



July 30, 2024

Bill Hendrickson
California Dairies, Inc.
2000 N Plaza Dr,
Visalia, CA 93291

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: S-10254
Project Number: S-1242862

Dear Mr. Hendrickson:

Enclosed for your review and comment is the District's analysis of California Dairies, Inc.'s application for an Authority to Construct for the installation of a new milk processing facility consisting of two 50.4 MMBtu/hr natural gas-fired boilers, an anaerobic digester system with a 3.79 MMBtu/hr digester gas-fired flare, and a 1.996 MMBtu/hr digester/natural gas-fired boiler, at 8801 Gosford Road, Bakersfield.

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. Sajjad Ahmad of Permit Services at (559) 230-5903.

Sincerely,



Brian Clements
Director of Permit Services

BC:sa

Enclosures

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

Samir Sheikh
Executive Director/Air Pollution Control Officer

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San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

New Milk Processing Operation with Two NG Fired Boilers,
an Anaerobic Digester with Flare, and a Digester Gas Fired Boiler

Facility Name:	California Dairies, Inc. (CDI)	Date:	July 30, 2024
Mailing Address:	2000 N Plaza Dr, Visalia, CA 93291	Engineer:	Sajjad Ahmad
		Lead Engineer:	Brian Clerico

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Contact Person #3: Bill Hendrickson (CDI Director of Environmental Affairs)

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Application #s: S-10254-1-0 thru '-4-0

Project #: S-1242862

Date Deemed Complete: May 22, 2024

I. Proposal

California Dairies, Inc. (CDI) has requested Authority to Construct (ATC) permits for the installation of a new milk processing facility consisting of the following permit units:

- ATCs S-10254-1-0 and '2-0: Two identical 50.4 MMBtu/hr natural gas-fired boilers, each equipped with a Selective Catalytic Reduction (SCR) system with ammonia injection and Flue Gas Recirculation (FGR). CDI has proposed to use 'Alternate Monitoring Scheme H' for these boilers using a portable analyzer according to District Policy SSP-1105, *Emissions Monitoring for Rules 4305, 4306, and 4320 (2/15/2017)*.
- ATC S-10254-3-0: An anaerobic digester system to treat wastewater generated from the new milk processing facility. The system will consist of an aboveground Anaerobic Fluidized Bed Digester (AEBD) vessel with a digester gas sulfur removal system consisting of two vessels operated in series, a digester gas collection tank, and a 3.79 MMBtu/hr digester gas-fired open¹ flare. CDI has proposed a maximum daily digester gas flaring limit not to exceed 28,200 scf/day (equivalent to 19.74 MMBtu/day as calculated in Section VII.C.2 below).

¹ Based on the spec sheet provided by the applicant, the flare has a 'visibility shroud', but is not designed to completely cover the flare, so it will be evaluated as an open flare.

- ATC S-10254-4-0: A 1.996 MMBtu/hr digester/natural gas-fired fire-tube boiler with low NOx burner. Since the boiler will be fired on a combination of digester gas and PUC-quality natural gas, it is not exempt from permits (see Rule 2020 discussion in Section VIII). The boiler is also subject to District Rule 4308 as discussed in Section VIII of this evaluation.

The draft ATCs are included in Appendix A.

II. Applicable Rules

Rule 1081	Source Sampling (12/16/93)
Rule 2020	Exemptions (12/18/14)
Rule 2201	New and Modified Stationary Source Review Rule (4/20/23)
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 4305	Boilers, Steam Generators, and Process Heaters - Phase 2 (8/21/03)
Rule 4306	Boilers, Steam Generators, and Process Heaters - Phase 3 (12/17/20)
Rule 4308	Boilers, Steam Generators, and Process Heaters – 0.075 MMBtu/hr to less than 2.0 MMBtu/hr (11/14/13)
Rule 4311	Flares (12/17/20)
Rule 4320	Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (12/17/20)
Rule 4351	Boilers, Steam Generators, and Process Heaters - Phase 1 (8/21/03)
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 8801 Gosford Road in Bakersfield, CA. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

The proposed milk processing facility will process fresh raw milk received from local dairies to produce pasteurized milk and other dairy products.

ATCs S-10254-1-0 & '2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

The natural gas-fired boilers will be used to produce steam and hot water that will be used in various milk processing operations.

ATC S-10254-3-0 (Anaerobic Digester System with Sulfur Removal and 3.79 MMBtu/hr Flare):

The primary purpose of the anaerobic digester system is to treat wastewater from the proposed milk processing facility before it is released from the facility to comply with the regional water board's requirements. The proposed digester system will be a self-supporting system designed in a way so that the digester gas generated will be sufficient during normal operation to be combusted in the 1.996 MMBtu/hr digester gas-fired boiler to maintain optimal temperature for the digester vessel. Any excess digester gas, if any, will be sent to the flare. The flare will be primarily used in the summer months when boiler will not be needed to heat the digester vessel.

Anaerobic Digester System

An anaerobic digester is a sealed basin or tank that is designed to accelerate and control the decomposition of organic matter by microorganisms in the absence of oxygen. The process of anaerobic decomposition results in the conversion of organic compounds in the substrate into methane (CH₄), carbon dioxide (CO₂), 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 (N₂), Oxygen (O₂), Hydrogen Sulfide (H₂S), and Ammonia (NH₃). 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 H₂S and other impurities and used as fuel.

CDI is proposing to use EMG's PurEffluent™ Anaerobic Fluidized Bed Digester (AFBD)² system. The proposed digester system will consist of the following major components:

- Wastewater pre-treatment system,
- Anaerobic Fluidized Bed Digester (AFBD) vessel,
- Digester gas collection system,
- Digester gas storage and conditioning system,
- Digester system 3.79 MMBtu/hr open flare, and
- Digester/natural gas-fired 1.996 MMBtu/hr boiler.

The purpose of the proposed anaerobic digester is to process wastewater from the facility prior to discharge and to generate digester gas with the primary constituents of methane (CH₄), carbon dioxide (CO₂), hydrogen sulfide (H₂S) and nitrogen (N₂). The process wastewater from the dairy manufacturing process will be pre-treated in the wastewater pretreatment system prior to the AFBD digester vessel. In the digester vessel, the organic constituents in the wastewater stream will be converted anaerobically into digester gas via fluidized bioparticles imbedded with the anerobic bacteria. The digester gas generated will then be collected and sent to the digester gas storage and conditioning system for sulfur removal and dehumidification.

² <https://www.emgint.com/the-emg-advantage/emgs-proprietary-pureffluent-anaerobic-technology/>

Sulfur Removal System:

For the sulfur removal system, CDI has proposed to use SULFURTRAP® ST1, which is an iron based desulfurizer adsorbent specifically designed for selective hydrogen sulfide (H₂S) removal from the raw digester gas. CDI is proposing two vessels in series (in a lead-lag configuration) each with a bed of SULFURTRAP® ST1 pellets used at the ambient temperature to provide a large surface area for 99% or greater sulfur removal efficiency. The sulfur removal is a closed system with no vent to the atmosphere.

Use of the Treated Digester Gas:

After conditioning, the digester gas will be used as fuel in the 1.996 MMBtu/hr digester gas-fired boiler. The digester gas fuel will be blended with the PUC-quality natural gas, as needed, to provide sufficient heat to maintain the optimal temperature of the AFBF digester vessel. In the event that the digester gas-fired boiler is unable to use all of the digester gas generated, it will be sent to the digester gas-fired flare for disposal. The flare will serve as a safety device to incinerate the excess methane (CH₄) present in the waste digester gas stream prior to discharge to the atmosphere. The proposed digester gas-fired flare will be a shrouded open type flare with an electric ignition system and no pilot flame or supplemental fuel.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

This is a fire tube boiler and will only combust a blend of treated digester gas and PUC-quality natural gas. As stated earlier, the primary function of this boiler is to provide steam to help maintain optimum temperature in the digester vessel.

V. Equipment Listing

- S-10254-1-0: 50.4 MMBTU/HR CLEAVER BROOKS MODEL CBEX-2W-700-1200-150ST NATURAL GAS FIRED BOILER WITH A LOW NOX BURNER, A SELECTIVE CATALYST REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AND FLUE GAS RECIRCULATION (FGR) (BOILER #1)
- S-10254-2-0: 50.4 MMBTU/HR CLEAVER BROOKS MODEL CBEX-2W-700-1200-150ST NATURAL GAS FIRED BOILER WITH A LOW NOX BURNER, A SELECTIVE CATALYST REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AND FLUE GAS RECIRCULATION (FGR) (BOILER #2)
- S-10254-3-0: ANAEROBIC DIGESTER SYSTEM CONSISTING OF AN ABOVEGROUND EMG MODEL PUREFFLUENT ANAEROBIC FLUIDIZED BED DIGESTER (AFBD) STEEL VESSEL WITH A CHEMICAL PRODUCTS INDUSTRIES MODEL SULFURTRAP ST1 H₂S SULFUR REMOVAL SYSTEM (TWO VESSELS IN SERIES), A DIGESTER GAS COLLECTION TANK, AND A 3.79 MMBTU/HR LSC ENVIRONMENTAL PRODUCTS MODEL CF-5 DIGESTER GAS-FIRED OPEN FLARE
- S-10254-4-0: 1.996 MMBTU/HR FULTON MODEL FBS-50 DIGESTER GAS/NATURAL GAS-FIRED FIRE-TUBE BOILER WITH A LOW-NOX BURNER

VI. Emission Control Technology Evaluation

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Emissions from natural gas-fired boilers include NO_x, SO_x, PM₁₀, CO, and VOC from the combustion of natural gas fuel.

NO_x is the major pollutant of concern when burning natural gas. NO_x formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_x) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_x). Due to the low fuel nitrogen content of natural gas, nearly all NO_x emissions are thermal NO_x. Formation of thermal NO_x is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case ammonia, are passed through an appropriate catalyst. Ammonia, will be injected upstream of the catalyst where it reacts and reduces NO_x, over the catalyst bed, to form elemental nitrogen and other by-products. Each of the two boilers will be equipped with an SCR system which is expected to reduce NO_x emissions by up to 90%.

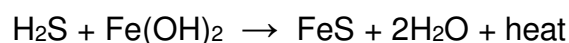
Flue gas recirculation (FGR) reduces NO_x emissions by recirculating a percentage of the exhaust gas back into the wind box. This reduces the oxygen concentration in the air-fuel mixture and regulates the combustion process, lowering the combustion temperature. The lowered availability of oxygen in conjunction with lowered combustion temperature reduces the formation of NO_x. Each of the two boilers will be equipped with FGR.

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

The only pollutant of concern from the digester system is hydrogen sulfide (H₂S), which will be removed in the sulfur removal system with a sulfur removal control efficiency of at least 99%. Any H₂S not removed by the sulfur removal system will be converted into SO_x emissions from the digester gas-fired flare and the boiler. Therefore, any H₂S not removed in the sulfur removal system will be fully accounted for in SO_x emissions from the combustion of treated digester gas in the flare and the boiler. Since the proposed digester and sulfur removal systems are fully enclosed, no H₂S emissions will be calculated for this permit unit.

H₂S Removal

Raw digester gas will pass through two SULFURTRAP® ST1 dry adsorbent vessels operated in series to remove H₂S from the gas prior to combustion in the proposed flare and boiler. The sulfur removal vessels will contain a bed of dry solid pellets composed of iron oxide and other materials, such as silica crystalline quartz and aluminum oxide. Iron oxide is the component that removes H₂S from the digester gas. As the gas passes through the SULFURTRAP material, H₂S is removed by the following chemical reaction producing black iron sulfide and water:



This reaction is not affected by other gas constituents. Before the SULFURTRAP bed is completely saturated, it must be replaced. Therefore, the two sulfur removal vessels will be operated in series in a lead-lag configuration. When the monitoring indicates that the first vessel in the lead position is reaching near saturation, it will be brought off-line while the second vessel remains in service. The useful life of the SULFURTRAP vessels will depend on the inlet concentration of H_2S , the flow rate, and the amount of pellets in the vessels. Spent SULFURTRAP pellets will be removed and sent to a regeneration facility or to an appropriate disposal site. The proposed system is expected to provide a sulfur control efficiency of at least 99% and will be capable of reducing H_2S concentrations in the digester gas to 100 ppmv or less. Reducing the H_2S concentration in the gas will minimize SO_x emissions from combustion in the flare and the boiler.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

The boiler will be equipped with a low NO_x burner to achieve 20 ppmv when fired on PUC-quality natural gas or 30 ppmv when fired on digester gas.

VII. General Calculations

A. Assumptions

All ATCs:

- Operating schedule is 24 hours per day and 365 days per year (8,760 hours per year) (worst case).
- To streamline emission calculations, $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions. Only if needed to determine if a project is a Federal major modification for $PM_{2.5}$ will specific $PM_{2.5}$ emission calculations be performed.

ATCs S-10254-1-0 & -2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

- Each boiler will be fired exclusively on PUC quality natural gas (per applicant).
- Natural Gas Heating Value: 1,000 Btu/scf (per District Practice).
- The oxygen-based F-factor for Natural Gas: 8,578 dscf/MMBtu corrected to 60° F (based on 8,710 dscf/MMBtu @ 68° F from 40 CFR 60, Appendix A-7, Table 19-2).
- Maximum startup and shutdown for each boiler is 2 hours per day (per applicant). Therefore, daily steady state NO_x emissions are calculated based on 22 hours/day (24 – 2 = 22 hours/day).
- Maximum number of startups and shutdowns for each boiler is 365 per year for a total of 730 hours per year (per applicant). Therefore, annual steady state NO_x emissions are calculated based on 8,030 hours/year (8,760 – 730 = 8,030 hours/year).

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):Assumptions for the Digester System:

- The only pollutant of concern from the digester is hydrogen sulfide (H_2S) which will be removed in the sulfur removal system with a sulfur removal control efficiency of at least 99%. Any H_2S not removed will be converted into SO_x emissions in the digester gas-fired flare and/or the boiler. Thus all H_2S not removed in the sulfur removal system will be fully accounted for in SO_x emissions from the combustion of treated digester gas in the flare and/or the boiler. Since the proposed digester and sulfur removal systems are fully enclosed, no H_2S emissions will be calculated for this permit unit.

Assumptions for the Digester Gas-Fired Flare

- Flare is the only source of emissions from this permit unit. Flare emissions result from the combustion of digester gas.
- Daily emissions from the flare will be calculated based on 19.74 MMBtu/day, which is calculated based on the maximum amount of digester gas combusted in the flare of 28,200 scf/day (per applicant).
- Annual emissions will be calculated based on 365 days/year (worst case operation).
- The flare will be equipped with a volumetric fuel flow meter (per applicant).
- The flare will be a shrouded open type flare with an electric ignition system and no pilot flame or supplemental fuel (per applicant).
- Maximum sulfur content of the digester gas combusted in the flare will be 100 ppmv as H_2S (proposed by applicant).
- Only treated digester gas will be combusted in the flare (per applicant).
- Digester gas properties:
 - Higher Heating Value = 700 Btu/scf (per applicant).
 - Digester gas F-factor = 9,100 dscf/MMBtu (dry, adjusted to 60 °F), (per District practice for dairy digester gas projects).
 - Molar specific volume = 379.5 scf/lb-mol (at 60°F).
- Molecular weights:

NO_x (as NO_2)	= 46 lb/lb-mol	CO = 28 lb/lb-mol	NH_3 = 17 lb/lb-mol
VOC (as CH_4)	= 16 lb/lb-mol	SO_x (as SO_2)	= 64.06 lb/lb-mol

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

- The boiler will only be fired on treated digester gas, PUC-quality natural gas, or a blend of treated digester gas and PUC-quality natural gas to provide sufficient heat for optimum temperature of the digester vessel (per applicant).
- The maximum operating schedule is 24 hours per day and 365 days per year (worst case).

- Maximum heat input rating is 1.996 MMBtu/h (per applicant).
- Natural Gas Heating Value: 1,000 Btu/scf (per District Practice).
- The oxygen-based F-factor for Natural Gas: 8,578 dscf/MMBtu corrected to 60 ° F (based on 8,710 dscf/MMBtu @ 68 ° F from 40 CFR 60, Appendix A-7, Table 19-2).
- Maximum sulfur content of digester gas is 100 ppmv as H₂S (per applicant).
- Only treated digester gas will be combusted in the boiler (per applicant).
- Digester gas properties:
 - Higher Heating Value = 700 Btu/scf (per applicant).
 - Digester gas F-factor = 9,100 dscf/MMBtu (dry, adjusted to 60 °F), (per District practice for dairy digester gas projects).
 - Molar specific volume = 379.5 scf/lb-mol (at 60°F).
- Molecular weights:
 - NO_x (as NO₂) = 46 lb/lb-mol CO = 28 lb/lb-mol NH₃ = 17 lb/lb-mol
 - VOC (as CH₄) = 16 lb/lb-mol H₂S = 34.082 lb/lb-mol
 - SO_x (as SO₂) = 64.06 lb/lb-mol

B. Emission Factors

ATCs S-10254-1-0 & -2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

The following table summarizes emission factors for each boiler:

Boilers Emission Factors			
Pollutant	ppmvd @3% O ₂	lb/MMBtu	Source
NO _x Steady State	2.5*	0.003	Manufacturer's Guarantee (Rule 4320 Emission Limit)
NO _x Startup/Shut Down	30*	0.0364	Per Manufacturer
SO _x	--	0.00285	District Policy APR-1720
PM ₁₀	--	0.003	District Practice for PUC Quality Natural Gas Combustion
CO	50*	0.03695	Applicant Proposal
VOC	--	0.0055	EPA AP-42, Table 1.4-2 (7/98)
NH ₃	10*	0.0045	District practice – see calculations below

*Proposed emission factors for NO_x, CO, and NH₃ converted from ppmv @ 3% O₂ to lb/MMBtu as below:

$$\begin{aligned} \text{NO}_x \text{ EF}_{\text{Steady State}} &= \frac{2.5 \text{ ft}^3\text{-NO}_x}{10^6 \text{ ft}^3\text{-Exhaust}} \times \frac{8,578 \text{ ft}^3\text{-Exhaust}}{1 \text{ MMBtu}} \times \frac{46 \text{ lb-NO}_x}{1 \text{ lb-mole}} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3\text{-NO}_x} \times \frac{20.9}{20.9-3} = 0.003 \frac{\text{lb-NO}_x}{\text{MMBtu}} \\ \text{NO}_x \text{ EF}_{\text{Startup/Shutdown}} &= \frac{30 \text{ ft}^3\text{-NO}_x}{10^6 \text{ ft}^3\text{-Exhaust}} \times \frac{8,578 \text{ ft}^3\text{-Exhaust}}{1 \text{ MMBtu}} \times \frac{46 \text{ lb-NO}_x}{1 \text{ lb-mole}} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3\text{-NO}_x} \times \frac{20.9}{20.9-3} = 0.0364 \frac{\text{lb-NO}_x}{\text{MMBtu}} \\ \text{CO EF} &= \frac{50 \text{ ft}^3\text{-CO}}{10^6 \text{ ft}^3\text{-Exhaust}} \times \frac{8,578 \text{ ft}^3\text{-Exhaust}}{1 \text{ MMBtu}} \times \frac{28 \text{ lb-CO}}{1 \text{ lb-mole}} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3\text{-CO}} \times \frac{20.9}{20.9-3} = 0.03695 \frac{\text{lb-CO}}{\text{MMBtu}} \\ \text{NH}_3 \text{ EF} &= \frac{10 \text{ ft}^3\text{-NH}_3}{10^6 \text{ ft}^3\text{-Exhaust}} \times \frac{8,578 \text{ ft}^3\text{-Exhaust}}{1 \text{ MMBtu}} \times \frac{17 \text{ lb-NH}_3}{1 \text{ lb-mole}} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3\text{-NH}_3} \times \frac{20.9}{20.9-3} = 0.0045 \frac{\text{lb-NH}_3}{\text{MMBtu}} \end{aligned}$$

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

EFs – Digester System Backup Flare		
Pollutant	EFs (lb/MMBtu)	Source
NO _x	0.06	Proposed by applicant
SO _x	0.0241*	100 ppmvd as H ₂ S in the treated digester gas flared (Proposed by applicant – see mass balance equation below)
PM ₁₀	0.02429	Manufacturer's Data - 17 lb/MMscf and 700 Btu/scf
CO	0.168	Manufacturer's Data
VOC	0.0021	Manufacturer's Data – 4.6 ppm @ 3% O ₂

*SO_x – proposed 100 ppmvd H₂S in flared digester gas is converted in units of lb/MMBtu as below:

$$\frac{100 \text{ ft}^3 - \text{H}_2\text{S}}{10^6 \text{ ft}^3 - \text{DG}} \times \frac{34.082 \text{ lb} - \text{H}_2\text{S}}{\text{lb} - \text{mol H}_2\text{S}} \times \frac{\text{lb} - \text{mol}}{379.5 \text{ ft}^3 - \text{H}_2\text{S}} \times \frac{64.06 \text{ lb} - \text{SO}_2}{34.082 \text{ lb} - \text{H}_2\text{S}} \times \frac{1 \text{ ft}^3 - \text{DG}}{700 \text{ Btu}} \times \frac{10^6 \text{ Btu}}{\text{MMBtu}} = 0.0241 \frac{\text{lb} - \text{SO}_x}{\text{MMBtu}}$$

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Emission factors for the proposed boiler are summarized in the table below:

Boiler Emission Factors			
Pollutant	ppmvd @3% O ₂	lb/MMBtu	Source
NO _x Digester Gas	30	0.036	Manufacturer's Guarantee (Rule 4308 Emission Limits)
NO _x PUC Natural Gas	20	0.024	
SO _x	100 ppmv as H ₂ S	0.0241**	Fuel sulfur content of 100 ppm H ₂ S (mass balance equation below**)
PM ₁₀	--	0.0076	EPA AP-42, Table 1.4-2 (7/98)
CO	50	0.0392*	Applicant Proposal
VOC	10 as methane	0.0045*	Applicant Proposal

*Proposed emission factors for CO and VOC converted from units of ppmv @ 3% O₂ to lb/MMBtu using equations below:

$$\text{CO EF} = \frac{50 \text{ ft}^3 - \text{CO}}{10^6 \text{ ft}^3 - \text{Exhaust}} \times \frac{9,100 \text{ ft}^3 - \text{Exhaust}}{1 \text{ MMBtu}} \times \frac{28 \text{ lb} - \text{CO}}{1 \text{ lb} - \text{mole}} \times \frac{1 \text{ lb} - \text{mole}}{379.5 \text{ ft}^3 - \text{CO}} \times \frac{20.9}{20.9 - 3} = 0.0392 \frac{\text{lb} - \text{CO}}{\text{MMBtu}}$$

$$\text{VOC EF} = \frac{10 \text{ ft}^3 - \text{VOC}}{10^6 \text{ ft}^3 - \text{Exhaust}} \times \frac{9,100 \text{ ft}^3 - \text{Exhaust}}{1 \text{ MMBtu}} \times \frac{16 \text{ lb} - \text{VOC}}{1 \text{ lb} - \text{mole}} \times \frac{1 \text{ lb} - \text{mole}}{379.5 \text{ ft}^3 - \text{VOC}} \times \frac{20.9}{20.9 - 3} = 0.0045 \frac{\text{lb} - \text{VOC}}{\text{MMBtu}}$$

**SO_x – proposed 100 ppmvd H₂S in the digester gas fuel is converted in units of lb/MMBtu as below:

$$\frac{100 \text{ ft}^3 - \text{H}_2\text{S}}{10^6 \text{ ft}^3 - \text{DG fuel}} \times \frac{34.082 \text{ lb} - \text{H}_2\text{S}}{\text{lb} - \text{mol H}_2\text{S}} \times \frac{\text{lb} - \text{mol}}{379.5 \text{ ft}^3 - \text{H}_2\text{S}} \times \frac{64.06 \text{ lb} - \text{SO}_2}{34.082 \text{ lb} - \text{H}_2\text{S}} \times \frac{1 \text{ ft}^3 - \text{DG Fuel}}{700 \text{ Btu}} \times \frac{10^6 \text{ Btu}}{\text{MMBtu}} = 0.0241 \frac{\text{lb} - \text{SO}_x}{\text{MMBtu}}$$

C. Calculations**1. Pre-Project Potential to Emit (PE1)**

Since these are new emissions units, PE1 = 0 for all pollutants.

2. Post-Project Potential to Emit (PE2)

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Daily and annual PE2 for each of the two boilers is calculated using the equations below and summarized in the following table:

NO_x:

$$\text{Daily PE2 (lb/day)} = \text{Heat Rating (MMBtu/hr)} \times [\{EF_{\text{Steady State (lb/MMBtu)}} \times 22 \text{ (hr/day)}\} + \{EF_{\text{Startup/shutdown (lb/MMBtu)}} \times 2 \text{ hr/day}\}]$$

$$\text{Annual PE2 (lb/year)} = \text{Heat Rating (MMBtu/hr)} \times [\{EF_{\text{Steady State (lb/MMBtu)}} \times 8,030 \text{ (hr/year)}\} + \{EF_{\text{Startup/shutdown (lb/MMBtu)}} \times 730 \text{ hr/year}\}]$$

SO_x, PM₁₀, CO, and VOC:

$$\text{Daily PE2 (lb/day)} = \text{Heat Rating (MMBtu/hr)} \times EF \text{ (lb/MMBtu)} \times 24 \text{ (hr/day)}$$

$$\text{Annual PE2 (lb/year)} = \text{Heat Rating (MMBtu/hr)} \times EF \text{ (lb/MMBtu)} \times 8,760 \text{ (hr/year)}$$

Post-Project Potential to Emit (PE2)							
Pollutant		EF	Heat Input	Daily Operation	Annual Operation	Daily PE2	Annual PE2
		(lb/MMBtu)	(MMBtu/hr)	(hr/day)	(hr/yr)	(lb/day)	(lb/yr)
NO _x	Steady State	0.003	50.4	22	8,030	3.3	1,214
	Startup/Shutdown	0.0364	50.4	2	730	3.7	1,339
	Total			24	8,760	7.0	2,553
SO _x		0.00285	50.4	24	8,760	3.4	1,258
PM ₁₀		0.003	50.4	24	8,760	3.6	1,325
CO		0.03695	50.4	24	8,760	44.7	16,314
VOC		0.0055	50.4	24	8,760	6.7	2,428
NH ₃		0.0045	50.4	24	8,760	5.4	1,987

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

The applicant has proposed to limit the daily amount of digester gas flared not to exceed 28,200 scf/day. Therefore, the maximum heat input to the flare is calculated as below:

$$\begin{aligned} \text{Maximum daily digester gas flow rate} &= 28,200 \text{ scf/day} \\ \text{Digester gas Higher Heating Value (HHV)} &= 700 \text{ Btu/scf} \end{aligned}$$

$$\begin{aligned}\text{Maximum daily heat input} &= 28,200 \text{ scf/day} \times 700 \text{ Btu/scf} \times 1 \text{ MMBtu}/10^6 \text{ Btu} \\ &= 19.74 \text{ MMBtu/day}\end{aligned}$$

The maximum annual heat input is calculated below based on the worst case operation of 365 days/year:

$$\begin{aligned}\text{Maximum annual heat input} &= \text{Daily heat input (MMBtu/day)} \times 365 \text{ days/year} \\ &= 19.74 \text{ MMBtu/day} \times 365 \text{ days/year} \\ &= 7,205 \text{ MMBtu/year}\end{aligned}$$

Daily and annual PE2 from the flare are calculated using the following equations and summarized in the table below:

$$\text{Daily PE2 (lb/day)} = \text{EF (lb/MMBtu)} \times \text{Daily Heat Input (MMBtu/day)}$$

$$\text{Annual PE2 (lb/year)} = \text{EF (lb/MMBtu)} \times \text{Annual Heat Input (MMBtu/year)}$$

Post-Project Potential to Emit (PE2)					
Pollutant	EF	Daily Operation	Annual Operation	Daily PE2	Annual PE2
	(lb/MMBtu)	(MMBtu/day)	(MMBtu/yr)	(lb/day)	(lb/yr)
NO _x	0.06	19.74	7,205	1.2	432
SO _x	0.0241	19.74	7,205	0.5	174
PM ₁₀	0.02429	19.74	7,205	0.5	175
CO	0.168	19.74	7,205	3.3	1,210
VOC	0.0021	19.74	7,205	0.0	15

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Daily and annual PE2 for the boiler is calculated using the equations below and summarized in the following table:

$$\text{Daily PE2 (lb/day)} = \text{Heat Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times 24 \text{ (hr/day)}$$

$$\text{Annual PE2 (lb/year)} = \text{Heat Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times 8,760 \text{ (hr/year)}$$

Post-Project Potential to Emit (PE2)						
Pollutant	EF	Heat Input	Daily Operation	Annual Operation	Daily PE2	Annual PE2
	(lb/MMBtu)	(MMBtu/hr)	(hr/day)	(hr/yr)	(lb/day)	(lb/yr)
NO _x	0.036*	1.996	24	8,760	1.7	629
SO _x	0.0241	1.996	24	8,760	1.2	421
PM ₁₀	0.0076	1.996	24	8,760	0.4	133
CO	0.0392	1.996	24	8,760	1.9	685
VOC	0.0045	1.996	24	8,760	0.2	79

*The higher NO_x emission factor, when fired on the digester gas, is used as a worst case.

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, including all ERCs held as certificates and all emission reduction credits sold or transferred.

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

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, except for emissions units proposed to be shut down as part of a Stationary Source Project, 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, including all ERCs held as certificates and all emission reduction credits sold or transferred.

Based on annual PE2 calculated in Section VII.C.2 above, SSPE2 is summarized in the table below:

SSPE2 (lb/year)						
Permit Unit	NO _x	SO _x	PM ₁₀	CO	VOC	NH ₃
ATC S-10254-1-0 (50.4 MMBtu/hr Boiler #1)	2,553	1,258	1,325	16,314	2,428	1,987
ATC S-10254-2-0 (50.4 MMBtu/hr Boiler #2)	2,553	1,258	1,325	16,314	2,428	1,987
ATC S-10254-3-0 (Digester with 3.79 MMBtu/hr Flare)	432	174	175	1,210	15	0
ATC S-10254-4-0 (1.996 MMBtu/hr DG/NG-fired Boiler)	629	421	133	685	79	0
SSPE2	6,167	3,111	2,958	34,523	4,950	3,974

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	0	0	0	0	0	0
SSPE2	6,167	3,111	2,958	2,958	34,523	4,950
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No	No

Note: PM_{2.5} 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 (Prevention of Significant Deterioration) Major Source Determination:

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

PSD Major Source Determination (tons/year)						
	NO ₂	VOC	SO ₂	CO	PM*	PM ₁₀
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source?	No	No	No	No	No	No

*PM assumed to be equal to PM₁₀.

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

6. Baseline Emissions (BE)

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

Pursuant to District Rule 2201, BE = PE1 for:

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

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

otherwise,

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

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

Therefore BE = PE1.

S-10254-1-0 thru '-5-0:

Since these are new emissions units, BE = PE1 = 0 for all pollutants.

7. Senate Bill 288 Major Modification

A Senate Bill (SB) 288 Major Modification is a federal major modification under 40 CFR 51.165 as it existed on December 19, 2002. 40 CFR Part 51.165 (12/19/02) defines a Major Modification as any physical change in or change in the method of operation of *an existing major stationary source* that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

Per section VII.C.5 above, this facility is not a Major Source for any of the pollutants addressed in this project. Thus, this project does not constitute an SB 288 major modification and no further discussion is required.

8. 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.

Per section VII.C.5 above, this facility is not a Major Source for any pollutants addressed in this project. Thus, this project does not constitute a Federal Major Modification and no further discussion is required.

New Major Source

Per section VII.C.5 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 Section 3.30 of District Rule 2201.

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

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

- 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)(iii). The PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO ₂	VOC	SO ₂	CO	PM	PM ₁₀
Total PE from New and Modified Units	3.1	2.5	1.6	17.3	1.5	1.5
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	No	No	No	No	No	No

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

10. Quarterly Net Emissions Change (QNEC)

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

VIII. Compliance Determination

Rule 1081 Source Sampling

The purpose of this rule is to ensure that any source operation which emits or may emit air contaminants provides adequate and safe facilities for use in sampling to determine compliance. This rule also specifies methods and procedures for source testing, sample collection, and compliance determination.

Pursuant to Section 2.0, this rule applies to any source operation which emits or may emit air contaminants.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

The proposed boiler will emit air contaminants; therefore, it will be subject to this rule.

Section 4.0 - Collection of Samples

Section 4.0 requires the owner of such a source operation, when requested by the APCO, shall provide records or other information which will enable the APCO to determine when a representative sample can be taken. In addition the owner shall collect, have collected, or allow the APCO to collect, a source sample.

Therefore, the following condition will be listed on the ATC to ensure compliance:

- Sampling facilities shall be provided to allow for fuel gas sampling at inlet to the boiler. [District Rule 1081]

Section 5.0 – Test Methods

Section 5.0 state that the applicable test methods, if not specified in the rule, shall be conducted in accordance with Title 40 CFR Subpart 60 Appendix A – Reference Methods, except PM10 for compliance with Rule 2201 requirements shall be conducted in accordance with Title 40 CFR Subpart 51, Appendix M, Method 201 or 201A. Where no test method exists in the preceding references for a source type, source sampling shall be conducted in accordance with CARB approved methods.

Therefore, the following conditions will be listed on the ATC to ensure compliance:

- The sulfur content of the digester gas shall be determined using EPA Method 11 or EPA Method 15, or an alternative method upon approval by the District. [District Rule 1081]
- NO_x emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rule 1081]
- CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rule 1081]

- Stack gas oxygen (O₂) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rule 1081]
- The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rule 1081]

Section 6.0 – Test Procedures

Section 6.0 list requirements for test procedures as follows:

- 6.1 For the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic mean of three (3) test runs shall apply, unless two (2) of the three (3) results are above the applicable limit. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit.
- 6.2 A schedule source test may not be discontinued solely due to the failure of one or more runs to meet applicable standards.
- 6.3 In the event that a sample is accidentally lost or conditions occur in which one (1) of the three (3) runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sampling train, extreme meteorological conditions presenting a hazard to the sampling team, or other circumstances beyond the owner or operators control, upon the APCO's approval, compliance may be determined using the arithmetic mean of the other two (2) runs.

Therefore, the following conditions will be listed on the ATC to ensure compliance:

- The sulfur content of the digester gas shall be determined within 60 days of initial start-up and at least once every twelve (12) months thereafter. [District Rule 1081]
- Source testing to measure NO_x and CO emissions from this unit while fired on digester gas blend and while fired on PUC quality natural gas shall be conducted within 120 days³ of initial start-up. [District Rule 1081]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rule 1081]

Section 7.0 Administrative Requirements

Section 7.0 lists the administrative requirements as follows:

- 7.1 The District must be notified 30 days prior to any compliance source testing and the owner shall submit a source test plan for District approval 15 days prior to source sampling.

³ Per District practice, the typical time period of initial compliance source testing is within 60 days of the initial startup. However, CDI has requested a longer time period of 120 days, because it will take some time for the digester anaerobic bacteria colony to grow and to accumulate sufficient digester gas to conduct the initial compliance source test.

- 7.2 Source sampling to determine the compliance status of an emission source shall be witnessed or authorized by District personnel.
- 7.3 Source test reports must be submitted to the District within 60 days of completion of field testing. Source tests must be submitted for all District authorized compliance source test regardless of pass, fail or reschedule because of failure, status. A District authorized compliance source test shall not be discontinued solely due to the failure of one (1) or more runs to meet applicable standards.

Therefore, the following conditions will be listed on the ATC to ensure compliance:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- {110} The results of each compliance test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
- Source testing shall be District witnessed or authorized and conducted by an ARB certified testing contractor. [District Rule 1081]

Rule 2020 Exemptions

This rule specifies emissions units that are not required to obtain an Authority to Construct or Permit to Operate.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Section 6.0 of the rule lists permit exempt source categories in Sections 6.1 through 6.18 for which no ATC or PTO is required.

Section 6.1.1 states a permit exemption for steam generators, steam superheaters, water boilers, water heaters, steam cleaners, and closed indirect heat transfer systems that have a maximum input heat rating of 5,000,000 Btu per hour (gross) or less and are equipped to be fired exclusively with:

- 6.1.1.1 Natural gas containing no more than five (5) percent by weight hydrocarbons heavier than butane and no more than 1.0 grain of total sulfur per 100 standard cubic feet of gas.
- 6.1.1.2 Liquefied petroleum gas containing no more than two (2) percent by volume hydrocarbons heavier than butane and no more than 15 grains of total sulfur per 100 standard cubic feet of gas; or
- 6.1.1.3 Any combination of gases specified in Sections 6.1.1.1 and 6.1.1.2.

Since the proposed boiler will be fired on a combination of digester gas and PUC-quality natural gas, it does not meet the above exemption criteria. Therefore, this boiler will be subject to District permit.

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*:

- Any new emissions unit with a potential to emit exceeding 2.0 pounds per day, or the relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding 2.0 pounds per day,
- Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2.0 pounds per day, and/or
- 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 or relocated emissions units – PE > 2.0 lb/day

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Based on emission calculations in Section VII.C.2 of this evaluation, BACT for each of the two new boilers is determined in the table below:

BACT for New Emission Units – 50.4 MMBtu/hr Boilers				
Pollutant	Daily PE2 (lb/day)	BACT Threshold (lb/day)	SSPE2 (lb/year)	BACT Triggered?
NO _x	7.0	> 2.0	n/a	Yes
SO _x	3.4	> 2.0	n/a	Yes
PM ₁₀	3.6	> 2.0	n/a	Yes
CO	44.7	> 2.0 and SSPE2 ≥ 200,000 lb/yr	34,523	No
VOC	6.7	> 2.0	n/a	Yes

As shown above, BACT is triggered for NO_x, SO_x, PM₁₀, and VOC emissions from each of the two new boilers.

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

Based on emission calculations in Section VII.C.2 of this evaluation, BACT for the flare is determined in the table below:

BACT for New Emission Units – 3.79 MMBtu/hr Flare				
Pollutant	Daily PE2 (lb/day)	BACT Threshold (lb/day)	SSPE2 (lb/year)	BACT Triggered?
NO _x	1.2	> 2.0	n/a	No
SO _x	0.5	> 2.0	n/a	No
PM ₁₀	0.5	> 2.0	n/a	No
CO	3.3	> 2.0 and SSPE2 ≥ 200,000 lb/yr	34,523	No
VOC	0.0	> 2.0	n/a	No

As shown above, BACT is not triggered for any pollutant for the proposed flare.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

BACT for New Emission Unit – 1.996 MMBtu/hr Boiler		
Pollutant	Daily PE2 (lb/day)	BACT Triggered?
NO _x	1.7	No
SO _x	1.2	No
PM ₁₀	0.4	No
CO	1.9	No
VOC	0.2	No

As shown above, BACT is not triggered for any pollutant for the proposed boiler.

b. Modification of emissions units – AIPE > 2.0 lb/day

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

c. 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

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

BACT Guideline 1.1.2 applies to PUC quality natural gas or propane fired boilers and steam generators with heat input rate greater than 20 MMBtu/hr (see Appendix B).

3. Top-Down BACT Analysis

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

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

Pursuant to the attached Top-Down BACT Analysis (see Appendix B), BACT has been satisfied with the following:

NO_x: 2.5 ppmvd @ 3% O₂ (0.003 lb/MMBtu)
SO_x, PM₁₀, and VOC: PUC quality natural gas or propane with LPG backup

Therefore, the following conditions will be listed on ATCs '-1-0 and '-2-0 to ensure compliance:

- Except during start-up and shutdown, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 2.5 ppmv NO_x @ 3% O₂ or 0.003 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]
- During startup and shutdown periods, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 30 ppmv NO_x @ 3% O₂ or 0.0364 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]
- {edited 4355} The unit shall only be fired on PUC-quality natural gas. [District Rules 2201, 4305, 4306, 4320, and 4801]

B. Offsets

1. District Emission Offset Requirements

a. District Offset Applicability

Pursuant to District Rule 2201, Section 4.5, District 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 District 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	6,167	3,111	2,958	34,523	4,950
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets Triggered?	No	No	No	No	No

b. District Offset Quantity (DOQ) Required

As shown above, the SSPE2 is not greater than the offset thresholds for all pollutants, therefore District offsets are not triggered. In conclusion, offsets will not be required for this project and no further discussion is required.

2. Federal Emission Offset Requirements

a. Federal Offset Applicability

Pursuant to District Rule 2201, Section 4.8, federal offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the project is a New Major Source or a Federal Major Modification.

As demonstrated in section VII.C.8 above, this project is not a New Major Source or a Federal Major Modification for any pollutant addressed in this project. Thus, federal offsets are not triggered for this project.

b. Federal Offset Quantity (FOQ) Required

As discussed above, this project does not trigger Federal Major Modification or New Major Source requirements; therefore, in conclusion, federal offsets will not be required for this project and no further discussion is required.

3. Federal Offset Equivalency Demonstration

Section 7.0 of District Rule 2201 provides the requirements for the District to demonstrate on an individual ATC issuance basis that the number of creditable emission reductions collected by the District equals or exceeds the amount of creditable emission reductions that would otherwise be required as offsets under a federal non-attainment NSR program meeting the applicable requirements of 40 CFR 51.165 and the CAA. As demonstrated above, this project does not require federal offsets; therefore, a federal offset equivalency demonstration is not 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 SSPE of greater than 20,000 lb/year for any pollutant,
- e. Any project at a minor source which results in an SSPE exceeding 80% of the major source threshold for any pollutant, and/or
- f. 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 does not include a new emissions unit which has daily emissions greater than 100 lb/day for any pollutant, therefore public noticing for PE > 100 lb/day purposes is not required.

c. Offset Threshold

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 (lb/year)					
	NO _x	SO _x	PM ₁₀	CO	VOC
SSPE1	0	0	0	0	0
SSPE2	6,167	3,111	2,958	34,523	4,950
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Public Notice Required?	No	No	No	No	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 and negative values are equated to zero. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds (lb/year)					
	NO _x	SO _x	PM ₁₀	CO	VOC
SSPE2	6,167	3,111	2,958	34,523	4,950
SSPE1	0	0	0	0	0
SSIPE	6,167	3,111	2,958	34,523	4,950
SSIPE Public Notice Threshold	20,000	20,000	20,000	20,000	20,000
Public Notice Required?	No	No	No	Yes	No

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

e. Minor Sources with SSPE Exceeding 80% of Major Source Threshold

Public notification is required for any project for new and/or modified stationary sources at minor source facilities that results in a SSPE exceeding 80% of the major source threshold.

As shown in Section VII.C.5 above, the facility is not a Major Source for any pollutant. The following table compares the SSPE1 with the SSPE2 in order to determine if 80% of any major source thresholds have been surpassed with this project.

80% of Major Source Thresholds (lb/year)					
	NO _x	SO _x	PM ₁₀	CO	VOC
SSPE1	0	0	0	0	0
SSPE2	6,167	3,111	2,958	34,523	4,950
80% of Major Source Threshold	16,000	112,000	112,000	160,000	16,000
Public Notice Required?	No	No	No	No	No

As demonstrated above, the SSPE2 did not surpass 80% of the major source threshold for any pollutant; therefore, public noticing for this purpose is not required.

f. 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 SSIPE for CO emissions exceeding the SSIPE public notice threshold of 20,000 lb/year. 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:

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Startup/shutdown:

- The total duration of startup and shutdown time shall not exceed any of the following limits: 2.0 hours per day or 730 hours per year. [District Rules 2201, 4305, 4306, and 4320]
- During startup and shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rules 2201, 4305, 4306 and 4320]
- During startup and shutdown periods, emissions from the combustion of natural gas from this boiler shall not exceed any of the following limits: 30 ppmv NO_x @ 3% O₂ or 0.0364 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

Steady state:

- Except during start-up and shutdown, emissions from the combustion of natural gas from this boiler shall not exceed any of the following limits: 2.5 ppmv NO_x @ 3% O₂ or 0.003 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

In addition the following permit conditions will be listed on ATC to ensure compliance:

- NH_3 emissions from the SCR system shall not exceed 10 ppmvd @ 3% O_2 . [District Rule 2201]
- {edited 4355} The boiler shall only be fired on PUC-quality natural gas. [District Rules 2201, 4305, 4306, 4320, and 4801]
- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rule 2201 and 40 CFR 60.48 (c)(g)]

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

- Only treated digester gas shall be combusted in the flare. [District Rules 2201 and 4801]
- Maximum sulfur content of the treated digester gas combusted in the flare shall not exceed 100 ppmv as H_2S . The permittee may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the sulfur content limit of the digester gas. [District Rules 2201 and 4801]
- The maximum amount of digester gas combusted in the flare shall not exceed 28,200 standard cubic feet in any one day (scf/day), equivalent to maximum daily heat input of 19.74 MMBtu/day. [District Rule 2201]
- The flare shall be equipped with an operational, non-resettable, totalizing mass or volumetric fuel flow meter or other District-approved alternative method to measure the amount of digester gas flared. [District Rule 2201]
- Emissions from the combustion of digester gas from this flare shall not exceed any of the following limits: 0.06 lb- NO_x /MMBtu, 0.0241 lb- SO_x /MMBtu, 0.02429 lb- PM_{10} /MMBtu, 0.168 lb-CO/MMBtu, or 0.0021 lb-VOC/MMBtu. [District Rule 2201]
- The total heating value of the digester gas combusted in the flare on any given day shall be calculated using the measured amount of gas combusted and the most recently determined higher heating value (HHV). [District Rule 2201]

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

- {edited 4355} The boiler shall only be fired on treated digester gas, PUC-quality natural gas, or a blend of treated digester gas and PUC-quality natural gas. [District Rules 2201, 4308, and 4801]
- Maximum sulfur content of the treated digester gas combusted in the boiler shall not exceed 100 ppmv as H_2S . The permittee may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the sulfur content limit of the digester gas. [District Rules 2201 and 4801]

- Emissions from the combustion of digester gas blend from this boiler shall not exceed any of the following limits: 30 ppmv NO_x @ 3% O₂ or 0.036 lb-NO_x/MMBtu; 0.0241 lb-SO_x/MMBtu; 0.0076 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% or 0.0392 lb-CO/MMBtu; or 0.0045 lb-VOC/MMBtu. [District Rules 2201 and 4308]
- Emissions from the combustion of natural gas from this boiler shall not exceed any of the following limits: 20 ppmv NO_x @ 3% O₂ or 0.024 lb-NO_x/MMBtu; 0.0241 lb-SO_x/MMBtu; 0.0076 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% or 0.0392 lb-CO/MMBtu; or 0.0045 lb-VOC/MMBtu. [District Rules 2201 and 4308]

All ATCs:

- {1407} 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]

E. Compliance Assurance

1. Source Testing

ATCs S-10254-1-0 & '2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

The boilers are subject to District Rule 4305, Boilers, Steam Generators and Process Heaters, Phase 2, District Rule 4306, Boilers, Steam Generators and Process Heaters, Phase 3, and District Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr. Since Rule 4320 has the most stringent requirements, source testing requirements will be discussed in Section VIII, District Rule 4320 of this evaluation.

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

Sulfur testing will be required to demonstrate compliance with the proposed maximum hydrogen sulfide content and the maximum daily flaring rate. Therefore, the following conditions will be listed on the ATC to ensure compliance:

- The sulfur content of the treated digester gas shall be determined within 60 days of initial startup of flaring operations and at least once every 12 months thereafter. [District Rule 2201]
- The sulfur content of the digester gas shall be determined using EPA Method 11 or EPA Method 15, or an alternative method upon approval by the District. [District Rule 2201]
- The higher heating value (HHV) of the digester gas flared shall be determined at least once every calendar quarter in which digester gas is flared. [District Rule 2201]

- The higher heating value (HHV) of the digester gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method as approved by the District. [District Rules 2201 and 4311]

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

As discussed under Rule 4308 discussion in Section VIII, the boiler will be subject to source testing requirements which are detailed under District Rule 1081 discussion above.

2. Monitoring

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

The boilers are subject to District Rule 4305, Boilers, Steam Generators and Process Heaters, Phase 2, District Rule 4306, Boilers, Steam Generators and Process Heaters, Phase 3, and District Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr. Since Rule 4320 has the most stringent requirements, monitoring requirements will be discussed in Section VIII, District Rule 4320 of this evaluation.

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

Digester gas fuel sulfur monitoring will be required to demonstrate ongoing compliance with the proposed maximum hydrogen sulfide content and the maximum daily flaring rate. Therefore, the following conditions will be listed on the ATC to ensure compliance:

- The sulfur content of the digester gas 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 shall not be required during periods in which the flare does not operate. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H₂S; 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 portable or in-line H₂S monitors; or an alternative method approved by the District. Prior to utilization of portable or in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitor(s), including the make, model, and detection limits, to the District and obtain District approval for each proposed monitor. [District Rule 2201]

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Digester gas fuel sulfur monitoring will be required to demonstrate ongoing compliance with the proposed maximum hydrogen sulfide content. Therefore, the following conditions will be listed on the ATC to ensure compliance:

- The sulfur content of the digester gas 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 shall not be required during periods in which the boiler does not operate. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H₂S; 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 portable or in-line H₂S monitors; or an alternative method approved by the District. Prior to utilization of portable or in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitor(s), including the make, model, and detection limits, to the District and obtain District approval for each proposed monitor. [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 will be listed on the ATCs to ensure compliance:

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

- Daily and annual records of the total duration of startup and shutdown time (in hours) shall be kept. [District Rules 2201, 4305, 4306, and 4320]
- Permittee shall maintain records of the amount of fuel combusted during each calendar month in this unit. [District Rule 2201 and 40 CFR 60.48 (c)(g)]
- All records shall be maintained and retained on-site for a period of at least 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, 4305, 4306 and 4320, and 40 CFR 60.48c(i)]

In addition, the boilers are subject to the recordkeeping requirements of District Rule 4320, 'Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr', as discussed in under Rule 4320 discussion in Section VIII of this evaluation.

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

- Permittee shall maintain the following records for each day the flare operates: 1) Total amount of digester gas combusted in the flare (in scf/day) and 2) Calculated total heating value of the digester gas combusted in the flare (in MMBtu/day). [District Rule 2201]
- Permittee shall maintain records of the sulfur content determinations for the digester gas flared, including the dates of the determinations, determination method(s) used, and the sulfur content values determined for each date. [District Rule 2201]
- Permittee shall maintain records of hydrogen sulfide analyzer(s) installed or utilized, including the calibration records of such analyzer(s). Records are only required on analyzer(s) utilized to demonstrate compliance with the requirements of this permit. [District Rule 2201]
- Permittee shall maintain records of higher heating value (HHV) determinations for the digester gas flared, including the dates of the determinations, determination method(s) used, and the HHV value determined for each date. [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]

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

- All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. Records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

Section 4.15 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 C of this document for the HRA/AAQA summary sheet.

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

The proposed location is in a non-attainment area for the state's PM₁₀ as well as federal and state PM_{2.5} thresholds. As shown by the HRA/AAQA summary sheet, the proposed equipment will not cause a violation of an air quality standard for PM₁₀ 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.

40 CFR Part 60 Subpart Db – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Db applies to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

ATCs S-10254-1-0 & '2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Since each of the two boilers has a maximum heat rating of 50.4 MMBtu/hr, these boilers are not subject to Subpart Db requirements.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Since the boiler has a maximum heat rating of 1.996 MMBtu/hr, it is not subject to Subpart Db requirements.

40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Dc applies to Small Industrial-Commercial-Institutional Steam Generators between 10 MMBtu/hr and 100 MMBtu/hr (post-6/9/89 construction, modification or, reconstruction). Subpart Dc has standards for SO_x and PM₁₀ emissions.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Subpart Dc only applies to boilers between 10 MMBtu/hr and 100 MMBtu/hr; therefore, 1.996 MMBtu/hr boiler is not subject to this subpart.

ATCs S-10254-1-0 & '2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Each of the two 50.4 MMBtu/hr boiler is subject to Subpart Dc requirements as discussed below:

60.42c – Standards for Sulfur Dioxide SO₂)

The requirements of this section are applicable to units which combust only coal or combusts coal in combination with other fuels. The proposed boilers will not combust coal or coal in combination with other fuels; therefore, the requirements of this section are not applicable.

60.43c – Standards for Particulate Matter (PM)

The boilers are not fired on coal, combust mixtures of coal with other fuels, combust wood, combust mixtures of wood with other fuels, or oil; therefore, this section is not applicable.

60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide.

Since the boilers are not subject to the sulfur dioxide requirements of this subpart, no testing is required to show compliance. Therefore, the requirements of this section are not applicable.

60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter

Since the boilers are not subject to the particulate matter requirements of this subpart, no testing is required to show compliance. Therefore, the requirements of this section are not applicable.

60.46c – Emission Monitoring for Sulfur Dioxide

Since the boilers are not subject to the sulfur dioxide requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable.

60.47c – Emission Monitoring for Particulate Matter

Since the boilers are not subject to the particulate matter requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

- (1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

The design heat input capacity and type of fuel combusted at the facility will be listed on each unit's equipment description. No conditions are required to show compliance with this requirement.

- (2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

This requirement is not applicable since the units are not subject to §60.42c or §40.43c.

- (3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility has not proposed an annual capacity factor; therefore one will not be required.

- (4) Notification if an emerging technology will be used for controlling SO₂ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

This requirement is not applicable since the units will not be equipped with an emerging technology used to control SO₂ emissions.

§60.48c(b) through (e) are applicable to units subject to the SO₂ and PM standards of §60.42c and §60.43c. Since the proposed units are not subject to §60.42c or §60.43c, the requirements of §60.48(b) through (e) are not applicable.

§60.48c(f) outlines the reporting and recordkeeping requirements for fuel supplier certifications, as required by §60.42c and §60.44c. The proposed units are not subject to either §60.42c or §60.44c; therefore, the requirements of this paragraph are not applicable.

Section 60.48c(g)(2), the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO₂ standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month. Therefore, the following conditions will be listed on the ATCs to ensure compliance:

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rule 2201 and 40 CFR 60.48 (c)(g)]
- Permittee shall maintain records of the amount of fuel combusted during each calendar month in this unit. [District Rule 2201 and 40 CFR 60.48 (c)(g)]

Section 60.48 c (i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 4320 has more stringent requirement of the records to be kept for five years. Therefore, the following condition will be listed on the ATCs to ensure compliance:

- All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320, and 40 CFR 60.48c(i)]

Therefore, compliance is expected with this regulation.

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

No subparts of 40 CFR Part 60 directly apply to digester gas-fired flares. However, District Rule 4311 requires open non-assisted flares to comply with the requirements of 40 CFR 60.18 when flare gas pressure is less than 5.0 psig. See Rule 4311 discussion in Section VIII of this evaluation for further details.

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.

40 CFR Part 63 Subpart DDDDD National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

This subpart is applicable to boilers and process heaters located at Major Sources of HAP emissions. This facility is not a Major source of HAP emissions. Therefore, the proposed units are not subject to this subpart.

40 CFR Part 63 Subpart JJJJJ National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Pursuant to Section 63.1195(e), a gas-fired boiler, as defined in Subpart JJJJJ, is not subject to any requirement of this Subpart. Pursuant to the definition in the subpart, a gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel.

Each of the boilers under ATCs '-1-0, '-2-0, and '-4-0 meets the definition of a "gas-fired boiler" as these units are required to use only gaseous fuels. Therefore, Subpart JJJJJ requirements are not applicable.

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

No subparts of 40 CFR Part 61 or 40 CFR Part 63 apply to digester gas-fired flares.

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). Therefore, the following conditions will be listed on the ATCs to ensure compliance:

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

- {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]

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

- {modified 649} Flare shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [District Rules 4101 and 4311]

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

- {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 and the following condition will be included on all ATCs to ensure 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.

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	3.22
Cancer Risk	1.56E-07
Acute Hazard Index	0.04
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 shown above, T-BACT is not required for this project because the HRA indicates that the worst-case cancer risk does not exceed one in one million; 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 C: HRA/AAQA Summary

The following permit condition will be listed on all ATCs to ensure compliance with the assumptions made for the risk management review:

- {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

Rule 4201 Particulate Matter Concentration

The purpose of this rule is to protect the ambient air quality by establishing a particulate matter emission standard. This rule applies to any source operation which emits or may emit dust, fumes, or total suspended particulate matter.

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, which is calculated as below for each permit unit associated with this project:

ATCs S-10254-1-0 & '2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

F-Factor for NG:	8,578 dscf/MMBtu at 60 °F
PM Emission Factor:	0.003 lb-PM/MMBtu (assuming 100% PM ₁₀ is PM)
Exhaust Oxygen (O ₂) Concentration:	3%
Excess Air Correction to F-Factor =	$\frac{20.9}{(20.9 - 3)} = 1.17$

Thus, grain loading (GL) is calculated as follows:

$$GL = \left(\frac{0.003 \text{ lb} - \text{PM}}{\text{MMBtu}} \times \frac{7,000 \text{ grain}}{\text{lb} - \text{PM}} \right) - \left(\frac{8,578 \text{ ft}^3}{\text{MMBtu}} \times 1.17 \right)$$

$$GL = 0.0021 \frac{\text{grain}}{\text{ft}^3}$$

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

F-Factor for digester gas:	9,100 dscf/MMBtu at 60 °F
PM Emission Factor:	0.02429 lb-PM/MMBtu (assuming 100% PM ₁₀ is PM)
Exhaust Oxygen (O ₂) Concentration:	3%
Excess Air Correction to F-Factor =	$\frac{20.9}{(20.9 - 3)} = 1.17$

Thus, grain loading (GL) is calculated as follows:

$$GL = \left(\frac{0.0076 \text{ lb} - \text{PM}}{\text{MMBtu}} \times \frac{7,000 \text{ grain}}{\text{lb} - \text{PM}} \right) - \left(\frac{9,100 \text{ ft}^3}{\text{MMBtu}} \times 1.17 \right)$$

$$GL = 0.005 \frac{\text{grain}}{\text{ft}^3}$$

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Digester Gas Fuel:

F-Factor for digester gas:	9,100 dscf/MMBtu at 60 °F
PM Emission Factor:	0.0076 lb-PM/MMBtu (assuming 100% PM ₁₀ is PM)

Exhaust Oxygen (O₂) Concentration: 3%

$$\text{Excess Air Correction to F-Factor} = \frac{20.9}{(20.9 - 3)} = 1.17$$

Thus, grain loading (GL) is calculated as follows:

$$GL = \left(\frac{0.0076 \text{ lb} - PM}{MMBtu} \times \frac{7,000 \text{ grain}}{\text{lb} - PM} \right) - \left(\frac{9,100 \text{ ft}^3}{MMBtu} \times 1.17 \right)$$

$$GL = 0.005 \frac{\text{grain}}{\text{ft}^3}$$

Natural Gas Fuel:

F-Factor for NG: 8,578 dscf/MMBtu at 60 °F
 PM Emission Factor: 0.0076 lb-PM/MMBtu (assuming 100% PM₁₀ is PM)
 Exhaust Oxygen (O₂) Concentration: 3%

$$\text{Excess Air Correction to F-Factor} = \frac{20.9}{(20.9 - 3)} = 1.17$$

Thus, grain loading (GL) is calculated as follows:

$$GL = \left(\frac{0.0076 \text{ lb} - PM}{MMBtu} \times \frac{7,000 \text{ grain}}{\text{lb} - PM} \right) - \left(\frac{8,578 \text{ ft}^3}{MMBtu} \times 1.17 \right)$$

$$GL = 0.0053 \frac{\text{grain}}{\text{ft}^3}$$

Since grain loading is less than 0.1 gr/dscf, compliance with District Rule 4201 requirements is expected for each permit unit. Therefore, the following condition will be listed on all ATCs to ensure compliance:

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

Rule 4301 Fuel Burning Equipment

This rule specifies maximum emission rates in lb/hr for SO₂, NO₂, and combustion contaminants (defined as total PM in Rule 1020). This rule also limits combustion contaminants to ≤ 0.1 gr/scf. According to AP 42 (Table 1.4-2, footnote c), all PM emissions from natural gas combustion are less than 1 μm in diameter.

ATCs S-10254-1-0 & '2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Hourly emission rates are calculated in the table below based on worst case daily PE2 calculated in Section VII.C.2 of this document. For NO_x worst case is during startup and shutdown period of 2 hr/day. For PM and SO_x, hourly rate is calculated by dividing by 24 hours/day and assuming that all PM₁₀ is PM for worst case in the table below:

District Rule 4301 Limits			
	NO ₂	Total PM	SO ₂
Daily PE2 (lb/day)	3.7	3.6	3.4
Operation (hr/day)	2	24	24
Hourly Rate (lb/hr)	1.85	0.15	0.14
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule for each boiler. Therefore, compliance is expected with this rule.

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

Section 3.1 defines ‘fuel burning equipment’ as “any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer”.

The primary function of the digester gas-fired flare is not to produce heat by indirect heat transfer. Therefore, it is not subject to this rule.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Hourly emission rates are calculated in the table below based on daily PE2 calculated in Section VII.C.2 of this document. Hourly rates are calculated by dividing by 24 hours/day and assuming that all PM₁₀ is PM for worst case in the table below:

District Rule 4301 Limits			
	NO ₂	Total PM	SO ₂
Daily PE2 (lb/day)	1.7	0.4	1.2
Operation (hr/day)	24	24	24
Hourly Rate (lb/hr)	0.07	0.02	0.05
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule for the boiler. Therefore, compliance is expected with this rule.

Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2

The purpose of this rule is to limit emissions of oxides of nitrogen (NO_x) and carbon monoxide (CO) from boilers, steam generators, and process heaters. This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Since the proposed 1.996 MMBtu/hr digester/natural gas-fired boiler has a heat input rating less than 5 MMBtu/hr, this boiler is not subject to this rule.

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Each of the two 50.4 MMBtu/hr natural gas-fired boiler has a maximum heat input greater than 5 MMBtu/hr; therefore, each boiler is subject to this rule and the following discussion applies only to these two boilers.

In addition, the boilers are also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3* and District Rule 4320 *Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr*.

Since the emissions limits and all other requirements of District Rule 4320 are equivalent to, or more stringent than District Rule 4305 requirements, compliance with District Rule 4320 requirements will satisfy requirements of District Rule 4305.

Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3

The purpose of this rule is to limit emissions of oxides of nitrogen (NO_x) and carbon monoxide (CO) from boilers, steam generators, and process heaters. This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a total rated heat input greater than 5 million Btu per hour (MMBtu/hr).

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Since the proposed 1.996 MMBtu/hr digester/natural gas-fired boiler has a heat input rating less than 5 MMBtu/hr, this boiler is not subject to this rule.

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Each of the two 50.4 MMBtu/hr natural gas-fired boiler has a maximum heat input greater than 5 MMBtu/hr; therefore, each boiler is subject to this rule and the following discussion applies only to these two boilers.

Section 5.1 NO_x and CO Emission Limits

Section 5.1.1 requires that except for units subject to Sections 5.2, on and after Compliance Deadline specified in section 7 unit shall not operate in a manner which exceed the applicable NO_x and Carbon monoxide emissions specified in Table 1 (Until December 30, 2023) and Table 2 (on and after December 31, 2023). All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

The following table summarizes the applicable emissions category of Table 2 of Section 5.1.1 for each boiler:

Table 2: Tier 2 NOx and CO Limits (on and after December 31, 2023)				
Permit Unit	Category #	Category Description	Operated on Gaseous Fuel	
			NOx Limit	CO Limit
S-10254-1-0 and '2-0	B.2	All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	7 ppmv or 0.0085 lb/MMBtu	400 ppmv

The following table summarizes the proposed NOx and CO emission limits for each boiler:

Pollutant	Emission Limits		Compliant with Rule 4306?
	ppmv @ 3% O₂	lb/MMBtu	
NOx	2.5	0.003	Yes
CO	50	0.03695	Yes

Therefore, compliance with Section 5.1.1 of District Rule 4306 is expected and the following conditions will be listed on ATCs to ensure compliance:

- Except during start-up and shutdown, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 2.5 ppmv NOx @ 3% O₂ or 0.003 lb-NOx/MMBtu; 0.00285 lb-SOx/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

Section 5.3, Start-up and Shutdown Provision

Section 5.3 states that on and after the full compliance schedule specified in Section 7.1, the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 shall not apply during start-up or shutdown provided an operator complies with the requirements specified below:

- 5.3.1 The duration of each start-up or each shutdown shall not exceed two hours, except as provided in Section 5.3.3.
- 5.3.2 The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown.

The applicant has provided a total startup and shutdown not to exceed two hours per day; therefore, compliance with this section is expected and the following conditions will be listed on the ATCs to ensure compliance with the startup and shutdown requirements:

- The total duration of startup and shutdown time shall not exceed any of the following limits: 2.0 hours per day or 730 hours per year. [District Rules 2201, 4305, 4306, and 4320]

- During startup and shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rules 2201, 4305, 4306 and 4320]
- During startup and shutdown periods, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 30 ppmv NO_x @ 3% O₂ or 0.0364 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

Section 5.4, Monitoring Provisions

Section 5.4.2 states that the operator of any unit subject to the applicable emission limits in Sections 5.1 shall install and maintain an operational APCO approved Continuous Emissions Monitoring System (CEMS) for NO_x, CO, and oxygen, or implement an APCO-approved Alternate Monitoring System. An APCO approved CEMS shall comply with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Part 60 Appendix B (Performance Specifications) and 40 CFR Part 60 Appendix F (Quality Assurance Procedures, and applicable provisions of Rule 1080 (Stack Monitoring)). An APCO approved Alternate Monitoring System shall monitor one or more of the following:

- 5.4.2.1 Periodic NO_x and CO exhaust emission concentrations,
- 5.4.2.2 Periodic exhaust oxygen concentration,
- 5.4.2.3 Flow rate of reducing agent added to exhaust,
- 5.4.2.4 Catalyst inlet and exhaust temperature,
- 5.4.2.5 Catalyst inlet and exhaust oxygen concentration,
- 5.4.2.6 Periodic flue gas recirculation rate,
- 5.4.2.7 Other operational characteristics.

Section 5.4.3 states that for units subject to the requirements of Section 5.2.1 or 5.2.2, the operator shall monitor, at least on a monthly basis, the operational characteristics recommended by the manufacturer and approved by the APCO.

Compliance with this section will be further discussed in District Rule 4320 Section 5.7 Monitoring Requirements, as requirements are equivalent to or more stringent than District Rule 4306 requirements.

Section 5.5, Compliance Determination

Section 5.5.1 states that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling).

Section 5.5.2 states all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. Unless otherwise specified in the Permit to Operate no determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0.

Section 5.5.4 states that for emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NO_x analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

Section 5.5.5 states that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit.

Compliance with this section will be further discussed in District Rule 4320 Section 5.8 Compliance Determination, as requirements are equivalent to or more stringent than District Rule 4306 requirements.

Section 6.0, Administrative Requirements

Section 6.1.3 requires that the operator of any unit subject to Section 5.2.1 or Section 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics of the unit have been performed.

The boilers in this project are not subject to this section and therefore, the requirements of this section do not apply.

Section 6.1.4 requires that the operator performing start-up or shutdown of a unit shall keep records of the duration of start-up or shutdown. The units are subject to the startup or shutdown provisions; therefore, the following condition will be listed on the ATCs to ensure compliance:

- Daily and annual records of the total duration of startup and shutdown time (in hours) shall be kept. [District Rules 2201, 4305, 4306, and 4320]

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NO _x	ppmv	EPA Method 7E or ARB Method 100
NO _x	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O ₂	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

Section 6.3.1 requires that units to be source tested to determine compliance with the applicable requirements of Section 5.1 or 5.2.3 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to 36 months.

Compliance with this sections 6.2 and 6.3.1 will be further discussed in District Rule 4320 Section 6.2, Test Methods, and Section 6.3, Compliance Testing, as requirements are equivalent to or more stringent than District Rule 4306 requirements.

Sections 6.3.2.1 through 6.3.2.7 address the requirements of group testing which is not proposed in this project therefore, these sections are not applicable.

Section 7.0, Compliance Schedule

Section 7.0 specifies ECP, ATC submittal, and compliance deadlines for existing units to meet applicable emission requirements of this rule. As discussed in Section 5.1 above, the new boilers will meet the applicable emission limits listed in Tables 2 of Section 5.1 at the time of installation. Therefore, the new boilers will comply with this rule at the time of the installation.

Conclusion

Since all other requirements of District Rule 4320 are equivalent to or more stringent than District Rule 4306 requirements, compliance with District Rule 4320 requirements will satisfy requirements of District Rule 4306.

Rule 4308 Boilers, Steam Generators, And Process Heaters – 0.075 MMBtu/hr to less than 2.0 MMBtu/hr

The purpose of this rule is to limit emissions of oxides of nitrogen (NO_x) and carbon monoxide (CO) from boilers, steam generators, process heaters and water heaters. This rule applies to any person who supplies, sells, offers for sale, installs, or solicits the installation of any boiler, steam generator, process heater or water heater with a rated heat input capacity greater than or equal to 75,000 British thermal units per hour and less than 2,000,000 British thermal units per hour.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

The proposed digester/natural gas-fired boiler with a heat input of 1.996 MMBtu/hr is subject to this rule.

Section 5.0 – Requirements

Section 5.0 lists the requirements of this rule as follows:

- 5.1 Until December 31, 2014, a person shall not supply, sell, offer for sale, install or solicit the installation of any boiler, process heater or water heater unless it has been certified pursuant to Section 6.1 and complies with Table 1 NO_x limits and CO limits specified in Section 5.3.*

The proposed boiler will be installed after December 31, 2014; therefore, this section is not applicable.

- 5.2 *On and after January 1, 2015, a person shall not supply, sell, offer for sale, install or solicit the installation of any boiler, process heater or water heater unless it has been certified pursuant to Section 6.1 and complies with Table 2 NOx limits and CO limits specified in Section 5.3.*

The proposed boiler will be installed after January 1, 2015; therefore, it is subject to this section and Table 2 emission limits specified in Section 5.3.

- 5.3 *Units with a rated heat input capacity of 0.4 MMBtu/hr to less than 2.0 MMBtu/hr shall not exceed the CO limit of 400 ppm at 3% stack gas oxygen by volume on a dry basis.*

The proposed digester/natural gas-fired boiler has a rated heat input of 1.996 MMBtu/hr; therefore, it is subject to this section and the applicable emissions limits of Table 2 as summarized below:

Table 2 Emission Limits (Effective on and after January 1, 2015)		
Type and Size of Unit, In MMBtu/hr	NOx Limit (at 3% stack gas oxygen by volume on a dry basis)	
	PUC Gas	Non PUC Gas or Liquid
	lb/MMBtu of heat input (ppmv)	lb/MMBtu of heat input (ppmv)
Units greater than 0.4 but less than 2.0	0.024 (20)	0.036 (30)

Based on the information provided by the boiler manufacturer, CDI has proposed the following emission limits:

- NOx – 0.024 lb/MMBtu (20 ppmv @3% O₂) when fired on PUC-quality natural gas,
- NOx – 0.036 lb/MMBtu (30 ppmv @3% O₂) when fired on digester gas, and
- CO – 0.0392 lb/MMBtu (50 ppmv @3% O₂) when fired on either fuel.

Therefore, the boiler is expected to comply with this section of the rule and the following conditions will be listed on the ATC to ensure compliance:

- Emissions from the combustion of digester gas blend from this boiler shall not exceed any of the following limits: 30 ppmv NOx @ 3% O₂ or 0.036 lb-NOx/MMBtu; 0.0241 lb-SOx/MMBtu; 0.0076 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% or 0.0392 lb-CO/MMBtu; or 0.0045 lb-VOC/MMBtu. [District Rules 2201 and 4308]

- Emissions from the combustion of natural gas from this boiler shall not exceed any of the following limits: 20 ppmv NO_x @ 3% O₂ or 0.024 lb-NO_x/MMBtu; 0.0241 lb-SO_x/MMBtu; 0.0076 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% or 0.0392 lb-CO/MMBtu; or 0.0045 lb-VOC/MMBtu. [District Rules 2201 and 4308]
- {edited 4355} The boiler shall only be fired on treated digester gas, PUC-quality natural gas, or a blend of treated digester gas and PUC-quality natural gas. [District Rules 2201, 4308, and 4801]

Section 6.0 – Administrative Requirements

Section 6.0 lists the administrative requirements as follow:

6.1 Methods of Emissions Certification

Certified emission levels shall be demonstrated by an emission certification approved under either of the following:

6.1.1 The District's certification program as described in Section 6.2 and 6.3 of this rule.

6.1.2 The SCAQMD Certification List for Rule 1146.2.

6.1.3 Other emission certification programs approved by the EPA and the APCO.

There are no commercially available boilers that have been certified on digester gas fuel produced from wastewater. Therefore, the unit will be required to demonstrate compliance with the applicable emission limits of Table 2 via source test, i.e. a certification in place. Source testing will be performed in accordance with the requirements of District Rule 1081 as previously discussed under Rule 1081 discussion of this evaluation.

Sections 6.2 thru 6.3 specify the certification requirements for unit manufacturers. Since CDI is not the manufacturer of the unit, these sections are not applicable.

Rule 4311 Flares

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

The purpose of this rule is to limit the emissions of volatile organic compounds (VOC), oxides of nitrogen (NO_x), and sulfur oxides (SO_x) from the operation of flares. This rule is applicable to operations involving the use of flares.

5.0 Requirements

Section 5.1 states that 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 flare is not an emergency only flare; therefore, this section is not applicable.

Section 5.2 states that 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. The flare is not limited to 200 hours of operation; therefore, this section is not applicable.

Section 5.3 requires that the flame shall be present at all times when combustible gases are vented through the flare. Therefore, the following condition will be listed on the ATC to ensure compliance:

- The flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311]

Section 5.4 requires that the 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. The proposed flare is equipped with an automatic ignition system; therefore, the following condition will be listed on the ATC to ensure compliance with this requirement:

- The flare outlet shall be equipped with an automatic ignition system. [District Rule 4311]

Section 5.5 requires that except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an alternative equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. The proposed flare is equipped with a solar powered⁴ automatic flow sensing ignition system with a solar trickle charge plate and spark plug igniters. Since the flare is equipped with a flow sensing ignition system with no pilot flame, this section does not apply.

Section 5.6 states that flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. Since the flare is equipped with a flow-sensing automatic ignition system and does not use a continuous flare pilot, this section applies and the following condition will be listed on the ATC to ensure compliance:

- Flare shall use purge gas for purging. [District Rule 4311]

Section 5.7 states that open flares 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. The requirements of this section shall not apply to Coanda effect flares.

Section 3.11 of the rule defines enclosed flare as being composed of multiple gas burners that are grouped in an enclosure, and are staged to operate at a wide range of flow rates. Based on the specifications provided by the applicant, the proposed flare will be equipped with a single burner with a 'visibility shield', which will not fully contain the actual flame⁵.

⁴ Per flare spec sheets, the proposed flare will be equipped with 6 volt solar trickle charge plate with a 5W charging panel and the fully charged system is designed to function for at least 20 days in darkness.

⁵ https://www.lscenv.com/product_pdfs/1464267868_Solar%20Spark%20Vent%20Flares.pdf

Therefore, the proposed flare is considered an open flare, and since flare gas pressure will be less than 5 psig, the flare is subject to this section and will be required to meet the provisions of 40 CFR 60.18 as discussed below:

40 CFR §60.18 – General Control Device and Work Practice Requirements

Pursuant to Section 60.18 (b), paragraphs (c) through (f) apply to flares.

Paragraph (c)(1) states that flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. Therefore, the following condition will be listed on the ATC with reference of Rule 4311 to ensure compliance with these requirements:

- {modified 649} Flare shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [District Rules 4101 and 4311]

Paragraph (c)(2) states that flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f). Therefore, the following condition will be listed on the ATC with reference of Rule 4311 to ensure compliance with this requirement:

- The flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311]

Paragraph (3) states that an owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

Paragraph (c)(3)(i) applies to flares with a diameter of 3 inches or greater, are non-assisted, have a hydrogen content of 8.0 percent (by volume) or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec). Since the digester gas combusted in the flare does not have hydrogen content of 8.0 percent (by volume) or greater, this paragraph does not apply.

Paragraph (c)(3)(ii) states that flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is non-assisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

Since the flare will only combust treated digester gas with a net heating value of 700 Btu/scf and the flare is non-assisted, the requirements of this paragraph have been satisfied.

Paragraph (c)(4)(i) states that steam-assisted and non-assisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4)(ii) and (iii) of this section. The flare associated with this project is non-assisted; therefore, this paragraph is applicable.

Based on the information provide, a design check is performed below to calculate the flare exit velocity:

Flare Exit Velocity Design Check:

Parameters used:

Maximum flow rate (Q) = 140 ft³/min (per applicant)

Flare tip internal diameter (D) = 8 inches (per flare specs)

Cross sectional area of tip (A) = ($\pi D^2/4$) inch²

Paragraph (f)(4) states that the actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

Therefore, flare exit velocity is calculated as below:

$$\begin{aligned} \text{Exit Velocity (V)} \frac{\text{ft}}{\text{sec}} &= \frac{\text{Max. Flow Rate (Q)} \left(\frac{\text{ft}^3}{\text{sec}} \right)}{\text{Cross Sectional Ara (A)} (\text{ft}^2)} \\ &= \frac{140 \left(\frac{\text{ft}^3}{\text{min}} \right) \times \left(\frac{1 \text{ min}}{60 \text{ sec}} \right)}{\frac{\pi}{4} \times \left(8 \text{ inch} \times \frac{1 \text{ ft}}{12 \text{ inch}} \right)^2} \\ &= 7 \frac{\text{ft}}{\text{sec}} \end{aligned}$$

Since this is less than 60 ft/sec, this demonstrates that the flare is properly designed to comply with the maximum exit velocity (60 ft/sec) requirement of paragraph (c)(4)(i). Therefore, the requirements of this paragraph are satisfied and no permit conditions are necessary to demonstrate ongoing compliance.

Paragraph (c)(4)(ii) states that steam-assisted and non-assisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

Since net heating value of the digester gas is less than 1,000 Btu/scf, this paragraph is not applicable.

Paragraph (c)(4)(iii) states that steam-assisted and non-assisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max} , as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed. As demonstrated above, the exit velocity is less than 60 ft/sec, which satisfies requirements of Paragraph (c)(4)(i); therefore, this paragraph is not applicable.

Paragraph (c)(5) states that air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max} , as determined by the method specified in paragraph (f)(6). Since the flare associated with this project is not air-assisted, this paragraph is not applicable.

Paragraph (c)(6) states that flares used to comply with this section shall be steam-assisted, air-assisted, or non-assisted. Since the flare associated with this project is non-assisted, it satisfies the requirements of this paragraph and no special condition is necessary.

Paragraph (d) states that owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices. Therefore, the following condition will be listed on the ATC with reference of Rule 4311 to ensure compliance with these requirements:

- Flare shall be maintained in good operating condition and shall be operated in accordance with the design specifications as recommended by the manufacturer. [District Rule 4311]

In addition, the flare will be subject to fuel sulfur monitoring requirements as discussed under Rule 2201 discussion above.

Paragraph (e) states that flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them. Therefore, the following condition will be listed on the ATC with reference of Rule 4311 to ensure compliance with these requirements:

- The flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311]

Paragraph (f)(1) states that Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22. Therefore, the following condition will be listed on the ATC with reference of Rule 4311 to ensure compliance with these requirements:

- {modified 650} Demonstration of compliance with the visible emissions limit of this permit shall be conducted at least once every 12 months, using EPA Method 22. The observation period shall be 2 hours. [District Rule 4311]

Paragraph (f)(2) states that the presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. Since the flare is equipped with a flow sensing ignition system with no pilot flame, this paragraph does not apply.

Paragraphs (f)(3) thru (f)(6) describe the methods to calculate the net heating value of the gas being combusted in the flare. Therefore, the following condition will be listed on the ATC with reference of Rule 4311 to ensure compliance with these paragraphs and to utilize test methods per District practice for digester gas operations:

- The higher heating value (HHV) of the digester gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method as approved by the District. [District Rules 2201 and 4311]

Paragraph (f)(4) states that the actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. As shown in the design check under paragraph (c)(4)(i) above, the flare design ensure compliance with the maximum exit velocity requirements. Therefore, information submitted with this ATC application and the design check is sufficient and no ongoing conditions are necessary.

Section 5.8 applies to ground-level enclosed flares. Since the flare associated with this project is an open type flare, this section does not apply.

Sections 5.9 and 5.10 apply to existing flares. Since the flare associated with this project is a new flare, these sections are not applicable.

Sections 5.11, 5.12, 5.13, and 5.15 apply to flares located at refineries or major sources. CDI is not a refinery or a major source; therefore, these sections do not apply.

Section 5.14 applies to existing flares subject to the annual throughput thresholds of Table 2. Since the flare associated with this project is a new flare, it is not subject to Table 2 and thus this section does not apply.

Section 5.15 is applicable to flares 50 MMBtu/hr or more located at a petroleum refinery or a major source, except landfill operations. Since the flare associated with this project is rated less than 50 MMBtu/hr and will not be located at a refinery or a major source, this section does not apply.

Section 6.0 Recordkeeping Requirements

Section 6.1 requires that the records specified in Section 6.1.1 thru 6.1.7 shall be maintained, retained on-site for a minimum of five years, and made available to the APCO, ARB, and EPA upon request. Therefore, the following condition will be listed on ATC to ensure compliance with this section:

- 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]

Sections 6.1.1 thru 6.1.7 are discussed below with applicable recordkeeping requirements for the flare associated with this project:

6.1.1 Copy of the compliance determination conducted pursuant to Section 6.4.1.

Section 6.4.1 states that, upon request, the operator of flares that are subject to Section 5.7 shall make available to the APCO the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). As discussed under 40 CFR 60.18 discussion above, the flare associated with this project is only subject to paragraph (c)(4)(i), which requires the flare to be operated with an exit velocity of less than 60 ft/sec. As shown in the design check under paragraph (c)(4)(i) above, the flare design ensure compliance with the maximum exit velocity requirements. Therefore, information submitted with this ATC application and the design check is sufficient and no ongoing recordkeeping conditions are necessary.

6.1.2 Copy of the source testing result conducted pursuant to Section 6.4.2. As discussed below Section 6.4.2 is not applicable to the proposed flare; therefore, this section is not applicable.

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. Since the proposed flare is not an emergency flare, this section is not applicable.

6.1.4 Operators claiming an exemption pursuant to Section 5.2 shall record annual hours of operation or annual throughput necessary to demonstrate an exemption under that section. Since the proposed flare does not claim an exemption pursuant to Section 5.2, this section is not applicable.

6.1.5 A copy of the approved flare minimization plan pursuant to Section 6.5. Since the proposed flare is not subject to Section 6.5, this section is not applicable.

6.1.6 A copy of annual reports submitted to the APCO pursuant to Section 6.2. Since the proposed flare is not subject to Section 6.2, this section is not applicable.

6.1.7 Monitoring data collected pursuant to Sections 5.13, 5.14, 6.6, 6.7, 6.8, 6.9, and 6.10. Since the proposed flare is not subject to any of these sections, this section is not applicable.

6.2 Flare Reporting

Subsections 6.2.1 and 6.2.2 specify reporting requirements for flares subject to Section 5.11. The flare associated with this project is not subject to Section 5.11; therefore, these subsections do not apply.

Subsection 6.2.3 specifies requirements for submitting annual monitoring reports for *any flare* subject to flare monitoring requirements pursuant to Sections 5.13, 5.14, 6.6, 6.7, 6.8, 6.9, and 6.10. The flare associated with this project is not subject to any of these sections; therefore, this section does not apply.

6.3 Test Methods

Section 6.3 specifies the test methods to be used to demonstrate compliance with this rule.

Subsections 6.3.1, 6.3.2, and 6.3.3 establish test methods for VOC, NO_x, and O₂ concentrations. However, the proposed flare is not subject to any of these subsections.

Subsection 6.3.4 establishes testing and sampling methods for flares subject to Section 6.6 (flares with capacity ≥ 50 MMBtu/hr, except landfill operations). As discussed below, the flare associated with this project is not subject to the requirements of Section 6.6; therefore, this section does not apply.

Subsection 6.3.5 establishes the test methods for purposes of the flow verification report required by Section 6.2.3.8. As discussed above, the flare associated with this project is not subject to the requirements of Section 6.2.3.8; therefore, this section does not apply.

Subsection 6.3.6 establishes the test methods to determine the heating value of flared gas for flares subject to Section 5.14 (existing flares subject to the annual throughput thresholds of Table 2 of the rule). As discussed above, the flare associated with this project is not subject to the requirements of Section 5.14 therefore, this section does not apply.

6.4 Compliance Determination

Section 6.4.1 requires the operator of flares that are subject to Section 5.7 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). As discussed under 40 CFR 60.18 discussion above, the flare associated with this project is only subject to Section (c)(4)(i) for which this section requires to keep records. As stated earlier, the flare design check demonstrates compliance and no permit conditions are necessary to demonstrate ongoing compliance.

Section 6.4.2 requires the operator of flares subject to emission limits in Table 1 and Table 3, Categories A, B, and C shall conduct source testing at least once every 12 months to demonstrate compliance with Section 5.8. Since the proposed flare is not subject to the emission limits in Table 1 or Table 3, Categories A, B, and C, the requirements of this section are not applicable.

6.5 Flare Minimization Plan

Section 6.5 specifies the flare minimization plan for flares at petroleum refineries or any flare at a major source, except landfill operations, that has a flaring capacity of greater than or equal to 5.0 MMBtu per hour. Since the proposed flare will not be located at a petroleum refinery nor will be located at a major source, the requirements of this section are not applicable.

Section 6.6 specifies vent gas composition monitoring requirements for flares with a flaring capacity equal to or greater than 50 MMBtu/hr, except landfill operations. The flare associated with this project does not have a flaring capacity equal to or greater than 50 MMBtu/hr and CDI is not a landfill operation. Therefore, this section does not apply.

Section 6.7 specifies pilot and purge gas monitoring requirements for flares with a flaring capacity equal to or greater than 50 MMBtu/hr. The flare associated with this project does not have a flaring capacity equal to or greater than 50 MMBtu/hr; therefore, this section does not apply.

Section 6.8 specifies water seal monitoring requirements for flares with a flaring capacity equal to or greater than 50 MMBtu/hr. The flare associated with this project does not have a flaring capacity equal to or greater than 50 MMBtu/hr; therefore, this section does not apply.

Section 6.9 provides guidelines on general monitoring for flares with a flaring capacity equal to or greater than 50 MMBtu/hr. The flare associated with this project does not have a flaring capacity equal to or greater than 50 MMBtu/hr; therefore, this section does not apply.

Section 6.10 specifies video monitoring requirements for flares operated at petroleum refineries. The flare associated with this project will not be operated at a petroleum refinery; therefore, this section does not apply.

Section 7.0 Compliance Schedule

Section 7.1 applies to flares that are exempt under Section 4.0. The flare associated with this project is not exempt under Section 4.0; therefore, this section does not apply.

Section 7.2 applies to flares opting to limit flaring annual throughput per Section 5.9.1. The flare associated with this project is not subject to Section 5.9; therefore, this section does not apply.

Section 7.3 applies to flares opting to replace or modify a flare to meet the emissions limits in Table 3 per Section 5.9.2. The flare associated with this project is not subject to Section 5.9; therefore, this section does not apply.

Section 7.4 applies to flares subject to Section 5.10. The flare associated with this project is not subject to Section 5.10; therefore, this section does not apply.

Compliance with this rule is expected.

Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

The purpose of this rule is to limit emissions of oxides of nitrogen (NO_x), carbon monoxide (CO), oxides of sulfur (SO₂), and particulate matter 10 microns or less (PM₁₀) from boilers, steam generators, and process heaters. This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a total rated heat input greater than 5 million Btu per hour.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Since the proposed 1.996 MMBtu/hr digester/natural gas-fired boiler has a heat input rating less than 5 MMBtu/hr, this boiler is not subject to this rule.

ATCs S-10254-1-0 & -2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Each of the two 50.4 MMBtu/hr natural gas-fired boiler has a maximum heat input greater than 5 MMBtu/hr; therefore, each boiler is subject to this rule and the following discussion applies only to these two boilers.

Section 5.0, Requirements

Section 5.1 states that an operator of a unit subject to this rule shall comply with all applicable requirements of the rule and one of the following, on a unit-by-unit basis:

- 5.1.1 Operate the unit to comply with the emission limits specified in Sections 5.2 and 5.4; or
- 5.1.2 Pay an annual emissions fee to the District as specified in Section 5.3 and comply with the control requirements specified in Section 5.4; or
- 5.1.3 Comply with the applicable Low-use Unit requirements of Section 5.5.

Section 5.2.1 requires that on and after the indicated Compliance Deadline, units shall not be operated in a manner which exceed the applicable NO_x emissions limit specified in Table 1 (until December 30, 2023) and Table 2 (on and after December 31, 2023). Units shall not be operated in a manner which exceeds a carbon monoxide (CO) emissions limit of 400 ppmv.

Section 5.2.3 states that all ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

The following table summarizes the applicable emission category of Table 2 of Section 5.2 for each boiler:

Table 2: Tier 2 NOx Emission Limits (on and after December 31, 2023)						
Permit Unit	Category #	Category Description	Operated on Gaseous Fuel			
			NOx Limit	Emission Control Plan	Authority to Construct	Compliance Deadline
S-10254-1-0 and '2-0	B.2	All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023

The following table summarizes the proposed NOx and CO emission limits for each boiler:

Pollutant	Emission Limits		Compliant with Rule 4320?
	ppmv @ 3% O ₂	lb/MMBtu	
NOx	2.5	0.003	Yes
CO	50	0.03695	Yes

Therefore, the proposed new boilers will comply with Section 5.2 of District Rule 4320 at the time of installation and the following conditions will be listed on ATCs to ensure compliance:

- Except during start-up and shutdown, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 2.5 ppmv NOx @ 3% O₂ or 0.003 lb-NOx/MMBtu; 0.00285 lb-SOx/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

Section 5.3, Annual Fee Calculation

Section 5.3.1 states on and after January 1, 2010, an operator with units that will comply with the requirements of 5.1.2 in lieu of complying with Section 5.2 Table 1 shall pay a total annual fee to the District based on the total NOx emissions from those units. As discussed above, the proposed new boilers will comply with Section 5.2 emission limits at the time of installation; therefore, this section is not applicable.

Section 5.4, Particulate Matter Control Requirements

Section 5.4.1 of this rule requires the operator to comply with one of the following requirements for control of particulate matter emissions, on and after the applicable NOx compliance deadline in Section 5.2 Table 1:

- 5.4.1.1 Fire the boiler exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases.
- 5.4.1.2 Limit fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet.

- 5.4.1.3 Install and properly operate an emission control system that reduces SO₂ emissions by at least 95% by weight; or limit exhaust SO₂ to less than or equal to 9 ppmv corrected to 3.0% O₂.

The proposed new boilers will only be fired on PUC-quality natural gas fuel, which meets Section 5.4.1.1 requirement above. Therefore, the following condition will be listed on the ATCs to ensure compliance:

- {4355} The unit shall only be fired on PUC-quality natural gas. [District Rules 2201 and 4320]

Section 5.5, Low-use Unit

Section 5.5 states for each unit that was installed prior to January 1, 2009 and is limited to less than or equal to 1.8 billion Btu per calendar year heat input pursuant to a District Permit to Operate, the operator shall comply with the requirement of Sections 5.7 and 7.3 and either Sections 5.5.1 or 5.5.2. The proposed boilers are not low use units and therefore this section is not applicable.

Section 5.6, Start-up and Shutdown Provision

Section 5.6 states that on and after the compliance deadline in Section 5.0, the applicable emission limits of Sections 5.2 Table 1, Table 2, and 5.5.2 shall not apply during start-up or shutdown, provided an operator complies with the requirements specified in Sections 5.6.1 through 5.6.5. Only Sections 5.6.1 and 5.6.2 apply to the new boilers as stated below:

- 5.6.1 The duration of each start-up or each shutdown shall not exceed two hours, except as provided in Section 5.6.3.
- 5.6.2 The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown.

Therefore, the following conditions will be listed on the ATCs to ensure compliance with the startup and shutdown requirements:

- The total duration of startup and shutdown time shall not exceed any of the following limits: 2.0 hours per day or 730 hours per year. [District Rules 2201, 4305, 4306, and 4320]
- During startup and shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rules 2201, 4305, 4306 and 4320]

- During startup and shutdown periods, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 30 ppmv NO_x @ 3% O₂ or 0.0364 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

Section 5.7, Monitoring Provisions

Section 5.7.1 requires that the operator of any unit subject to the applicable emission limits in Sections 5.2 shall install and maintain an operational APCO approved Continuous Emissions Monitoring System (CEMS) for NO_x, CO, and oxygen, or implement an APCO-approved Alternate Monitoring System. An APCO approved CEMS shall comply with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Part 60 Appendix B (Performance Specifications) and 40 CFR Part 60 Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). An APCO-approved Alternate Monitoring System shall monitor one or more of the following:

- 5.7.1.1 Periodic NO_x and CO exhaust emission concentrations,
- 5.7.1.2 Periodic exhaust oxygen concentration,
- 5.7.1.3 Flow rate of reducing agent added to exhaust,
- 5.7.1.4 Catalyst inlet and exhaust temperature,
- 5.7.1.5 Catalyst inlet and exhaust oxygen concentration,
- 5.7.1.6 Periodic flue gas recirculation rate, or
- 5.7.1.7 Other operational characteristics.

Since each new boilers will be equipped with an SCR system, the applicant has proposed to use the pre-approved alternate monitoring scheme H (pursuant to District Policy SSP-1105), which requires monitoring of NO_x, CO, O₂, and ammonia slip exhaust concentrations least once per month (in which a source test is not performed) using a portable analyzer. Therefore, the following conditions will be listed on the ATCs to ensure compliance:

- {4319} The permittee shall monitor and record the stack concentration of NO_x, CO, NH₃ and O₂ at least once during each month in which source testing is not performed. NO_x, CO and O₂ monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH₃ monitoring shall be conducted utilizing gas detection tubes (Draeger brand or District approved equivalent). Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless it has been performed within the last month. [District Rules 4305, 4306, and 4320]
- {4320} If the NO_x, CO or NH₃ concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting

a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

- {4321} All NO_x, CO, O₂ and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NO_x, CO and O₂ analyzer as well as the NH₃ emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]
- {4322} Ammonia emissions readings shall be conducted at the time the NO_x, CO and O₂ readings are taken. The readings shall be converted to ppmvd @ 3% O₂. [District Rules 4305, 4306, and 4320]
- {4323} The permittee shall maintain records of: (1) the date and time of NO_x, CO, NH₃ and O₂ measurements, (2) the O₂ concentration in percent by volume and the measured NO_x, CO and NH₃ concentrations corrected to 3% O₂, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH₃ emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 4305, 4306, and 4320]

Sections 5.7.2 and 5.7.3 specify monitoring requirements for units that are subject to the low-use requirements specified in Section 5.5. As discussed above, the boilers are not subject to the low-use requirements of Section 5.5. Therefore, these sections are not applicable.

Section 5.7.4 allows units operated at seasonal sources and subject to 40 CFR 60 Subpart Db to install a parametric monitoring system in lieu of a CEMS. The boilers will not be operated at a seasonal source. Therefore, this section is not applicable.

5.7.6 Monitoring SO_x Emissions

Section 5.7.6 outlines requirements for monitoring SO_x emissions. Section 5.7.6.1 states that operators complying with Sections 5.4.1.1 or 5.4.1.2 shall provide an annual fuel analysis to the District unless a more frequent sampling and reporting period is included in the Permit to Operate. Sulfur analysis shall be performed in accordance with the test methods in Section 6.2.

The facility has proposed to show compliance using the requirements in Section 5.4.1.1 by firing exclusively on PUC-quality natural gas. Therefore, the following conditions will be listed on the ATCs to ensure compliance:

- {4355} The unit shall only be fired on PUC-quality natural gas. [District Rules 2201 and 4320]
- {4356} Permittee shall determine sulfur content of combusted gas annually or shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320]

Section 5.8, Compliance Determination

Section 5.8.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.2. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the ATCs to ensure compliance:

- {4350} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

Section 5.8.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following condition will be listed on the ATCs to ensure compliance:

- {4351} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rules 4320. [District Rules 4305, 4306, and 4320]

Section 5.8.4 requires that for emissions monitoring pursuant to Sections 5.7.1 and 6.3.1 using a portable NO_x analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

Therefore, the following condition will be listed on the ATCs to ensure compliance:

- {4321} All NO_x, CO, O₂ and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NO_x, CO and O₂ analyzer as well as the NH₃ emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]

Section 5.8.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following condition will be listed on the ATCs to ensure compliance:

- {4352} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]

Section 6.1, Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.5 shall be maintained for five calendar years and shall be made available to the APCO and EPA upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule. Therefore, the following condition will be listed on the ATCs to ensure compliance:

- All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320, and 40 CFR 60.48c(i)]

Section 6.1.2 requires that the operator of a unit subject to Section 5.5 shall record the amount of fuel use at least on a monthly basis. Since the units are not subject to the requirements listed in Section 5.5, this section is not applicable.

Section 6.1.3 requires that the operator of a unit subject to Section 5.5.1 or 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics have been performed. The units are not subject to Sections 5.5.1, whereas the applicable requirements of Section 6.3.1 are discussed below.

Section 6.1.4 requires that the operator of a unit with startup or shutdown provisions keep records of the duration of the startups or shutdowns. The units are subject to the startup or shutdown provisions; therefore, the following condition will be listed on the ATCs to ensure compliance:

- Daily and annual records of the total duration of startup and shutdown time (in hours) shall be kept. [District Rules 2201, 4305, 4306, and 4320]

Section 6.1.5 requires that the operator of a unit fired on liquid fuel during PUC-quality natural gas curtailment periods record the sulfur content of the fuel, amount of fuel used, and duration of the natural gas curtailment period. The facility has not proposed the use of curtailment fuels; therefore, this section is not applicable.

Section 6.2, Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Test Methods		
Pollutant	Units	Test Method Required
NO _x	ppmv	EPA Method 7E or ARB Method 100
NO _x	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O ₂	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

Therefore, the following conditions will be listed on the ATCs to ensure compliance:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- {4346} NO_x emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320]
- {4347} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306, and 4320]
- {4348} Stack gas oxygen (O₂) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]

Additionally, BAAQMD Method ST-1B will be required to determine the ammonia emissions. The following condition will be listed on the ATC to ensure compliance:

- Source testing for ammonia slip shall be conducted utilizing BAAQMD method ST-1B. [District Rule 1081]

Section 6.3 Compliance Testing

Section 6.3.1 requires that these units be source tested to determine compliance with the applicable requirements of section 5.2 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months. Therefore, the following conditions will be listed on the ATCs to ensure compliance with the initial and ongoing compliance testing requirements:

- Source testing to measure natural gas combustion NO_x, CO, and NH₃ emissions from this unit shall be conducted within 60 days of initial start-up. [District Rules 4305, 4306, and 4320]
- Source testing to measure natural gas combustion NO_x, CO, and NH₃ emissions from this unit shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests when unit is fired on natural gas, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]
- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Sections 6.3.2.1 through 6.3.2.7 address the requirements of group testing, which is not proposed in this project. Therefore, these sections are not applicable.

Section 6.4 specifies Emissions Control Plan (ECP) for existing units. Since these boilers are new, this section is not applicable.

Section 7.0, Compliance Schedule

Section 7.0 specifies ECP, ATC submittal, and compliance deadlines for existing units to meet applicable emission requirements listed in Table 2 of Section 5.2. As discussed under Section 5.2 above, the new boilers will comply with this rule at the time of the installation.

Therefore, compliance with District Rule 4320 requirements is expected.

Rule 4351 Boilers, Steam Generators and Process Heaters – Phase I

This rule applies to boilers, steam generators, and process heaters at NO_x Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. In addition, the rule only applies to boilers with a rated heat input greater than 5 MMBtu/hr.

ATCs S-10254-1-0 & '-2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

As shown in Section VII.C.5 of this document, the facility is not a Major Source for NO_x emissions. Therefore, this rule is not applicable to these boilers.

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Since the proposed 1.996 MMBtu/hr digester/natural gas-fired boiler has a heat input rating less than 5 MMBtu/hr, this boiler is not subject to this rule.

Rule 4801 Sulfur Compounds

A person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2% by volume (equivalent to 2,000 ppmv) calculated as SO₂, on a dry basis averaged over 15 consecutive minutes.

ATCs S-10254-1-0 & -2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

$$\text{Volume SO}_2 = \frac{n RT}{P}$$

With:

n = moles SO₂

T (Standard Temperature) = 60 °F = 520 °R

P (Standard Pressure) = 14.7 psi

R (Universal Gas Constant) = $\frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}}$

EPA F-Factor: 8,578 dscf/MMBtu at 60 °F

Thus, sulfur compound emissions are calculated as below:

$$\frac{0.00285 \text{ lb} - \text{SO}_x}{\text{MMBtu}} \times \frac{1 \text{ MMBtu}}{8,578 \text{ dscf}} \times \frac{1 \text{ lb} \cdot \text{mol}}{64 \text{ lb} - \text{SO}_x} \times \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}} \times \frac{520 ^\circ\text{R}}{14.7 \text{ psi}} \times \frac{1,000,000 \text{ parts}}{\text{million}} = 1.97 \frac{\text{parts}}{\text{million}}$$

Sulfur Concentration = 1.97 ppmv ≤ 2000 ppmv

Therefore, the boilers are expected to comply with Rule 4801 and the following condition will be listed on the ATCs to ensure compliance:

- {edited 4355} The boiler shall only be fired on PUC-quality natural gas. [District Rules 2201, 4305, 4306, 4320, and 4801]

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from the flare will be calculated based on the maximum sulfur content allowed in the digester gas combusted in the flare: 0.0241 lb-SO_x/MMBtu (based on a maximum digester gas sulfur content of 100 ppmv as H₂S).

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

$$\text{Volume SO}_2 = \frac{n RT}{P}$$

Where:

N = moles SO₂

T (Standard Temperature) = 60 °F = 520 °R

P (Standard Pressure) = 14.7 psi

R (Universal Gas Constant) = $\frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}}$

Estimated F-Factor for the Digester Gas: 9,100 dscf/MMBtu at 60 °F

Thus, sulfur compound emissions are calculated as below:

$$\frac{0.0241 \text{ lb} - \text{SO}_x}{\text{MMBtu}} \times \frac{1 \text{ MMBtu}}{9,100 \text{ dscf}} \times \frac{1 \text{ lb} \cdot \text{mol}}{64 \text{ lb} - \text{SO}_x} \times \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}} \times \frac{520 ^\circ\text{R}}{14.7 \text{ psi}} \times \frac{1,000,000 \text{ parts}}{\text{million}} = 16 \frac{\text{parts}}{\text{million}}$$

Sulfur Concentration = 16 ppmv ≤ 2000 ppmv

Therefore, the flare is expected to comply with Rule 4801 and the following conditions will be listed on the ATC to ensure compliance:

- Only treated digester gas shall be combusted in the flare. [District Rules 2201 and 4801]
- Maximum sulfur content of the treated digester gas combusted in the flare shall not exceed 100 ppmv as H₂S. The permittee may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the sulfur content limit of the digester gas. [District Rules 2201 and 4801]

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

$$\text{Volume SO}_2 = \frac{n RT}{P}$$

Where:

N = moles SO₂

T (Standard Temperature) = 60 °F = 520 °R

P (Standard Pressure) = 14.7 psi

R (Universal Gas Constant) = $\frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}}$

Digester Gas Fuel

Estimated F-Factor for the Digester Gas: 9,100 dscf/MMBtu at 60 °F

Thus, sulfur compound emissions are calculated as below:

$$\frac{0.0241 \text{ lb} - \text{SOx}}{\text{MMBtu}} \times \frac{1 \text{ MMBtu}}{9,100 \text{ dscf}} \times \frac{1 \text{ lb} \cdot \text{mol}}{64 \text{ lb} - \text{SOx}} \times \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}} \times \frac{520 ^\circ\text{R}}{14.7 \text{ psi}} \times \frac{1,000,000 \text{ parts}}{\text{million}} = 16 \frac{\text{parts}}{\text{million}}$$

Sulfur Concentration = 16 ppmv ≤ 2000 ppmv

Natural Gas Fuel

EPA F-Factor for Natural Gas: 8,578 dscf/MMBtu at 60 °F

Thus, sulfur compound emissions are calculated as below:

$$\frac{0.0241 \text{ lb} - \text{SOx}}{\text{MMBtu}} \times \frac{1 \text{ MMBtu}}{8,578 \text{ dscf}} \times \frac{1 \text{ lb} \cdot \text{mol}}{64 \text{ lb} - \text{SOx}} \times \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}} \times \frac{520 ^\circ\text{R}}{14.7 \text{ psi}} \times \frac{1,000,000 \text{ parts}}{\text{million}} = 17 \frac{\text{parts}}{\text{million}}$$

Sulfur Concentration = 17 ppmv ≤ 2000 ppmv

Therefore, the boiler is expected to comply with Rule 4801 and the following conditions will be listed on the ATC to ensure compliance:

- {edited 4355} The boiler shall only be fired on treated digester gas, PUC-quality natural gas, or a blend of treated digester gas and PUC-quality natural gas. [District Rules 2201, 4308, and 4801]
- Maximum sulfur content of the treated digester gas combusted in the boiler shall not exceed 100 ppmv as H₂S. [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)

The City of Bakersfield (City) is the public agency having principal responsibility for approving the Project. As such, the City served as the Lead Agency for the Project. The City determined the project to be exempt from CEQA according to CEQA Guidelines §15268 (Ministerial Projects). Consistent with CEQA Guidelines §15062, a Notice of Exemption was prepared and adopted by the City.

Pursuant to CEQA Guidelines §15250, the District is a Responsible Agency for the Project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381).

The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's thresholds of significance for criteria pollutants. Thus, the District concludes that through a combination of project design elements and permit conditions, project specific stationary source emissions will be reduced to less than significant levels. 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), an indemnification agreement (IA) and/or a letter of credit (LOC) may be required. The decision to require an IA and/or an LOC 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 IA and/or an LOC will not be required for this project.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs S-10254-1-0 thru '4-0 subject to the permit conditions on the attached draft ATCs in Appendix A.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-10254-1-0	3020-02-H	50.4 MMBtu/hr boiler	\$1,238
S-10254-2-0	3020-02-H	50.4 MMBtu/hr boiler	\$1,238
S-10254-3-0	3020-02-F	3.79 MMBtu/hr flare	\$731
S-10254-4-0	3020-02-E	1.996 MMBtu/hr boiler	\$495

XI. Appendixes

- A: Draft ATCs
- B: BACT Guideline and BACT Analysis (50.4 MMBtu/hr Boilers)
- C: HRA/AAQA Summary
- D: Quarterly Net Emissions Change (QNEC)

APPENDIX A

Draft ATCs

APPENDIX B

**BACT Guideline and BACT Analysis –
50.4 MMBtu/hr Boilers (ATCs S-10254-1-0 & '-2-0)**

Top Down BACT Analysis for 50.4 MMBtu/hr Boilers **(ATCs S-10254-1-0 and '-2-0)**

BACT Guideline 1.1.2 (last updated 11/30/2022) is applicable to PUC quality natural gas or propane fired boilers and steam generators with heat input rate greater than 20 MMBtu/hr. In accordance with the District BACT policy, information from this BACT guideline will be utilized without further analysis.

1. BACT Analysis for NO_x Emissions:

a. Step 1 - Identify All Control Technologies

BACT Guideline 1.1.2 identifies only one control option as below:

- 2.5 ppmvd @ 3% O₂ (0.003 lb/MMBtu) – Achieved in Practice.

No Technologically Feasible control options or Alternate Basic Equipment are listed.

b. Step 2 - Eliminate Technologically Infeasible Options

The only control option listed in Step 1 is not technologically infeasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

No ranking needs to be done because there is only one control option listed in Step 1.

d. Step 4 - Cost Effectiveness Analysis

No cost effective analysis needs to be done as the only control option under consideration is also Achieved in Practice and has been proposed by the applicant.

e. Step 5 - Select BACT

BACT for NO_x emission is not to exceed 2.5 ppmvd @ 3% O₂ (0.003 lb/MMBtu). The applicant has proposed to utilize SCR system for each new boiler to achieve this limit. Therefore, BACT will have been satisfied for NO_x emissions.

2. BACT Analysis for SO_x, PM₁₀, and VOC Emissions:

a. Step 1 - Identify all control technologies

BACT Guideline 1.1.2 identifies only one control option for SO_x, PM₁₀, and VOC emissions as below:

- PUC quality natural gas or propane with LPG backup – Achieved in Practice.

No Technologically Feasible control options or Alternate Basic Equipment are listed.

b. Step 2 - Eliminate Technologically Infeasible Options

The only control option listed in Step 1 is not technologically infeasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

No ranking needs to be done because there is only one control option listed in Step 1.

d. Step 4 - Cost Effectiveness Analysis

No cost effective analysis needs to be done as the only control option under consideration is also Achieved in Practice and has been proposed by the applicant.

e. Step 5 - Select BACT

BACT for SO_x, PM₁₀, and VOC emissions is use of PUC quality natural gas or propane with LPG backup. The applicant has proposed to use only PUC quality natural gas as fuel for these boilers. Therefore, BACT has been satisfied for SO_x, PM₁₀, and VOC emissions.

APPENDIX C

HRA/AAQA Summary

APPENDIX D

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:

Since these are new emission units, PE1 is zero, thus:

$PE1_{quarterly} = 0$ lb/qtr for all pollutants

ATCs S-10254-1-0 & '2-0 (50.4 MMBtu/hr Natural Gas-Fired Boilers):

Pollutant	Annual PE1 (lb/yr)	Quarterly PE1 (lb/qtr)
NO _x	0	0
SO _x	0	0
PM ₁₀	0	0
CO	0	0
VOC	0	0

Pollutant	Annual PE2 (lb/yr)	Quarterly PE2 (lb/qtr)
NO _x	2,553	638.25
SO _x	1,258	314.5
PM ₁₀	1,325	331.25
CO	16,314	4,078.5
VOC	2,428	607

$QNEC \text{ (lb/qtr)} = PE2 \text{ (lb/qtr)} - PE1 \text{ (lb/qtr)}$

Quarterly NEC [QNEC]			
Pollutant	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO _x	638.25	0	638.25
SO _x	314.5	0	314.5
PM ₁₀	331.25	0	331.25
CO	4,078.5	0	4,078.5
VOC	607	0	607

Since QNEC values are entered in PAS database as whole numbers, QNEC will be distributed in four quarters as summarized in the table below:

Quarterly NEC [QNEC]					
Quarter	NOx	SOx	PM ₁₀	CO	VOC
1 st	638	314	331	4,078	607
2 nd	638	314	331	4,078	607
3 rd	638	315	331	4,079	607
4 th	639	315	332	4,079	607

ATC S-10254-3-0 (Anaerobic Digester System with 3.79 MMBtu/hr Flare):

Pollutant	Annual PE1 (lb/yr)	Quarterly PE1 (lb/qtr)
NOx	0	0
SOx	0	0
PM ₁₀	0	0
CO	0	0
VOC	0	0

Pollutant	Annual PE2 (lb/yr)	Quarterly PE2 (lb/qtr)
NOx	432	108
SOx	174	43.5
PM ₁₀	175	43.75
CO	1,210	302.5
VOC	15	3.75

$$\text{QNEC (lb/qtr)} = \text{PE2 (lb/qtr)} - \text{PE1 (lb/qtr)}$$

Quarterly NEC [QNEC]			
Pollutant	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NOx	108	0	108
SOx	43.5	0	43.5
PM ₁₀	43.75	0	43.75
CO	302.5	0	302.5
VOC	3.75	0	3.75

Since QNEC values are entered in PAS database as whole numbers, QNEC will be distributed in four quarters as summarized in the table below:

Quarterly NEC [QNEC]					
Quarter	NOx	SOx	PM ₁₀	CO	VOC
1 st	108	43	43	302	3
2 nd	108	43	44	302	4
3 rd	108	44	44	303	4
4 th	108	44	44	303	4

ATC S-10254-4-0 (1.996 MMBtu/hr Digester/Natural Gas-Fired Boiler):

Pollutant	Annual PE1 (lb/yr)	Quarterly PE1 (lb/qtr)
NOx	0	0
SOx	0	0
PM ₁₀	0	0
CO	0	0
VOC	0	0

Pollutant	Annual PE2 (lb/yr)	Quarterly PE2 (lb/qtr)
NOx	629	157.25
SOx	421	105.25
PM ₁₀	133	33.25
CO	685	171.25
VOC	79	19.75

$$\text{QNEC (lb/qtr)} = \text{PE2 (lb/qtr)} - \text{PE1 (lb/qtr)}$$

Quarterly NEC [QNEC]			
Pollutant	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NOx	157.25	0	157.25
SOx	105.25	0	105.25
PM ₁₀	33.25	0	33.25
CO	171.25	0	171.25
VOC	19.75	0	19.75

Since QNEC values are entered in PAS database as whole numbers, QNEC will be distributed in four quarters as summarized in the table below:

Quarterly NEC [QNEC]					
Quarter	NOx	SOx	PM ₁₀	CO	VOC
1 st	157	105	33	171	19
2 nd	157	105	33	171	20
3 rd	157	105	33	171	20
4 th	158	106	34	172	20

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT

PERMIT NO: S-10254-1-0

LEGAL OWNER OR OPERATOR: CALIFORNIA DAIRIES, INC.

MAILING ADDRESS: 2000 N PLAZA DR
VISALIA, CA 93291

LOCATION: 8801 GOSFORD RD
BAKERSFIELD, CA 93313

EQUIPMENT DESCRIPTION:

50.4 MMBTU/HR CLEAVER BROOKS MODEL CBEX-2W-700-1200-150ST NATURAL GAS FIRED BOILER WITH A LOW NOX BURNER, A SELECTIVE CATALYST REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AND FLUE GAS RECIRCULATION (FGR) (BOILER #1)

CONDITIONS

1. {1407} 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. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {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]
6. The unit shall only be fired on PUC-quality natural gas. [District Rules 2201, 4305, 4306, 4320, and 4801]
7. {4356} Permittee shall determine sulfur content of combusted gas annually or shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320]
8. The total duration of startup and shutdown time shall not exceed any of the following limits: 2.0 hours per day or 730 hours per year. [District Rules 2201, 4305, 4306, and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

Brian Clements, Director of Permit Services

S-10254-1-0 : Jul 30 2024 12:41PM -- AHMADS : Joint Inspection NOT Required

9. During startup and shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rule 2201, 4305, 4306 and 4320]
10. Except during start-up and shutdown, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 2.5 ppmv NO_x @ 3% O₂ or 0.003 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]
11. During startup and shutdown periods, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 30 ppmv NO_x @ 3% O₂ or 0.0364 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]
12. NH₃ emissions from the SCR system shall not exceed 10 ppmvd @ 3% O₂. [District Rule 2201]
13. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rule 2201 and 40 CFR 60.48 (c)(g)]
14. {4319} The permittee shall monitor and record the stack concentration of NO_x, CO, NH₃ and O₂ at least once during each month in which source testing is not performed. NO_x, CO and O₂ monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH₃ monitoring shall be conducted utilizing Draeger tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless it has been performed within the last month. [District Rules 4305, 4306 and 4320]
15. {4320} If the NO_x, CO or NH₃ concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4320]
16. {4321} All NO_x, CO, O₂ and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NO_x, CO and O₂ analyzer as well as the NH₃ emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]
17. {4322} Ammonia emission readings shall be conducted at the time the NO_x, CO and O₂ readings are taken. The readings shall be converted to ppmvd @ 3% O₂. [District Rules 4305, 4306 and 4320]
18. {4323} The permittee shall maintain records of: (1) the date and time of NO_x, CO, NH₃ and O₂ measurements, (2) the O₂ concentration in percent by volume and the measured NO_x, CO and NH₃ concentrations corrected to 3% O₂, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH₃ emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 4305, 4306 and 4320]
19. Source testing to measure natural gas combustion NO_x, CO, and NH₃ emissions from this unit shall be conducted within 60 days of initial start-up. [District Rules 4305, 4306, and 4320]
20. Source testing to measure natural gas combustion NO_x, CO, and NH₃ emissions from this unit shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests when unit is fired on natural gas, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

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21. {4350} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]
22. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
23. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
24. {4346} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320]
25. {4347} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306, and 4320]
26. {4348} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]
27. Source testing for ammonia slip shall be conducted utilizing BAAQMD method ST-1B. [District Rule 1081]
28. {4351} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 4305, 4306, and 4320]
29. {4352} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]
30. Daily and annual records of the total duration of startup and shutdown time (in hours) shall be kept. [District Rules 2201, 4305, 4306, and 4320]
31. Permittee shall maintain records of the amount of fuel combusted during each calendar month in this unit. [District Rule 2201 and 40 CFR 60.48 (c)(g)]
32. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320, and 40 CFR 60.48c(i)]

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AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT

PERMIT NO: S-10254-2-0

LEGAL OWNER OR OPERATOR: CALIFORNIA DAIRIES, INC.

MAILING ADDRESS: 2000 N PLAZA DR
VISALIA, CA 93291

LOCATION: 8801 GOSFORD RD
BAKERSFIELD, CA 93313

EQUIPMENT DESCRIPTION:

50.4 MMBTU/HR CLEAVER BROOKS MODEL CBEX-2W-700-1200-150ST NATURAL GAS FIRED BOILER WITH A LOW NOX BURNER, A SELECTIVE CATALYST REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AND FLUE GAS RECIRCULATION (FGR) (BOILER #2)

CONDITIONS

1. {1407} 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. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {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]
6. The unit shall only be fired on PUC-quality natural gas. [District Rules 2201, 4305, 4306, 4320, and 4801]
7. {4356} Permittee shall determine sulfur content of combusted gas annually or shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320]
8. The total duration of startup and shutdown time shall not exceed any of the following limits: 2.0 hours per day or 730 hours per year. [District Rules 2201, 4305, 4306, and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

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Samir Sheikh, Executive Director / APCO

Brian Clements, Director of Permit Services

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9. During startup and shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rule 2201, 4305, 4306 and 4320]
10. Except during start-up and shutdown, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 2.5 ppmv NO_x @ 3% O₂ or 0.003 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]
11. During startup and shutdown periods, emissions from natural gas combustion from this unit shall not exceed any of the following limits: 30 ppmv NO_x @ 3% O₂ or 0.0364 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% O₂ or 0.03695 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]
12. NH₃ emissions from the SCR system shall not exceed 10 ppmvd @ 3% O₂. [District Rule 2201]
13. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rule 2201 and 40 CFR 60.48 (c)(g)]
14. {4319} The permittee shall monitor and record the stack concentration of NO_x, CO, NH₃ and O₂ at least once during each month in which source testing is not performed. NO_x, CO and O₂ monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH₃ monitoring shall be conducted utilizing Draeger tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless it has been performed within the last month. [District Rules 4305, 4306 and 4320]
15. {4320} If the NO_x, CO or NH₃ concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4320]
16. {4321} All NO_x, CO, O₂ and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NO_x, CO and O₂ analyzer as well as the NH₃ emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]
17. {4322} Ammonia emission readings shall be conducted at the time the NO_x, CO and O₂ readings are taken. The readings shall be converted to ppmvd @ 3% O₂. [District Rules 4305, 4306 and 4320]
18. {4323} The permittee shall maintain records of: (1) the date and time of NO_x, CO, NH₃ and O₂ measurements, (2) the O₂ concentration in percent by volume and the measured NO_x, CO and NH₃ concentrations corrected to 3% O₂, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH₃ emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 4305, 4306 and 4320]
19. Source testing to measure natural gas combustion NO_x, CO, and NH₃ emissions from this unit shall be conducted within 60 days of initial start-up. [District Rules 4305, 4306, and 4320]
20. Source testing to measure natural gas combustion NO_x, CO, and NH₃ emissions from this unit shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests when unit is fired on natural gas, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

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CONDITIONS CONTINUE ON NEXT PAGE

21. {4350} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]
22. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
23. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
24. {4346} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320]
25. {4347} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306, and 4320]
26. {4348} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]
27. Source testing for ammonia slip shall be conducted utilizing BAAQMD method ST-1B. [District Rule 1081]
28. {4351} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 4305, 4306, and 4320]
29. {4352} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]
30. Daily and annual records of the total duration of startup and shutdown time (in hours) shall be kept. [District Rules 2201, 4305, 4306, and 4320]
31. Permittee shall maintain records of the amount of fuel combusted during each calendar month in this unit. [District Rule 2201 and 40 CFR 60.48 (c)(g)]
32. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320, and 40 CFR 60.48c(i)]

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AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT

PERMIT NO: S-10254-3-0

LEGAL OWNER OR OPERATOR: CALIFORNIA DAIRIES, INC.

MAILING ADDRESS: 2000 N PLAZA DR
VISALIA, CA 93291

LOCATION: 8801 GOSFORD RD
BAKERSFIELD, CA 93313

EQUIPMENT DESCRIPTION:

ANAEROBIC DIGESTER SYSTEM CONSISTING OF AN ABOVEGROUND EMG MODEL PUREFFLUENT ANAEROBIC FLUIDIZED BED DIGESTER (AFBD) STEEL VESSEL WITH A CHEMICAL PRODUCTS INDUSTRIES MODEL SULFURTRAP ST1 H₂S SULFUR REMOVAL SYSTEM (TWO VESSELS IN SERIES), A DIGESTER GAS COLLECTION TANK, AND A 3.79 MMBTU/HR LSC ENVIRONMENTAL PRODUCTS MODEL CF-5 DIGESTER GAS-FIRED OPEN FLARE

CONDITIONS

1. {1407} 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. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. {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]
5. Emissions from the combustion of digester gas from this flare shall not exceed any of the following limits: 0.06 lb-NO_x/MMBtu, 0.0241 lb-SO_x/MMBtu, 0.02429 lb-PM₁₀/MMBtu, 0.168 lb-CO/MMBtu, or 0.0021 lb-VOC/MMBtu. [District Rule 2201]
6. Only treated digester gas shall be combusted in the flare. [District Rules 2201 and 4801]
7. Maximum sulfur content of the treated digester gas combusted in the flare shall not exceed 100 ppmv as H₂S. The permittee may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the sulfur content limit of the digester gas. [District Rules 2201 and 4801]

CONDITIONS CONTINUE ON NEXT PAGE

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Samir Sheikh, Executive Director / APCO

Brian Clements, Director of Permit Services

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8. The maximum amount of digester gas combusted in the flare shall not exceed 28,200 standard cubic feet in any one day (scf/day), equivalent to maximum daily heat input of 19.74 MMBtu/day. [District Rule 2201]
9. The flare shall be equipped with an operational, non-resettable, totalizing mass or volumetric fuel flow meter or other District-approved alternative method to measure the amount of digester gas flared. [District Rule 2201]
10. The flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311]
11. The flare outlet shall be equipped with an automatic ignition system. [District Rule 4311]
12. Flare shall use purge gas for purging. [District Rule 4311]
13. Flare shall be maintained in good operating condition and shall be operated in accordance with the design specifications as recommended by the manufacturer. [District Rule 4311]
14. Flare shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [District Rules 4101 and 4311]
15. Demonstration of compliance with the visible emissions limit of this permit shall be conducted at least once every 12 months, using EPA Method 22. The observation period shall be 2 hours. [District Rule 4311]
16. The total heating value of the gas combusted in the flare on any given day shall be calculated using the measured amount of gas combusted and the most recently determined higher heating value (HHV). [District Rule 2201]
17. The sulfur content of the treated digester gas shall be determined within 60 days of initial startup of flaring operations and at least once every 12 months thereafter. [District Rule 2201]
18. The sulfur content of the digester gas flared shall be determined using EPA Method 11 or EPA Method 15, or an alternative method upon approval by the District. [District Rule 2201]
19. The higher heating value (HHV) of the digester gas flared shall be determined at least once every calendar quarter in which digester gas is flared. [District Rule 2201]
20. The higher heating value (HHV) of the digester gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method as approved by the District. [District Rules 2201 and 4311]
21. The sulfur content of the digester gas 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 shall not be required during periods in which the flare does not operate. [District Rule 2201]
22. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H₂S; 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 portable or in-line H₂S monitors; or an alternative method approved by the District. Prior to utilization of portable or in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitor(s), including the make, model, and detection limits, to the District and obtain District approval for each proposed monitor. [District Rule 2201]
23. Permittee shall maintain the following records for each day the flare operates: 1) Total amount of digester gas combusted in the flare (in scf/day) and 2) Calculated total heating value of the digester gas combusted in the flare (in MMBtu/day). [District Rule 2201]
24. Permittee shall maintain records of the sulfur content determinations for the digester gas flared, including the dates of the determinations, determination method(s) used, and the sulfur content values determined for each date. [District Rule 2201]
25. Permittee shall maintain records of hydrogen sulfide analyzer(s) installed or utilized, including the calibration records of such analyzer(s). Records are only required on analyzer(s) utilized to demonstrate compliance with the requirements of this permit [District Rule 2201]
26. Permittee shall maintain records of higher heating value (HHV) determinations for the digester gas flared, including the dates of the determinations, determination method(s) used, and the HHV value determined for each date. [District Rule 2201]

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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]

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AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT

PERMIT NO: S-10254-4-0

LEGAL OWNER OR OPERATOR: CALIFORNIA DAIRIES, INC.

MAILING ADDRESS: 2000 N PLAZA DR
VISALIA, CA 93291

LOCATION: 8801 GOSFORD RD
BAKERSFIELD, CA 93313

EQUIPMENT DESCRIPTION:

1.996 MMBTU/HR FULTON MODEL FBS-50 DIGESTER GAS/NATURAL GAS-FIRED FIRE-TUBE BOILER WITH A LOW-NOX BURNER

CONDITIONS

1. {1407} 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. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {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]
6. The boiler shall only be fired on treated digester gas, PUC-quality natural gas, or a blend of treated digester gas and PUC-quality natural gas. [District Rules 2201, 4308, and 4801]
7. Maximum sulfur content of the treated digester gas combusted in the boiler shall not exceed 100 ppmv as H₂S. The permittee may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the sulfur content limit of the digester gas. [District Rules 2201 and 4308]
8. Emissions from the combustion of digester gas blend from this boiler shall not exceed any of the following limits: 30 ppmv NO_x @ 3% O₂ or 0.036 lb-NO_x/MMBtu; 0.0241 lb-SO_x/MMBtu; 0.0076 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% or 0.0392 lb-CO/MMBtu; or 0.0045 lb-VOC/MMBtu. [District Rules 2201 and 4308]

CONDITIONS CONTINUE ON NEXT PAGE

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Samir Sheikh, Executive Director / APCO

Brian Clements, Director of Permit Services

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9. Emissions from the combustion of natural gas from this boiler shall not exceed any of the following limits: 20 ppmv NO_x @ 3% O₂ or 0.024 lb-NO_x/MMBtu; 0.0241 lb-SO_x/MMBtu; 0.0076 lb-PM₁₀/MMBtu; 50 ppmv CO @ 3% or 0.0392 lb-CO/MMBtu; or 0.0045 lb-VOC/MMBtu. [District Rules 2201 and 4308]
10. The sulfur content of the treated digester gas shall be determined within 60 days of initial start-up and at least once every twelve (12) months thereafter. [District Rule 1081]
11. Source testing to measure NO_x and CO emissions from this unit while fired on digester gas blend and while fired on PUC quality natural gas shall be conducted within 120 days of initial start-up. [District Rule 1081]
12. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rule 1081]
13. Sampling facilities shall be provided to allow for fuel gas sampling at inlet to the boiler. [District Rule 1081]
14. The sulfur content of the digester gas shall be determined using EPA Method 11 or EPA Method 15, or an alternative method upon approval by the District. [District Rule 1081]
15. NO_x emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rule 1081]
16. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rule 1081]
17. Stack gas oxygen (O₂) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rule 1081]
18. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rule 1081]
19. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
20. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
21. Source testing shall be District witnessed or authorized and conducted by an ARB certified testing contractor. [District Rule 1081]
22. The sulfur content of the digester gas 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 shall not be required during periods in which the boiler does not operate. [District Rule 2201]
23. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H₂S; 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 portable or in-line H₂S monitors; or an alternative method approved by the District. Prior to utilization of portable or in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitor(s), including the make, model, and detection limits, to the District and obtain District approval for each proposed monitor. [District Rule 2201]
24. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. Records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

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San Joaquin Valley Air Pollution Control District

Risk Management Review and Ambient Air Quality Analysis

To: Sajjad Ahmad – Permit Services

From: Will Worthley – Technical Services

Date: July 02, 2024

Facility Name: CALIFORNIA DAIRIES, INC.

Location: 8801 GOSFORD RD, BAKERSFIELD

Application #(s): S-10254-1-0, -2-0, -3-0, -4-0

Project #: S-1242862

1. Summary

1.1 Risk Management Review (RMR)

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
1-0	1.32	0.00	0.00	6.72E-08	No	Yes
2-0	1.32	0.00	0.00	6.58E-08	No	Yes
3-0	0.17	0.00	0.00	1.14E-08	No	Yes
4-0	0.41	0.04	0.01	1.15E-08	No	Yes
Project Totals	3.22	0.04	0.01	1.56E-07		
Facility Totals	<1	0.04	0.01	1.56E-07		

1.2 Ambient Air Quality Analysis (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 ³
PM2.5				Pass ⁴	Pass ⁴

Notes:

- Results were taken from the attached AAQA Report.
- The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2) unless otherwise noted below.
- 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.
- 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.

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

Unit # 1-0, 2-0, 3-0, & 4-0

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

2. Project Description

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

- Unit -1-0: 50.4 MMBTU/HR CLEAVER BROOKS MODEL CBEX-2W-700-1200-150ST NATURAL GAS FIRED BOILER WITH A LOW NOX BURNER, A SELECTIVE CATALYST REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AND FLUE GAS RECIRCULATION (FGR) (BOILER #1)
- Unit -2-0: 50.4 MMBTU/HR CLEAVER BROOKS MODEL CBEX-2W-700-1200-150ST NATURAL GAS FIRED BOILER WITH A LOW NOX BURNER, A SELECTIVE CATALYST REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AND FLUE GAS RECIRCULATION (FGR) (BOILER #2)
- Unit -3-0: ANAEROBIC DIGESTER SYSTEM WITH 3.79 MMBTU/HR DIGESTER GAS-FIRED FLARE
- Unit -4-0: 1.996 MMBTU/HR FULTON MODEL FBS-50 DIGESTER GAS/NATURAL GAS-FIRED BOILER WITH A LOW-NOX BURNER AND A FLUE GAS RECIRCULATION (FGR) 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 units', 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 a 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 units that exceed a cancer risk of one in a million, Toxic Best Available Control Technology (TBACT) must be implemented.

Air toxics emissions for this project were calculated using the following methods:

- Dairy biogas process rates for the proposed operation were provided by the Permit Engineer. These process rates were speciated into air toxics using emission factors derived from the 2009 report, Dairy Biomethane characterization in Pipeline Quality Biomethane: North American Guidance Document for Introduction of Dairy Waste Derived Biomethane Into Existing Natural Gas Networks.
- Natural gas usage rates for the proposed operation were provided by the Permit Engineer. These usage rates were speciated into air toxics using emission factors derived from the table, "Natural Gas Fired External Combustion Equipment", in the 2001 report, Ventura County Air Pollution Control District AB 2588 Combustion Emission Factors.

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 2018-2022 from Bakersfield (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	NG Usage	MMscf	0.05	441.5
2	1	NG Usage	MMscf	0.05	441.5
3	1	DG Usage	MMscf	0.001	10.29
4	1	DG/NG Usage	MMscf	0.003	25.02

:

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 NO₂ 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	Bakersfield-Muni	Kern	Bakersfield	2022
NOx	Bakersfield-California	Kern	Bakersfield	2022
PM10	Bakersfield-California	Kern	Bakersfield	2022
PM2.5	Bakersfield-California	Kern	Bakersfield	2022
SOx	Fresno - Garland	Fresno	Fresno	2022

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	1.84	0.14	1.86	0.15	0.15
2	1	1.84	0.14	1.86	0.15	0.15
3	1	0.23	0.09	0.64	0.09	0.09
4	1	0.08	0.05	0.08	0.02	0.02

Emission Rates (lbs/year)						
Unit ID	Process	NOx	SOx	CO	PM10	PM2.5
1	1	1,258	1,258	16,314	1,325	1,325
2	1	1,258	1,258	16,314	1,325	1,325
3	1	174	174	1,210	175	175
4	1	422	422	686	133	133

The AERMOD model was used to determine if emissions from the project would cause or contribute to an exceedance of any state or federal air quality standard. The parameters outlined below and meteorological data for 2018-2022 from Bakersfield (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	NG Boiler	9.14	500	14.61	0.81	Vertical
2	NG Boiler	9.14	500	14.61	0.81	Vertical
3	DG Flare	6.10	922	1.31	0.20	Vertical
4	DG/NG Boiler	10.64	422	4.98	0.36	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

RMR REQUEST Form

Please send this request to: HRAModeler@valleyair.org

Facility Name:	California Dairies, Inc.	Processing Engineer:	Sajjad Ahmad
Mailing Address:	2000 N Plaza Dr Visalia, CA	Tec Svces Processing Staff:	
Location:	8801 Gosford Rd Bakersfield, CA	Tec Svces Reviewer:	
Contact Name:	Carlo Jo, York Engineering		
Telephone:	(559) 365-8099		
Application #:	S-10254-1-0 thru -5-0	Completed Date:	
Project #:	S-1242862		

Information Required

Please check which information is provided to Tec. Services:

Information ALWAYS Required	Additional Info Required Based on the Source Category
	<i>Oil Facilities / Glass Plant/ Power Plant</i>
	<i>Plasma Cutting / Soil Remediation / Concrete Batch</i>
☒ Receptor Distances	☒ Stack Velocity
☒ Process Rates (hour & annual)	☒ Stack Height
☒ Emission Rates (hour & annual)	☒ Stack temperature
☒ Hours of Operation	☐ MSDS
Life of Project:	☒ Other (for area sources)

Source of Information

Please check which form is attached to this HRA request (it can be a combination of any of the following):

☒ Supplemental Application Form
☒ HRA Request - Project Information Form
☒ Information supplied by the applicant (attached)

Notification Requirement

Is it obvious that notification is required?	NSR (Public Notice)	Yes: ☒	No: ☐
	COC (EPA Notice)	Yes: ☐	No: ☒
	School Notice	Yes: ☐	No: ☒

Please note that in case notification is required, please provide distance to fence line in all four directions. Include hourly and annual emissions of VOC, NOx, SOx, CO, PM10, and PM2.5

Prevention of Significant Deterioration (PSD)

AQE:

1. Based on the prelim review, is the Project subject to PSD for other pollutant than GHG? Yes: ☐ No: ☒
2. Is the facility a PSD Major Source located within 10 km of a Class I area? Yes: ☐ No: ☒

If either "Yes" box is checked, please provide all modeling and impact analyses submitted by the applicant to Technical Services. In this case, the project cannot be deemed complete until Technical Services indicates it is complete.

Tec Svces:

PSD Major Source located within 10 km of a Class I area AND project impact $\geq 1 \mu\text{g}/\text{m}^3$? Yes: ☐ No: ☐

Supervisor Review: Application Complete for PSD Modeling ☐ Date Returned to AQE: _____.

Reimbursable Overtime

Has the applicant requested reimbursable overtime processing?

Yes: ☒ No: ☐

If YES, please send HRA request to Tech Services before deeming complete

Supervisor's signature: _____

Comments and References:

Project requires a 30-day public notice due to CO emissions SSIPE > 20,000 lb/year, so AAQA needs to be done. Please see attached map with facility boundaries and boilers stack location.

3.79 MMBtu/hr Flare will be limited on daily fuel usage not to exceed 28,200 scf/day (equivalent to 19.74 MMBtu/day based on digester gas HHV of 700 Btu/scf).

For digester gas upgrade system with sulfur removal (ATC -4-0) and small 1.999 MMBtu/hr digester gas fired boiler (ATC -5-0), the facility has not provided stack parameters yet. I have asked them to provide this information and will forward as soon as it is available.

RMR REQUEST

PROJECT INFORMATION Form

I. Project Description: Install a new milk processing facility, consisting of two 50.4 MMBtu/hr natural gas-fired boilers (ATCs S-10254-1-0 and '-2-0), an anaerobic digester system with a 3.79 MMBtu/hr digester gas-fired flare (ATC '-3-0), a digester gas upgrade system with a sulfur removal system (ATC '-4-0), and a 1.999 MMBtu/hr digester gas/natural gas-fired boiler (ATC '-5-0).

The primary purpose of the proposed anaerobic digester system is to treat the waste water before release from the facility. As proposed, the digester system will be self-supporting system. The system is designed so that the digester gas generated will be sent to the digester gas boiler to maintain optimal temperature for the digester vessel, with excess digester gas, if any, be sent to the flare. Flare will only be used in the summer months when boiler will not be needed to heat the digester vessel.

II Receptor Location(s)

Please see attached facility site map and supplemental application forms.

Receptor Description	Distance From Source
Residence	3,950 feet Northwest
Business	375 feet North

III. Process Rate to be Modeled

Process Description	Process Rates	
	Hourly Rate	Annual Rate

IV. Emission Rate or Substances to be Modeled

Potential to Emit to be modeled (lb/hr)									
Permit		NO _x	SO _x	PM ₁₀	*PM _{2.5}	CO	VOC	NH ₃	H ₂ S
-1-0 (50.4 MMBtu/hr NG boiler #1)	Steady state	0.153	0.144	0.151	0.151	1.862	0.277	0.226	-
	Startup/shutdown	1.835							
-2-0 (50.4 MMBtu/hr NG boiler #2)	Steady state	0.153	0.144	0.151	0.151	1.862	0.277	0.226	-
	Startup/shutdown	1.835							
-3-0 (3.79 MMBtu/hr DG fired flare)		0.227	0.091	0.092	0.092	0.637	0.008	-	-
-4-0 (sulfur treatment)		-	-	-	-	-	-	-	0.079
-5-0 (1.999 MMBtu/hr DG/NG boiler)		0.077	0.048	0.015	0.015	0.078	0.009	-	-

Potential to Emit to be modeled (lb/year)									
Permit		NO _x	SO _x	PM ₁₀	*PM _{2.5}	CO	VOC	NH ₃	H ₂ S
-1-0 (50.4 MMBtu/hr NG boiler #1)	Steady state	1,230	1,258	1,325	1,325	16,314	2,428	1,982	-
	Startup/shutdown	1,339							
-2-0 (50.4 MMBtu/hr NG boiler #2)	Steady state	1,230	1,258	1,325	1,325	16,314	2,428	1,982	-
	Startup/shutdown	1,339							
-3-0 (3.79 MMBtu/hr DG fired flare)		432	174	175	175	1,210	15	-	-
-4-0 (sulfur treatment)		-	-	-	-	-	-	-	690
-5-0 (1.999 MMBtu/hr DG/NG boiler)		676	422	133	133	686	79	-	-

*For projects triggering AAQA

V. Project Location (*Select One*)

- ☒ Urban – Area of dense population
☐ Rural – Area of sparse population

VI. Point Sources

Stack Parameters:

ATC	Stack Height (Units)	Rain Cap Type	Inside Diameter (Units)	Gas Exit Flowrate (Units)	Exhaust Discharge Direction	Gas Exit Temperature (Units)
-1-0 & -2-0 (50.4 MMBtu/hr boilers identical units)	30 feet	None	32 inches	16,060 cfm	Vertically upward	440 F
-3-0 (3.79 MMBtu/hr DG fired flare)	96 inches	None	8 inches	90 cfm	Vertically upward	1,200 F
-4-0 (sulfur treatment)*						
-5-0 (1.999 MMBtu/hr DG/NG boiler)*						

*I have asked the facility to provide this information.

VII. Area Sources¹ Parameters

Release Height ² (Units)	Length Of Side (Units)

1. An area source is defined as in an area with four equal sides.
2. Release height is defined as the physical height of the source. For example, if a sump has a three meter brim surrounding it. The physical height of the sump is three meters. Height is measured from the ground to the top of the source.



Fulton Equipment Pacific LLC
5160 Fulton Drive
Fairfield, CA 94534

Heating Hot Water Process Boilers

Manufacturer:	Fulton
Model:	FBS-50
Quantity:	(1)
Tag:	HHWB-1
Design Pressure:	150 PSIG
Boiler Horsepower:	50
Heating Capacity:	1,996,000 BTUH
Operating Temp:	180°/150° Supply/Return
Fuels:	Natural Gas & Digester Gas
NO _x Performance:	Natural Gas – <20 ppm, Digester Gas - <30 ppm
CO Performance:	<50 ppm
Combustion Control:	Parallel Positioning Siemens LMV Combustion Control/VSD
Approximate Shipping Wt:	11,000 #
Normal Water Wt:	18,210 #
Electrical Service:	460/3/60
FD Fan Motor Size:	1.5 HP
Control Circuit:	120/1/60, 1 KVA through step-down transformer
Dimensions:	262" OAL (with tube pull) x 152" OAW (with clearance) 165" OAH (with clearance)



San Joaquin Valley Air Pollution Control District Supplemental Application Form



Boilers, Steam Generators, Dryers, and Process Heaters

Please complete one form for each different piece of equipment. For streamlining, make note if one form covers identical equipment.

This form must be accompanied by a completed [Authority to Construct/Permit to Operate Application form](#)

PERMIT TO BE ISSUED TO: California Dairies, Inc.
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: 8801 Gosford Road, Bakersfield, CA 93313

EQUIPMENT DESCRIPTION

Equipment Details	☒ Boiler ☐ Steam Generator ☐ Dryer ☐ Process Heater ☐ Other: _____	
	Number of Identical Units This Application Covers (if applicable): 2	
	Check all that apply: ☐ Oilfield Steam Generator ☐ Refinery Unit ☐ Wastewater Treatment Facility ☐ Fired on < 50%, by volume, PUC quality gas	
	Manufacturer: Cleaver Brooks	
	Model: CBEX-2W-700-1200-150ST	Serial Number:
	☐ Indirect-Fired ☒ Direct-Fired	
	Flue Gas Recirculation: ☐ Forced FGR ☒ Induced FGR ☐ None	
	Is an O ₂ Controller present? ☐ No ☒ Yes, Manufacturer:	
Rule 4320 Type of Use and Emissions Monitoring Provisions	☒ Full Time	
	☐ Low Use - for units installed prior to January 1, 2009 and limited to less than 1.8 billion Btu/year, must have fuel use meter	
	☐ Tune the unit at least twice per calendar year in accordance with District Rule 4304	
	☐ Operate the unit in a manner that maintains exhaust O ₂ concentration ≤ 3.00% by volume on a dry basis	
	☐ Pay Annual Fee - in lieu of complying with NO _x and CO emission limits of the Rule, pay annual fee per §5.1.2	
	Note: Low Use units must identify operational characteristics recommended by the manufacturer, which can be monitored on a monthly basis (please provide details in additional documentation).	
	Note: Full Time units must have either a Continuous Emission Monitoring System (CEMS) or one of the following alternate emissions monitoring plans	
	☐ CEMS, please specify all pollutants monitored: ☐ NO _x ☐ CO ☐ O ₂ ☐ Other: _____ ☒ Monitoring of NO _x , CO, and O ₂ concentrations ☐ Periodic determination of flue gas recirculation rate by temperature measurement ☐ Periodic determination of flue gas recirculation rate by O ₂ measurement ☐ Monitoring of burner mechanical adjustments and O ₂ concentration ☐ Monitoring of the flue gas recirculation valve(s) setting ☐ Other Alternate Monitoring Plan (approved on a case by case basis), attach details	
Note: See District policy (SSP-1105) for additional details of pre-approved alternate emissions monitoring plans, at: http://www.valleyair.org/policies_per/Policies/SSP_1105.pdf		
Fuel Use Meter	☒ Gaseous Fuel Meter ☐ Liquid Fuel Meter ☐ None	
Primary Burner	Manufacturer: Cleaver Brooks	Type: ☐ Standard ☒ Low NO _x ☐ Ultra Low NO _x
	Model: NT	Serial Number:
	Maximum Heat Input Rating: 50.4 MMBtu/hr	Annual Heat Input: _____ billion Btu/year
Secondary Burner (if more than one burner is present)	Manufacturer:	Type: ☐ Standard ☐ Low NO _x ☐ Ultra Low NO _x
	Model:	Serial Number:
	Maximum Heat Input Rating: _____ MMBtu/hr	Annual Heat Input: _____ billion Btu/year

EMISSIONS DATA

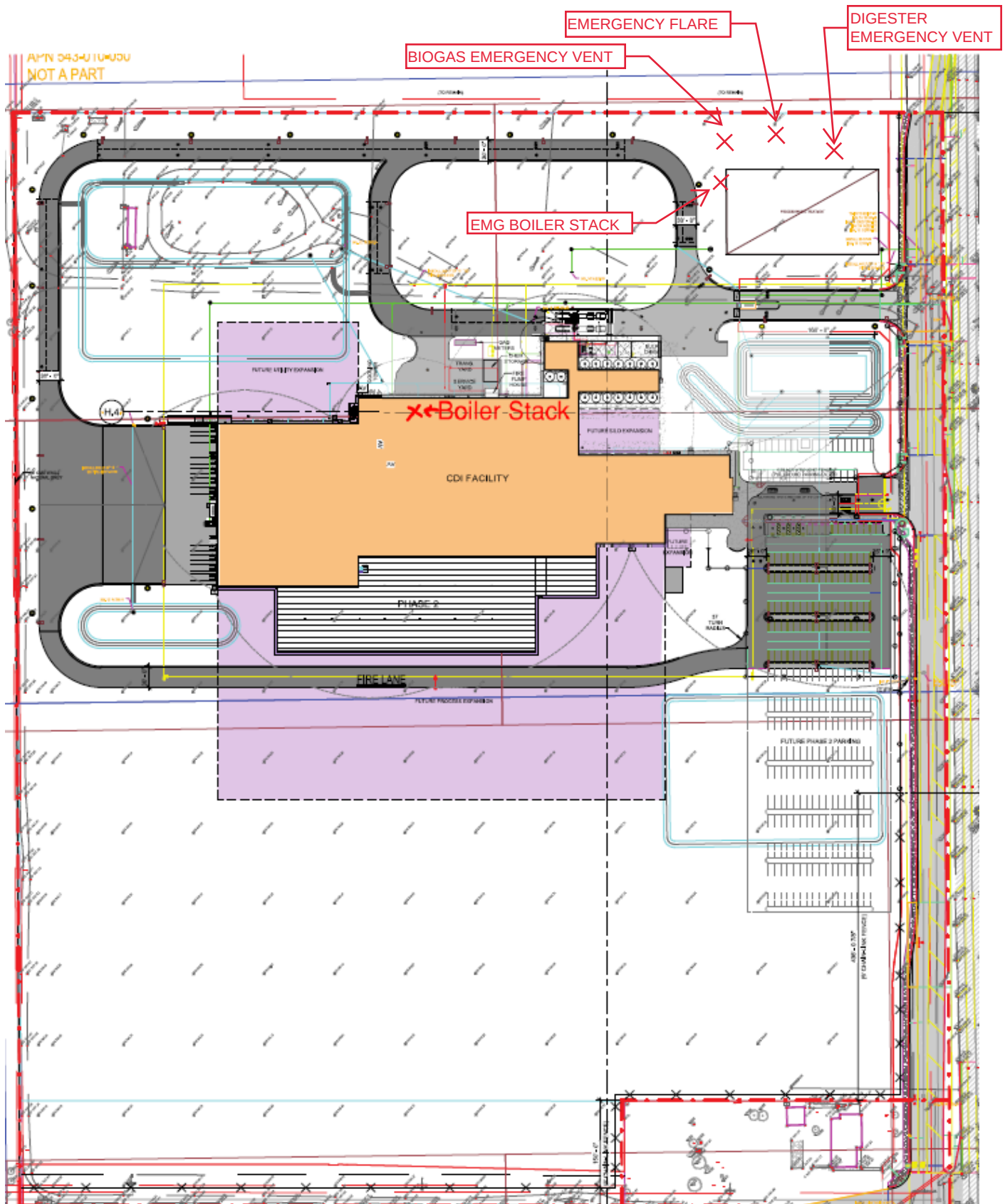
Note: See District BACT and District Rule 4320 requirements for applicability to proposed unit at <http://www.valleyair.org/busind/pto/bact/chapter1.pdf>, and <http://www.valleyair.org/rules/currntrules/r4320.pdf>.

Primary Fuel	Fuel Type: ☒ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf			Sulfur Content: _____ % by weight or _____ gr/scf		
Primary Fuel Emissions Data	Operational Mode	Steady State (ppmv) (lb/MMBtu)		Start-up (ppmv) (lb/hr)		Shutdown (ppmv) (lb/hr)
	Nitrogen Oxides	2.5	0.003	30	0.036	30 0.036
	Carbon Monoxide	50	0.037	50	0.037	50 0.037
	Volatile Organic Compounds	10	0.0055	10	0.0055	10 0.0055
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day _____ hr/yr
	% O ₂ , dry basis, if corrected to other than 3%: _____ %					
Secondary Fuel	Fuel Type: ☐ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf			Sulfur Content: _____ % by weight or _____ gr/scf		
	How will the secondary fuel be used? ☐ Secondary full-time fuel ☐ Backup for primary fuel ☐ Other: _____					
Secondary Fuel Emissions Data	Operational Mode	Steady State (ppmv) (lb/MMBtu)		Start-up (ppmv) (lb/hr)		Shutdown (ppmv) (lb/hr)
	Nitrogen Oxides					
	Carbon Monoxide					
	Volatile Organic Compounds					
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day _____ hr/yr
	% O ₂ , dry basis, if corrected to other than 3%: _____ %					
Source of Data	☒ Manufacturer's Specifications ☐ Emission Source Test ☐ Other _____ (please provide copies)					
Additional Emissions Control Equipment	☒ Selective Catalytic Reduction - Manufacturer: <u>RF MacDonald</u> Model: _____ ☒ Ammonia (NH ₃) ☐ Urea ☐ Other: _____					
	☐ Non-Selective Catalytic Reduction - Manufacturer: _____ Model: _____					
	Control Efficiencies: NO _x _____ %, SO _x _____ %, PM ₁₀ _____ %, CO _____ %, VOC _____ %					
	☐ Other (please specify): _____					

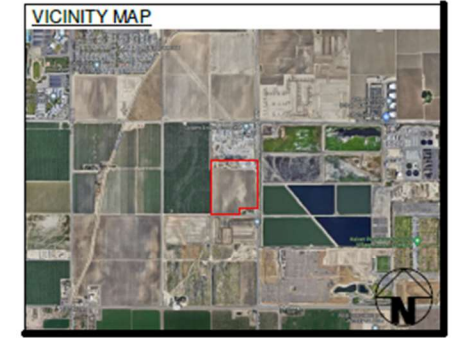
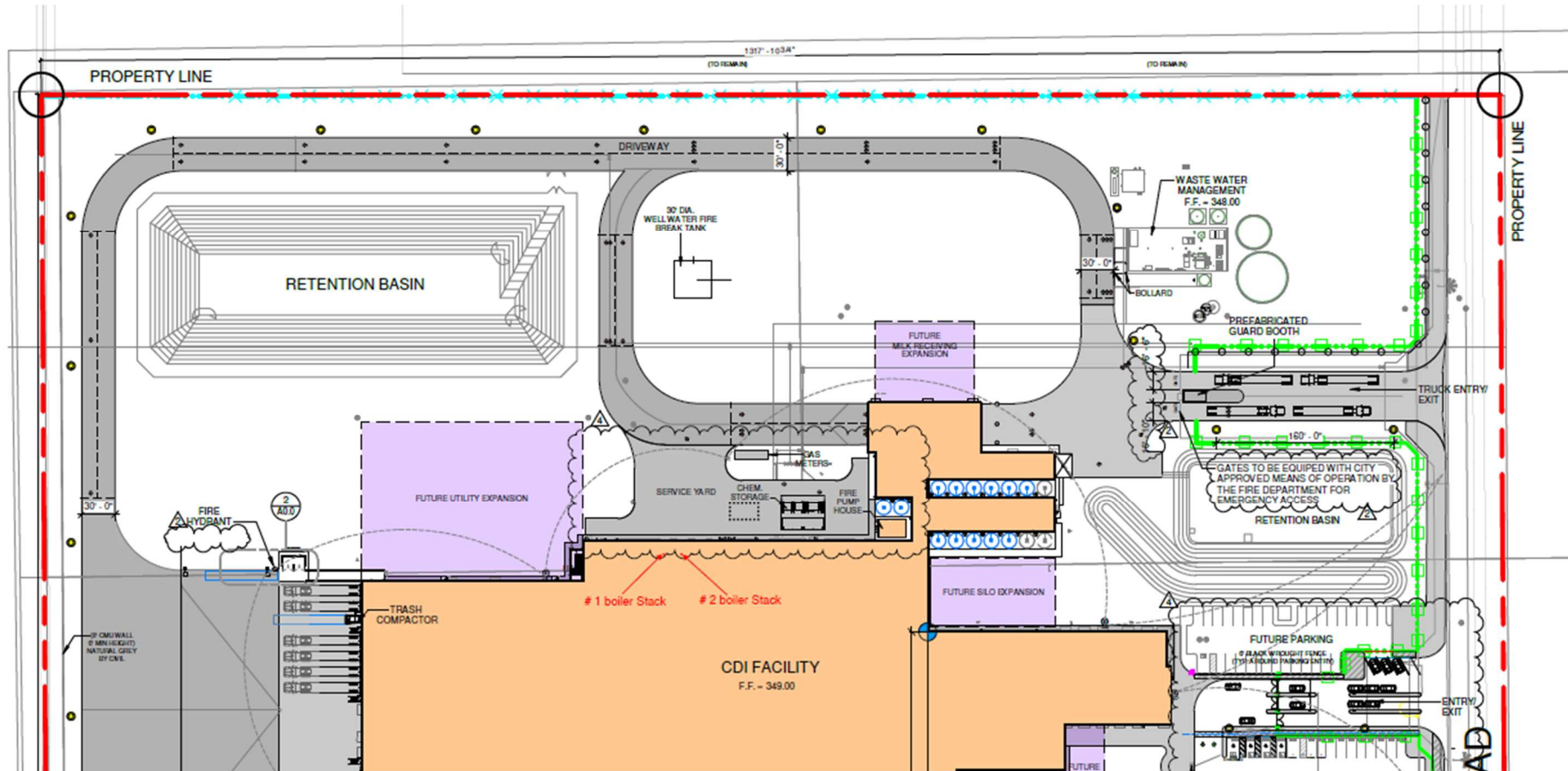
HEALTH RISK ASSESSMENT DATA

Note: See Manufacturer's Specifications for Stack Parameters and Exhaust Data. All information is required.

Operating Hours	Maximum Operating Schedule: <u>24</u> hours per day, and <u>8,760</u> hours per year		
Receptor Data	Distance to nearest Residence	<u>3,950</u> feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	<u>Northwest</u>	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	<u>375</u> feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	<u>North</u>	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	<u>30</u> feet above grade	
	Stack Diameter	<u>32</u> inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: <u>16,060</u> acfm		Temperature: <u>440</u> °F
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		
	Include a facility plot plan showing the location of the stack. Please indicate North on the plot plan. For public notice projects, indicate on plot plan the facility boundaries or fence line and distance(s) from stack to boundaries.		







PROJECT SITE INFORMATION

PROJECT ADDRESS: 8801 GOSFORD RD
BAKERSFIELD CA 93313-9753
PM 9739 LOT B
APN: 543-010-02-00-7

LAND USE DESIGNATION: ZONING: LI

SITE PROPERTY AREA: 43.790ac

NFPA SPRINKLER CODE: 13

BUILDING INFORMATION

CONSTRUCTION TYPE: IB

OCCUPANCY TYPE: E-1 S-1 B

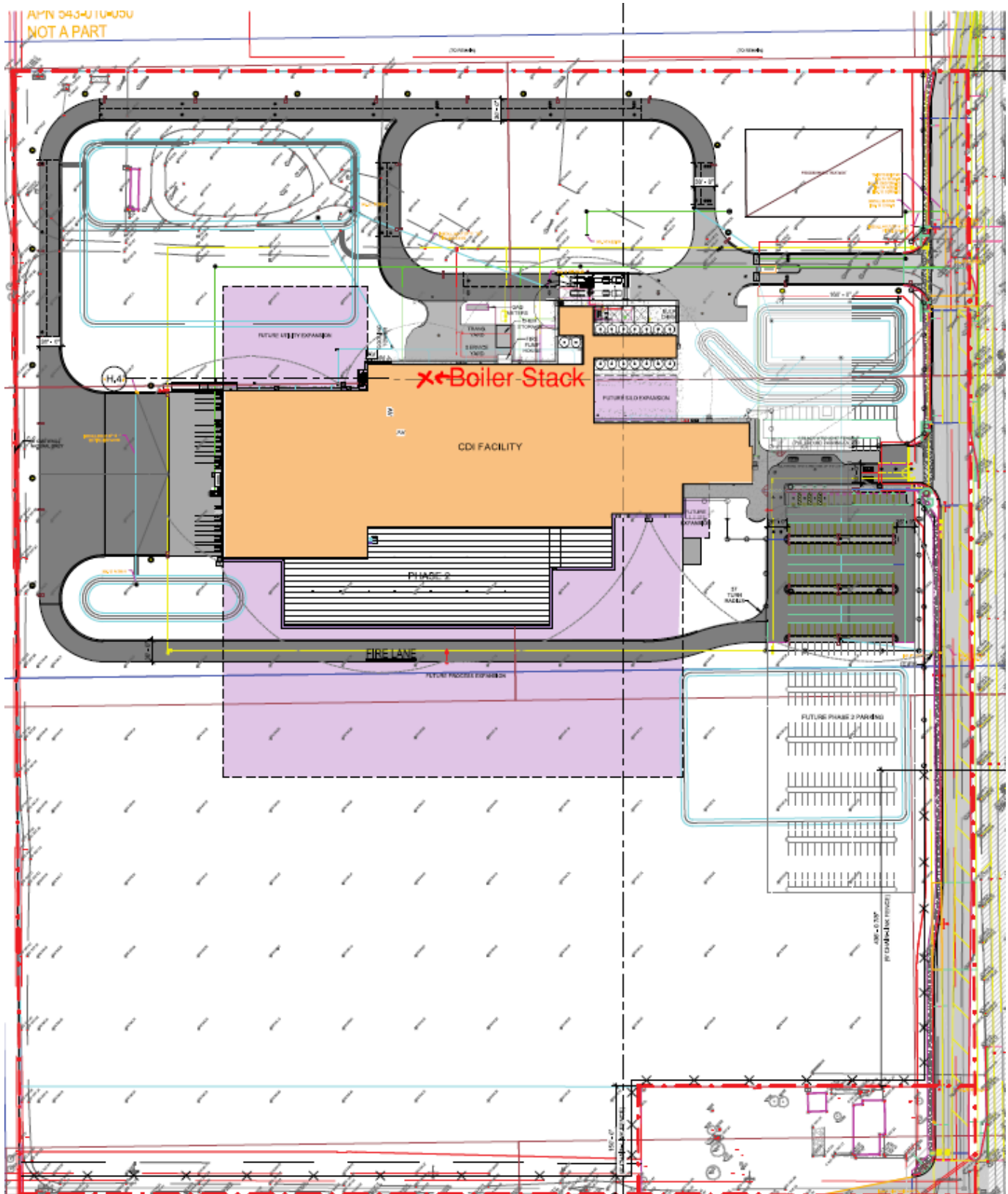
FIRE SPRINKLES: 100% COVERAGE

APPLICABLE CODE:

BAKERSFIELD MUNICIPAL CODE 2023

2022 CBC	2022 CFC	2022 CEC
2022 CFSC	2022 CGBSC	2022 CMC
2022 CPC	2022 CENG	2010 ADA Standard
2010 CCCTC	2019 CSCC	2018 CCREC

APN 043-010-000
NOT A PART







San Joaquin Valley Air Pollution Control District Supplemental Application Form



Boilers, Steam Generators, Dryers, and Process Heaters

Please complete one form for each different piece of equipment. For streamlining, make note if one form covers identical equipment.

This form must be accompanied by a completed Authority to Construct/Permit to Operate Application form

PERMIT TO BE ISSUED TO: California Dairies, Inc.
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: 8801 Gosford Road, Bakersfield, CA 93313

EQUIPMENT DESCRIPTION

Equipment Details	☒ Boiler ☐ Steam Generator ☐ Dryer ☐ Process Heater ☐ Other: _____	
	Number of Identical Units This Application Covers (if applicable): _____	
	Check all that apply: ☐ Oilfield Steam Generator ☐ Refinery Unit ☐ Wastewater Treatment Facility ☐ Fired on < 50%, by volume, PUC quality gas	
	Manufacturer: TBD	
	Model: TBD	Serial Number: _____
	☐ Indirect-Fired ☒ Direct-Fired	
	Flue Gas Recirculation: ☐ Forced FGR ☐ Induced FGR ☐ None	
	Is an O ₂ Controller present? ☐ No ☐ Yes, Manufacturer: _____	
Rule 4320 Type of Use and Emissions Monitoring Provisions	☒ Full Time	
	☐ Low Use - for units installed prior to January 1, 2009 and limited to less than 1.8 billion Btu/year, must have fuel use meter	
	☐ Tune the unit at least twice per calendar year in accordance with District Rule 4304	
	☐ Operate the unit in a manner that maintains exhaust O ₂ concentration ≤ 3.00% by volume on a dry basis	
	☐ Pay Annual Fee - in lieu of complying with NO _x and CO emission limits of the Rule, pay annual fee per §5.1.2	
	Note: Low Use units must identify operational characteristics recommended by the manufacturer, which can be monitored on a monthly basis (please provide details in additional documentation).	
	Note: Full Time units must have either a Continuous Emission Monitoring System (CEMS) or one of the following alternate emissions monitoring plans	
	☐ CEMS, please specify all pollutants monitored: ☐ NO _x ☐ CO ☐ O ₂ ☐ Other: _____ ☒ Monitoring of NO _x , CO, and O ₂ concentrations ☐ Periodic determination of flue gas recirculation rate by temperature measurement ☐ Periodic determination of flue gas recirculation rate by O ₂ measurement ☐ Monitoring of burner mechanical adjustments and O ₂ concentration ☐ Monitoring of the flue gas recirculation valve(s) setting ☐ Other Alternate Monitoring Plan (approved on a case by case basis), attach details	
Note: See District policy (SSP-1105) for additional details of pre-approved alternate emissions monitoring plans, at: http://www.valleyair.org/policies_per/Policies/SSP_1105.pdf		
Fuel Use Meter	☒ Gaseous Fuel Meter ☐ Liquid Fuel Meter ☐ None	
Primary Burner	Manufacturer: _____	Type: ☐ Standard ☒ Low NO _x ☐ Ultra Low NO _x
	Model: _____	Serial Number: _____
	Maximum Heat Input Rating: _____ 1.999 MMBtu/hr	Annual Heat Input: _____ billion Btu/year
Secondary Burner (if more than one burner is present)	Manufacturer: _____	Type: ☐ Standard ☐ Low NO _x ☐ Ultra Low NO _x
	Model: _____	Serial Number: _____
	Maximum Heat Input Rating: _____ MMBtu/hr	Annual Heat Input: _____ billion Btu/year

EMISSIONS DATA

Note: See District BACT and District Rule 4320 requirements for applicability to proposed unit at <http://www.valleyair.org/busind/pto/bact/chapter1.pdf>, and <http://www.valleyair.org/rules/curnrules/r4320.pdf>.

Primary Fuel	Fuel Type: ☒ Natural Gas ☐ LPG/Propane ☐ Diesel ☒ Other: Natural gas and digester gas blend					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf			Sulfur Content: _____ % by weight or _____ gr/scf		
Primary Fuel Emissions Data	Operational Mode	Steady State (ppmv) (lb/MMBtu)		Start-up (ppmv) (lb/hr)		Shutdown (ppmv) (lb/hr)
	Nitrogen Oxides	30	0.386			
	Carbon Monoxide	50	0.039			
	Volatile Organic Compounds	10				
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day _____ hr/yr
	% O ₂ , dry basis, if corrected to other than 3%: _____ %					
Secondary Fuel	Fuel Type: ☐ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf			Sulfur Content: _____ % by weight or _____ gr/scf		
	How will the secondary fuel be used? ☐ Secondary full-time fuel ☐ Backup for primary fuel ☐ Other: _____					
Secondary Fuel Emissions Data	Operational Mode	Steady State (ppmv) (lb/MMBtu)		Start-up (ppmv) (lb/hr)		Shutdown (ppmv) (lb/hr)
	Nitrogen Oxides					
	Carbon Monoxide					
	Volatile Organic Compounds					
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day _____ hr/yr
	% O ₂ , dry basis, if corrected to other than 3%: _____ %					
Source of Data	☐ Manufacturer's Specifications ☐ Emission Source Test ☐ Other _____ (please provide copies)					
Additional Emissions Control Equipment	☐ Selective Catalytic Reduction - Manufacturer: _____ Model: _____ ☐ Ammonia (NH ₃) ☐ Urea ☐ Other: _____					
	☐ Non-Selective Catalytic Reduction - Manufacturer: _____ Model: _____					
	Control Efficiencies: NO _x _____ %, SO _x _____ %, PM ₁₀ _____ %, CO _____ %, VOC _____ %					
	☐ Other (please specify): _____					

HEALTH RISK ASSESSMENT DATA

Note: See Manufacturer's Specifications for Stack Parameters and Exhaust Data. All information is required.

Operating Hours	Maximum Operating Schedule: <u>24</u> hours per day, and <u>8,760</u> hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	_____ feet above grade	
	Stack Diameter	_____ inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☐ None ☐ Other: _____	
	Direction of Flow	☐ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: _____ acfm	Temperature: _____ °F	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		
	Include a facility plot plan showing the location of the stack. Please indicate North on the plot plan. For public notice projects, indicate on plot plan the facility boundaries or fence line and distance(s) from stack to boundaries.		



San Joaquin Valley Air Pollution Control District Supplemental Application Form



Boilers, Steam Generators, Dryers, and Process Heaters

Please complete one form for each different piece of equipment. For streamlining, make note if one form covers identical equipment.

This form must be accompanied by a completed Authority to Construct/Permit to Operate Application form

PERMIT TO BE ISSUED TO: California Dairies, Inc.
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: 8801 Gosford Road, Bakersfield, CA 93313

EQUIPMENT DESCRIPTION

Equipment Details	☒ Boiler ☐ Steam Generator ☐ Dryer ☐ Process Heater ☐ Other: _____	
	Number of Identical Units This Application Covers (if applicable): 2	
	Check all that apply: ☐ Oilfield Steam Generator ☐ Refinery Unit ☐ Wastewater Treatment Facility ☐ Fired on < 50%, by volume, PUC quality gas	
	Manufacturer: Cleaver Brooks	
	Model: CBEX-2W-700-1200-150ST	Serial Number:
	☐ Indirect-Fired ☒ Direct-Fired	
	Flue Gas Recirculation: ☐ Forced FGR ☒ Induced FGR ☐ None	
	Is an O ₂ Controller present? ☐ No ☒ Yes, Manufacturer:	
Rule 4320 Type of Use and Emissions Monitoring Provisions	☒ Full Time ☐ Low Use - for units installed prior to January 1, 2009 and limited to less than 1.8 billion Btu/year, must have fuel use meter ☐ Tune the unit at least twice per calendar year in accordance with District Rule 4304 ☐ Operate the unit in a manner that maintains exhaust O ₂ concentration ≤ 3.00% by volume on a dry basis ☐ Pay Annual Fee - in lieu of complying with NO _x and CO emission limits of the Rule, pay annual fee per §5.1.2	
	Note: Low Use units must identify operational characteristics recommended by the manufacturer, which can be monitored on a monthly basis (please provide details in additional documentation).	
	Note: Full Time units must have either a Continuous Emission Monitoring System (CEMS) or one of the following alternate emissions monitoring plans ☐ CEMS, please specify all pollutants monitored: ☐ NO _x ☐ CO ☐ O ₂ ☐ Other: _____ ☒ Monitoring of NO _x , CO, and O ₂ concentrations ☐ Periodic determination of flue gas recirculation rate by temperature measurement ☐ Periodic determination of flue gas recirculation rate by O ₂ measurement ☐ Monitoring of burner mechanical adjustments and O ₂ concentration ☐ Monitoring of the flue gas recirculation valve(s) setting ☐ Other Alternate Monitoring Plan (approved on a case by case basis), attach details	
	Note: See District policy (SSP-1105) for additional details of pre-approved alternate emissions monitoring plans, at: http://www.valleyair.org/policies_per/Policies/SSP_1105.pdf	
	Fuel Use Meter ☒ Gaseous Fuel Meter ☐ Liquid Fuel Meter ☐ None	
	Primary Burner Manufacturer: Cleaver Brooks Type: ☐ Standard ☒ Low NO _x ☐ Ultra Low NO _x Model: NT Serial Number: Maximum Heat Input Rating: 50.4 MMBtu/hr Annual Heat Input: _____ billion Btu/year	
	Secondary Burner (if more than one burner is present) Manufacturer: _____ Type: ☐ Standard ☐ Low NO _x ☐ Ultra Low NO _x Model: _____ Serial Number: Maximum Heat Input Rating: _____ MMBtu/hr Annual Heat Input: _____ billion Btu/year	

EMISSIONS DATA

Note: See District BACT and District Rule 4320 requirements for applicability to proposed unit at <http://www.valleyair.org/busind/pto/bact/chapter1.pdf>, and <http://www.valleyair.org/rules/curmtrules/r4320.pdf>.

Primary Fuel	Fuel Type: ☒ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf			Sulfur Content: _____ % by weight or _____ gr/scf		
Primary Fuel Emissions Data	Operational Mode	Steady State (ppmv) (lb/MMBtu)		Start-up (ppmv) (lb/hr)		Shutdown (ppmv) (lb/hr)
	Nitrogen Oxides	2.5	0.003	30	0.036	30 0.036
	Carbon Monoxide	50	0.037	50	0.037	50 0.037
	Volatile Organic Compounds	10	0.0055	10	0.0055	10 0.0055
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day _____ hr/yr
	% O ₂ , dry basis, if corrected to other than 3%: _____ %					
Secondary Fuel	Fuel Type: ☐ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf			Sulfur Content: _____ % by weight or _____ gr/scf		
	How will the secondary fuel be used? ☐ Secondary full-time fuel ☐ Backup for primary fuel ☐ Other: _____					
Secondary Fuel Emissions Data	Operational Mode	Steady State (ppmv) (lb/MMBtu)		Start-up (ppmv) (lb/hr)		Shutdown (ppmv) (lb/hr)
	Nitrogen Oxides					
	Carbon Monoxide					
	Volatile Organic Compounds					
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day _____ hr/yr
	% O ₂ , dry basis, if corrected to other than 3%: _____ %					
Source of Data	☒ Manufacturer's Specifications ☐ Emission Source Test ☐ Other _____ (please provide copies)					
Additional Emissions Control Equipment	☒ Selective Catalytic Reduction - Manufacturer: <u>RF MacDonald</u> Model: _____ ☒ Ammonia (NH ₃) ☐ Urea ☐ Other: _____					
	☐ Non-Selective Catalytic Reduction - Manufacturer: _____ Model: _____ Control Efficiencies: NO _x _____ %, SO _x _____ %, PM ₁₀ _____ %, CO _____ %, VOC _____ %					
	☐ Other (please specify): _____					

HEALTH RISK ASSESSMENT DATA

Note: See Manufacturer's Specifications for Stack Parameters and Exhaust Data. All information is required.

Operating Hours	Maximum Operating Schedule: <u>24</u> hours per day, and <u>8,760</u> hours per year		
Receptor Data	Distance to nearest Residence	<u>3,950</u> feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	<u>Northwest</u>	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	<u>375</u> feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	<u>North</u>	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	<u>30</u> feet above grade	
	Stack Diameter	<u>32</u> inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☐ None ☒ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: <u>16,060</u> acfm	Temperature: <u>440</u> °F	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		
	Include a facility plot plan showing the location of the stack. Please indicate North on the plot plan. For public notice projects, indicate on plot plan the facility boundaries or fence line and distance(s) from stack to boundaries.		



San Joaquin Valley Unified Air Pollution Control District Supplemental Application Form



Flares

Please complete one form for each flare.

This form must be accompanied by a completed Authority to Construct/Permit to Operate Application form

PERMIT TO BE ISSUED TO: California Dairies, Inc.
FLARE LOCATION (STREET ADDRESS or ¼ SECTION, TOWNSHIP, & RANGE or LAT/LONG): 8801 Gosford Road, Bakersfield, CA 93313

PROCESS DESCRIPTION

Process Data	Gas Streams/Processes the Flare Serves (include permit number(s), if applicable): Digester gas/biogas	
	Is the flare gas pressure $\geq$ 5 psig? ☐ Yes ☒ No	
	Maximum Potential Flare Gas Flowrate: _____ acf/hr, <u>28,200</u> scf/day, _____ acf/year	
	Is this a municipal landfill flare? ☐ Yes ☒ No	Is this an emergency flare? ☐ Yes ☒ No

EQUIPMENT DESCRIPTION

Tip Data	Tip Manufacturer: LSC Environmental Products	Tip Model: CF-5
	Serial No.:	Tip Manufacturer's rated capacity: _____ (MMcf/hr)
	Tip Opening Cross Sectional Area: _____ (ft ²)	
Flare Design and Emission Control Equipment	☐ Air-assist flare, _____ scfm of assist air	
	☐ Steam assist flare, _____ lb/min of assist steam	
	☐ Coanda effect flare	
	☒ Other type of flare (please provide details): Enclosed flare	
	Smokeless Operation? ☐ Yes ☐ No, Source: _____	
Flare Emissions Data	NO _x Emission Factor: <u>0.06</u> (lb/MMBtu)	
	PM ₁₀ Emission Factor: <u>0.2429</u> (lb/MMBtu)	
	CO Emission Factor: <u>0.168</u> (lb/MMBtu)	
	VOC Emission Factor: <u>0.0021</u> (lb/MMBtu)	
	VOC destruction efficiency: _____ %	
Source of Data	☒ Manufacturer's Specifications ☐ Emissions Source Test ☐ AP-42	
	☐ Other _____ Note: please provide copies of all sources of emissions data.	

FLARED GAS DATA

Flared Gas Data	Fuel Type: Digester gas/biogas
	Flare Gas Fuel Flow Meter? ☒ Yes ☐ No

	Higher Heating Value: <u>700</u> Btu/scf	Sulfur Content: _____ gr/100 scf
	Carbon to Hydrogen ratio:	
	Percent weight of hydrocarbons heavier than pentane (please attach gas analysis):	

PILOT EQUIPMENT AND FUEL DATA

Pilot Type	Intermittent ☐	Continuous ☐	Automatic (Flow Sensing) Ignition System ☒	Heat Sensing Ignition System ☐
Pilot Fuel Data	Type of pilot gas fuel (e.g., LPG/propane, methane, or process gas stream): N/A			
	Pilot Fuel Consumption: _____ (scf/hr)		Sulfur Content: _____ gr/100 scf	
	Pilot Gas Fuel Flow Meter: ☐ Yes ☐ No			

GAS SULFUR TREATMENT (if applicable)

Sulfur Treatment System	Type of system (submit manufacturer's documentation): Sulfurtrap media scrubber
	Control Efficiency: <u>>99%</u> %, Source: Manufacturer's Specifications
	Outlet sulfur concentration: _____ ppmw or gr-S/100 scf, Source:

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: _____ hours per day, and _____ hours per year		
Receptor Data	Distance to nearest _____ feet	Distance is measured from the proposed flare location to the nearest property line of the nearest apartment, house, dormitory, etc.	
	Direction to nearest _____	Direction from the flare to the receptor, i.e. Northeast or South.	
	Distance to nearest Business _____ feet	Distance is measured from the proposed flare location to the nearest property line of the nearest office building, factory, store, etc.	
	Direction to nearest Business _____	Direction from the flare to the receptor, i.e. North or Southwest.	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		
Select the Appropriate Flare Type and Fill Out the Required Modeling Parameters			
Flare Type	☐ Open Flare ¹	☐ Partially Enclosed Flare ²	☒ Enclosed Flare ³
Flare Tip Height	_____ feet above grade	_____ feet above grade	<u>N/A</u>
Enclosure Height	<u>N/A</u>	_____ feet above grade	_____ feet above grade
Velocity	<u>N/A</u>	Flowrate: _____ acfm	Flowrate: <u>90</u> acfm
Diameter	_____ inches at flare tip	_____ inches at flare tip	<u>8</u> inches at enclosure opening
Temperature	_____ °F	_____ °F	<u>900-1200</u> °F

¹A vertically or horizontally oriented open pipe flare from which gases are released into the air before combustion is commenced.

²A flare composed of gas burner(s) within an enclosure such that the flame is visible beyond the end of the enclosure when active.

³A flare composed of gas burner(s) within an enclosure such that the flame is **not** visible beyond the end of the enclosure when active.

Prioritization Score For California Dairies Inc Project : S1242862

Device ID 1	Device Name NG Boiler	Emissions and Potency Method					Dispersion Adjustment Method		
Process ID : 1									
CAS#	Pollutant Name	Lbs / Hour	Lbs / Year	Cancer	Chronic	Acute	Cancer	Chronic	Acute
1151	PAHs, total, w/o individ. components reported [T	5.04E-06	4.42E-02	0.374			0.37		
50000	Formaldehyde	6.20E-04	5.43E+00	0.251	0.010	0.017	0.25	0.01	0.02
71432	Benzene	2.92E-04	2.56E+00	0.572	0.015	0.016	0.57	0.01	0.02
75070	Acetaldehyde	1.56E-04	1.37E+00	0.028	0.000	0.000	0.03	0.00	0.00
91203	Naphthalene	1.51E-05	1.32E-01	0.035	0.000		0.03	0.00	
100414	Ethyl benzene	3.48E-04	3.05E+00	0.059	0.000		0.06	0.00	
107028	Acrolein	1.36E-04	1.19E+00		0.058	0.082		0.06	0.08
108883	Toluene	1.34E-03	1.17E+01		0.000	0.000		0.00	0.00
110543	Hexane	2.32E-04	2.03E+00		0.000			0.00	
115071	Propylene	2.67E-02	2.34E+02		0.001			0.00	
1330207	Xylenes (mixed)	9.93E-04	8.70E+00		0.000	0.000		0.00	0.00
Prioritization Score for Process 1				1.32E+00	8.60E-02	1.16E-01	1.32E+00	8.60E-02	1.16E-01
Prioritization Score for Device 1				1.32E+00	8.60E-02	1.16E-01	1.32E+00	8.60E-02	1.16E-01
Device ID 2	Device Name NG Boiler	Emissions and Potency Method					Dispersion Adjustment Method		
Process ID : 1									
CAS#	Pollutant Name	Lbs / Hour	Lbs / Year	Cancer	Chronic	Acute	Cancer	Chronic	Acute
1151	PAHs, total, w/o individ. components reported [T	5.04E-06	4.42E-02	0.374			0.37		
50000	Formaldehyde	6.20E-04	5.43E+00	0.251	0.010	0.017	0.25	0.01	0.02
71432	Benzene	2.92E-04	2.56E+00	0.572	0.015	0.016	0.57	0.01	0.02
75070	Acetaldehyde	1.56E-04	1.37E+00	0.028	0.000	0.000	0.03	0.00	0.00
91203	Naphthalene	1.51E-05	1.32E-01	0.035	0.000		0.03	0.00	

Prioritization Score For California Dairies Inc Project : S1242862

Device ID 2	Device Name NG Boiler	Emissions and Potency Method					Dispersion Adjustment Method		
100414	Ethyl benzene	3.48E-04	3.05E+00	0.059	0.000		0.06	0.00	
107028	Acrolein	1.36E-04	1.19E+00		0.058	0.082		0.06	0.08
108883	Toluene	1.34E-03	1.17E+01		0.000	0.000		0.00	0.00
110543	Hexane	2.32E-04	2.03E+00		0.000			0.00	
115071	Propylene	2.67E-02	2.34E+02		0.001			0.00	
1330207	Xylenes (mixed)	9.93E-04	8.70E+00		0.000	0.000		0.00	0.00
Prioritization Score for Process 1				1.32E+00	8.60E-02	1.16E-01	1.32E+00	8.60E-02	1.16E-01
Prioritization Score for Device 2				1.32E+00	8.60E-02	1.16E-01	1.32E+00	8.60E-02	1.16E-01

Device ID 3	Device Name DG Flare	Emissions and Potency Method					Dispersion Adjustment Method		
Process ID : 1									
CAS#	Pollutant Name	Lbs / Hour	Lbs / Year	Cancer	Chronic	Acute	Cancer	Chronic	Acute
56235	Carbon tetrachloride	5.72E-07	5.01E-03	0.002	0.000	0.000	0.00	0.00	0.00
71432	Benzene	6.34E-06	5.56E-02	0.012	0.000	0.000	0.01	0.00	0.00
84742	Dibutyl phthalate	8.01E-07	7.02E-03						
91203	Naphthalene	4.57E-07	4.01E-03	0.001	0.000		0.00	0.00	
95636	1,2,4-Trimethylbenzene	2.56E-07	2.24E-03		0.000	0.000		0.00	0.00
100414	Ethyl benzene	5.83E-07	5.10E-03	0.000	0.000		0.00	0.00	
108883	Toluene	3.45E-06	3.03E-02		0.000	0.000		0.00	0.00
117817	Di(2-ethylhexyl) phthalate	5.15E-07	4.51E-03	0.000			0.00		
463581	Carbonyl sulfide	1.28E-04	1.12E+00		0.002	0.000		0.00	0.00
621647	N-Nitrosodi-n-propylamine	1.14E-06	9.99E-03	0.154			0.15		
1330207	Xylenes (mixed)	1.32E-06	1.15E-02		0.000	0.000		0.00	0.00
Prioritization Score for Process 1				1.69E-01	2.26E-03	6.45E-04	1.69E-01	2.26E-03	6.45E-04

Prioritization Score For California Dairies Inc Project : S1242862

Device ID 3	Device Name DG Flare	Emissions and Potency Method					Dispersion Adjustment Method		
		Prioritization Score for Device 3		1.69E-01	2.26E-03	6.45E-04	1.69E-01	2.26E-03	6.45E-04
Device ID 4	Device Name DG-NG Boiler	Emissions and Potency Method					Dispersion Adjustment Method		
Process ID : 1									
CAS#	Pollutant Name	Lbs / Hour	Lbs / Year	Cancer	Chronic	Acute	Cancer	Chronic	Acute
56235	Carbon tetrachloride	1.39E-06	1.22E-02	0.004	0.000	0.000	0.00	0.00	0.00
71432	Benzene	1.54E-05	1.35E-01	0.030	0.001	0.001	0.03	0.00	0.00
84742	Dibutyl phthalate	1.95E-06	1.71E-02						
91203	Naphthalene	1.11E-06	9.74E-03	0.003	0.000		0.00	0.00	
95636	1,2,4-Trimethylbenzene	6.22E-07	5.45E-03		0.000	0.000		0.00	0.00
100414	Ethyl benzene	1.42E-06	1.24E-02	0.000	0.000		0.00	0.00	
108883	Toluene	8.40E-06	7.35E-02		0.000	0.000		0.00	0.00
117817	Di(2-ethylhexyl) phthalate	1.25E-06	1.10E-02	0.000			0.00		
463581	Carbonyl sulfide	3.11E-04	2.72E+00		0.005	0.001		0.00	0.00
621647	N-Nitrosodi-n-propylamine	2.77E-06	2.43E-02	0.374			0.37		
1330207	Xylenes (mixed)	3.20E-06	2.80E-02		0.000	0.000		0.00	0.00
7783064	Hydrogen sulfide	7.90E-02	6.90E+02		1.185	2.821		1.18	2.82
		Prioritization Score for Process 1		4.11E-01	1.19E+00	2.82E+00	4.10E-01	1.19E+00	2.82E+00
		Prioritization Score for Device 4		4.11E-01	1.19E+00	2.82E+00	4.10E-01	1.19E+00	2.82E+00

Emissions and Potency Method

Prioritization Scores

Cancer	CHRONIC	ACUTE
3.22E+00	1.36E+00	3.06E+00

TS = Total Score

t = Specific Toxic Substance

EYR = Emissions Lbs / Year

EHR = Emissions Lbs / Hour

NF = Normalization Factor (Cancer = 7700, Acute = 1500, Chronic = 150)

URF = Unit Risk Factor

AREL = Acute Reference Exposure Level

CREL = Chronic Reference Exposure Level

RP = Receptor Proximity Adjustment Factor

R = Receptor Distance

RP	
0m < R < 100m	1.0
100m < R < 250m	0.25
250m < R < 500m	0.04
500m < R < 1000m	0.011
1000m < R < 1500m	0.003
1500m < R < 2000m	0.002
R > 2000m	0.001

Cancer Score:

$$TS(t) = EYR(t) * URF(t) * RP * 7700$$

Acute Score:

$$TS(t) = [EHR(t) / AREL(t)] * RP * 1500$$

Chronic Score:

$$TS(t) = \{ ([EYR(t) / \text{Hours Of Operation}] / CREL(t)) * RP * 150 \}$$

Dispersion Adjustment Method

Prioritization Scores

Cancer	CHRONIC	ACUTE
3.21E+00	1.36E+00	3.06E+00

TS = Total Score

t = Specific Toxic Substance

EYR = Emissions Lbs / Year

EHR = Emissions Lbs / Hour

NF = Normalization Factor (Cancer = 128, Acute = 25, Chronic = 2.5)

URF = Unit Risk Factor

AREL = Acute Reference Exposure Level

CREL = Chronic Reference Exposure Level

SHA = Stack Height Adjustment (< 20m = 60, < 45m = 9, >= 45m = 1)

RP = Receptor Proximity Adjustment Factor

R = Receptor Distance

H = Stack Height

For Stack - 0m <= H < 20m		For Stack - 20m <= H < 45m		For Stack - H >= 45m	
RP		RP		RP	
0m < R < 100m	1.0	0m < R < 100m	1.0	0m < R < 100m	1.0
100m < R < 250m	0.25	100m < R < 250m	0.85	100m < R < 250m	1.0
250m < R < 500m	0.04	250m < R < 500m	0.22	250m < R < 500m	0.90
500m < R < 1000m	0.011	500m < R < 1000m	0.064	500m < R < 1000m	0.40
1000m < R < 1500m	0.003	1000m < R < 1500m	0.018	1000m < R < 1500m	0.13
1500m < R < 2000m	0.002	1500m < R < 2000m	0.009	1500m < R < 2000m	0.066
R > 2000m	0.001	R > 2000m	0.006	R > 2000m	0.042

Cancer Score:

$$TS(t) = EYR(t) * URF(t) * RP * SHA * 128$$

Acute Score:

$$TS(t) = [EHR(t) / AREL(t)] * RP * SHA * 25$$

Chronic Score:

$$TS(t) = \{ ([EYR(t) / \text{Hours Of Operation}] / CREL(t)) * RP * SHA * 2.5 \}$$

Facility Summary: CALIFORNIA DAIRIES, I

REGION: S

FACID: 10254

PROJECT	Unit ID	MOD #	EQUIPMENT	Prioritization Scores			HARP2 Risk Scores		
				CANCER	ACUTE	CHRONIC	CANCER	ACUTE	CHRONIC
1242862	1	0	NG BOILER	1.320	0.116	0.086	6.72E-08	1.87E-06	2.60E-05
1242862	2	0	NG BOILER	1.320	0.116	0.086	6.58E-08	1.84E-06	2.62E-05
1242862	3	0	DG FLARE	0.169	0.001	0.002	1.14E-08	1.38E-05	1.03E-07
1242862	4	0	DG/NG BOILER	1.320	0.116	0.086	1.15E-08	4.46E-02	5.19E-03
Project Totals				4.129	0.349	0.260	1.56E-07	4.46E-02	5.24E-03
Facility Totals				4.129	0.349	0.260	1.56E-07	4.46E-02	5.24E-03

AAQA Summary

National Ambient Air Quality Standard

Pollutant	Modeled Conc. (ug/m3)	Background (ug/m3)	Total (ug/m3)	AAQS (ug/m3)	SIL (ug/m3)	Exceeds AAQS	Exceeds SIL
CO, 1_Hour	104.32	1355.59	1459.91	23000	2000	NO	--
CO, 8_Hour	46.95	1030.43	1077.38	10000	500	NO	--
NO2, 1_Hour	47.29	92.9	140.19	188	7.5	NO	--
NO2, 1_Hour	47.29	92.9	140.19	188	7.5	NO	--
NO2, Annual	0.4479	25.13	25.5779	100	0	NO	--
PM10-24Hr, 24_H	3.4446	86	89.4446	150	5	NO	--
PM2.5, 24_Hour	3.4446	48	51.4446	35	1.2	YES	YES
PM2.5, Annual	0.1748	13.67	13.8448	12	0.2	YES	NO
SOx, 1_Hour	14.698	6.02	20.718	196	7.8	NO	--
SOx, 24_Hour	3.5188	2.09	5.6088	365	5	NO	--
SOx, 3_Hour	9.753	4.45	14.203	1300	25	NO	--
SOx, Annual	0.2303	0.836	1.0663	80	1	NO	--

California Ambient Air Quality Standard

Pollutant	Modeled Conc. (ug/m3)	Background (ug/m3)	Total (ug/m3)	AAQS (ug/m3)	SIL (ug/m3)	Exceeds AAQS	Exceeds SIL
CO, 1_Hour	104.32	1816.99	1921.31	23000	2000	NO	--
CO, 8_Hour	46.95	1030.43	1077.38	10000	500	NO	--
NO2, 1_Hour	47.29	100.79	148.08	339	7.5	NO	--
NO2, Annual	0.4479	25.13	25.5779	57	0	NO	--
PM10, Annual	0.1748	40.05	40.2248	20	1	YES	NO
PM10-24Hr, 24_H	3.4446	100	103.4446	50	5	YES	NO
PM2.5, Annual	0.1748	13.67	13.8448	12	0.2	YES	NO
SOx, 1_Hour	14.698	6.02	20.718	655	7.8	NO	--
SOx, 24_Hour	3.5188	2.88	6.3988	105	5	NO	--

Results Summary

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PM-2.5 NAAQS - Concentration - Source Group: ALL

Averaging Period	Rank	Peak	Units	X (m)	Y (m)	ZELEV (m)	ZFLAG (m)	ZHILL (m)	Peak Date, Start Hour
24-HR	1ST	1.94211	ug/m^3	309545.27	3905982.36	106.38	0.00	106.38	
24-HR	8TH	1.17032	ug/m^3	309520.31	3905982.70	106.38	0.00	106.38	

PM-2.5 NAAQS - Concentration - Source Group: UNIT1

Averaging Period	Rank	Peak	Units	X (m)	Y (m)	ZELEV (m)	ZFLAG (m)	ZHILL (m)	Peak Date, Start Hour
24-HR	1ST	0.24062	ug/m^3	309320.66	3905985.48	106.37	0.00	106.37	
24-HR	8TH	0.09957	ug/m^3	309743.39	3905671.36	106.07	0.00	106.07	

PM-2.5 NAAQS - Concentration - Source Group: UNIT2

Averaging Period	Rank	Peak	Units	X (m)	Y (m)	ZELEV (m)	ZFLAG (m)	ZHILL (m)	Peak Date, Start Hour
24-HR	1ST	0.24269	ug/m^3	309320.66	3905985.48	106.37	0.00	106.37	
24-HR	8TH	0.10160	ug/m^3	309743.39	3905671.36	106.07	0.00	106.07	

PM-2.5 NAAQS - Concentration - Source Group: UNIT3

Averaging Period	Rank	Peak	Units	X (m)	Y (m)	ZELEV (m)	ZFLAG (m)	ZHILL (m)	Peak Date, Start Hour
24-HR	1ST	1.88783	ug/m^3	309545.27	3905982.36	106.38	0.00	106.38	
24-HR	8TH	1.13600	ug/m^3	309520.31	3905982.70	106.38	0.00	106.38	

Results Summary

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PM-2.5 NAAQS - Concentration - Source Group: UNIT4

Averaging Period	Rank	Peak	Units	X (m)	Y (m)	ZELEV (m)	ZFLAG (m)	ZHILL (m)	Peak Date, Start Hour
24-HR	1ST	0.07630	ug/m^3	309744.00	3905813.09	106.07	0.00	106.07	
24-HR	8TH	0.05817	ug/m^3	309744.00	3905813.09	106.07	0.00	106.07	

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.1.2*

Last Update: 11/30/2022

Natural gas or propane fired boilers/steam generators with heat input rate
greater than 20 MMBtu/hr**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	PUC quality natural gas or propane with LPG backup		
SOx	PUC quality natural gas or propane with LPG backup		
PM10	PUC quality natural gas or propane with LPG backup		
NOx	2.5 ppmvd @ 3% O2 (0.003 lb/MMBtu)		
CO	50 ppmvd @ 3% O2 (0.037 lb/MMBtu)		

* This is a Summary Page for this Class of Source.

** This guideline is applicable to units fired solely on natural gas from a PUC or FERC regulated source or propane/LPG. This guideline is not applicable to Oilfield Steam Generators or Electric Utility Steam Generating Units.

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**