johann Dairy (lessor), at 11883 W Floral Ave, Fresno. The proposed 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

Anaerobic Digester System

An anaerobic digester is a sealed basin or tank that is designed to accelerate and control the decomposition of organic matter by microorganisms in the absence of oxygen. Anaerobic decomposition results in the conversion of organic compounds in the substrate into methane (CH_4), carbon dioxide (CO_2), and water rather than intermediate volatile organic compounds (VOCs). The gas generated by this process will be identified as digester gas in this project but may otherwise be referred to as biogas or waste gas.

The digester gas is expected to be comprised of 60-70% CH_4 and 30-40% CO_2 but may contain small amounts of nitrogen (N_2), oxygen (O_2), hydrogen sulfide (H_2S), ammonia (NH_3) and trace amounts of various VOCs that remain from incomplete digestion of the volatile solids; however, the VOC content is negligible. A digester gas VOC content of 0.5% by weight is assumed for this project. Since the primary constituent of digester gas is methane (also the main component of natural gas), digester gas can be treated to remove H_2S and other impurities and used as fuel.

The proposed DVO, in-ground, mesophilic, mixed plug-flow anaerobic digester system is designed to process 100% of the manure from the dairy operation. The manure will be flushed from the milking parlor and the cow housing areas and will be routed via the existing underground piping system to reception pits. At the reception pits, the manure will be adjusted to 9-15% solids and then pumped into the proposed digester. Excess manure liquid from the reception pits will be sent to a separated liquids pit where the liquid will be available for use again in the dairy flush system.

The proposed digester vessel will be constructed of reinforced concrete. The approximate external dimensions of the concrete digester vessel will be 219.6 feet × 348 feet × 16 feet (14 feet underground and 2 feet above ground) with an approximate internal volume of 9,121,686 gallons (per applicant). The inside of the digester will be coated with a chemical resistant sprayed-on elastomeric polyurethane to prevent leakage through the porous concrete. Each section of the digester will include different compartments for the digestion processes and will use digester gas for vertical mixing of the digester contents and will include separate pits for the removal of sludge and digester effluent. The digester system will have a retention time of approximately 22 days. To maintain the required digester temperature of 90 - 100°F, heat will be recovered from the IC engines using heat exchangers.

The digester effluent will be pumped to a solid separation area where a two stage slope screen separator and roller press will be used to separate the fiber solids and liquid digester effluent. The separated solids will be conveyed to a bin storage system and up to 50% of the solids will be returned to the dairy to be used as bedding for the cattle. Remaining solids will be sold to a vendor for use as a soil amendment. The liquid digester effluent will be pumped back to the separated liquids pit for use in the dairy flush system. Excess liquid from the separated liquids pit not used in the dairy flush system will flow to the existing dairy lagoon and applied to adjacent cropland. The proposed digester may also accept available dairy feed waste that is deemed not suitable for the cattle.

Biogas Conditioning

The completed digester system will include a digester management system (DMS) to monitor the pH, temperature, and gas composition and adjust pH and temperature to provide the optimal environment for the anaerobes to flourish for maximum digester efficiency.

A proprietary iron oxide additive, FeSfix, will be added directly to the digester vessel to remove most of the H_2S from the digester gas. Additional H_2S removal will be with air injection Basalis strain remediation where air is continuously injected into the headspace of the digester vessel with sulfur oxidizing microorganisms. This facilitates the oxidation of sulfides in the digester gas and the surface of the digester slurry to elemental sulfur and water.

Produced digester gas will be piped from the digester to a gas dehydrator and then it will be pressurized to 4 psi. Pressurized digester gas will be sent through an activated carbon scrubber for polishing and additional H_2S removal. Sulfur removed from the gas stream in the carbon scrubber may be collected and made available for agricultural land application. The digester gas will then be sent to the IC engines for use as fuel.

Backup/Emergency Digester Gas-Fired Flare

The proposed digester system must be equipped with a backup/emergency flare as a VOC control device if there is excess digester gas that must be disposed of. Since the proposed digester is a concrete vessel it has a fixed volume and cannot accommodate storage of excess digester gas. There may be excess digester gas in cases when either one or more IC engine is not operating due to breakdown or maintenance. However, with three IC engines, the flare is expected to only operate in emergency situations since having three IC engines will allow the operator to stage planned maintenance shutdowns.

The proposed digester gas-fired flare will be located adjacent to the proposed mechanical building. The digester system is estimated to produce 1,078,312 scf-digester gas/day (per applicant) and 393,583,880 scf-digester gas/year (assuming 365 days/year).

Maximum operation of the backup/emergency flare will be limited to 5% per year (applicant proposed and required as Best Available Control Technology (BACT)), equivalent to 438 hours per year (24 hr/day × 365 day/year × 0.05). The maximum potential flaring rate is approximately 290 scf/min and 17,500 scf/hr (per applicant). Annual flare operation will be limited to 5% of full time operation (based on 95% of IC engine up time per applicant), equivalent to 7,665,000 scf/year (17,500 scf/hr × 8,760 hr/year × 0.05).

Digester Gas-Fired IC Engines

The project location will include a mechanical building next to the proposed digester to house the three proposed 1,609 bhp MTU lean-burn digester gas-fired IC engines. Each engine will be equipped with an oxidizing catalyst, an SCR system, and a heat exchanger and will power a 1,145 kW electrical generator. Heat will be recovered from the engines using the heat exchangers and will be used to heat the digester vessel.

The maximum operating schedule for the IC engines is 24 hr/day and 365 days/year. Based on typical operation of existing similar digester gas-fired power plants (outside of SJVUAPCD) operated by CH4 Power (parent company to CDE 4, LLC), the expected operational time for this plant is from 95% to 98% of full-time with only 2% to 5% of down time.

V. Equipment Listing

C-9070-1-0: DVO MIXED PLUG-FLOW MESOPHILIC ANAEROBIC DIGESTER SYSTEM CONSISTING OF A RECEPTION PIT AND AN IN-GROUND CONCRETE VESSEL (348 FT X 219.6 FT X 16 FT) WITH ONE 12.25 MMBTU/HR DVO MODEL 7618 8" DIGESTER GAS-FIRED BACKUP/EMERGENCY FLARE SERVED BY A BIOLOGICAL H2S REMOVAL SYSTEM AND A CARBON H2S SCRUBBER

C-9070-2-0: 1,609 BHP MTU MODEL GB1145B6 DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH AN OXIDIZING CATALYST, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH A UREA INJECTION SYSTEM, AND A HEAT EXCHANGER POWERING AN ELECTRICAL GENERATOR

C-9070-3-0: 1,609 BHP MTU MODEL GB1145B6 DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH AN OXIDIZING CATALYST, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH A UREA INJECTION SYSTEM, AND A HEAT EXCHANGER POWERING AN ELECTRICAL GENERATOR

C-9070-4-0: 1,609 BHP MTU MODEL GB1145B6 DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH AN OXIDIZING CATALYST, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH A UREA INJECTION SYSTEM, AND A HEAT EXCHANGER POWERING AN ELECTRICAL GENERATOR

VI. Emission Control Technology Evaluation

Digester System With Backup/Emergency Flare

The dairy digester may emit volatile organic compounds (VOC) and hydrogen sulfide (H_2S). Results of dairy digester gas analyses have indicated very low to negligible VOC content with concentrations less than 1% by weight. The District assumes VOC content of digester gas is 0.5%.

The following proposed H_2S removal systems are expected to reduce H_2S concentrations in the digester gas to 40 ppmv or less.

- Proprietary iron oxide additive, FeSfix
- Air injection with microorganisms
- Activated carbon scrubber

Under normal operation, the digester vessel is assumed to capture 100% of the produced digester gas and all gas is combusted in the three IC engines to power the electrical generators. If produced digester gas cannot be combusted in the IC engines due to either breakdown of one or more IC engines, the excess gas will be vented to the backup/emergency flare for methane control. The flare is an emissions unit since it is proposed as a methane control device and not for control of any criteria pollutants. Operation of the flare results in oxides of nitrogen (NOx), oxides of sulfur (SOx), particulate matter less than 10 microns (PM_{10}) and less than 2.5 microns ($PM_{2.5}$), carbon monoxide (CO), and VOC emissions.

H_2S Removal

As stated above, a proprietary iron oxide compound, FeSfix, will be added to the digester to remove H_2S from the digester gas. FeSfix is a mixture of FeO and Fe_2O_3 with other trace elements. H_2S is a weak acid and disassociates resulting in the formation of the dissolved sulfide. Iron oxides combine with the dissolved sulfide and form an iron sulfide precipitate, which is removed from the digester with the effluent. Additional H_2S will be removed from the digester gas through use of air injection with Basalis strain bacteria that oxidizes the H_2S to elemental sulfur and sulfates.

For final polishing, additional H_2S and moisture will be removed from the digester gas by use of an activated carbon H_2S scrubber prior to combustion in the proposed IC engines. H_2S will be adsorbed as the gas flows through the activated carbon bed. Activated carbon has a high surface area for adsorption due to a large number of pores. Contaminants in the digester gas diffuse into these pores and are retained on the carbon surface due to both chemical and physical forces. Activated carbon used for the removal of H_2S is usually treated with chemical bases to increase the holding capacity for H_2S.

The proposed activated carbon scrubber will consist of enclosed vessel(s) filled with treated activated carbon. The digester gas will be pumped through the vessel(s) to a dryer and chiller to remove moisture. There will be a secondary carbon scrubber unit that will be brought online when monitoring indicates the primary unit is nearing saturation. The useful life of the activated carbon vessels will vary depending on the inlet concentration of H_2S, the flow rate, and the mass in the vessels.

Digester Gas-Fired IC Engines

The IC engines may emit NOx, SOx, PM_{10}, $PM_{2.5}$, CO, VOC, and ammonia (NH_3). The proposed engines will be equipped with the following technology:

- Turbocharger
- Intercooler
- Air/fuel ratio controller
- Lean-burn technology
- Oxidation catalyst
- Selective catalytic reduction (SCR) with urea injection

The turbocharger reduces NOx emissions from IC engines 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 and lowering the peak combustion temperature, which reduces the formation of thermal NOx.

The air-to-fuel ratio (AFR) controller is used to monitor the amount of oxygen in the exhaust stream and adjust engine air and fuel injection to optimize engine operation and catalyst function. Lean-burn technology increases the volume of air in the combustion process compared to the volume of fuel. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. With lower fuel content and better mixing, the combustion temperatures are lowered and the fuel is used more efficiently resulting in reduced formation of NOx.

An oxidation catalyst reduces CO and VOC emissions by using a catalyst to promote the chemical oxidation of VOC and CO into H_2O and CO_2. An SCR system reduce NOx emissions through the use of a catalyst and a reagent, in this case urea. Urea is injected into the exhaust gas stream downstream of (after) the oxidizing catalyst and upstream (prior) to the NOx catalyst and is converted to ammonia. The ammonia is used with the catalyst to reduce NOx to elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NOx emissions by up to 90%. The urea injection results in some unreacted ammonia passing through the catalyst and out to the atmosphere. This excess ammonia is known as ammonia slip. Generally, urea injection is carefully monitored and adjusted to maintain the required NOx exhaust concentration and excess ammonia is limited by the operator to reduce the cost of urea used in the system. Ammonia slip will be limited by permit condition to not exceed 10 ppmv @ 15% O_2.

Exhaust SOx emissions are reduced by the use of fuel with reduced H_2S concentration, as previously discussed. PM_{10} and $PM_{2.5}$ emissions are reduced/limited by the use of gaseous fuel.

VII. General Calculations

A. Assumptions

- CDE 4 (facility C-9070) and Johann Dairy (facility C-5469) are separate stationary sources at the same site.
- The digester will capture 100% of the produced digester gas for combustion in the IC engines or the backup flare.
- The proposed digester system will result in an overall net reduction in VOC emissions from the dairy's liquid manure management system, since:
  - Manure that is currently stored in uncovered lagoons and ponds will instead be diverted into a closed digester vessel, thereby decreasing volatilization of VOC from the manure.
  - An anaerobic digester reduces VOC emissions by optimizing the conversion of manure volatile solids into methane instead of intermediary VOC compounds.
  - Any VOC remaining in the digester gas will be controlled further by combustion in the engine, which has a VOC control efficiency of at least 98%.

  A modification of the dairy's liquid manure management permit is therefore not required.
- Fugitive VOC emissions from the digester system are assumed to be negligible, consistent with District Policy SSP 2015.
- PM emissions from the handling of separated solids for the digester system are considered negligible because of the high moisture content (> 6%) of separated manure solids.
- Emissions from post-digester solids are considered negligible.
- Digester gas properties:
  - Molar composition is about 70% methane and 30% carbon dioxide, with trace amounts of hydrogen sulfide, VOC, and other compounds.[1]

[1] U.S. EPA AgSTAR (http://www2.epa.gov/agstar), "Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities" (November 2011, http://www2.epa.gov/agstar/agstar-market-opportunities-report); "Anaerobic Digestion Overview", David Schmidt, University of Minnesota Department of Biosystems and Agricultural Engineering:.(http://www.extension.umn.edu/agriculture/manure-management-and-air-quality/manure-treatment/docs/anaerobic-digestion-overview.pdf); and "Anaerobic Digestion of Animal Wastes: Factors to

  - Higher Heating Value = 700 Btu/scf (Based on 70% methane content, also used in other similar District projects)
  - EPA F-factor = 9,100 dscf/MMBtu (dry, adjusted to 60 °F), (Estimated based on previous digester gas fuel analyses for source tests)
  - Maximum sulfur content = 40 ppmv as H_2S (approximately 2.4 grains/100 scf; proposed by applicant and required as BACT for the IC engines)
  - Maximum VOC content = 0.5% by weight
  - Molar specific volume = 379.5 scf/lb-mol (at 60°F)
- Molecular weights:
  - NO_X (as NO_2) = 46 lb/lb-mol
  - CO_2 = 44 lb/lb-mol
  - NH3 = 17 lb/lb-mol
  - VOC (as CH_4) = 16 lb/lb-mol
  - SO_X (as SO_2) = 64.06 lb/lb-mol
- Maximum engine operation schedule is 24 hours/day and 365 days per year.
- Bhp to Btu/hr conversion = 2,545 Btu/bhp-hr.
- Engine thermal efficiency = 30% (District practice).
- The engines will not require any commissioning period. All emission control equipment will be installed to manufacturer specifications prior to startup.
- Ammonia slip from SCR = 10 ppmvd @ 15% O_2 (proposed by applicant).
- The flare is a control device and will be operated only for testing and maintenance, required regulatory purposes, backup purposes, and during emergency situations (proposed by applicant; District limitations for backup/emergency classification).
- An emergency is a situation or condition arising from a sudden and reasonably unforeseeable and unpreventable event beyond the control of the operator, such as, but not limited to, unpreventable equipment failure, natural disasters, acts of war or terrorism, and external power curtailment (except due to interruptible power service agreements). An emergency situation requires immediate corrective action to restore safe operation.
- Maximum flare gas flow rate = 17,500 scf/hr, hence maximum daily (i.e. 24-hour) flaring rate = 0.420 MMscf; (equivalent to 294.0 MMBtu @ 700 Btu/scf).
- Flaring will be limited to a maximum of 7.665 MMscf/year (equivalent to 5,366 MMBtu/year @ 700 Btu/scf); (per applicant, engines will be running at least 95% of the time, hence flare operation shall not exceed 5% of the time, i.e. 438 hours/year).
- Flare VOC destruction efficiency = 98%.[2]
- $PM_{2.5}$ emissions from the digester gas-fired backup flare and IC engines are assumed to be equal to PM_{10} emissions.

[2] AP-42, Draft Section 2.4, Municipal Solid Waste Landfills, (October 2008). The valued stated (97.7%) has been rounded off to 98% as discussed in the BACT determination (Appendix D).

B. Emission Factors

The emission factors for flaring of digester gas are summarized in the following table:

Emissions Factors for Digester Gas Flaring			
Pollutant	**lb/MMBtu**	**lb/scf**	**Source**
NO_X	0.056	3.92×10^{-5}*	District Practice and/or BACT
SO_X	0.0096	6.72×10^{-6}*	Applicant proposal (see calculations below)
PM_{10}	0.008	5.60×10^{-6}*	District Practice (Value for Industrial Flares)[3]
CO	0.066	4.60×10^{-5}	AP-42 Draft Table 2.4.4 (October 2008) (Value for Landfill Gas Flares)[3]
VOC	0.0092	6.44×10^{-6}*	0.5% VOC by weight and 98% VOC Destruction Efficiency (see calculations below)

*lb/scf equivalent = lb/MMBtu x 0.0007 MMBtu/scf.

Flare Emission Factor Calculations

SO_X

$$\frac{40\ ft^3 H2S}{10^6\ ft^3\ DG} x \frac{32.06\ lb\ S}{lb-mol\ H2S} x \frac{lb-mol}{379.5\ ft^3} x \frac{64.06\ lb\ SO2}{32.06\ lb\ S} x \frac{1\ ft^3}{700\ Btu} x \frac{10^6\ Btu}{MMBtu} = 0.0096 \frac{lb\ SOx}{MMBtu}$$

CO – based on 46 lb-CO/10^6 dscf

$$\frac{46\ lb-CO}{10^6\ dscf} x \frac{1\ scf}{700\ Btu} x \frac{10^6\ Btu}{MMBtu} = 0.066 \frac{lb-CO}{MMBtu}$$

VOC

$$\frac{0.5\ lb-VOC}{100\ lb-DG} x \frac{(0.7\ x\ 16) + (0.3\ x\ 44)\ lb-DG}{lb-mol} x \frac{lb-mol}{379.5\ ft^3} x \frac{ft^3}{700\ Btu} x \frac{10^6\ Btu}{MMBtu} x\ (1-0.98) = 0.0092 \frac{lb-VOC}{MMBtu}$$

[3] Since digester gas and landfill gas are both types of biogas, it is expected that they have similar properties and emissions. However, digester gas has higher methane content and heating value, which should result in lower emission rates for incomplete combustion pollutants such as PM, CO, and VOC. Using landfill gas values is therefore conservative. The AP-42 (Draft Table 2.4.4) emission factor for PM_{10} is 15 lb/10^6 dscf CH_4, which is equivalent to 0.021 lb/MMBtu when adjusted for the higher heating value of digester gas. However, since the flare will be subject to a 5% visible emissions opacity limit (~ no visible emissions) the corresponding PM_{10} emission rate for industrial flares, derived from AP-42 Section 13.5, is more accurate and will be used instead.

The emissions factors for the digester gas-fired engine are summarized in the following table:

Emission Factors for Digester Gas-Fired IC Engine				
Pollutant	**g/bhp·hr**	**lb/MMBtu**	**ppmvd (@ 15%O_2)**	**Source**
NO_X	0.15	0.0390	10 ppmvd	BACT Requirement/Proposed by Applicant (See Calculations Below)
SO_X	0.04	0.0096	40 ppmvd in fuel gas	BACT Requirement (See Calculations Below)
PM_{10}	0.05	--	--	Applicant proposal (with 150% compliance margin)
CO	0.50	0.130	55 ppmvd	Applicant proposal (See Calculations Below)
VOC	0.10	0.026	19 ppmvd as CH_4	BACT Requirement/Proposed by Applicant (See Calculations Below)
NH_3	0.06	0.0144	10 ppmvd	10 ppmvd @ 15% O_2 in exhaust; Required/Proposed (See Calculations Below)

IC Engine Emission Factor Calculations

NO_X – 0.15 g/bhp-hr

$$0.15\,\frac{\text{g NOx}}{\text{bhp-hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp-hr}}{2{,}545\,\text{Btu}} \times \frac{0.30\,\text{Btu}_{out}}{1\,\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.0390\,\frac{\text{lb NOx}}{\text{MMBtu}}$$

$$0.0390\,\frac{\text{lb NOx}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{46\,\text{lb NOx}} \times \frac{10^6\,\text{ppmv}}{1} = 10\ \text{ppmvd NOx @ 15\% } O_2$$

SO_X – 40 ppmvd H_2S in fuel gas

$$\frac{40\,\text{ft}^3\,H_2S}{10^6\,\text{ft}^3} \times \frac{32.06\,\text{lb S}}{\text{lb-mol}\,H_2S} \times \frac{\text{lb-mole}}{379.5\,\text{ft}^3} \times \frac{64.06\,\text{lb}\,SO_2}{32.06\,\text{lb S}} \times \frac{\text{ft}^3}{700\,\text{Btu}} \times \frac{10^6\,\text{Btu}}{\text{MMBtu}} = 0.0096\,\frac{\text{lb SOx}}{\text{MMBtu}}$$

$$0.0096\,\frac{\text{lb SOx}}{\text{MMBtu}} \times \frac{1\,\text{MMBtu}}{10^6\,\text{Btu}} \times \frac{\text{Btu}_{in}}{0.30\,\text{Btu}_{out}} \times \frac{2{,}545\,\text{Btu}}{\text{hp-hr}} \times \frac{453.59\,\text{g}}{\text{lb}} = 0.04\,\frac{\text{g SOx}}{\text{bhp-hr}}$$

CO – 0.50 g/bhp-hr

$$0.50\,\frac{\text{g CO}}{\text{bhp-hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp-hr}}{2{,}545\,\text{Btu}} \times \frac{0.30\,\text{Btu}_{out}}{1\,\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.130\,\frac{\text{lb CO}}{\text{MMBtu}}$$

$$0.130\,\frac{\text{lb CO}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{28\,\text{lb CO}} \times \frac{10^6\,\text{ppmv}}{1} = 55\,\text{ppmvd CO @ } 15\%\ O_2$$

VOC – 0.10 g/bhp-hr

$$0.10\,\frac{\text{g VOC}}{\text{bhp-hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp-hr}}{2{,}545\,\text{Btu}} \times \frac{0.30\,\text{Btu}_{out}}{1\,\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.026\,\frac{\text{lb VOC}}{\text{MMBtu}}$$

$$0.026\,\frac{\text{lb VOC}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{16\,\text{lb VOC}} \times \frac{10^6\,\text{ppmv}}{1} = 19\,\text{ppmvd VOC @ } 15\%\ O_2$$

NH_3 – 10 ppmvd @ 15% O_2 in exhaust

$$\frac{10\,\text{ppmv}\ NH_3}{10^6} \times \frac{17\,\text{lb}\ NH_3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{379.5\,\text{ft}^3} \times \frac{9{,}100\,\text{ft}^3}{\text{MMBtu}} \times \frac{20.9\%\ O_2}{(20.9-15)\%\ O_2} = 0.0144\,\frac{\text{lb}\ NH_3}{\text{MMBtu}}$$

$$0.0144\,\frac{\text{lb}\ NH_3}{\text{MMBtu}} \times \frac{1\,\text{MMBtu}}{10^6\,\text{Btu}} \times \frac{\text{Btu}_{in}}{0.30\,\text{Btu}_{out}} \times \frac{2{,}545\,\text{Btu}}{\text{hp-hr}} \times \frac{453.59\,\text{g}}{\text{lb}} = 0.06\,\frac{\text{g}\ NH_3}{\text{bhp-hr}}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since the proposed digester system, backup flare, and three IC engines are new emissions units, PE1 = 0 for all pollutants.

2. Post Project Potential to Emit (PE2)

Digester System with Backup/Emergency Flare

As explained above, the applicant has proposed to construct a new enclosed, mixed plug flow anaerobic digester that will have negligible fugitive emissions; therefore, emissions for the digester will be calculated only based on combustion of the digester gas in the flare.

The potential to emit for the flare will be calculated based on the maximum flare gas flow rate of 17,500 scf per hour (420,000 scf per day) and the annual limit of 7.665 MMscf/yr of digester gas combusted in the flare.

The daily PE for each pollutant is calculated as follows:

PE (lb/day) = [EF (lb/scf) x Gas flow rate (scf/hr) x Operation schedule (hrs/day)]

The daily PE is summarized in the following table:

Daily PE2 Summary - Flare							
Pollutant	**Emission Factor (lb/scf)**	**x**	**Gas Flow Rate (scf/hr)**	**x**	**Op. Schedule (hrs/day)**	**=**	**PE2 (lb/day)**
NO_X	3.92E-5	x	17,500	x	24	=	16.5
SO_X	6.72E-6	x	17,500	x	24	=	2.8
PM_{10}	5.60E-6	x	17,500	x	24	=	2.4
CO	4.60E-5	x	17,500	x	24	=	19.3
VOC	6.44E-6	x	17,500	x	24	=	2.7

The annual PE for each pollutant is calculated as follows:

PE (lb/yr) = [EF (lb/scf) x Maximum gas flared annually (MMscf/yr) x 10^6 scf/MMscf]

The annual PE is summarized in the following table:

Annual PE2 Summary - Flare							
Pollutant	**Emission Factor (lb/scf)**	**x**	**Maximum Gas Flared Annually (MMscf/yr)**	**x**	**10^6 scf/MMscf**	**=**	**PE2 (lb/yr)**
NO_X	3.92E-5	x	7.665	x	10^6	=	300
SO_X	6.72E-6	x	7.665	x	10^6	=	52
PM_{10}	5.60E-6	x	7.665	x	10^6	=	43
CO	4.60E-5	x	7.665	x	10^6	=	353
VOC	6.44E-6	x	7.665	x	10^6	=	49

Digester Gas-Fired IC Engines

The daily PE for each pollutant is calculated as follows:

PE (lb/day) = [EF (g/bhp-hr) x Rating (bhp) x Operation schedule (hrs/day)] / [453.6 g/lb]

The daily PE is summarized in the following table:

Daily PE Summary – Each IC Engine										
Pollutant	**Emission Factor (g/bhp-hr)**	**x**	**Rating (bhp)**	**x**	**Op. Schedule (hrs/day)**	**/**	**g/lb**	**=**	**PE (lb/day)**
NO_X	0.15	x	1,609	x	24	/	453.6	=	12.8
SO_X	0.04	x	1,609	x	24	/	453.6	=	3.4
PM_{10}	0.05	x	1,609	x	24	/	453.6	=	4.3
CO	0.50	x	1,609	x	24	/	453.6	=	42.6
VOC	0.10	x	1,609	x	24	/	453.6	=	8.5
NH_3	0.06	x	1,609	x	24	/	453.6	=	5.1

The annual PE for each pollutant is calculated as follows:

PE (lb/yr) = [EF (g/bhp-hr) x Rating (bhp) x Operation schedule (hrs/yr)] / [453.6 g/lb]

The annual PE is summarized in the following table:

Annual PE Summary – Each IC Engine									
Pollutant	**Emission Factor (g/bhp-hr)**	**x**	**Rating (bhp)**	**x**	**Op. Schedule (hrs/yr)**	**/**	**g/lb**	**=**	**PE (lb/yr)**
NO_X	0.15	x	1,609	x	8,760	/	453.6	=	4,661
SO_X	0.04	x	1,609	x	8,760	/	453.6	=	1,243
PM_{10}	0.05	x	1,609	x	8,760	/	453.6	=	1,554
CO	0.50	x	1,609	x	8,760	/	453.6	=	15,537
VOC	0.10	x	1,609	x	8,760	/	453.6	=	3,107
NH_3	0.06	x	1,609	x	8,760	/	453.6	=	1,864

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.

Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 is equal to zero for all pollutants.

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 this is a new facility, the SSPE2 is based on the PE for the new emissions units, as determined in the preceding sections and summarized in the following table:

SSPE2 (lb/year)						
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**	**NH_3**
ATC C-9070-1-0	300	52	43	353	49	0
ATC C-9070-2-0	4,661	1,243	1,554	15,537	3,107	1,864
ATC C-9070-3-0	4,661	1,243	1,554	15,537	3,107	1,864
ATC C-9070-4-0	4,661	1,243	1,554	15,537	3,107	1,864
SSPE2	**14,283**	**3,781**	**4,705**	**46,964**	**9,370**	**5,592**

5. Major Source Determination

Rule 2201 Major Source Determination:

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 Section 51.165

Rule 2201 Major Source Determination (lb/year)						
	NOx	**SOx**	**PM_{10}**	**$PM_{2.5}$***	**CO**	**VOC**
SSPE1	0	0	0	0	0	0
SSPE2	14,283	3,781	4,705	4,705	46,964	9,370
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No	No

*$PM_{2.5}$ assumed to be equal to PM_{10}

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	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source?	N	N	N	N	N	N

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.

<u>C-9070-1-0, -2-0, -3-0, & -4-0</u>

Since these 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)[4]
- 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. Note that for the purpose of this determination, PM_{10} is conservatively assumed to be 50% of PM (Section 4.11 of Rule 2201).

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	7.1	4.7	1.9	23.5	4.7	2.4
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

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.

[4] 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 SOx 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. With this assumption, the total PE for H_2S for all new and modified units is equal to the total PE for SOx, which is 1.9 TPY. This is well below the applicable PSD threshold of 250 TPY.

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 F.

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 Adjusted Increase in Permitted Emissions (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

<u>Digester System and Backup/Emergency Flare</u>

The proposed digester emits only VOC and H_2S. The PE for the digester system with a backup/emergency flare is greater than 2.0 lb/day for NOx, SOx, PM_{10}, CO, and VOC. BACT is therefore triggered for VOC since the PE is greater than 2 lb/day. NOx, SOx, PM_{10}, and CO emissions are incidental to the control device (i.e. byproducts of combustion in the flare). In accordance with District practice, BACT requirements are not applicable to control devices. Collateral emissions resulting from a control device are therefore not subject to BACT requirements.

<u>IC Engines</u>

The proposed IC engines each have a PE > 2.0 lb/day for NOx, SOx, PM_{10}, CO, VOC, and NH_3. BACT is triggered for NOx, SOx, PM_{10}, and VOC for PE > 2.0 lb/day purposes. BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lb/year, as demonstrated in Section VII.C.5 above. BACT is not triggered for

NH_3 since NH_3 slip emissions result from operation of an emissions control device (SCR) and not the emissions unit (engine); therefore, BACT is not triggered for NH_3 PE > 2.0 lb/day purposes.

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 purposes.

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 modified emissions units purposes.

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 or a Federal Major Modification for any pollutant. Therefore, BACT is not triggered for major modification purposes.

2. BACT Guidelines

Digester System with Backup/Emergency Flare

BACT Guideline 5.8.12 applies to dairy manure digesters with backup/emergency flares (see Appendix D).

IC Engine

BACT Guideline 3.3.15 applies to digester 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.

Backup/Emergency Flare

Pursuant to the attached BACT Determination (see Appendix D), BACT has been satisfied with the following:

VOC: Open flare (98% control efficiency)

IC Engines

Pursuant to the attached 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

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals 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)					
	NOx	**SOx**	**PM_{10}**	**CO**	**VOC**
SSPE2	14,283	3,781	4,705	46,964	9,370
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets Triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As shown above, no SSPE2 is greater than the offset threshold for any pollutant; 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. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required 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 > 100 lb/day purposes is not required.

c. Offset Threshold

Projects which result in SSPE2 surpassing the offset threshold for any pollutant will trigger public noticing requirements. 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?
NOx	0	14,283	20,000 lb/year	No
SOx	0	3,781	54,750 lb/year	No
PM_{10}	0	4,705	29,200 lb/year	No
CO	0	46,964	200,000 lb/year	No
VOC	0	9,370	20,000 lb/year	No

As shown above, no offset threshold is surpassed as a result of this project; therefore, public noticing is not required for surpassing an offset threshold 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 SSIPEs are compared to the SSIPE Public Notice threshold in the following table:

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NOx	14,283	0	14,283	20,000 lb/year	No
SOx	3,781	0	3,781	20,000 lb/year	No
PM_{10}	4,705	0	4,705	20,000 lb/year	No
CO	46,964	0	46,964	20,000 lb/year	Yes
VOC	9,370	0	9,370	20,000 lb/year	No
NH_3	5,592	0	5,592	20,000 lb/year	No

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

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 Permit Modification and public noticing is not required for Title V Significant Permit Modification purposes.

2. Public Notice Action

As discussed above, public noticing is required for this project for CO SSIPE greater than 20,000 lb/year purposes. Public notice documents will be submitted to the California Air Resources Board (ARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATCs for the proposed 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 ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions

Digester System and Backup/Emergency Flare

- 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 1/4 or 5% opacity. [District Rules 2201 and 4101]
- Only digester gas shall be flared. [District Rule 2201]

- A flame shall be present at all times whenever combustible gases are vented through the flare. [District Rule 2201]

- The flare outlet shall be equipped with an automatic ignition system, or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 2201]

- The flare shall be equipped with an operational, non-resettable, totalizing mass or volumetric fuel flow meter or other District-approved alternative method to measure the quantity of digester gas flared. [District Rule 2201]

- The flare shall be operated only for testing and maintenance, backup, and emergency purposes. [District Rule 2201]

- Flaring of digester gas for testing and maintenance, required regulatory purposes, and backup purposes shall not exceed either of the following limits: 0.420 MMscf (equivalent to 294.0 MMBtu @ 700 Btu/scf) in any one day and 7.665 MMscf (equivalent to 5,366 MMBtu @ 700 Btu/scf) in any rolling 12-month period. [District Rule 2201]

- Emissions from the flare shall not exceed any of the following limits: 0.056 lb-NOx/MMBtu, 0.008 lb-PM10/MMBtu, 0.066 lb-CO/MMBtu, or 0.0092 lb-VOC/MMBtu. [District Rule 2201]

- The VOC content of the digester gas shall not exceed 0.5% by weight. [District Rule 2201]

- The sulfur content of the digester gas combusted in this flare 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 and 4801]

Digester Gas-Fired Engines

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

- 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; 0.05 g-PM10/bhp-hr; 0.50 g-CO/bhp-hr (equivalent to 55 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 19.2 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. An averaging period of up to 24 hours in length may be utilized for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

- Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

Digester System and Backup/Emergency Flare

Source testing of this unit is not required to demonstrate compliance with the Rule 2201 emission limits for NOx, PM_{10}, CO, or VOC. However, periodic testing of the fuel sulfur content of the digester gas will be required to ensure compliance with the digester gas fuel sulfur content limit. The following condition will be included on the flare permit as a mechanism to enforce compliance.

- Digester gas sulfur content analysis shall be performed at least once every 12 months using EPA Method 11 or EPA Method 15, as appropriate. Records of the digester gas sulfur content analysis shall be maintained and provided to the District upon request. [District Rule 2201]

Digester Gas-Fired IC Engines

NOx, CO, & VOC Source Testing

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

PM_{10} Source Testing

The applicant has proposed a PM_{10} emission factor slightly lower than the AP-42 emission factor for similar equipment. However, in order to demonstrate compliance with the proposed PM_{10} emission factor, initial source testing will be required.

Since the engines are not served by any control devices for PM_{10} emissions, it is not expected that the PM_{10} emissions will change much over time as long as the quality of the gas combusted remains fairly consistent. The facility will be required to monitor the sulfur content of the digester gas 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 included on each IC engine permit as a mechanism to enforce compliance.

- Source testing to measure NOx, CO, VOC, PM_{10}, and NH_3 emissions from this unit shall be conducted within 60 days of initial startup operation. [District Rules 1081, 2201, and 4702]

- Source testing to measure NOx, CO, VOC, and 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, or ARB Method 5 in combination with Method 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, 2201, 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]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [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

<u>Digester System and Backup/Emergency Flare</u>

Because of the variable composition of digester gas, monitoring of the fuel sulfur content will be required. The following conditions will be placed on the flare permit as a mechanism to enforce compliance.

- The sulfur content of the digester gas combusted in this flare shall be monitored and recorded at least once every calendar quarter in which a digester gas sulfur content analysis is not performed. If quarterly monitoring shows a violation of the sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the sulfur content limit. Once compliance with the 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 flared shall not be required if the flare does not operate during that period. Records of the results of monitoring of the digester gas sulfur content shall be maintained. [District Rule 2201]

- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; 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 Rule 2201]

Digester Gas-Fired IC Engines

The proposed digester gas-fired IC engines are subject to District Rule 4702 – Internal Combustion Engines. Monitoring in compliance with Rule 4702 will satisfy monitoring for Rule 2201. Rule 4702 requires the following:

- Section 5.8.1 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 6.5.3 requires monthly monitoring for engines equipped with non-certified control devices.

Therefore, monthly monitoring of NOx, CO, and O_2 concentrations in accordance with pre-approved alternate monitoring plan "A" will be required. Since each engine will be equipped with an SCR system, quarterly monitoring of ammonia slip will also be required. The following conditions will be included on each IC engine permit as a mechanism to enforce 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]

- {modified 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 Rules 2201 and 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 included on each IC engine permit as a mechanism to enforce 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]

- 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 H_2S; 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 included on each permit as specified as a mechanism to enforce compliance.

<u>Digester System and Backup/Emergency Flare</u>

- Permittee shall maintain daily and annual records of the quantity of digester gas combusted in the flare in standard cubic feet (scf). [District Rules 1070 and 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. Records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070, 2201, and 4311]

<u>Digester Gas-Fired IC Engines</u>

- 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 NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 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, 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]

- {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 1070, 2201, 4311, 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 E 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 (NSPS)

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.

No subparts of 40 CFR Part 60 apply to digester gas-fired flares. Therefore, no discussion is required for permit unit C-9070-1. The following subpart is applicable to stationary spark ignition IC engines.

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

The District has not been delegated the authority to implement NSPS requirements for non-Major Sources; therefore, no discussion is required and no conditions will be included on the IC engine permits.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

This rule incorporates NESHAPs from Part 61, Chapter I, Subchapter C, Title 40, CFR and the NESHAPs from Part 63, Chapter I, Subchapter C, Title 40, CFR; and applies to all sources of hazardous air pollution listed in 40 CFR Part 61 or 40 CFR Part 63.

No subparts of 40 CFR Part 61 or Part 63 apply to digester gas-fired flares. Therefore, no discussion is required for permit unit C-9070-1. The following subpart is applicable to stationary reciprocating IC engines.

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

The District has not been delegated the authority to implement NESHAP requirements for non-Major Sources; therefore, no discussion is required and no conditions will be included on the IC engine permits.

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).

Digester System and Backup/Emergency Flare

Since the flare will only combust digester gas, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity. Additionally, to ensure compliance with the particulate matter emission limit and BACT, visible emissions from the flare will be limited to no more than 5% opacity. The following condition will be included on the flare permit as a mechanism to enforce compliance.

- 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 1/4 or 5% opacity. [District Rules 2201 and 4101]

Digester Gas-Fired IC Engines

As the IC engines will be fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity. Also, based on past District inspections of digester gas-fired IC engines, compliance is expected. The following condition will be listed on each IC engine permit as a mechanism to enforce 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. The following conditions will be included on each permit in this project as a mechanism to enforce compliance.

- {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

- {modified 271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rules 2201 and 4102]

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 E), 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 in the following table:

RMR Summary						
Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required?	Special Permit Requirements?
1-0: Flare	0.15	0.00	0.00	3.90E-09	No	No
2-0: IC Engine	2.58	0.07	0.05	8.03E-07	No	Yes
3-0: IC Engine	2.58	0.07	0.05	8.08E-07	No	Yes
4-0: IC Engine	2.58	0.07	0.05	8.08E-07	No	Yes
Project Totals	7.76	0.21	0.16	2.42E-06		
Facility Totals	>1	0.21	0.16	2.42E-06		

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 in the Technical Services Memo in Appendix E of this report, the emissions increases for this project were determined to be less than significant.

Digester System and Backup/Emergency Flare

There are no special permit conditions required on this permit to ensure compliance with the HRA.

Digester Gas-Fired IC Engines

The following conditions will be included on each IC engine permit as a mechanism to enforce compliance with the HRA.

- {1898} 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.

Digester System and Backup/Emergency Flare

For the following calculation, PM_{10} is conservatively assumed to be 50% of PM, per Section 4.11 of Rule 2201.

$$PM\ Concentration = \frac{0.008\ lb - PM}{MMBtu} \times \frac{MMBtu}{9{,}100\ dscf} \times \frac{7{,}000\ grain}{lb}$$

$$= \frac{0.006\ grain - PM}{dscf} < \frac{0.1\ grain - PM}{dscf}$$

Since 0.006 grain-PM/dscf is less than 0.1 grain-PM/dscf, the flare is expected to comply with this rule.

Digester Gas-Fired IC Engines

For the following calculation, PM_{10} is conservatively assumed to be 50% of PM, per Section 4.11 of Rule 2201.

$$PM\ Concentration = \frac{0.05\ g - PM}{bhp - hr} \times \frac{bhp - hr}{2{,}545\ Btu} \times \frac{1E6\ Btu}{9{,}100\ dscf} \times \frac{0.30\ Btu_{out}}{Btu_{in}} \times \frac{15.43\ grain}{g}$$

$$= \frac{0.010\ grain - PM}{dscf} < \frac{0.1\ grain - PM}{dscf}$$

Since 0.010 grain-PM/dscf is less than 0.1 grain-PM/dscf, compliance with this rule is expected.

The following condition will be included on each permit as a mechanism to enforce compliance:

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

Rule 4311 Flares

The purpose of this rule is to limit the emissions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx) from the operation of flares.

Pursuant to Section 4.3, except for the record keeping requirement of Section 6.1.4 the requirements of this rule do not apply to any flare located at a stationary source with potential emissions less than 10.0 tons per year of VOC and 10.0 tons per year of NOx.

Section 6.1 requires that records shall be maintained, retained on-site for a minimum of five years, and made available to the APCO, ARB, and EPA upon request.

Section 6.1.4 requires an operator claiming exemption under Section 4.3 to record annual throughput, material usage, or other information necessary to demonstrate compliance with the terms of the exemption.

The following conditions will be included on the permits as shown as a mechanism to enforce compliance with this recordkeeping requirement:

Digester System with Backup/Emergency Flare

- The permittee shall maintain records of annual throughput, material usage, or other information necessary to demonstrate that this stationary source (C-9070) has the potential to emit, for all processes, less than ten (10.0) tons per year of VOC and less than ten (10.0) tons per year of NOx. [District Rule 4311]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. Records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070, 2201, and 4311]

Compliance with the requirements of this rule is expected.

Rule 4701 Internal Combustion Engines – Phase I

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

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

Section 5.2.2.1 requires that 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 NOx, CO, and VOC emission limits pursuant to Table 2;
5.2.2.1.2 SOx 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 NOx emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District. The applicant has not proposed to comply with the fee paying option allowed by this section.

Section 5.2.2.3 allows that in lieu of complying with the NOx, CO, and VOC limits of Table 2, an operator may elect to implement an alternative emission control plan (AECP) pursuant to Section 8.0. The applicant has proposed to comply with the Table 2 emissions limits and has not proposed an AECP.

The following table summarizes the emission limits from Table 2 of Rule 4702 that are applicable to the IC engines in this project:

Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations			
Engine Type	NOx Emission Limit (ppmv @ 15% O_2, dry)	CO Emission Limit (ppmv @ 15% O_2, dry)	VOC Emission Limit (ppmv @ 15% O_2, dry)
2.d. Waste Gas Fueled	65 ppmv or 90% reduction	2,000 ppmv	750 ppmv

Since the proposed engines will be operated as part of a stationary source that is separate from the host dairy, they are non-agricultural engines. The engines are required to comply with the emission limits from Table 2, Row 2.d for waste gas fueled engines. The following condition will be included on each IC engine permit as a mechanism to enforce compliance with these limits:

- Emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 0.50 g-CO/bhp-hr (for periodic alternate monitoring, 55 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, 19.2 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3 contains requirements for agricultural IC engines. As stated above, the proposed engines will be operated as part of a non-agricultural stationary source. Therefore, the requirements of Section 5.2.3 are not applicable.

Section 5.2.4 contains requirements for certified compression-ignited IC engines. The engines in this project are spark-ignited IC engines. Therefore, the requirements of Section 5.2.4 are not applicable.

Section 5.3 contains requirements for continuous emission monitoring systems (CEMS) emissions measurements. The applicant has proposed APCO-approved alternate emissions monitoring for the engines in this project; therefore, the engines will not be equipped with CEMS and Section 5.3 is not applicable.

Sections 5.4 and 5.5 contain requirements for engines that will use percent emission reductions to comply with the NOx emission limits of Section 5.2. The proposed engines will not use percent emission reductions for compliance; therefore, Sections 5.4 and 5.5 are not applicable.

Section 5.6 specifies procedures for compliance with the fee paying option. The proposed engines will not utilize the fee paying option for compliance; therefore, Section 5.6 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 SO2 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 each engine will be limited to 40 ppmv (approximately equal to 2.4 grains sulfur per 100 standard cubic feet). The following condition will be included on each IC engine permit as a mechanism to enforce 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 Sections 5.8.1 through 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 NOx, CO, and oxygen or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (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 NOx 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 utilizing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic monitoring of NOx, CO, and O2 emissions concentrations as specified in District Policy SSP-1810. The following condition will be included on each IC engine permit as a mechanism to enforce 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 are subject to Section 5.8.1; therefore Section 5.8.2 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 applicant has proposed to utilize a pre-approved alternate emissions monitoring plan for each engine; therefore, the requirements of Section 5.8.3 are satisfied.

Section 5.8.4 contains requirements for the operation of a CEMS. The proposed engines will not be equipped with CEMS; therefore, the requirements of Section 5.8.4 are 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 previously stated, the proposed engine will use a pre-approved alternate emissions monitoring plan. Therefore, the requirements of Section 5.8.5 are 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. Each proposed engine will be equipped with a nonresettable elapsed operating time meter. The following condition will be included on each IC engine permit as a mechanism to enforce compliance:

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

Section 5.8.7 requires that for each engine, the permittee shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5.

Section 5.8.8 requires that for each engine, the permittee shall collect data through the I&M plan in a form approved by the APCO.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, the permittee shall use a portable NOx analyzer to take NOx 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 NOx 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 NOx emissions readings shall be reported to the APCO in a manner approved by the APCO. NOx 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.

The following conditions will be included on each IC engine permit as a mechanism to enforce 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]

- {modified 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 Rules 2201 and 4702]

Section 5.8.10 specifies requirements for APCO approval of an alternative monitoring system. The applicant has proposed to utilize a pre-approved alternate monitoring system; therefore, Section 5.8.10 is not applicable.

Section 5.8.11 contains requirements for engines utilizing an Alternate Emission Control Plan (AECP). The proposed engines are not subject to an AECP; therefore, the requirements of Section 5.8.11 are 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, the requirements of Section 5.9 are not applicable.

Section 5.10 specifies SOx Emissions Monitoring Requirements. 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 included on each IC engine permit as a mechanism to enforce 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 contains requirements for engines that are not required to have a Permit to Operate pursuant to California Health and Safety Code Section 42301.16. The proposed engines are required to have a PTO; therefore, Section 5.11 are 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 (ECP) of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. With the submittal of the complete ATC application, the requirement for an approvable ECP are satisfied.

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 included on each IC engine permit as a mechanism to enforce 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 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 condition will be included on each IC engine permit as a mechanism to enforce 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 1070, 2201, 4311, and 4702]

Section 6.2.3 contains requirements for operators that claim an exemption under Section 4.2 or Section 4.3. There are no applicable exemption criteria for the IC engines in this project; therefore, Section 6.2.3 is not applicable.

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 compliance testing requirements. 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 IC engine permit as a mechanism to enforce compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days of initial startup operation. [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. 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 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 shall be reported as methane. VOC, NOx, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. The following conditions will be included on each IC engine permit as a mechanism to enforce compliance:

- 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 Rules 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 NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that 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 requirements for engines that are limited by Permit-to-Operate condition to be fueled exclusively with PUC quality natural gas. The proposed engines will not have such a limit; therefore, Section 6.3.5 is not applicable.

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. This project includes 3 identical IC engines. The applicant has not proposed representative testing for the proposed engines. Therefore, Section 6.3.6 is not applicable.

Section 6.4 specifies source testing procedures for compliance testing. The following conditions will be included on each IC engine permit as a mechanism to enforce 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, or ARB Method 5 in combination with Method 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, 2201, 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. 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

Section 6.5.2 specifies 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 specifies 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.

Each proposed engine will be equipped with an SCR system for the control of NOx emissions and an oxidation catalyst for the control of CO and VOC emissions. The applicant has proposed the following alternate monitoring program to ensure compliance with Sections 6.5.2 and 6.5.3 of the Rule:

<u>Alternate Monitoring: NOx Emissions</u>

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

1. Measurement of NOx emissions concentrations 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 the catalyst control system inlet exhaust temperature and NOx emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

<u>Alternate Monitoring: CO and VOC Emissions</u>

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

1. Measurement of CO emissions concentrations with a portable analyzer at least once every calendar quarter. Generally, if the oxidation catalyst is controlling CO

emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, no additional monitoring for VOC emissions is required.

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

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 NOx, 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 NOx, CO, VOC, or oxygen concentrations.

The applicant has proposed that the alternate monitoring program will ensure compliance with Sections 6.5.3, 6.5.4, and 6.5.5. The following conditions will be included on each IC engine permit as a mechanism to enforce compliance:

- During initial performance testing, and during subsequent performance tests as needed, 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 limit(s) 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%). Records of the established acceptable inlet temperature(s) and back pressure(s) demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

- During initial performance testing, and during subsequent performance tests as needed, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) 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%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

- The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system 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 range(s), 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(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) 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 operating within the acceptable range(s) demonstrated to result in compliance with the CO and VOC emission limits of this permit. [District Rule 4702]

- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) 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 and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 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]

Section 6.5.6 requires procedures and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that each engine will be operated and maintained per the specifications of the manufacturer or emissions control system supplier. The following conditions will be included on each IC engine permit as a mechanism to enforce 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]

Section 6.5.7 requires procedures and a schedule for using a portable NOx analyzer to take NOx emission readings pursuant to Section 5.8.9. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the rule. The following condition will be placed on the permit to ensure continued compliance:

- {modified 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 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. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the rule. The following condition will be included on each IC engine permit as a mechanism to enforce compliance:

- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 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]

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. 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 included on each IC engine permit as a mechanism to enforce 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 and compliance with the requirements of this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP). An AECP will not be used for the engines in this project; therefore, Section 8.0 is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. No certification of an emissions control system is proposed with this project; therefore, Section 9.0 is not applicable.

As discussed above, the proposed engines are expected to comply with the applicable requirements of this rule upon initial startup and during subsequent continued operation.

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) = $(n \times R \times T) \div P$

Where:

N = moles SOx

T = standard temperature: 60 °F or 520 °R

R = universal gas constant: $\frac{10.73 \, psi \cdot ft^3}{lb \cdot mol \cdot °R}$

To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from the flare and engines will be calculated using the maximum sulfur content allowed for the digester gas, which is 40 ppmv, equivalent to 0.0096 lb-SOx/MMBtu (assuming 700 Btu/scf heating value for digester gas).

$$\frac{0.0096\ lb{-}SO_x}{MMBtu} \times \frac{MMBtu}{9{,}100\ scf{-}exhaust} \times \frac{lb{-}mol}{64\ lb{-}SO_2} \times \frac{10.73\ psi{-}ft^3}{lb{-}mol\ x\ °R} \times \frac{520\ °R}{14.7\ psi}\ x\ 10^6 = 6.3\ ppmv$$

Since 6.3 ppmv is less than 2000 ppmv, the flare and IC engines are expected to comply with Rule 4801. The following conditions will be included on each permit as shown as a mechanism to enforce compliance.

Digester System and Backup/Emergency Flare

- The sulfur content of the digester gas combusted in this flare shall not exceed 40 ppmv as H_2S. The District may approve an averaging period of up to one calendar day in length for demonstration of compliance with the digester gas sulfur content limit. [District Rules 2201 and 4801]

C-9070-2-0, -3-0, & -4-0: Digester Gas-Fired IC Engines

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. 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]

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)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The 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; and
- 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

District is a Responsible Agency

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 County of Fresno (County) is the public agency having principal responsibility for approving the project. As such, the County served as the Lead Agency (CCR §15367). In approving the project, the Lead Agency prepared and adopted a Mitigated Negative Declaration. The Lead agency filed a Notice of Determination, stating that the environmental document was adopted pursuant to the provisions of CEQA and concluding that the project would not have a significant effect on the environment.

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). As a Responsible Agency the District complies with CEQA by considering the environmental document prepared by the Lead Agency, and by reaching its own conclusion on whether and how to approve the project (CCR §15096).

The District has considered the Lead Agency's environmental document and finds that it adequately characterizes the project's potential impact on air quality. In addition, all feasible and cost-effective control measures to reduce potential impacts on air quality resulting from project related stationary source emissions have been applied to the project. Furthermore, the District has conducted an engineering evaluation of the project, this document, which demonstrates that Stationary Source emissions from the project would be reduced. Thus, the District finds that through a combination of project design elements, compliance with applicable District rules and regulations, and compliance with District air permit conditions, project specific stationary source emissions would be reduced to lessen the impacts on air quality. The District does not have authority over any of the other project impacts and has, therefore, determined that no additional findings are required (CEQA Guidelines §15096(h)).

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-9070-1-0, 2-0, 3-0, and 4-0 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-9070-1-0	3020-02-G	12.25 MMBtu/hr Flare	$936.00
C-9070-2-0	3020-10-F	1,609 bhp IC Engine	$860.00
C-9070-3-0	3020-10-F	1,609 bhp IC Engine	$860.00
C-9070-4-0	3020-10-F	1,609 bhp IC Engine	$860.00

Appendices

A: Draft ATCs
B: BACT Guideline 3.3.15
C: BACT Analysis for IC Engines
D: BACT Determination for Digester With Backup/Emergency Flare
E: HRA and AAQA Summary
F: QNEC Calculations

APPENDIX A

Draft ATCs

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: C-9070-1-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: CALIFORNIA DAIRY ENERGY 4, LLC
MAILING ADDRESS: 145 NORTH N STREET, SUITE A
TULARE, CA 93274

LOCATION: 11883 W FLORAL AVE
FRESNO, CA 93706

EQUIPMENT DESCRIPTION:
DVO MIXED PLUG-FLOW MESOPHILIC ANAEROBIC DIGESTER SYSTEM CONSISTING OF A RECEPTION PIT AND AN IN-GROUND CONCRETE VESSEL (348 FT X 219.6 FT X 16 FT) WITH ONE 12.25 MMBTU/HR DVO MODEL 7618 8" DIGESTER GAS-FIRED BACKUP/EMERGENCY FLARE SERVED BY A BIOLOGICAL H2S REMOVAL SYSTEM AND A CARBON H2S SCRUBBER

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rules 2201 and 4102]
3. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. 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 1/4 or 5% opacity. [District Rules 2201 and 4101]
5. The flare shall be equipped with an operational, non-resettable, totalizing mass or volumetric fuel flow meter or other District-approved alternative method to measure the quantity of digester gas flared. [District Rule 2201]
6. The flare shall be operated only for testing and maintenance, backup, and emergency purposes. An emergency is a situation or condition arising from a sudden and reasonably unforeseeable and unpreventable event beyond the control of the operator, such as, but not limited to, unpreventable equipment failure, natural disasters, acts of war or terrorism, and external power curtailment (except due to interruptible power service agreements). An emergency situation requires immediate corrective action to restore safe operation. [District Rule 2201]
7. A flame shall be present at all times whenever combustible gases are vented through the flare. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services

C-9070-1-0 : Aug 28 2018 1:27PM – AIYABEIJ : Joint Inspection Required with AIYABEIJ

8. The flare outlet shall be equipped with an automatic ignition system, or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 2201]
9. Only digester gas shall be flared. [District Rule 2201]
10. Flaring of digester gas for testing and maintenance, required regulatory purposes, and backup purposes shall not exceed either of the following limits: 0.420 MMscf (equivalent to 294.0 MMBtu @ 700 Btu/scf) in any one day and 7.665 MMscf (equivalent to 5,366 MMBtu @ 700 Btu/scf) in any rolling 12-month period. [District Rule 2201]
11. Emissions from the flare shall not exceed any of the following limits: 0.056 lb-NOx/MMBtu, 0.008 lb-PM10/MMBtu, 0.066 lb-CO/MMBtu, or 0.0092 lb-VOC/MMBtu. [District Rule 2201]
12. The VOC content of the digester gas shall not exceed 0.5% by weight. [District Rule 2201]
13. The sulfur content of the digester gas combusted in this flare 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 and 4801]
14. The sulfur content of the digester gas combusted in this flare shall be monitored and recorded at least once every calendar quarter in which a digester gas sulfur content analysis is not performed. If quarterly monitoring shows a violation of the sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the sulfur content limit. Once compliance with the 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 flared shall not be required if the flare does not operate during that period. Records of the results of monitoring of the digester gas sulfur content shall be maintained. [District Rule 2201]
15. Digester gas sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the digester gas sulfur content analysis shall be maintained and provided to the District upon request. [District Rule 2201]
16. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; 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 Rule 2201]
17. 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]
18. Permittee shall maintain daily and annual records of the quantity of digester gas combusted in the flare in standard cubic feet (scf). [District Rules 1070 and 2201]
19. The permittee shall maintain records of annual throughput, material usage, or other information necessary to demonstrate that this stationary source (C-9070) has the potential to emit, for all processes, less than ten (10.0) tons per year of VOC and less than ten (10.0) tons per year of NOx. [District Rule 4311]
20. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. Records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070, 2201, and 4311]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: C-9070-2-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: CALIFORNIA DAIRY ENERGY 4, LLC
MAILING ADDRESS: 145 NORTH N STREET, SUITE A
TULARE, CA 93274

LOCATION: 11883 W FLORAL AVE
FRESNO, CA 93706

EQUIPMENT DESCRIPTION:
1,609 BHP MTU MODEL GB1145B6 DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH AN OXIDIZING CATALYST, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH A UREA INJECTION SYSTEM, AND A HEAT EXCHANGER POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
3. {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]
4. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rules 2201 and 4102]
5. {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]
6. {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]
7. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control devices and minimize emissions at all times. [District Rule 2201]
8. {1898} 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]
9. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services

Central Regional Office • 1990 E. Gettysburg Ave. • Fresno, CA 93726 • (559) 230-5900 • Fax (559) 230-6061

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

11. 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]

12. 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; 0.50 g-CO/bhp-hr (equivalent to 55 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 19.2 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

13. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rule 2201]

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

15. Source testing to measure NOx, CO, VOC, PM10, and NH3 emissions from this unit shall be conducted within 60 days of initial startup operation. [District Rules 1081, 2201, and 4702]

16. {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]

17. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

18. 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 Rules 2201 and 4702]

19. 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 NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

20. 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, or ARB Method 5 in combination with Method 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, 2201, and 4702]

21. 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]

22. During initial performance testing, and during subsequent performance tests as needed, 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 limit(s) stated in this permit. Acceptable values and ranges shall be established for each load at which the engine is expected to operate, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature(s) and back pressure(s) demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

23. During initial performance testing, and during subsequent performance tests as needed, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load at which the engine is expected to operate, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

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

25. 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 range(s), 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(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) 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 operating within the acceptable range(s) demonstrated to result in compliance with the CO and VOC emission limits of this permit. [District Rule 4702]

26. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) 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 and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

27. 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 Rules 2201 and 4702]

28. 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]

29. 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]

30. 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]

31. 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]

CONDITIONS CONTINUE ON NEXT PAGE

32. 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]

33. If the NOx, CO, or NH3 concentrations, 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]

34. 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]

35. {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]

36. {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

37. 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]

38. 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]

39. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 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]

40. 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]

CONDITIONS CONTINUE ON NEXT PAGE

41. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. Records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

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San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: C-9070-3-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: CALIFORNIA DAIRY ENERGY 4, LLC
MAILING ADDRESS: 145 NORTH N STREET, SUITE A
TULARE, CA 93274

LOCATION: 11883 W FLORAL AVE
FRESNO, CA 93706

EQUIPMENT DESCRIPTION:
1,609 BHP MTU MODEL GB1145B6 DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH AN OXIDIZING CATALYST, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH A UREA INJECTION SYSTEM, AND A HEAT EXCHANGER POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
3. {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]
4. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rules 2201 and 4102]
5. {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]
6. {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]
7. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control devices and minimize emissions at all times. [District Rule 2201]
8. {1898} 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]
9. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

CONDITIONS CONTINUE ON NEXT PAGE

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Samir Sheikh, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services

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

11. 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]

12. 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; 0.50 g-CO/bhp-hr (equivalent to 55 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 19.2 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

13. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rule 2201]

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

15. Source testing to measure NOx, CO, VOC, PM10, and NH3 emissions from this unit shall be conducted within 60 days of initial startup operation. [District Rules 1081, 2201, and 4702]

16. {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]

17. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

18. 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 Rules 2201 and 4702]

19. 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 NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

20. 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, or ARB Method 5 in combination with Method 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, 2201, and 4702]

21. 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]

22. During initial performance testing, and during subsequent performance tests as needed, 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 limit(s) stated in this permit. Acceptable values and ranges shall be established for each load at which the engine is expected to operate, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature(s) and back pressure(s) demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

23. During initial performance testing, and during subsequent performance tests as needed, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load at which the engine is expected to operate, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

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

25. 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 range(s), 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(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) 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 operating within the acceptable range(s) demonstrated to result in compliance with the CO and VOC emission limits of this permit. [District Rule 4702]

26. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) 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 and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

27. 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 Rules 2201 and 4702]

28. 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]

29. 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]

30. 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]

31. 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]

CONDITIONS CONTINUE ON NEXT PAGE

32. 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]

33. If the NOx, CO, or NH3 concentrations, 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]

34. 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]

35. {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]

36. {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

37. 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]

38. 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]

39. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 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]

40. 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]

CONDITIONS CONTINUE ON NEXT PAGE

41. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. Records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

DRAFT

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: C-9070-4-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: CALIFORNIA DAIRY ENERGY 4, LLC
MAILING ADDRESS: 145 NORTH N STREET, SUITE A
TULARE, CA 93274

LOCATION: 11883 W FLORAL AVE
FRESNO, CA 93706

EQUIPMENT DESCRIPTION:
1,609 BHP MTU MODEL GB1145B6 DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH AN OXIDIZING CATALYST, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH A UREA INJECTION SYSTEM, AND A HEAT EXCHANGER POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
3. {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]
4. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rules 2201 and 4102]
5. {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]
6. {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]
7. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control devices and minimize emissions at all times. [District Rule 2201]
8. {1898} 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]
9. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

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Arnaud Marjollet, Director of Permit Services

C-9070-4-0 : Aug 28 2018 12:00PM -- AIYABEIJ : Joint Inspection Required with AIYABEIJ

10. This engine shall only be fired on digester gas. [District Rule 2201]
11. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. 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]
12. 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% O_2), NOx referenced as NO_2; 0.08 g-PM10/bhp-hr; 0.50 g-CO/bhp-hr (equivalent to 55 ppmvd CO @ 15% O_2); or 0.10 g-VOC/bhp-hr (equivalent to 19.2 ppmvd VOC @ 15% O_2), VOC referenced as CH_4. [District Rules 2201 and 4702]
13. Ammonia (NH_3) emissions from this engine shall not exceed 10 ppmvd @ 15% O_2. [District Rule 2201]
14. Source testing to measure NOx, CO, VOC, and NH_3 emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]
15. Source testing to measure NOx, CO, VOC, PM10, and NH_3 emissions from this unit shall be conducted within 60 days of initial startup operation. [District Rules 1081, 2201, and 4702]
16. {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]
17. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
18. 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 Rules 2201 and 4702]
19. 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]
20. 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, 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, 2201, and 4702]
21. 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]
22. During initial performance testing, and during subsequent performance tests as needed, 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 limit(s) stated in this permit. Acceptable values and ranges shall be established for each load at which the engine is expected to operate, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature(s) and back pressure(s) demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]
23. During initial performance testing, and during subsequent performance tests as needed, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load at which the engine is expected to operate, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

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

25. 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 range(s), 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(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) 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 operating within the acceptable range(s) demonstrated to result in compliance with the CO and VOC emission limits of this permit. [District Rule 4702]

26. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) 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 and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

27. 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 Rules 2201 and 4702]

28. 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]

29. 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]

30. 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]

31. 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]

CONDITIONS CONTINUE ON NEXT PAGE

32. 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]

33. If the NOx, CO, or NH3 concentrations, 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]

34. 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]

35. {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]

36. {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

37. 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]

38. 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]

39. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 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]

40. 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]

CONDITIONS CONTINUE ON NEXT PAGE

41. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. Records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

APPENDIX B

BACT Guideline 3.3.15

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.3.15*

Last Update: 03/06/2013

Waste Gas-Fired IC Engine**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
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 CH4)
Sox	Sulfur content of fuel gas < or = 40 ppmv (as H2S) (dry absorption, wet absorption, chemical H2S reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance)		
PM10	Sulfur content of fuel gas < or = 40 ppmv (as H2S)		
Nox	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% O2) 3. Gas Turbine (<9 ppmv @ 15% O2) (Note: gas turbines only ABE for projects > or = to 3 MW)
CO	2.0 g/bhp-hr		1. Fuel Cells (<0.10 lb/MW-hr) 2. Microturbines (<60 ppmv @ 15% O2) 3. Gas Turbine (<60 ppmv @ 15% O2) (Note: gas turbines only ABE for projects > or = 3 MW)
Ammonia (NH3) Slip	< or = 10 ppmv @ 15% O2		

**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**

APPENDIX C

BACT Analysis for IC Engines

1. BACT Analysis for NOx Emissions

a. Step 1 - List all control technologies

District BACT Guideline 3.3.15 lists the following options to reduce NOx emissions from waste gas-fired IC engines:

1) NOx emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)
2) Fuel Cells (≤ 0.05 lb/MW-hr) (Alternate Basic Equipment)
3) Microturbines (< 9 ppmv NOx @ 15% O_2) (Alternate Basic Equipment)
4) Gas Turbine (< 9 ppmv NOx @ 15% O_2) (Alternate Basic Equipment)

Description of Control Technologies

1) NOx emissions ≤ 0.15 g/bhp-hr (9-11 ppmv NOx @ 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 NOx, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NOx emissions by up to 90%.

2) Fuel Cells (≤ 0.05 lb- NOx/MW-hr ≈ 1.5 ppmv NOx @ 15% O_2) (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. 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) Microturbines (< 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.[5] 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

[5] "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)

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[6], 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 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[7] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8] (October 5, 2015) also indicate 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 gas turbines rated 1,145 kW each, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas

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[6] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles
[7] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies
[8] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

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

2) Microturbines (< 9 ppmv NO_x @ 15% O_2) (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)

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. The 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.d: 65 ppmvd NO_x (or 90% reduction), 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 lower 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 demonstrates that replacement of the proposed engines with a fuel cell is not 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)
- 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)*[9] *beginning June 1, 2016*)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and fuel cells will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8]
- 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 biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [8]

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

- Engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines = 30% (District practice)
- The maximum total annual heating value for of the digester gas used by engine will be: 119,571.2 MMBtu/year (*1,609 bhp_{out}/engine x 1 bhp_{in}/0.30 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 8,760 hr/year*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,145 kW without add-on air pollution control equipment: $1,713/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total installation cost for biogas-fueled IC engine rated 1,145 kW: $2,100/kW
- Estimated operation costs for CHP IC engine rated 1,145 kW without add-on air pollution control costs: $0.019/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)

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[9] 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)

- 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 biogas-fueled 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.
- 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)

<u>Assumptions for Fuel Cell System</u>

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 42.5% (*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: 1,145 kW (an equivalently-rated fuel cell system is generally not likely to be available, hence actual capital expenditures may be higher due to need to purchase over-rated unit, or multiple units to better match the needed capacity.)
- Estimated purchase and installation cost for MCFC: $4,550/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".*)
- Additional capital investment for biogas conditioning and cleanup for fuel cells: $563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total installation cost for biogas-fueled fuel cell system: $5,113/kW
- Typical operation costs for natural gas-fueled fuel cell system, 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 cell system: $0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)

- Total operation costs for biogas-fueled fuel cell system: \$0.19/kW-hr
- Fuel cell system 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 system 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)

Capital Cost

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

(1,145 kW x \$5,113/kW) - (1,145 kW x \$2,100/kW) = \$3,449,885

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)

$$A = [\$3{,}449{,}885 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \$561{,}453/\text{year}$$

Annual Costs

Electricity Generated

The quantity of electricity potentially generated by each option is calculated as follows:

Proposed IC Engine

1,145 kW x 8,760 hr/yr = 10,030,200 kW-hr/year

Fuel Cell (Alternate Equipment)

119,571.2 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.425 (electrical efficiency) = 14,889,470 kW-hr/year

Cost (Decrease) from Increased Revenue for Power Generation from Replacing Proposed 1,145 kW Engine with a Fuel Cell System

(10,030,200 kW-hr/yr - 14,889,470 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = -$620,626/year

Annual Operation and Maintenance Cost

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

Proposed 1,145 IC kW Engine

10,030,200 kW-hr/yr x $0.019/kW-hr = $190,574/year

Fuel Cell (Alternate Equipment)

14,889,470 kW-hr/yr x $0.19/kW-hr = $2,828,999/year

Annual Costs of Increased Maintenance

$2,828,999/yr - $190,574/yr = $2,638,425/year

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

$561,453/year + (-$620,626/year) + $2,638,425/year = $2,579,252/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 5.2.1, Table 1, 2.b. 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: 0.2540 lb-NO_X/MMBtu (65 ppmv NO_X @ 15% O_2) and 1.0 g-VOC/bhp-hr

Emissions from Fuel Cells as Alternative Equipment: 0.01 lb-NO_X/MW-hr and 0.02 lb-VOC/MW-hr as CH_4

Emission Reductions:

The Proposed Engine Compared to a Fuel Cell System based on District Standard Emission Reductions

NOx Emission Reductions (65 ppmv @ 15% $O_2 \rightarrow$ 0.01 lb-NOx/MW-hr)

(119,571.2 MMBtu/yr x 0.2540 lb-NOx/MMBtu) – (14,889,470 kW-hr/yr x 1 MW/1,000 kW x 0.01 lb-NOx/MW-hr)

= 30,222 lb-NOx/year (15.11 ton-NOx/year)

VOC Emission Reductions (1.0 g/bhp-hr $\rightarrow$ 0.02 lb-VOC/MW-hr)

(1,609 bhp/engine x 8,760 hr/yr x 1 engine x 1.0 g-VOC/bhp-hr x 1 lb/453.6 g) – (14,889,470 kW-hr/yr x 1 MW/1,000 kW x 0.02 lb-VOC/MW-hr)

= 30,775 lb-VOC/year (15.39 ton-VOC/year)

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

(15.11 ton-NOx/year x $24,500/ton-NOx) + (15.39 ton-VOC/year x $17,500/ton-VOC)

= $639,520/year

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

Option 2 - Microturbines (≤ 9 ppmv NOx @ 15% O_2) (Alternate Basic Equipment)

The cost analysis below demonstrates that the NOx emission reductions achieved by replacement of the proposed engine with microturbines would not be cost effective based on the District's Revised BACT Cost Effectiveness Thresholds (May 14, 2008).
In addition, it should be noted that large lean burn IC engines generally have higher overall efficiencies than microturbines. The difference in efficiency between engines and microturbines will minimize and possibly eliminate any overall differences in NOx emissions between these options. For example, information from a Capstone Turbine Corporation specification sheet indicates that the guaranteed NOx emissions rate of 9 ppmvd @ 15% O_2 for their 1,000 kW renewable gas fuel microturbine package is equivalent to 0.14 g-NOx/hp-hr.[10] This level is not significantly different from the current BACT requirement for waste gas-fired engines of 0.15 g-NOx/bhp-hr.

[10] See: http://www.adigo.no/wordpress/wp-content/uploads/2015/02/CR1000-teknisk-spesifikasjon-engelsk.pdf. Note that because of lower efficiencies for smaller microturbines, the guaranteed emission rate of 9 ppmvd NOx @ 15% O_2 from smaller units will actually be higher than 0.15 g-NOx/bhp-hr

The following discussion demonstrates how the difference in the efficiency of engines and microturbines can affect the emission rate. NOx emissions from the engine will be limited to no more than 0.15 g/bhp-hr (approximately 11 ppmv NOx @ 15% O_2). Microturbine suppliers will generally guarantee NOx emissions ≤ 9 ppmv @ 15% O_2 for digester gas-fired microturbines. The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11] (March 2015), Table 2-2: Gas Spark Ignition Engine CHP - Typical Performance Parameters, lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12] (October 5, 2015), Page A-28 indicates that "Typical observed efficiencies on IC engines deployed in the SGIP are 27% for electrical conversion (HHV)..." Therefore, the expected HHV electrical efficiency of the proposed 1,145 kW engines is between 27% and 36.8%.

The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11], Table 5-2: Gas Spark Ignition Engine CHP - Microturbine Cost and Performance Characteristics, lists HHV electrical efficiencies of 26 - 28% for microturbine systems rated at least 200 kW. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12], Table A-15: Microturbine Electrical Conversion Efficiency, lists a HHV electrical efficiencies of 21% for microturbines based on SGIP metered data. Therefore, the expected HHV electrical efficiency of large microturbines is between 21% and 28%.

The maximum expected NOx emission factor for the proposed engine-generator set is approximately 0.47 lb/MW-hr (based on 0.15 g/bhp-hr and 95% generator efficiency). Based on 9 ppmv NOx @ 15% O_2 and the expected range of microturbine electrical conversion efficiency given above, the NOx emission factor from large digester gas-fueled microturbines is expected to range from 0.43 – 0.57 lb/MW-hr. Because the maximum NOx emission factor for the proposed engine-generator sets falls within this range, the options could be considered equivalent.

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)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engine and microturbines will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[11] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12]

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

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

- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and microturbines, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [12]
- 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 biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines or microturbines must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because the required level of sulfur removal is adequate for use in both engines and microturbines and the same amount of total digester gas will be available for either option, there will be no difference in operating costs related to cleaning the digester gas for use in IC engines or microturbines.
- 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) beginning June 1, 2016*)

Assumptions for Proposed Digester Gas-Fired IC Engines (Each Engine)

- Engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines = 30% (District practice)
- The maximum total annual heating value for of the digester gas used by engine will be: 119,571.2 MMBtu/year (*1,609 bhp_{out}/engine x 1 bhp_{in}/0.30 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 8,760 hr/year*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,145 kW without add-on air pollution control equipment: $1,713/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engine: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total installation cost for biogas-fueled IC engine rated 1,145 kW: $2,100/kW
- Estimated operation costs for CHP IC engine rated 1,145 kW without add-on air pollution control costs: $0.019/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu

Assumptions for Microturbines

- Net HHV electrical efficiency for a 950 kW net (1,000 kW nominal capacity) microturbine package: 21% (*SGIP metered data*)
- Size of microturbine system needed to replace engine: 1,145 kW net (an equivalently-rated microturbine is generally not likely to be available, hence actual capital expenditures may be higher due to need to purchase over-rated unit, or multiple units to better match the needed capacity.)
- Estimated purchase and installation cost for microturbine package: $2,500/kW (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- Estimated additional capital investment for biogas conditioning and cleanup for microturbines: $744/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled microturbine system: $3,244/kW
- Typical operation costs for a microturbine package: $0.012/kW-hr (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- NO_X Emissions for Digester gas-fueled microturbines: ≤ 9 ppmv NO_X @ 15% O_2 (~ 0.0352 lb-NOx/MMBtu)

Capital Cost

The incremental capital cost for replacement of each proposed IC engine with a microturbine system is calculated as follows:

(1,145 kW x $3,244/kW) - (1,145 kW x $2,100/kW) = $1,309,880

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)

$$A = [\$1,309,880 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \$213,177/\text{year}$$

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Proposed IC Engine

1,145 kW x 8,760 hr/yr = 10,030,200 kW-hr/year

Microturbine Package (Alternate Equipment)

119,571.2 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.21 (electrical efficiency) = 7,357,150 kW-hr/year

Cost of Decreased Revenue from Power Generation from Replacing each Proposed 1,145 kW Engine with Microturbine

(10,030,200 kW-hr/yr - 7,357,150 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = $341,402/year

Annual Operation and Maintenance Cost

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

Proposed 1,145 kW IC Engine

10,030,200 kW-hr/yr x $0.019/kW-hr = $190,574/year

Microturbine (Alternate Equipment)

7,357,150 kW-hr/yr x $0.012/kW-hr = $88,286/year

Cost (Decrease) from Annual Maintenance Costs

$88,286/yr - $190,574/yr = -$102,288/year

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

$213,177/year + $341,402/year + (-$102,288/year) = $452,291/year

Emission Reductions:

NO_x 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 5.2.1, Table 1, 2.b.

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

District Standard Emissions: 0.2540 lb-NO_X/MMBtu (65 ppmv NO_X @ 15% O_2)

Emissions from Microturbines as Alternative Equipment: 0.0352 lb-NO_X/MMBtu (9 ppmv NO_X @ 15% O_2)

Emission Reductions for Each Proposed Engine Compared to Microturbines based on District Standard Emission Reductions

NO_X Emission Reductions (65 ppmv @ 15% O_2 → 9 ppmv @ 15% O_2)

119,571.2 MMBtu/yr x (0.2540 lb-NO_X/MMBtu – 0.0352 lb-NO_X/MMBtu)
= 26,162 lb-NO_X/year (13.08 ton-NO_X/year)

Cost of NO_X Emission Reductions

Cost of reductions = ($452,291/year)/[(26,162 lb-NO_X/year)(1 ton/2000 lb)]
= $34,576/ton of NO_X reduced

As shown above, the cost of the NO_X emission reductions for replacing the proposed engine with a microturbine exceeds the $24,500/ton cost effectiveness threshold of the District BACT policy. Therefore, this option is not cost effective and is being removed from consideration.

Option 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)

This option 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 the Digester Gas-fired Engines must be satisfied with the following: NO_X: NO_X emissions to ≤ 0.15 g/bhp-hr

The applicant has proposed to use SCR systems for the digester gas-fired lean burn IC engines to reduce 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 engines 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 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 engines 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 SO_x 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) VOC emissions ≤ 0.10 g/bhp-hr (lean burn or equivalent and positive crankcase ventilation) (Achieved in Practice)
2) Fuel Cells (≤ 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 Cells (≤ 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 Cells (≤ 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 IC engines with VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

APPENDIX D

BACT Determination for Digester With Backup/Emergency Flare

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 5.8.12

Emission Unit: Dairy Manure Digester with Backup/Emergency Flare

Industry Type: Dairy Manure Digesters

Last Update: August 2, 2018

Equipment Rating:

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
VOC	Open flare (98% control efficiency)	Ultra-low emissions (ULE) enclosed flare (99% control efficiency)	

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 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 Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 5.8.12

Emission Unit: Dairy Manure Digester with Backup/Emergency Flare

Equipment Rating:

References: C-9070-1-0

Facility: California Dairy Energy 4, LLC

Date of Determination: August 2, 2018

Location: 11883 W Floral Ave
Fresno, CA

Pollutant	BACT Requirements
VOC	Open flare (98% control efficiency)

BACT Status:

X Achieved in practice Small Emitter T-BACT
Technologically feasible BACT
At the time of this determination achieved in practice BACT was equivalent to technologically feasible BACT
Contained in EPA approved SIP
Alternate Basic Equipment
The following alternate basic equipment was not cost effective:

Mail to: CAPCOA BACT Clearinghouse Project Assessment Branch P.O. Box 2815 Sacramento, CA 95812	For CAPCOA use only Record No.: ;Form No.: ;BLIS District Code: Codes - EPA Source: ;SCAQMD: ;EPA ID No.: ARB Sc: ,Ctrl: ;BLIS Process: ;AIRS Facility No.:

CAPCOA BACT DETERMINATION REPORTING FORM

Instructions: Complete this form when issuing an authority to construct. Please use on form per determination (i.e. pollutant). Please use one form per determination (i.e. pollutant) Section A need only be completed on one form in the case of a source with multiple determinations. See the reverse side for descriptions of the field identifiers used below. Please attach a copy of the permit or permit conditions if practical. Please call (916)327-5601 for clarification of any questions. (1/5/94)

SECTION A. Source Information

Company and Project Name: California Dairy Energy 4, LLC

Facility Address: 11883 W Floral Ave, Fresno, CA SIC Code: 4911

Application No.: C-1162454 ; Authority to Construct No.: C-9070-1-0 Authority to Construct Issue Date:

District: SJVUAPCD; District Contact: Arnaud Marjollet; Phone No.: (559) 230-5900

Est. Startup Date: ; Today's Date: August 2, 2018; Permit Unit Status: *New*

Basic Equip./Process (include make and model): Dairy manure digester with backup/emergency flare

Rated Capacity: 12.25 MMBtu/hr; Output: N/A ; SCC Code:

Fuel Type: Dairy manure digester gas ; Backup Fuel(s): N/A ; Project Cost: $

SECTION B. Control Data Pollutant: VOC

Control Equip. Open flare

Emissions: Uncontrolled: lbm/day Controlled Limit: 2.7 lbm/day

Enforceable Permit Emissions Limit(s): 0.0092 lb/MMBtu

Emission Type: point; Cost of Control Equipment: N/A

Regulatory Requirement: *District-Defined BACT* *Other:* N/A

BACT/LAER Specification: Reference or Basis: SJVUAPCD

Mass Emission Rate: ; Destruction efficiency (%): 98

Normalized Mass Emission Rate: 0.0092 lbm/MMBtu; N/A g/bhp-hr; N/A lbm per ton input

Emission Concentration: *ppmvd or gr/dscf* at

Other: N/A

Method of Compliance Verification: N/A

Other Relevant Permit Limits: Time of Operation: N/A

Fuel use: Percent Capacity/Use:
Throughput: N/A
Other: N/A

Remarks:

BACT ANALYSIS

Dairy Manure Digester with Backup/Emergency Flare

Facility Name:	California Dairy Energy 4, LLC	Date:	August 2, 2018
Mailing Address:	145 North N St, Ste A Tulare, CA 93274	Engineer:	Jonah Aiyabei
		Lead Engineer:	Jerry Sandhu
Contact Person:	Ray Brewer		
Telephone:	(559) 366-7052		
E-Mail:	ray@ch4power.com		
Application #:	C-9070-1-0		
Project #:	C-1162454		
Deemed Complete:	February 24, 2017		

I. PROPOSAL

California Dairy Energy 4, LLC has applied for Authority to Construct (ATC) permits for a digester gas-fired power plant. The plant will consist of a DVO Inc complete mix mesophilic anaerobic digester vessel (in-ground concrete vessel, 348' x 219.6' x 16') with one 12.25 MMBtu/hr digester gas-fired backup/emergency open flare, and three 1,609 bhp digester gas-fired IC engines powering electrical generators.

Under normal operation, conditioned digester gas will be fired in the engines to produce power. In the event that the engines are not in operation, such as during a breakdown or required maintenance, excess digester gas will be disposed of using the flare. The flare will only be permitted to operate for maintenance and testing, backup, and emergency purposes.

II. PROCESS DESCRIPTION

An anaerobic digester is a sealed basin or tank that is designed to accelerate and control the decomposition of organic matter by microorganisms in the absence of oxygen. Anaerobic digestion results in the conversion of organic compounds in the substrate into methane (CH_4), carbon dioxide (CO_2), and water rather than intermediate Volatile Organic Compounds (VOC). Since the digestion process is not 100% efficient, a small proportion of VOC is still produced. In addition, small amounts of Nitrogen (N_2), Oxygen (O_2), Hydrogen Sulfide (H_2S), and Ammonia (NH_3) are also produced. The gas generated by this process is known as biogas, waste gas, or digester gas. After processing to remove H_2S and other impurities, biogas can be used as fuel.

A proprietary iron oxides product, FeSfix, will be added directly into the digester to remove most of the H_2S from the digester gas. In addition to FeSfix inoculation, air injection will also be utilized to further reduce H_2S concentrations. From the digester, the gas is piped into a gas dehydrator for the removal of excess moisture. The gas is then pressurized and passed through an activated carbon scrubber for polishing and further H_2S removal.

Under normal operation, conditioned digester gas will be fired in three 1,609 bhp MTU GB1145B6 lean burn IC engines, which will power electrical generators to produce power. In the event that the engines are not in operation, such as during breakdowns or required maintenance, or when the engines' fuel consumption capacity is temporarily exceeded, excess digester gas will be disposed of using the flare. The quantity of gas flared will be limited to 7.665 MMscf/yr, which is approximately equivalent to the flare operating for 5% of the year (438 hours) at the proposed maximum hourly gas flow rate.

III. EMISSION CONTROL TECHNOLOGY EVALUATION

A. 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.

New emissions units - PE > 2 lb/day

The daily PE for the proposed digester backup/emergency operation is summarized in the following table:

Daily PE2 Summary – Dairy Manure Digester with Backup/Emergency Flare								
Pollutant	**Emission Factor (lb/scf)**	**x**	**Gas Flow Rate (scf/hr)**	**x**	**Op. Schedule (hrs/day)**	**=**	**PE2 (lb/day)**
NO_X	3.92E-5	x	17,500	x	24	=	**16.5**
SO_X	6.72E-6	x	17,500	x	24	=	**2.8**
PM_{10}	5.60E-6	x	17,500	x	24	=	**2.4**
CO	4.60E-5	x	17,500	x	24	=	**19.3**
VOC	6.44E-6	x	17,500	x	24	=	**2.7**

BACT is triggered for VOC since the PE is greater than 2 lb/day for this pollutant. BACT is not triggered for NOx, SOx, PM_{10}, and CO since these are secondary pollutants resulting from combustion of the digester gas in the flare, which is an emissions control device. In accordance with District definitions, an emissions control device is not an emission unit. Per District Rule 2201, only emission units can trigger

BACT. Therefore, secondary emissions resulting from an emissions control device are not subject to BACT requirements.

Relocation/modification of emissions units - PE > 2 lb/day

As discussed in the engineering evaluation for project C-1162454, the proposed project does not involve the relocation of any emission units. BACT is therefore not triggered under this category.

Modification of emissions units - AIPE > 2 lb/day

As discussed in the engineering evaluation for project C-1162454, there are no modified emission units associated with this project. BACT is therefore not triggered under this category.

SB 288/Federal Major Modification

As determined in the engineering evaluation for project C-1162454, the proposed project does not constitute an SB 288 and/or federal major modification. BACT is therefore not triggered under this category.

B. BACT Policy

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. For source categories or classes covered in the BACT clearinghouse, relevant information under each of the analysis steps may simply be cited from the clearinghouse without further analysis. However, there is no BACT guideline in the District's BACT clearinghouse which governs this project's source category. Therefore, a new top-down BACT analysis will be conducted for inclusion of a new guideline in the District's BACT clearinghouse.

C. Top-Down BACT Analysis for Permit Unit C-9070-1-0

1. Current District Requirements and Performance Standards for Dairy Manure Digester Backup/Emergency Operations

The District has recently issued Authority to Construct (ATC) permits for several dairy manure digesters with flares for backup/emergency operations. It was summarily determined that these proposed flares are control devices and therefore not subject to BACT. Therefore, no BACT determinations or top-down analyses were conducted for any of these recently permitted backup/emergency operations. The District intends to clarify in the current evaluation that the digester itself is the emission unit. A BACT determination and/or top-down BACT analysis is therefore required to establish the appropriate BACT - flare or other equivalent or more effective device/method - to be applied to emissions from the digester during backup/emergency operation.

Open Flares

The data for the recently permitted units are summarized in the following table:

ATC/PTO	Rating (MMBtu/hr)	ATC Issued	Implemented	VOC Emission Factor (lb/MMBtu)
C-6817-10	11.2	2016	Yes	0.063
C-5343-10	11.2	2016	Yes	0.063
S-8741-1	10.5	2016	No	0.014
S-6718-18	15.75	2015	Yes	0.063
S-8363-1	10.7	2013	Yes	0.0055

The sources of the VOC emission factors used are summarized in the following table:

Sources of Current District VOC Emission Factors for Dairy Manure Digester Gas-Fired Open Flares	
Emission Factor (lb/MMBtu)	**Source**
0.063	District Practice - Derived from AP-42 Section 13.5 (April 2015) - Industrial Flares.
0.0092[1] (previously 0.014)	Based on 98% VOC destruction efficiency (per AP-42 Table 2.4-3, October 2008 Draft) and maximum digester gas VOC content of 0.5% VOC by weight (District practice).
0.0055[2]	AP-42 Table 1.4-2 (July 1998) - Value for Natural Gas.

District standard emissions are used for the calculation of emission reductions for cost effectiveness analysis. Pursuant to District practice, District standard emissions for new emission units are equal to the emissions level allowed by applicable District rule requirements. The emission limits in the applicable District prohibitory rule shall be those that the particular emission unit is subject to. If there is no District prohibitory rule emission limit that applies to the particular new emission unit, District standard emissions for the unit shall be equal to the emissions from similar equipment that is commonly available in the District. If insufficient information is available to make a determination regarding emissions from commonly available equipment, District standard emissions will be estimated based on EPA's Compilation of Air Pollutant Emission Factors (AP-42), or other references as determined by the District to be appropriate.

[1] This emission factor was previously stated as 0.014 but has subsequently been revised to 0.0092, based on a change in the District's assumption regarding the HHV for digester gas – from 600 Btu/scf to 700 Btu/scf; and a change in the VOC control efficiency value used from 97.7% to 98% (value was rounded off).

[2] The District has subsequently discontinued use of this emission factor as it was drawn from a source not typically associated with flares.

Since the proposed open flare is not subject to any District prohibitory rule emission limits, the emissions from similar flares currently permitted in the District and/or AP-42, as summarized in the preceding table, will be used as District standard emissions.

Enclosed Flares

The District has also recently issued an ATC permit (N-6311-10, issued in 2016) for one dairy manure digester backup/emergency operation with an enclosed flare rated 5.3 MMBtu/hr. The operation was initially permitted in 2007 and was source tested in 2010. The permit was re-issued in 2011 and again in 2016 to address several compliance issues with the originally proposed emission limits. The VOC source test result was 0.0023 lb/MMBtu. This emission rate theoretically corresponds to a control efficiency of approximately 99.5%, relative to the previously discussed open flare emission rate of 0.0092 lb/MMBtu. However, since there was no analysis of the digester gas or measurement of the VOC concentration in the influent gas stream, it is not possible to calculate the actual control efficiency associated with the measured emission rate.

Pursuant to the District's BACT policy, the control alternatives to be considered in a BACT determination should include not only existing controls for the source category in question, but also through technology transfer, controls applied to similar source categories and gas streams. Landfills and other anaerobic digesters (e.g. food waste and wastewater anaerobic digesters) produce gas streams fairly similar to manure digester gas. Just like manure digesters, these sources use biogenic materials as feedstock and rely on the same microbial mechanisms to produce gas. The resultant gas streams differ only in methane content and the types/proportions of undesirable contaminants such as hydrogen sulfide and siloxanes. Therefore, consistent with this technology transfer provision, the following source test results from wastewater digester gas-fired enclosed flares will also be considered in establishing BACT limits for manure digester backup/emergency operations:

Summary of VOC Source Test Results for Wastewater Digester Gas-Fired Enclosed Flares				
Permit Unit	**Rating and Type**	**Source Test Yr**	**Result (lb/MMBtu)**	**Notes**
N-811-18	36 MMBtu/hr John Zinc Thermal Oxidizer Flare (ZTOF)	2000	<0.0010*	The source test did not include a VOC control efficiency test or provide any data that could be used to determine the control efficiency. The original application included the following manufacturer specifications: • Overall destruction efficiency: 98% to 99% • Typical destruction efficiency: 99.8% • Minimum guaranteed destruction efficiency (DRE): 99.95%

*No non-methane hydrocarbons detected

Summary of VOC Source Test Results for Wastewater Digester Gas-Fired Enclosed Flares				
Permit Unit	**Rating and Type**	**Source Test Yr**	**Result (lb/MMBtu)**	**Notes**
C-535-9	36.3 MMBtu/hr John Zinc	2012	<0.0011*	No manufacturer data were found. The permit originally required a VOC destruction efficiency (DE) of 95% (based on the applicant's proposal), but this requirement was subsequently removed after a source test in 2004 failed to demonstrate the required DE. The 2004 source test indicated that the VOC concentration of the influent gas was 12.2 ppm while the VOC concentration in the flare exhaust was 18 ppm. The 2012 source test did not include a VOC control efficiency test or provide any data that could be used to determine the control efficiency.
S-548-33	12.4 Flare Industries, Inc., Model 566	2012	0.00055	The source test did not include a VOC control efficiency test. The fuel analysis indicated a VOC (hexanes) content of 0.014% by weight. Based on the rest of the fuel analysis parameters,[3] the calculated uncontrolled emission rate for this VOC content is approximately 0.02474 lb/MMBtu, hence the source test result of 0.00055 lb/MMBtu indicates a control efficiency of approximately 98%. The original application included the following manufacturer specifications: • Guaranteed destruction efficiency: 99%+ • Actual destruction efficiency: ~99.5%

*No non-methane hydrocarbons detected

A review of these source test data demonstrates that a very low exhaust emission rate is not necessarily indicative of a correspondingly high control efficiency. More likely, as in the case of permit unit C-535-9, it is indicative of a very low VOC concentration in the influent gas stream. In addition, since very high destruction efficiency guarantees such as those cited above are based on assumptions of substantial VOC concentrations in the influent gas streams, they generally do not hold up when confronted with low influent VOC concentrations such as those expected in digester gas. Additional design and operation considerations such as those associated with ultra-low emissions (ULE) flares would therefore be required to achieve destruction efficiencies in the 99% range.

[3] 7.258% O_2, 23.018% N_2, 41.779% CO_2, 27.931% CH_4, all by weight, and 471.48 Btu/ft^3. Refer to Section VII of the engineering evaluation for the emission rate calculation assumptions and formula.

2. Top-Down BACT Analysis for VOC Emissions

Step 1 - Identify All Possible Control Technologies

The U.S. Environmental Protection Agency (USEPA) RACT/BACT/LAER Clearinghouse, the California Air Resources Board (CARB) BACT Clearinghouse, as well as San Joaquin Valley APCD, South Coast AQMD, Bay Area AQMD, and Sacramento Metropolitan AQMD BACT guidelines and rules were reviewed to identify any other control technologies for this class and category of operation that could be comparable to, or more effective/beneficial than the current District requirements identified in Section III.C.1 above.

No BACT guidelines, rules, or other requirements or performance standards that could be directly applied to dairy manure digester gas-fired flares were found. However, as previously stated, controls applied to similar source categories and gas streams should also be considered. The following requirements or performance standards will therefore be taken into consideration:

USEPA RACT/BACT/LAER Clearinghouse – 19.320 Digester and Landfill Gas Flares

ULE Enclosed Flares

RBLC ID: RI-0023 (PSD-BACT) – ULE Flare (Regen), Landfill Gas, (2009)

- VOC/NMOC limit: 99% destruction, or 5 ppmvd as hexane @ 3% O_2

Enclosed Flares

1. RBLC ID: RI-0023 (PSD-BACT) – 3,000 cfm Enclosed Flares, Landfill Gas, (2009)
    - VOC/NMOC limit: 98% destruction, or 5 ppmvd as hexane @ 3% O_2
2. RBLC ID: NY-0090 (Other/BACT-PSD) – 168.56 MMBtu/hr Enclosed Flare, Landfill Gas
    - VOC/NMOC Limit: 98% efficiency, 1.6 lb/hr
3. RBLC ID: CA-0440 (BACT-PSD) – 30 MMBtu/hr Enclosed Flare, Landfill Gas
    - VOC/NMHC Limit: 98% efficiency, 20 lb/day

Open Flares

1. RBLC ID: IA-0095 (BACT-PSD) – 100 MMBtu/hr Flare, Anaerobic Digesters
    - VOC Limit: 98% reduction, or 0.14 lb/MMBtu (source test - average of 3 test runs)
2. RBLC ID: VA-0294 (BACT-PSD) – 3,500 SCFM Flare, Landfill Gas
    - VOC Limit: 98% efficiency, 0.6 lb/hr

3. RBLC ID: VA-0294 (BACT-PSD) – 2,500 SCFM Flare, Landfill Gas
   - VOC Limit: 98% efficiency/reduction
4. RBLC ID: NJ-0053 (BACT-PSD) – 90 MMBtu/hr Open Flare, Landfill Gas
   - VOC/NMOC Limit: 98% efficiency, 0.038 lb/MMBtu (3.4 lb/hr)
   - VOC/NMOC Limit: 98% efficiency, 0.028 lb/MMBtu (2.5 lb/hr)
5. RBLC ID: CT-0100 (Other) – 650 SCFM Flare, Landfill Gas
   - VOC/Total Hydrocarbons Limit: 98% efficiency, 1.14 lb/hr

USEPA RACT/BACT/LAER Clearinghouse – 19.200 Emission Control Burners & Incinerators (Combustion Gasses Only)

1. RBLC ID: TX-0747 (BACT-PSD) – 10 MMBtu/hr Thermal Oxidizer, Natural Gas Fractionation Units, (2014)
   - VOC limit: 99% destruction & removal efficiency
2. RBLC ID: LA-0240 (LAER) – Thermal Oxidizer, Natural Gas, (2010)
   - VOC limit: 99.0% control efficiency

South Coast AQMD

BACT Guideline for Flares: Digester Gas or Landfill Gas from Non-Hazardous Waste Landfill[4]

- VOC: Ground Level, Shrouded, ≥ 0.6 Sec. Retention Time at ≥ 1400 °F, Auto Combustion Air Control, Automatic Shutoff Gas Valve and Automatic Re-Start System

  This requirement represents good combustion practices generally associated with a 98% control efficiency for enclosed flares.

ULE Enclosed Flares

Three ULE enclosed flares were identified as already in operation in the South Coast AQMD. The data for these flares are summarized in the following table:

[4] South Coast Air Quality Management District. (2016). *Best Available Control Technology Guidelines – PART D: BACT Guidelines for Non-Major Polluting Facilities* [PDF file]. Retrieved from http://www.aqmd.gov/docs/default-source/bact/bact-guidelines/part-d---bact-guidelines-for-non-major-polluting-facilities.pdf

Data Summary for South Coast AQMD ULE Enclosed Flares				
Flare Rating and Type	**Source Category**	**Start-Up Year**	**VOC Limit**	**Source Test Result**
39.3 MMBtu/hr John Zink ULE	Utility - Food waste & manure digester	2008	5.5 lb/day	5.05 ppm VOC (as CH4) 0.08 lb VOC/hr (as CH4)
12 MMBtu/hr Bekaert CEB 350	Utility - Wastewater digester	2011	0.038 lb/MMBtu	96.9% TGNMO[5] Destruction Effic.; 99.99 HC Destruction Effic. 0.02 ppm VOC (as hexane)
120 MMBtu/hr John Zink ULE	Utility - Landfill	2009	1.33 lb/hr 98% control	98.9% TGNMO Destruction Effic. 2.13 ppm VOC (as hexane) @ 3% O_2

Bay Area AQMD, BACT Guideline for Flares: Digester Gas or Landfill Gas from Non-Hazardous Waste Landfill[6]

- POC[7]: Achieved in Practice: Ground level, enclosed, >0.6 sec. retention time at >1400 °F, auto combustion air control, automatic shutoff gas valve and automatic re-start system

  This requirement represents good combustion practices generally associated with a 98% control efficiency for enclosed flares.

San Joaquin Valley APCD

Rule 4311, Flares, Section 5.7, Ground-Level Enclosed Flares, 10 – 100 MMBtu/Hr

- VOC Limit: 0.0027 lb/MMBtu

  Compared to the previously discussed open flare emission rate of 0.0092 lb/MMBtu, this emission rate corresponds to a control efficiency of approximately 99.4%.

Thermal Oxidizers

A large number of regenerative thermal oxidizers (RTO) were identified as already permitted and/or in operation within the District. The VOC control efficiencies for these units range from 95% to 100%. BACT guidelines 4.2.5, 4.3.14, and 4.8.9 established a VOC control efficiency requirement of 98% for thermal oxidizers serving various types of processes.

5 Volatile Organic Compounds (VOC) as Total Gaseous Non-Methane Organics (TGNMO), per South Coast AQMD Method 25.1

6 Bay Area Air Quality Management District. (2015). *Best Available Control Technology (BACT) Guideline* [PDF file]. Retrieved from http://www.baaqmd.gov/~/media/files/engineering/bact-tbact-workshop/waste-processing-industry/80-1.pdf?la=en

7 [Ozone] Precursor Organic Compound, generally considered the same as VOC.

Based on the preceding data and information, the following are identified as possible control technologies:

Open Flare (98% Control Efficiency)

A flare is a combustion device in which organic compounds such as VOC and methane are thermally oxidized into carbon dioxide and water, with the production of small quantities of combustion byproducts such as NOx, SOx, PM, and CO.

An open flare consists of a stack (typically vertical/elevated) with a pilot/ignition system at the tip. Gas to be flared is piped into the flare from the base and is burned as it exits at the stack tip. The stack diameter and height are chosen based on the anticipated maximum gas flow rate and availability of space to disperse radiant heat and combustion byproducts. The higher the gas flow rate, the greater the required stack diameter; and the closer the flare is to personnel, buildings or other structures, the higher the required stack elevation. The stack tip may be equipped with various types of weather shrouds or shields for improved flame stability.

Smokeless combustion is used as a primary indicator of proper flare function and optimum control efficiency. Smokeless combustion is usually a function of the type and quality of gas being flared. Gases with a low C:H ratio, such as digester gas (~ 70% CH_4), usually burn smokelessly in a standard open flare.[8] Special types of open flares such as steam-assist, air-assist, pressure-assist, or Coanda effect flares are only necessary if the gas to be flared has a tendency to smoke (due to chemical composition such as high C:H ratio or quality issues) and supplemental combustion air or pressure must be provided to improve the combustion quality. They are not considered to provide a higher control efficiency or any additional benefit in cases where optimum combustion quality can be achieved with a standard open flare.

As discussed in Section III.C.1, the District currently uses a VOC control efficiency of 97.7%, based on AP-42 data, for dairy manure digester gas-fired open flares. This is corroborated by the RBLC data outlined above, which all cite a 98% control efficiency for open flares. For consistency with the RBLC data, the value currently used by the District will be rounded off to 98%, since rounding off is almost certainly the only difference between this value and the value used in the RBLC determinations.

Enclosed Flare (98% Control Efficiency)

An enclosed flare consists of gas burners at or near ground level, which are located at the base of a refractory-lined[9] chimney-type combustion chamber. The combustion chamber completely encloses the burners and the flame, and also enables the combustion process to proceed more completely (i.e. increased residence time). As the exhaust exits at the top of the combustion chamber, a draft that naturally draws in combustion air from the bottom is created. The size (height and width/length or diameter) of the combustion chamber is determined by the required flaring capacity and also the emissions specifications to be met.

[8] AP-42 Section 13.5-4.

[9] While refractory lining is considered standard, other types of insulation, or materials/designs not requiring added insulation may also be used.

Based on the data sources outlined above, enclosed flares generally have a VOC control efficiency of 98%. The enclosed flare operation parameters specified in the South Coast AQMD and Bay Area AQMD landfill gas flare BACT guidelines (i.e. ≥ 0.6 Sec. Retention Time at ≥ 1400 °F, Auto Combustion Air Control) are those typically associated with enclosed flares and thermal oxidizers in the 98% control efficiency range; with required residence time expected to be much shorter for smaller units such as the one proposed in this project. Although the emission limits specified in District Rule 4311 for enclosed flares (e.g. 0.0027 lb/MMBtu for flares rated 10 – 100 MMBtu/hr and 0.0013 for those rated > 100 MMBtu) appear to correspond to VOC control efficiencies greater than 99%, a review of the 2006 and 2009 staff reports for this rule indicates that only control efficiency - 98% - was used for flares. The available staff reports do not cite the sources of the enclosed flare VOC emission limits and do not differentiate standard enclosed flares from ULE enclosed flares. Currently available data suggest that the emission limits in question are more characteristic of ULE enclosed flares rather than standard enclosed flares.

ULE Enclosed Flare (99% Control Efficiency)

Ultra-low emissions (ULE) flares are enclosed flares that have been equipped with enhanced features (e.g. blowers, pre-mix systems, temperature controls) to facilitate a more precise control of the level of combustion air and other combustion parameters. With these additional features, ULE flares are designed to achieve lower NOx emissions and higher VOC destruction efficiencies than standard enclosed flares. Based on the data sources outlined above, ULE enclosed flares can achieve a VOC control efficiency of 99%.

Regenerative Thermal Oxidizer (RTO)

A thermal oxidizer is a VOC/HAP disposal device in which organic compounds are chemically oxidized, under high temperatures and in the presence of oxygen, into carbon dioxide (CO_2) and water (H_2O). The high temperatures required for the oxidation to occur are typically maintained by the combustion of a supplemental fuel such as natural gas.

The simplest type of thermal oxidizer, the direct-fired thermal oxidizer (DFTO), consists of a refractory-lined combustion chamber with a burner and an exhaust stack. The process stream with waste gasses is introduced into the combustion chamber through or near the burner and enough residence time is provided to get the desired destruction efficiency. The combustion products are then evacuated directly through the stack. DFTOs operate at temperatures between 1,800 °F and 2,190 °F and are suitable for the disposal of process streams (liquid or gaseous) with high concentrations of organic compounds. Since DFTOs are generally considered to be a category enclosed flares,[10] they will not be addressed as a separate control technology in this evaluation.

Regenerative or recuperative thermal oxidizers (RTOs) also consist of a refractory-lined combustion chamber with a burner and an exhaust stack. Unlike DFTOs, however, RTOs

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10 Anguil Environmental. (2018). *Direct Fired Thermal Oxidizer (DFTO)*. Retrieved from https://www.anguil.com/oxidizers/direct-fired-thermal-oxidizer-dfto/

are equipped with sophisticated heat recovery systems that are used to preheat the process stream before it enters the combustion chamber. RTOs operate at temperatures around 1,600 °F and can achieve exceptionally high combustion efficiencies, thus minimizing or completely eliminating the need for supplemental fuel. RTOs can also achieve much lower NOx emissions than flares and DFTOs. Some advanced RTO systems equipped with catalysts or flameless combustion technology are capable of virtually eliminating NOx emissions. RTOs are, however, only suitable for process streams with very dilute organic contents. In order to minimize fire and explosion hazards as well as RTO damage due to excessive temperature rise, most engineering standards require that the VOC/organics content of RTO process streams shall not exceed 25% of the lower explosive limit (LEL).[11] By this standard, only a very low quality digester gas with a methane/VOC content less than 1.25%[12] by volume could be safely disposed of using an RTO. Based on the data sources outlined above, RTOs generally have a VOC control efficiency of 98% - 99%.

Other Possible Control Technologies

Carbon Adsorption System

Carbon adsorption is a control technology in which pollutants are removed from an exhaust stream by physical adsorption onto activated carbon grains. Carbon (charcoal or biochar) is "activated" for this purpose by further oxidization at high temperatures, which creates porous particles with a large internal surface area for adsorption of organic molecules as well as certain metal and inorganic molecules.

The control efficiencies for carbon adsorption systems can be as high as 99%, depending on the system design and the characteristics of the particular pollutant and exhaust stream.[13]

Scrubber

A scrubber is a control device in which pollutants are removed from an exhaust stream by absorption into or reaction with a suitable medium – in most cases water or an aqueous solution. In typical scrubber designs, the exhaust stream travels upwards through a scrubber medium that is cascading downwards. As the exhaust stream and the scrubber medium pass each other, the target pollutants are passed into the scrubber medium while the clean (scrubbed) exhaust stream is released into the atmosphere through the scrubber's stack.

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[11] Banks Engineering. (2007). *About RTOs (Regenerative Thermal Oxidizers)* [PDF file]. Retrieved from http://banksengineering.com/About%20RTOs%20Banks%20Engineering%2010-8-2007.pdf
McGowan, T. (2014). *VOC and Air Toxics Control by Oxidation and Other Methods* [PDF file]. Retrieved from http://www.tmtsassociates.com/images/apc_20140901_0023.pdf
Essa, M. I. & Ennis, T. (2001). *Thermal Oxidiser Fire & Explosion Hazards* [PDF file]. Retrieved from https://www.icheme.org/communities/subject_groups/safety%20and%20loss%20prevention/resources/hazards%20archive/~/media/Documents/Subject%20Groups/Safety_Loss_Prevention/Hazards%20Archive/XVI/XVI-Paper-55.pdf

[12] The LEL for methane, the primary organic constituent in digester gas, is 5% by volume.

[13] Refer to BACT determination IDs CA-0430, CA-0434, and TN-0041 (1993) in the EPA RACT/BACT/LAER clearinghouse.

The control efficiencies for scrubbers can be as high as 99%, depending on the system design and the characteristics of the particular pollutant and exhaust stream. However, 95% is generally accepted as the minimum control efficiency for most types of VOC. For instance, in the San Joaquin Valley Air Pollution Control District's BACT clearinghouse, BACT guidelines 4.12.5 and 4.12.8 have already established a VOC control efficiency requirement of 95% and BACT guidelines 4.12.4, 5.2.9, 5.4.8, and 7.1.15 have already established a VOC control efficiency requirement greater than 95% for scrubbers serving various types of processes.

Biofilter

A biofilter is a control device in which pollutants in an exhaust stream are removed by the metabolic activities of microorganisms living within an organic medium such as peat, compost, or wood chips, through which the exhaust stream is passed prior to release into the atmosphere. Some biofilters (often known as bioreactors) may also be designed in the form of scrubbers with the desired microorganisms living within a liquid, or mostly liquid medium. Given a constant supply of food (from the pollutants in the exhaust stream), moisture, and a conducive temperature, the desired biofilter mechanisms usually propagate naturally within a few days or weeks. Biofilters may also be inoculated with artificially propagated microorganism to optimize control efficiency, or in case the desired strains do not occur naturally in sufficient quantities. Various microorganisms metabolize both VOC and methane into carbon dioxide.

The control efficiencies for biofilters vary, depending on the system design and the characteristics of the particular pollutant and exhaust stream. However, 95% is generally accepted as an average control efficiency for most types of VOC. For instance, in the San Joaquin Valley Air Pollution Control District's BACT clearinghouse, BACT guidelines 4.3.15 and 4.3.16 (coating operations), 5.2.10 (gluten drying), and 5.5.3 (candy panning/engrossing) have already established a VOC control efficiency requirement of 95% for biofilters.

Storage

Like other types of gaseous fuel, digester gas can be stored for use at a later time. Large scale digester operations such as those associated with wastewater treatment plants for large municipalities often use storage as a means to stabilize the flow of gas (i.e. ensure constant flow) or to maximize revenue by matching gas usage with periods of peak energy demand. Likewise, digester gas can be diverted into storage when the usage equipment (e.g. IC engine or boiler) is not available due to emergency, maintenance, or other reasons. Once the usage equipment is back online, the stored gas can be withdrawn at the desired rate for normal usage.

For covered lagoon digesters, storage is most readily accomplished using the digester headspace under the lagoon cover. Lagoon covers are flexible and are designed to inflate slightly as digester gas accumulates underneath. This design feature, in combination with the extensive nature of the lagoon's surface area, results in the creation of a considerable headspace underneath the lagoon cover. Proper cover design (i.e.

appropriately flexible material installed with sufficient slack) can therefore be employed to ensure sufficient storage capacity for downtime events.

Since digester vessels and tanks are significantly smaller than lagoon digesters and therefore do not have much headspace volume, their internal gas storage capacity is negligible. For these types of digesters, gas storage must be provided externally. The most economical type of storage is the double membrane gas sphere, which can be installed on top of a digester vessel/tank (for circular vessels/tanks),[14] or separately on its own pad. The system consists of an outer air-filled membrane that provides weather protection and constant gas pressure, and an internal/bottom membrane that encloses the gas storage space. The internal membrane expands and contracts as gas is added or withdrawn. A blower is required to maintain a constant air pressure under the outer membrane, but the stored gas itself does not need to be compressed. Double membrane storage systems are available in various capacities ranging from a few thousand cubic feet to well over 100,000 cubic feet. Other storage options such as high pressure gas spheres/vessels or low pressure bladder tanks are available, but are generally considered less economical.

Since the objective of storage would be to ensure that the excess digester gas is not released via any routes until it can be used in the intended fashion, it will be considered to provide 100% VOC control.

Determination of Achieved in Practice Control Options

Pursuant to the District's BACT policy, in order for a control technology to be deemed as having been achieved in practice, the following conditions must be met:

- The rating and capacity for the unit where the control was achieved must be approximately the same as that for the proposed unit.
- The type of business (i.e. class of source) where the emissions units are utilized must be the same.
- The availability of resources (i.e. fuel, water) necessary for the control technology must be approximately the same.

Open Flare (98% Control Efficiency)

As discussed in Section III.C.1, there are several dairy manure digester backup/emergency operations served by open flares with a 98% VOC control efficiency already in operation within the District. The flares serving these existing operations range in rating from 10.7 MMBtu/hr to 15.75 MMBtu/hr, which is approximately the same rating as the proposed 12.25 MMBtu/hr unit. The existing units discussed are also all operated at dairy facilities with the same resources as the dairy facility at which the proposed unit will be operated. Therefore, an open flare with a VOC control efficiency of 98% meets all the conditions outlined in the BACT policy and is determined to be achieved in practice.

[14] Note: For the purposes of this analysis, a gas storage system installed on top of a digester vessel/tank shall not be considered part of the digester's headspace. Headspace shall only refer to the space that is created when a standard type of cover, whether rigid or flexible, that is necessary for the digester to function properly is installed.

Enclosed Flare (98% Control Efficiency)

As discussed in Section III.C.1, one dairy manure digester backup/emergency operation served by an enclosed flare is already in operation within the District. This existing unit is rated 5.3 MMBtu/hr, which is approximately 43% of the rated capacity of the proposed 12.25 MMBtu/hr unit. In addition, the backup/emergency operation served by this enclosed flare differs significantly from the one associated with the proposed open flare, in that it is equipped with a gas storage system (dual-membrane spheres installed over aboveground digester tanks) that is designed to regulate the flow of digester gas and also reduce the need for flaring by storing excess gas when the primary use equipment (i.e. IC engine) is offline. This resource (gas storage) is not available at the proposed project's facility. Therefore, the existing enclosed flare does not meet all the conditions outlined in the BACT policy and is determined NOT to be achieved in practice. No other enclosed flares being operated at dairy facilities were identified.

Storage

As discussed above, one dairy manure digester operation equipped with a gas storage system is already in operation within the District. However, the subject storage system is not primarily a backup/emergency system. It is intended to regulate the flow of digester gas into the primary combustion device (i.e. IC engine) and, to some extent, reduce the need for flaring by temporarily holding the gas when the engine is offline. Once the maximum storage capacity is reached, the excess gas is routed to the flare for disposal. In addition, the digester system on which this storage system is installed uses aboveground vertical cylindrical digester tanks. These types of digester tanks lend themselves more readily to the installation of dual-membrane gas storage spheres, which double up as digester covers. The current project's proposed digester system will use an in-ground concrete vessel with a solid concrete cover. Therefore, the existing storage system does not meet all the conditions outlined in the BACT policy and is determined NOT to be achieved in practice.

ULE Enclosed Flare, Regenerative Thermal Oxidizer (RTO), Carbon Adsorption System, Scrubber, and Biofilter

Since no ULE enclosed flares, RTOs, carbon adsorption systems, scrubbers, or biofilters serving dairy manure digester backup/emergency operations were identified, these control technologies do not meet all the conditions outlined in the BACT policy and are therefore determined NOT to be achieved in practice.

Based on the preceding analyses, the control technology options identified are listed below:

- Option 1: Open Flare (98% Control Efficiency) – **Achieved in Practice**
- Option 2: Enclosed Flare (98% Control Efficiency)
- Option 3: ULE Enclosed Flare (99% Control Efficiency)
- Option 4: Regenerative Thermal Oxidizer (99% Control Efficiency)
- Option 5: Carbon Adsorption System (99% Control Efficiency)
- Option 6: Scrubber (95% Control Efficiency)

- Option 7: Biofilter (95% Control Efficiency)
- Option 8: Storage (100% Control Efficiency)

Step 2 - Eliminate Technologically Infeasible Options

Enclosed Flare

The available data demonstrate that enclosed flares have the same VOC control efficiency as open flares (98%). There is therefore no basis for requiring the use of an enclosed flare for VOC control, even though the technology itself is feasible. This option will therefore be eliminated from further consideration.

Regenerative Thermal Oxidizer (RTO)

As previously discussed in Step 1, an RTO is not technologically feasible for the disposal of dairy manure digester gas. This control option will therefore be eliminated from further consideration.

Carbon Adsorption

While activated carbon may be highly effective in the removal of digester gas VOC, its capacity to adsorb methane, the primary constituent of digester gas, is estimated at only 0.0003%[15], which is practically zero. This technology is therefore not feasible because it does not meet the primary objective of the proposed backup/emergency operation – the destruction of excess methane.

Scrubber

Scrubbers are also expected to be highly effective in the removal of digester gas VOC. However, their effect on methane is negligible. As a matter of fact, scrubbers are commonly used to upgrade digester gas since they can effectively remove major pollutants such as carbon dioxide and sulfur dioxide while methane passes through unaffected in quantity or quality. This technology is therefore not feasible because it does not meet the primary objective of the proposed backup/emergency operation – the destruction of excess methane.

Biofilter

This control technology relies on the establishment and maintenance of robust populations of living organisms, which require a constant supply of food and water. If a biofilter was 'idled' for more than a few days, the microorganism populations will begin to deplete rapidly back to the baseline levels corresponding to no control. In order to place the biofilter back into service, it will need to be conditioned for several days to a few weeks as the microorganism populations replicate back to the levels corresponding to the desired control

[15] Shepherd, A. P.E., C.I.H. (2001, May). *Activated Carbon Adsorption for Treatment of VOC Emissions* [PDF Document]. Paper presented at the 13th Annual EnviroExpo, Boston, MA. Retrieved from www.carbtrol.com/images/white-papers/voc.pdf

level. This control option is therefore not feasible for backup/emergency operations, which are brief and sporadic in nature.

Storage

The available information indicates that storage may not be suitable as a sole/primary backup/emergency system. First, regardless of design, storage systems will be limited in capacity – probably within a range of several hours to several days. Once the maximum storage capacity is reached, another backup/emergency system/device will be required to take over, or else the excess digester gas will have to be vented uncontrolled. More importantly, since storage systems/vessels are not immune to failure, the storage of any significant quantities of digester gas raises serious safety concerns such as fire, explosion, H_2S poisoning, and asphyxiation.[16] The larger the quantity of gas stored, the more serious the associated safety hazards, especially considering that dairy manure digesters are typically located within close range of living/working quarters and livestock housing facilities. In order to address these safety issues, the storage must necessarily be limited in capacity and/or equipped with a backup/emergency system or device, such as a flare, that can be used for rapid and safe disposal of the stored gas in the event of an emergency or other problems with the storage system/vessel. Therefore, it is not feasible to require the use of storage as the sole/primary backup/emergency system.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Control Technology Rankings		
Rank	**Option**	**Control**
I	ULE Enclosed Flare – Technologically Feasible	99%
II	Open Flare – Achieved in Practice	98%

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis will now be performed for each control technology which has not been proposed or achieved in practice.

ULE Enclosed Flare (99% Control Efficiency)

Cost

Several flare manufacturers were contacted to obtain cost estimates for ULE enclosed flares. It should be noted that manufacturer representatives consistently stress that each flare must be custom-made for a specific project, and therefore actual costs will depend on the specifications of each project. Nonetheless, the District has been able to obtain the following cost estimates which are applicable to this project:

[16] Westenbroek, P. A. and Martin II, J. (2012). *Anaerobic Digesters and Biogas Safety*. Retrieved from http://articles.extension.org/pages/30311/anaerobic-digesters-and-biogas-safety

- $240,000 (12 MMBtu/hr CEB-350, per Mr. Phanindra Kondagari, representative for Aereon, (512) 836-9473)

- $355,000 (13 MMBtu/hr ZULE Flare System, per Mr. Ryan Morgan, representative for John Zink, (918) 234-1800)

The cost estimates provided are assumed to reflect budget prices for flare systems equipped with all the standard manufacturer features (e.g. control panels, pilot and auto-ignition systems). As previously noted, flare projects are highly custom, hence there is no way to make reliable estimates for additional costs such as installation and recurring operation and maintenance.

The lower of the capital cost estimates provided ($240,000) will be used in this analysis.

The equivalent annual cost is calculated as shown below:

$$A = P \frac{i(1+i)^n}{(1+i)^n - 1} \quad \text{where:}$$

A = equivalent annual control equipment capital cost

P = present value of the control equipment, including installation cost

i = interest rate (generally assumed to be 10%, unless the applicant demonstrates that a different rate is more representative of the specific operation)

n = equipment life (generally assumed to be 10 years, unless the applicant demonstrates that a different rate is more representative of the specific operation)

$$A = \$240{,}000 \times \frac{0.1(1+0.1)^{10}}{(1+0.1)^{10} - 1}$$

$$= \$39{,}059/\text{yr}$$

No operation costs were obtained for this control option. If the technology is determined not to be cost effective based on the capital costs alone, then consideration of the operation costs will not be necessary, since such additional costs would only remove the technology even farther from the cost effectiveness threshold.

Emission Reduction

Pursuant to District practice, Emission Reduction = District Standard Emissions – Emissions with Technologically Feasible BACT

Based on the VOC emission rate (0.0092 lb/MMBtu) and control efficiency (98%) discussed in Section III.C.1, a ULE enclosed flare VOC control efficiency of 99%, the maximum heat input rating of the proposed flare (12.25 MMBtu/hr), and the proposed maximum annual operation schedule (438 hrs/yr), the VOC reduction is calculated as follows:

Uncontrolled VOC emission rate = (0.0092 lb/MMBtu)/(1 – 0.98) = 0.46 lb/MMBtu

ULE enclosed flare VOC emission rate = (0.46 lb/MMBtu) x (1 – 0.99) = 0.0046 lb/MMBtu

VOC reduction = [(0.0092 – 0.0046) lb/MMBtu] x 12.25 MMBtu/hr x 438 hrs/yr x (1 ton/2,000 lb)
= 0.01 tons/yr

Cost of Reduction

Cost of reduction = [Cost ($/yr)] / [VOC Reduction (tons/yr)]
= ($39,059/yr) / (0.01 tons/yr)
= $3,905,900/ton

Cost Effectiveness

Based on the minimum possible capital cost, and not taking recurring annual operating costs into consideration, the cost of reduction for a ULE enclosed flare ($3,905,900/ton) is greater than the cost effectiveness threshold ($17,500/ton). Therefore, this control technology option is considered not cost effective and is eliminated from further consideration.

Open Flare (98% Control Efficiency)

As previously discussed in Step 1, this control option is achieved in practice. Pursuant to the District's BACT policy, cost effectiveness analysis is not required for control alternatives which are deemed achieved-in-practice, except for achieved in practice alternate basic equipment or process.

Step 5 - Select BACT

Pursuant to the District's BACT policy, the most effective control technology not eliminated in Step 4 shall be selected as BACT. Therefore, the use of an open flare with a 98% control efficiency is selected as BACT.

APPENDIX E

HRA and AAQA Summary

REVISED
San Joaquin Valley Air Pollution Control District
Risk Management Review

To:	Jonah Aiyabei – Permit Services
From:	Seth Lane – Technical Services
Date:	August, 28 2018
Facility Name:	California Diary Energy (CDE) 4, LLC
Location:	11883 W Floral Ave, Fresno
Application #(s):	C-9070-1-0, 2-0, 3-0, & 4-0
Project #:	C-1162454

A. RMR SUMMARY

RMR Summary						
Units	**Prioritization Score**	**Acute Hazard Index**	**Chronic Hazard Index**	**Maximum Individual Cancer Risk**	**T-BACT Required?**	**Special Permit Requirements?**
Unit 1-0 (Flare)	0.15	0.00	0.00	3.90E-09	No	No
Unit 2-0 (Digester)	2.58	0.07	0.05	8.03E-07	No	Yes
Unit 3-0 (Digester)	2.58	0.07	0.05	8.08E-07	No	Yes
Unit 4-0 (Digester)	2.58	0.07	0.05	8.08E-07	No	Yes
Project Totals	7.76	0.21	0.16	2.42E-06		
Facility Totals	>1	0.21	0.16	2.42E-06		

Proposed Permit Requirements

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Unit # 1-0

No special requirements are required.

Unit # 2-0, 3-0, & 4-0

1. 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.

B. RMR REPORT

I. Project Description

Technical Services received a revised request on August 28, 2018, to perform an Ambient Air Quality Analysis and a Risk Management Review for a new dairy digester operation with three 1,609 bhp lean-burn digester gas-fired IC engines with each engine equipped with a selective catalytic reduction (SCR) system powering electrical generators, and a backup flare.

II. Analysis

Toxic emissions for these Dairy Gas Fired internal combustion (4 Stroke Lean Burn) Engines were calculated using emission factors from 2000, AP 42, Fifth Edition, Volume I, Chapter 3: Stationary Internal Combustion Sources, Section 2: Natural Gas-Fired Reciprocating Engines and Dairy Biomethane characterization from 2009 report, Pipeline Quality Biomethane: North American Guidance Document for Introduction of Dairy Waste Derived Biomethane Into Existing Natural Gas Networks. Toxic emissions for the emergency backup flare were calculated using 2001 Ventura County's Air Pollution Control District's emission factors for Natural Gas Fired external combustion and based on the Dairy Biomethane characterization in Pipeline Quality Biomethane: North American Guidance Document for Introduction of Dairy Waste Derived Biomethane Into Existing Natural Gas Networks (2009). These emissions were then input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 2016 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required. The AERMOD model was used, with the parameters outlined below and meteorological data for 2007-2011 from Mendota to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 1-0 (Flare)			
Source Type	Point	**Location Type**	Rural
Eff. Stack Height (m)	9.28	**Closest Receptor (m)**	1,446.58
Eff. Stack Diameter. (m)	1.93	**Type of Receptor**	Residential
Eff. Exit Velocity (m/s)	11.95	**Max Hours per Year**	438
Stack Exit Temp. (°K)	1088.71	**Fuel Type**	Dairy Digester Gas
Fuel Usage (mmscf/hr)	0.0175	**Fuel Usage (mmscf/yr)**	7.67

Analysis Parameters: Unit 2-0, 3-0, 4-0 (Digester Engines)			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	10.06	**Closest Receptor (m)**	1,446.58
Stack Diameter. (m)	0.36	**Type of Receptor**	Residential
Stack Exit Velocity (m/s)	14.72	**Max Hours per Year**	8760
Stack Exit Temp. (°K)	425.22	**Fuel Type**	Dairy Digester Gas
Fuel Usage Non-Commission (MMscf/hr)	0.02	**Fuel Usage Non-Commission (MMscf/yr)**	138.8
NH_3 Non-Commission (lbs/hr)	0.21	**NH_3 Non-Commission (lbs/yr)**	1,864

Technical Services performed modeling for criteria pollutants CO, NO_x, SO_x, and PM10 with the emission rates below:

Unit #	**NO_x (Lbs.)**		**SO_x (Lbs.)**		**CO (Lbs.)**		**PM_{10} (Lbs.)**	
	Hr.	Yr.	Hr.	Yr.	Hr.	Yr.	Hr.	Yr.
1-0	0.69	300	0.12	52	0.80	353	0.10	43
2-0	0.53	4,661	0.14	1,243	1.78	15.537	0.17	1,554
3-0	0.53	4,661	0.14	1,243	1.78	15.537	0.17	1,554
4-0	0.53	4,661	0.14	1,243	1.78	15.537	0.17	1,554

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

	Background Site	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Turlock (2015)	Pass	**X**	Pass	**X**	**X**
NO_x	Turlock (2015)	Pass[1]	**X**	**X**	**X**	Pass
SO_x	Fresno – Garland (2015)	Pass	Pass	**X**	Pass	Pass
PM_{10}	Turlock (2015)	**X**	**X**	**X**	Pass[2]	Pass[2]
$PM_{2.5}$	Turlock (2015)	**X**	**X**	**X**	Pass[3]	Pass[3]

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures[2]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
[3]The court has vacated EPA's $PM_{2.5}$ SILs. Until such time as new SIL values are approved, the District will use the corresponding PM_{10} SILs for both PM_{10} and $PM_{2.5}$ analyses.

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with each unit is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit requirements listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Prioritization score w/ toxic emissions summary
D. Facility Summary
E. AAQA Report

APPENDIX F

QNEC Calculations

Quarterly Net Emissions Change (QNEC)

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:

$PE2_{quarterly} = PE2_{annual} \div 4$ qtrs/yr

$PE1_{quarterly} = PE1_{annual} \div 4$ qtrs/yr

The QNEC calculations are summarized in the following tables:

QNEC Calculations Summary – Digester System and Backup/Emergency Flare (C-9070-1-0)				
Pollutant	**PE2 (lb/yr)**	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NOx	300	75.00	0	75.00
SOx	52	13.00	0	13.00
PM_{10}	43	10.75	0	10.75
CO	353	88.25	0	88.25
VOC	49	12.25	0	12.25

QNEC Calculations Summary – Each IC Engine (C-9070-2-0 through 4-0)				
Pollutant	**PE2 (lb/yr)**	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NOx	4,661	1,165.25	0	1,165.25
SOx	1,243	310.75	0	310.75
PM_{10}	2,486	621.50	0	621.50
CO	15,537	3,884.25	0	3,884.25
VOC	3,107	776.75	0	776.75