July 27, 2022

Ignacio Sanchez
VS Digester LLC
1588 N Batavia St
Orange, CA 92867

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: N-9354
Project Number: N-1220041

Dear Mr. Sanchez:

Enclosed for your review and comment is the District's analysis of VS Digester LLC's application for an Authority to Construct for a digester system equipped with a backup flare and a regenerative thermal oxidizer (ATC N-9354-1-1), at 13775 Murphy Rd in Escalon, CA.

The notice of preliminary decision for this project has been posted on the District's website (www.valleyair.org). 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. Matthew Robinson of Permit Services at (209) 557-6454.

Sincerely,

Brian Clements
Director of Permit Services

BC:mr

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

Digester System with Backup Flare, RTO and Digester Gas Upgrading Operation

Facility Name:	VS Digester LLC	Date:	June 10, 2022
Mailing Address:	1588 N Batavia St, Ste 1C Orange, CA 92867	Engineer:	Matthew Robinson
		Lead Engineer:	James Harader
Contact Person:	Suparna Chakladar		
Telephone:	(951) 833 4153		
E-Mail:	Schakladar@opalfuels.com		
Application #s:	N-9354-1-1		
Project #:	N-1220041		
Deemed Complete:	February 14, 2022		

I. Proposal

VS Digester LLC has proposed modifications to the equipment and operational parameters of the digester gas upgrading system recently authorized under Authority to Construct (ATC) permit N-9354-1-0 in project N-1170108. Consequently, the permit for the digester system incorporating these changes to the digester gas upgrading system will be re-evaluated as new equipment under ATC N-9354-1-1 under this project. The applicant is not proposing any changes to the 3 associated natural gas-fired IC engines (ATCs N-9354-2-0, ‘-3-0, and ‘-4-0) that were previously issued under project N-1170108. The proposal for the digester gas system is included below:

> The digester system consists of two covered digester lagoons, a hydrolyzer to combine and homogenize the feedstock, a digester gas-fired backup flare, a digester gas upgrading system, and permit exempt boilers that are fired on natural gas and have a maximum heat input less than 5.0 MMBtu/hr. The captured digester gas from the digester system will be treated and purified onsite to pipeline quality renewable natural gas (RNG) in the proposed digester gas upgrading operation consisting of feed gas blowers, compressors, coolers, chillers, iron sponge H_2S removal, a membrane CO_2 removal system, and product gas compressors served by a regenerative thermal oxidizer (RTO).
>
> During normal operation the digester system will capture biogas produced from decomposition of liquid manure, send it to the digester gas upgrading operation that will be built next to the new digester system, and purify that biogas to pipeline quality RNG for injection into the PG&E statewide grid via a point of pipeline interconnection for delivery to the end users. Unusable “tail-gas” is oxidized through the RTO. During backup operation, produced biogas that cannot be received by the upgrading operation is diverted to the flare.

The proposed digester system and upgrading operation will be constructed on open land leased from an existing dairy, Vander Schaaf Dairy #3 (N-5768), and will receive liquid manure from the dairy. The two digester lagoons are newly constructed and will receive liquid manure from Vander Schaaf Dairy #3. Liquid manure routed to the digester and upgrading operation reduces the amount routed to Vander Schaaf Dairy #3's liquid manure system, which otherwise operates independently from the proposed digester system. Therefore, the liquid manure system is not being modified and an ATC is not required for Vander Schaaf Dairy #3.

VS Digester LLC and Vander Schaaf Dairy #3 are separate companies that will work together for the construction and operation of the proposed project. VS Digester LLC has indicated that the dairy and the digester facility will be separately owned and operate as separate businesses. The following is a summary of the business relationship between VS Digester LLC and Vander Schaaf Dairy #3 and information on the operational structure and indivdual responsibilities, as provided by the applicant. The proposed digester system and digester gas upgrading operation will be owned, installed, operated, maintained, and repaired if necessary by VS Digester LLC. The responsibility of the dairy will be limited to providing the manure feedstock and disposing of the effluent, which the dairy already must do for compliance with local water quality regulations. VS Digester LLC will not be involved in the dairy's primary activity, the production of milk. VS Digester LLC will be solely responsible for ensuring that the digester system and digester gas upgrading operation comply with all applicable air quality regulations. Because the dairy at the site will be separately owned and operated from the proposed digester system and upgrading operation, and will have different two-digit Standard Industrial Classification (SIC) codes (Industry Group 02: Agricultural Production – Livestocks and Animal Specialties for the dairy vs. Industry Group 49: Electric, Gas, And Sanitary Services for the digester system and proposed equipment in this project), pursuant to Section 3.39 of District Rule 2201, the proposed equipment will not be part of the dairy agricultural stationary source. Therefore, the proposed operation and equipment will be permitted as a separate non-agricultural stationary source (Facility N-9354).

The facility has not installed the equipment authorized by ATC N-9354-1-0. Instead, VS Digester LLC has proposed to modify the equipment and assumptions of permit N-9354-1-0. Proposed modifications are summarized in the table below:

Description	**Previous**	**Current**
RTO heat input rating (MMBtu/hr)	1.25	2.0 MMBtu/hr
RTO NOx (lb/MMBtu)	0.022	0.04
Flare heat input rating (MMBtu/hr)	37.465	34.4
Flare Maximum Operation (hr/year)	200 non-emergency	750
Flare SOx (lb/MMBtu)	0.35	0.64
Flare PM10 (lb/MMBtu)	0.015	0.008
Flare CO (lb/MMBtu)	0.046	0.0793

Since ATC N-9354-1-0 cannot and will not be implemented, ATC N-9354-1-1 will supercede it.

II. Applicable Rules

Rule 2020	Exemptions (12/18/14)
Rule 2201	New and Modified Stationary Source Review Rule (8/15/19)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (8/15/19)
Rule 4001	New Source Performance Standards (4/14/99)
Rule 4002	National Emissions 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 4301	Fuel Burning Equipment (12/17/92)
Rule 4311	Flares (12/17/20)
Rule 4801	Sulfur Compounds (12/17/92)
CH&SC 41700	Health Risk Assessment
CH&SC 42301.6	School Notice

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

III. Project Location

The facility is located at 13775 Murphy Rd in Escalon, CA. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

N-9354-1-1 (Digester System)
A 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 is known as biogas, waste gas, or digester gas. In addition to methane and carbon dioxide, biogas may also contain small amounts of Nitrogen (N_2), Oxygen (O_2), Hydrogen Sulfide (H_2S), and Ammonia (NH_3). Digester gas may also include trace amounts of various VOCs that remain from incomplete digestion of the volatile solids in the incoming substrate. Because digester gas is mostly composed of methane, the main component of natural gas, the gas produced in the digester can be cleaned to remove H_2S and other impurities and used as fuel.

The proposed digester system will be designed to process the manure generated by the cattle at Vander Schaaf Dairy #3 and will capture fugitive methane that is currently being released from the uncovered lagoon and storage ponds at the dairy. The manure will be flushed from the milking parlor and the cow housing areas at the dairy and the manure will be pumped via an underground piping system to a hydrolyzer where the waste stream will be adjusted to the proper solids content (9-15% solids) and then pumped into the new digester system. Excess manure liquid from the reception pits will be sent to a separated liquids pit where the liquid will be available for the dairy to use in the flush system. The effluent from the digester will be pumped to a solids separation area where the fibrous solids will be separated from the liquid digester effluent. After the fibrous solids have been separated, the liquid digester effluent will be pumped back to the separated liquids pit to be used in the flush system. Excess liquid from the separated liquids pit will flow to the existing dairy storage ponds to be used to fertilize adjacent cropland.

The effluent leaving the digester will be sent to a solids separation area where it will be pumped over a two stage slope screen separator for separation of the digested manure fiber solids from the liquid. The digested solids will be returned to the dairy for use as bedding for the cattle at the dairy or stored for use as a soil amendment. The liquid effluent from the mechanical separators will be directed to the separated liquids pit for reuse in the dairy flush system. The existing dairy storage ponds will be utilized for capture of any overflow from the separated liquids. The dairy will continue to use the existing storage ponds to irrigate and fertilize adjacent cropland.

V. Equipment Listing

<u>Pre-Project Equipment Description</u>

N-9354-1-0: DIGESTER SYSTEM CONSISTING OF TWO COVERED DIGESTER LAGOONS, ONE LAGOON, ONE HYDROLYZER, ONE 37.468 MMBTU/HR DIGESTER GAS-FIRED BACKUP FLARE, PERMIT EXEMPT BOILERS (NATURAL GAS-FIRED, 5 MMBTU/HR OR LESS), AND A DIGESTER GAS UPGRADING OPERATION CONSISTING OF FEED GAS BLOWERS, COMPRESSORS, COOLERS, CHILLERS, IRON SPONGE H2S REMOVAL, A MEMBRANE CO2 REMOVAL SYSTEM, PRODUCT GAS COMPRESSORS, AND A 1.25 MMBTU/HR TRITON 4.95 NATURAL GAS-FIRED REGENERATIVE THERMAL OXIDIZER (RTO)

<u>Modification</u>

N-9354-1-1: MODIFICATION OF: DIGESTER SYSTEM CONSISTING OF TWO COVERED DIGESTER LAGOONS, ONE LAGOON, ONE HYDROLYZER, ONE 37.468 MMBTU/HR DIGESTER GAS-FIRED BACKUP FLARE, PERMIT EXEMPT BOILERS (NATURAL GAS-FIRED, 5 MMBTU/HR OR LESS), AND A DIGESTER GAS UPGRADING OPERATION CONSISTING OF FEED GAS BLOWERS, COMPRESSORS, COOLERS, CHILLERS, IRON SPONGE H2S REMOVAL, A MEMBRANE CO2 REMOVAL SYSTEM, PRODUCT GAS COMPRESSORS, AND A 1.25 MMBTU/HR TRITON 4.95 NATURAL GAS-FIRED REGENERATIVE THERMAL OXIDIZER (RTO): DECREASE BACKUP FLARE HEAT INPUT RATING TO 34.4 MMBTU/HR, INCREASE RTO HEAT INPUT RATING TO 2.0 MMBTU/HR, INCREASE THE BACKUP FLARE HOURS OF OPERATION TO 750

HOURS/YEAR, AND REVISE THE EMISSION FACTORS FOR THE BACKUP FLARE AND RTO.

Post-Project Equipment Description

N-9354-1-1: DIGESTER SYSTEM CONSISTING OF TWO COVERED DIGESTER LAGOONS, ONE LAGOON, ONE HYDROLYZER, ONE 34.4 MMBTU/HR DIGESTER GAS-FIRED BACKUP FLARE, PERMIT EXEMPT BOILERS (NATURAL GAS-FIRED, 5 MMBTU/HR OR LESS), AND A DIGESTER GAS UPGRADING OPERATION CONSISTING OF FEED GAS BLOWERS, COMPRESSORS, COOLERS, CHILLERS, H2S SCRUBBER, A MEMBRANE CO2 REMOVAL SYSTEM, PRODUCT GAS COMPRESSORS, AND A 2.0 MMBTU/HR CATALYTIC PRODUCTS INTERNATIONAL NATURAL GAS-FIRED REGENERATIVE THERMAL OXIDIZER (RTO)

VI. Emission Control Technology Evaluation

N-9354-1-1

Digester System

As previously discussed, a digester system 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 greater conversion of organic compounds in the substrate into methane (CH_4), carbon dioxide (CO_2), and water rather than intermediate Volatile Organic Compounds (VOCs). Because construction of the digester system will allow the liquid manure to be anaerobically treated as opposed to be being processed through an open lagoon, construction of the digester is intended to reduce VOC emissions from the dairy's liquid manure handling system.

Under normal operation, 100% of the produced digester gas is assumed captured and routed to the upgrading operation served by the RTO. In limited circumstances when the produced digester gas cannot be received by the upgrading operation, it is vented to the backup flare.

The flare and RTO are considered emissions control devices and the products of combustion, which includes oxides of nitrogen (NOx), oxides of sulfur (SOx), particulate matter less than 10 microns (PM_{10}) and less than 2.5 microns ($PM_{2.5}$), and carbon monoxide (CO) emissions are secondary pollutants.

Normal Operation – Digester Gas Upgrading

H_2S Removal

An H_2S scrubber reduces H_2S prior to further processing in the gas upgrading plant.

An iron sponge scrubber is composed of vessel(s) containing a hydrated form of iron oxide infused onto wood shavings. The wood shavings serve only as a carrier for the iron oxide powder. The iron oxide infused into the wood surface will not wash off or migrate with the gas. As the gas passes through the iron sponge material, the H_2S is removed by the following chemical reaction producing black iron sulfide and water:

$$H_2S + Fe(OH)_2 \rightarrow FeS + 2H_2O + heat$$

For the iron sponge to perform effectively, it must be maintained within a defined range of moisture content. This requirement is typically satisfied if the gas is saturated with water vapor, as is frequently the case with biogas. If the iron sponge becomes dry, moisture can be added and it will remain effective.

The scrubber consists of enclosed vessels filled with iron sponge or other dry media for removal of H_2S. The digester gas flows through the scrubber and then to a dryer and chiller to remove moisture. For continuous operation, there will be a secondary unit that will be brought online at specified times or when monitoring indicates that the primary unit is nearing saturation. Valves can be arranged so either bed can operate while the other is serviced. The useful life of the iron sponge vessels will vary depending on the inlet concentration of H_2S, the flow rate, and the mass in the vessels. Before a scrubber is completely spent, it must be regenerated or replaced. The spent scrubber vessels will be sent to a regeneration facility or to an appropriate disposal facility.

<u>CO2 Membrane</u>

Pursuant to Newpoint Gas, LLC[1], carbon dioxide membranes operate on the principle of selective permeation. Each gas component has a specific permeation rate. The rate of permeation is determined by the rate which a component dissolves into the membrane surface and the rate at which it diffuses through the membrane.

The components with higher permeation rates (such as CO2, H2, and H2S) will permeate faster through the membrane module than components with lower permeation rates (such as N2, C1, C2 and heavier hydrocarbons). For example, carbon dioxide is a “fast,” more permeable, gas than methane. When a stream consisting of these two gases contacts the membrane, the carbon dioxide will permeate through the fiber at a faster rate than the methane. Thus, the feed stream is separated into a methane-rich (residual) stream on the exterior of the membrane fiber and a carbon dioxide-rich (permeate) stream on the interior of the membrane fiber.

The primary driving force of the separation is the differential partial pressure of the permeating component. Therefore, the pressure difference between the feed gas and permeate gas and the concentration of the permeating component determine the product purity and the amount of carbon dioxide membrane surface required.

This system is a closed system and the waste tail gas created in this project will be sent to be combusted in the RTO.

[1] https://www.newpointgas.com/services/carbon-dioxide-co2-removal/

RTO

The portion of the raw digester gas that cannot be otherwise collected in the gas upgrading operation, either by purification to PUC quality natural gas or capture with sorbent, is called the waste tail gas. The RTO receives waste tail gas and serves as a control device for residual H2S, NH3, and VOC. The RTO exhausts to atmosphere.

Backup Operation – Venting to Flare

Raw Digester Gas-Fired Flare

The proposed digester system is equipped with a backup/emergency flare to which mitigates risks of vented excess raw digester gas in cases when the upgrading equipment is not operating due to breakdown or maintenance. The flare oxidizes components of the biogas (i.e. H2S, NH3, VOC) to less harmful compounds. As the upgrading operation serves the primary purpose of the proposal and is expected to be properly maintained, operation of the flare is limited herein to 750 hr/year.

Fugitive Emissions

Previous analyses of digester gas have consistently demonstrated that the non-exempt VOC content of digester gas is very low (less than 1% by weight). District Policy SSP 2015 – Procedures for Quantifying Fugitive VOC Emissions at Petroleum and SOCMI (Synthetic Organic Chemical Manufacturing Industry) Facilities specifies that fugitive VOC emissions are not assessed for piping and components handling fluid streams with a VOC content of 10% or less by weight. Therefore, because of the very low VOC content of the digester gas, fugitive VOC emissions from the digester system and associated equipment are assumed to be negligible, consistent with District Policy SSP 2015 (9/15/2005).

VII. General Calculations

A. Assumptions

N-9354-1-1

Digester System and Upgrading Equipment:

- VS Digester LLC (Facility N-9354) and Vander Schaaf Dairy #3 (Facility N-5768) are separate stationary sources at the same site.
- PM emissions from the handling of separated solids for the digester system are considered negligible because of the high moisture content of separated manure solids.
- All emissions from the manure processed in the digester system are allocated to the liquid manure handling system at the dairy because the manure for the digester system will be taken from the flush system at the dairy and the effluent from the digester system will be returned to the dairy for use.
- The proposed digester system will reduce potential VOC emissions from manure generated by the cattle at the dairy. Manure that is currently stored in an uncovered lagoon and ponds will instead be placed in covered digester lagoons at the VS Digester LLC facility, thereby decreasing volatilization of compounds from the manure. In the digester, most VOCs present will be converted to methane (an exempt organic compound) and carbon dioxide further reducing the potential for VOC emissions. The

results of digester gas analyses have consistently demonstrated very low VOC content (less than 1% by weight). District Policy SSP 2015 specifies that fugitive VOC emissions are not assessed for piping and components handling fluid streams with a VOC content of 10% or less by weight. Therefore, consistent with District Policy SSP 2015, the VOC content of the digester gas will be limited by permit condition to no more than 10% by weight and the fugitive VOC emissions from the digester system will be assumed to be negligible.

- To streamline emission calculations, PM2.5 emissions are assumed to be equal to PM10 emissions.
- Digester gas properties:
  - Higher Heating Value = 580 Btu/scf (per applicant)
  - F-factor = 9,100 dscf/MMBtu (dry, adjusted to 60 °F), (Estimated based on previous digester gas fuel analyses for source tests)
  - Maximum VOC content = 0.5% by weight
  - Molar specific volume = 379.5 scf/lb-mol (at 60°F)
- Natural gas properties:
  - F-factor = 8,578 dscf/MMBtu (dry, adjusted to 60 °F), per 40 CFR 60, Appendix B
- 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

Backup flare:

- Flare operation is limited to 750 hr/year.
- Maximum flare gas flow rate = 57,360 scf/hr, hence maximum daily (i.e. 24-hour) flaring rate = 1.38 MMscf/day (equivalent to 34.4 MMBtu/hr and 825.6 MMBtu/day @ 580 Btu/scf) (per applicant)
- Flaring will be limited to a maximum of 44.48 MMscf/year (equivalent to 25,800 MMBtu/year @ 580 Btu/scf) calculated as follows:

  Per applicant, the gas upgrading equipment will be running a majority of the time, hence flare operation shall not exceed 750 hours/year to satisfy the HRA/AAQA requirements discussed in more detail in the Rule 4102 Compliance section):
  750 hrs/year x 34.4 MMBtu/hr = 25,800 MMBtu/year
  25,800 MMBtu/year ÷ 580 Btu/scf = 44.48 MMscf/year
- Flare VOC destruction efficiency = 98%.[2]

Digester Gas Upgrading Operation Served by RTO:

- Maximum waste tail gas venting rate from the CO2 membrane to the RTO = 276 scfm (per applicant)
- 100% of waste tail gas vented to the RTO

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

B. Emission Factors

<u>N-9354-1-1</u>

Digester System and Upgrading Equipment:

- Previous analyses of digester gas have consistently demonstrated that the VOC content of digester gas is very low (less than 1% by weight). District Policy SSP 2015 – Procedures for Quantifying Fugitive VOC Emissions at Petroleum and SOCMI (Synthetic Organic Chemical Manufacturing Industry) Facilities specifies that fugitive VOC emissions are not assessed for piping and components handling fluid streams with a VOC content of 10% or less by weight. Therefore, because of the very low VOC content of the digester gas, fugitive VOC emissions from the digester system and associated equipment are assumed to be negligible, consistent with District Policy SSP 2015.

Backup Flare

- The NO_X emission factor (0.06 lb/MMBtu) is based on the Industry Standard NO_X emission factor for biogas flares[3] and District practice for permitting biogas flares.
- The SO_X emission factor (0.63 lb/MMBtu) is based on the maximum sulfur content of the dairy digester gas proposed by the applicant (2,200 ppmv as H_2S).
- The PM10 emission factor (0.008 lb/MMBtu) is based on District experience with industrial flares with no visible emissions.
- The CO emission factor (0.0793 lb/MMBtu) is based on the values given for landfill gas-fired flares in AP-42, Section 2.4 Municipal Solid Waste Landfills (1998).
- The VOC emission factor for the digester gas-fired flare (0.006 lb/MMBtu) is based on the VOC emission for landfill gas and digester gas-fired flares (2.50 g/MMBtu or 0.0055 lb/MMBtu) from the California Air Resources Board (ARB) Low Carbon Fuel Standard (LCFS) pathways for the production of LCFS fuels from landfill gas and digester gas,[4] and was also assumed to be similar to the AP-42 VOC emission factor for digester gas-fired turbines (0.0058 lb/MMBtu). The assumption that the AP-42 VOC emission factor for the digester gas-fired flare is similar to digester gas-fired turbines is conservative because AP-42, Draft Section 2.4 Municipal Solid Waste Landfills (October 2008) lists a typical VOC control efficiency of 97.7% for landfill gas-fired flares compared to 94.4% for landfill gas-fired turbines and greater VOC control efficiency would result in lower VOC emissions. Additionally, as noted above, the VOC content of dairy digester gas is generally negligible to very low; therefore, using a VOC emission factor of 0.006 lb/MMBtu will result in a reasonably conservative estimate of VOC emissions from the digester gas backup flare.

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[3] John Zink® has previously indicated that the industry standard NO_X emission factor for biogas flares is 0.06 lb-NO_X/MMBtu. See: John Zink (March 1998) Ultra-Low Emission Enclosed Landfill Gas Flare – A Full Scale Factory Test. Presented at the **Solid Waste Association of North America (SWANA)** 21nd Annual Landfill Gas Symposium, Austin, Texas, March 1998. https://www.johnzinkhamworthy.com/wp-content/uploads/tp_UltraLowEmmission.pdf. John Zink® also stated that one of their standard flares is expected to comply with the 0.06 lb-NO_X/MMBtu emission limit when flaring low Btu gas from a digester gas refining process. See: Sacramento Metropolitan Air Quality management District (SMAQMD) BACT determination for flaring low Btu digester gas (July 25, 2017):
http://www.airquality.org/StationarySources/Documents/Flare%20Waste%20Gas%20Low%20BTU%20BACT%20140.pdf

[4] Examples of ARB Low Carbon Fuel Standard (LCFS) pathways for landfill gas and digester gas are available at: https://www.arb.ca.gov/fuels/lcfs/092309lcfs_lfg_lng.pdf and https://www.arb.ca.gov/fuels/lcfs/2a2b/apps/wws2bm-rpt-082514.pdf ; Also see: https://www.arb.ca.gov/fuels/lcfs/2a2b/2a-2b-apps.htm

Post-Project Emissions Factors for Backup Flare			
Pollutant	lb/MMBtu	lb/scf*	Source
NO_X	0.06	3.48×10^{-5}	Industry Standard/District Practice for Permitting Biogas Flares
SO_X	0.64	-	2,200 ppmvd in flared gas (Proposed by Applicant, see mass balance equation below)
PM_{10}	0.008	1.45×10^{-5}	District Practice for Industrial Flares with no visible emissions
CO	0.0793	4.60×10^{-5}	AP-42 Table 2.4.4 (1998) (Value for Landfill Gas Flares)
VOC	0.006		Based on ARB LCFS Pathway Biogas Flare VOC EF/Also Conservatively Assumed to be similar to Digester Gas-Fired Turbines

*lb/scf equivalent = lb/MMBtu x 0.000580 MMBtu/scf

SO_X – 2,200 ppmvd H_2S in flared gas

$$\frac{2{,}200\ \mathrm{ft^3\ H_2S}}{10^6\ \mathrm{ft^3}} \times \frac{32.06\ \mathrm{lb-S}}{\mathrm{lb-mol\ H_2S}} \times \frac{\mathrm{lb-mol}}{379.5\ \mathrm{ft^3}} \times \frac{64.06\ \mathrm{lb-SO_2}}{32.06\ \mathrm{lb-S}} \times \frac{1\ \mathrm{ft^3}}{580\ \mathrm{Btu}} \times \frac{10^6\ \mathrm{Btu}}{\mathrm{MMBtu}} = 0.64\ \frac{\mathrm{lb-SO_X}}{\mathrm{MMBtu}}$$

Digester Gas Upgrading Operation

The tail-gas from the digester gas upgrading equipment has an H2S content of less than 4 ppm (equivalent to 0.0016 lb-SOx/MMBtu). Thus, worst-case SOx emissions from the RTO serving the digester gas upgrading equipment occurs when the unit is fired solely on natural gas, which has a higher emission factor of 0.00285 lb/MMBtu.

Emission Factors for Natural Gas-Fired RTO		
Pollutant	**Post-Project Emission Factors (EF2)**	**Source**
NO_X	0.04 lb-NO_X/MMBtu	Manufacturer's specification
SO_X	0.00285 lb-SO_X/MMBtu	District Policy APR 1720
PM_{10}	0.0075 lb-PM_{10}/MMBtu	AP-42 (07/98) Table 1.4-2
CO	0.0824 lb-CO/MMBtu	AP-42 (07/98) Table 1.4-1
VOC	0.0054 lb-VOC/MMBtu	AP-42 (07/98) Table 1.4-2

C. Calculations

1. Pre-Project Potential to Emit (PE1)

As discussed in section I above, ATC N-9354-1-0 will not be implemented into a PTO, but will be superseded by the proposed design changes of ATC N-9354-1-1. Since '-1-0 is unable to be implemented, PE1 is considered to be zero for all pollutants.

2. Post-Project Potential to Emit (PE2)

N-9354-1-1

Digester System with Backup Flare:

Daily PE = EF (lb/MMBtu) × Heat Input (MMBtu/hr) × Op. Sched. (hr/day)

Annual PE = EF (lb/MMBtu) × Annual Heat Input (MMBtu/yr)

Daily PE2 for the Digester System with Backup Flare							
Pollutant	Emission Factor (lb/MMBtu)	x	Hourly Heat Input of Gas Flared (MMBtu/hr)	x	Daily Hours of Operation (hr/day)	=	Daily PE2 (lb/day)
NO_X	0.06	x	34.4	x	24	=	**49.5**
SO_X	0.64	x	34.4	x	24	=	**528.4**
PM_{10}	0.008	x	34.4	x	24	=	**6.6**
CO	0.0793	x	34.4	x	24	=	**65.5**
VOC	0.006	x	34.4	x	24	=	**5.0**

Annual PE2 for the Digester System with Backup Flare					
Pollutant	Emission Factor (lb/MMBtu)	x	Annual Heat Input of Gas Flared (MMBtu/yr)	=	PE2 (lb/year)
NO_X	0.06	x	25,800	=	**1548**
SO_X	0.64	x	25,800	=	**16512**
PM_{10}	0.008	x	25,800	=	**206**
CO	0.0793	x	25,800	=	**2046**
VOC	0.006	x	25,800	=	**155**

<u>Digester Gas Upgrading Operation Served by an RTO</u>

The PE for each pollutant is calculated with the following equation:

PE = EF (lb/MMBtu) $\times$ Heat Input (MMBtu/hr) $\times$ Op. Sched. (hr/day)

RTO Daily PE2								
NO_x	0.04	(lb/MMBtu) x	2.0	(MMBtu/hr) x	24	(hr/day) =	1.9	(lb/day)
SO_x	0.00285	(lb/MMBtu) x	2.0	(MMBtu/hr) x	24	(hr/day) =	0.1	(lb/day)
PM_{10}	0.0075	(lb/MMBtu) x	2.0	(MMBtu/hr) x	24	(hr/day) =	0.4	(lb/day)
CO	0.0824	(lb/MMBtu) x	2.0	(MMBtu/hr) x	24	(hr/day) =	4.0	(lb/day)
VOC	0.0054	(lb/MMBtu) x	2.0	(MMBtu/hr) x	24	(hr/day) =	0.3	(lb/day)

RTO Annual PE2								
NO_x	0.04	(lb/MMBtu) x	2.0	(MMBtu/hr) x	8,760	(hr/year) =	701	(lb/year)
SO_x	0.00285	(lb/MMBtu) x	2.0	(MMBtu/hr) x	8,760	(hr/year) =	50	(lb/year)
PM_{10}	0.0075	(lb/MMBtu) x	2.0	(MMBtu/hr) x	8,760	(hr/year) =	131	(lb/year)
CO	0.0824	(lb/MMBtu) x	2.0	(MMBtu/hr) x	8,760	(hr/year) =	1,444	(lb/year)
VOC	0.0054	(lb/MMBtu) x	2.0	(MMBtu/hr) x	8,760	(hr/year) =	95	(lb/year)

While typical operation will not involve simultaneous operation of the backup flare and RTO, maintanence or testing of either component might require both to operate simultaneously. Therefore, as a worst case conservative estimate, the total potential emissions will be estimated assuming the backup flare operates 750 hours/yr and the digester gas upgrade system operates 8,760 hours/yr.

Total Emissions for N-9354-1-1

Total Daily PE2 Summary for N-9354-1-1			
Pollutant	**Backup Flare (lb/day)**	**RTO (lb/day)**	**Total PE (lb/day)**
NO_X	49.5	1.9	51.4
SO_X	528.4	0.1	528.5
PM_{10}	6.6	0.4	7.0
CO	65.5	4.0	69.5
VOC	5.0	0.3	5.3

Total Annual PE2 Summary for N-9354-1-1			
Pollutant	**Backup Flare (lb/year)**	**RTO (lb/year)**	**Total PE (lb/year)**
NO_X	1548	701	2,249
SO_X	16512	50	16,562
PM_{10}	206	131	337
CO	2046	1,444	3,490
VOC	155	95	250

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.

Valid ATCs, PTOs, and ERCs at this Stationary Source are summarized in the table below. As ATC N-9354-1-0 cannot be implemented and will be superseded by N-9354-1-1, it is not included in SSPE1.

SSPE1 (lb/year)						
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**	**NH3**
N-9354-2-0	730	116	122	8,107	1,013	567
N-9354-3-0	730	116	122	8,107	1,013	567
N-9354-4-0	730	116	122	8,107	1,013	567
SSPE1	**2,190**	**348**	**366**	**24,321**	**3,039**	**1,701**

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.

SSPE2 (lb/year)						
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**	**NH3**
N-9354-1-1	2,249	16,562	337	3,490	250	0
N-9354-2-0	730	116	122	8,107	1,013	567
N-9354-3-0	730	116	122	8,107	1,013	567
N-9354-4-0	730	116	122	8,107	1,013	567
SSPE2	**4,439**	**16,910**	**703**	**27,811**	**3,289**	**1701**

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), pursuant to the Clean Air Act, Title 3, Section 302, US Codes 7602(j) and (z)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 70.2

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1	2,190	348	366	366	24,321	3,039
SSPE2	4,439	16,910	703	703	27,811	3,289
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No	No

Note: PM2.5 assumed to be equal to PM10

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

Rule 2410 Major Source Determination:

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

PSD Major Source Determination (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Estimated Facility PE before Project Increase	1.1	1.5	0.2	12	0.2	0.2
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source?	No	No	No	No	No	No

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

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.

Since this unit is located at a non-major source, BE = PE1 = 0 for all pollutants.

6. SB 288 Major Modification

40 CFR Part 51.165 defines a SB 288 Major Modification 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 and no further discussion is required.

7. Federal Major Modification / New Major Source

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.

As defined in 40 CFR 51.165, Section (a)(1)(v) and part D of Title I of the CAA, a Federal Major Modification is 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. The significant net emission increase threshold for each criteria pollutant is included in Rule 2201.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification and no further discussion is required.

New Major Source

As demonstrated above, this facility is not becoming a Major Source as a result of this project, therefore, this facility is not a New Major Source pursuant to 40 CFR 51.165 a(1)(iv)(A)(3).

8. 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)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10

I. Project Emissions Increase - New Major Source Determination

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

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

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Total PE from New and Modified Units	1.12	0.13	8.28	1.75	0.17	0.17
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	No	No	No	No	No	No

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

9. Quarterly Net Emissions Change (QNEC)

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

VIII. Compliance Determination

Rule 2020 Exemptions

Natural Gas-Fired Boilers
Pursuant to Section 6.1.1 of this Rule, a permit is not required for boilers that have a maximum heat input rating of 5.0 MMBtu/hr or less and is equipped to be fired exclusively with natural gas containing 5% by weight of hydrocarbons heavier than butane and no more than 1.0 gr-S/100 scf. Since the proposed boilers are fired solely on PUC-quality natural gas with a maximum heat input less than 5.0 MMBtu/hr, they are exempt from permitting and NSR requirements.

Manure Dryer
Additionally, pursuant to Section 6.19 of this Rule, a permit is not required for a low emitting unit which does not cause a significant health risk to the public. Section 3.10 of this Rule defines a low emitting unit as an emissions unit with an uncontrolled emissions rate of each air contaminant, less than or equal to two pounds per day, or if greater than two pounds per day, is less than or equal to 75 pounds per year. The PE for the dryer is calculated below:

Emission Factors:

Burner Emission Factors		
Operation	Emission Rate	Source
Natural gas combustion in the burner	0.10 lb-NO_x/MMBtu	AP-42, Table 1.4-1 & -2 (7/98)
	0.00285 lb-SO_x/MMBtu	APR-1720 (12/01)
	0.0076 lb-PM_{10}/MMBtu	AP-42, Table 1.4-1 & -2 (7/98)
	0.084 lb-CO/MMBtu	AP-42, Table 1.4-1 & -2 (7/98)
	0.0055 lb-VOC/MMBtu	AP-42, Table 1.4-1 & -2 (7/98)

Potential to Emit:

Daily PE2 from the dryer is calculated using the following equation and summarized in the table below.

$PE2_{Dryer}$ (lb/day) = EF (lb/MMBtu) x Maximum Heat Input (MMBtu/day)

Daily PE2 Natural Gas-Fired Dryer			
Pollutant	EF (lb/MMBtu)	Max Heat Input (MMBtu/day)	PE2 (lb/day)
NO_x	0.1	20	2.0
SO_x	0.00285	20	0.1
PM_{10}	0.0076	20	0.2
CO	0.084	20	1.7
VOC	0.0055	20	0.1

As shown above, emissions from the dryer does not exceed two pounds per day for any air contaminant with a daily limit of 20 MMBtu/day and as shown in Appendix D, the operation does not cause a significant health impact to the public. Therefore, the manure dryer is exempt from permitting and NSR requirements. A confirmation of the permit exempt status of the equipment discussed above will be issued under a separate cover letter.

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

Pursuant to District Rule 2201, Section 4.1, 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>**N-9354-1-1**</u>
The proposed operation is considered as two emissions units as discussed below.

<u>Digester System and Backup Flare</u>
Under normal operation all biogas is routed to the upgrading operation and there are no emissions from the digester system. If the upgrading operation is unable to accept produced biogas it vented to the backup flare. Emissions via the backup flare are of two categories: combustion products from the natural gas fuel, and emissions originating from the decomposition of manure within the digester.

The flare is an emissions control device used to mitigate risks from the gas from the digester system. Per Section 3.46.2 of District Rule 1020, an emissions control device is not a source operation; consequently, it does not meet the definition of an emission unit per Section 3.17 of District Rule 2201. Therefore, emissions from natural gas combustion in the flare are not subject to BACT.

The emissions originating from the decomposition of liquid manure have previously been accounted for in the host dairy's liquid manure handling permit (N-5768-3-2) which includes open lagoons. Though the digester permit of this project and the pre-existing liquid manure handling permit will be active simultaneously and each permitted to process the the full volume produced by the dairy, the overall volume of liquid manure is unchanged. Thus, the magnitude of emissions from decomposition of liquid manure is not expected to vary from current levels.

The sulfur concentration of the liquid manure is dependent on the dietary requirements of the dairy cows. The PE of sulfur compounds associated with this project, in this project in the form of SOx, are expected to be of similar magnitude as the displaced PE of sulfur compounds from the lagoons. The displaced potential H2S of the lagoon and potential SOx of this project exist in a precursor-secondary air contaminant relationship. Despite the accelerated oxidation provided by the flare, displaced H2S emissions from the lagoons would have naturally oxidized to a similar amount of SOx in the environment. Precursor-secondary pollutants are allowed simultaneous consideration for new source review purposes (per Section 3.31 of District Rule 2201,). Similarly, precursor-secondary relationships exist for other emissions displaced from the existing lagoons and the NOx and PM10 of this project. Therefore, the NOx, SOx, and PM10 resulting from combustion of biogas in the backup flare are not considered new emissions and are not subject to BACT.

Though PE of VOC from the digester also displaces PE from the pre-existing liquid manure handling permits, the design of the digester may be optimized to maximize gaseous hydrocarbon production (primarily the exempt organic compound methane). Thus the PE of VOC from the digester (controlled with 98% efficiency by the flare) may reflect increased emissions and is subject to BACT. The controlled emissions exceed 2.0 lb-VOC/day, thus BACT is triggered.

Potential emissions of CO are greater than 2 lb/day. However, 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.

Digester Gas Upgrading Operation Served by an RTO

The applicant proposes to install a digester gas upgrading operation served by an RTO to control H_2S, VOC, and NH_3 emissions. The control device (RTO) is not an emission unit, so it cannot trigger BACT. The source operation (digester gas upgrading operation) served by the RTO will not have any emissions greater than 2.0 lb/day; therefore, BACT is not triggered by this source operation.

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.

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

As discussed in Section I above, there are no emissions units being modified; therefore BACT is not triggered.

d. SB 288/Federal Major Modification

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

2. BACT Guideline

Digester System and Backup Flare
BACT Guideline 5.8.12 applies to dairy manure digesters with backup/emergency flares (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.

Digester System and Backup Flare
Pursuant to the attached BACT Determination (see Appendix C), BACT has been satisfied with the following:

VOC: 98% control efficiency

B. Offsets

1. Offset Applicability

Pursuant to District Rule 2201, Section 4.5, 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)					
	NO_X	SO_X	PM_{10}	CO	VOC
SSPE2	**4,439**	**16,910**	**703**	**27,811**	**3,289**
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets Triggered?	No	No	No	No	No

2. Quantity of District Offsets Required

As discussed above, the SSPE2 is not greater than the offset thresholds for all pollutants; therefore, District offsets are not triggered. In addition, as demonstrated above, this project does not trigger Federal Major Modification or New Major Source requirements. In conclusion, offsets will not be required for this project and no further discussion is required.

C. Public Notification

1. Applicability

Pursuant to District Rule 2201, Section 5.4, 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

As shown in Section VII.C.5 above, the SSPE2 of this new facility is not greater than the Major Source threshold for any pollutant. Therefore, this new facility is not a New Major Source and public noticing for this project for New Major Source, Federal Major Modification, or SB 288 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 includes a new digester system with a backup flare which has daily emissions greater than 100 lb/day for SOx, therefore public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

Public notification is required if the pre-project Stationary Source Potential to Emit (SSPE1) is increased to a level exceeding the offset threshold levels. The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Thresholds				
Pollutant	**SSPE1 (lb/year)**	**SSPE2 (lb/year)**	**Offset Threshold**	**Public Notice Required?**
NO_X	2,190	4,439	20,000 lb/year	No
SO_X	348	16,910	54,750 lb/year	No
PM_{10}	366	703	29,200 lb/year	No
CO	24,321	27,811	200,000 lb/year	No
VOC	3,039	3,289	20,000 lb/year	No

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

d. SSIPE > 20,000 lb/year

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

SSIPE Public Notice Thresholds					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_x	4,439	2,190	2,249	20,000 lb/year	No
SO_x	16,910	348	16,562	20,000 lb/year	No
PM_{10}	703	366	337	20,000 lb/year	No
CO	27,811	24,321	3,490	20,000 lb/year	No
VOC	3,289	3,039	250	20,000 lb/year	No
NH3	1,701	1,701	0	20,000 lb/year	No

As demonstrated above, SSIPE is less than 20,000 lb/year for each pollutant; therefore public noticing for SSIPE purposes is not required.

e. Title V Significant Permit Modification

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

2. Public Notice Action

As discussed above, public noticing is required for this project for SO_X emissions in excess of 100 lb/day. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be electronically published on the District's website prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest 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:

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- {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 Rule 2201]
- The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
- The sulfur content of the digester gas combusted in the flare shall not exceed 2,200 ppmv as H2S. The permittee 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]
- A flame shall be present at all times whenever combustible gases are vented through the flare. [District Rules 2201 and 4311]
- Visible emissions from the flare shall not equal or exceed 5% opacity for a period or periods aggregating more than three minutes in any one hour. [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 Rules 2201 and 4311]
- The flare shall be equipped with an operational, non-resettable, totalizing mass or volumetric flow meter or other District-approved alternative method to measure the quantity of digester gas flared. [District Rules 2201 and 4311]
- Unless the flare is equipped with a flow-sensing ignition system, the flare shall be equipped and operated with a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame. [District Rules 2201 and 4311]
- The flare shall be operated only for testing and maintenance, backup, and emergency purposes. [District Rule 2201]

- Flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rules 2201 and 4311]
- Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. [District Rules 2201 and 4311]
- Upon request, the operator of an open flare in which the flare gas pressure is less than 5 psig shall make available records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). [District Rules 2201 and 4311]
- Emissions rates from the combustion of digester gas in the flare shall not exceed any of the following limits: 0.06 lb-NOx/MMBtu, 0.64 lb-SOx/MMBtu, 0.008 lb-PM10/MMBtu, 0.0793 lb-CO/MMBtu, or 0.006 lb-VOC/MMBtu. [District Rule 2201]
- Only PUC quality natural gas shall be used in the RTO as supplemental fuel. [District Rules 2201 and 4801]
- The RTO shall be operated with a combustion chamber temperature of no less than 1600 degrees F and the retention time shall be no less than 0.5 seconds. [District Rule 2201]
- The RTO shall be heated to the proper operating temperature prior to introducing the contaminated air stream. [District Rules 2201 and 4104]
- Emissions from the RTO shall not exceed any of the following limits: 0.04 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0075 lb-PM10/MMBtu, 0.0824 lb-CO/MMBtu, or 0.0054 lb-VOC/MMBtu. [District Rule 2201]

Since the flare can operate a maximum capacity for 24 hours/day, no daily limit is required; however, since the flare's annual operation is limited, the following condition will be included as a mechanism to ensure compliance:

- The maximum amount of gas combusted by the flare shall not exceed 44.48 million standard cubic feet (MMscf) per year. [District Rules 2201, 4102, and 4311]

E. Compliance Assurance

1. Source Testing

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Pursuant to District Policy APR 1705, source testing is required for units equipped with afterburner, thermal incinerator, or catalytic incinerator for controlling VOCs. The RTO proposed in this project is not used to control VOCs; therefore, source testing of the RTO is not required. Additionally, source testing is not required for any other unit in this operation.

2. Monitoring

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

Additionally, the following condition will be placed on the permit as a mechanism to ensure compliance:

- The RTO temperature shall be monitored and recorded utilizing a continuous monitoring and recording device. The monitoring and recording device shall be maintained in proper operating condition at all times. [District Rule 2201]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following conditions are listed on the permit to operate:

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- Permittee shall maintain annual records of the amount of gas combusted by the flare, in million standard cubic feet (MMscf). [District Rules 1070 and 2201]
- 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]

- The RTO temperature shall be monitored and recorded utilizing a continuous monitoring and recording device. The monitoring and recording device shall be maintained in proper operating condition at all times. [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. Records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070, 2201, and 4311]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

Section 4.14 of District Rule 2201 requires that an AAQA be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to Appendix D of this document for the AAQA summary sheet.

Though this project only included modifications of permit unit 1, since the prior iteration had not been implemented it is considered part of the larger project including permit units 2-4. As such, permit units 1-4 were included in HRA and AAQA consideration for this project.

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 in Appendix D, 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 or natural gas-fired RTOs. Therefore, no discussion is required for permit unit N-9354-1.

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 or natural gas-fired RTOs. Therefore, no discussion is required for permit unit N-9354-1.

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).

Since the flare will only combust digester gas, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.
Additionally, as the RTO will be fired solely on natural gas fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity. Also, based on past District inspections of natural gas-fired RTOs and IC engines, compliance is expected. The following condition will be listed on the permits as a mechanism to enforce compliance:

N-9354-1-1:

- {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]

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.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification of an existing source shall not result in an increase in cancer risk greater than the District's significance level (20 in a million) and shall not result in acute and/or chronic risk indices greater than 1.

Though this project only included modifications of permit unit 1, since the prior iteration had not been implemented it is considered part of the larger project including permit units 2 through 4. As such, the emissions from permit units 1 through 4 were included in HRA and AAQA consideration for this project.

According to the Technical Services Memo for this project, 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 resulting prioritization score, acute hazard index, chronic hazard index, and cancer risk for this project is shown below.

Health Risk Assessment Summary	
	Worst Case Potential
Prioritization Score	>1
Cancer Risk	0.150 in a million
Acute Hazard Index	0.07
Chronic Hazard Index	0.01
T-BACT Required?	No*

Discussion of T-BACT

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

In accordance with District policy APR 1905, no further analysis is required, and compliance with District Rule 4102 requirements is expected.

See Appendix D: Health Risk Assessment Summary

The following permit conditions are required to ensure compliance with the assumptions made for the risk management review:

N-9354-1-1:

- {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]

- The flare shall not operate for more than 750 hours per year. [District Rules 2201, 4102, and 4311]

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.
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.

N-9354-1-1:
Digester System and Backup/Emergency Flare

For the following calculation, PM_{10} is conservatively assumed to be 100% of PM.

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

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

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

Natural Gas-Fired RTO
For the following calculation, PM_{10} is conservatively assumed to be 100% of PM.

$$PM\ Concentration = \frac{0.0075\ lb - PM}{MMBtu} \times \frac{MMBtu}{8{,}578\ dscf} \times \frac{7{,}000\ grain}{lb}$$

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

Since 0.006 grain-PM/dscf is less than 0.1 grain-PM/dscf, compliance with this rule is expected.

Rule 4311 Flares

The purpose of this rule to limit the emissions of volatile organic compounds (VOC), oxides of nitrogen (NO_X), and sulfur oxides (SO_X) from the operation of flares.

The proposed backup flare listed under ATC N-9354-1-1 is subject to Rule 4311. The requirements of Rule 4311 that apply to the proposed backup flare are discussed below.

Section 5.0 - Requirements
Pursuant to Section 5.1, flares that are permitted to operate only during an emergency are not subject to the requirements of Sections 5.7, 5.8, 5.9 and 5.10. The proposed backup flare will be permitted allowing limited operation during times that are not emergencies. Therefore, this section does not apply to the proposed flare.

Pursuant to Section 5.2, flares that are operated 200 hours or less per calendar year as specified in the Permit to Operate, or with an annual throughput limit equivalent to 200 hours per year at flare rating (MMBtu/hr) as specified in the Permit to Operate, are exempt from the requirements of Sections 5.9 and 5.10 provided that one of the following two conditions are satisfied.

5.2.1 For the 200 hours per year validation, the operator shall use a calibrated non-resettable totalizing time meter or equivalent method approved in writing by the APCO; or

5.2.2 For the annual throughput limit equivalent to 200 hours per year validation, the operator shall use a calibrated fuel meter or equivalent method approved in writing by the APCO.

The proposed backup flare may operate more than 200 hours/year. Therefore, this exemption does not apply and the flare is subject to 5.9 and 5.10.

Section 5.3 requires that a flame always be present in the flare whenever combustible gases are present. The following condition will be included on the ATC as a mechanism to ensure compliance:

- A flame shall be present at all times in the flare whenever combustible gases are vented through the flare. [District Rules 2201 and 4311]

Section 5.4 requires that the flare be equipped with either an automatic ignition system or operated with a continuous pilot. Per the applicant, this unit is equipped with an automatic ignition system. The following condition will be included on the ATC as a mechanism to ensure compliance:

- 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 Rules 2201 and 4311]

Section 5.5 requires that, except for flares equipped with a flow-sensing ignition system, flares must be equipped with a device to monitor and confirm operation of the pilot flame. The following condition will be included on the ATC as a mechanism to ensure compliance:

- Unless the flare is equipped with a flow-sensing ignition system, the flare shall be equipped and operated with a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame. [District Rules 2201 and 4311]

Section 5.6 requires that flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot must use purge gas for purging. The following condition will be included on the ATC as a mechanism to ensure compliance:

- Flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rules 2201 and 4311]

Section 5.7 requires open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig to be operated in such a manner that meets the provisions of 40 CFR 60.18. The following condition will be included on the ATC as a mechanism to ensure compliance:

- Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. [District Rules 2201 and 4311]

Section 5.8 establishes emission limits for ground-level enclosed flares. The proposed flare is not a ground level enclosed flare. Therefore, the requirements of Section 5.8 are not applicable to the proposed flare.

Section 5.9 requires that digester flares with throughputs ≤100,000 MMBtu/year and located at non-Major Sources must meet certain emission limits, or complete specified alternative requirements. The prescribed emission limits for a Flares at Digester Operations are compared to proposed emissions below:

Rule 4311, Section 5.9 Emission Requirements (Table 3)			
Pollutant	N-9354-1 Proposed	Rule Requirement	Meets Limit
VOC (lb/MMBtu)	0.006	N/A	N/A
NOx (lb/MMBtu)	0.06	≤ 0.06	Yes

The proposed flare meets the requirements of Table 3, thus compliance with Section 5.9 is expected. The following condition will be included on the ATC as a mechanism to ensure compliance:

- Emissions rates from the combustion of digester gas in the flare shall not exceed any of the following limits: 0.06 lb-NOx/MMBtu, 0.64 lb-SOx/MMBtu, 0.008 lb-PM10/MMBtu, 0.0793 lb-CO/MMBtu, or 0.006 lb-VOC/MMBtu. [District Rule 2201, 4311]

Section 5.10 applies to operators of flares that opt to comply with section 5.9.1. The proposed equipment meets the requirements of Table 3, thus is not subject to 5.9.1, and therefore, 5.10.

Section 5.11 prohibits flaring unless it is consistent with an approved flare minimization plan (FMP), pursuant to Section 6.5 or is caused by an emergency and is necessary to prevent an accident, hazard, or release of vent gas directly to the atmosphere. Section 6.5 specifies that a flare minimization plan is required for refinery flares and flares at a major source. The proposed flare is not a refinery flare and is not at a major source. Therefore, a flare minimization plan is not required and this section does not apply.

Section 5.12 establishes SO_2 emission reduction standards for petroleum refinery flares. The proposed flare is not a petroleum refinery flare. Therefore, this section does not apply.

Section 5.13 requires the operator of a flare subject to flare minimization requirements pursuant to Section 5.11 to monitor the vent gas flow to the flare with a flow measuring device and to maintain records pursuant to Section 6.1.7. Flares that the operator can verify, based on permit conditions, are not capable of producing reportable flare events pursuant to Section 6.2.2 shall not be required to monitor vent gas flow to the flare. As discussed above, the proposed flare is not subject to flare minimization requirements pursuant to Section 5.11. Therefore, this section does not apply.

Section 5.14 requires the operator of a flare subject to the annual throughput thresholds in Table 2 to monitor the vent gas flow rate to the flare with a flow measuring device. Flares that the operator can verify are not capable of exceeding the annual throughput thresholds are not required to monitor the vent gas flow to the flare. Since the flare is not physically capable of flaring enough gas to exceed the threshold in Table 2, this section does not apply.

Section 5.15 requires the operator of a petroleum refinery or a flare with a flaring capacity equal to or greater than 50 MMBtu/hr to monitor the flare pursuant to Sections 6.6, 6.7, 6.8, 6.9, and 6.10. The proposed flare is not a petroleum refinery flare. Therefore, this section does not apply.

Section 6.0 - Administrative Requirements

Section 6.1 requires the operator of a flare to maintain certain records for five years. The following conditions will be placed on the permit to ensure compliance:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4311]

Section 6.1 also states that the operator of a flare subject to this rule shall maintain the following records:

6.1.1 Copy of the compliance determination conducted pursuant to Section 6.4.1
6.1.2 Copy of the source testing result conducted pursuant to Section 6.4.2
6.1.3 For flares used during an emergency, record of the duration of flare operation, amount of gas burned, and the nature of the emergency situation
6.1.4 Operators claiming an exemption pursuant to Section 4.3 shall record annual throughput, material usage, or other information necessary to demonstrate an exemption under that section
6.1.5 A copy of the approved flare minimization plan pursuant to Section 6.5
6.1.6 Where applicable, a copy of annual reports submitted to the APCO pursuant to Section 6.2
6.1.7 Where applicable, monitoring data collected pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10

The proposed flare is not subject to any of the sections or requirements listed above; therefore, these recordkeeping requirements are not applicable.

Section 6.2.1 requires the operator of a flare subject to flare minimization plans pursuant to Section 5.8 to notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. As discussed above, the proposed flare is not subject to flare minimization requirements pursuant to Section 5.8. Therefore, this section does not apply.

Section 6.2.2 states that effective on and after July 1, 2012, and annually thereafter, the operator of a flare subject to flare minimization plans pursuant to Section 5.11 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined Section 3.0 that occurred during the previous 12 month period. As discussed above, the proposed flare is not subject to flare minimization requirements pursuant to Section 5.11. Therefore, this section does not apply.

Section 6.2.3 states that effective on and after July 1, 2012, and annually thereafter, the operator of a flare subject to flare monitoring requirements pursuant to Sections 5.13, 5.14, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO within 30 days following the end of each 12 month period. The proposed flare is not a petroleum refinery flare and is not located at a major source. Therefore, the flare is not subject to the requirements of Sections 5.13, 5.14, 6.6, 6.7, 6.8, 6.9, and 6.10 and the requirements of this section are not applicable.

Section 6.3 specifies test methods to demonstrate compliance with Rule 4311. The proposed flare is not a ground level enclosed flare and is not subject the testing or monitoring requirements of this section; therefore, this section does not apply.

Section 6.4.1 requires the operator of flares that are subject to Section 5.6 to make available to the APCO upon request the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). The following condition will be included on the ATC to ensure compliance with the requirements of Section 6.4.1:

- Upon request, the operator of an open flare in which the flare gas pressure is less than 5 psig shall make available records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). [District Rules 2201 and 4311]

Section 6.4.2 requires the operator of ground-level enclosed flares, or flares subject to the emission limits in Table 3 to conduct source testing at least once every 12 months to demonstrate compliance with Section 5.8. As discussed above, the proposed flare is not a ground level enclosed flare and is not subject to the emission limits in Table 3; therefore, this section does not apply.

Section 6.5 specifies requirements for operators of flares that are subject to the flare minimization plan (FMP) provisions of District Rule 4311. As discussed above, the proposed flare is not subject to flare minimization requirements pursuant to Section 5.8. Therefore, this section does not apply.

Sections 6.6, 6.7, 6.8, 6.9, and 6.10 require additional monitoring for petroleum refinery flares and any flare located at a major source. The proposed flare is not a petroleum refinery flare and is not located at a major source. Therefore, these sections do not apply.

Compliance with the requirements of this Rule 4311 is expected.

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:

$$\text{Volume of } SO_X \text{ as } (SO_2) = (n \times R \times T) \div P$$

Where:

N = moles SOx

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

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

N-9354-1-1:
Digester System and Backup/Emergency Flare
To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from the flare will be calculated using the maximum sulfur content allowed for the digester gas.

$$\frac{0.64\ lb{-}SO_x}{MMBtu} \times \frac{MMBtu}{9{,}100\ scf{-}exhaust} \times \frac{lb{-}mol}{64\ lb{-}SO_2} \times \frac{10.73\ psi{-}ft^3}{lb{-}m \quad x\ °R} \times \frac{520\ °R}{14.7\ psi}\ x\ 10^6 = 417\ ppmv$$

Since 417 ppmv is less than 2000 ppmv, the flare is expected to comply with Rule 4801.

Natural Gas-Fired RTO
To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from each engine will be calculated using the maximum sulfur content allowed for the natural gas, which is 0.00285 lb-SO_X/MMBtu.

$$\frac{0.00285\ lb}{MMBtu}\ x\ \frac{1\ MMBtu}{8{,}578\ scf}\ x\ \frac{1\ lb{-}mol}{64\ lb{-}SO}\ x\ \frac{10.73\ psi \quad {}^3}{lb{-}mol{-}°R}\ x\ \frac{520\ °R}{14.7\ psi}\ x1{,}000{,}000\ ppm = 1.97\ ppmv$$

Since 1.97 ppmv is less than 2000 ppmv, the engines are expected to comply with Rule 4801.

N-9354-1-1:
- The sulfur content of the digester gas combusted in the flare shall not exceed 7,000 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]
- Only PUC quality natural gas shall be used in the RTO as supplemental fuel. [District Rules 2201 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

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 San Joaquin (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. Furthermore, the District has conducted an engineering evaluation of the project, this document, which demonstrates that Stationary Source emissions from the project would be below the District's thresholds of significance for criteria pollutants. 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 will have a less than significant impact 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 N-9354-1-1subject 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**
N-9354-1-1	3020-02-H	36.4 MMBtu/hr	$1,238

Appendices

A: Draft ATCs
B: BACT Guideline
C: BACT Analysis
D: HRA and AAQA Summary
E: Quarterly Net Emissions Change

APPENDIX A
Draft ATCs

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9354-1-1 **ISSUANCE DATE:** DRAFT

DRAFT

LEGAL OWNER OR OPERATOR: VS DIGESTER
MAILING ADDRESS: 13749 MURPHY RD
ESCALON, CA 95320

LOCATION: 13749 MURPHY RD
ESCALON, CA 95320

EQUIPMENT DESCRIPTION:
MODIFICATION OF: DIGESTER SYSTEM CONSISTING OF TWO COVERED DIGESTER LAGOONS, ONE LAGOON, ONE HYDROLYZER, ONE 37.468 MMBTU/HR DIGESTER GAS-FIRED BACKUP FLARE, PERMIT EXEMPT BOILERS (NATURAL GAS-FIRED, 5 MMBTU/HR OR LESS), AND A DIGESTER GAS UPGRADING OPERATION CONSISTING OF FEED GAS BLOWERS, COMPRESSORS, COOLERS, CHILLERS, IRON SPONGE H2S REMOVAL, A MEMBRANE CO2 REMOVAL SYSTEM, PRODUCT GAS COMPRESSORS, AND A 1.25 MMBTU/HR TRITON 4.95 NATURAL GAS-FIRED REGENERATIVE THERMAL OXIDIZER (RTO): DECREASE BACKUP FLARE HEAT INPUT RATING TO 34.4 MMBTU/HR, AND INCREASE RTO HEAT INPUT RATING TO 2.0 MMBTU/HR. POST PROJECT DESCRIPTION TO READ: DIGESTER SYSTEM CONSISTING OF TWO COVERED DIGESTER LAGOONS, ONE LAGOON, ONE HYDROLYZER, ONE 34.4 MMBTU/HR DIGESTER GAS-FIRED BACKUP FLARE, PERMIT EXEMPT BOILERS (NATURAL GAS-FIRED, 5 MMBTU/HR OR LESS), AND A DIGESTER GAS UPGRADING OPERATION CONSISTING OF FEED GAS BLOWERS, COMPRESSORS, COOLERS, CHILLERS, H2S SCRUBBER, A MEMBRANE CO2 REMOVAL SYSTEM, PRODUCT GAS COMPRESSORS, AND A 2.0 MMBTU/HR TRITON 6.95 NATURAL GAS-FIRED REGENERATIVE THERMAL OXIDIZER (RTO)

CONDITIONS

1. {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 Rule 2201]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
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. Visible emissions from the flare shall not equal or exceed 5% opacity or 1/4 Ringelmann for a period or periods aggregating more than three minutes in any one hour. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

Samir Sheikh, Executive Director / APCO

DRAFT

Brian Clements, Director of Permit Services
N-9354-1-1 : Jul 12 2022 8:41AM -- ROBINSOM : Joint Inspection NOT Required

5. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
6. The exhaust stacks of the flare and RTO 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]
7. The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
8. The flare shall be operated only for testing and maintenance, backup, and emergency purposes. [District Rule 2201]
9. The maximum amount of gas combusted by the flare shall not exceed 44.48 million standard cubic feet (MMscf) per year. [District Rules 2201, 4102, and 4311]
10. The flare shall be equipped with an operational, non-resettable, totalizing mass or volumetric flow meter or other District-approved alternative method to measure the quantity of digester gas flared. [District Rules 2201 and 4311]
11. Emissions rates from the combustion of digester gas in the flare shall not exceed any of the following limits: 0.06 lb-NOx/MMBtu, 0.64 lb-SOx/MMBtu, 0.008 lb-PM10/MMBtu, 0.0793 lb-CO/MMBtu, or 0.006 lb-VOC/MMBtu. [District Rule 2201]
12. The sulfur content of the digester gas combusted in the flare shall not exceed 2,200 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]
13. 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]
14. 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]
15. A flame shall be present at all times whenever combustible gases are vented through the flare. [District Rules 2201 and 4311]
16. 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 Rules 2201 and 4311]
17. Unless the flare is equipped with a flow-sensing ignition system, the flare shall be equipped and operated with a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame. [District Rules 2201 and 4311]
18. Flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rules 2201 and 4311]
19. Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. [District Rules 2201 and 4311]
20. Upon request, the operator of an open flare in which the flare gas pressure is less than 5 psig shall make available records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). [District Rules 2201 and 4311]
21. Only PUC quality natural gas shall be used in the RTO as supplemental fuel. [District Rules 2201 and 4801]

CONDITIONS CONTINUE ON NEXT PAGE

22. The RTO shall be operated with a combustion chamber temperature of no less than 1600 degrees F and the retention time shall be no less than 0.5 seconds. [District Rule 2201]

23. The RTO shall be heated to the proper operating temperature prior to introducing the contaminated air stream. [District Rules 2201 and 4104]

24. Emissions from the RTO shall not exceed any of the following limits: 0.04 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0075 lb-PM10/MMBtu, 0.0824 lb-CO/MMBtu, or 0.0054 lb-VOC/MMBtu. [District Rule 2201]

25. The RTO temperature shall be monitored and recorded utilizing a continuous monitoring and recording device. The monitoring and recording device shall be maintained in proper operating condition at all times. [District Rule 2201]

26. Permittee shall maintain annual records of the amount of gas combusted by the flare, in million standard cubic feet (MMscf). [District Rules 1070 and 2201]

27. 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]

28. {3658} This permit does not authorize the violation of any conditions established for this facility in the Conditional Use Permit (CUP), Special Use Permit (SUP), Site Approval, Site Plan Review (SPR), or other approval documents issued by a local, state, or federal agency. [Public Resources Code 21000-21177: California Environmental Quality Act]

APPENDIX B
BACT Guideline

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 5.8.12*

Last Update: 8/2/2018

Dairy Manure Digester with Backup/Emergency Flare

Pollutant	Achieved in Practice or contained in the 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**

APPENDIX C
BACT Analysis

BACT Analysis for Dairy Manure Digester with Backup/Emergency Flare

Top-Down BACT Analysis for VOC Emissions

Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) Open flare (98% control efficiency) (Achieved in Practice)
2) Ultra-low emissions (ULE) enclosed flare (Technologically Feasible)

Step 2 - Eliminate technologically infeasible options

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

Step 3 - Rank remaining options by control effectiveness

1) Ultra-low emissions (ULE) enclosed flare (99% control efficiency) (Technologically Feasible)
2) Open flare (98% control efficiency) (Achieved in Practice)

Step 4 - Cost Effectiveness Analysis

Option 1: Ultra-low emissions (ULE) enclosed flare (99% control efficiency) (Technologically Feasible)

Emissions of VOC from the ULE (99% control) in comparison to an open flare (98% control) will be used to determine if this option is cost-effective.

Uncontrolled VOC emission rate is back calculated from the controlled emission factor and open flare control efficiency as shown below:

Uncontrolled VOC emission rate = (0.006 lb/MMBtu)/(1 – 0.98) = 0.3 lb/MMBtu

Controlled VOC emission rate of the ULE is calculated from the uncontrolled rate, above, and the required control efficiency as shown below:

ULE VOC emission rate = (0.3 lb/MMBtu) x (1 – 0.99) = 0.003 lb/MMBtu

Reduction in VOC emission achieved by the ULE over the open flare is calculated as shown below:

VOC reduction = [(0.006 – 0.003) lb/MMBtu] x 33.33 MMBtu/hr x 750 hrs/yr x (1 ton/2,000 lb)
= 0.0375 tons-VOC/year

Cost

Several flare manufacturers were contacted for cost estimates in Project C-1162454, which was finalized in November 2018, which was for a similar operation, but with a smaller flare (12.25 MMBtu/hr vs 34.4 MMBtu/hr). Cost information was also obtained for the development of Rule 4311 for a 16.5 MMBtu/hr flare. A summary of the cost estimates received are summarized below:

Emission Factors for Natural Gas-Fired RTO		
Flare Size	**Installed Cost**	**Source**
12 MMBtu/hr	$240,000	Project C-11692454: Aereon Representative
13 MMBtu/hr	$355,000	Project C-11692454: John Zink Representative
16.5 MMBtu/hr	$361,858	District Rule 4311 Staff Report

Since these costs are for flares less than half the size of the proposed flare, these cost estimates are conservative estimates for this project. Therefore, the lowest cost listed above, $240,000 will be used for this analysis, excluding any adjustment for inflation.

Pursuant to District Policy APR 1305, section F (6/1/21), the incremental capital cost for the purchase of the flare will be spread over the expected life of the flare using the capital recovery equation. The expected life of the flare will be estimated at 10 years. A 4% 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 (4%)
N = Equipment Life (10 years)

$$A = [\$240,000 \times 0.04(1.04)^{10}]/[(1.04)^{10}-1]$$
$$= \$29,589/\text{year}$$

No operation costs are included at this time. If the technology is determined to not 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 further from the cost effectiveness threshold.

<u>Value of VOC Reduction</u>

Per the version of APR 1305 that was in effect when this project was deemed complete, Section C (6/1/21) the cost effectiveness threshold for VOC reductions is $22,600/ton. The value of the VOC reduction achieved with ULE instead of open flare is calculated below.

Value of VOC Reduction = (0.0375 ton-VOC/year x $22,600/ton-VOC)
= $847.50/year

Cost Effectiveness of VOC Reduction

As shown above, the annualized capital cost of this alternate option ($29,589/yr) exceeds the value of the VOC emission reductions ($848/yr). Therefore, this option is not cost effective and is being removed from consideration.

Option 2: Open flare (98% control efficiency) (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.

Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed flare is an open flare with a 98% control efficiency. The applicant has proposed an enclosed flare with a 98% control efficiency. Though the proposed flare is enclosed, rather than open as mentioned in the guideline, it has the manufacturers guaranteed to have a 98% or greater control efficiency in this application. The District's primary intention with BACT guidelines is reduction in emissions, regardless of method used to achieve said reduction. Therefore, the BACT requirements for VOC are satisfied.

APPENDIX D
HRA and AAQA Summary

San Joaquin Valley Air Pollution Control District
Risk Management Review and Ambient Air Quality Analysis

To:	Matthew J Robinson – Permit Services
From:	Adrian Ortiz – Technical Services
Date:	July 5, 2022
Facility Name:	VS DIGESTER
Location:	13749 MURPHY RD, ESCALON
Application #(s):	N-9354-1-1, -2-0, -3-0, -4-0
Project #:	N-1220041

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1. Summary

1.1 RMR

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
1-1	16.91	0.07	0.01	1.50E-07	No	Yes
Project Totals	16.91	0.07	0.01	1.50E-07		
Facility Totals	>1	0.23	0.15	2.41E-06		

1.2 AAQA

Pollutant	Air Quality Standard (State/Federal)				
	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass		Pass		
NO_x	Pass				Pass
SO_x	Pass	Pass		Pass	Pass
PM10				Pass[3]	Pass
PM2.5				Pass[4]	Pass[4]

Notes:

1. Results were taken from the attached AAQA Report.
2. The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2) unless otherwise noted below.
3. Modeled PM10 concentrations were below the District SIL for non-fugitive sources of 5 μg/m³ for the 24-hour average concentration and 1 μg/m³ for the annual concentration.
4. Modeled PM2.5 concentrations were below the District SIL for non-fugitive sources of 1.2 μg/m³ for the 24-hour average concentration and 0.2 μg/m³ for the annual concentration.

1.3 Proposed Permit Requirements

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

Unit # 1-1

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.

2. Project Description

Technical Services received a request on January 25, 2022 to perform a Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) for the following:

- Unit -1-1: MODIFICATION OF: DIGESTER SYSTEM CONSISTING OF TWO COVERED DIGESTER LAGOONS, ONE LAGOON, ONE HYDROLYZER, ONE 37.468 MMBTU/HR DIGESTER GAS-FIRED BACKUP FLARE, PERMIT EXEMPT BOILERS (NATURAL GAS-FIRED, 5 MMBTU/HR OR LESS), AND A DIGESTER GAS UPGRADING OPERATION CONSISTING OF FEED GAS BLOWERS, COMPRESSORS, COOLERS, CHILLERS, IRON SPONGE H2S REMOVAL, A MEMBRANE CO2 REMOVAL SYSTEM, PRODUCT GAS COMPRESSORS, AND A 1.25 MMBTU/HR TRITON 4.95 NATURAL GAS-FIRED REGENERATIVE THERMAL OXIDIZER (RTO): DECREASE BACKUP FLARE HEAT INPUT RATING TO 34.4 MMBTU/HR, AND INCREASE HEAT INPUT RATING TO 2.0 MMBTU/HR. POST PROJECT DESCRIPTION TO READ: DIGESTER SYSTEM CONSISTING OF TWO COVERED DIGESTER LAGOONS, ONE LAGOON, ONE HYDROLYZER, ONE 34.4 MMBTU/HR DIGESTER GAS-FIRED BACKUP FLARE, PERMIT EXEMPT BOILERS (NATURAL GAS-FIRED, 5 MMBTU/HR OR LESS), AND A DIGESTER GAS UPGRADING OPERATION CONSISTING OF FEED GAS BLOWERS, COMPRESSORS, COOLERS, CHILLERS, IRON SPONGE H2S REMOVAL, A MEMBRANE CO2 REMOVAL SYSTEM, PRODUCT GAS COMPRESSORS, AND A 2.0 MMBTU/HR TRITON 6.95 NATURAL GAS-FIRED REGENERATIVE THERMAL OXIDIZER (RTO)

For the AAQA, the emissions from units 2-0 to 4-0 from project N-1170108 were included with this project since their ATCs have not yet been implemented. This is to insure that the revised project does not cause or contribute to an exceedance of any ambient air quality standard.

- Unit -2-0: 770 BHP 2G ENERGY MODEL AVUS 500PLUS NATURAL GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM POWERING AN ELECTRICAL GENERATOR AND PROVIDING HEAT FOR THE DIGESTER SYSTEM
- Unit -3-0: 770 BHP 2G ENERGY MODEL AVUS 500PLUS NATURAL GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM POWERING AN ELECTRICAL GENERATOR AND PROVIDING HEAT FOR THE DIGESTER SYSTEM
- Unit -4-0: 770 BHP 2G ENERGY MODEL AVUS 500PLUS NATURAL GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM POWERING AN ELECTRICAL GENERATOR AND PROVIDING HEAT FOR THE DIGESTER SYSTEM

3. RMR Report

3.1 Analysis

The District performed an analysis pursuant to the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015) to determine the possible cancer and non-cancer health impact to the nearest resident or worksite. This policy requires that an assessment be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold

Then, generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than 1.0. If a preliminary analysis demonstrates that either the unit's or the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required

If a refined assessment is greater than one in a million but less than 20 in one million for carcinogenic impacts (Cancer Risk) and less than 1.0 for the Acute and Chronic hazard indices(Non-Carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For unit's that exceed a cancer risk of 1 in one million, Toxic Best Available Control Technology (TBACT) must be implemented.

Toxic emissions for this project were calculated using the following methods:

- Toxic emissions for this proposed unit 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 input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy, 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 2013-2017 from Stockton (rural dispersion coefficient selected) 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:

Source Process Rates					
Unit ID	Process ID	Process Material	Process Units	Hourly Process Rate	Annual Process Rate
1-1	1	Flare Dairy Gas	MMscf	0.06	44.5
1-1	2	RTO Dairy Gas	MMscf	0.02	196

Point Source Parameters						
Unit ID	Unit Description	Release Height (m)	Temp. (°K)	Exit Velocity (m/sec)	Stack Diameter (m)	Vertical/ Horizontal/ Capped
1-1	Flare	9.14	533	16.16	0.66	Vertical
1-1	RTO	9.14	533	30.48	0.51	Vertical

4. AAQA Report

The District modeled the impact of the proposed project on the National Ambient Air Quality Standard (NAAQS) and/or California Ambient Air Quality Standard (CAAQS) in accordance with District Policy APR-1925 (Policy for District Rule 2201 AAQA Modeling) and EPA's Guideline for Air Quality Modeling (Appendix W of 40 CFR Part 51). The District uses a progressive three level approach to perform AAQAs. The first level (Level 1) uses a very conservative approach. If this analysis indicates a likely exceedance of an AAQS or Significant Impact Level (SIL), the analysis proceeds to the second level (Level 2) which implements a more refined approach. For the 1-hour NO_2 standard, there is also a third level that can be implemented if the Level 2 analysis indicates a likely exceedance of an AAQS or SIL.

The modeling analyses predicts the maximum air quality impacts using the appropriate emissions for each standard's averaging period. Required model inputs for a refined AAQA include background ambient air quality data, land characteristics, meteorological inputs, a receptor grid, and source parameters including emissions. These inputs are described in the sections that follow.

Ambient air concentrations of criteria pollutants are recorded at monitoring stations throughout the San Joaquin Valley. Monitoring stations may not measure all necessary pollutants, so background data may need to be collected from multiple sources. The following stations were used for this evaluation:

Monitoring Stations				
Pollutant	Station Name	County	City	Measurement Year
CO	HAZELTON-HD, STOCKTON	San Joaquin	Stockton	2018
NOx	HAZELTON-HD, STOCKTON	San Joaquin	Stockton	2018
PM10	HAZELTON-HD, STOCKTON	San Joaquin	Stockton	2018
PM2.5	HAZELTON-HD, STOCKTON	San Joaquin	Stockton	2018
SOx	Fresno - Garland	Fresno	Fresno	2018

Technical Services performed modeling for directly emitted criteria pollutants with the emission rates below:

Emission Rates (lbs/hour)						
Unit ID	Process	NOx	SOx	CO	PM10	PM2.5
1-1	1	2.10	22.00	2.70	0.30	0.30
1-1	2	0.08	0.01	0.16	0.02	0.02
2-0	1	0.12	0.02	1.00	0.02	0.02
3-0	1	0.12	0.02	1.00	0.02	0.02
4-0	1	0.12	0.02	1.00	0.02	0.02

Emission Rates (lbs/year)						
Unit ID	Process	NOx	SOx	CO	PM10	PM2.5
1-1	1	1,548	16,512	2,046	206	206
1-1	2	701	50	1,444	131	131
2-0	1	1,041	149	8,922	149	149
3-0	1	1,041	149	8,922	149	149
4-0	1	1,041	149	8,922	149	149

The AERMOD model was used to determine if emissions from the project would cause or contribute to an exceedance of any state of federal air quality standard. The parameters outlined below and meteorological data for 2013-2017 from Stockton (rural dispersion coefficient selected) were used for the analysis:

The following parameters were used for the review:

Point Source Parameters						
Unit ID	Unit Description	Release Height (m)	Temp. (°K)	Exit Velocity (m/sec)	Stack Diameter (m)	Vertical/ Horizontal/ Capped
1-1	Flare	9.14	533	16.16	0.66	Vertical
1-1	RTO	9.14	533	30.48	0.51	Vertical
2-0	770 BHP NG ICE	10.06	393	16.24	0.27	Vertical
3-0	770 BHP NG ICE	10.06	393	16.24	0.27	Vertical
4-0	770 BHP NG ICE	10.06	393	16.24	0.27	Vertical

5. Conclusion

5.1 RMR

The cumulative acute and chronic indices for this facility, including this project, are below 1.0; and the cumulative cancer risk for this facility, including this project, is less than 20 in a million. In addition, the cancer risk for each unit in this project 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.

5.2 AAQA

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

6. Attachments

A. Modeling 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 results

APPENDIX E
Quarterly Net Emissions Change (QNEC)

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:

$PE2_{quarterly} = PE2_{annual} \div 4$ quarters/year

$PE1_{quarterly} = PE1_{annual} \div 4$ quarters/year

Quarterly NEC [QNEC] for N-9354-1-1			
Pollutant	**PE2 (lb/yr)**	**PE1 (lb/yr)**	**QNEC (lb/qtr)**
NO_X	2,249	0	562.25
SO_X	16,562	0	4,140.5
PM_{10}	337	0	84.25
CO	3,490	0	872.5
VOC	250	0	62.5