San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUG 01 2012

Matt Schmitt
Colony Energy Partners - Tulare, LLC
4940 Campus Drive, Suite C
Newport Beach, CA 92660

Re: Notice of Preliminary Decision - Authority to Construct
Project Number: S-1121205

Dear Mr. Schmitt:

Enclosed for your review and comment is the District's analysis of Colony Energy Partners - Tulare, LLC's application for an Authority to Construct for two digester gas/natural gas-fired cogeneration IC engines and a digester gas-fired flare, at Paige Avenue (west of Enterprise Street) in Tulare, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments on this project within the 30-day public comment period which begins on the date of publication of the public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Stanley Tom of Permit Services at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:st

Enclosures

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
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www.valleyair.org www.healthyairliving.com

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

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Mike Tollstrup, Chief
Project Assessment Branch
Stationary Source Division
California Air Resources Board
PO Box 2815
Sacramento, CA 95812-2815

Re: Notice of Preliminary Decision - Authority to Construct
Project Number: S-1121205

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Visalia Times-Delta
Visalia Times-Delta

NOTICE OF PRELIMINARY DECISION
FOR THE PROPOSED ISSUANCE OF
AN AUTHORITY TO CONSTRUCT

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the proposed issuance of Authority to Construct to Colony Energy Partners - Tulare, LLC for two digester gas/natural gas-fired cogeneration IC engines and a digester gas-fired flare, at Paige Avenue (west of Enterprise Street) in Tulare, CA.

The analysis of the regulatory basis for this proposed action, Project #S-1121205, is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and the District office at the address below. Written comments on this project must be submitted within 30 days of the publication date of this notice to **DAVID WARNER, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review
Two Cogeneration Systems Consisting of Two Digester Gas/Natural Gas-Fired IC Engines and Digester Gas-fired Flare

Facility Name:	Colony Energy Partners – Tulare, LLC	Date:	July 20, 2012
Mailing Address:	4940 Campus Drive, Suite C Newport Beach, CA 92660	Engineer: Lead Engineer:	Stanley Tom Joven Refuerzo
Contact Person:	Matt Schmitt		
Telephone:	(949) 842-4827		
Fax:	(949) 752-7666		
E-Mail:	matt@colonyenergypartners.com		
Application No:	S-8153-1-0, '2-0, and '3-0		
Project No:	S-1121205		
Deemed Complete:	April 27, 2012		

I. Proposal

Colony Energy Partners – Tulare, LLC (CEP) has requested Authority to Construct (ATC) permits for an anaerobic digester system and the installation of two cogeneration (heat and electric) systems each equipped with 2,165 bhp 2G-Cenergy Model OTTO Avus TCG 2020 MWM lean burn digester gas/natural gas-fired internal combustion (IC) engine with selective catalytic reduction with urea injection served by one 41 MMBtu/hr Bekaert Model CEB 1200 digester gas-fired air-assisted ground level enclosed flare.

The proposed equipment will be used to generate electricity to be sold to the local utility power grid. The plant will be equipped to handle various types of feedstock substrates including food and agricultural processing residuals, dairy manure, cheese whey permeate, paunch, food waste diverted from landfills, and fat/oil/grease. Feedstock will arrive to the plant by truck and the fiber residuals and digester backend material (digestate) will be sold as compost transported by truck.

Two anaerobic digester tanks will be used to digest (ferment) the feedstock materials. The total digester gas (digester gas) generation rate is 1,200,000 standard cubic feet per day (scf/day) and 438,000,000 standard cubic feet per year (scf/year). The digester gas will be sent to two cogeneration engines to produce electricity. Plate heat exchangers will transfer the jacket water heat from the cogeneration engines to the digester hot water circuit. Hot water will be used to heat the digesters, reception tanks, mixing tanks, and desulfurization unit. The digester gas will be sent to an enclosed flare when the digester gas cannot be combusted in the cogeneration engines.

The digester gas will contain trace amounts of hydrogen sulfide (H2S) which is produced during the anaerobic digestion process. A desulfurization unit consisting of an in-tank bio-scrubber along with an external physical contact scrubber (iron sponge) is integrated into the process design to reduce H2S.

This facility will not be a major source for any pollutant.

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (4/21/11)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
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 4311	Flares (6/18/09)
Rule 4565	Biosolids, Animal Manure, and Poultry Litter Operations (3/15/07)
Rule 4566	Organic Material Composting Operations (8/18/11)
Rule 4701	Internal Combustion Engines (8/21/03)
Rule 4702	Internal Combustion Engines – Phase 2 (8/18/11)
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

II. Project Location

The facility is located at Paige Avenue (west of Enterprise Street) in Tulare, CA (S/2 Section 16, Township 20S, Range 24E Mount Diablo Base and Meridian). 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.

III. Process Description

CEP is proposing to construct and operate a digester gas plant in Tulare, CA. The plant will consist of two anaerobic digesters that will process incoming organic materials (substrates) and produce digester gas and digestate. The digester gas will be used by two cogeneration engines that will produce electricity and heat. The digester gas will be sent to an enclosed flare when the digester gas cannot be combusted in the cogeneration engines. The facility will operate 24 hours per day and 365 days per year.

<u>Organic Material Delivery</u>

The proposed facility will continuously receive organic material (substrates) in both liquid and solid form. All solid unloading will happen in the enclosed solid reception bunker under slight negative pressure. The liquid unloading will take place through two hose connections located at the side of the solid reception building. The trucks will connect their content outlet to the appropriate hose for the delivery of the liquids into the reception tanks.

Liquid Feedstock

Liquid feedstocks will be delivered to the site by waste haulers. Operators will drive their trucks to the liquid reception area and dock. The truck operator will proceed to the discharge coupling protruding from the building wall. Hanging on the wall beside the tee will be a variety of flexible hoses with different sizes of cam and groove couplings to accommodate different discharge valves. The truck operator will activate the liquid organics pump to allow the feedstock to flow to its destination storage tank selected by the plant operator upon receipt of the manifest from the truck operator. Any inadvertently spilled organics will be immediately washed from the concrete and contained area by the truck operator into floor drains which are plumbed to the reception pit.

Solid Feedstock

Solid feedstocks will be delivered to the site by waste haulers. Truck operators will back their trucks up to the solid reception building and await the plant operator to open the exterior door of the building. Once open, the truck operator will reverse the truck into the solid reception building until he has clearance to close the exterior door. The plant operator will open the hydraulic lid of the underground pit to receive the incoming solid organic feedstock. The truck operator will tip the truck box or activate the walking floor mechanism to empty the load of solid organic feedstock into the reception pit.

Odor emissions are mitigated in the solid feedstock offloading area by using an air lock system. Conveyors handling the solids will also be covered, preventing direct exposure to the atmosphere at any time.

The air lock system ensures that the feedstock processing will not be directly exposed to the atmosphere at any time by using interior and exterior doors. When a truck arrives to unload feedstock, it will enter the exterior set of doors and the interior doors will be closed. Once the truck is between the two sets of doors, the exterior doors will close and the interior doors will open to allow access to the unloading area. Upon exit, the exterior door is only permitted to open when a) all interior doors and/or the reception pit cover is closed; and b) 15 minutes have passed since the last closing of the interior door.

This system will ensure that all potential odors that have migrated to the area between the interior and exterior doors will have been ventilated to the air duct. This air is directed to the cogeneration engines for combustion. The delay of 15 minutes is based on a circulation rate of four air changes per hour. The delay allows for truck inspection, washing of tires, area cleanup, and completion of administrative duties with the plant operator.

Feedstock Pre-Treatment

Pre-treatment of organic feedstock is intended to render all materials received into a form that is pumpable and compatible with the anaerobic digestion system. All pre-treatment will happen prior to materials entering the reception tanks. Examples of pre-treatment include: 1) chopping – fine size reduction of organic materials and 2) dilution – addition of process and/or condensate and/or treated water to substrates. Solid organic feedstock will be tipped into the below ground reception pit. The below ground reception pit will be outfitted with a mixer and a chopper pump. The pumping system will include a recirculation loop to allow for the reduction of large particles into smaller ones; smaller particles make for easier pumping and expose more surface area for more thorough digestion. The slurry will be pumped into a bio-separator which will capture and remove debris such as plastic, stones, etc. that may be entrained in the solid organic feedstocks. A centrifugal force will allow the lighter particles to be screened off and send to a loadout bin.

Feedstock Storage

The feedstocks that arrive in the facility are separated in categories depending upon the physical composition and compatibility. Based on this categorization the incoming substrates of each category will arrive at the facility throughout the year and will be stored in separate storage tanks. There will be two reception tanks used for receiving the feedstock, and a dilution water tank used for receiving Filtrate that will be used for diluting the feedstock when necessary.

The hard top reception tanks will be constructed above grade with completely sealed wall surface that is water tight and air tight. The dilution water tank is a pre-manufactured tank.

All feedstock storage tanks will have one liquid inlet above the liquid level, and two liquid outlets below the liquid level; one for transferring the feedstock to the anaerobic digestion system; the other for evacuation during shutdown or emergency.

Internally, the reception tank will contain mixers to avoid any probability of solids or sediments settling in these tanks. Flangeless hot water piping will be installed around the circumference of the tank to heat the feedstock (cheese whey permeate and fat, oil, and grease). A hot water circuit (obtained from the cogeneration engines) goes through the piping; the same type of system is used to heat the digesters, reception tanks, and desulfurization unit. Through continuous monitoring of temperature and level, with instruments installed in the tank and read by the PLC, tank temperature and level are regulated accordingly, to avoid mixing and pumping issues.

The breathing lines from the reception tanks will be directly connected to the air duct which brings the ventilation air from the solids unloading bunkers to the engines. The engines will use the ventilation air coming from the air duct as combustion air. The amount of air needed by the engines for the combustion process is much higher than the amount of ventilation air being directed to the engine building, ensuring that any odors in the ventilation air are not released to the atmosphere.

Digester Gas System

The digester gas system consists of digesters and a buffer storage tank located together with the two feedstock reception tanks and the dilution water tank. The digesters utilize a UTS process design with the UTS Triton®, ring in ring tank design. Feedstock will be digested in the inner and outer rings, in series, of the two digesters, which will function in parallel. The digested substrate is then pumped to the buffer storage tank, where some additional digester gas will be produced. The total digester gas flow produced in the digesters and in the buffer storage tank will be directed through a digester gas manifold to a conditioning system and then to the cogeneration engines that will convert the digester gas to electricity and heat. The digesters and the buffer storage tank include a double membrane digester gas holder roof that allows homogenization of the digester gas produced, as well as the capacity to provide short term digester gas storage.

Digester

The anaerobic digestion of the substrate occurs in the digester tanks. Each digester is identical in construction. The inner ring where the final digestion process will occur will be constructed of a dual layer flexible membrane. The outer and inner ring of each digester will be mixed with submersible hydraulic mixers which ensure thorough mixing and homogenization of incoming feedstock and substrates in the digesters.

In the engine building, plate heat exchangers (one per engine) will transfer the jacket water heat from the engines to the digesters hot water circuit. The heat will then be transferred from the pipes surrounding the inner walls of the digester's rings to the digesting feedstock providing the appropriate temperature to the naturally present microorganisms which are responsible for the anaerobic digestion.

In order to maintain mesophilic temperature range in the digesters, the rings will be insulated. The malodorous compounds within the organic substrate, known as volatile organic acids (e.g. acetic acid, propanoic acid, butanoic acid) are what the anaerobic microorganisms (methanogenic bacteria) eventually consume to produce digester gas. In the process of digesting these volatile organic acids odors are minimized. The hydraulic retention time inside the digesters is between 25 and 35 days. The hydraulic retention time is a measure of the average time that one unit of feedstock (organic matter) remains within the digester.

The digester gas production from the input substrates is optimized through the anaerobic digestion system. The outer ring is used as a primary digester, for introduction of the feedstock, and the inner ring is used as a secondary digester. The biological anaerobic digestion of the feedstock will first take place in the outer ring producing digester gas as a result of the process. The partly digested feedstock is then conducted to the inner ring where further anaerobic digestion occurs yielding additional digester gas from the feedstock.

The dual layer flexible membrane of the inner rings allows mixing and storage of the digester gas produced. The inner membrane has a special coating for gas tightness and gas resistance and the outer membrane is UV-stabilized. Each cover includes a dedicated air blower that keeps the external membrane inflated which the internal membrane fluctuates in position based on the digester gas production and the digester gas use (i.e. differential pressure). A level transducer mounted in the outside membrane tracks the relative position of the internal membrane. A methane detector is provided at the backpressure valve air outlet of the inter-membrane space. The methane sensor measures methane content in the existing air and alarms at present methane concentrations. This security system indicates if there is a leak in the internal membrane. The membrane will have low permeability, preventing the release of odors or gaseous compounds to the atmosphere.

Each digester is equipped with a pair of flash-back (flame) arresters and pressure/vacuum relief valves connected to the digester roof piped in parallel with a three-way manual change over valve installed in the common supply piping so that there shall be only one of the flash-back arrester and pressure/vacuum relief valves in effective service at all times.

Buffer Storage Tank

Digestate, the remainder of the substrates following anaerobic digestion, is pumped intermittently from each digester to the buffer storage tank. The roof will consist of a dual layer flexible membrane. The buffer storage tank has two submerged mixers to prevent settling of solids.

This tank provides additional residence time required for the digestate, thus greatly reducing the likelihood of undigested organic matter leaving the system. The buffer storage allows degasification and liberates the entrapped gases thereby reducing the odor level of post-digestion handling to an almost undetectable level, and prevents the unwanted release of methane during the next stage of pressing (i.e., composting or land application). Furthermore, the buffer storage tank provides capacity to handle any scheduled and unscheduled maintenance situation for downstream process equipment such as solid separation or wastewater treatment.

The buffer storage tank also provides for digester gas storage in its double membrane gas holder roof. The inner membrane has a special coating for gas tightness and gas resistance and the outer membrane is UV-stabilized. Each cover includes a dedicated air blower that keeps the external membrane inflated, which the internal membrane fluctuates in position base on gas production as gas use (e.g. differential pressure). A level transducer mounted in the outside membrane tracks the relative position of the internal membrane. A methane detector is provided at the backpressure valve air outlet of the inter-membrane space. The methane sensor measures methane content in the existing air and alarms at present methane concentrations. This security system indicates if there is a leak in the internal membrane.

The buffer storage tank is equipped with a pair of flash-back (flame) arresters and pressure/vacuum relief valves connected to the digester roof piped in parallel with a three-way manual change over valve installed in the common supply piping so that there shall be only one of the flash-back arrester and pressure/vacuum relief valves in effective service at all times.

The capacity of the dual membrane roof of the buffer storage tank in additional to that of the two digester tanks provides sufficient storage of digester gas for the majority of maintenance and service of the cogeneration engines.

Lastly, the buffer storage tank acts as a digestate storage and volume buffering tank. Depending on the digestate management strategy, digestate may be processed intermittently, therefore the tank is large enough to provide several days of storage.

Digester Gas Conditioning

The facility will produce digester gas in the two digesters and in the buffer storage tank composed of approximately 64% methane. The rest of the digester gas will be mainly carbon dioxide with some traces of other compounds like hydrogen sulfide.

The digester gas collected from the head space of the digesters and the buffer storage tank is conducted to a digester gas common pipe by means of compressors. Before combustion in the engines, the digester gas needs to be conditioned to remove harmful substances which may cause damage to the cogeneration engines. The conditioning system consists of a desulfurization system to reduce the hydrogen sulfide contained in the digester gas and a digester gas cooling system to reduce the moisture content of the digester gas. The condensate from the gas cooling system is pumped into the gas condensate tank. The flare, downstream of the conditioning system, will combust the digester gas in the event that it cannot be used by the engines.

Chillers are used to cool down the digester gas produced in the digesters and buffer holding tank to reduce the moisture content prior to combustion in the engines. The chillers utilize heat exchange via a refrigeration cycle. The resulting condensate is cooled into an underground tank and pumped back into the dilution tank. The tank is level controlled.

Digester Gas Desulfurization Unit

Hydrogen sulfide (H2S) is present in the digester gas produced during anaerobic digestion due to the degradation of proteins and other sulfur containing compounds present in the feedstock. In the cogeneration engines, H2S reacts with water to form sulfuric acid (H2SO4) which is highly corrosive.

An in-tank bio-scrubber, along with an external physical contact scrubber (iron sponge) is integrated into the process design to effect H2S reduction. The in-tank H2S removal utilizes bio-scrubbers in a two stage process: absorption of H2S via a liquid medium followed by the biological oxidation of H2S in the liquid. Bacteria like Thiobacillus sp. (which have the ability to grow under various environmental stress conditions such as oxygen deficiency, acid conditions, etc.) are used for the conversion of H2S and other sulfur compounds by biological processes.

Regulated and controlled air will be dosed into the digester gas space. Multi-location probes regularly sample the digester gas, sending data to the central PLC. The PLC regulates the on and off valve to ensure that the oxygen level is adequate to promote desulfurization but remains below explosive limits.

External H2S removal will be effected with an iron sponge system. Iron sponge is a non-renewable method of removing H2S. The H2S reacts with the iron to form iron sulfide. The iron sponge consists of wood shavings or wood chips impregnated with hydrated iron oxide. Exposure of H2S to mercaptans produces iron sulfides and iron mercaptides. The chemical process of H2S removal with the iron sponge produces iron sulfides.

$$2FeO_3 + H_2O + 6H_2S \rightarrow 2Fe_2S_3 + 8H_2O$$

The process occurs after gas/liquid separation and prior to the dehydration process. For the iron sponge to effectively perform, it must be maintained within a defined range of sufficient moisture content. This requirement is typically satisfied if the gas is saturated with water vapor, as is frequently the case with digester gas or digester gas. Therefore, no water spray is required for a digester gas application. Excess water is well tolerated by the iron sponge as long as the excess is drained off so as not to flood the bed. Also, the reaction of iron oxide with H2S produces water contributing to proper hydration. The moisture drained is collected in the condensate tank and used for process dilution in the front end of the process along with other condensate.

Iron oxide impregnated into the wood surface will not wash off or migrate with the gas. If the iron sponge has dried in storage it can be re-wet and remain effective. A maximum temperature 120 degrees F should not be exceeded. The minimum temperature is 50 degrees F, or whatever is necessary to avoid hydrate formation relative to the system pressure and composition of the digester gas. The iron sponge reaction is not pressure sensitive and is not affected by other gas constituents.

The equipment needed for iron sponge treatment consists of a vessel which is filled with iron oxide. The gas is passed down flow with the H2S removed to meet the designed 40 ppmv requirement until the iron sponge is exhausted. The sponge is then either revivified or replaced. For continuous operation there will be an alternate vessel provided (standby unit) all piped to operate the process without any interruption. Valves can be arranged so either bed can operate while the other is serviced. The system is total enclosed and there is no potential of leaks. The multi stage method of desulfurization is capable of reducing H2S levels in the digester gas from 1,500 ppm down to between 10 and 50 ppm.

Natural Gas Supply

The digester gas plant will have a natural gas supply. Natural gas will be used during the commissioning of the digester gas plant to fuel the cogeneration engines to produce the amount of electricity initially required. This will also provide the plant with the necessary heat for the reception tanks and digesters. During normal operation, natural gas may be added to the digester gas in order to optimize the digester gas quality and the efficiency of the engines.

Digestate Management System

The digestate that leaves the buffer storage tank will be low solid organic slurry that hall be dewatered by filter screw press(es). The press will separate the digestate into liquid and solid fractions. The liquid fraction (filtrate) is sent to a Dissolved Air Floatation (DAF) unit for further solid separation. The solids removed from the DAF unit are dewatered using a horizontal decanter/centrifuge. The solids fraction of the digestate has a commercial value and shall be sold as a byproduct. All process liquid effluent, meeting specified discharge requirements, will be directed to the Tulare Industrial WWTP for further treatment.

A feed pump will be used to transfer digestate from the buffer holding tank to the filter screw press. The flow to the press will be monitored and controlled using a Magmeter. The press will be elevated and dewater solids and will discharge by gravity to a solids pad directly below.

The liquid effluent from the filtrate will flow by gravity to an intermediary tank from which it will be pumped to a DAF system. Polymer is added to the DAF influent to promote flocculation and removal of suspended solids. The polymer system doses polymer based on the DAF influent rate measured using a Magmeter. Through primary and secondary solid separation with a filter screw press and DAF of the pressage, suspended solids are significantly reduced to < 0.5% total solids. The float from the DAF is collected and pumped to a centrifuge for further dewatering. The dewatered solids fall by gravity to the solids pad to be combined with the press cake from the filter screw press for sale as compost. Clarified effluent from both the DAF and centrifuge is discharged directly to the Tulare Industrial WWTP for further treatment.

The polymer make down system will utilize a dry polymer which is diluted and aged prior to dosing into the DAF system. The dry polymer is supplied in bead-form (crystals) which eliminates dust while handling. The beads are packaged in small 25 kg bags from which the operator transfer them to a polymer hopper. The polymer make down system will use a vacuum polymer unloading and conveying system to transfer powder into the polymer mixing system for dilution with water. An air blower will transfer the polymer via a venture educator to a wetting head above the polymer mixing tank. The system utilizes totally enclosed conveying, mixing and storage units.

Digester Gas Cogeneration Engines

The digester gas produced in the facility will be used as fuel by the cogeneration engines. The reciprocating digester gas engines are coupled with an alternator and this combination is term a genset. Internal combustion gas gensets will be used in the facility to produce electricity and heat. Heat will be obtained from two sources: the high temperature circuit of the engine (which is cooling down the engine; the lubricating oil as well as the intercooler first stage) and the exhaust gases (which leave the engine at a temperature above 400 degrees C). The digester gas will be pumped by compressors through the gas pipe to the engines.

The cooling system of the engine consists of closed water circuits including one low temperature circuit and one high temperature circuit. The circuits consist of pumps, regulation valves, safety valves, sensors and radiators. The radiators will be mounted on the engine building roof. The high temperature circuit heat will be recovered by means of plate heat exchangers. The heat will be transferred to the hot water circuit that will heat the reception tanks and digesters.

The exhaust gas system consists of piping, insulation, a steam boiler, a silencer, and a stack. The steam boilers will produce steam out of the heat of the exhaust gases. The steam boiler will have a bypass flap in case no or less steam is needed by the consumers. Each engine will have its own exhaust stack.

The engine room will have a ventilation system which provides combustion air to the engines and cooling for the engines. The air duct coming from the solid reception building, where the breathing lines of the reception tanks are connected, is directed to the engine room in order to use the ventilation air of the solid reception building as combustion air for the engines. The ventilation air from the reception building and the breathing air from the reception tanks will be guided via a duct direct to the engine combustion filters. The engines will use this air as part of the needed combustion air and will therefore burn any odor produced in these buildings/tanks.

Digester Gas Flare

The normal operation of the digester gas plant consists of using the digester gas produced in the digesters and in the buffer storage tank as fuel for the engines in order to produce electricity and heat. The digesters and the buffer tank have some digester gas storage capacity making it possible to hold produced digester gas for limited periods of time.

When digester gas cannot be utilized by the engines and there is no available storage capacity in the digester gas plant, the digester gas will be combusted by the flare. The flare will combust the digester gas produced by the facility during the commissioning period as the digester gas may have not yet reached the adequate quantity and/or quality to run the engines.

V. Equipment Listing

S-8153-1-0: DIGESTER GAS PRODUCTION OPERATION CONSISTING OF ONE 211,338 GALLON MANURE RECEPTION TANK, ONE 92,460 GALLON DILUTION TANK, ONE 132,086 GALLON FAT, OIL, GREASE, VEGETABLE WASTE RECEPTION TANK, ONE 92,460 GALLON MIXING (FEED) TANK, TWO 2,150,100 GALLON ANAEROBIC DIGESTER TANKS, ONE 311,195 DIGESTATE (BUFFER) HOLDING TANK, DIGESTER GAS TREATMENT SYSTEM CONSISTING OF A CHILLER, COMPRESSOR, HYDROGEN SULFIDE REMOVAL UNIT (IN-TANK BIO-SCRUBBER AND IRON SPONGE SCRUBBER), AND ONE 41 MMBTU/HR BEKAERT MODEL CEB 1200 DIGESTER GAS-FIRED AIR-ASSIST GROUND LEVEL ENCLOSED FLARE AND DIGESTATE MANAGEMENT SYSTEM CONSISTING OF ONE FILTER SCREW PRESS WITH ONE 8,400 GALLON OVERFLOW BUFFER TANK,

ONE 2,000 GALLON SCREW PRESS BUFFER TANK, A POLYMER MAKE-DOWN SYSTEM, A DISSOLVED AIR FLOATATION (DAF) SYSTEM AND ONE DIGESTATE BY-PRODUCT LOADOUT STATION

S-8153-2-0: 2,165 BHP 2G-CENERGY MODEL OTTO AVUS TCG 2020 MWM LEAN BURN DIGESTER GAS/NATURAL GAS-FIRED IC ENGINE WITH TURBOCHARGER, INTERCOOLER, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND SELECTIVE CATALYTIC REDUCTION WITH UREA INJECTION COGENERATION SYSTEM

S-8153-3-0: 2,165 BHP 2G-CENERGY MODEL OTTO AVUS TCG 2020 MWM LEAN BURN DIGESTER GAS/NATURAL GAS-FIRED IC ENGINE WITH TURBOCHARGER, INTERCOOLER, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND SELECTIVE CATALYTIC REDUCTION WITH UREA INJECTION COGENERATION SYSTEM

VI. Emission Control Technology Evaluation

S-8153-1-0

The digester tanks and digestate (buffer) holding tank will be equipped with a pressure-vacuum (PV) relief valve. All tanks will be fully enclosed and vent to the engines with the exception of the overflow buffer tank and screw press buffer tank which vent locally via an air filter.

An in-tank bio-scrubber, along with an external physical contact scrubber (iron sponge) is integrated into the process design to effect H2S reduction of the digester gas. The in-tank H2S removal utilizes bio-scrubbers in a two stage process: absorption of H2S via a liquid medium followed by the biological oxidation of H2S in the liquid. Bacteria like Thiobacillus sp. (which have the ability to grow under various environmental stress conditions such as oxygen deficiency, acid conditions, etc.) are used for the conversion of H2S and other sulfur compounds by biological processes.

The equipment needed for iron sponge treatment consists of a vessel which is filled with iron oxide. The gas is passed down flow with the H2S removed to meet the designed 40 ppmv requirement until the iron sponge is exhausted. The sponge is then either revivified or replaced. For continuous operation there will be an alternate vessel provided (standby unit) all piped to operate the process without any interruption. Valves can be arranged so either bed can operate while the other is serviced. The system is total enclosed and there is no potential of leaks. The multi stage method of desulfurization is capable of reducing H2S levels in the digester gas from 1,500 ppm down to between 10 and 50 ppm.

The digester gas-fired enclosed flare proposed in this project has the potential to emit NOx, SOx, PM10, CO, and VOC emissions due to the incineration of digester gas generated by the anaerobic digester system. The enclosed flare uses a digester gas-fired automatic ignition pilot.

The system utilizes totally enclosed conveying, mixing and storage units. No additional emission controls are required.

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The engines are equipped with:

[X] Turbocharger
[X] Intercooler
[X] Positive Crankcase Ventilation (PCV)
[X] Air/Fuel Ratio Controller
[X] Lean Burn Technology
[X] Selective Catalytic Reduction

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

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

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

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

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

VII. General Calculations

A. Assumptions

- Operation schedule = 24 hr/day and 365 days/year (per applicant)
- Maximum digester gas generation rate = 50,000 scf/hr, 1,200,000 scf/day, 438 MMscf/year (per applicant)
- Maximum flare digester gas flow rate = 50,000 scf/hr, 1,200,000 scf/day, 43.8 MMscf/year (per applicant)

- Digester gas heating value = 600 Btu/scf (per applicant)
- Natural gas heating value = 1000 Btu/scf (District Practice)
- Digester gas F-factor = 9,100 dscf/MMBtu (per applicant)
- Natural gas F-factor (adjusted to 60 °F) = 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- Post desulfurization unit digester gas H_2S concentration = 40 ppmv (per applicant based on BACT limit and four hour averaging period)
- Natural gas sulfur concentration = 1.0 gr-S/100 scf or 0.00285 lb-SO_2/MMBtu (District Policy APR 1720)
- Engine exhaust flow rate = 4,281.3 cfm (per applicant)
- Engine digester gas fuel consumption rate = 21,480 scf/hr (based on 2G CENERGY spec sheet of 12,845 MBtu/hr x scf/600 Btu)
- Engine natural gas fuel consumption rate = 43,920 scf/day (limit to less than 2 lb/day for all pollutants)
- BHP to Btu/hr conversion: 2,542.5 Btu/bhp-hr
- Thermal efficiency of engine: commonly ≈ 35%

Feedstock Substrates		
Feedstock	Daily Throughput (tons/day)	Annual Throughput (tons/year)
Dairy Manure (Paunch)	407.5 (62.3)	127,561 (22,721)
Cheese Whey Waste	48.5	15,188
Food Waste (restaurant and cafeteria scraps)	20.8	7,574
Fat, Oils, & Grease (FOG)	103	32,194
Other Ag/Food Waste (citrus residue, cheese WWTP sludge)	83	30,295

Loadout Solids		
	Daily Throughput (tons/day)	Annual Throughput (tons/year)
Total Solids Loadout	37.2	13,571

B. Emission Factors

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The flare will only be fired on digester gas fuel at all times.

Flare Emissions Digester Gas Fuel		
Pollutant	lb/MMBtu	Source
NO_X	0.03	Manufacturer Guarantee
SO_X	0.0112	Mass balance equation below based on BACT limit of 40 ppmv H2S in fuel and four hour averaging period
PM_{10}	0.008	Manufacturer Guarantee
CO	0.30	Manufacturer Guarantee
VOC	0.068	Manufacturer Guarantee

$$SOx = \frac{\left(50{,}000\frac{ft^3-fuel}{hr}\right)\left(\frac{40\,ft^3-H_2S}{10^6\,ft^3-fuel}\right)\left(34\frac{lb-H_2S}{lb-mol}\right)}{\left(379.5\frac{ft^3-H_2S}{lb-mol}\right)\left(\frac{34\,lb-H_2S}{32\,lb-S}\right)\left(\frac{32\,lb-S}{64\,lb-SO_2}\right)}$$

SOx = 0.34 lb/hr

SOx = 0.34 lb/hr ÷ (50,000 scf/hr x 600 Btu/scf) x 1E6/MM = 0.0112 lb/MMBtu

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The following emission factors are for each engine after the SCR treatment.

Engine Digester Gas Fuel			
Pollutant	g/hp-hr	ppmv @ 15% O2	Source
NO_X	0.15	11	Manufacturer Guarantee
SO_X	0.037		Mass balance equation below based on BACT limit of 40 ppmv H2S in fuel and four hour averaging period
PM_{10}	0.033		AP-42 (7/00) Table 3.2-2*
CO	1.9	246.1	Manufacturer Guarantee
VOC	0.15	34.0	Manufacturer Guarantee

$$\left(\frac{40\,ft^3-H_2S}{10^6\,ft^3-fuel}\right)\left(\frac{scf\ fuel}{600\,Btu}\right)\left(\frac{2{,}542.5\,Btu}{bhp-hr}\right)\left(\frac{1\,bhp\ input}{0.35\,bhp\ output}\right)\left(\frac{lb-mol\,H_2S}{379.5\,scf\,H_2S}\right)\left(\frac{lb-mol\,SO_2}{lb-mol\,H_2S}\right)\left(\frac{64\,lb\,SO_2}{lb-mol\,SO_2}\right)\left(\frac{453.6\,g}{lb}\right)=0.037\frac{g-SO_2}{bhp-hr}$$

* PM10 value includes both filterable (7.71×10^{-5} lb/MMBtu) and condensable (9.91×10^{-3} lb/MMBtu) emissions.

Engine Natural Gas Fuel			
Pollutant	g/hp-hr	ppmv @ 15% O2	Source
NO_X	0.10	8.4	Manufacturer Guarantee
SO_X	0.0094	--	Mass Balance Equation Below
PM_{10}	0.033	--	AP-42 (7/00) Table 3.2-2*
CO	0.68	93.4	Manufacturer Guarantee
VOC	0.15	36.1	Manufacturer Guarantee

$$0.00285 \ \frac{lb - SO_x}{MMBtu} \times \frac{1\,MMBtu}{1{,}000{,}000\ Btu} \times \frac{2{,}542.5\ Btu}{bhp - hr} \times \frac{1\,bhp\ input}{0.35\ bhp\ out} \times \frac{453.6\ g}{lb} = 0.0094 \ \frac{g - SO_x}{bhp - hr}$$

* PM10 value includes both filterable (7.71×10^{-5} lb/MMBtu) and condensable (9.91×10^{-3} lb/MMBtu) emissions.

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since these are new emission units, PE1 = 0.

2. Post Project PE (PE2)

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The feedstock materials are solid or liquid organic substances and have a moisture content of 88% or more. The material is dumped directly into the totally enclosed solids reception tank and immediately diluted. The tank is equipped with a hydraulic cover that opens only for reception of feedstock and closes immediately afterwards. Chopping occurs during dilution, therefore there will be no PM10 emissions associated with receiving or processing the solids feedstock.

The feedstock materials are non-volatile organic substances. The reception storage tanks are not temperature controlled. The maximum storage temperature will be the ambient temperature of the City of Tulare which has a maximum average temperature of 96 degrees F. The solids reception tank will always be under negative pressure to capture odor. The liquid reception tank will have a slight negative pressure from the ventilation fan. All tanks are fully enclosed and vent to the engines.

Therefore, the following units will not be assessed PM10 or VOC emissions but will be listed on the permit since the units vent to the engines.

- Solids Reception Tank (800 m^3 = 211,338 gallons)
- Dilution Tank (350 m^3 = 92,460 gallons)
- Liquid Reception Tank (500 m^3 = 132,086 gallons)
- Mixing (Feed) Tank (350 m^3 = 92,460 gallons)

The digester tanks and digestate (buffer) holding tank handle low solid organic slurry material and are equipped with a pressure-vacuum (PV) relief valve. All tanks are fully enclosed and vent to the engines with the exception of the overflow buffer tank and screw press buffer tank which vent locally via an air filter.

Therefore, the following units will not be assessed PM10 or VOC emissions but will be listed on the permit since the units vent to the engines with the exception of the overflow buffer tank and screw press buffer tank which vent locally via an air filter.

- Two Anaerobic Digester Tanks (8,139 m^3 = 2,150,100 gallons)
- Digestate (Buffer) Holding Tank (1,178 m^3 = 311,195 gallons)
- Overflow Buffer Tank (8,400 gallons)
- Screw Press Buffer Tank (2,000 gallons)

The Digestate Management System will further separate the digestate into liquid and solid fractions. The liquid effluent will be discharged and the solid fraction will be loaded out and sold as a by-product. The facility does not anticipate any VOC emissions from the cake discharged by the Screw Press as the vast majority of the digestible solids are degraded in the digester. The press cake is composed of settleable, non-digestable fiber, biomass and silt, or clay like residuals. Both the cake and pressed fiber has a high moisture content (approximately 77%) which eliminates the risk of PM10 emissions. However, as explained in the source testing section, the loaded out wet cake and pressed fiber will be tested to validate the above assumption.

Based on the above proposed throughput of loadout solids, the VOC content will need to exceed the following in order to trigger permitting requirements.

VOC Content = 2.049 lb/day x day/37.2 tons-solids x ton/2,000 lb = 0.0000275 lb-VOC/lb-solid = 0.00275% by weight

At this point, the following units will not be assessed PM10 or VOC emissions but will be listed on the permit so that source testing can be performed to validate that these units have no emissions.

- Filter Screw Press
- Dissolved Air Floatation System
- Digestate Loadout Station

Daily Flare Emissions

Daily Post-Project Emissions – Flare (Digester Gas Fuel)												
Pollutant	Emission Factors			Heat input						PE2 Total		
NO_X	0.03	(lb-NO_X/MMBtu)	x	1.2	(MMscf/day)	x	600	(Btu/scf)	=	21.6	(lb-NO_X/day)	
SO_X	0.0112	(lb-SO_X/MMBtu)	x	1.2	(MMscf/day)	x	600	(Btu/scf)	=	8.1	(lb-SO_X/day)	
PM_{10}	0.008	(lb-PM_{10}/MMBtu)	x	1.2	(MMscf/day)	x	600	(Btu/scf)	=	5.8	(lb-PM_{10}/day)	
CO	0.30	(lb-CO/MMBtu)	x	1.2	(MMscf/day)	x	600	(Btu/scf)	=	216.0	(lb-CO/day)	
VOC	0.068	(lb-VOC/MMBtu)	x	1.2	(MMscf/day)	x	600	(Btu/scf)	=	49.0	(lb-VOC/day)	

Annual Flare Emissions

Annual Post-Project Emissions – Flare (Digester Gas Fuel)											
Pollutant	Emission Factors			Heat input						PE2 Total	
NO_X	0.03	(lb-NO_X/MMBtu)	x	43.8	(MMscf/year)	x	600	(Btu/scf)	=	788	(lb-NO_X/year)
SO_X	0.0112	(lb-SO_X/MMBtu)	x	43.8	(MMscf/year)	x	600	(Btu/scf)	=	294	(lb-SO_X/year)
PM_{10}	0.008	(lb-PM_{10}/MMBtu)	x	43.8	(MMscf/year)	x	600	(Btu/scf)	=	210	(lb-PM_{10}/year)
CO	0.30	(lb-CO/MMBtu)	x	43.8	(MMscf/year)	x	600	(Btu/scf)	=	7,884	(lb-CO/year)
VOC	0.068	(lb-VOC/MMBtu)	x	43.8	(MMscf/year)	x	600	(Btu/scf)	=	1,787	(lb-VOC/year)

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Daily Engine Emissions

Digester Gas Fuel or Digester Gas/Natural Gas Fuel Mixture

The following emission rates are for each engine after the SCR treatment.

Daily Post-Project Emissions – Each Engine (Digester Gas Fuel or Digester Gas/Natural Gas Fuel Mixture)					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Daily Hours of Operation (hrs/day)	Conversion (g/lb)	PE2 Total (lb/day)
NO_X	0.15	2,165	24	453.6	17.2
SO_X	0.037	2,165	24	453.6	4.2
PM_{10}	0.033	2,165	24	453.6	3.8
CO	1.9	2,165	24	453.6	217.6
VOC	0.15	2,165	24	453.6	17.2

Natural Gas

The engine emissions when fired on natural gas will be limited to 2 lb/day and calculated by the following:

$$\left(\frac{0.15\ g-VOC}{bhp-hr}\right)\left(\frac{1{,}830\ scf\ \ fuel}{hr}\right)\left(\frac{1000\ Btu}{scf\ \ fuel}\right)\left(\frac{24\ hr}{day}\right)\left(\frac{bhp-hr}{2{,}542.5\ Btu}\right)\left(\frac{0.35\ bhp\ output}{1\ bhp\ input}\right)\left(\frac{lb}{453.6\ g}\right)=2.0\frac{lb-VOC}{day}$$

Daily Post-Project Emissions – Each Engine (Natural Gas Fuel)								
Pollutant	Emissions Factor (g/bhp-hr)	Fuel Consumption (scf/hr)	Heating Value (Btu/scf)	Hours of Operation (hrs/day)	Conversion (Btu/bhp-hr)	% Efficiency	Conversion (g/lb)	PE2 Total (lb/day)
NO_X	0.10	1,830	1,000	24	2,542.5	0.35	453.6	1.3
SO_X	0.0094	1,830	1,000	24	2,542.5	0.35	453.6	0.1
PM_{10}	0.033	1,830	1,000	24	2,542.5	0.35	453.6	0.4
CO	0.68	1,830	1,000	24	2,542.5	0.35	453.6	9.1
VOC	0.15	1,830	1,000	24	2,542.5	0.35	453.6	2.0

Ammonia

Ammonia (NH_3) emissions will be emitted by the operation of the SCR system. The proposed daily NH_3 emissions can be calculated as follows:

PE = ppm x MW x (2.64×10^{-9}) x exhaust flow rate x 1440 min/day

Where:

- ppm is the emission concentration in ppmvd @ 15% O_2
- MW is the molecular weight of the pollutant (MW_{NH3} = 17 lb/lb-mol)
- 2.64 x 10^{-3} is the inverse of the molar specific volume (lb/scf, at 60 °F)
- Exhaust flow rate = 4,281.3 scf/min (per manufacturer)
- engine is operated a maximum of 1440 min/day and 8,760 hours/year.

NH_3 PE (lb/day) = 5×10^{-6} x 17 x (2.64×10^{-3}) (lb-mol/scf) x 4,281.3 (scf/min) x 1440 (min/day)
= 1.4 lb-NH_3/day

Daily Worst Case Post-Project Emissions – Each Engine (Digester Gas and/or Natural Gas Fuel)	
Pollutant	PE2 Total (lb/day)
NO_X	17.2
SO_X	4.2
PM_{10}	3.8
CO	217.6
VOC	17.2
NH_3	1.4

Annual Engine Emissions

Digester Gas Fuel or Digester Gas/Natural Gas Fuel Mixture

Annual Post-Project Emissions – Each Engine (Digester Gas Fuel or Digester Gas/Natural Gas Fuel Mixture)					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Daily Hours of Operation (hrs/year)	Conversion (g/lb)	PE2 Total (lb/year)
NO_X	0.15	2,165	8760	453.6	6,272
SO_X	0.037	2,165	8760	453.6	1,547
PM_{10}	0.033	2,165	8760	453.6	1,380
CO	1.9	2,165	8760	453.6	79,441
VOC	0.15	2,165	8760	453.6	6,272

Natural Gas

Daily Post-Project Emissions – Each Engine (Natural Gas Fuel)								
Pollutant	Emissions Factor (g/bhp-hr)	Fuel Consumption (scf/hr)	Heating Value (Btu/scf)	Hours of Operation (hrs/year)	Conversion (Btu/bhp-hr)	% Efficiency	Conversion (g/lb)	PE2 Total (lb/year)
NO_X	0.10	1,830	1,000	8760	2,542.5	0.35	453.6	487
SO_X	0.0094	1,830	1,000	8760	2,542.5	0.35	453.6	46
PM_{10}	0.033	1,830	1,000	8760	2,542.5	0.35	453.6	161
CO	0.68	1,830	1,000	8760	2,542.5	0.35	453.6	3,308
VOC	0.15	1,830	1,000	8760	2,542.5	0.35	453.6	730

Ammonia

The proposed annual NH_3 emissions can be calculated as follows:

PE = ppm x MW x (2.64×10^{-9}) x exhaust flow rate x 1440 min/day x 365 day/year

NH_3 PE (lb/year) = 5×10^{-6} x 17 x (2.64×10^{-3}) (lb-mol/scf) x 4,281.3 (scf/min) x 1440 (min/day) x 365 day/year
= **504 lb-NH_3/year**

Annual Worst Case Post-Project Emissions – Each Engine (Digester Gas and/or Natural Gas Fuel)	
Pollutant	PE2 Total (lb/year)
NO_X	6,272
SO_X	1,547
PM_{10}	1,380
CO	79,441
VOC	6,272
NH_3	504

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

Pursuant to District Rule 2201, the Pre-Project Stationary Source Potential to Emit (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 that have occurred at the source, and which have not been used on-site.

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

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

Pursuant to District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) 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 that have occurred at the source, and which have not been used on-site.

Post-Project Stationary Source Potential to Emit [SSPE2] (lb/year)					
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC
S-8153-1-0	788	294	210	7,884	1,787
S-8153-2-0	6,272	1,547	1,380	79,441	6,272
S-8153-3-0	6,272	1,547	1,380	79,441	6,272
Post-Project SSPE (SSPE2)	13,332	3,388	2,970	166,766	14,331

5. Major Source Determination

Pursuant to District Rule 2201, a Major Source is a stationary source with post-project emissions or a Post Project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values. However, for the purposes of determining major source status, the SSPE2 shall not include the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Major Source Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Post-Project SSPE (SSPE2)	13,332	3,388	2,970	166,766	14,331
Major Source Threshold	20,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No

6. Baseline Emissions (BE)

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

Pursuant to District Rule 2201, BE = Pre-project Potential to Emit 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.

7. SB 288 Major Modification

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

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

8. Federal Major Modification

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

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification. Additionally, since the facility is not a major source for PM_{10} (140,000 lb/year), it is not a major source for $PM_{2.5}$ (200,000 lb/year).

9. 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.

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Quarterly NEC [QNEC]			
	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO_X	197	0	197
SO_X	74	0	74
PM_{10}	53	0	53
CO	1,971	0	1,971
VOC	447	0	447

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Quarterly NEC [QNEC]			
	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO_X	1,568	0	1,568
SO_X	387	0	387
PM_{10}	345	0	345
CO	19,860	0	19,860
VOC	1,568	0	1,568

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

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

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

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

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The applicant is proposing to install a new digester system served by a digester gas-fired flare with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, CO, and VOC. As the flare has VOC emissions greater than 2 lb/day, it can be reasonably concluded that the digester system uncontrolled VOC emissions are greater than 2 lb/day. BACT is required for emission units with a PE greater than 2 lb/day; therefore, the digester system triggers BACT for VOC. The flare is a control device to the digester system that is combusting the digester gas produced by the digester system such that it is not vented directly to the atmosphere. Therefore, the digester gas-fire flare is considered a control device and will not be considered an emission unit for the purposes of this project.

Digester Gas Fuel – Flare		
Pollutant	**Daily PE2**	**BACT Triggered?**
NO_x	21.6 lb/day	Yes
SO_x	8.1 lb/day	Yes
PM_{10}	5.8 lb/day	Yes
CO	216.0 lb/day	No*
VOC	49.0 lb/day	Yes

* BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year

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As seen in Section VII.C.2 above, the applicant is proposing to install a new digester gas/natural gas-fired IC engine with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, CO, and VOC when fired on digester gas and CO when fired on natural gas and a PE less than 2 lb/day for NO_X, SO_X, PM_{10}, and VOC when fired on natural gas. BACT is triggered for NO_X, SO_X, PM_{10}, and VOC when fired on digester gas since the PEs are greater than 2 lbs/day. However BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 above.

Digester Gas Fuel – Each Engine		
Pollutant	**Daily PE2**	**BACT Triggered?**
NO_x	17.2 lb/day	Yes
SO_x	4.2 lb/day	Yes
PM_{10}	3.8 lb/day	Yes
CO	217.6 lb/day	No*
VOC	17.2 lb/day	Yes
NH_3	1.4 lb/day	No

* BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year

Natural Gas Fuel – Each Engine		
Pollutant	**Daily PE2**	**BACT Triggered?**
NO_x	1.3 lb/day	No
SO_x	0.1 lb/day	No
PM_{10}	0.4 lb/day	No
CO	9.1 lb/day	No*
VOC	2.0 lb/day	No
NH_3	1.4 lb/day	No

* BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year

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

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

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

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

d. SB 288/Federal Major Modification

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

2. BACT Discussion/Guideline

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There are increases in emissions associated with the flare. The flare is used to control the digester gas that is generated by the digester system and therefore is an emission control device. In accordance with District definitions, an emission control device is not an emission unit. Per District Rule 2201, only emission units can trigger BACT. Therefore, an emission control device cannot be subject to BACT requirements.

District BACT Guideline 1.4.4 applies to digester gas-fired flares. This BACT guideline was established prior to the District formalizing a position of BACT on control equipment. The guideline was simply a place to list the criteria to be a well controlled flare, but as the flare would not trigger BACT, it is inappropriate to have a BACT guideline for a flare. However, upon review of the BACT Guideline 1.4.4, the proposed flare will operate with NOx emissions of 0.03 lb/MMBtu, operate with a dry and wet absorption such that fuel sulfur content 40 ppmv (as H_2S), smokeless operation with a 5% opacity limit, and VOC emissions of 0.068 lb/MMBtu which meets the achieved in practice BACT requirements for this type of operation. Therefore, the proposed flare is minimizing the generation of collateral pollutants and is equivalent to the best control alternatives available for this type of operation.

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BACT Guideline 3.3.XX, applies to the digester gas-fired IC engines. [Waste Gas-Fired I.C. Engine] (See Attachment A)

3. Top-Down BACT Analysis

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

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

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NO_X: NO_X emissions ≤ 0.15 g/bhp-hr
SO_X: Dry and wet absorption such that fuel sulfur content ≤ 40 ppmv (as H2S)
PM_{10}: Fuel sulfur content ≤ 40 ppmv (as H2S)
VOC: VOC emissions ≤ 0.15 g/bhp-hr and Positive Crankcase Ventilation (PCV)

B. Offsets

1. Offset Applicability

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

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

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Post Project SSPE (SSPE2)	13,332	3,388	2,970	166,766	14,331
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

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

C. Public Notification

1. Applicability

Public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB288 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, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.

a. New Major Sources, Federal Major Modifications, and SB288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required for this project for new Major Source purposes.

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

b. PE > 100 lb/day

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

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PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO_X	21.6	100 lb/day	No
SO_X	8.1	100 lb/day	No
PM_{10}	5.8	100 lb/day	No
CO	216.0	100 lb/day	Yes
VOC	49.0	100 lb/day	No

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PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO_X	17.2	100 lb/day	No
SO_X	4.2	100 lb/day	No
PM_{10}	3.8	100 lb/day	No
CO	217.6	100 lb/day	Yes
VOC	17.2	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

The following table compares pollutant will trigger public noticing requirements. As seen the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	13,332	20,000 lb/year	No
SO_X	0	3,388	54,750 lb/year	No
PM_{10}	0	2,970	29,200 lb/year	No
CO	0	166,766	200,000 lb/year	No
VOC	0	14,331	20,000 lb/year	No

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

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

Stationary Source Increase in Permitted Emissions [SSIPE] – Public Notice					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	13,332	0	13,332	20,000 lb/year	No
SO_x	3,388	0	3,388	20,000 lb/year	No
PM_{10}	2,970	0	2,970	20,000 lb/year	No
CO	166,766	0	166,766	20,000 lb/year	Yes
VOC	14,331	0	14,331	20,000 lb/year	No

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

2. Public Notice Action

As discussed above, public noticing is required for this project for the flare CO emissions and engine CO emissions in excess of 100 lb/day and for SSIPE greater than 20,000 lb/year for CO for the flare. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

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

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- The amount of digester gas combusted in the flare shall not exceed any of the following limits: 1.2 MMscf in any one day or 43.8 MMscf in any consecutive 365-day period. [District Rule 2201]
- Emissions from the flare shall not exceed any of the following limits: 0.03 lb-NOx/MMBtu; 0.0112 lb-SOx/MMBtu (based on 40 ppmv sulfur content in fuel (as H2S) and four hour averaging period); 0.008 lb-PM10/MMBtu; 0.30 lb-CO/MMBtu; or 0.068 lb-VOC/MMBtu. [District Rule 2201]

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As explained above, natural gas will be used during the commissioning of the digester gas plant to fuel the cogeneration engines to produce the amount of electricity initially required. This will also provide the plant with the necessary heat for the reception tanks and digesters. During normal operation, natural gas may be added to the digester gas in order to optimize the digester gas quality and the efficiency of the engines.

Rule 4320 establishes different emission limits for units that fire on more than one type fuel once a fuel exceeds 50% by volume. Similarly, the engines in this project will be subject to different emission limits when fired on more than 50% by volume digester gas. Per the applicant, the engines will typically be fired on a maximum 2% natural gas during normal operation.

- Emissions from the IC engine when fired on digester gas, or a mixture of greater than 50% by volume digester gas, shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr, 0.037 g-SOx/bhp-hr (based on 40 ppmv sulfur content in fuel (as H2S) and four hour averaging period), 0.033 g-PM10/bhp-hr, 1.9 g-CO/bhp-hr, or 0.15 g-VOC/bhp-hr. [District Rules 2201 and 4702, and 40 CFR 60 Subpart JJJJ]
- Emissions from the IC engine when fired on natural gas shall not exceed any of the following limits: 0.10 g-NOx/bhp-hr, 0.0094 g-SOx/bhp-hr, 0.033 g-PM10/bhp-hr, 0.68 g-CO/bhp-hr, or 0.15 g-VOC/bhp-hr. [District Rules 2201 and 4702, and 40 CFR 60 Subpart JJJJ]
- The ammonia (NH3) emission concentration shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

The facility has stated the below natural gas fuel usage limit will be met at all times, including the commissioning period.

- Fuel consumption of natural gas shall not exceed 43,920 scf in any one day. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

Pursuant to District Policy APR 1705, source testing is required to demonstrate compliance with Rule 2201.

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The following conditions will be placed on the permit to ensure compliance with the assumptions made for Rule 2201. Source testing will be required within 120 days of initial start-up since there will be a commissioning period of up to 60 days.

- Source testing to measure NOx, CO and VOC emissions from the digester-fired flare shall be conducted within 120 days of initial start-up and at least once every twelve (12) months thereafter. [District Rule 2201]
- For source test purposes, NOx emissions from the flare shall be determined using EPA Method 19 on a heat input basis, or EPA Method 3A, EPA Method 7E, or ARB Method 100 on a ppmv basis. [District Rule 2201]
- For source test purposes, CO emissions from the flare shall be determined using EPA Method 10 or 10B, ARB Methods 1 through 5 with 10, or ARB Method 100. [District Rule 2201]
- For source test purposes, VOC emissions from the flare shall be determined using EPA Method 25 or 25a. [District Rule 2201]
- Stack gas oxygen (O2) shall be determined using EPA Method 3A, EPA Method 7E, or ARB Method 100. [District Rule 2201]
- Operator shall determine digester gas fuel higher heating value annually by ASTM D 1826 or D 1945 in conjunction with ASTM D 3588 for gaseous fuels. [District Rule 2201]

To validate the assumption that the solid fraction produced in the digestate management system does not result in any VOC emissions, an initial source test will be required. The VOC content of the loaded out wet cake and pressed fiber will be determined using EPA Test Methods 413.2 and 418.1 and/or if necessary SCAQMD Test Method 25.3 and/or EPA Test Method 8240.

Based on the maximum throughput of the wet cake and pressed fiber, a calculation will be performed to determine if the VOC emissions exceed two pounds per day. If the VOC emissions exceed two pounds per day, the applicant will be required to submit an Authority to Construct application to assess VOC emissions for the wet cake and pressed fiber loadout operation. The following condition will be placed on the permit to ensure compliance:

- Within 60 days of production of wet cake/pressed fiber, the VOC content of the material shall be determined using EPA Test Methods 413.2 and 418.1 and EPA Test Method 8260, and if necessary EPA Test Method 204 and 204D with either EPA Test Method 25A and 18 or SCAQMD Test Method 25.3, or any other test method approved by the District. If VOC emissions are greater than two pounds per day (based on maximum throughput of the loaded out material), the permittee shall submit an Authority to Construct application for the wet cake/pressed fiber loadout operation within 15 days of the test results. [District Rule 2201]

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As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, this IC engine is subject to source testing requirements. Source testing requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

2. Monitoring

The following conditions will be placed on the permit to ensure compliance with the assumptions made for Rule 2201.

- The sulfur content of the digester gas combusted in this flare shall be monitored and recorded monthly. After eight (8) consecutive monthly tests show compliance, the digester gas sulfur content monitoring frequency may be reduced to once every calendar quarter. If quarterly monitoring shows a violation of the digester gas sulfur content limit of this permit, then monthly monitoring shall resume and continue until eight consecutive months of monitoring show compliance with the gas sulfur content limit. Once compliance with the gas sulfur content limit is shown for eight consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas shall not be required if the flare does not operate during that period. Records of the results of monitoring of the digester gas sulfur content shall be maintained. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using a Testo 350 XL portable emission monitor; District-approved in-line H2S monitors; gas detection tubes calibrated for H2S; District-approved source test methods, including EPA Method 11 or EPA Method 15, ASTM Method D1072, D4084, and D5504; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

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As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, this IC engine is subject to monitoring requirements. Monitoring requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following condition will appear on the permit:

- 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 Rule 1070]

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- Permittee shall maintain daily and annual records of quantity of digester gas combusted in the flare and annual test results of higher heating value of digester gas. [District Rules 1070 and 2201]
- Permittee shall maintain daily and annual records of amount of the quantity of digester gas combusted in the flare. [District Rule 1070 and 2201]

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As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, this IC engine is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

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

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

The proposed location is in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	2.95	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

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)

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

S-8153-2-0 and '3-0

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 JJJJ applies to spark-ignited internal combustion engines.

Section 60.4230(a) states the provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (5) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

Section 60.4230(a)(4) states owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (i) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500

HP and less than 1,350 HP); (ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (iii) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP) are applicable to the provisions of this subpart.

The engines in this project commenced construction and were manufactured in 2012 and are non-emergency lean burn engines with a maximum engine power of 2,165 HP each. Therefore, this section is applicable and the engines in this project are subject to this subpart.

Sections 60.4231 and 60.4232 apply only to the manufacturers of stationary SI internal combustion engines. These sections do not apply to owners or operators of such engines. Therefore, these sections do not apply.

Section 60.4233 lists emission standards for owners and operators. Per Section 60.4233(e), owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.

Table 1 of this subpart for digester gas-fired engines HP ≥ 500 and manufacture date 7/1/2010 or later lists the NOx standard as 2.0 g/bhp-hr (equivalent to 150 ppmv @ 15% O2), the CO standard as 5.0 g/bhp-hr (equivalent to 610 ppmv @ 15% O2), and the VOC standard as 1.0 g/bhp-hr (equivalent to 80 ppmv @ 15% O2). Table 1 of this subpart for non-emergency natural gas-fired engines HP ≥ 500 and manufacture date 7/1/2010 for later lists the NOx standard as 1.0 g/bhp-hr (equivalent to 82 ppmv @ 15% O2), the CO standard as 2.0 g/bhp-hr (equivalent to 270 ppmv @ 15% O2), and the VOC standard as 0.7 g/bhp-hr (equivalent to 60 ppmv @ 15% O2). Emissions from the proposed engines meet the required emissions standards. The following condition will be placed on the permit to ensure compliance:

- Emissions from the IC engine when fired on digester gas, or a mixture of digester gas and natural gas, shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr, 0.037 g-SOx/bhp-hr (based on 40 ppmv sulfur content in fuel (as H2S) and four hour averaging period), 0.033 g-PM10/bhp-hr, 1.9 g-CO/bhp-hr, or 0.15 g-VOC/bhp-hr. [District Rules 2201 and 4702, and 40 CFR 60 Subpart JJJJ]
- Emissions from the IC engine when fired on natural gas shall not exceed any of the following limits: 0.10 g-NOx/bhp-hr, 0.0094 g-SOx/bhp-hr, 0.033 g-PM10/bhp-hr, 0.68 g-CO/bhp-hr, or 0.15 g-VOC/bhp-hr. [District Rules 2201 and 4702, and 40 CFR 60 Subpart JJJJ]

Section 60.4234 states owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in Section 60.4233 over the entire life of the engine.

District Rule 4702 requires periodic monitoring to ensure that the applicable emission limits contained in the permit are met. Additionally, the emissions rates for the engines will be listed as a permit condition for the life of the permit. Therefore, the requirements of this section are satisfied.

Section 60.4235 applies only to SI ICE that use gasoline. The proposed engines do not use gasoline. Therefore, this section does not apply.

Section 60.4236(b) states that after July 1, 2009, owners and operators may not install stationary SI ICE with a maximum engine power of greater than or equal to 500 HP that do not meet the applicable requirements in §60.4233, except that lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP that do not meet the applicable requirements in §60.4233 may not be installed after January 1, 2010.

As previously discussed, the proposed engines meet the applicable requirements of Section 60.4233. Therefore, the requirements of Section 60.4236 are satisfied.

Section 60.4237 lists monitoring requirements for emergency stationary SI ICE. The proposed engines are not used for emergency operation. Therefore, this section does not apply.

Sections 60.4238 through 60.4242 apply only to manufacturers of stationary SI ICE. Therefore, these sections do not apply.

Section 60.4243 lists compliance requirements for owners and operators of stationary SI ICE. Section 60.4243(b)(2)(ii) states that owners or operators of a stationary SI internal combustion engine greater than 500 HP must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, the owner or operator must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

As Rule 4702 requires source testing once every 24 months, the 24 month source testing requirement will be required since it is more stringent than the 3 year source testing requirement of this subpart. Source testing will be required within 120 days of initial start-up since there will be a commissioning period of up to 60 days. The following conditions will be placed on the permit to ensure compliance:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: total hours of operation, type and quantity of fuel used, maintenance or modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

- Source testing to measure digester gas-combustion NOx and CO emissions from this unit shall be conducted within 120 days of initial start-up and once every 8,760 hours of operation or 24 months, whichever comes first, thereafter. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]
- Source testing to measure natural gas fuel combustion NOx, CO and VOC emissions from this unit shall be conducted within 120 days of initial start-up. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]
- Source testing to measure natural gas fuel combustion NOx, CO and VOC emissions from this unit shall be conducted within 60 days of natural gas fuel usage exceeding 1,284,500 scf during any rolling 12-month period. [District Rules 2201 and 4702]
- This engine shall be operated and maintained in proper operating condition according to the manufacturer's specifications. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

Section 60.4243(g) states that it is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The ARF controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

The following condition will be added to the permits to ensure compliance:

- Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201 and 40 CFR 60 Subpart JJJJ]

Section 60.4244 lists test methods and other procedures for owners and operators of stationary SI ICE who conduct performance tests. Three separate test runs are required for each performance test, and each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load. Additionally, performance tests may not be conducted during periods of startup, shutdown, or malfunction.

The following condition will be added to the permits to ensure compliance:

- For initial emissions source testing, the arithmetic average of three 60-consecutive-minute test runs shall apply. Each test run shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. NOx, CO and VOC concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]
- Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

Section 60.4245(a) states that owners and operators of all stationary SI ICE must keep records of the following information:

- All notifications submitted to comply with this subpart and all documentation supporting any notification.
- Maintenance conducted on the engine.
- If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90, 1048, 1054, and 1060, as applicable.
- If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

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

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: total hours of operation, type and quantity of fuel used, maintenance or modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

Section 60.4245(c) states owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in §60.4231 must submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section.

(1) Name and address of the owner or operator;
(2) The address of the affected source;
(3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;
(4) Emission control equipment; and
(5) Fuel used.

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

- Notification of the date construction of this engine commenced shall be submitted to the District and EPA and shall be postmarked no later than 30 days after such date as construction commenced. The notification shall contain the following information: 1) Name and address of the owner or operator; 2) The address of the affected source; 3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; 4) Emission control equipment; and 5) Fuel used. [40 CFR 60, Subpart JJJJ]

Section 60.4245(d) states owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test within 60 days after the test has been completed.

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

- The results of each source test shall be submitted to the District and EPA within 60 days after completion of the source test. [District Rule 1081 and 40 CFR 60 Subpart JJJJ]

Therefore, compliance with the requirements of this rule is expected.

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

40 CFR Part 63, Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

S-8153-2-0 and '3-0

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

Section 63.6585 states you are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.
(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.
(c) An area source of HAP emissions is a source that is not a major source.
(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.
(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

The proposed engines are stationary and the facility is an area source of HAP emissions. Therefore, the provisions of this subpart are applicable.

Section 63.6590 states this subpart applies to each affected source.

(a) Affected source. An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

The proposed engines in this project are new and located at an area source of HAP emissions.

(1) Existing stationary RICE.
  (i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.
  (ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.
  (iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.
  (iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

The proposed engines in this project are not existing stationary RICE.

(2) New stationary RICE.
  (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.
  (ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.
  (iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

The proposed engines in this project are new stationary RICE.

(3) Reconstructed stationary RICE.
  (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.
  (ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the

definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

The proposed engines in this project are not reconstructed stationary RICE.

(b) Stationary RICE subject to limited requirements.

The proposed engines in this project are not stationary RICE subject to limited requirements.

(c) Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;
(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;
(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;
(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;
(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;
(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;
(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

The proposed engines in this project are new stationary RICE located at an area source subject to 40 CFR part 60 subpart JJJJ. Therefore, no further requirements apply for such engines under this part.

Therefore, compliance with the requirements of this rule is expected.

Rule 4101 Visible Emissions

Rule 4101 states that 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.

The following condition will be added to the permit to ensure compliance:

S-8153-1-0

- 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 ¼ or 5% opacity. [District Rules 2201 and 4101]

S-8153-2-0 and '3-0

- 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

Section 4.0 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 added to the permit 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.

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

The cancer risk for this project is shown below:

HRA Summary		
Unit	Cancer Risk	T-BACT Required
S-8153-1-0	0.0 per million	No
S-8153-2-0	3.65 per million	Yes
S-8153-3-0	3.69 per million	Yes

Discussion of T-BACT

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

For this project T-BACT is triggered for PM_{10} and VOC. T-BACT is satisfied with BACT for PM_{10} and VOC (see Attachment A), which is a sulfur content in the fuel gas of ≤ 40 ppmv (as H2S) and a VOC emission limit of 0.15 g/bhp-hr; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 10 in a million). As outlined by the HRA Summary in Attachment B of this report, the emissions increases for this project was determined to be less than significant.

S-8153-2-0 and '3-0

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

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

Rule 4201 Particulate Matter Concentration

Section 3.0 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.

S-8153-1-0

Particulate matter calculations were performed for each piece of equipment by the following equation:

F-Factor for digester gas:	9,100 dscf/MMBtu
PM_{10} Emission Factor:	0.008 lb-PM_{10}/MMBtu
Percentage of PM as PM_{10} in Exhaust:	100%

$$GL = \left(\frac{0.008\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM} \right) / \left(\frac{9{,}100\ ft^3}{MMBtu} \right)$$

$$GL = 0.006\ grain/dscf < 0.1\ grain/dscf$$

Since the particulate matter concentration is ≤ 0.1 grains per dscf, compliance with Rule 4201 is expected.

S-8153-2-0 and '3-0

$$0.033\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1\ bhp-hr}{2{,}542.5\ Btu} \times \frac{10^6\ Btu}{8{,}578\ dscf} \times \frac{0.35\ Btu_{out}}{1\ Btu_{in}} \times \frac{15.43\ grain}{g} = 0.008\ \frac{grain-PM}{dscf}$$

Since the particulate matter concentration is ≤ 0.1 grains per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the permits 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 SO_2, NO_2, 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. As shown below, each unit's maximum hourly emission rates are below the Rule 4301 limits.

District Rule 4301 Limits			
Unit	**NO_2**	**Total PM**	**SO_2**
S-8153-1-0 (Digester Gas)	0.90	0.24	0.34
S-8153-2-0 or '3-0 (Digester Gas)	0.72	0.16	0.18
S-8153-2-0 or '3-0 (Natural Gas)	0.05	0.02	0.004
Rule 4301 Limit	**140 lb/hr**	**10 lb/hr**	**200 lb/hr**

As shown above, compliance with this rule is expected.

Rule 4311 Flares

Rule 4311 limits the emissions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx), and sulfur oxides (SOx) from the operation of flares.

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

Section 6.1.4 requires an operator claiming exemption under Section 4.3 to record annual throughput, material usage, or other information necessary to demonstrate compliance with the terms of the exemption. The following condition will ensure compliance with this recordkeeping requirement:

- The facility shall maintain records of annual throughput, material usage, or other information necessary to demonstrate that facility-wide emissions are less than ten tons per year for both NOx and VOC. [District Rule 4311]

Therefore, compliance with the requirements of this rule is expected.

Rule 4565 Biosolids, Animal Manure, and Poultry Litter Operations

The purpose of this rule is to limit the emissions volatile organic compounds (VOC) from operations involving the management of biosolids, animal manure, or poultry litter.

This rule applies to all facilities whose throughput consists entirely or in part of biosolids, animal manure, or poultry litter and the operator who landfills, land applies, composts, or co-composts these materials.

Compost is defined in Section 3.14 as the controlled biological decomposition of organic material, such as sewage sludge, animal manures, or crop residues, under aerobic (with air) or anaerobic (without air) conditions to form a humus-like material. This facility does not incorporate controlled biological decomposition of organic material. Therefore, this facility does not perform composting.

Co-compost is defined in Section 3.12 as composting where biosolids and/or animal manure and/or poultry litter are mixed with other materials, including amendments, to produce compost. Co-composting includes both the active and curing phases of the composting process. This facility does not mix biosolids and/or animal manure and/or poultry litter with other materials, including amendments, to produce compost.

This facility does not landfill, land apply, compost, or co-compost biosolids, animal manure, or poultry litter. Therefore, the requirements of this rule are not applicable to this project.

Rule 4566 Organic Material Composting Operations

The purpose of this rule is to limit emissions of volatile organic compounds (VOC) from composting operations.

The provisions of this rule apply to composting facilities that compost and/or stockpile organic material.

Section 3.13 defines composting as a process in which solid organic waste materials are decomposed in the presence of oxygen through the action of bacteria and other microorganisms.

This facility does not perform composting as a process in which solid organic waste materials are decomposed in the presence of oxygen through the action of bacteria and other microorganisms. Therefore, this facility is not subject to the requirements of this rule.

Rule 4701 Stationary Internal Combustion Engines – Phase I

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

Rule 4702 Internal Combustion Engines – Phase 2

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

Section 2.0 states that this rule applies to any internal combustion engine rated at 25 brake horsepower or greater. Each of the proposed engines for cogeneration system is rated at 2,165 bhp. Therefore, this rule is applicable to each engine.

Section 5.2, Table 2, Category 2.d. for spark-ignited internal combustion engine rated at >50 bhp used exclusively in non-agricultural operations engine type lean-burn engines four-stroke requires the owner or operator to comply with the following emission limits:

Table 2 Emission Limits for a Spark-Ignited Internal Combustion Engine Rated at >50 bhp Used Exclusively in Non-AO (All ppmv limits are corrected to 15% oxygen on a dry basis). Emission Limits are effective according to the compliance schedule specified in Section 7.5.

Engine Type	NOx Limit (ppmv)	CO Limit (ppmv)	VOC Limit (ppmv)
2. Lean-Burn Engines			
d. Lean-Burn Engine, not listed above	11	2000	750

The facility has proposed to achieve the following emissions:

<u>Digester Gas Fuel or Digester Gas/Natural Gas Fuel Mixture</u>

NO_x: 11 ppmvd @ 15 % O_2;
CO: 246.1 ppmvd @ 15 % O_2; and
VOC: 34.0 ppmvd @ 15 % O_2

Natural Gas Fuel

NO_x: 8.4 ppmvd @ 15 % O_2;
CO: 93.4 ppmvd @ 15 % O_2; and
VOC: 36.1 ppmvd @ 15 % O_2

The proposed emissions are less than the Table 2 limits. Therefore, compliance with this section is expected.

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

Sections 5.4 and 5.5 outlines calculation methodologies and requirements for percent emission reductions, if used to comply with the NOx emission limits. The IC engines involved with this project do not propose to use percent emission reductions to comply with the NOx emission limits; therefore this section of the rule is not applicable.

Section 5.6 outlines the requirements for payment of an annual fee in lieu of complying with a NOx emission limit. The IC engines involved with this project do not propose to pay an annual fee in lieu of complying with the NOx emission limits; therefore this section of the rule is not applicable.

Section 5.7 outlines sulfur oxides (SOx) emission control requirements. On and after the compliance schedule specified in Section 7.5, operators of non-AO spark-ignited engines and non-AO compression-ignited engines shall comply with one of the following requirements:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or
5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or
5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or
5.7.4 Use California Reformulated Diesel for compression-ignited engines; or
5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or
5.7.6 Install and properly operate an emission control system that reduces SO2 emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

The facility is proposing to use digester gas and natural gas fuel with a sulfur content no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet. Therefore, compliance with this section is expected.

$$\left(\frac{40\ ft^3 - H_2S}{10^6\ ft^3 - fuel}\right)\left(\frac{lb - mol\ H_2S}{379.5\ scf\ H_2S}\right)\left(\frac{lb - mol\ S}{lb - mol\ H_2S}\right)\left(\frac{32\ lb\ S}{lb - mol\ S}\right)\left(\frac{7000\ gr}{lb}\right)(100) = 2.36\frac{gr - S}{100\ scf}$$

Section 5.8.1 outlines monitoring requirements for non-AO spark-ignited engines subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0. The IC engines involved with this project are non-AO spark-ignited engines subject to the requirements of Section 5.2.

Section 5.8.1 requires that for each engine with a rated brake horsepower of 1,000 bhp or greater and which is allowed by Permit-to-Operate or Permit-Exempt Equipment Registration condition to operate more than 2,000 hours per calendar year, or with an external emission control device, either install, operate, and maintain continuous monitoring equipment for NOx, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

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

The applicant has chosen to meet the requirements of Section 5.8.1 of the rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_x, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following conditions will be listed on proposed ATC to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, O_2, and NH3 at least once every month (in which a source test is not performed). NOx, CO, and O_2 concentrations shall be performed using a portable emission monitor that meets District specifications. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- If the NOx or CO concentrations corrected to 15% O2, as measured by the portable analyzer, or the NH3 concentrations corrected to 15% O2, as measured by District approved gas-detection tubes, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible,

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

- {2994} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.6 requires that for each engine, install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner or operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO and is allowed by a Permit-to-Operate condition. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

The applicant has proposed this engine will be equipped with a nonresettable elapsed operating time meter. The following condition will be listed on the permit to ensure compliance:

- This engine shall be equipped with a nonresettable elapsed operating time meter and a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved alternative. [District Rules 2201 and 4702 and 40 CFR 60 Subpart JJJJ]

Section 5.8.7 requires that for each engine, the permittee implement the Inspection and Monitoring (I&M) plan, if any, submitted to and approved by the APCO pursuant to Section 6.5. The following condition will be listed on the permit to ensure compliance:

- {3202} This engine shall be operated and maintained in proper operating condition per the manufacturer's requirements as specified on the Inspection and Monitoring (I&M) plan submitted to the District. [District Rule 4702]

Section 5.8.8 requires that for each engine, collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M plan and the implementation of this plan will be explained below in the discussion of Section 6.5 of this rule.

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

The alternate monitoring scheme proposed in Section 5.8.1 will satisfy the requirements of Section 5.8.9. The following conditions will be listed on the permit to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, O_2, and NH3 at least once every month (in which a source test is not performed). NOx, CO, and O_2 concentrations shall be performed using a portable emission monitor that meets District specifications. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- {2994} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.9 of the rule presents the alternative monitoring requirements for various engines not subject to the normal monitoring requirements of Section 5.8. These engines are required to monitor emissions under Section 5.8, so Section 5.9 does not apply.

Section 5.10 requires that on and after the compliance schedule specified in Section 7.5, an operator of a non-AO engine shall comply with the following requirements:

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

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

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

This unit is fired on PUC-Regulated natural gas and/or digester gas. Therefore, the following requirement will be included on the permit to comply with the SOx emissions monitoring requirement:

- The permittee shall submit an analysis showing the natural gas fuel sulfur content at least once every year. Valid purchase contracts, supplier certifications, tariff sheets, or transportation contacts may be used to satisfy this requirement, provided they establish the fuel parameters mentioned above. [District Rules 2201 and 4702]
- The sulfur content of the digester gas combusted in this engine shall be monitored and recorded monthly. After eight (8) consecutive monthly tests show compliance, the digester gas sulfur content monitoring frequency may be reduced to once every calendar quarter. If quarterly monitoring shows a violation of the digester gas sulfur content limit of this permit, then monthly monitoring shall resume and continue until eight consecutive months of monitoring show compliance with the gas sulfur content limit. Once compliance with the gas sulfur content limit is shown for eight consecutive months, then the monitoring frequency may return to quarterly. Records of the results of monitoring of the digester gas sulfur content shall be maintained. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using a Testo 350 XL portable emission monitor; District-approved in-line H2S monitors; gas detection tubes calibrated for H2S; District-approved source test methods, including EPA Method 11 or EPA Method 15, ASTM Method D1072, D4084, and D5504; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

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

Section 6.1.2 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engine is in compliance with the emission requirements of this rule.

This submitted ATC application satisfies the requirements of this section.

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

- Total hours of operation,
- Type of fuel used,
- Maintenance or modifications performed,
- Monitoring data,
- Compliance source test results, and
- Any other information necessary to demonstrate compliance with this rule.

Therefore, the following condition will be included on the permit to ensure compliance:

- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: total hours of operation, type and quantity of fuel used, maintenance or modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request. Therefore, the following condition will be included on the permit to ensure compliance:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

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

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

The engines in this project have been retrofitted with an exhaust control device. Therefore, Sections 6.3.2 through Section 6.3.4 are applicable to the engines in this project.

Section 6.3.2 requires that the operator of an engine subject to the requirements of Section 5.2, which engine equipped with an exhaust control device, to demonstrate compliance with the applicable emission limits during the initial start-up and at least once every 24 months thereafter.

Section 6.3.3 requires that the test must be conducted with the unit operating at normal operating conditions and using three 30-consecutive minute test runs. In addition, VOC shall be reported as methane, VOC, NOx, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen.

Section 6.3.5 specifies that engine that is limited by PTO condition to be fueled exclusively with PUC-quality natural gas shall not be subject to reoccurring source test requirements of Section 6.3.2 for VOC emissions.

Typically, the District requires secondary fuel source testing if the unit operates greater than 100 hours per year. This value was converted to a fuel use limit to provide the facility more flexibility.

The fuel use limit shown below is the maximum amount of natural gas that can be combusted in a year before a source test is required.

12.845 MMBtu/hr x 100 hr/year x scf/1000 Btu x 10^6/MM = 1,284,500 scf/year

Source testing will be required within 120 days of initial start-up since there will be a commissioning period of up to 60 days. The following conditions will be included on the permit to ensure compliance:

- Source testing to measure digester gas fuel combustion NOx, CO, VOC and ammonia emissions from this unit shall be conducted within 120 days of initial start-up and once every 8,760 hours of operation or 24 months, whichever comes first, thereafter. [District Rules 2201 and 4702 and 40 CFR 60 Subpart JJJJ]
- Source testing to measure natural gas fuel combustion NOx, CO, VOC and ammonia emissions from this unit shall be conducted within 120 days of initial start-up. [District Rules 2201 and 4702 and 40 CFR 60 Subpart JJJJ]
- Source testing to measure natural gas fuel combustion NOx, CO, VOC and ammonia emissions from this unit shall be conducted within 60 days of natural gas fuel usage exceeding 1,284,500 scf during any rolling 12-month period. [District Rules 2201 and 4702]
- Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For initial emissions source testing, the arithmetic average of three 60-consecutive-minute test runs shall apply. Each test run shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. If two of three runs are above an

applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. NOx, CO and VOC concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

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

- Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
- Carbon monoxide - EPA Method 10, or ARB Method 100.
- Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
- Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100.
- Operating horsepower determination - any method approved by EPA and the APCO.

Therefore, the following condition will be included on the permit to ensure compliance:

- The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, CO (ppmv) - EPA Method 10 or ARB Method 100, stack gas oxygen - EPA Method 3 or 3A or ARB Method 100, and VOC (ppmv) - EPA Method 25A or 25B, or ARB Method 100. [District Rules 1081 and 4702]
- Source testing for ammonia slip shall be conducted utilizing BAAQMD method ST-1B. [District Rule 1081]

Section 6.5 requires that the owner of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.0, shall submit to the APCO for approval, an I&M plan that specifies all actions to be taken to satisfy the following requirements and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below.

Section 6.5.1 states the requirements of Section 6.5.2 through Section 6.5.9 shall apply to the following engines:

6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.5.1.2 Engines subject to Section 8.0;
6.5.1.3 An AO spark-ignited engine that is subject to the requirements of Section 8.0.
6.5.1.4 An AO spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

The engines in this project have been retrofitted with an exhaust control device. Therefore, Sections 6.5.2 through Section 6.5.9 are applicable to the engines in this project.

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

Section 6.5.3 specifies procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule listed in the I&M plan. The applicant has previously proposed that the alternate monitoring program will ensure compliance with Sections 6.5.2 and 6.5.3 of the Rule. Therefore, the following condition will ensure compliance with the I&M requirements of this rule:

- The permittee shall monitor and record the stack concentration of NOx, CO, O2, and NH3 at least once every month (in which a source test is not performed). NOx, CO, and O2 concentrations shall be performed using a portable emission monitor that meets District specifications. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

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

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

The applicant has proposed that the alternate monitoring program will ensure compliance with these two sections of the Rule. The following condition will ensure compliance with these requirements:

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

Section 6.5.6 specifies procedures for preventive and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engines will be operated and maintained per the manufacturer's specifications. Therefore, the following condition will be included on the permit to ensure compliance:

- {3202} This engine shall be operated and maintained in proper operating condition per the manufacturer's requirements as specified on the Inspection and Monitoring (I&M) plan submitted to the District. [District Rule 4702]

Section 6.5.7 specifies procedures and a schedule for using a portable NO_x analyzer to take NO_x emission readings pursuant to Section 5.8.9. The applicant has proposed that the alternate monitoring program will ensure compliance with this Section of the Rule. The following condition will ensure compliance with this requirement:

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

Section 6.5.8 specifies procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO. The applicant has proposed that the alternate monitoring program will ensure compliance with this Section of the Rule. The following condition will ensure compliance with this requirement:

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

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or

Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time. The applicant has proposed that they will modify their I&M plan per this section of the Rule. Therefore, the following condition will be placed on the permit to ensure continued compliance:

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

Section 7.1 requires that the owner of an engine which becomes subject to the emission limits of this rule through loss of exemption shall not operate the subject engine, except as required for obtaining a new or modified Permit-to-Operate for the engine, until the owner demonstrates full compliance with the requirements of this rule.

The engines in this project did not become subject to this rule through a loss of exemption; therefore, the requirements of this section are not applicable.

Section 7.5.1 requires an operator with non-AO spark-ignited engines at a stationary source subject to Table 2 or Section 8.0 emission limits, SOx control requirements of Section 5.7, and the SOx monitoring requirements of Section 5.10 shall comply with the schedule specified in Table 5.

Table 5 Compliance Schedule for Non-AO Spark-Ignited Engines Subject to Table 2 Emission Limits, and SOx Control and Monitoring Requirements

Engines to be in Compliance at a Stationary Source	Emission Control Plan	Authority to Construct and Inspection and Monitoring Plan	Full Compliance
Operator with at least two engines, but less than 12 engines at a stationary source			
33% or more of the engines subject to Table 2 emission limits as of August 18, 2011	7/1/12	1/1/13	1/1/14
66% or more of the engines subject to Table 2 emission limits as of August 18, 2011	7/1/12	1/1/14	1/1/15
100% of the engines subject to Table 2 emission limits	7/1/12	1/1/15	1/1/16

The engines involved with this project will meet all the requirements of Rule 4702 at the time of initial operation. Therefore, the engines are in meet the compliance schedule requirements of Table 5.

Section 8.0 allows that an operator may comply with the NOx emission requirements of Section 5.2 for a group of engines by meeting the requirements below. An operator that is subject to the requirements below shall also comply with all the applicable requirements of Sections 5.0, 6.0, and 7.0. Only engines subject to Section 5.2 are eligible for inclusion in an AECP.

The applicant has not proposed an Alternative Emission Control Plan (AECP). Therefore, this section of the Rule is not applicable to the engines involved with this project.

Therefore, compliance with the requirements of this Rule is expected.

Rule 4801 Sulfur Compounds

Rule 4801 requires that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

S-8153-1-0

F-Factor for Digester gas: 9,100 dscf/MMBtu

$$\frac{0.0112\, lb - SOx}{MMBtu} \times \frac{MMBtu}{9{,}100\, dscf} \times \frac{1\, lb \cdot mol}{64\, lb} \times \frac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520^\circ R}{14.7\, psi} \times \frac{1{,}000{,}000 \cdot parts}{million} = 7.3 \frac{parts}{million}$$

Since the SOx concentration is ≤ 2,000 ppmv, the flare is expected to comply with Rule 4801.

S-8153-2-0 and '3-0

Digester Gas Fuel

$$40 \quad \frac{scf - H_2S}{MMscf - fuel} \times \frac{lbmol - H_2S}{379.5\, scf - H_2S} \times \frac{lbmol - SO_2}{lbmol - H_2S} \times \frac{1\, scf - fuel}{600\, Btu} \times \frac{1\, MMBtu}{9{,}100\, scf} \times \frac{10.73\, psi - ft^3}{lb - mol - {}^\circ R} \times \frac{520^\circ R}{14.7\, psi} \times 1{,}000{,}000 = \quad 7.3 \quad \text{ppmv}$$

Natural Gas Fuel

$$2.85 \quad \frac{lb - S}{MMscf - gas} \times \frac{1\, scf - gas}{1{,}000\, Btu} \times \frac{1\, MMBtu}{8{,}578\, scf} \times \frac{1\, lb - mol}{64\, lb - S} \times \frac{10.73\, psi - ft^3}{lb - mol - {}^\circ R} \times \frac{520^\circ R}{14.7\, psi} \times 1{,}000{,}000 = \quad 1.97 \quad \text{ppmv}$$

Since the SOx concentration is ≤ 2,000 ppmv, the engine is expected to comply with Rule 4801.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

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

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.
- Identify the ways that environmental damage can be avoided or significantly reduced.
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The City of Tulare (City) is the public agency having principal responsibility for approving the Project. As such, the City serves as the Lead Agency for the project. Consistent with CEQA Guidelines §15070, the City has prepared a Mitigated Negative Declaration which is currently being circulated for public review and comment. The comment period for the Lead Agency's environmental document closes June 25, 2012.

The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). As a Responsible Agency the District complies with CEQA by considering the Mitigated Negative Declaration prepared by the Lead Agency, and by reaching its own conclusion on whether and how to approve the project (CEQA Guidelines §15096).

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. The District's proposed approval of the project is being circulated for public comment concurrent with the CEQA process to eliminate avoidable delays. Consistent with CEQA requirements, if the Lead Agency approves the project, the District will review the Lead Agency's final environmental document and reach its on conclusion on whether and how to approve the project.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue Authorities to Construct S-8153-1-0, '2-0, '3-0 subject to the permit conditions on the attached draft Authorities to Construct in Attachment C.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-8153-1-0	3020-02-H	41 MMBtu/hr flare	$1030.00
S-8153-2-0	3020-10-F	2,165 hp IC engine	$749.00
S-8153-3-0	3020-10-F	2,165 hp IC engine	$749.00

Attachments

A: Waste Gas-Fired IC Engine BACT Determination and Engine Top Down BACT Analysis
B: Health Risk Assessment and Ambient Air Quality Analysis
C: Draft ATCs

Attachment A

Waste Gas-Fired IC Engine BACT Determination and Engine Top Down BACT Analysis

New BACT Determination 3.3.XX:
Waste Gas-Fired IC Engine

Facility Name:	Colony Energy Partners – Tulare,	Date:	May 27, 2012
Mailing Address:	4940 Campus Drive, Suite C Newport Beach, CA 92660	Engineer: Lead Engineer:	Stanley Tom Joven Refuerzo
Contact Person:	Matt Schmitt		
Telephone:	(949) 842-4827		
Application #:	S-8153-1-0, '2-0, and '3-0		
Project #:	S-1121205		
Location:	Paige Avenue (West of Enterprise Street) in Tulare, CA (S/2 Section 16, Township 20S, Range 24E)		
Complete:	April 27, 2012		

I. PROPOSAL

Colony Energy Partners – Tulare, LLC (CEP) has requested Authority to Construct (ATC) permits for an anaerobic digester system and the installation of two cogeneration (heat and electric) systems each equipped with 2,165 bhp 2G-Cenergy Model OTTO Avus TCG 2020 MWM lean burn digester gas/natural gas-fired internal combustion (IC) engine with selective catalytic reduction with urea injection served by one 41 MMBtu/hr Bekaert Model CEB 1200 digester gas-fired air-assisted ground level enclosed flare.

The proposed equipment will be used to generate electricity to be sold to the local utility power grid. The plant will be equipped to handle various types of feedstock substrates including food and agricultural processing residuals, dairy manure, cheese whey permeate, paunch, food waste diverted from landfills, and fat/oil/grease. Feedstock will arrive to the plant by truck and the fiber residuals and digester backend material (digestate) will be sold as compost transported by truck.

Two anaerobic digester tanks will be used to digest (ferment) the feedstock materials. The total digester gas (digester gas) generation rate is 1,200,000 standard cubic feet per day (scf/day) and 438,000,000 standard cubic feet per year (scf/year). The digester gas will be sent to two cogeneration engines to produce electricity. Plate heat exchangers will transfer the jacket water heat from the cogeneration engines to the digester hot water circuit. Hot water will be used to heat the digesters, reception tanks, mixing tanks, and desulfurization unit. The digester gas will be sent to an enclosed flare when the digester gas cannot be combusted in the cogeneration engines.

The digester gas will contain trace amounts of hydrogen sulfide (H2S) which is produced during the anaerobic digestion process. A desulfurization unit consisting of an in-tank bio-scrubber along with an external physical contact scrubber (iron sponge) is integrated into the process design to reduce H2S.

This facility will not be a major source for any pollutant.

II. PROJECT LOCATION

The facility is located at Paige Avenue (west of Enterprise Street) in Tulare, CA (S/2 Section 16, Township 20S, Range 24E Mount Diablo Base and Meridian).

III. EQUIPMENT LISTING

S-8153-1-0: DIGESTER GAS PRODUCTION OPERATION CONSISTING OF ONE 211,338 GALLON MANURE RECEPTION TANK, ONE 92,460 GALLON DILUTION TANK, ONE 132,086 GALLON FAT, OIL, GREASE, VEGETABLE WASTE RECEPTION TANK, ONE 92,460 GALLON MIXING (FEED) TANK, TWO 2,150,100 GALLON ANAEROBIC DIGESTER TANKS, ONE 311,195 DIGESTATE (BUFFER) HOLDING TANK, DIGESTER GAS TREATMENT SYSTEM CONSISTING OF A CHILLER, COMPRESSOR, HYDROGEN SULFIDE REMOVAL UNIT (IN-TANK BIO-SCRUBBER AND IRON SPONGE SCRUBBER), AND ONE 41 MMBTU/HR BEKAERT MODEL CEB 1200 DIGESTER GAS-FIRED AIR-ASSIST GROUND LEVEL ENCLOSED FLARE AND DIGESTATE MANAGEMENT SYSTEM CONSISTING OF ONE FILTER SCREW PRESS WITH ONE 8,400 GALLON OVERFLOW BUFFER TANK, ONE 2,000 GALLON SCREW PRESS BUFFER TANK, A POLYMER MAKE-DOWN SYSTEM, A DISSOLVED AIR FLOATATION (DAF) SYSTEM AND ONE DIGESTATE BY-PRODUCT LOADOUT STATION

S-8153-2-0: 2,165 BHP 2G-CENERGY MODEL OTTO AVUS TCG 2020 MWM LEAN BURN DIGESTER GAS/NATURAL GAS-FIRED IC ENGINE WITH TURBOCHARGER, INTERCOOLER, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND SELECTIVE CATALYTIC REDUCTION WITH UREA INJECTION COGENERATION SYSTEM

S-8153-3-0: 2,165 BHP 2G-CENERGY MODEL OTTO AVUS TCG 2020 MWM LEAN BURN DIGESTER GAS/NATURAL GAS-FIRED IC ENGINE WITH TURBOCHARGER, INTERCOOLER, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND SELECTIVE CATALYTIC REDUCTION WITH UREA INJECTION COGENERATION SYSTEM

IV. PROCESS DESCRIPTION

CEP is proposing to construct and operate a digester gas plant in Tulare, CA. The plant will consist of two anaerobic digesters that will process incoming organic materials (substrates) and produce digester gas and digestate. The digester gas will be used by two cogeneration engines that will produce electricity and heat. The digester gas will be sent to an enclosed flare when the digester gas cannot be combusted in the cogeneration engines. The facility will operate 24 hours per day and 365 days per year.

Organic Material Delivery

The proposed facility will continuously receive organic material (substrates) in both liquid and solid form. All solid unloading will happen in the enclosed solid reception bunker under slight negative pressure. The liquid unloading will take place through two hose connections located at the side of the solid reception building. The trucks will connect their content outlet to the appropriate hose for the delivery of the liquids into the reception tanks.

Liquid Feedstock

Liquid feedstocks will be delivered to the site by waste haulers. Operators will drive their trucks to the liquid reception area and dock. The truck operator will proceed to the discharge coupling protruding from the building wall. Hanging on the wall beside the tee will be a variety of flexible hoses with different sizes of cam and groove couplings to accommodate different discharge valves. The truck operator will activate the liquid organics pump to allow the feedstock to flow to its destination storage tank selected by the plant operator upon receipt of the manifest from the truck operator. Any inadvertently spilled organics will be immediately washed from the concrete and contained area by the truck operator into floor drains which are plumbed to the reception pit.

Solid Feedstock

Solid feedstocks will be delivered to the site by waste haulers. Truck operators will back their trucks up to the solid reception building and await the plant operator to open the exterior door of the building. Once open, the truck operator will reverse the truck into the solid reception building until he has clearance to close the exterior door. The plant operator will open the hydraulic lid of the underground pit to receive the incoming solid organic feedstock. The truck operator will tip the truck box or activate the walking floor mechanism to empty the load of solid organic feedstock into the reception pit.

Odor emissions are mitigated in the solid feedstock offloading area by using an air lock system. Conveyors handling the solids will also be covered, preventing direct exposure to the atmosphere at any time.

The air lock system ensures that the feedstock processing will not be directly exposed to the atmosphere at any time by using interior and exterior doors. When a truck arrives to unload feedstock, it will enter the exterior set of doors and the interior doors will be closed. Once the truck is between the two sets of doors, the exterior doors will close and the interior doors will open to allow access to the unloading area. Upon exit, the exterior door is only permitted to open when a) all interior doors and/or the reception pit cover is closed; and b) 15 minutes have passed since the last closing of the interior door.

This system will ensure that all potential odors that have migrated to the area between the interior and exterior doors will have been ventilated to the air duct. This air is directed to the cogeneration engines for combustion. The delay of 15 minutes is based on a circulation rate of four air changes per hour. The delay allows for truck inspection, washing of tires, area cleanup, and completion of administrative duties with the plant operator.

Feedstock Pre-Treatment

Pre-treatment of organic feedstock is intended to render all materials received into a form that is pumpable and compatible with the anaerobic digestion system. All pre-treatment will happen prior to materials entering the reception tanks. Examples of pre-treatment include: 1) chopping – fine size reduction of organic materials and 2) dilution – addition of process and/or condensate and/or treated water to substrates. Solid organic feedstock will be tipped into the below ground reception pit. The below ground reception pit will be outfitted with a mixer and a chopper pump. The pumping system will include a recirculation loop to allow for the reduction of large particles into smaller ones; smaller particles make for easier pumping and expose more surface area for more thorough digestion. The slurry will be pumped into a bio-separator which will capture and remove debris such as plastic, stones, etc. that may be entrained in the solid organic feedstocks. A centrifugal force will allow the lighter particles to be screened off and send to a loadout bin.

Feedstock Storage

The feedstocks that arrive in the facility are separated in categories depending upon the physical composition and compatibility. Based on this categorization the incoming substrates of each category will arrive at the facility throughout the year and will be stored in separate storage tanks. There will be two reception tanks used for receiving the feedstock, and a dilution water tank used for receiving Filtrate that will be used for diluting the feedstock when necessary.

The hard top reception tanks will be constructed above grade with completely sealed wall surface that is water tight and air tight. The dilution water tank is a pre-manufactured tank.

All feedstock storage tanks will have one liquid inlet above the liquid level, and two liquid outlets below the liquid level; one for transferring the feedstock to the anaerobic digestion system; the other for evacuation during shutdown or emergency.

Internally, the reception tank will contain mixers to avoid any probability of solids or sediments settling in these tanks. Flangeless hot water piping will be installed around the circumference of the tank to heat the feedstock (cheese whey permeate and fat, oil, and grease). A hot water circuit (obtained from the cogeneration engines) goes through the piping; the same type of system is used to heat the digesters, reception tanks, and desulfurization unit. Through continuous monitoring of temperature and level, with instruments installed in the tank and read by the PLC, tank temperature and level are regulated accordingly, to avoid mixing and pumping issues.

The breathing lines from the reception tanks will be directly connected to the air duct which brings the ventilation air from the solids unloading bunkers to the engines. The engines will use the ventilation air coming from the air duct as combustion air. The amount of air needed by the engines for the combustion process is much higher than the amount of ventilation air being directed to the engine building, ensuring that any odors in the ventilation air are not released to the atmosphere.

Digester Gas System

The digester gas system consists of digesters and a buffer storage tank located together with the two feedstock reception tanks and the dilution water tank. The digesters utilize a UTS process design with the UTS Triton®, ring in ring tank design. Feedstock will be digested in the inner and outer rings, in series, of the two digesters, which will function in parallel. The digested substrate is then pumped to the buffer storage tank, where some additional digester gas will be produced. The total digester gas flow produced in the digesters and in the buffer storage tank will be directed through a digester gas manifold to a conditioning system and then to the cogeneration engines that will convert the digester gas to electricity and heat. The digesters and the buffer storage tank include a double membrane digester gas holder roof that allows homogenization of the digester gas produced, as well as the capacity to provide short term digester gas storage.

Digester

The anaerobic digestion of the substrate occurs in the digester tanks. Each digester is identical in construction. The inner ring where the final digestion process will occur will be constructed of a dual layer flexible membrane. The outer and inner ring of each digester will be mixed with submersible hydraulic mixers which ensure thorough mixing and homogenization of incoming feedstock and substrates in the digesters.

In the engine building, plate heat exchangers (one per engine) will transfer the jacket water heat from the engines to the digesters hot water circuit. The heat will then be transferred from the pipes surrounding the inner walls of the digester's rings to the digesting feedstock providing the appropriate temperature to the naturally present microorganisms which are responsible for the anaerobic digestion.

In order to maintain mesophilic temperature range in the digesters, the rings will be insulated. The malodorous compounds within the organic substrate, known as volatile organic acids (e.g. acetic acid, propanoic acid, butanoic acid) are what the anaerobic microorganisms (methanogenic bacteria) eventually consume to produce digester gas. In the process of digesting these volatile organic acids odors are minimized. The hydraulic retention time inside the digesters is between 25 and 35 days. The hydraulic retention time is a measure of the average time that one unit of feedstock (organic matter) remains within the digester.

The digester gas production from the input substrates is optimized through the anaerobic digestion system. The outer ring is used as a primary digester, for introduction of the feedstock, and the inner ring is used as a secondary digester. The biological anaerobic digestion of the feedstock will first take place in the outer ring producing digester gas as a result of the process. The partly digested feedstock is then conducted to the inner ring where further anaerobic digestion occurs yielding additional digester gas from the feedstock.

The dual layer flexible membrane of the inner rings allows mixing and storage of the digester gas produced. The inner membrane has a special coating for gas tightness and gas resistance and the outer membrane is UV-stabilized. Each cover includes a dedicated air blower that keeps the external membrane inflated which the internal membrane fluctuates in position based on the digester gas production and the digester gas use (i.e. differential pressure). A level transducer mounted in the outside membrane tracks the relative position of the internal membrane. A methane detector is provided at the backpressure valve air outlet of the inter-membrane space. The methane sensor measures methane content in the existing air and alarms at present methane concentrations. This security system indicates if there is a leak in the internal membrane. The membrane will have low permeability, preventing the release of odors or gaseous compounds to the atmosphere.

Each digester is equipped with a pair of flash-back (flame) arresters and pressure/vacuum relief valves connected to the digester roof piped in parallel with a three-way manual change over valve installed in the common supply piping so that there shall be only one of the flash-back arrester and pressure/vacuum relief valves in effective service at all times.

Buffer Storage Tank

Digestate, the remainder of the substrates following anaerobic digestion, is pumped intermittently from each digester to the buffer storage tank. The roof will consist of a dual layer flexible membrane. The buffer storage tank has two submerged mixers to prevent settling of solids.

This tank provides additional residence time required for the digestate, thus greatly reducing the likelihood of undigested organic matter leaving the system. The buffer storage allows degasification and liberates the entrapped gases thereby reducing the odor level of post-digestion handling to an almost undetectable level, and prevents the unwanted release of methane during the next stage of pressing (i.e., composting or land application). Furthermore, the buffer storage tank provides capacity to handle any scheduled and unscheduled maintenance situation for downstream process equipment such as solid separation or wastewater treatment.

The buffer storage tank also provides for digester gas storage in its double membrane gas holder roof. The inner membrane has a special coating for gas tightness and gas resistance and the outer membrane is UV-stabilized. Each cover includes a dedicated air blower that keeps the external membrane inflated, which the internal membrane fluctuates in position base on gas production as gas use (e.g. differential pressure). A level transducer mounted in the outside membrane tracks the relative position of the internal membrane. A methane detector is provided at the backpressure valve air outlet of the inter-membrane space. The methane sensor measures methane content in the existing air and alarms at present methane concentrations. This security system indicates if there is a leak in the internal membrane.

The buffer storage tank is equipped with a pair of flash-back (flame) arresters and pressure/vacuum relief valves connected to the digester roof piped in parallel with a three-way manual change over valve installed in the common supply piping so that there shall be only one of the flash-back arrester and pressure/vacuum relief valves in effective service at all times.

The capacity of the dual membrane roof of the buffer storage tank in additional to that of the two digester tanks provides sufficient storage of digester gas for the majority of maintenance and service of the cogeneration engines.

Lastly, the buffer storage tank acts as a digestate storage and volume buffering tank. Depending on the digestate management strategy, digestate may be processed intermittently, therefore the tank is large enough to provide several days of storage.

Digester Gas Conditioning

The facility will produce digester gas in the two digesters and in the buffer storage tank composed of approximately 64% methane. The rest of the digester gas will be mainly carbon dioxide with some traces of other compounds like hydrogen sulfide.

The digester gas collected from the head space of the digesters and the buffer storage tank is conducted to a digester gas common pipe by means of compressors. Before combustion in the engines, the digester gas needs to be conditioned to remove harmful substances which may cause damage to the cogeneration engines. The conditioning system consists of a desulfurization system to reduce the hydrogen sulfide contained in the digester gas and a digester gas cooling system to reduce the moisture content of the digester gas. The condensate from the gas cooling system is pumped into the gas condensate tank. The flare, downstream of the conditioning system, will combust the digester gas in the event that it cannot be used by the engines.

Chillers are used to cool down the digester gas produced in the digesters and buffer holding tank to reduce the moisture content prior to combustion in the engines. The chillers utilize heat exchange via a refrigeration cycle. The resulting condensate is cooled into an underground tank and pumped back into the dilution tank. The tank is level controlled.

Digester Gas Desulfurization Unit

Hydrogen sulfide (H2S) is present in the digester gas produced during anaerobic digestion due to the degradation of proteins and other sulfur containing compounds present in the feedstock. In the cogeneration engines, H2S reacts with water to form sulfuric acid (H2SO4) which is highly corrosive.

An in-tank bio-scrubber, along with an external physical contact scrubber (iron sponge) is integrated into the process design to effect H2S reduction. The in-tank H2S removal utilizes bio-scrubbers in a two stage process: absorption of H2S via a liquid medium followed by the biological oxidation of H2S in the liquid. Bacteria like Thiobacillus sp. (which have the ability to grow under various environmental stress conditions such as oxygen deficiency, acid conditions, etc.) are used for the conversion of H2S and other sulfur compounds by biological processes.

Regulated and controlled air will be dosed into the digester gas space. Multi-location probes regularly sample the digester gas, sending data to the central PLC. The PLC regulates the on and off valve to ensure that the oxygen level is adequate to promote desulfurization but remains below explosive limits.

External H2S removal will be effected with an iron sponge system. Iron sponge is a non-renewable method of removing H2S. The H2S reacts with the iron to form iron sulfide. The iron sponge consists of wood shavings or wood chips impregnated with hydrated iron oxide.

Exposure of H2S to mercaptans produces iron sulfides and iron mercaptides. The chemical process of H2S removal with the iron sponge produces iron sulfides.

$2FeO_3 + H_2O + 6H_2S \rightarrow 2Fe_2S_3 + 8H_2O$

The process occurs after gas/liquid separation and prior to the dehydration process. For the iron sponge to effectively perform, it must be maintained within a defined range of sufficient moisture content. This requirement is typically satisfied if the gas is saturated with water vapor, as is frequently the case with digester gas or digester gas. Therefore, no water spray is required for a digester gas application. Excess water is well tolerated by the iron sponge as long as the excess is drained off so as not to flood the bed. Also, the reaction of iron oxide with H2S produces water contributing to proper hydration. The moisture drained is collected in the condensate tank and used for process dilution in the front end of the process along with other condensate.

Iron oxide impregnated into the wood surface will not wash off or migrate with the gas. If the iron sponge has dried in storage it can be re-wet and remain effective. A maximum temperature 120 degrees F should not be exceeded. The minimum temperature is 50 degrees F, or whatever is necessary to avoid hydrate formation relative to the system pressure and composition of the digester gas. The iron sponge reaction is not pressure sensitive and is not affected by other gas constituents.

The equipment needed for iron sponge treatment consists of a vessel which is filled with iron oxide. The gas is passed down flow with the H2S removed to meet the designed 40 ppmv requirement until the iron sponge is exhausted. The sponge is then either revivified or replaced. For continuous operation there will be an alternate vessel provided (standby unit) all piped to operate the process without any interruption. Valves can be arranged so either bed can operate while the other is serviced. The system is total enclosed and there is no potential of leaks. The multi stage method of desulfurization is capable of reducing H2S levels in the digester gas from 1,500 ppm down to between 10 and 50 ppm.

Natural Gas Supply

The digester gas plant will have a natural gas supply. Natural gas will be used during the commissioning of the digester gas plant to fuel the cogeneration engines to produce the amount of electricity initially required. This will also provide the plant with the necessary heat for the reception tanks and digesters. During normal operation, natural gas may be added to the digester gas in order to optimize the digester gas quality and the efficiency of the engines.

Digestate Management System

The digestate that leaves the buffer storage tank will be low solid organic slurry that hall be dewatered by filter screw press(es). The press will separate the digestate into liquid and solid fractions. The liquid fraction (filtrate) is sent to a Dissolved Air Floatation (DAF) unit for further solid separation. The solids removed from the DAF unit are dewatered using a horizontal decanter/centrifuge. The solids fraction of the digestate has a cornmercial value and shall be sold as a byproduct. All process liquid effluent, meeting specified discharge requirements, will be directed to the Tulare Industrial WWTP for further treatment.

A feed pump will be used to transfer digestate from the buffer holding tank to the filter screw press. The flow to the press will be monitored and controlled using a Magmeter. The press will be elevated and dewater solids and will discharge by gravity to a solids pad directly below.

The liquid effluent from the filtrate will flow by gravity to an intermediary tank from which it will be pumped to a DAF system. Polymer is added to the DAF influent to promote flocculation and removal of suspended solids. The polymer system doses polymer based on the DAF influent rate measured using a Magmeter. Through primary and secondary solid separation with a filter screw press and DAF of the pressage, suspended solids are significantly reduced to < 0.5% total solids. The float from the DAF is collected and pumped to a centrifuge for further dewatering. The dewatered solids fall by gravity to the solids pad to be combined with the press cake from the filter screw press for sale as compost. Clarified effluent from both the DAF and centrifuge is discharged directly to the Tulare Industrial WWTP for further treatment.

The polymer make down system will utilize a dry polymer which is diluted and aged prior to dosing into the DAF system. The dry polymer is supplied in bead-form (crystals) which eliminates dust while handling. The beads are packaged in small 25 kg bags from which the operator transfer them to a polymer hopper. The polymer make down system will use a vacuum polymer unloading and conveying system to transfer powder into the polymer mixing system for dilution with water. An air blower will transfer the polymer via a venture educator to a wetting head above the polymer mixing tank. The system utilizes totally enclosed conveying, mixing and storage units.

<u>Digester Gas Cogeneration Engines</u>

The digester gas produced in the facility will be used as fuel by the cogeneration engines. The reciprocating digester gas engines are coupled with an alternator and this combination is term a genset. Internal combustion gas gensets will be used in the facility to produce electricity and heat. Heat will be obtained from two sources: the high temperature circuit of the engine (which is cooling down the engine; the lubricating oil as well as the intercooler first stage) and the exhaust gases (which leave the engine at a temperature above 400 degrees C). The digester gas will be pumped by compressors through the gas pipe to the engines.

The cooling system of the engine consists of closed water circuits including one low temperature circuit and one high temperature circuit. The circuits consist of pumps, regulation valves, safety valves, sensors and radiators. The radiators will be mounted on the engine building roof. The high temperature circuit heat will be recovered by means of plate heat exchangers. The heat will be transferred to the hot water circuit that will heat the reception tanks and digesters.

The exhaust gas system consists of piping, insulation, a steam boiler, a silencer, and a stack. The steam boilers will produce steam out of the heat of the exhaust gases. The steam boiler will have a bypass flap in case no or less steam is needed by the consumers. Each engine will have its own exhaust stack.

The engine room will have a ventilation system which provides combustion air to the engines and cooling for the engines. The air duct coming from the solid reception building, where the breathing lines of the reception tanks are connected, is directed to the engine room in order to use the ventilation air of the solid reception building as combustion air for the engines. The ventilation air from the reception building and the breathing air from the reception tanks will be guided via a duct direct to the engine combustion filters. The engines will use this air as part of the needed combustion air and will therefore burn any odor produced in these buildings/tanks.

Digester Gas Flare

The normal operation of the digester gas plant consists of using the digester gas produced in the digesters and in the buffer storage tank as fuel for the engines in order to produce electricity and heat. The digesters and the buffer tank have some digester gas storage capacity making it possible to hold produced digester gas for limited periods of time.

When digester gas cannot be utilized by the engines and there is no available storage capacity in the digester gas plant, the digester gas will be combusted by the flare. The flare will combust the digester gas produced by the facility during the commissioning period as the digester gas may have not yet reached the adequate quantity and/or quality to run the engines.

IV. CONTROL EQUIPMENT EVALUATION

S-8153-1-0

The digester tanks and digestate (buffer) holding tank will be equipped with a pressure-vacuum (PV) relief valve. All tanks will be fully enclosed and vent to the engines with the exception of the overflow buffer tank and screw press buffer tank which vent locally via an air filter.

An in-tank bio-scrubber, along with an external physical contact scrubber (iron sponge) is integrated into the process design to effect H2S reduction of the digester gas. The in-tank H2S removal utilizes bio-scrubbers in a two stage process: absorption of H2S via a liquid medium followed by the biological oxidation of H2S in the liquid. Bacteria like Thiobacillus sp. (which have the ability to grow under various environmental stress conditions such as oxygen deficiency, acid conditions, etc.) are used for the conversion of H2S and other sulfur compounds by biological processes.

The equipment needed for iron sponge treatment consists of a vessel which is filled with iron oxide. The gas is passed down flow with the H2S removed to meet the designed 40 ppmv requirement until the iron sponge is exhausted. The sponge is then either revivified or replaced. For continuous operation there will be an alternate vessel provided (standby unit) all piped to operate the process without any interruption. Valves can be arranged so either bed can operate while the other is serviced. The system is total enclosed and there is no potential of leaks. The multi stage method of desulfurization is capable of reducing H2S levels in the digester gas from 1,500 ppm down to between 10 and 50 ppm.

The digester gas-fired enclosed flare proposed in this project has the potential to emit NOx, SOx, PM10, CO, and VOC emissions due to the incineration of digester gas generated by the anaerobic digester system. The enclosed flare uses a digester gas-fired automatic ignition pilot.

The system utilizes totally enclosed conveying, mixing and storage units. No additional emission controls are required.

S-8153-2-0 and '3-0

The engines are equipped with:
[X] Turbocharger
[X] Intercooler
[X] Positive Crankcase Ventilation (PCV)
[X] Air/Fuel Ratio Controller
[X] Lean Burn Technology
[X] Selective Catalytic Reduction

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

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

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

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

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

A. Best Available Control Technology (BACT) for Permit Unit S-8153-2-0 and '3-0

Applicability

District Rule 2201 states that BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following:

a) Any new emissions unit with a potential to emit exceeding two pounds per day,
b) The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day, and/or

c) Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day.
d) When a Major Modification is triggered for a modification project at a facility that is a Major Source.

As shown below, BACT is triggered for NOx, SOx, PM10, and VOC emissions for the engines when fired on digester gas fuel.

Digester Gas Fuel – Each Engine		
Pollutant	**Daily PE2**	**BACT Triggered?**
NO_x	17.2 lb/day	Yes
SO_x	4.2 lb/day	Yes
PM_{10}	3.8 lb/day	Yes
CO	217.6 lb/day	No*
VOC	17.2 lb/day	Yes

* BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year

Natural Gas Fuel – Each Engine		
Pollutant	**Daily PE2**	**BACT Triggered?**
NO_x	1.3 lb/day	No
SO_x	0.1 lb/day	No
PM_{10}	0.4 lb/day	No
CO	9.1 lb/day	No*
VOC	2.0 lb/day	No

* BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year

B. BACT Policy

Per District Policy APR 1305, Section IX, "A top-down BACT analysis shall be performed as a part of the Application Review for each application subject to the BACT requirements pursuant to the District's NSR Rule for source categories or classes covered in the BACT Clearinghouse, relevant information under each of the following steps may be simply cited from the Clearinghouse without further analysis".

The District's 2nd quarter 2012 BACT Clearinghouse was surveyed to determine if an existing BACT guideline was applicable for this class and category of operation. No BACT guidelines were found that cover waste gas-fired IC engines. The District previously issued BACT Guideline 3.3.13 to cover waste gas-fired full-time IC engines. However, this guideline was rescinded on August 22, 2008 and since has not been reissued. There have been various project specific BACT determinations performed for waste gas-fired IC engines since BACT Guideline 3.3.13 was rescinded. An industry-wide BACT determination will be performed in this project for waste gas-fired IC engines. Pursuant to the District's BACT policy, a Top-Down BACT analysis will be performed for inclusion of a new determination in the District's BACT Clearinghouse.

C. BACT Determination for Waste Gas Fired IC Engines

The Environmental Protection Agency (EPA), California Air Resources Board (CARB), San Diego County Air Pollution Control District (SDCAPCD), South Coast Air Quality Management District (SCAQMD), Bay Area Air Quality Management District (BAAQMD) and the San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT clearinghouses were reviewed to determine potential control technologies for this class and category of operation.

1. NOx Top-Down BACT Analysis for Permit Unit S-8153-2-0 and '3-0

<u>District Rule 4702</u>

District Rule 4702 limits emissions from spark-ignited internal combustion engines rated at >50 bhp used exclusively in non-agricultural operations for both rich and lean burn engines to 11 ppmv NOx corrected to 15% oxygen on a dry basis.

<u>South Coast AQMD Proposed Rule 1110.2</u>

SCAQMD proposed Rule 1110.2 which limits emissions from liquid and gaseous fueled engines proposes an emission limit of 11 ppmvd NOx (equivalent to 0.15 g/bhp-hr), 250 ppmvd CO (equivalent to 1.9 g/bhp/hr), and 30 ppmvd VOC (equivalent to 0.15 g/bhp-hr), all at @ 15% O2, for digester gas-fired engines.

<u>CARB Document Entitled "Stationary Source Emission Limit and Mobile Mitigation Measures Tables Excerpted from Air Quality Guidance for Siting Biorefineries in California (November 2011)"</u>

CARB drafted a document entitled "Stationary Source Emission Limit and Mobile Mitigation Measures Tables Excerpted from Draft Air Quality Guidance for Siting Biorefineries in California (October 2010)" which summarizes the most stringent permitted emission limits ARB staff identified for stationary source process equipment commonly used at biorefineries. Table V-2 lists emission limits of 11 ppmvd NOx (equivalent to 0.15 g/bhp-hr), 250 ppmvd CO (equivalent to 1.9 g/bhp-hr), and 20 ppmvd VOC (equivalent to 0.09 g/bhp-hr), all corrected to 15% O2 for biogas-fired reciprocating IC engines.

<u>Gallo Cattle Company Dairy Digester Gas-Fired Engine with NSCR (Permit N-1660-9)</u>

Gallo Cattle Company has installed a 545 bhp rich burn digester gas-fired engine with NSCR (Permit N-1660-9). The 545 bhp engine is subject to a BACT emission limit for NOx of 9.0 ppmvd @ 15% O2 or 0.15 g/bhp-hr.

Initial installation of the 545 bhp engine resulted in various compliance issues with the catalyst. The two problems that required correction were thermal damage and destruction of catalysts and emission excursions related to the engine entering lean conditions. The thermal damage and destruction of catalysts occurred because there was no interconnection between the generator and Air to Fuel Ratio controller to immediately close the fuel valve when there was an ignition fault. This was causing a delay of up to 15 seconds where unspent fuel could enter the hot catalyst after the engine was shut off. The facility installed ignition system fault circuits to correct this problem. The lean conditions resulted from a combination of issues: inadequately sized gas blower for the two engines, gas drying system not sufficiently drying the gas, which increased water vapor resulting in less gas and lower heat content, and dust/debris entering the fuel lines. This problem was most pronounced during hot weather because of the lower density of the gaseous fuel and greater water vapor content of the fuel which displaced fuel and reduced the heating value per volume of gas delivered. The facility upgraded the blower, replaced the dryer, and installed a coalescing filter canister. Correction of these problems solved the facility's compliance issues.

The digester gas-fired engine at Gallo Cattle Company was source tested on January 28, 2010. The results of the source tests were as follows:

Permit N-1660-9: 575 bhp digester gas-fired IC Engine with NSCR		
Parameter	**Result**	**Permit Limit**
NOx, ppmvd @ 15% O2	3.18	9.0
NOx, g/bhp-hr	0.061	0.15
CO, ppmvd @ 15% O2	384.64	1,100
CO, g/bhp-hr	4.513	9.0
VOC, ppmvd @ 15% O2	11.19	20
VOC, g/bhp-hr	0.075	0.09
Fuel H2S, ppmv	<1.0	59

The catalyst has continued to function satisfactorily and portable analyzer monitoring and results of the source test have shown that NOx emissions from engine N-1660-9 have been 9 ppmv @ 15% O2 or less since late September 2009.

Woodbridge Winery Digester Gas-Fired Engines with NSCR (Permits N-2321-649 & -650)

Woodbridge Winery has installed two 122 bhp rich burn digester gas-fired engines with NSCR (Permits N-2321-649 & -650). Both engines are subject to a BACT limit for NOx of 11.0 ppmvd @ 15% O2 or 0.15 g/bhp-hr.

The digester gas-fired engines at Woodbridge Winery were source tested on October 6 and 7, 2009 and November 15, 2011. The results of the source tests were as follows:

Permit N-2321-649: 122 bhp digester gas-fired IC Engine with NSCR (October 6, 2009)		
Parameter	**Result**	**Permit Limit**
NOx, ppmvd @ 15% O2	3.1	11
NOx, g/bhp-hr	--	0.15
CO, ppmvd @ 15% O2	5.9	70
CO, g/bhp-hr	--	0.60
VOC, ppmvd @ 15% O2	< 0.3	51
VOC, g/bhp-hr	--	0.25
Fuel H2S, ppmv	--	25

Permit N-2321-649: 122 bhp digester gas-fired IC Engine with NSCR (November 15, 2011)		
Parameter	**Result**	**Permit Limit**
NOx, ppmvd @ 15% O2	0.75	11
NOx, g/bhp-hr	0.0068	0.15
CO, ppmvd @ 15% O2	2.12	70
CO, g/bhp-hr	0.0118	0.60
VOC, ppmvd @ 15% O2	< 0.14	51
VOC, g/bhp-hr	< 0.0004	0.25
Fuel H2S, ppmv	8.3	25

Permit N-2321-650: 122 bhp digester gas-fired IC Engine with NSCR (October 7, 2009)		
Parameter	**Result**	**Permit Limit**
NOx, ppmvd @ 15% O2	3.6	11
NOx, g/bhp-hr	--	0.15
CO, ppmvd @ 15% O2	8.0	70
CO, g/bhp-hr	--	0.60
VOC, ppmvd @ 15% O2	< 0.3	51
VOC, g/bhp-hr	--	0.25
Fuel H2S, ppmv	--	25

Permit N-2321-650: 122 bhp digester gas-fired IC Engine with NSCR (November 15, 2011)		
Parameter	**Result**	**Permit Limit**
NOx, ppmvd @ 15% O2	1.83	11
NOx, g/bhp-hr	0.0167	0.15
CO, ppmvd @ 15% O2	2.11	70
CO, g/bhp-hr	0.0117	0.60
VOC, ppmvd @ 15% O2	< 0.14	51
VOC, g/bhp-hr	< 0.0004	0.25
Fuel H2S, ppmv	8.3	25

<u>Fiscalini Farms Digester Gas-Fired Engines with SCR (Permit N-6311-9)</u>

Fiscalini Farms has installed a 1,057 bhp lean burn digester gas-fired engine with SCR (Permit N-6311-9). The 1,057 bhp engine is subject to a BACT emission limit for NOx of 11.0 ppmvd @ 15% O2 or 0.15 g/bhp-hr.

Initial installation of the 1,057 bhp engine resulted in various compliance issues. There were initial problems with the urea injection system. When the system was shut down for an extended period, urea dried in the solenoid valves for the pump. The pump was not pumping urea so the SCR system was not functioning; this problem was identified fairly quickly and the pumps were repaired.

Another issue related to the urea injection system was the orientation of the injectors. In the original orientation, urea would accumulate in the interior of the engine exhaust and periodically release. The sensor that the SCR supplier uses to reduce NOx and ammonia slip responds to reactive nitrogen (NOx and NH3), so these periodic releases of urea would cause incorrect readings and lead to periodic spikes in emissions. The SCR supplier addressed this issue by changing the orientation of the injectors to spray in the direction of the exhaust and this solved the problem.

The most persistent problems have been related to gas production, gas quality, and engine operation. The digester gas-fired engine is rated at 710 kW but because of problems with the digester tanks and breakdowns causing the shutdown of one of the digester tanks, the amount of gas produced has been lower than anticipated and the digester gas-fired engine has generally operated at 400 kW or less, sometimes producing less than 200 kW. The engine was also operating with very high temperatures and high pre-catalyst NOx emissions. The facility had stated that the pre-catalyst NOx emissions from the engine would be < 50 ppmv @ 15% O2 but the pre-catalyst NOx emissions at times were greater than 150 ppmv @ 15% O2 and sometimes the pre-catalyst emissions were unstable. The SCR system was actually very effective at reducing NOx (the control efficiency for NOx was typically ~ 85%). However, the extremely high pre-catalyst NOx emissions would sometimes lead to higher than desired post-catalyst emissions (though the control efficiency and emission reductions were satisfactory) and when the pre-catalyst emissions were unstable it caused difficulties for the SCR system to rapidly adjust injection rates. The highest exhaust temperatures and high and unstable emission concentrations would generally occur during periods of low load operation. This was likely because the engine and air-to-fuel controller had not been adjusted and tuned for running at such low loads since this is not typical for engines powering large generators. This caused periods of low oxygen and/or high engine temperatures leading to high NOx emissions and unstable emissions. The engine and air to fuel controller were adjusted for lower emissions at low load operation and this resulted in much lower pre-catalyst NOx emissions and more stable operation.

The other issue was the high sulfur content of the digester gas. The Fiscalini Farms permit includes a 50 ppmv limit for sulfur in the digester gas but the sulfur content has generally been in the hundreds of ppmv and even as high as 3,000 ppmv. Such high sulfur contents can decrease the effectiveness of catalysts and reduce catalyst life. The SCR catalyst that the system uses has proved to be fairly resistant to sulfur but the effectiveness of the oxidation catalyst coating has been greatly reduced. Fiscalini Farms received a variance so they could test different technologies to reduce sulfur in the digester gas.

Overall, the SCR system has proven that it is capable of consistently meeting the District's NOx limit of 0.15 g/bhp-hr provided that engine is properly tuned and operated.

The digester gas-fired engine at Fiscalini Farms was source tested on May 14, 2012. The results of the source tests were as follows:

Permit N-6311-9: 1,057 bhp digester gas-fired IC Engine with SCR		
Parameter	**Result**	**Permit Limit**
NOx, ppmvd @ 15% O2	5.63	11.0
NOx, g/bhp-hr	0.082	0.15
CO, ppmvd @ 15% O2	112.82	210
CO, g/bhp-hr	1.00	1.75
VOC, ppmvd @ 15% O2	14.77	28
VOC, g/bhp-hr	0.075	0.13

<u>Waste Gas Cleanup</u>

For natural gas engines, the use of catalyst after-treatment is an effective method for pollutant control. Higher emission limits are allowed for waste gas engines because of catalyst fouling when exposed to the combustion products. The cause of the catalyst fouling was due to a specific impurity in the gas stream. These impurities are known as siloxanes. Siloxanes result from the decomposition of silicon compounds generally found in items such as human cosmetics. When siloxanes are combusted and then cool in the exhaust, they create a glass-like coating that covers and deactivates catalysts and causes damage to downstream equipment.

A prime concern for many waste gas engine operators is the quality of the fuel going into the engines. Waste gas, whether coming from a wastewater treatment plant digester or from a landfill, has many impurities, including but not limited to sulfur-containing compounds and siloxanes, that require some sort of treatment. If left untreated, raw waste gas can damage engine components that will require more maintenance and ultimately, reduce the longevity of the engine. Siloxanes can crystallize and become deposited in fuel lines and engine parts. As a result, more frequent major maintenance on engines is required so that deposits from untreated waste gas can be cleaned up from within the engine. Failure to perform this kind of maintenance can result in catastrophic damage to an engine. The pretreatment of waste gas is even more critical with the employment of catalyst-based after-treatment technologies downstream from the engines. If left untreated, impurities such as siloxanes can result in the rapid poisoning of the catalyst downstream of the engine. The active sites of the catalyst become masked by the deposition of silica, therefore reducing the efficiency of the entire catalyst.

It has been established that waste gas cleanup cannot consist of siloxane removal only. Depending on the source of the raw waste gas, some facilities have waste gas profiles that contain varying levels of other pollutants, such as VOCs and sulfur compounds. Also, with the installation of fuel cells, the fuel specifications for these sophisticated units are extremely stringent for impurities. Waste gas entering a fuel cell must be completely cleaned of many impurities to guarantee proper performance.

Some facilities currently have practically no gas cleanup while most others employ some sort of gas cleanup for improved engine maintenance. On the other hand, a few facilities already employ a complete waste gas cleanup system for protection of post combustion catalysts or turbines. Many facilities often utilize a typical cleanup system that results in moisture and particulate removal. Depending on the existing level of contaminants, some facilities may have to install complete, skid-mounted gas cleanup systems that will include water and particulate removal filters, sorbent vessels for H2S and siloxane removal, compressors, chillers, coalescing filters, and vessels for VOC and sulfur species removal if necessary.

There are two types of siloxane removal systems, regenerative and non-regenerative. Regenerative siloxane removal systems do not require constant removal of the sorbent material from its vessel. It is regenerated using a heated purge gas, while a second vessel handles the siloxane cleanup load. Non-regenerative siloxane removal systems require periodic replacement of the sorbent material (activated carbon or silica gel) once it is spent. Additionally, the use of two beds is more beneficial in that one bed can still be used while the other is recharged with fresh sorbent and vice versa. These kinds of systems are sized to handle the site-specific siloxane load; higher amounts of sorbent are required for waste gas streams with higher levels of siloxanes and must be able to handle intermittent spikes.

Due to these ongoing issues regarding siloxane waste gas impurities, the BACT Guideline in this project will apply only to sources where siloxane removal is not an issue. The siloxane issue is not applicable for all industries as many waste gas streams do not contain siloxanes including agricultural waste gas. Additionally, systems have now been developed and demonstrated that removal of siloxanes from waste gases is feasible; therefore, even for non-agricultural waste gas, the cost of these systems must be evaluated prior to ruling out add-on control options. Because further reductions in NO_X emission are critical for the District's ability to reach attainment of health-based air quality standards for ozone and particulate matter, in accordance with District Rule 2201, the District will identify and evaluate potential add-on controls and alternative equipment with reduced NO_X emissions and perform an industry wide BACT analysis for the waste gas streams where siloxanes are not an issue.

Based on review of the available technical information and contacts with catalyst suppliers, the District has determined that catalytic controls are a technologically feasible control IC engines fired on waste gas. Therefore, this option will be evaluated for the project. Additionally, information from multiple sources indicates that alternative technologies (such as fuel cells and microturbines) have been utilized at a number of facilities to produce electricity from various types of waste gas. These technologies have significantly lower NOx emissions than uncontrolled reciprocating IC engines. Therefore, these technologies will also be included in the BACT analysis as alternate basic equipment. The BACT analysis for the proposed waste gas-fired engine will identify catalytic controls as technologically feasible and will also list the alternate equipment options that are evaluated below.

Step 1 – Identify all control technologies

The following control technologies and alternative equipment options have been identified for waste gas-fired IC engines. Emissions from each technology are estimated based on a review of technical documents, contacts with suppliers, and/or engineering judgment.

NOx

As shown above, District Rule 4702 requires and South Coast AQMD Rule 1110.2 has proposed an emission limit of 11 ppmvd NOx @ 15% O2 as an Achieved in Practice limit. CARB has released a document identifying stationary source equipment achieving 11 ppmvd NOx @ 15% O2 (equivalent to 0.15 g/bhp-hr). Gallo Cattle Company, Fiscalini Farms, and Woodbridge Winery current operate digester gas-fired IC engines which meet 9-11 ppmvd NOx @ 15% O2 (equivalent to 0.15 g/bhp-hr). Therefore, 0.15 g/bhp-hr will be established as the Achieved in Practice NOx limit.

1) NO_X emissions ≤ 0.15 g/bhp-hr (Non-Selective Catalytic Reduction (NSCR) for rich burn engines, Selective Catalytic Reduction (SCR) for lean burn engines, or equivalent) (Achieved in Practice)
2) Small Gas Turbine (< 25 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
3) Microturbine (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
4) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
5) Stirling Engine (≤ 30 ppmv NO_X @ 3% O_2 external combustion ≈ 10 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Description of Control Technologies

1) NO_X emissions ≤ 0.15 g/bhp-hr (Achieved in Practice)

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

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

The digester gas produced in the Colony Energy Partners – Tulare, LLC facility will be used as fuel by the cogeneration engines. The reciprocating digester gas engines are coupled with an alternator and this combination is term a genset. Internal combustion gas gensets will be used in the facility to produce electricity and heat. Heat will be obtained from two sources: the high temperature circuit of the engine (which is cooling down the engine; the lubricating oil as well as the intercooler first stage) and the exhaust gases (which leave the engine at a temperature above 400 degrees C). The digester gas will be pumped by compressors through the gas pipe to the engines. The engine manufacturer has guaranteed a NOx emission rate of 0.15 g/bhp-hr.

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

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

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

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

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

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 waste gas-fired microturbines operating in California as of the year 2006.[1] Microturbines generally have electrical efficiencies of 25-30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30-33%. Microturbine manufacturers include Capstone Microturbines and Ingersoll Rand Energy Systems.

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

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_X, CO, and VOC emissions than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_X, or DLN) combustion technology. Microturbines manufacturers will generally guarantee NO_X emissions of 9-15 ppmv @ 15% O_2. However, several emission tests performed on waste gas-fired microturbines have indicated even lower emissions. A number of dairy digester gas-fired microturbines have been installed in Europe and some have recently been installed at dairies in the United States, including Twin Birch Dairy and New Hope Farm View Dairy in New York and den Dulk Dairy in Michigan.[2]

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

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of CO_2 that is found waste gas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for waste gas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cells. Although this expense can be substantial, waste gas-fueled fuel cells have been installed at several wastewater treatment plants and fuel cells have also been fueled with other types of waste gas (e.g. landfill gas and brewery wastewater gas). A dairy digester gas-fired fuel cell test project was also installed at Haubenschild Dairy in Minnesota. The fuel cell operated successfully but the cost of gas cleanup and reforming to hydrogen for the low temperature Proton Exchange Membrane (PEM) fuel cell was prohibitive. A Cornell University, Manure Management Program study about using fuel cells to generate energy from waste gas found that fuel cells were "technically feasible on dairy farms with 1,000 cows" (http://www.manuremanagement.cornell.edu/Docs/Fuel%20Cell%20Technote%2010-07-04%20FINAL.pdf).

5) Stirling Engine (≤ 30 ppmv NO_X @ 3% O_2 external combustion ≈ 10 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Stirling engines are external combustion engines that use an external heat source to transfer energy to a working fluid sealed inside the engine. The inert working fluid sealed inside Stirling

[2] See EPA AgStar Program "Guide to Anaerobic Digesters" (http://www.epa.gov/agstar/operational.html)

engines is usually either helium or hydrogen. Stirling engines are generally rated in the smaller size range of less than 55 kW and are typically produced for specialized applications. The overall efficiency of Stirling engines is around 15-30%.

Because Stirling engines use external combustion, they have the potential for very low emissions equivalent to those produced by a boiler. A few waste gas-fired Stirling external combustion engines were tested at landfills but there were problems keeping the working fluid completely sealed in the engines. No digester gas-fired external combustion engines that are currently operating could be identified. It is not known if Stirling engines are currently being commercially produced. The main producer of Stirling engines, STM Power, closed in 2007 and was only recently revived as Stirling Biopower. Therefore, this option will not be evaluated further for this project.

Step 2 - Eliminate Technologically Infeasible Options

All of the options listed above are considered to be feasible with the exception of option 3.

Option 3 is determined to be infeasible for the following reasons:

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

According to Solar Turbines, waste gas-fired gas turbines rated less than 3 MW are not currently being produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines. The proposed project would require a gas turbine rated 1550 kW, which is below the range that is currently being marketed; therefore, small waste gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	Fuel Cells (<0.05 lb/MW-hr ≈ 1.5 ppmv @ 15% O_2)	N
2	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)	Y

There are no remaining control technologies for NOx.

Step 4 - Cost Effectiveness Analysis

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

The proposed digester gas-fired engine is a lean burn, digester gas-fired, engine is subject to the District Rule 4702 emission limits for non-agricultural, lean burn, waste gas-fired IC engines. Therefore, in accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo, the District Standard Emissions used for the BACT cost analysis below for the proposed engine will be based on the emission limits for non-agricultural, lean burn, waste gas-fired IC engines contained in District Rule 4702, Section 5.1.1, Table 2, 2.d (11 ppmvd NO_X, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2)).

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

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

Assumptions

- Hours of Operation for the Engine = 8,760 (proposed by applicant)
- Waste gas F-Factor: 9,100 dscf/MMBtu (60 °F)
- Higher Heating Value for Waste Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (60°F)
- Price for electricity: $0.08843/kW-hr (based on California Renewable Energy Tariff for projects on-line in 2011)
- BHP to Btu/hr conversion: 2,542.5 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- Typical mechanical efficiency for engine: 35%
- Generator Efficiency: 95%
- The total annual heating input of the digester gas combusted in either one of the proposed engines (S-8153-2 or '3) will not exceed 137,770 MMBtu/year (2,165 bhp x 24 hr/day x 365 day/year x 2,542.5 Btu/hp-hr x 1 $hp\text{-}hr_{in}/0.35\ hp\text{-}hr_{out}$ x 1 MMBtu/10^6 Btu). This is equivalent to 229.6 MMscf/year based on a digester gas heating value of 600 Btu/scf.
- Typical purchase and Installation Cost for digester engines: $1,475/kW (estimated based on review conducted by District)
- Typical operation costs for engines: $0.0152/kW-hr (estimated based on review conducted by District)
- Rule 4702 NO_X emission limit for non-agricultural, lean burn, waste gas-fired IC engines: 11 ppmv @ 15% O_2 (0.042 lb/MMBtu) = 0.14 lb/MW-hr @ 35% engine efficiency
- Rule 4702 VOC emission limit for non-agricultural, lean burn, waste gas-fired IC engines: 750 ppmv @ 15% O_2 as CH_4 (1.00 lb/MMBtu) = 3.41 lb/MW-hr @ 35% engine efficiency

Assumptions for Fuel Cell System

- Net electrical efficiency for fuel cell power plant: 39% (includes parasitic load for gas conditioning system)
- Typical Purchase and Installation Cost for fuel cells including cost for waste gas conditioning system: $7,000/kW (based on review conducted by District)
- Typical operation costs for fuel cells: $0.0215/kW-hr (based on review conducted by District)
- Fuel Cell Stack Replacement Cost: $500/kW-yr (conservatively estimated based stack replacement being one quarter of initial installation cost and stack replacement being required every 3.5 years) [3]
- Fuel Cell NO_X emissions: 0.05 lb/MW-hr = 0.0058 lb/MMBtu (≤ 1.5 ppmv NO_X @ 15% O_2) *(Note: fuel cells are usually certified to the ARB Distributed Generation Certification level of 0.07 lb-NO_X/MW-hr; however, measured emissions from many fuel cells have been lower)*
- Fuel Cell VOC emissions: 0.02 lb-VOC/MW-hr = 0.0027 lb/MMBtu (≤ 2.0 ppmv VOC @ 15% O_2 as CH_4 based on ARB Distributed Generation Certification level of 0.02 lb-VOC/MW-hr and emission tests on fuel cells)
- Size of fuel cell system needed for proposed project: 1797 kW (137,770 MMBtu/year x year/8760 hr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.39 (electrical efficiency))
- Fuel cells may offer the ability for greater heat recovery in comparison to an IC engine; however, the value of this heat will not be quantified since it is not known if the facility has an economical use for it.

Capital Cost

The estimated increased incremental capital cost for replacement of one of the proposed 2,165 bhp IC engines with a fuel cell is calculated based on the difference in cost of a fuel cell power plant and the IC engine.

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

1797 kW x ($7,000/kW – $1,475/kW) = $9,928,425

Annualized Capital Cost

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

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[3] Examples of fuel cell stack replacement costs and intervals are provided in the following links:
http://www.ornl.gov/sci/femp/pdfs/020501-Hughes-fuelcell-WashingtonDC.pdf,
http://masstech.org/Project%20Deliverables/GB_GSI_FeasibilityStudy_Gill_Montague.pdf,
http://www.masstech.org/is/westover_profile.pdf,
http://www.epa.gov/chp/documents/catalog_chptech_fuel_cells.pdf
http://dodfuelcell.cecer.army.mil/climate/reports/AK_PostOfficeReport.pdf
http://www.fuelcellenergy.com/files/Copy%20of%20DFC300MA%20Spec%20_9318.pdf

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

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

A = $[\$9,928,425 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$
= **$1,615,805/year**

Annual Costs

Electricity Generated

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

Proposed IC Engine
1550 kW x 24 hr/day x 365 day/yr = 13,578,000 kW-hr/year

Fuel Cells (Alternate Equipment)
137,770 MMBtu/year x year/8760 hr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.39 (electrical efficiency) = 1797 kW

137,770 MMBtu/year x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.39 (electrical efficiency) = 15,742,836 kW-hr/year

Revenue from Increased Electric Generation from a Fuel Cell Power Plant
(15,742,836 kW-hr/year – 13,578,000 kW-hr/year) x $0.08843/kW-hr = $191,436/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Proposed IC Engines
13,578,000 kW-hr/year x $0.0152/kW-hr = $206,386/year

Fuel Cells (Alternate Equipment)
15,742,836 kW-hr/year x $0.0215/kW-hr = $338,471/year

Annual Costs of Increased Maintenance
$338,471/year – $206,386/year = $132,085/year

Fuel Cell Stack Replacement Costs
$500/kW-yr x 1797 kW = $898,500/year

<u>Total Increased Annual Costs for Fuel Cell System as an Alternative to Proposed Engines</u>

Annual Capital Cost – Revenue from Increased Electric Generation from a Fuel Cell Power Plant + Annual Costs of Increased Maintenance + Fuel Cell Stack Replacement Costs

$1,615,805/year – $191,436/year + $132,085/year + $898,500/year = **$2,454,954/year**

<u>Emission Reductions:</u>

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to compare with the alternative equipment will be based on the emission limits for lean burn agricultural IC engines contained in District Rule 4702, Section 5.2, Table 2, 2.d. The following emissions factors will be used for the cost analysis:

<u>District Standard Emissions:</u> 0.14 lb-NO_X/MW-hr (11 ppmv NO_X @ 15% O_2) and 3.41 lb-VOC/MW-hr (750 ppmv VOC @ 15% O_2 as CH_4)

<u>Emissions from Fuel Cells as Alternative Equipment:</u> 0.05 lb-NO_X/MW-hr (1.5 ppmv @ 15% O_2) and 0.02 lb-VOC/MW-hr (2 ppmv @ 15% O_2 as CH_4)

<u>NO_X Emission Reductions (11 ppmv → 1.5 ppmv)</u>
1550 kW x 8760 hr/yr x 1 MW/1,000 kW x (0.14 lb-NO_X/MW-hr – 0.05 lb-NO_X/MW-hr) = 1,222 lb-NO_X/year (0.61 ton/year)

<u>VOC Emission Reductions (750 ppmv → 2.0 ppmv)</u>
1550 kW x 8760 hr/yr x 1 MW/1,000 kW x (3.41 lb-VOC/MW-hr – 0.02 lb-VOC/MW-hr) = 46,029 lb-VOC/year (23.0 ton/year)

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

(0.61 ton-NO_X/year x $24,500/ton-$NO_X$) + (23.0 ton-VOC/year x $17,500/ton-VOC)
= **$417,445/year**

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

<u>Option 2: NO_X emissions ≤ 0.15 g/bhp-hr (Achieved in Practice)</u>

The applicant has proposed this option; therefore a cost analysis is not required.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the digester gas-fired engine must be satisfied with the following:

NO_X: NO_X emissions ≤ 0.15 g/bhp-hr (Achieved in Practice)

The applicant has proposed to apply an SCR system to a lean burn IC engine to reduce NO_X emissions to ≤ 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

2. SOx Top-Down BACT Analysis for Permit Unit S-8153-2-0 and '3-0

South Coast AQMD Rule 431.1

SCAQMD Rule 431.1 which limits the sulfur content for gaseous fuels contains an emission limit of 40 ppmv sulfur (calculated as H2S based on a four hour averaging period) for "Other Gases" which does not include landfill gas or sewage digester gas. As the proposed BACT Guideline in this project is only applicable to non-municipal waste gas, the 40 ppmv sulfur limit (calculated as H2S) is applicable.

Step 1 – Identify all control technologies

The following control technologies have been identified for waste gas-fired IC engines.

SOx

1) Dry absorption such that fuel sulfur content ≤ 40 ppmv (as H2S) (98-99% - Technologically Feasible)
2) Wet absorption such that fuel sulfur content ≤ 40 ppmv (as H2S) (95-98% - Technologically Feasible)
3) Sulfur Content of fuel gas ≤ 40 ppmv (as H2S) (90-98% - Achieved in Practice/Contained in SIP)
4) Influent fuel H2S reduction by addition of chemicals such that fuel sulfur content ≤ 40 ppmv (as H2S) (90% - Technologically Feasible)
5) Water scrubbing such that fuel sulfur content ≤ 40 ppmv (as H2S) (80% - Technologically Feasible)

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

Step 2 - Eliminate Technologically Infeasible Options

All of the options listed above are considered to be feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Control Efficiency	Achieved in Practice
1	Dry absorption such that fuel sulfur content ≤ 40 ppmv (as H2S)	98-99%	N
2	Wet absorption such that fuel sulfur content ≤ 40 ppmv (as H2S)	95-98%	N
3	Sulfur Content of fuel gas ≤ 40 ppmv (as H2S)	90-98%	Y
4	Influent fuel H2S reduction by addition of chemicals such that fuel sulfur content ≤ 40 ppmv (as H2S)	90%	N
5	Water scrubbing such that fuel sulfur content ≤ 40 ppmv (as H2S)	80%	N

There are no remaining control technologies for SOx.

Step 4 - Cost Effectiveness Analysis

The digester gas in this project can have a sulfur content greater than 4,000 ppmv as H2S. The applicant has proposed to use an in-tank bio-scrubber system which utilizes bio-scrubbers in a two stage process: absorption of H2S via a liquid medium followed by the biological oxidation of H2S in the liquid and external iron sponge dry scrubber to reduce the sulfur content of the gas combusted in the engine to ≤ 40 ppmv as H2S. Because the applicant has chosen the most effective option listed above, a dry scrubber reducing the fuel sulfur content to ≤ 40 ppmv as H2S, no cost analysis is required.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the digester gas-fired engine must be satisfied with the following:

SO_X: Dry absorption such that fuel sulfur content ≤ 40 ppmv (as H2S) (Technologically Feasible)

The applicant has proposed to apply an in-tank bio-scrubber system and external iron sponge to reduce the sulfur content in the fuel gas to ≤ 40 ppmv (as H2S). Therefore, the BACT requirements are satisfied.

3. PM10 Top-Down BACT Analysis for Permit Unit S-8153-2-0 and '3-0

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Waste gas is the planned fuel for the proposed IC engines. Waste gas is primarily of methane and CO_2 and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the waste gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly H_2S) resulting in the formation of sulfur-containing particulate. Therefore, limiting the sulfur content of the waste gas is the principal means to reduce particulate emissions.

Step 1 – Identify all control technologies

The following control technology has been identified for waste gas-fired IC engines.

PM10

1) Sulfur Content of fuel gas ≤ 40 ppmv (as H2S) (90-98% - Achieved in Practice/Contained in SIP)

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

Step 2 - Eliminate Technologically Infeasible Options

All of the options listed above are considered to be feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	Sulfur Content of fuel gas ≤ 40 ppmv (as H2S)	Y

There are no remaining control technologies for PM10.

Step 4 - Cost Effectiveness Analysis

The digester gas in this project can have a sulfur content greater than 4,000 ppmv as H2S. The applicant has proposed to use an in-tank bio-scrubber system which utilizes bio-scrubbers in a two stage process: absorption of H2S via a liquid medium followed by the biological oxidation of H2S in the liquid and external iron sponge dry scrubber to reduce the sulfur content of the gas combusted in the engine to ≤ 40 ppmv as H2S. Because the applicant has chosen the most effective option listed above, a dry scrubber reducing the fuel sulfur content to ≤ 40 ppmv as H2S, no cost analysis is required.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the digester gas-fired engine must be satisfied with the following:

PM10: Fuel sulfur content ≤ 40 ppmv (as H_2S) (Achieved in Practice)

The applicant has proposed to apply an in-tank bio-scrubber system and external iron sponge to reduce the sulfur content in the fuel gas to ≤ 40 ppmv (as H_2S). Therefore, the BACT requirements are satisfied.

4. CO Top-Down BACT Analysis for Permit Unit S-8153-2-0 and '3-0

BACT for CO is not triggered for permit units S-8153-2-0 and '3-0 but will be established for the BACT Guideline for waste gas-fired IC engines.

South Coast AQMD Proposed Rule 1110.2

SCAQMD proposed Rule 1110.2 which limits emissions from liquid and gaseous fueled engines proposes an emission limit of 11 ppmvd NOx (equivalent to 0.15 g/bhp-hr), 250 ppmvd CO (equivalent to 1.9 g/bhp/hr), and 30 ppmvd VOC (equivalent to 0.15 g/bhp-hr), all at @ 15% O2, for digester gas-fired engines.

CARB Document Entitled "Stationary Source Emission Limit and Mobile Mitigation Measures Tables Excerpted from Air Quality Guidance for Siting Biorefineries in California (November 2011)"

CARB drafted a document entitled "Stationary Source Emission Limit and Mobile Mitigation Measures Tables Excerpted from Draft Air Quality Guidance for Siting Biorefineries in California (October 2010)" which summarizes the most stringent permitted emission limits ARB staff identified for stationary source process equipment commonly used at biorefineries. Table V-2 lists emission limits of 11 ppmvd NOx (equivalent to 0.15 g/bhp-hr), 250 ppmvd CO (equivalent to 1.9 g/bhp-hr), and 20 ppmvd VOC (equivalent to 0.09 g/bhp-hr), all corrected to 15% O2 for biogas-fired reciprocating IC engines.

40 CFR Part 60 Subpart JJJJ

This rule incorporates New Source Performance Standards 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 JJJJ applies to spark-ignited internal combustion engines.

Table 1 of this subpart lists the CO standard as 5.0 g/bhp-hr or 610 ppmv @ 15% O2 for all landfill/digester gas-fired engines.

District Rule 4702

Section 5.2, Table 2, Category 2.d. for spark-ignited internal combustion engine rated at >50 bhp used exclusively in non-agricultural operations engine type lean-burn engines four-stroke requires the owner or operator to comply with the following emission limits:

Table 2 Emission Limits for a Spark-Ignited Internal Combustion Engine Rated at >50 bhp Used Exclusively in Non-AO (All ppmv limits are corrected to 15% oxygen on a dry basis). Emission Limits are effective according to the compliance schedule specified in Section 7.5.			
Engine Type	NOx Limit (ppmv)	CO Limit (ppmv)	VOC Limit (ppmv)
2. Lean-Burn Engines			
d. Lean-Burn Engine, not listed above	11	2000	750

Step 1 – Identify all control technologies

Both the CARB document entitled "Stationary Source Emission Limit and Mobile Mitigation Measures Tables Excerpted from Air Quality Guidance for Siting Biorefineries in California (November 2011)" and South Coast AQMD Rule 1110.2 list a CO emission limit of 1.9 g/bhp-hr for digester gas-fired IC engines. The engines operating at Gallo Cattle Company, Woodbridge Winery, and Fiscalini Farms have been source tested and continue to operate at a CO emission rate below 1.9 g/bhp-hr. As waste gas streams can vary depending on the type of feedstock, the limit of 1.9 g/bhp-hr will be established as the Achieved in Practice BACT option for CO.

The following control technology has been identified for waste gas-fired IC engines.

CO

1) CO emissions ≤ 1.9 g/bhp-hr (Achieved in Practice)

Step 2 - Eliminate Technologically Infeasible Options

All of the options listed above are considered to be feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	CO emissions ≤ 1.9 g/bhp-hr	Y

There are no remaining control technologies for CO.

Step 4 - Cost Effectiveness Analysis

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

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the digester gas-fired engine must be satisfied with the following:

CO: CO emissions ≤ 1.9 g/bhp-hr (Achieved in Practice)

The applicant has proposed a CO emission limit of 1.9 g/bhp-hr. Therefore, the BACT requirements are satisfied.

5. **VOC Top-Down BACT Analysis for Permit Unit S-8153-2-0 and '3-0**

South Coast AQMD Proposed Rule 1110.2

SCAQMD proposed Rule 1110.2 which limits emissions from liquid and gaseous fueled engines proposes an emission limit of 11 ppmvd NOx (equivalent to 0.15 g/bhp-hr), 250 ppmvd CO (equivalent to 1.9 g/bhp/hr), and 30 ppmvd VOC (equivalent to 0.15 g/bhp-hr), all at @ 15% O2, for digester gas-fired engines.

CARB Document Entitled "Stationary Source Emission Limit and Mobile Mitigation Measures Tables Excerpted from Air Quality Guidance for Siting Biorefineries in California (November 2011)"

CARB drafted a document entitled "Stationary Source Emission Limit and Mobile Mitigation Measures Tables Excerpted from Draft Air Quality Guidance for Siting Biorefineries in California (October 2010)" which summarizes the most stringent permitted emission limits ARB staff identified for stationary source process equipment commonly used at biorefineries. Table V-2 lists emission limits of 11 ppmvd NOx (equivalent to 0.15 g/bhp-hr), 250 ppmvd CO (equivalent to 1.9 g/bhp-hr), and 20 ppmvd VOC (equivalent to 0.09 g/bhp-hr), all corrected to 15% O2 for biogas-fired reciprocating IC engines.

40 CFR Part 60 Subpart JJJJ

This rule incorporates New Source Performance Standards 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 JJJJ applies to spark-ignited internal combustion engines.

Table 1 of this subpart lists the VOC standard as 1.0 g/bhp-hr or 80 ppmv @ 15% O2 for all landfill/digester gas-fired engines.

District Rule 4702

Section 5.2, Table 2, Category 2.d. for spark-ignited internal combustion engine rated at >50 bhp used exclusively in non-agricultural operations engine type lean-burn engines four-stroke requires the owner or operator to comply with the following emission limits:

Table 2 Emission Limits for a Spark-Ignited Internal Combustion Engine Rated at >50 bhp Used Exclusively in Non-AO (All ppmv limits are corrected to 15% oxygen on a dry basis). Emission Limits are effective according to the compliance schedule specified in Section 7.5.

Engine Type	NOx Limit (ppmv)	CO Limit (ppmv)	VOC Limit (ppmv)
2. Lean-Burn Engines			
d. Lean-Burn Engine, not listed above	11	2000	750

Step 1 – Identify all control technologies

Both the CARB document entitled "Stationary Source Emission Limit and Mobile Mitigation Measures Tables Excerpted from Air Quality Guidance for Siting Biorefineries in California (November 2011)" and South Coast AQMD Rule 1110.2 list a VOC emission limit of 0.15 g/bhp-hr for digester gas-fired IC engines. The engines operating at Gallo Cattle Company, Woodbridge Winery, and Fiscalini Farms have been source tested and continue to operate at a VOC emission rate below 0.15 g/bhp-hr. As waste gas streams can vary depending on the type of feedstock, the limit of 0.15 g/bhp-hr will be established as the Achieved in Practice BACT option for VOC.

The following control technology has been identified for waste gas-fired IC engines.

VOC

1) VOC emissions ≤ 0.15 g/bhp-hr (Achieved in Practice)
2) Microturbine (≤ 35 ppmv VOC @ 15% O_2 as CH_4) (Alternate Basic Equipment)
3) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Step 2 - Eliminate Technologically Infeasible Options

All of the options listed above are considered to be feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	Fuel Cells (<0.02 lb/MW-hr ≈ 2.0 ppmv @ 15% O_2 as CH_4)	N
2a	Microturbines (<30 ppmv @ 15% O_2)	N
2b	VOC emissions ≤ 0.15 g/bhp-hr	Y

There are no remaining control technologies for VOC.

Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cells (≤ 0.02 lb/MW-hr ≈ 2.0 ppmv VOC @ 15% O_2 as CH_4) (Alternate Basic Equipment)

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

Option 2: Microturbines ≤ 30 ppmv @ 15% O2 (Alternate Basic Equipment)

Test results have indicated that waste gas-fired microturbines are capable of meeting very low VOC emission limits. The actual amount of VOC emitted from an efficient lean burn IC engine or microturbine will actually be more dependent on the type of fuel used and the VOC content of the fuel prior to combustion. Because waste gas generally contains only small amounts of VOCs, the difference in emissions for combustion in an engine meeting BACT and a microturbine will not be substantial. Therefore, this option will be deemed equivalent to the achieved in practice BACT level shown above for waste gas-fired reciprocating IC engines. Because microturbines will only be listed as an equivalent alternative option to the achieved in practice standard for VOC and are not being required, a cost analysis is not necessary.

Option 3: VOC Emissions ≤ 0.15 g/bhp-hr (Achieved in Practice)

This option listed above has been identified as achieved in practice for VOC emissions. Therefore, a cost analysis is not necessary.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the digester gas-fired engine must be satisfied with the following:

VOC: VOC emissions ≤ 0.15 g/bhp-hr (Achieved in Practice)

The applicant has proposed a VOC emission limit of 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

Proposed Pages For the BACT Clearinghouse

San Joaquin Valley Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.3.XX

Emission Unit: Waste Gas-Fired IC Engine** **Industry Type:** All

Equipment Rating: None **Last Update:** May 27, 2012

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NOx	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)		1. Fuel Cells (<0.05 lb/MW-hr ≈ 1.5 ppmv @ 15% O_2) 2. Microturbines (<9 ppmv @ 15% O_2) 3. Gas Turbine (<9 ppmv @ 15% O_2) *(Note: large gas turbines only ABE for projects ≥ 3 MW)*
SOx	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)	1. Dry absorption such that fuel sulfur content ≤ 40 ppmv (as H_2S) 2. Wet absorption such that fuel sulfur content ≤ 40 ppmv (as H_2S) 3. Influent fuel H2S reduction by addition of chemicals such that fuel sulfur content ≤ 40 ppmv (as H_2S) 4. Water scrubbing such that fuel sulfur content ≤ 40 ppmv (as H_2S)	
PM10	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)		
CO	1.9 g/bhp-hr		
VOC	0.15 g/bhp-hr (lean burn or equivalent and either positive crankcase ventilation (PCV) or a 90% efficient crankcase control device)		Fuel Cells (<0.02 lb/MW-hr ≈ 2.0 ppmv @ 15% O_2 as CH_4)

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

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

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

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.3.XX A

Emission Unit: Waste Gas-Fired IC Engine

Equipment Rating: None

Facility: Colony Energy Partners – Tulare. LLC

References: ATC #: S-8153-2-0 and '3-0
Project #: 1121205

Location: Paige Avenue (west of Enterprise Street) in Tulare, CA (S/2 Section 16, Township 20S, Range 24E)

Date of Determination: May 27, 2012

Pollutant	BACT Requirements
NOx	Lean-burn with SCR and NO_x emissions of 0.15 g/bhp-hr
SOx	Dry absorption and digester gas fuel sulfur content ≤ 40 ppmv (as H_2S)
PM10	Digester gas fuel sulfur content ≤ 40 ppmv (as H_2S)
CO	BACT NOT TRIGGERED
VOC	VOC emissions of 0.15 g/bhp-hr and Positive Crankcase Ventilation (PCV)

BACT Status:

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

1) Fuel Cells (<0.05 lb-NO_X/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2)
2) Fuel Cells (<0.02 lb-VOC/MW-hr ≈ 2.0 ppmv VOC @ 15% O_2)

BACT CLEARINGHOUSE

--Submission Form--

Category

Source Category	Electric Power Generation	
SIC Code	4911	**View SIC Code List**
NAICS Code		View NAICS Code List

Emission Unit Information

Manufacturer	2G-Cenergy
Type	Lean Burn
Model	Otto Avus TCG 2020 MWM
Equipment Description	2,165 BHP 2G-CENERGY MODEL OTTO AVUS TCG 2020 MWM LEAN BURN DIGESTER GAS/NATURAL GAS-FIRED IC ENGINE WITH TURBOCHARGER, INTERCOOLER, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND SELECTIVE CATALYTIC REDUCTION WITH UREA INJECTION COGENERATION SYSTEM
Capacity/Dimensions	2,165 BHP
Fuel Type	Digester Gas and Natural Gas
Multiple Fuel Types	Digester Gas and Natural Gas
Operating Schedule	Continuous 24 hrs/day, 8,760 hrs/yr
Function of Equipment	The proposed equipment will be used to generate electricity to be sold to the local utility power grid.

Facility/District Information

Facility Name	Colony Energy Partners – Tulare, LLC
Facility County	Tulare County
Facility Zip Code	93274
District Contact	David Warner, San Joaquin Valley Air Pollution District
District Contact Phone	(559) 230-6000
District Contact E-mail	carlos.garcia@valleyair.org

Project/Permit Information

Application or Permit Number	S-8153-2-0 and '3-0
New Construction/Modification	New Construction
ATC Date (mm-dd-yyyy)	TBD
PTO Date (mm-dd-yyyy)	TBD
Startup Date (mm-dd-yyyy)	TBD
Technology Status	None
Source Test Available	No
Source Test Results	TBD

BACT Information

Pollutant Limit(s) and Control Method(s) – Please include proper units

NOx	Limit: 0.15 Units: g/bhp-hr Averaging Time: Control Method Type: Selective Catalytic Reduction Control Method Description:
CO	Limit: 1.9 Units: g/bhp-hr Averaging Time: Control Method Type: Control Method Description:
VOC	Limit: 0.15 Units: g/bhp-hr Averaging Time: Control Method Type: Positive Crankcase Ventilation Control Method Description:
PM	Limit: Units: Averaging Time: Control Method Type: Control Method Description:
PM 2.5	Limit: Units: Averaging Time: Control Method Type: Control Method Description:
PM 10	Limit: 40 Units: ppmv Averaging Time: Control Method Type: Control Method Description:
SOx	Limit: 40 Units: ppmv Averaging Time: Control Method Type: Dry absorption Control Method Description:

Attachment B

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Air Pollution Control District
Risk Management Review
(Revised 7-30-12)

To: Stanly Tom, AQE– Permit Services

From: Esteban Gutierrez, AQS– Technical Services

Date: July 30, 2012

Facility Name: Colony Energy Partners- Tulare LLC

Location: Paige Ave. (West of Enterprise St), Tulare CA

Application #(s): S-8153-1-0 thru 3-0

Project #: S-1121205

A. RMR SUMMARY

RMR Summary					
Categories	**Flare (Unit 1-0)**	**Digester gas ICE (Unit 2-0)**	**Digester gas ICE (Unit 3-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	0.01	0.85	0.85	1.71	>1.0
Acute Hazard Index	0.00	0.01	0.01	0.02	0.02
Chronic Hazard Index	0.00	0.01	0.01	0.02	0.02
Maximum Individual Cancer Risk (10^{-6})	0.00	3.65	3.69	7.35	7.35
T-BACT Required?	**No**	**Yes**	**Yes**		
Special Permit Conditions?	**No**	**Yes**	**Yes**		

<u>Proposed Permit Conditions</u>

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

<u>Unit # 1-0</u>

No special conditions are required.

<u>Unit # 2-0 & 3-0</u>

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. [District Rule 4102]

T-BACT is required for this unit because of emissions of digester gas combustion which are a VOC/PM-10. In accordance with District policy, BACT for units 2-0 and 3-0 will be considered to be T-BACT.

B. RMR REPORT

I. Project Description

Technical Services received a request on July 30, 2012, to perform a Revised Ambient Air Quality Analysis and a Risk Management Review for a proposed installation of a cogeneration operation. The facility proposes to install a standby flare and two digester gas-fired IC engines. This revision is to add ammonia emissions for the two engines.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculated using internal combustion of digester gas for the engines along with ammonia emissions and flare combustion of digester gas and were input into the HEARTs database. The AERMOD model was used, with the parameters outlined below and meteorological data for 2005-2009 from Tulare 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 Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 1-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	6	**Closest Receptor (m)**	>1000
Stack Diameter. (m)	0.78	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	20	**Max Hours per Year**	8760
Stack Exit Temp. (°K)	1273	**Fuel Type**	Digester
Flare (MMBTU/Hr)	41		

Analysis Parameters Unit 2-0 & 3-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	10	**Closest Receptor (m)**	>1000
Stack Diameter. (m)	0.3	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	25.6	**Max Hours per Year**	8760
Stack Exit Temp. (°K)	453	**Fuel Type**	Digester
Engine (BHP)	2165	**Ammonia (lb/yr)**	504 each

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The **revised** emission rates used for criteria pollutant modeling were;

Pollutant	1-0 flare		2-0 ICE		3-0 ICE	
	Lbs./day	lbs./yr	lbs./day	lbs./yr	lbs./day	lbs./yr
NO_X	21.6	788	17.5	6272	17.5	6272
SO_X	8.1	294	4.2	1547	4.2	1547
PM_{10}	5.8	210	3.8	1380	3.8	1380
CO	216	7884	217.6	79441	217.6	79441

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	**X**	Pass	**X**	**X**
NO_x	Pass	**X**	**X**	**X**	Pass
SO_x	Pass	Pass	**X**	Pass	Pass
PM_{10}	**X**	**X**	**X**	Pass[1]	Pass[1]
$PM_{2.5}$	**X**	**X**	**X**	Pass[1]	Pass[1]

*Results were taken from the attached PSD spreadsheet.
[1]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk associated with the project is greater than 1.0 in a million, but less than 10 in a million. **In accordance with the District's Risk Management Policy, the project is approved with Toxic Best Available Control Technology (T-BACT).**

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

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

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

IV. Attachments

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

Attachment C
Draft ATCs

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8153-1-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: COLONY ENERGY PARTNERS-TULARE, LLC
MAILING ADDRESS: 4940 CAMPUS DRIVE, SUITE C
NEWPORT BEACH, CA 92660

LOCATION: PAIGE AVE (WEST OF ENTERPRISE STREET)
TULARE, CA

EQUIPMENT DESCRIPTION:
DIGESTER GAS PRODUCTION OPERATION CONSISTING OF ONE 211,338 GALLON MANURE RECEPTION TANK, ONE 92,460 GALLON DILUTION TANK, ONE 132,086 GALLON FAT, OIL, GREASE, VEGETABLE WASTE RECEPTION TANK, ONE 92,460 GALLON MIXING (FEED) TANK, TWO 2,150,100 GALLON ANAEROBIC DIGESTER TANKS, ONE 311,195 DIGESTATE (BUFFER) HOLDING TANK, DIGESTER GAS TREATMENT SYSTEM CONSISTING OF A CHILLER, COMPRESSOR, HYDROGEN SULFIDE REMOVAL UNIT (IN-TANK BIO-SCRUBBER AND IRON SPONGE SCRUBBER), AND ONE 41 MMBTU/HR BEKAERT MODEL CEB 1200 DIGESTER GAS-FIRED AIR-ASSIST GROUND LEVEL ENCLOSED FLARE AND DIGESTATE MANAGEMENT SYSTEM CONSISTING OF ONE FILTER SCREW PRESS WITH ONE 8,400 GALLON OVERFLOW BUFFER TANK, ONE 2,000 GALLON SCREW PRESS BUFFER TANK, A POLYMER MAKE-DOWN SYSTEM, A DISSOLVED AIR FLOATATION (DAF) SYSTEM AND ONE DIGESTATE BY-PRODUCT LOADOUT STATION

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. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rules 2201 and 4101]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. Except for the overflow buffer tank, screw press buffer tank and digestate management system, all equipment listed in this permit shall vent to the facility cogeneration engine(s). [District Rule 2201]
6. Only digester gas shall be combusted in the flare. [District Rule 2201]

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.

Seyed Sadredin, Executive Director / APCO

DRAFT

DAVID WARNER, Director of Permit Services

7. The amount of digester gas combusted in the flare shall not exceed any of the following limits: 1.2 MMscf in any one day or 43.8 MMscf in any consecutive 365-day period. [District Rule 2201]

8. 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 gas combusted in the flare. [District Rule 2201]

9. Emissions from the flare shall not exceed any of the following limits: 0.03 lb-NOx/MMBtu; 0.0112 lb-SOx/MMBtu (based on 40 ppmv sulfur content in fuel (as H2S) and four hour averaging period); 0.008 lb-PM10/MMBtu; 0.30 lb-CO/MMBtu; or 0.068 lb-VOC/MMBtu. [District Rule 2201]

10. Source testing to measure NOx, CO and VOC emissions from the digester-fired flare shall be conducted within 120 days of initial start-up and at least once every twelve (12) months thereafter. [District Rule 2201]

11. Within 60 days of production of wet cake/pressed fiber, the VOC content of the material shall be determined using EPA Test Methods 413.2 and 418.1 and EPA Test Method 8260, and if necessary EPA Test Method 204 and 204D with either EPA Test Method 25A and 18 or SCAQMD Test Method 25.3, or an alternative method approved by the District. If VOC emissions are greater than two pounds per day (based on maximum throughput of the loaded out material), the permittee shall submit an Authority to Construct application for the wet cake/pressed fiber loadout operation within 15 days of the test results. [District Rule 2201]

12. The sulfur content of the digester gas combusted in this flare shall be monitored and recorded monthly. After eight (8) consecutive monthly tests show compliance, the digester gas sulfur content monitoring frequency may be reduced to once every calendar quarter. If quarterly monitoring shows a violation of the digester gas sulfur content limit of this permit, then monthly monitoring shall resume and continue until eight consecutive months of monitoring show compliance with the gas sulfur content limit. Once compliance with the gas sulfur content limit is shown for eight consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas shall not be required if the flare does not operate during that period. Records of the results of monitoring of the digester gas sulfur content shall be maintained. [District Rule 2201]

13. Monitoring of the digester gas sulfur content shall be performed using a Testo 350 XL portable emission monitor; District-approved in-line H2S monitors; gas detection tubes calibrated for H2S; District-approved source test methods, including EPA Method 11 or EPA Method 15, ASTM Method D1072, D4084, and D5504; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

14. For source test purposes, NOx emissions from the flare shall be determined using EPA Method 19 on a heat input basis, or EPA Method 3A, EPA Method 7E, or ARB Method 100 on a ppmv basis. [District Rule 2201]

15. For source test purposes, CO emissions from the flare shall be determined using EPA Method 10 or 10B, ARB Methods 1 through 5 with 10, or ARB Method 100. [District Rule 2201]

16. For source test purposes, VOC emissions from the flare shall be determined using EPA Method 25 or 25a. [District Rule 2201]

17. Stack gas oxygen (O2) shall be determined using EPA Method 3A, EPA Method 7E, or ARB Method 100. [District Rule 2201]

18. Operator shall determine digester gas fuel higher heating value annually by ASTM D 1826 or D 1945 in conjunction with ASTM D 3588 for gaseous fuels. [District Rule 2201]

19. 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. 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]

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

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CONDITIONS CONTINUE ON NEXT PAGE

22. Permittee shall maintain daily and annual records of quantity of digester gas combusted in the flare and annual test results of higher heating value of digester gas. [District Rules 1070 and 2201]

23. The facility shall maintain records of annual throughput, material usage, or other information necessary to demonstrate that facility-wide emissions are less than ten tons per year for both NOx and VOC. [District Rule 4311]

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. [District Rule 1070]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8153-2-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: COLONY ENERGY PARTNERS-TULARE, LLC
MAILING ADDRESS: 4940 CAMPUS DRIVE, SUITE C
NEWPORT BEACH, CA 92660

LOCATION: PAIGE AVE (WEST OF ENTERPRISE STREET)
TULARE, CA

EQUIPMENT DESCRIPTION:
2,165 BHP 2G-CENERGY MODEL OTTO AVUS TCG 2020 MWM LEAN BURN DIGESTER GAS/NATURAL GAS-FIRED IC ENGINE WITH TURBOCHARGER, INTERCOOLER, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND SELECTIVE CATALYTIC REDUCTION WITH UREA INJECTION COGENERATION SYSTEM

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. This engine shall be operated and maintained in proper operating condition per the manufacturer's requirements as specified on the Inspection and Monitoring (I&M) plan submitted to the District. [District Rule 4702]
6. This engine shall be operated and maintained in proper operating condition according to the manufacturer's specifications. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]
7. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201 and 40 CFR 60 Subpart JJJJ]
8. This engine shall be equipped with a nonresettable elapsed operating time meter and a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved alternative. [District Rules 2201 and 4702 and 40 CFR 60 Subpart JJJJ]

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.

Seyed Sadredin, Executive Director / APCO

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DAVID WARNER, Director of Permit Services

9. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]

10. Fuel consumption of natural gas shall not exceed 43,920 scf in any one day. [District Rule 2201]

11. Emissions from the IC engine when fired on digester gas, or a mixture of greater than 50% by volume digester gas, shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr, 0.037 g-SOx/bhp-hr (based on 40 ppmv sulfur content in fuel (as H2S) and four hour averaging period), 0.033 g-PM10/bhp-hr, 1.9 g-CO/bhp-hr, or 0.15 g-VOC/bhp-hr. [District Rules 2201 and 4702, and 40 CFR 60 Subpart JJJJ]

12. Emissions from the IC engine when fired on natural gas shall not exceed any of the following limits: 0.10 g-NOx/bhp-hr, 0.0094 g-SOx/bhp-hr, 0.033 g-PM10/bhp-hr, 0.68 g-CO/bhp-hr, or 0.15 g-VOC/bhp-hr. [District Rules 2201 and 4702, and 40 CFR 60 Subpart JJJJ]

13. The ammonia (NH3) emission concentration shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

14. Source testing to measure digester gas fuel combustion NOx, CO, VOC and ammonia emissions from this unit shall be conducted within 120 days of initial start-up and once every 8,760 hours of operation or 24 months, whichever comes first, thereafter. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

15. Source testing to measure natural gas fuel combustion NOx, CO, VOC and ammonia emissions from this unit shall be conducted within 120 days of initial start-up. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

16. Source testing to measure natural gas fuel combustion NOx, CO, VOC and ammonia emissions from this unit shall be conducted within 60 days of natural gas fuel usage exceeding 1,284,500 scf during any rolling 12-month period. [District Rules 2201 and 4702]

17. The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, CO (ppmv) - EPA Method 10 or ARB Method 100, stack gas oxygen - EPA Method 3 or 3A or ARB Method 100, and VOC (ppmv) - EPA Method 25A or 25B, or ARB Method 100. [District Rules 1081 and 4702]

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

19. The permittee shall monitor and record the stack concentration of NOx, CO, O2, and NH3 at least once every month (in which a source test is not performed). NOx, CO, and O2 concentrations shall be performed using a portable emission monitor that meets District specifications. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

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

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

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CONDITIONS CONTINUE ON NEXT PAGE

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

23. The sulfur content of the digester gas combusted in this flare shall be monitored and recorded monthly. After eight (8) consecutive monthly tests show compliance, the digester gas sulfur content monitoring frequency may be reduced to once every calendar quarter. If quarterly monitoring shows a violation of the digester gas sulfur content limit of this permit, then monthly monitoring shall resume and continue until eight consecutive months of monitoring show compliance with the gas sulfur content limit. Once compliance with the gas sulfur content limit is shown for eight consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas shall not be required if the flare does not operate during that period. Records of the results of monitoring of the digester gas sulfur content shall be maintained. [District Rule 2201]

24. Monitoring of the digester gas sulfur content shall be performed using a Testo 350 XL portable emission monitor; District-approved in-line H2S monitors; gas detection tubes calibrated for H2S; District-approved source test methods, including EPA Method 11 or EPA Method 15, ASTM Method D1072, D4084, and D5504; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

25. The permittee shall submit an analysis showing the natural gas fuel sulfur content at least once every year. Valid purchase contracts, supplier certifications, tariff sheets, or transportation contacts may be used to satisfy this requirement, provided they establish the fuel parameters mentioned above. [District Rules 2201 and 4702]

26. For initial emissions source testing, the arithmetic average of three 60-consecutive-minute test runs shall apply. Each test run shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. NOx, CO and VOC concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

27. {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]

28. Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

29. The results of each source test shall be submitted to the District and EPA within 60 days after completion of the source test. [District Rule 1081 and 40 CFR 60 Subpart JJJJ]

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

31. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: total hours of operation, type and quantity of fuel used, maintenance or modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

32. Notification of the date construction of this engine commenced shall be submitted to the District and EPA and shall be postmarked no later than 30 days after such date as construction commenced. The notification shall contain the following information: 1) Name and address of the owner or operator; 2) The address of the affected source; 3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; 4) Emission control equipment; and 5) Fuel used. [40 CFR 60 Subpart JJJJ]

CONDITIONS CONTINUE ON NEXT PAGE

33. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-8153-3-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: COLONY ENERGY PARTNERS-TULARE, LLC
MAILING ADDRESS: 4940 CAMPUS DRIVE, SUITE C
NEWPORT BEACH, CA 92660

LOCATION: PAIGE AVE (WEST OF ENTERPRISE STREET)
TULARE, CA

EQUIPMENT DESCRIPTION:
2,165 BHP 2G-CENERGY MODEL OTTO AVUS TCG 2020 MWM LEAN BURN DIGESTER GAS/NATURAL GAS-FIRED IC ENGINE WITH TURBOCHARGER, INTERCOOLER, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND SELECTIVE CATALYTIC REDUCTION WITH UREA INJECTION COGENERATION SYSTEM

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. This engine shall be operated and maintained in proper operating condition per the manufacturer's requirements as specified on the Inspection and Monitoring (I&M) plan submitted to the District. [District Rule 4702]
6. This engine shall be operated and maintained in proper operating condition according to the manufacturer's specifications. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]
7. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201 and 40 CFR 60 Subpart JJJJ]
8. This engine shall be equipped with a nonresettable elapsed operating time meter and a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved alternative. [District Rules 2201 and 4702 and 40 CFR 60 Subpart JJJJ]

CONDITIONS CONTINUE ON NEXT PAGE

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Seyed Sadredin, Executive Director / APCO

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DAVID WARNER, Director of Permit Services

9. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]

10. Fuel consumption of natural gas shall not exceed 43,920 scf in any one day. [District Rule 2201]

11. Emissions from the IC engine when fired on digester gas, or a mixture of greater than 50% by volume digester gas, shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr, 0.037 g-SOx/bhp-hr (based on 40 ppmv sulfur content in fuel (as H2S) and four hour averaging period), 0.033 g-PM10/bhp-hr, 1.9 g-CO/bhp-hr, or 0.15 g-VOC/bhp-hr. [District Rules 2201 and 4702, and 40 CFR 60 Subpart JJJJ]

12. Emissions from the IC engine when fired on natural gas shall not exceed any of the following limits: 0.10 g-NOx/bhp-hr, 0.0094 g-SOx/bhp-hr, 0.033 g-PM10/bhp-hr, 0.68 g-CO/bhp-hr, or 0.15 g-VOC/bhp-hr. [District Rules 2201 and 4702, and 40 CFR 60 Subpart JJJJ]

13. The ammonia (NH3) emission concentration shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

14. Source testing to measure digester gas fuel combustion NOx, CO, VOC and ammonia emissions from this unit shall be conducted within 120 days of initial start-up and once every 8,760 hours of operation or 24 months, whichever comes first, thereafter. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

15. Source testing to measure natural gas fuel combustion NOx, CO, VOC and ammonia emissions from this unit shall be conducted within 120 days of initial start-up. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

16. Source testing to measure natural gas fuel combustion NOx, CO, VOC and ammonia emissions from this unit shall be conducted within 60 days of natural gas fuel usage exceeding 1,284,500 scf during any rolling 12-month period. [District Rules 2201 and 4702]

17. The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, CO (ppmv) - EPA Method 10 or ARB Method 100, stack gas oxygen - EPA Method 3 or 3A or ARB Method 100, and VOC (ppmv) - EPA Method 25A or 25B, or ARB Method 100. [District Rules 1081 and 4702]

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

19. The permittee shall monitor and record the stack concentration of NOx, CO, O2, and NH3 at least once every month (in which a source test is not performed). NOx, CO, and O2 concentrations shall be performed using a portable emission monitor that meets District specifications. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

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

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

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CONDITIONS CONTINUE ON NEXT PAGE

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

23. The sulfur content of the digester gas combusted in this flare shall be monitored and recorded monthly. After eight (8) consecutive monthly tests show compliance, the digester gas sulfur content monitoring frequency may be reduced to once every calendar quarter. If quarterly monitoring shows a violation of the digester gas sulfur content limit of this permit, then monthly monitoring shall resume and continue until eight consecutive months of monitoring show compliance with the gas sulfur content limit. Once compliance with the gas sulfur content limit is shown for eight consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas shall not be required if the flare does not operate during that period. Records of the results of monitoring of the digester gas sulfur content shall be maintained. [District Rule 2201]

24. Monitoring of the digester gas sulfur content shall be performed using a Testo 350 XL portable emission monitor; District-approved in-line H2S monitors; gas detection tubes calibrated for H2S; District-approved source test methods, including EPA Method 11 or EPA Method 15, ASTM Method D1072, D4084, and D5504; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

25. The permittee shall submit an analysis showing the natural gas fuel sulfur content at least once every year. Valid purchase contracts, supplier certifications, tariff sheets, or transportation contacts may be used to satisfy this requirement, provided they establish the fuel parameters mentioned above. [District Rules 2201 and 4702]

26. For initial emissions source testing, the arithmetic average of three 60-consecutive-minute test runs shall apply. Each test run shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. NOx, CO and VOC concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

27. {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]

28. Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

29. The results of each source test shall be submitted to the District and EPA within 60 days after completion of the source test. [District Rule 1081 and 40 CFR 60 Subpart JJJJ]

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

31. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: total hours of operation, type and quantity of fuel used, maintenance or modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. [District Rule 4702 and 40 CFR 60 Subpart JJJJ]

32. Notification of the date construction of this engine commenced shall be submitted to the District and EPA and shall be postmarked no later than 30 days after such date as construction commenced. The notification shall contain the following information: 1) Name and address of the owner or operator; 2) The address of the affected source; 3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; 4) Emission control equipment; and 5) Fuel used. [40 CFR 60 Subpart JJJJ]

CONDITIONS CONTINUE ON NEXT PAGE

33. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

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