Air Pollution Control
Title V Permit to Operate
Statement of Basis for Permit No V-SUIT-000012-2014.00
{Date}

Red Cedar Gathering Company
Coyote Gulch Treating Plant
Southern Ute Indian Reservation
La Plata County, Colorado

1. Facility Information

a. Location

The Coyote Gulch Treating Plant, owned and operated by Red Cedar Gathering Company (Red Cedar), is located within the exterior boundary of the Southern Ute Indian Reservation. The exact location is Section 17, T32N, R11W, in La Plata County, at latitude North 37.0137 and longitude West 108.061219. The Mailing address is:

Red Cedar Gathering Company
Coyote Gulch Treating Plant
125 Mercado St.; Suite 201
Durango, CO 81301

b. Contacts

Facility Contact:
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c. Description of Operations

According to Red Cedar's application, the Coyote Gulch Treating Plant, owned and operated by Red Cedar Gathering Company, is located in southwestern Colorado within the exterior boundaries of the Southern Ute Indian Reservation. Coyote Gulch is a production field facility prior to the point of custody transfer. Natural gas product is provided to Coyote Gulch from several upstream wells and compression stations. This facility has two trains which have roughly the same process. The entire treating plant encompasses three separate processes; one for the gas, one for the glycol, and one for the amine.

Gas flow process: The gas enters the facility at medium pressure (approximately 300psi). The gas is compressed through a combination of 2 natural gas fired compressor engines (units E-03 and E-07) and three electric compressors to approximately 500-530psi. The gas then goes through the amine contactor towers where it mixes with the amine solution, and C02 is removed. The gas then proceeds to the dehydrator contactor tower, where it contacts the triethylene glycol and water is removed. The gas is then compressed further (through the same combination of compressors) to high pressure (approx. 1100psi) and is then discharged from the station.

Glycol flow process: The glycol regeneration process is similar for each of the trains. The lean glycol (without water) is pumped into the top of the dehydration unit contactor tower where it comes into contact with the saturated gas and removes the water (thereby becoming rich glycol). This rich glycol then goes into the dehydrator reboilers where the water is removed from the glycol using heat. The glycol then repeats this process. Emissions from the dehydrator still vents on units V2 and V4 are routed, via a closed vent system, to an enclosed combustion device, or incinerator. This unit combusts the dehydrator vent gas to reduce benzene emissions to less than 0.9 Mg/yr. Train 2 has two dehydrator reboilers and still vents (referred to as the north and south dehys) which share common glycol pumps and a common contactor tower. Emissions from these two dehydrator units are calculated separately as they typically do not run at the same time.

Amine flow process: The amine regeneration process is similar to the glycol process. The lean amine is pumped into the top of the amine contactor tower where it comes into contact with the gas and removes the C02. The rich amine is then transferred to the amine regenerator. The amine is heated in the regenerator either directly (Train 1 units H1A and H1B) or indirectly via a heat exchange process using hot oil (Train 2 units H3 and H4). The lean amine then recirculates through the process.

The facility does not extract natural gas liquids from field gas nor fractionate mixed NGL's to natural gas products. The facility has storage vessels, but none with the potential for flash emissions. Coyote Gulch's primary emitters consist of 2 compressor engines, 4 large process heaters, two C02 vents, and three glycol dehydration units. The facility has several heaters, and tanks that qualify as insignificant emission units. Coyote Gulch does not engage in pigging operations.

The 2 compressor engines are 4SLB SI RICE. One of these compressor engines (E-07) is subject to 40 CFR Part 63 Subpart ZZZZ regulations. Red Cedar has selected oxidation catalyst as the means to satisfy the regulatory requirements for Carbon Monoxide (CO) reduction. The three dehydration units are subject to 40 CFR part 63 Subpart HH. Two of these dehydrator units (V2 and V4) are subject to control requirements under this subpart. Red Cedar has selected an internal combustion device (incinerator) connected to the units via a closed loop system to satisfy these control requirements.

d. <u>List of All Units and Emission-Generating Activities</u>

Red Cedar provided the information contained in Tables 1 and 2 in its initial part 70 permit application. Table 1 lists emission units and emission generating activities, including any air pollution control devices. Emission units identified as "insignificant" emitting units (IEUs) are listed separately in Table 2.

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Table 1 – Emission Units
Red Cedar Gathering Company, Coyote Gulch Treating Plant

Emission Unit ID[1]	Description	Control Equipment
E-03	1 – Caterpillar G3612LE (SI 4SLB) natural gas-fired Compressor Engine, 3,550 HP Serial No.: 1YG00071 Installed: 01/01/1997	AFRC
E-07	1– Caterpillar G3616LE (SI 4SLB) natural gas-fired Compressor Engine 4,735 HP Serial No.:BLB00302 Installed: 03/04/2011	EMIT oxidation catalyst with AFRC
H1A (Train 1) H1B (Train 1)	2 – Optimized Process Furnace, Natural Gas-Fired Amine Regenerator Reboiler (Process Heater), 33.5 MMBtu/hr Serial No.: 14-0401-A Installed: 03/14/1996 Serial No.: 14-0401-B Installed: 03/14/1996	None
H3	1 – Econo-Therm, Natural Gas-Fired Hot Oil Heater (Process Heater), 40 MMBtu/hr Serial No.: J-66-308 Installed: 12/01/1998	None
H4	1 – Econo-Therm, Natural Gas-Fired Hot Oil Heater (Process Heater), 60 MMBtu/hr Serial No.: 69539 Installed: 12/01/1998	None
V1	1 – Amine Regenerator CO_2 Vent, Amine Plant #1, Maximum 5.0 MMscf/hr Serial No.: NA Installed: 03/01/1996	None
V3	1 – Amine Regenerator CO_2 Vent, Amine Plant #2, Maximum 5.8 MMscf/hr Serial No.: NA Installed: 01/01/1998	None
V2	1 – Sivalls Tank Co., Triethylene Glycol Dehydrator, 120 MMscf/day Serial No.: NA Installed: 12/01/1996	Flash Tank Combustion Device and Regenerator Combustion Device
V4	1 – QB Johnson, Triethylene Glycol Dehydrator, 120 MMscf/day Serial No.: NA Installed: 01/01/1998	Flash Tank Combustion Device and Regenerator Combustion Device
	1 – QB Johnson, Triethylene Glycol Dehydrator, 80 MMscf/day	Flash Tank Combustion Device

V5	Serial No.: NA	Installed: 01/01/2002	

The Southern Ute Indian Tribe/State of Colorado Environmental Commission's Reservation Air Code allows sources to separately list in the permit application units or activities that qualify as "insignificant" based on potential emissions below 2 tpy for all regulated pollutants that are not listed as hazardous air pollutants (HAPs) under Section 112(b) of the Clean Air Act (CAA) and below 1,000 lbs per year or the de minimis level established under Section 112(g), whichever is lower, for HAP emissions [RAC 2-106(4)(f); RAC 1-103(36) and (37)]. However, the application may not omit information needed to determine the applicability of, or to impose, any applicable requirement, or to calculate the fee [RAC 2-106(4)(f)]. Units that qualify as "insignificant" for the purposes of the Part 70 application are in no way exempt from applicable requirements or any requirements of the Part 70 permit.

Red Cedar stated in its Part 70 initial permit application that the emission units in Table 2, below, are insignificant. The application provided calculations for heater/reboiler emissions based on EPA's AP-42 emission factors. Red Cedar provided sufficient information, including EPA Tanks 4.0.9d calculations, to verify any emissions from liquids in the tanks were insignificant. This data supports Red Cedar's claim that these units qualify as insignificant.

Table 2 – Insignificant Emission Units
Red Cedar Gathering Company, Coyote Gulch Treating Plant

Emission Unit ID	Description	Size/Rating
07-V-8930	1 - Train 1 Dehydrator Regenerator Reboiler	1.8 MMBtu/hr
07-NBC-4060	1 - Train 2 South Dehydrator Regenerator Reboiler	2.0 MMBtu/hr
E-102	1 - Train 2 North Dehydrator Regenerator Reboiler	1.8 MMBtu/hr
TK-07-22-0501	2 - TEG Waste Water (still vent) Tank (Trains 1 & 2)	90 bbl
TK-03-1241	5 - Lubricating oil makeup tank	500 gal
TK-03-1240	3 - Coolant storage tank	500 gal
TK-01-18-8101	2 - Used oil underground sump (Trains 1 & 2)	1,000 gal
TK-18-3302	1 - Amine storage tank	4,200 gal
TK-18-3301	1 - Treated water storage tank	42,000 gal
TK-07-BJ-4100	1 - TEG makeup storage tank	4,200 gal
TK-MBJ-1540	1 - Hot oil storage tank	9,000 gal
TK-03-1316	1 - Hot oil storage tank	500 gal
TK-G1	1 - Gasoline storage tank	1,050 gal
TK-18-8103,4	2 - Wastewater/oil tank	8,820 gal
TK-18-3303,4	2 - Relief blowdown/Amine storage tank	12,600 gal
H7, H8	2 - Tank heater	0.325 MMBtu/hr
NA	Fugitive Emissions	Estimated 2,482 components

e. <u>Facility Construction and/or Permitting History</u>

The Coyote Gulch Treating Plant commenced amine sweetening and dehydration operations in 1996. In 1997, compression was supplemented with the addition of one Caterpillar engine (E-03). In January 1998, a second process train was constructed at the facility. This modification did not require a PSD permit as the potential emissions increases of the project were below major source thresholds. With this new

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construction, the facility became a major PSD source for Colorado. Therefore, the emissions from any newly proposed construction from that point forward were to be compared to PSD significance levels rather than PSD major source levels when determining PSD applicability. EPA issued the initial part 71 permit, # V-SU-0012-00.00, in March of 2000. That permit was modified in November of 2001. In 2002, Red Cedar Gathering Company took over operation of the Coyote Gulch Treating Plant. A permit modification was submitted September 3, 2002 to reflect this change in operator as well as to address multiple other corrections to emission factors and emission units operating at the facility. EPA issued Coyote Gulch's first permit renewal as permit #V-SU-0012-05.00 on January 3, 2007. That permit was administratively amended three times and underwent a minor modification. EPA issued a Compliance Assistance Plan (CAP) for CAA violations at Coyote Gulch on August 11, 2010. On March 8, 2011, EPA issued a minor modification to incorporate applicable emission limitation requirements under 40 CFR part 63, Subpart HH as required by the CAP. Additionally, the minor modification incorporated the applicable requirements of 40 CFR part 60, subpart Dc and the installation of compressor engine E-07, along with the corresponding requirements of 40 CFR part 63, Subpart ZZZZ for that unit. Coyote Gulch is currently operating under permit #V-SU-000012-2011.00. That permit will be replaced by this initial part 70 permit, # V-SUIT-000012-2014.00.

f. <u>Potential to Emit</u>

Under RAC 1-103(51), potential to emit (PTE) is defined as the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design <u>if</u> the limitation, or the effect it would have on emissions, is federally enforceable.

<u>Greenhouse Gas Tailoring Rule</u>

On June 3, 2010, EPA promulgated the final PSD and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule established the applicability criteria that determine which stationary sources and modification projects are subject to PSD and Title V permitting requirements for greenhouse gas (GHG) emissions. As of January 2, 2011, GHGs are regulated NSR pollutants under the PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds.

For PSD and Title V purposes, GHGs are a single air pollutant defined as the aggregate group of the following six gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). CO_2-equivalent (CO_2e) is defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential value in Table A-1 of the Greenhouse Gas Reporting Program (40 CFR Part 98, Subpart A, Table A-1).

The Tailoring Rule established the following applicability criteria for GHGs:

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PSD Applicability Criteria

PSD applies to GHGs if any of the following conditions are met:

1. The source is a new source otherwise subject to PSD (for another regulated NSR pollutant) and the source has a GHG PTE equal to or greater than
   - 75,000 tpy CO_2e;
2. The source is a new source and has a GHG PTE equal to or greater than:
   - 100,000 tpy CO_2e, and
   - 100 / 250 tpy mass basis
3. A modification to an existing source is otherwise subject to PSD (for another regulated NSR pollutant) and has a GHG emissions increase and net emissions increase:
   - Equal to or greater than 75,000 tpy CO_2e, and
   - Greater than 0 tpy mass basis
4. An existing source has a GHG PTE equal to or greater than:
   - 100,000 tpy CO_2e, and
   - 100 / 250 tpy mass basis

   and a modification to an existing source has a GHG emissions increase and net emissions increase:
   - Equal to or greater than 75,000 tpy CO_2e, and
   - Greater than 0 tpy mass basis
5. The source is an existing minor source for PSD, and a modification alone has actual or potential GHG emissions equal to or greater than:
   - 100,000 tpy CO_2e, and
   - 100 / 250 tpy mass basis

Title V Applicability Criteria

Title V applies to GHGs at the following sources:

1. Existing or newly constructed sources that emit or have a PTE equal to or greater than:
   - 100,000 tpy CO_2e, and
   - 100 tpy mass basis

A detailed summary and guidance of permitting requirements established by the Tailoring Rule can be found in the March 2011 EPA document titled "PSD and Title V Permitting Guidance for Greenhouse Gases", located at http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

The PTE for Coyote Gulch Treating Plant was listed by Red Cedar in Forms "GIS", "PTE", and the various forms "EMISS" of the Part 70 operating permit initial application. Table 3 shows PTE data broken down by each individual emission unit, as well as the total facility-wide PTE.

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Table 3 - Potential to Emit (uncontrolled)
Red Cedar Gathering Company, Coyote Gulch Treating Plant

Emission Unit ID	Regulated Air Pollutants[1,2,3] in tpy (uncontrolled)								
	NO_X	VOC	SO_2	PM_{10}	CO	Lead	Total HAPs	Largest *Single* HAP (CH_2O)	GHGs (CO_2e mtpy)
E-03	24.0	30.6	0.0	0.0	85.7	0.0	11.6	8.9	16,001.2
E-07	32.0	40.5	0.0	0.0	114.3	0.0	15.8	11.9	21,497.6
H1A	14.5	0.8	0.0	1.1	12.2	0.0	1.9	0.1	15,807.9
H1B	14.5	0.8	0.0	1.1	12.2	0.0	1.9	0.1	15,807.9
H3	17.3	1.0	0.0	1.3	14.5	0.0	2.3	0.1	18,875.0
H4	25.9	1.4	0.0	2.0	21.8	0.0	3.4	0.2	28,312.6
V1	0.0	12.1	0.0	0.0	0.0	0.0	0.0	0.0	46,308.3
V3	0.0	14.2	0.0	0.0	0.0	0.0	0.1	0.0	125,731.9
V2	0.0	62.3	0.0	0.0	0.0	0.0	25.8	1.4	3,359.5
V4	0.0	49.1	0.0	0.0	0.0	0.0	22.0	1.1	2,502.4
V5	0.0	45.2	0.0	0.0	0.0	0.0	18.0	1.0	2,522.1
Total IEUs	2.8	0.5	0.0	0.3	2.4	0.0	0.4	0.0	3515.5
	131.0	**260.9**	**0.0**	**5.8**	**263.0**	**0.0**	**103.2**	**21.4**	**300,241.9**

1 Uncontrolled NO_x, CO, & VOC emissions are based on manufacturer specifications. HAP emissions were calculated using the highest emissions factor from a composite of AP-42, GRI field data, and GRI literature data.
2 Uncontrolled dehydrator emissions based on GRI-GLY-Calc modeled emissions.
3 Heater/reboiler emissions were calculated using AP-42 emission factors

2. Tribal Authority

Coyote Gulch Treating Plant is located within the exterior boundaries of the Southern Ute Indian Reservation and is thus within Indian Country as defined at 18 U.S.C. §1151. On March 2, 2012, the EPA determined that the Southern Ute Indian Tribe of the Southern Ute Indian Reservation had met the requirements of 40 CFR §70.4(b) for full approval to administer its Clean Air Act Title V, Part 70 Permitting Program (Program). In concert with that Program approval, the EPA also found that the Tribe met the requirements of Section 301(d)(2) of the CAA and 40 CFR §49.6 for treatment "in the same manner as a state" for the purposes of issuing CAA Title V, Part 70 operating permits. The EPA promulgated its approval of the Tribe's applications on March 15, 2012 (77 FR 15267). The requirements of the Clean Air Act Title V, Part 70 Permitting Program (Program) have been incorporated at Article II, Part 1 of the Reservation Air Code. Therefore, the Southern Ute Indian Tribe is the appropriate governmental entity to issue the Title V permit to this facility.

The Reservation Air Code: The Reservation Air Code was adopted pursuant to the authority vested in the Southern Ute Indian Tribe/State of Colorado Environmental Commission by (1) the Intergovernmental Agreement Between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian Reservation dated December 13, 1999, (2) tribal law (Resolution of the Council of the Southern Ute Indian Tribe No. 00-09), (3) State law (C.R.S. § 24- 62-101), and (4) as recognized in federal law (Act of October 18, 2004, Pub. L. No. 108-336, 118 Stat.1354).

NSPS and NESHAP Delegation: On September 6, 2013, the Southern Ute Indian Tribe received delegation from the EPA to incorporate by reference into the Reservation Air Code and enforce certain subparts of the new source performance standards and national emission standards for hazardous air pollutants under Sections 111 and 112 of the Clean Air Act, respectively (78 FR 40635). These NSPS and NESHAP subparts generally apply to oil and gas operations within the exterior boundaries of the Southern Ute Indian Reservation and were adopted, unchanged, into the Reservation Air Code as Parts 2 and 3.

Southern Ute Indian Tribe Minor Source Program: The Southern Ute Indian Tribe/State of Colorado Environmental Commission is currently developing a Minor Source Program in order to fill a regulatory gap wherein sources of air pollution located on the Reservation have been subject to fewer requirements than similar sources located on land under the jurisdiction of a state air pollution control agency. Until such time that EPA approves the Minor Source Program as part of a TIP under the Tribal Authority Rule, affected sources must comply with the federal rule "Review of New Sources and Modifications in Indian Country" that was published on July 1, 2011 (76 FR 38748). This rule requires new and existing synthetic minor sources currently operating under federal operating permits for sources in Indian country (regulated at 40 CFR Part 71), as well as sources proposing minor modifications at existing major sources, to submit applications to EPA starting August 30, 2011. Existing true minor sources are required to register with the permitting authority no later than March 1, 2013. After September 2, 2014, all true minor sources that intend to construct or modify will have to apply for a preconstruction permit.

3. Applicable Requirements

The following discussion addresses a selection of the regulations from the Code of Federal Regulations (CFR) at Title 40. Note that this discussion does not include the full spectrum of potentially applicable regulations and is not intended to represent official applicability determinations. These discussions are based on the information provided by Red Cedar in its Part 70 initial permit application and are only intended to present the information certified to be true and accurate by the Responsible Official of this facility.

Prevention of Significant Deterioration (PSD) - 40 CFR 52.21

PSD is a preconstruction review requirement of the CAA that applies to proposed projects that are sufficiently large (in terms of emissions) to be a "major" stationary source or "major" modification of an existing stationary source. A new stationary source, or a modification to an existing minor stationary source, is major if the proposed project has the potential to emit any pollutant regulated under the CAA in amounts equal to or exceeding specified major source thresholds, which are 100 tpy for 28 listed industrial source categories and 250 tpy for all other sources. PSD also applies to modifications at existing major sources that cause a "significant net emissions increase" at that source. Significance levels for each pollutant are defined in the PSD regulations at 40 CFR 52.21. A modification is a physical change or change in the method of operation.

Coyote Gulch is not a PSD named source. Therefore, the PTE threshold for determining PSD applicability for this source is 250 tpy for criteria pollutants and 100,000 tpy for CO_2e. The PTE for CO, VOC, and CO_2e at Coyote Gulch are above the major source thresholds, and the facility is classified as major for PSD permitting purposes. **Therefore, any project or major modification at the site resulting in an increase of any regulated NSR pollutant must be compared to the PSD significance levels rather than major source thresholds when determining PSD applicability.**

New Source Performance Standards (NSPS)

<u>40 CFR Part 60, Subpart A</u>: General Provisions. This subpart applies to the owner or operator of any stationary source that contains an affected facility, the construction or modification of which is commenced after the date of publication of any standard in Part 60. The general provisions under Subpart A apply to sources that are subject to the specific subparts of Part 60.

> As explained below, the Coyote Gulch Treating Plant is subject to 40 CFR Part 60, Subpart Dc. **Therefore, the General Provisions of Part 60 apply**.

<u>40 CFR Part 60, Subpart Dc</u>: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This rule applies to steam generating units with a maximum design heat capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr and commenced construction, modification, or reconstruction after June 9, 1989.

> According to Red Cedar, units H1A and H1B, located at the Coyote Gulch Treating Plant, are steam generating units with a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Units H1A and H1B are subject to this subpart. However, since these units are fueled only by natural gas, there are no emission requirements for these units. **Therefore, Subpart Dc does apply.**

<u>40 CFR Part 60, Subpart K</u>: Standards of performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. 40 CFR Part 60, Subpart K does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

> According to Red Cedar, the Coyote Gulch Treating Plant has no tanks that were constructed, reconstructed, or modified after June 11, 1973 and prior to May 19, 1978. **Therefore, Subpart K does not apply.**

<u>40 CFR Part 60, Subpart Ka</u>: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to June 23, 1984. This rule applies to storage vessels for petroleum liquids with a storage capacity greater

than 40,000 gallons. Subpart Ka does not apply to petroleum storage vessels with a capacity of less than 420,000 gallons used for petroleum or condensate stored, processed, or treated prior to custody transfer.

> According to Red Cedar, the Coyote Gulch Treating Plant has no tanks that were constructed, reconstructed, or modified after May 18, 1978 and prior to June 23, 1984. **Therefore, Subpart Ka does not apply.**

40 CFR Part 60, Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This rule applies to storage vessels with a capacity greater than or equal to 75 cubic meters (~629 bbl).

> According to Red Cedar, the Coyote Gulch Treating Plant has no tanks with a capacity greater than 75 m^3 (~629 bbl or 19,813 gal) that are used to store volatile organic liquids. **Therefore, Subpart Kb does not apply.**

40 CFR Part 60, Subpart KKK: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. This rule applies to compressors and other equipment at onshore natural gas processing facilities. As defined in this subpart, a natural gas processing plant is any processing site engaged in the extraction of natural gas liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both. NGLs are defined as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

> According to Red Cedar, the Coyote Gulch Treating Plant does not extract natural gas liquids from field gas, nor does it fractionate mixed NGLs to natural gas products, and thus does not meet the definition of a natural gas processing plant under this subpart. **Therefore, Subpart KKK does not apply.**

40 CFR Part 60, Subpart LLL: Standards of Performance for SO_2 emissions from Onshore Natural Gas Processing for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. This rule applies to sweetening units and sulfur recovery units at onshore natural gas processing facilities. As defined in this subpart, sweetening units are process devices that separate hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from a sour natural gas stream. Sulfur recovery units are defined as process devices that recover sulfur from the acid gas (consisting of H_2S and CO_2) removed by a sweetening unit.

> According to Red Cedar, there are no sweetening or sulfur recovery units at the Coyote Gulch Treating Plant. **Therefore, Subpart LLL does not apply.**

40 CFR Part 60, Subpart JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. This subpart establishes emission standards and compliance requirements for the control of emissions from stationary spark ignition (SI) internal combustion engines (ICE) that

commenced construction, modification or reconstruction after June 12, 2006, where the SI ICE are manufactured on or after specified manufacture trigger dates. The manufacture trigger dates are based on the engine type, fuel used, and maximum engine horsepower.

For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator (See 40 CFR 60.4230(a)).

Red Cedar provided the following information:

Table 3 - NSPS Subpart JJJJ Applicability Determination
Red Cedar Gathering Company, Coyote Gulch Treating Plant

Unit	Serial No	Unit Description	Fuel	Maximum HP	Commence Construction, Modification, or Reconstruction Date	Install/ Startup Date	Trigger Date for Applicability-Manufactured on or after
E-03	1YG00071	Caterpillar 3612LE 4SLB Compressor Engine	Natural Gas	3,550	01/01/1997	01/01/1997	07/01/2007
E-07	BLB00302	Caterpillar 3616LE 4SLB Compressor Engine	Natural Gas	4,735	03/31/2006[1]	03/04/2011	07/01/2007

1. Per Red Cedar, these engines have not been modified or reconstructed (as defined in Part 60) since June 12, 2006.

According to Red Cedar, E-03 and E-07 were manufactured prior to July 1, 2007 (the trigger date for engines with maximum engine power greater than or equal to 500 HP as defined in §60.4230). The engines have not been reconstructed or modified (as defined in §60.15) since June 12, 2006. **Therefore, the requirements of Subpart JJJJ do not apply to units E-03 and E-07**.

Should Red Cedar propose to install a replacement engine for E-03 or E-07, which is subject to Subpart JJJJ, Red Cedar will not be allowed to use the off permit changes provision, and will be required to submit a minor permit modification application to incorporate Subpart JJJJ requirements into the permit.

40 CFR Part 60, Subpart OOOO: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. This subpart establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011. Affected facilities under this subpart include gas wells, compressors, pneumatic controllers, storage vessels, process unit equipment, and sweetening units. The effective date for this subpart is October 15, 2012.

According to Red Cedar, the Coyote Gulch Treating Plant does not have any affected facilities under the rule that commenced construction after August 23, 2011. **Therefore, Subpart OOOO does not apply.**

National Emission Standards for Hazardous Air Pollutants (NESHAP)

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40 CFR Part 63, Subpart A: General Provisions. This subpart contains national emissions standards for HAPs that regulate specific categories of sources that emit one or more HAP regulated pollutants under the CAA. The general provisions under subpart A apply to sources that are subject to the specific subparts of Part 63.

As explained below, the Coyote Gulch Treating Plant is subject to 40 CFR 63 Subparts HH, ZZZZ, and DDDDD. **Therefore the General Provisions of Part 63 apply** as specified in the relevant subparts.

40 CFR Part 63, Subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. This subpart applies to the owners and operators of affected units located at natural gas production facilities that are area or major sources of HAPs, and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. The affected units are glycol dehydration units, storage vessels with the potential for flash emissions, and the group of ancillary equipment, and compressors intended to operate in volatile hazardous air pollutant service, which are located at natural gas processing plants.

Throughput Exemption

Those sources whose maximum natural gas throughput, as appropriately calculated per §63.760(a)(1)(i) through (a)(1)(iii), is less than 18,400 standard cubic meters per day are exempt from the requirements of this subpart.

Source Aggregation

Major source, as used in this subpart, has the same meaning as in §63.2, except that:

1) Emissions from any oil and gas production well with its associated equipment and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units.

2) Emissions from processes, operations, or equipment that are not part of the same facility shall not be aggregated.

3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination.

Facility

For the purpose of a major source determination, facility means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in

Subpart HH. Examples of facilities in the oil and natural gas production category include, but are not limited to: well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Production Field Facility

Production field facilities are those located prior to the point of custody transfer. The definition of custody transfer (40 CFR 63.761) means the point of transfer after the processing/treating in the producing operation, except for the case of a natural gas processing plant, in which case the point of custody transfer is the inlet to the plant.

Natural Gas Processing Plant

A natural gas processing plant is defined in 40 CFR 63.761 as any processing site engaged in the extraction of NGLs from field gas, or the fractionation of mixed NGLs to natural gas products, or a combination of both. A treating plant or gas plant that does not engage in these activities is considered to be a production field facility.

Major Source Determination for Production Field Facilities

The definition of major source in subpart HH (at 40 CFR 63.761) states, in part, that only emissions from the dehydration units and storage vessels at production field facilities shall be aggregated when comparing to the major source thresholds.

For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated.

Area Source Applicability

40 CFR Part 63, Subpart HH also applies to area sources of HAPs. An area source is a HAP source whose total HAP emissions are less than 10 tpy of any single HAP or 25 tpy for all HAPs in aggregate. This subpart requires different emission reduction requirements for glycol dehydration units found at oil and gas production facilities based on their geographical location.

Units located in densely populated areas (determined by the Bureau of Census) and known as urbanized areas with an added 2-mile offset and urban clusters of 10,000 people or more, are required to have emission controls. Units located outside these areas will be required to have the glycol recirculation pump rate optimized or operators must document that uncontrolled annual actual benzene emissions are less than 0.9 megagrams (1,984 lbs.).

Any source that determines that it is not a major source but has actual emissions of 5 tons per year of a single HAP or 12.5 tons per year of a combination of HAP (i.e. 50 percent of the major source thresholds), shall update its major source determination within 1 year of the prior determination and each year thereafter, using gas composition data measured during the preceding 12 months.

Applicability of Subpart HH to the Coyote Gulch Treating Plant

According to Red Cedar, the Coyote Gulch Treating Plant is a major source of HAPs, upgrades natural gas, and is located prior to the point of custody transfer (and therefore prior to the point at which natural gas leaves the natural gas processing category and enters the natural gas transmission and storage category). Because the facility is in the natural gas processing category only emissions from dehydration units and storage vessels with the potential for flash emissions need to be aggregated when determining major source status. The total HAP emissions from the glycol dehydrators and storage vessels are above major source thresholds. **Therefore, Coyote Gulch is subject to the major source requirements of Subpart HH.**

Dehydration unit V5 qualifies as an affected source under this rule. This unit is an existing small dehydration unit, as uncontrolled actual average benzene emissions were determined to be less than 0.90 megagrams per year. As an affected major source not located within an Urban 1 county (or any UA plus offset and UC boundary), unit V5 is subject to the requirements for small dehydrators located at a major source of HAPs, and must meet these requirements no later than October 15, 2015, per §63.760(f)(7).

Dehydration units V2 and V4 also qualify as affected sources under this subpart. These units are large dehydrators, as the actual annual benzene emissions for each of these units exceed 0.90 megagrams per year. As an affected major source not located within an Urban 1 county (or any UA plus offset and UC boundary), units V2 and V4 are subject to the requirements for large dehydrators located at a major source of HAPs

<u>40 CFR Part 63, Subpart HHH</u>: National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. This subpart applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user, and that are a major source of hazardous air pollutant (HAP) emissions. Natural gas transmission means the pipelines are used for long distance transport (excluding processing).

According to Red Cedar, the Coyote Gulch Treating Plant is not part of the natural gas transmission and storage source category. **Therefore, Subpart HHH does not apply.**

<u>40 CFR Part 63, Subpart ZZZZ (RICE MACT)</u>: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This rule establishes national emission limitations and operating limitations for HAPs emitted from stationary spark ignition internal combustion engines (SI ICE) and stationary compression ignition internal combustion engines (CI ICE).

For the purposes of this standard, construction or reconstruction is as defined in §63.2.

Summary of Applicability to Engines at Major HAP Sources

Major HAP Sources			
Engine Type	**Horse Power Rating**	**New / Existing**	**Applicability Trigger Date**
SI ICE – All[1]	≥ 500 HP	New	On or After: 12/19/2002
SI ICE – 4SRB	> 500 HP	Existing	Before: 12/19/2002
SI ICE – All[1]	≤ 500 HP	New	On or After: 6/12/2006
SI ICE – All[1]	≤ 500 HP	Existing	Before: 6/12/2006
CI ICE – All[2]	≥ 500 HP	New	On or After: 12/19/2002
CI ICE – Non Emergency	> 500 HP	Existing	Before: 12/19/2002
CI ICE – All[2]	≤ 500 HP	New	On or After: 6/12/2006
CI ICE – All[2]	≤ 500 HP	Existing	Before: 6/12/2006

1. All includes emergency ICE, limited use ICE, ICE that burn land fill or digester gas, 4SLB, 2SLB, and 4SRB.
2. All includes emergency ICE and limited use ICE

Summary of Applicability to Engines at Area Hap Sources

Area HAP Sources			
Engine Type	**Horse Power Rating**	**New / Existing**	**Applicability Trigger Date**
SI ICE – All[1]	All HP	New	On or After: 6/12/2006
SI ICE – All[1]	All HP	Existing	Before: 6/12/2006
CI ICE – All[2]	All HP	New	On or After: 6/12/2006
CI ICE – All[2]	All HP	Existing	Before: 6/12/2006

1. All includes emergency ICE, limited use ICE, ICE that burn land fill or digester gas, 4SLB, 2SLB, and 4SRB.
2. All includes emergency ICE and limited use ICE

Applicability of 40 CFR 63, Subpart ZZZZ to the Coyote Gulch Treating Plant:

Unit	Serial Number	Unit Description	Fuel	Site Rated HP	Commenced Construction, Reconstruction, or Modification Date	Initial Installation Date
E-03	1YG00071	Caterpillar 3612LE 4SLB Compressor Engine	Natural Gas	3,550	Prior to 12/19/2002	01/01/1997
E-07	BLB00302	Caterpillar 3616LE 4SLB Compressor Engine	Natural Gas	4,735	After 12/19/2002	03/04/2006

According to Red Cedar, Coyote Gulch is a major source as defined in Subpart ZZZZ. Unit E-07 is a four-stroke lean-burn (4SLB) stationary RICE > 500 site-rated HP constructed after December 19, 2002, and has not been reconstructed since this date. **Therefore, Unit E-07 is considered new stationary RICE, and is subject to the major source requirements for new 4SLB engines.**

Unit E-03 is a four-stroke lean-burn (4SLB) stationary RICE > 500 site-rated HP constructed prior to December 19, 2002, and has not been reconstructed since this date. Unit E-03 is therefore considered an existing 4SLB stationary RICE. According to **§**63.6590(b)(3)(ii) this unit has no requirements under this part or 40 CFR Part 63, Subpart A, including initial notification requirements. **Therefore, Unit E-03 is not subject to Subpart ZZZZ.**

40 CFR Part 63, Subpart DDDDD (Boiler MACT (for major sources)): National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. This rule establishes national emission limitations and operating limitations for HAPs emitted from new and existing industrial boilers, institutional boilers, commercial boilers, and process

heaters that are located at major sources of HAPs. Boilers or process heaters that combust natural gas for fuel or have a maximum designed heat input capacity less than 10 MMBtu/hr are subject to work practice standards in lieu of emission limits. For the purposes of this subpart, an affected unit is an existing unit if it was constructed prior to June 4, 2010.

The Coyote Gulch Treating Plant is a major source as defined in §63.7575. This subpart potentially applies to the triethylene glycol (TEG) reboilers and tank heaters at the facility because these units are considered process heaters under the subpart. However, the TEG reboilers are not subject to this subpart as they are listed as an affected source under Subpart HH, per §63.7491(h). According to Red Cedar, units H1A, H1B, H3, and H4 are existing natural gas-fired process heaters with a heat input capacity of greater than 10 MMBtu/hr without a continuous oxygen trim system. **Therefore, units H1A, H1B, H3, and H4 are subject to Subpart DDDDD.**

Compliance Assurance Monitoring (CAM) Rule

40 CFR Part 64: Compliance Assurance Monitoring Provisions. According to 40 CFR 64.2(a), the CAM rule applies to each Pollutant Specific Emission Unit (PSEU) at a major source that is required to obtain a Part 70 or Part 71 permit if the unit satisfies all of the following criteria:

1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant other than an emissions limitation or standard that is exempt under §64.2(b)(1);

"§64.2(b)(1): Exempt emission limitations or standards. The requirements of this part shall not apply to any of the following emission limitations or standards:

(i) Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to Section 111 or 112 of the Act;
(ii) Stratospheric ozone protection requirements under Title VI of the Act;
(iii) Acid Rain Program requirements pursuant to Sections 404, 405, 406, 407(a), 407(b) or 410 of the Act;
(iv) Emissions limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions with a source or between sources;
(v) An emissions cap that meets the requirements specified in §70.4(b)(12) or §71.6(a)(13)(iii) of this chapter;
(vi) Emission limitations or standards for which a Part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1."

"§64.1: Continuous compliance method means a method, specified by the applicable standard or an applicable permit condition, which:

(1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and
(2) Provides data either in units of the standard or correlated directly with the compliance limit."

2) The unit uses a control device to achieve compliance with any such limit or standard; and

3) The unit has pre-control device emissions of the applicable regulated pollutant that are equal to or greater than 100% of the amount, in tons per year, required for a source to be classified as a major source.

According to Red Cedar, the CAM rule does not apply to any of the units at the Coyote Gulch Treating Plant as the pre-controlled emissions for each unit are less than the major source threshold. **Therefore, CAM does not apply.**

Chemical Accident Prevention Program

40 CFR Part 68: Chemical Accident Prevention Provisions. This rule applies to stationary sources that manufacture, process, use, store, or otherwise handle more than the threshold quantity of a regulated substance in a process. Regulated substances include 77 toxic and 63 flammable substances which are potentially present in the natural gas stream entering the facility and in the storage vessels located at the facility. The quantity of a regulated substance in a process is determined according to the procedures presented under §68.115. §68.115(b)(l) and (2)(i) indicate that toxic and flammable substances in a mixture do not need to be considered when determining whether more than a threshold quantity is present at a stationary source if the concentration of the substance is below one percent by weight of the mixture. §68.115(b)(2)(iii) indicates that prior to entry into a natural gas processing plant, regulated substances in naturally occurring hydrocarbon mixtures need not be considered when determining whether more than a threshold quantity is present at a stationary source. Naturally occurring hydrocarbon mixtures include condensate, field gas, and produced water.

According to Red Cedar, the Coyote Gulch Treating Plant does have regulated substances above the threshold quantities in this rule. **Therefore the facility is subject to the requirement to develop and submit a risk management plan.**

Stratospheric Ozone and Climate Protection

40 CFR Part 82, Subpart F: Air Conditioning Units. According to Red Cedar, no maintenance, service, repair or disposal of any equipment containing Class I or Class II refrigerants chlorofluorocarbons (CFCs)) occurs at Coyote Gulch Treating Plant. However, if Red Cedar were to engage in any of the afore mentioned activities it must comply with the standards of part 82, Subpart F for recycling and emissions reduction if they service, maintain, or repair the air conditioning units in any way or if they dispose of the units.

40 CFR Part 82, Subpart H: Halon Fire Extinguishers. According to Red Cedar, there are no halon fire extinguishers at Coyote Gulch Treating Plant. However, should Red Cedar obtain any halon fire extinguishers, then it must comply with the standards of 40 CFR Part 82, Subpart H for halon emissions reduction, if it services, maintains, tests, repairs, or disposes of equipment that contains halon or uses such equipment during technician training. Specifically, Red Cedar would be required to comply with 40 CFR Part 82 and submit an application for a modification to this Title V permit.

Mandatory Greenhouse Gas Reporting

40 CFR Part 98: Mandatory Greenhouse Gas Reporting. This rule requires sources above certain emission thresholds to calculate, monitor, and report greenhouse gas emissions. The requirements of 40 CFR Part 98 and CAA §307(d)(1)(V), the CAA authority under which 40 CFR Part 98 was promulgated, however, need not be included in a tribal-issued part 70 permit because those requirements are not included in the definition of “applicable requirement” in either 40 CFR part 70 or RAC 1-103(11). Although the rule is not an applicable requirement under 40 CFR Part 70 or the RAC, the source is not relieved from the requirement to comply with the rule separately from compliance with its Part 70 operating permit. It is the responsibility of each source to determine whether Part 98 is applicable and to comply, if necessary.

4. Public Participation

a. Public Notice

Per RAC § 2-109, all Part 70 draft operating permits shall be publicly noticed and made available for public comment.

Public notice is given by publication in a newspaper of general circulation in the area where the source is located or in a state publication designed to give general public notice, to persons on a mailing list developed by the Tribe, including those who request in writing to be on the list, and by other means if necessary to assure adequate notice to the affected public. If an interested person would like to be added to the Tribe’s mailing list to be informed of future actions on permits issued by the Tribe, please send your name and address:

by United State Postal Service to:

Part 70 Permitting Contact
Southern Ute Indian Tribe
Environmental Programs Division
Part 70 Program
PO Box 737 MS #84
Ignacio, Colorado 81137

by any other delivery service to:

Part 70 Permitting Contact
Southern Ute Indian Tribe
Environmental Programs Division
Part 70 Program
398 Ouray Drive
Ignacio, Colorado 81137

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Public notice will be published in the Durango Herald as detailed in the cover letter of this draft permit package, giving opportunity for public comment on the draft permit and the opportunity to request a public hearing.

b. Opportunity for Comment

Members of the public will be given an opportunity to review a copy of the draft permit prepared by the Tribe, the application, this statement of basis for the draft permit, and all supporting materials for the draft permit. Copies of these documents are available at:

Southern Ute Indian Tribe
Environmental Programs Division
Air Quality Program
115 County Road 517
Ignacio, Colorado 81137

All documents are available for review at the Southern Ute Indian Tribe's Environmental Programs Division office Monday through Friday from 9:00 a.m. to 4:00 p.m. (excluding holidays).

Any interested person may submit written comments on the draft Part 70 operating permit during the public comment period to the Part 70 Permit Contact at the address listed above. The Tribe will consider and address comments in making a final decision on the permit. The Tribe keeps a record of the commenters and of the issues raised during the public participation process.

Anyone, including the applicant, who believes any condition of the draft permit is inappropriate should raise all reasonably ascertainable issues and submit all arguments supporting his or her position by the close of the public comment period. Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has already been submitted as part of the administrative record in the same proceeding or consists of Environmental Commission, tribal, state or Federal statutes and regulations, EPA documents of general applicability, or other generally available reference material.

c. Opportunity to Request a Hearing

A person may submit a written request for a public hearing to the Part 70 Permit Contact, at the address listed above, by stating the nature of the issues to be raised at the public hearing. Based on the number of hearing requests received, the Tribe will hold a public hearing whenever it finds there is a significant degree of public interest in a draft operating permit. The Tribe will provide public notice of the public hearing. If a public hearing is held, any person may submit oral or written statements and data concerning the draft permit.

d. Public Petitions to the Administrator

In the event the Administrator of the United States Environmental Protection Agency does not object to issuance of the permit, on the basis that it would not be in compliance with applicable requirements, within its 45-day review period, any person may then petition the Administrator within 60 days after the expiration of the Administrator's 45-day review period to make such objection. Any such petition must be based only on objections to the permit that were raised with reasonable specificity during the public comment period unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objections arose after such period. If the administrator objects to a permit as a result of this petition, the Tribe shall not issue the permit until the Administrator's objection has been resolved, except that a petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the 45-day review period and before the Administrator's objection.

e. Appeal of Permits

Within 60 days after the Tribe's final permit action, an applicant, any person who filed comments on the draft permit or participated in the public hearing, and any other person who could obtain judicial review of that action under applicable law, may appeal to the Environmental Commission in accordance with the RAC and the Commission's Procedural Rules.

Petitions for administrative review of final permit actions can be filed after the deadline designated by the Commission only if they are based solely on grounds arising after the deadline for administrative review has passed. Such petitions shall be filed no later than 60 days after the new grounds for review arise. If the final permit action being challenged is the Tribe's failure to take final action, a petition for administrative review may be filed any time before the Tribe denies or issues the final permit.

f. Notice to Affected States/Tribes

As described in RAC § 2-109(3), public notice will be given by notifying all affected programs.
The following entities will be notified:

- State of Colorado, Department of Public Health and Environment
- State of New Mexico, Environment Department
- Ute Mountain Ute Tribe, Environmental Programs Department
- Navajo Tribe, Navajo Nation EPA
- Jicarilla Tribe, Environmental Protection Office
- National Park Service, Air Resources Division, Denver, CO
- U.S. Department of Agriculture, United States Forest Service, Rocky Mountain Region

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