Noncovered Source Permit Review Summary (Renewal)

Application No.: 0008-13

Permit No.: 0008-02-N

Applicant: Puna Geothermal Venture

Facility Title: Forty-one (41) MW (Nominal) Geothermal Power Plant, Wellfield, and Geothermal Exploratory/Developmental Wells
Located At: 14-3860 Kapoho-Pahoa Road, Pahoa, HI 96778
UTM Coordinates: Zone 4
East 301,000 m - 301,660 m, North 2,154,840 m - 2,155,580 m

Mailing Address: Puna Geothermal Venture
P.O. Box 30
Pahoa, Hawaii 96778

Responsible Official: Mike McVey
Plant Manager
Ph. (808) 965-2847

Application Date: September 11, 2014

Proposed Project:

SICC 4911 (Electrical Services)

The applicant (Puna Geothermal Venture) is applying to renew its existing noncovered source permit, NSP No. 0008-02-N, which expires on December 14, 2014. The permit is currently shielded, since the renewal application was submitted on a timely basis.

The Puna Geothermal Venture (PGV) facility is located approximately twenty-one (21) miles southeast of the city of Hilo in the Puna district of the island of Hawaii. The facility occupies approximately twenty-five (25) acres within a 500-acre area in the Kapoho section of the Kilauea Lower East Rift Zone (LERZ).

The PGV geothermal power plant produces electricity using geothermal fluids produced from the facility's geothermal wellfield. Approximately 800,000 pounds per hour of geothermal fluid is used to produce the electrical power. The facility, which is designed for an operating life of at least thirty-five (35) years, sells its electrical energy to Hawaiian Electric Light Company (HELCO) for their electrical grid system.

The power plant operates by first separating the geothermal fluid into liquid (brine) and vapor (steam) phases by using a flash separator. The brine is routed directly to the reinjection wells and a portion of the steam is routed to a steam turbine to produce electricity. The unused steam portion is combined with the spent steam exiting the steam turbine, and is then routed to turbine/generator modules.

The turbine/generator modules produce additional electricity by using a pressurized hydrocarbon vapor (pentane) to drive a turbine. Within the module's vaporizer, liquid pentane is converted to a pressurized gas used to drive an organic turbine. One organic turbine and one steam turbine are connected to a single electrical generator. Ten parallel generators are used to produce the net power of thirty-five (35) MW (nominal). The pentane exiting the organic turbine is condensed within air coolers, pumped through a pentane preheater, and back into the vaporizer to complete the closed loop.

The geothermal fluids, including any separated brine and noncondensible gases are reinjected back into the ground. There are six (6) production wells and four (4) injection wells currently in use.

The applicant proposed the following changes to Attachment IIB, Special Condition No. F.2 (third paragraph) of the permit:

> During normal operation of each well, the sampling and testing of the resource shall be performed on an **annual basis**. During the testing of the noncondensable gases, if the hydrogen sulfide concentrations deviates more than +10 percent of the <u>previous</u> [initial] well test measurement, the permittee shall repeat the sampling and testing of the resource for the steam condensate, brine and noncondensible gases within the next **six (6) months**. The permittee shall be required to perform a retest only **once** after performing an annual resource test.

An application fee of $100.00 was submitted and processed for the permit renewal.

Equipment Description:

1. Forty-one (41) MW (Nominal) Geothermal Power Plant with the following:
    a. Ten (10) integrated back pressure steam turbine and air cooled binary cycle turbine/generator modules. Ormat Energy Converter (OEC) or equivalent;
    b. Noncondensible gas (NCG) compressor units;
    c. Vapor Recovery Unit (VRU);
    d. Sulfa-Treat System (two (2) abatement reactor vessels);
    e. Emergency Steam Release Facility (ESRF)
        i. Rock Mufflers
        ii. Sodium Hydroxide (NaOH) or equivalent chemical storage tank(s);
    f. Portable H_2S Abatement System;
    g. Two (2) Integrated Two Level Units (ITLU);
    h. Vapor Recovery Maintenance Unit (VRMU); and
    i. No. 2 Vapor Recovery Maintenance Unit (VRMU).
    j. Pressure Relief Valves (Turbine/Generator Modules PSEs and PSVs)

2. Wellfield:
    a. Pad A Wellfield: Production Wells KS-9, KS-10, and KS-16, Injection Wells KS-1A, KS-11, and KS-13, and associated equipment;
    b. Pad B Wellfield: Injection Well KS-15, and associated equipment;
    c. Pad E Wellfield: Production Wells KS-5, KS-6, KS-14, and KS-17, Injection Well KS-3, and associated equipment;
    d. Fourteen (14) Geothermal Exploratory/Developmental Wells;
    e. Drilling rig no. 1 (Rig 51):

   i. Three (3) 877 hp diesel engine drives, Waukesha model L5792, serial nos. 363805, 363806, 363807 (nonroad engines);
   ii. Two (2) 435 hp diesel engine generators, Caterpillar model D353, serial nos. 46B09273 and 46B09281 (nonroad engines); and
   iii. One (1) 800 hp diesel engine for Top Drive unit, Caterpillar Model C27, serial no. RAM00139 (nonroad engine).

f. Drilling rig no. 2 (Geodrill Rig 4):
   i. One (1) 470 hp rig drive diesel engine, Caterpillar model C-13, serial no. LEE19127 (nonroad engine);
   ii. One (1) 284 hp diesel engine generator, John Deere model 6068HF485, serial no. PE6068L039306 (nonroad engine); and
   iii. One (1) 630 hp mud pump diesel engine, Caterpillar model C-18 DITA, serial no. WJH00848 (nonroad engine).

g. Portable H_2S Abatement System.

h. Pressure Relief Valves (Production and Injection Wells PSEs and PSVs)

Air Pollution Controls:

1. Vapor Recovery Unit (VRU)
   A small quantity of noncondensable gases (N_2 and O_2) accumulates in the turbine/generator module's recirculating pentane system and must be periodically vented to the atmosphere. The Vapor Recovery Unit (VRU) system collects pentane and noncondensable gases vented from the pentane condenser. The VRU uses a two-stage (2-stage) refrigeration cycle to condense the pentane and water from the vapor. The noncondensable gases are released to the atmosphere. The pentane vapors are collected, condensed and returned to the pentane storage vessels. The VRU should have a control efficiency (recovery efficiency) of at least ninety-five percent (95%).

2. Vapor Recovery Maintenance Unit (VRMU)
   The VRMU is used to evacuate and recover pentane before venting noncondensible gases from the pentane system (turbines, cooler, heat exchanger, etc.). The VRMU utilizes a four-step (4-step) recovery and an activated carbon filtering system. The recovered pentane is returned to the pentane storage vessels.

3. Sulfa-Treat System
   This system collects and abates fugitive hydrogen sulfide emissions utilizing two (2) abatement reactors in series. The system operates on a vacuum to collect the fugitive emissions from the dynamic seals of the steam turbines.

4. Emergency Steam Release Facility (ESRF)
   An emergency steam relief facility (ESRF) is installed on the common header and is used to remove H_2S, and minimize noise during the emergency release of steam or during well testing. H_2S abatement is accomplished through the addition of sodium hydroxide (NaOH) or equivalent, and noise is controlled through the use of rock mufflers. The ESRF is designed to handle emergency situations such as a problem with the electrical transmission line(s) out of the power plant, upset of the geothermal fluid injection system, or if the pressure in the steam line exceeds the set points. The ESRF is used for upset conditions to prevent a release of unabated H_2S to the atmosphere.

5. Portable H_2S Abatement Vessel, Power Plant
   A portable system is used to abate potential emissions when maintenance work is performed on systems that may contain residual H_2S gas.

6. Portable H_2S Abatement Vessel, Wellfield
   A portable abatement system for H_2S is used during well maintenance operations.

7. Fuel oil no. 2 with a maximum sulfur content not to exceed 0.0015 percent by weight is used to control SO_2 in all the diesel engines.

Applicable Requirements:

Hawaii Administrative Rules (HAR)

Title 11, Chapter 59	Ambient Air Quality Standards
Title 11, Chapter 60.1	Air Pollution Control
Subchapter 1	General Requirements
Subchapter 2	General Prohibitions
HAR 11-60.1-31	Applicability
HAR 11-60.1-32	Visible Emissions
HAR 11-60.1-38	Sulfur Oxides from Fuel Combustion
Subchapter 4	Noncovered Sources
Subchapter 6	Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
HAR 11-60.1-111	Definitions
HAR 11-60.1-117	General Fee Provisions for Noncovered Sources
HAR 11-60.1-118	Application Fees for Noncovered Sources
HAR 11-60.1-119	Annual Fees for Noncovered Sources

Non-applicable Requirements:

Hawaii Administrative Rules (HAR)

Title 11, Chapter 60.1	Air Pollution Control
Subchapter 5	Covered Sources
Subchapter 7	Prevention of Significant Deterioration Review
Subchapter 8	Standards of Performance for Stationary Sources
Subchapter 9	Hazardous Air Pollution Sources

Federal Requirements

40 CFR Part 52.21 - Prevention of Significant Deterioration of Air Quality
40 CFR Part 60 - Standards of Performance for New Stationary Sources (NSPS)
40 CFR Part 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPS)
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants Source Categories
40 CFR Part 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP).

40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ are not applicable to the three (3) 877 hp diesel engine drives, Waukesha model L5792; two (2) 435 hp diesel engine generators, Caterpillar model D353; and one (1) 800 hp diesel engine for Top Drive unit, Caterpillar Model C27; of drilling rig no. 1 and one (1) 470 hp rig drive diesel engine, Caterpillar model C-13; one (1) 284 hp diesel engine generator, John Deere model 6068HF485; and one (1) 630 hp mud pump diesel engine, Caterpillar model C-18 DITA; of drilling rig no. 2 since these are considered nonroad engines. A nonroad engine is any internal combustion engine that, by itself or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or move from one location to another.

Best Available Control Technology (BACT):

A Best Available Control Technology (BACT) analysis is required for new or modified sources that have the potential to emit or increase emissions above significant levels as defined in HAR §11-60.1. There are no proposed changes in this permit renewal that results in an increase in emissions. Thus, a BACT analysis is not required for this permit renewal.

Prevention of Significant Deterioration (PSD):

This source is not a major stationary source nor are there modifications proposed that by itself constitute a major stationary source that is subject to PSD review. Therefore, PSD is not applicable.

Air Emissions Reporting Requirements (AERR):

40 CFR Part 51, Subpart A – Air Emissions Reporting Requirements, is based on the emissions of criteria air pollutants from Type B point sources (as defined in 40 CFR Part 51, Subpart A), that emit as the AERR triggering levels as shown in the table below.

Pollutant	Type B AERR Triggering Levels [1] (tpy)	Pollutant	In-house Total Facility Triggering Levels [1] (tpy)	Total Facility Emissions [1] (tpy)
NO_x	≥100	NO_x	≥25	54.8
SO_x	≥100	SO_x	≥25	0.03
CO	≥1000	CO	≥250	14.6
$PM_{10}/PM_{2.5}$	≥100/100	PM/PM_{10}	≥25/25	PM = 1.2, PM_{10} = 1.0, $PM_{2.5}$ = 1.0
VOC	≥100	VOC	≥25	56.25
		HAPS	≥5	7.48 E-02

[1] Based on potential emissions

This facility does not emit at the AERR triggering levels. Therefore, AERR is not applicable.

Although AERR for the facility is not triggered, the Clean Air Branch requests annual emissions reporting from those facilities that have facility-wide emissions of a single pollutant exceeding in-house triggering levels. Since the total emissions of NO_x and VOC from point sources within the facility are greater than twenty-five (25) tons per year, annual emissions reporting for the facility will be required for in-house recordkeeping purposes.

Compliance Assurance Monitoring (CAM):

40 CFR Part 64

Applicability of the CAM Rule is determined on a pollutant specific basis for each affected emission unit. Each determination is based upon a series of evaluation criteria. In order for a source to be subject to CAM, each source must:

- Be located at a major source per Title V of the Clean Air Act Amendments of 1990;
- Be subject to federally enforceable applicable requirements;
- Have pre-control device potential emissions that exceed applicable major source thresholds;
- Be fitted with an "active" air pollution control device; and
- Not be subject to certain regulations that specifically exempt it from CAM.

Emission units are any part or activity of a stationary source that emits or has the potential to emit any air pollutant.

CAM is not applicable since this facility is a noncovered source.

Synthetic Minor Source:

For the geothermal exploratory/developmental wells, there is a fuel limitation of 250,000 gal/yr on the nine (9) diesel engines for the drilling rigs such that the major source threshold is not triggered. Therefore, this facility is a synthetic minor.

Exemptions:

1. *Per HAR §11-60.1-62(d)(3)*
   a. Three (3) 10,000 gallon pentane storage tanks;
   b. One (1) 100 gallon diesel storage tank for emergency water pump, wellfield;
   c. One (1) 500 gallon diesel storage tank for emergency firewater pump, power plant;
   d. One (1) 1,500 gallon diesel storage tank for standby diesel generator, power plant;
   e. One (1) 1,000 gallon diesel storage tank for vehicles;
   f. One (1) 1,000 gallon gasoline storage tank for vehicles;
   g. One (1) 13,000 gallon diesel storage tank to fill the drilling rig day tanks;
   h. Three (3) forty-gallon (40 gallon) diesel storage day tanks for each of the (3) 877 diesel engines;
   i. One (1) forty-gallon (40 gallon) diesel storage day tank for the two (2) 435 hp diesel engine generators;
   j. One (1) 3,000 gallon diesel storage day tank for the 800 hp diesel engine for Top Drive unit; and
   k. Four (4) 500 gallon diesel storage tanks for miscellaneous use (cement, nitrogen, coil tubing units).

2. *Per HAR §11-60.1-62(d)(8)*
   a. One (1) 370 hp, diesel driven emergency firewater pump, power plant; and
   b. One (1) 1400 kW standby diesel generator, power plant.

Alternate Operating Scenarios:

No alternate operating scenarios are proposed.

Project Emissions:

1. Power Plant Emissions

   The primary emissions from the power plant are hydrogen sulfide (H_2S) and pentane, both of which can result from various emission sources (fugitive and point). Fugitive geothermal gas emissions containing hydrogen sulfide can occur from leaks in power plant components such as compressors, pumps, pipe fittings, valves, etc. Treated geothermal gas emissions containing hydrogen sulfide are released from the Emergency Steam Relief Facility (ESRF) when there is overpressurization in the main geothermal steam supply line to the power plant. Treated geothermal gas emissions containing hydrogen sulfide are also released from the Sulfa-Treat system, which receives gas vented from the steam turbine seals. Fugitive pentane emissions can occur from leaks in the turbine/generator modules due to leaks in flanges, fittings, valves, and pumps. Treated pentane emissions occur from the vapor recovery unit (VRU), which treat gases vented from the pentane condenser. Within the power plant, only point source emissions not due to upset or emergency scenarios can be calculated. This would be from the VRU and Sulfa-Treat system. Calculations are shown below.

   a. Vapor Recovery Unit

      Emissions from the VRU can be estimated from the quantity of pentane recovered by condensation to determine the maximum flow rate (gal/hr) of pentane condensed. Using a VRU recovery efficiency of ninety-five percent (95%), a density of pentane of 5.29 lb/gal and maximum flow rate of 206 gal/hr from flow totalizer data, the controlled emissions are estimated as follows:

      Controlled emissions = Uncontrolled emissions - pentane recovered

      Uncontrolled emissions = pentane recovered / recovery eff.

      Controlled emissions = (pentane recovered/ recovery eff.) - pentane recovered

      Controlled emissions = pentane recovered [(1/recovery eff.) - 1]

      Maximum controlled emissions = 206 gal/hr x 5.29 lb/gal [(1/0.95) - 1]

      Maximum controlled emissions = <u>57.3 lb/hr of pentane</u>

      The VRU operates approximately sixteen (16) hrs/yr during purges and about 100 hrs/yr during maintenance activities or a total of 116 hrs/yr. In this instance, the potential to emit (PTE) is limited by the operational design of the VRU so 116 hrs/yr is a good estimate.

The permits has an emission limit of 300 lb/day of pentane. This is equivalent to an emission rate of 12.5 lb/hr which is less than the estimated maximum controlled emission rate of 57.3 lb/hr. Using the allowable emission rate of 300 lb/day x 365 days/yr = 109,500 lb/yr or <u>54.75 tpy of pentane</u>. The estimated controlled annual emissions = 12.5 lb/hr x 116 hr/yr = 1450 lb/yr or <u>0.72 tpy of pentane</u>

b. Sulfa-Treat System

Emission calculations were based on measured inlet and outlet concentrations of H_2S for the Sulfa-Treat system since AP-42 emission factors and manufacturer's performance data is not available.

Using typical operating concentrations of 20,000 ppmv and eighteen (18) ppmv for inlet and outlet H_2S concentrations and the ideal gas law results in the following:

i. Uncontrolled emission rate (lb/hr) = C_{in} x Q_{eff} x 60 min/hr

C_{in} = [20,000 x 10^{-6} (moles H_2S/mole air) x 1.2 atm x 34.1(lb/lb-mole)] / [0.7302 (ft^3 atm/lb-mole ^{o}R) x 589.67^{o}R] = 1.90 x 10^{-3} lb/ft^3

Q_{eff} = 60 ft^3/min

Uncontrolled emission rate (lb/hr) = 1.90 x 10^{-3} lb/ft^3 x 60 ft^3/min x 60 min/hr = <u>6.84 lb/hr of H_2S</u>

Uncontrolled annual emission rate (tpy) = 6.84 lb/hr x 8760 hr/yr x 0.0005 tons/lb = <u>29.96 tpy of H_2S</u>

ii. Controlled emission rate (lb/hr) = C_{out} x Q_{eff} x 60 min/hr

C_{out} = [18 x 10^{-6} (moles H_2S/mole air) x 1.0 atm x 34.1(lb/lb-mole)] / [0.7302 (ft^3 atm/lb-mole ^{o}R) x 539.67^{o}R] = 1.56 x 10^{-6} lb/ft^3

Controlled emission rate (lb/hr) = 1.56 x 10^{-6} lb/ft^3 x 60 ft^3/min x 60 min/hr = <u>0.0056 lb/hr of H_2S</u>

Controlled annual emission rate (tpy) = 0.0056 lb/hr x 8760 hr/yr x 0.0005 tons/lb = <u>0.025 tpy of H_2S</u>

Power Plant Emissions

Pollutant	Uncontrolled Emissions		Controlled Emissions		Allowable Emissions	
	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/day)	(tons/yr)
Pentane	n/a	n/a	57.3	54.75	300	54.75
Hydrogen Sulfide	6.84	29.96	0.0056	0.025	n/a	n/a

2. Wellfield Emissions

Wellfield emissions (H_2S) primarily occur during nonroutine conditions such as well drilling, flow testing and abated well cleanout. Wellfield emissions can also occur from leaks in flanges, connections, valves, or fittings. When completed wells are not experiencing any equipment failure or malfunction, there are no wellfield emissions.

3. Geothermal Exploratory/Developmental Wells - Drilling Rig Diesel Engines

Since the overall fuel consumption limit of 250,000 gallon/yr of fuel for the total facility (nine diesel engines) is not being revised, the total facility emissions remains unchanged and are shown in the table below. Total facility emissions were calculated on a “worst case” scenario of operation. The “worst case” scenario for potential emissions was based on the fuel consumption limit of 250,000 gallons/yr of fuel burning in one of the three (3) types of diesel engines of drilling rig no. 1, since drilling rig no. 1 would be operated continuously in drilling a well. The diesel engine with the highest emissions of NO_x (the 877 hp diesel engine) was selected as the “worst case” scenario.

Total Emissions for Diesel Engines

Pollutant	Controlled Emission Rate [1,2] (lb/1000 gal)	Controlled Emission Rate [4] (lb/hr)	Controlled Annual Emissions [5] (tpy)
NO_x	438.4	22.0	54.8
SO_2	0.21 [3]	0.01	0.03
CO	116.5	5.8	14.6
VOC	12.3	0.6	1.5
PM	9.6	0.5	1.2
PM_{10}	7.9	0.4	1.0
$PM_{2.5}$	7.6	0.4	1.0
Benzene	1.06 E-01	5.31 E-03	1.33 E-02
Toluene	3.85 E-02	1.93 E-03	4.81 E-03
Xylenes	2.64 E-02	1.32 E-03	3.31 E-03
Propylene	3.82 E-01	1.91 E-02	4.78 E-02
Formaldehyde	1.08 E-02	5.41 E-04	1.35 E-03
Acetaldehyde	3.45 E-03	1.73 E-04	4.32 E-04
Acrolein	1.08 E-03	5.41 E-05	1.35 E-04
Total PAH	2.90 E-02	1.45 E-03	3.63 E-03
Total HAPs	5.97 E-01	2.99 E-02	7.48 E-02

Notes:
1. Emission factors from AP-42 (10/96) Tables 3.4-1, 3.4-2, 3.4-3, 3.4-5
2. Based on fuel oil no.2 with a heating value of 137,000 Btu/gal
3. Based on fuel oil no.2, S=0.0015
4. Based on a fuel consumption rate of 50.1 gal/hr for a 877 hp diesel engine
5. Based on an annual fuel limitation of 250,000 gal/yr for all diesel engines applied to a 877 hp diesel engine, i.e., annual operating hours = (250,000 gal/yr) / (50.1 gal/hr) = 4990 hrs/yr
6. Total PAH includes Naphthelene

Greenhouse Gas (GHG) Emissions:

Mass Greenhouse Gas (GHG) Emissions

Unit No.	Fuel Type	Annual Operating Hours (hrs/yr)	Heat Input Capacity (MMBtu/hr)	CO_2 Emission Factor [1] (lb/MMBtu)	CO_2 Annual Emissions (ton/yr)	N_2O Emission Factor [1] (lb/MMBtu)	N_2O Annual Emissions (tons/yr)	CH_4 Emission Factor [1] (lb/MMBtu)	CH_4 Annual Emissions (tons/yr)
877 hp Diesel Engine	No. 2 Diesel	4990	6.86	163.1	2792	1.32E-03	0.02	6.62E-03	0.11
Total Annual Greenhouse Gas Emissions					2792		0.02		0.11

[1] 40 CFR Part 98 Subpart C, Table C-1 and Table C-2

CO_2 Equivalent (CO_2e) Emissions

CO_2e (tpy) [1]			
Unit No.	**CO_2**	**N_2O**	**CH_4**
877 hp Diesel Engine	2792	6.0	2.8
Total Annual CO_2e(tpy) = 2801 (one engine)			
Total Annual CO_2e(tpy) = 2801 x 9 = 25,209 (nine engines)			

[1] CO_2e calculated using global warming potential (GWP) from 40 CFR Part 98 Subpart A, Table A-1. GWP: CO_2 = 1, N_2O = 298, CH_4 = 25

Ambient Air Quality Impact Assessment (AAQIA):

An ambient air quality impact assessment (AAQIA) is not required to be performed since there are no changes proposed for this renewal application that will result in an emissions increase.

Significant Permit Conditions:

For the renewal of this noncovered source permit, the following permit conditions were revised or added. As is custom when modifying regulatory language, new language is underlined, while [deleted language is shown in brackets].

• Added Attachment IIA, Special Condition No. A.1.j

j. Pressure Relief Valves (Turbine/Generator Modules PSEs and PSVs)

• Revised Attachment IIA, Special Condition No. B.5

5. The ESRF shall be maintained and be fully operational at all times. The ESRF [rock muffler(s) in service] shall have a design capacity [be capable] of handling 100 percent of the total actual power plant steam flow.

• Revised Attachment IIA, Special Condition No. B.7

7. The ESRF shall be equipped and maintained at all times with a minimum of 3000 gallons of sodium hydroxide. The chemical abatement system shall operate automatically when steam is released through the rock muffler(s). A minimum sodium hydroxide treatment mole ratio of 4 to 1 ($NaOH/H_2S$) shall be used. [If the duration of the steam release is greater than fifteen (15) minutes, the permittee shall monitor the perimeter of the rock muffler(s) using portable hydrogen sulfide analyzers.]

   Upon utilizing the ESRF, the permittee shall take immediate action to the extent practical to reduce the steam flow and perform the necessary corrective actions. The steam flow rate shall be reduced, as a minimum, to fifty (50) percent of full flow within four (4) hours after initiating the use of the ESRF.

• Added Attachment IIA, Special Condition No. B.15

15. The pressure relief valves for the turbine/generator modules shall be maintained and operated at all times in accordance with the manufacturer's operational specifications and design.

• Revised Attachment IIA, Special Condition No. C.2

2. Records shall be maintained on all incidents resulting in the release of pentane to the atmosphere; including the purging of noncondensable gases from the turbine/generator modules; the maintenance and overhaul of the turbine/generator modules, VRU, and VRMU; equipment malfunctions; usage of the VRU and VRMU with hours of operation; and all fugitive emission measurements greater than 10,000 ppm and the corrective measures taken. Records shall include the date and time of each incident, the estimated amount of pentane emitted from each incident, the date and quantity of pentane received from the supplier, and the corresponding pentane tank level readings before and after receipt of the pentane from the supplier. The total pentane emissions from the facility shall be recorded on a **quarterly basis** to calculate the average daily emissions. [In addition to estimating the amount of pentane emitted from each incident, records shall also include information on the date and quantity of pentane received from the supplier and the corresponding pentane tank level reading. The above records shall be recorded on a **quarterly basis** to calculate the average daily emissions.]

• Revised and renumbered Attachment IIA, Special Condition No. C.4 to C.3

3. The permittee shall operate and maintain a minimum of three (3) meteorological monitoring stations, three (3) ambient air quality monitoring stations for hydrogen sulfide and one (1) PM_{10} monitor. The three (3) ambient air quality monitoring stations shall be operated at all times, except during periods of maintenance, repair, or quality assurance/quality control procedures, and unforeseen events beyond the control of the permittee, including, but not limited to, the following: acts of nature, acts of war or terrorism, or equipment failure. Only one (1) of the ambient air quality monitoring stations shall be taken out of service for maintenance, repair, or quality assurance/quality control procedures at any one time. The PM_{10} monitor shall only be operated during drilling operations, flow testing, and well cleanouts. The permittee shall maintain a file of all measurements collected from and performed on the ambient air monitoring stations, including the monitoring system performance evaluations; calibration checks; and adjustments and maintenance performed on the system or devices. The measured data shall meet U.S. EPA capture requirements and quality assurance guidelines. As a minimum, a quality assurance check shall be conducted on each monitoring station every other day.

   The three (3) ambient air quality monitoring stations shall be equipped with emergency backup power in the event of power outages [disruptions] to the monitoring stations. The emergency backup power shall have the capability to supply emergency power to the ambient air quality monitoring stations to ensure that the ambient air quality monitoring stations have power to operate at all times. The permittee shall also maintain a spare hydrogen sulfide analyzer for the ambient air quality monitoring stations.

• Added Attachment IIA, Special Condition No. C.6

6. Leak Inspections for Hydrogen Sulfide

   The permittee shall perform daily leak inspections of all steam, brine, and noncondensable gas piping for hydrogen sulfide. For the daily leak inspections, detection methods incorporating sight, sound, smell, and an instrument are acceptable. When a leak is detected, an instrument which continuously monitors hydrogen sulfide levels must be used to determine if the leak is at levels above the OSHA threshold of ten (10) ppm at a distance of one (1) meter. For all leaks with readings above these levels, an initial attempt to secure or repair the leak shall be made as soon as possible, not to exceed twelve (12) hours. For all leaks below these levels, an attempt to secure the leak shall be made as soon as possible not to exceed twelve (12) hours or repair of the leak shall be made in a timely manner not to exceed thirty (30) days, unless circumstances dictate a longer timetable, i.e., procurement of necessary materials, contractors, equipment, shipping issues, etc.

   A log entry shall be made in the Central Station Control (CSC) operations logbook and shall be signed by the permittee at the completion of each inspection. Each detection of a hydrogen sulfide leak shall be recorded in the CSC operations log book. The permittee shall record for each leak that is detected the following information:

   a. The equipment type and identification number;
   b. The nature of the leak (i.e., vapor or liquid) and the method of detection (i.e., sight, sound, smell, or instrument). If an instrument is used to detect a leak, the hydrogen sulfide level;
   c. The date/time the leak was detected and the date of each attempt to repair the leak;
   d. Repair methods applied in each attempt to repair the leak; and
   e. The date/time of successful repair of the leak.

• Added Attachment IIA, Special Condition No. C.7

7. If the duration of the steam release from the ESRF is greater than fifteen (15) minutes, the permittee shall monitor the perimeter of the facility and the ESRF using portable hydrogen sulfide analyzers. Records shall be maintained and include the following:

   a. Dates, times, and locations of hydrogen sulfide concentration readings; and
   b. Hydrogen sulfide concentration readings in ppbv.

• Revised and renumbered Attachment IIA, Special Condition No. C.3 to C.8

8. The following data shall be recorded during periods in which the hydrogen sulfide abatement system is operating at the ESRF:

   a. The <u>dates and</u> operating times of the ESRF;
   b. The injection rate of sodium hydroxide;
   c. The quantity of sodium hydroxide remaining in the abatement equipment storage tanks.[and]
   d. <u>The total quantity of hydrogen sulfide emissions released (abated), in pounds;</u> [The hydrogen sulfide readings from the portable H_2S analyzers in accordance with Special Condition No. B.7 of Attachment IIA.]
   <u>e.</u> <u>The initial and final steam flow rates</u>; and
   <u>f.</u> <u>The reason for using the ESRF.</u>

• Added Attachment IIA, Special Condition No. C.9

9. If any of the pressure relief valves for the turbine/generator modules has a malfunction, the permittee shall monitor the perimeter of the facility using portable hydrogen sulfide analyzers. Records shall be maintained and include the following:

    a. Dates, times, and locations of hydrogen sulfide concentration readings; and
    b. Hydrogen sulfide concentration readings in ppbv.

• Revised Attachment IIA, Special Condition No. D.7

7. The permittee shall notify the Department immediately in the event the ESRF has operated more than fifteen (15) minutes in duration in accordance with Special Condition No. C.7 [B.7] of Attachment IIA.

• Added Attachment IIA, Special Condition No. D.8

8. The permittee shall immediately notify the Department of an unforeseen event beyond the control of the permittee that affects the operation of the three (3) ambient air quality monitoring stations specified in Special Condition No. C.3 of Attachment IIA, unless the protection of personnel or public health or safety demands immediate attention and makes such notification infeasible. In the latter case, the notice shall be provided as soon as practicable.

• Revised Attachment IIB, Special Condition No. A.1

1. This permit encompasses the following equipment and related appurtenances:

    a. Pad A Wellfield: Production Wells KS-9, [and] KS-10, and KS-16, Injection Wells KS-1A, KS-11, and KS-13, and associated equipment;
    b. Pad B Wellfield: Injection [Production] Well KS-15, and associated equipment;
    c. Pad E Wellfield: Production Wells KS-5, KS-6, [and] KS-14, and KS-17, Injection Well KS-3, and associated equipment;
    d. Fourteen (14) Geothermal Exploratory/Developmental Wells;
    e. Drilling rig no. 1 (Rig 51):

        i. Three (3) 877 hp diesel engine drives, Waukesha model L5792, serial nos. 363805, 363806, and 363807 (nonroad engines);
        ii. Two (2) 435 hp diesel engine generators, Caterpillar model D353, serial nos. 46B09273 and 46B09281 (nonroad engines); and
        iii. One (1) 800 [950] hp diesel engine for Top Drive unit, Caterpillar model C27 [C32], serial no. RAM00139 [TLD00590] (nonroad engine).

    f. Drilling rig no. 2 (Geodrill Rig 4):

        i. One (1) 470 hp rig drive diesel engine, Caterpillar model C-13, serial no. LEE19127 (nonroad engine);
        ii. One (1) 284 hp diesel engine generator, John Deere model 6068HF485, serial no. PE6068L039306 (nonroad engine); and
        iii. One (1) 630 hp mud pump diesel engine, Caterpillar model C-18 DITA, serial no. WJH00848 (nonroad engine).

g. Portable H_2S Abatement System.
<u>h. Pressure Relief Valves (Production and Injection Wells PSEs and PSVs)</u>

• Removed Attachment IIB, Section B as follows:

[**<u>Section B. Applicable Federal Regulations</u>**

The one (1) 470 hp diesel engine and one (1) 284 hp diesel engine of drilling rig no. 2 are subject to the provisions of the following federal regulations:

1. 40 Code Federal Regulations (CFR) Part 60, Standards of Performance for New Stationary Sources, Subpart A, General Provisions;
2. 40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines;
3. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards), Subpart A, General Provisions; and
4. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards), Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

The permittee shall comply with all applicable provisions of these standards, including all emission limitations and all notifications, testing, monitoring, and reporting requirements. The major requirements of these standards are detailed in the special conditions of this permit.]

• Revised Attachment IIB, Special Condition No. B.19

19. <u>The diesel engines shall be fired only on fuel oil no. 2 with a maximum sulfur content of 0.0015% by weight and a minimum cetane index of forty (40) or a maximum aromatic content of thirty-five (35) volume percent.</u>

    [The three (3) 877 hp, two (2) 435 hp, and one (1) 800 hp diesel engines for drilling rig no. 1, and one (1) 630 hp diesel engine for drilling rig no. 2 shall be fired only on fuel oil no. 2 with a maximum sulfur content not to exceed 0.5 percent by weight. The one (1) 470 hp diesel engine and one (1) 284 hp diesel engine for drilling rig no. 2 shall be fired only on fuel oil no. 2 with:

    a. A maximum sulfur content of 0.0015% by weight; and
    b. A cetane index or aromatic content as follows:

        i. Minimum cetane index of forty (40); or
        ii. Maximum aromatic content of thirty-five (35) volume percent.]

• Added Attachment IIB, Special Condition No. B.22

22. Nonroad Engine Requirements

For the purpose of retaining the diesel engine's status as a nonroad engine, the diesel engine shall not remain at a location for more than twelve (12) consecutive months, except for equipment storage. A location is any single site at a building, structure, facility or installation. Any engine (or engines) that replace an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period. Should the diesel engine remain at a location for more than twelve (12) consecutive months, the diesel engine would no longer be classified as a nonroad engine and would be subject to the requirements of 40 Code of Federal Regulations (CFR) Part 63, Subpart ZZZZ.

• Added Attachment IIB, Special Condition No. B.23

23. The pressure relief valves for the production and injection wells shall be maintained and operated at all times in accordance with the manufacturer's operational specifications and design.

• Added Attachment IIB, Special Condition No. C.8

8. Nonroad Engine Location Changes

For the purpose of demonstrating compliance with Attachment IIB, Special Condition No. B.22, and to retain the diesel engine's status as a nonroad engine, the permittee shall maintain a log of all location changes of the diesel engine. For each location change, the permittee shall record in a log:

a. A description of where on the property the diesel engine(s) is moving;
b. The date the diesel engine(s) is moved to another location;
c. The make, model, and serial number of each diesel engine involved in the move; and
d. The purpose or reason for the location change.

The permittee is prohibited from circumventing or attempting to circumvent the residence time requirements of Attachment IIB, Special Condition No. B.22 (i.e., moving the diesel engine only for the purpose of avoiding the applicability of 40 CFR Part 63, Subpart ZZZZ).

The relocation of nonroad engines within a single property does not need the approval of the Department.

• Added Attachment IIB, Special Condition No. C.9

9. If any of the pressure relief valves for the production and injection wells has a malfunction, the permittee shall monitor the perimeter of the facility using portable hydrogen sulfide analyzers. Records shall be maintained and include the following:

a. Dates, times, and locations of hydrogen sulfide concentration readings; and
b. Hydrogen sulfide concentration readings in ppbv.

• Added Attachment IIB, Special Condition No. C.10

10. Leak Inspections for Hydrogen Sulfide

The permittee shall perform daily leak inspections of all steam, brine, and noncondensable gas piping for hydrogen sulfide. For the daily leak inspections, detection methods incorporating sight, sound, smell, and an instrument are acceptable. When a leak is detected, an instrument which continuously monitors hydrogen sulfide levels must be used to determine if the leak is at levels above the OSHA threshold of ten (10) ppm at a distance of one (1) meter. For all leaks with readings above these levels, an initial attempt to secure or repair the leak shall be made as soon as possible, not to exceed twelve (12) hours. For all leaks below these levels, an attempt to secure the leak shall be made as soon as possible not to exceed twelve (12) hours or repair of the leak shall be made in a timely manner not to exceed thirty (30) days, unless circumstances dictate a longer timetable, i.e., procurement of necessary materials, contractors, equipment, shipping issues, etc.

A log entry shall be made in the Central Station Control (CSC) operations logbook and shall be signed by the permittee at the completion of each inspection. Each detection of a hydrogen sulfide leak shall be recorded in the CSC operations log book. The permittee shall record for each leak that is detected the following information:

a. The equipment type and identification number;
b. The nature of the leak (i.e., vapor or liquid) and the method of detection (i.e., sight, sound, smell, or instrument). If an instrument is used to detect a leak, the hydrogen sulfide level;
c. The date/time the leak was detected and the date of each attempt to repair the leak;
d. Repair methods applied in each attempt to repair the leak; and
e. The date/time of successful repair of the leak.

• Revised Attachment IIB, Special Condition No. E.2 (third paragraph)

During normal operation of each well, the sampling and testing of the resource shall be performed on an **annual basis**. During the testing of the noncondensable gases, if the hydrogen sulfide concentrations deviates more than +10 percent of the <u>previous</u> [initial] well test measurement, the permittee shall repeat the sampling and testing of the resource for the steam condensate, brine and noncondensable gases within the next **six (6) months**. The permittee shall be required to perform a retest only **once** after performing an annual resource test.

Conclusion and Recommendations:

Recommend issuing the renewal for Noncovered Source Permit, NSP No. 0008-02-N, subject to the significant permit changes shown above. The facility shall remain in compliance with all Federal and State ambient air quality standards. This permit shall supersede Noncovered Source Permit (NSP) No. 0008-02-N issued on December 15, 2009, and amended on April 29, 2010, November 14, 2011, December 2, 2011, July 10, 2013, August 20, 2014, and December 31, 2014, in its entirety.

Reviewer: Darin Lum
Date: 8/2015