Site Specific Test Plan

Williams - Rocky Mountain Midstream, LLC
3601 Stagecoach Road, Suite 202
Longmont, Colorado 80504

Discovery Lochbuie Compressor Station
Weld County, Colorado

(3) Caterpillar 3606 Engines (C-210, C-211, C-212)
(1) Caterpillar 3516 Engine (C-213)
Performance Test – NOx, CO, VOC

Proposed Test Date: April 10-12, 2019

AST Project No. 2019-0490D

Prepared By
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5530 Marshall Street
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Regulatory Information

Permit No.(s)	CDPHE Permit 17WE1195
Regulatory Citation(s)	40 CFR Part 60, Subpart JJJJ

Source Information

Source Name	*Source Identification*	*Target Parameter(s)*
(1) Caterpillar 3606 4SLB RICE	C-210, AIRS 001	NOx, CO, VOC
(1) Caterpillar 3606 4SLB RICE	C-211, AIRS 002	NOx, CO, VOC
(1) Caterpillar 3606 4SLB RICE	C-212, AIRS 003	NOx, CO, VOC
(1) Caterpillar 3516 4SLB RICE	C-213, AIRS 004	NOx, CO, VOC

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1. Introduction

Alliance Source Testing, LLC (AST) was retained by Rocky Mountain Midstream LLC (RMM) to conduct compliance testing at the Discovery DJ Services LLC operated Discovery Lochbuie Compressor Station (CS) located in Weld County, Colorado. The Colorado Department of Public Health and Environment (CDPHE) Construction Permit 17WE1195 and 40 CFR Part 60, Subpart JJJJ requires testing for the facility. Testing will be conducted to determine the emission rates of nitrogen oxides (NO_X), carbon monoxide (CO) and volatile organic compounds (VOC) from three (3) Caterpillar 3606 natural gas fired engines (C-210, C-211, C-212/ AIRS 001, 002. 003) and one (1) Caterpillar 3516 natural gas fired engine (C-213 / AIRS 004).

This site-specific test plan (SSTP) has been prepared to address the notification and testing requirements of CDPHE Construction Permit 17WE1195 and 40 CFR Part 60, Subpart JJJJ.

2. Plant Description

The Discovery Lochbuie CS (AIRS 123/9F74) is a Natural Gas Compressor Station located in SEC 21 T1N R65WE in Weld County, Colorado. Three (3) Caterpillar 3606 natural gas-fired, turbo-charged, four stroke lean burn (4SLB reciprocating internal combustion engines (RICE) (C-210, C-211, C-212 / AIRS 001, 002, 003) and one (1) Caterpillar G3516 natural gas-fired, turbo-charged, 4SLB RICE (C-213 / AIRS 004) are in service for the compression of natural gas. C-210 through C-212 are site rated at 1,875 horsepower (hp) and C-213 is site rated at 1,380 hp. All engines are equipped with oxidation catalyst and air/fuel ratio control (AFRC) for pollutant control.

3. Process Description

All testing will be performed in accordance with specifications stipulated in U.S. Environmental Protection Agency (EPA) Reference Test Methods (RM) 1, 2, 3A, 25A and 320 referenced in 40 CFR Part 60, Appendix A and 40 CFR Part 63, Appendix A.

At the exhaust of each engine, three, 1-hour test runs will be conducted to determine the emission concentrations of NOx (NO, NO_2), CO and VOC. Concentration data will be combined with concurrently collected oxygen (O_2), carbon dioxide (CO_2), moisture (H_2O) and gas velocity data to determine volumetric flow rate (VFR) and mass emission rates of each analyte in units of pounds per hour (lb/hr) and tons per year (tpy). Mass emissions will be combined with engine operating load to calculate emissions in units of grams per brake-horsepower hour (g/bhp-hr).

EPA RM 25A will be conducted to measure total volatile organic compounds (TVOC) or non methane organic compounds (NMOC) emission concentrations. Methane and ethane emission levels will be measured with EPA RM 320. Compliance with VOC standards will be demonstrated with EPA RM 25A measurements, excluding the contribution of methane and ethane.

The source will be operating within 10% of peak load or at the highest achievable load during the test program. The engine's operating and control equipment parameters will be recorded throughout the test program by Lochbuie CS site personnel for inclusion in the test report, including;

- Catalysts differential pressure (inches of water)
- Catalyst inlet temperature (degrees Fahrenheit)
- Engine load (bhp)
- AFR readings

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Source identification and permitted emission limits are summarized in Table 1.

Table 1
Source Identification

Source Identification	Emission Standards for Required Testing
(3) Caterpillar 3606 4SLB RICE C-210, C-211 & C-212 AIRS 001, 002 & 003 SN: JFE00952, JFE00970 & JFE00917 Capacity: 1,875 hp	NO_X: 1.0 g/bhp-hr, 9.1 tpy CO: 2.0 g/bhp-hr, 2.8 tpy VOC: 0.7 g/bhp-hr, 5.5 tpy
(1) Caterpillar 3516 4SLB RICE C-213 AIRS 004 SN: N6W00317 Capacity: 1,380 hp	NO_X: 1.0 g/bhp-hr, 6.7 tpy CO: 2.0 g/bhp-hr, 2.7 tpy VOC: 0.7 g/bhp-hr, 4.8 tpy

4. Permits and Regulations

The data collected during the test program will be used to determine the compliance status of the units with respect to applicable CDPHE Construction Permit 17WE1195 and 40 CFR Part 60, Subpart JJJJ requirements.

5. Stack Schematic

The stack diameter, upstream and downstream disturbance distances and nipple lengths will be measured on site with a verification measurement provided by the Field Team Leader. Table 2 provides source identification, stack dimensions and the number of gas velocity sampling points. RM 2 sampling points will be in accordance with RM 1. A stratification test will be conducted to determine RM 3A sampling points. RM 25A and 320 will be conducted from a single point.

Table 2
Sample Location Summary

Source Identification	Diameter (inches)	Port Location to Nearest Disturbance	Traverse Points
(3) Caterpillar 3606 4SLB RICE C-210, C-211 & C-212 AIRS 001, 002 & 003	15.75”	Upstream: > ½ D Downstream: > 2D	16
(1) Caterpillar 3516 4SLB RICE C-213 AIRS 004	12”	Upstream: > ½ D Downstream: > 2D	16

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6. Methods

All testing will be performed in accordance with specifications stipulated in EPA RM 1, 2, 3A, 25A and 320. The emissions testing program will provide all necessary equipment and labor for the determination of all emissions parameters detailed in Table 3. Gas analyzers will be housed in a mobile, analytical trailer to provide a temperature-controlled environment for stable, accurate analyzer response.

Table 3
Sampling and Analytical Methods

Parameter	EPA RM	Analytical Method
VFR	1, 2	Full Velocity Traverses
O_2, CO_2	3A	Instrumental Analysis
TVOC / NMOC	25A	Instrumental Analysis
H_2O, NOx, NO, NO_2, CO, VOC, methane, ethane	320	Instrumental Analysis / Fourier Transform Infrared (FTIR) spectrometer

6.1. U.S. EPA Reference Test Methods 1 and 2 - Stack Gas Velocity and Volumetric Flow Rate

Stack gas velocity and volumetric flow rate will be measured in accordance with EPA RM 1 and 2.

The sampling location and number of traverse points will be selected in accordance with EPA RM 1. To determine the minimum number of traverse points, the upstream and downstream distances will be equated into equivalent diameters and compared to Figure 1-2 in EPA RM 1.

Full velocity traverses will be conducted in accordance with EPA RM 2 to determine the stack gas velocity pressure, static pressure and temperature. The velocity and static pressure measurement system will consist of a pitot tube and inclined manometer. The stack gas temperature will be measured with a K-type thermocouple and pyrometer. The pitot assembly will be leak checked pre and post each sampling period.

The temperature and differential pressure traverse data will be combined with concurrently collected diluent data to calculate the stack gas velocity and volumetric flow rate in units of feet per second (ft/sec), actual cubic feet per minute (acfm), dry standard (1 atmosphere and 68°F) cubic feet per minute (dscfm), and pounds per hour (lb/hr).

6.2 U.S. EPA Reference Test Method 3A – Oxygen and Carbon Dioxide

O_2 and CO_2 emission concentrations will be measured in accordance with EPA RM 3A.

Each sampling period will consist of extracting a gas sample from the stack at a constant flow rate of approximately two liters per minute (lpm). The sample will pass through a refrigeration-type gas conditioner to remove moisture and into the sampling port of a Servomex Series 1400 paramagnetic O_2 / non-dispersive infrared CO_2 analyzer. The gas concentrations will be displayed on the analyzer front panels in units of percent, dry volume basis (%vd – O_2 and CO_2) and logged to a computerized data acquisition system (CDAS).

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The initial three-point calibration test for each species will be conducted in direct calibration mode. Before and after each sampling period, the sample system will be challenged with calibration gases for a system bias check, and to quantify zero and span drift for the previous sampling period. The calibration gases will be prepared and certified in accordance with EPA Protocol 1.

The initial 3-point calibration error must be less than ±2% of the calibration span gas (CS). The sampling system bias recorded during the performance test must be less than ±5 percent of the CS. The zero and span calibration drift must not exceed ±3 percent of the CS over the period of each run. If the bias values exceed the specified limits, the run is void. If the drift values exceed the specified limits, the results will be reported using pre and post run calibration data. In both cases, another 3-point calibration and 2-point bias verification must be passed before the next run.

Prior to sampling, the stratification test procedures outlined in Section 8.1.2 of EPA RM 7E will be performed to determine the appropriate sampling points on stacks larger than 6 inches. The stratification test will be conducted using a single analyte of interest (O_2 or CO_2) along three (3) points (16.7%, 50.0%, and 83.3% of the stack diameter) passing through the centroidal area of the stack. If the stack gas is not stratified (concentrations are within +/- 5% or +/- 0.5 ppm of the mean concentration), a single measurement point will be selected.

Following sampling, the CDAS data will be averaged in one-minute increments, corrected for instrumental drift, and reported as average O_2 and CO_2 emission concentrations for each sampling period in units of %vd.

6.3 U.S. EPA Reference Test Method 25A – Volatile Organic Compounds

TVOC concentrations will be measured in accordance with EPA RM 25A using a hydrocarbon analyzer. If the hydrocarbon analyzer is equipped with a methane separator NMOC concentrations will be measured.

Each sampling period will consist of extracting a hot, wet gas sample from a single centrally located point in the stack at a constant flow rate of approximately two liters per minute using a heated Teflon line. The gas will be directed into a column of the Thermo Model 51i (TVOC) or 55C (NMOC) flame ionization analyzer. VOC concentrations will be displayed on the analyzer front panel in units of parts per million, wet volume basis (ppmvw – as propane) and logged to a CDAS.

Prior to sampling, the analyzer will be challenged with the zero and high-level EPA Protocol 1 calibration gases to linearize the instrument. Then the low and mid-level calibration gases will be introduced through the sampling system. The sampling system is acceptable, if the linear relationship between the zero and high-level calibration gases predict the low and mid-level calibration gas measurement system response within 5% of the respective calibration gas value. The time required for the analyzer reading to reach 95% of the high-level gas concentration will be recorded to determine the response time of the sampling system.

After each sampling period, the measurement system will be challenged with the zero and mid-level calibration gas. If the analyzer drift exceeds 3% of the analyzer span, then the system will be re-linearized with the zero and high-level calibration gases, and the measurement system verified with the low and mid-level calibration gases. If the drift limits are exceeded, the results will be reported using both sets of calibration data.

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Following sampling, the CDAS data will be averaged in one-minute increments, corrected for instrumental drift, and reported as average emission concentrations for each sampling period. The concentration data will be combined with concurrently collected flow data to calculate VOC emissions as propane in units of lb/hr and g/bhp-hr.

6.4 U.S. EPA Reference Test Method 320 – H_2O, NOx, NO, NO_2, CO, VOC, Methane & Ethane

NO_X, NO, NO_2, CO, VOC, propane, methane, ethane, ethylene, propylene, acetylene, butane and H_2O emission concentrations will be measured in accordance with EPA RM 320 by extractive FTIR using a MKS 2030.

Each sampling period will consist of extracting a sample of gas at a constant flow rate from a single representative point of the exhaust stack. The sample will pass through a sample probe, through a heated Teflon sample line, through a heated head pump, through a heated Teflon jumper to the enclosed FTIR gas cell and then to the instrument detector. The FTIR gas cell will be maintained at 191°C. Sample measurements will be made approximately once every minute.

The FTIR will provide concentration values using MG 2000 software and R3 recipes. The gas concentrations will be reported in units of either parts per million, wet volume basis (ppmvw – NO_X, NO, NO_2, CO, methane, ethane), parts per million, dry volume basis (ppmvd – VOC) or percent, wet volume basis (%vw – H_2O) and logged to a computerized data acquisition system (CDAS). The R3 recipe quantifies VOC emissions based on propane, ethylene, propylene, acetylene and butane levels. NO_X, CO and VOC emission concentrations will be combined with concurrently collected gas flow data to determine emission rates in units of lb/hr, tpy and g/bhp-hr. VOC measurements will not be used for compliance purposes, but for comparison with RM 25A measurements only.

Once per system set-up and prior to testing; (i) a screen shot of the peak analysis screen with laser frequency and FWHH values included, and (ii) a recovery check will be performed by spiking known concentrations of acetaldehyde (or other surrogate) with sulfur hexafluoride into the flue gas of the stacks via the calibration line of the heated sample line. The spiking levels and spike recoveries will demonstrate adequate system performance. For an additional daily quality check, the sample system will be challenged with NO and CO calibration gases for a system bias check. NO and CO concentrations will be approximately 100 ppm. All calibration gases will be prepared and certified in accordance with EPA Protocol 1. During one run the spectral residual and concentration validation check will be conducted for NO, NO_2, CO, H_2O, CO_2 and ethylene using the analysis validation utility (AVU) software from MKS.

A cylinder of nitrogen will be used for purging the instrument's optics. Nitrogen will be passed through the cell to obtain a back ground spectrum and at least eight blank spectra for error analysis and determining minimum detection limits in accordance with the ASTM D6348-03 pre-test MDC2 formula. A screen shot of the signal to noise ratio will be included in the report.

Before and after every run the path length of infrared light through the cell will be measured using a Calibration Transfer Standard (CTS) gas. The CTS gas will be approximately 100 ppm ethylene blended in nitrogen. The CTS pre and post run mean differences will meet the method's requirements (< 5% difference between CTS gas pre and post run measurements).

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7. Quality Control / Quality Assurance

AST follows the procedures outlined in the Quality Assurance/Quality Control (QA/QC) Management Plan to ensure the continuous production of useful and valid data throughout the course of this test program. The QC checks and procedures described in this section represent an integral part of the overall sampling and analytical scheme. Adherence to prescribed procedures is quite often the most applicable QC check.

Field test equipment is assigned a unique, permanent identification number. Prior to mobilizing for the test program, equipment is inspected before being packed to detect equipment problems prior to arriving on site. This minimizes lost time on the job site due to equipment failure. Occasional equipment failure in the field is unavoidable despite the most rigorous inspection and maintenance procedures. Therefore, replacements for critical equipment or components are brought to the job site. Equipment returning from the field is inspected before it is returned to storage. During these inspections, items are cleaned, repaired, reconditioned and recalibrated where necessary.

8. Equations

See *Appendix 3 – Equations*

9. Data Sheets

See *Appendix 4 – Data Sheets*

10. Safety Requirements

Testing personnel will undergo site-specific safety training for all applicable areas upon arrival at the site. AST personnel will have current OSHA or MSHA safety training and be equipped with hard hats, safety glasses with side shields, steel-toed safety shoes, hearing protection, fire resistant clothing, and fall protection (including shock-corded lanyards and full-body harnesses). AST personnel will comport themselves in a manner consistent with Client and AST's safety policies.

A Job Safety Analysis (JSA) will be completed daily by the AST Field Team Leader.

11. Test Schedule

Testing is proposed for the week of April 8, 2019. The testing will require three (3), approximate, 10-hour test days to complete. Testing personnel will arrive on-site the day before testing to set up the necessary sampling apparatus. Table 4 presents an outline and tentative schedule for the emissions testing program.

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Table 4
Program Outline and Tentative Test Schedule

Testing Location	Parameter	U.S. EPA Method	Runs	Run Duration	Est. Onsite Time
DAY 1 – April 10, 2019					
Equipment Setup & Pretest QA/QC Checks					10-hours
(1) Caterpillar 3516 4SLB RICE C-213 AIRS 004	VFR	1, 2	3	60-minutes	
	O_2, CO_2	3A			
	VOC	25A			
	H_2O, NOx, NO, NO_2, CO, VOC, methane, ethane	320			
DAY 2 – April 11, 2019					
(1) Caterpillar 3606 4SLB RICE C-210 AIRS 001	VFR	1, 2	3	60-minutes	10-hours
	O_2, CO_2	3A			
	VOC	25A			
	H_2O, NOx, NO, NO_2, CO, VOC, methane, ethane	320			
(1) Caterpillar 3606 4SLB RICE C-211 AIRS 002	VFR	1, 2	3	60-minutes	
	O_2, CO_2	3A			
	VOC	25A			
	H_2O, NOx, NO, NO_2, CO, VOC, methane, ethane	320			
DAY 3 – April 12, 2019					
(1) Caterpillar 3606 4SLB RICE C-212 AIRS 003	VFR	1, 2	3	60-minutes	10-hours
	O_2, CO_2	3A			
	VOC	25A			
	H_2O, NOx, NO, NO_2, CO, VOC, methane, ethane	320			

12. Test Report

The final test report must be submitted to CDPHE within 30-days of the completion of the testing and will include the following information.

- *Introduction* – Brief discussion of project scope of work and activities.
- *Results and Discussion* – A summary of test results and process/control system operational data with comparison to regulatory requirements or vendor guarantees along with a description of process conditions and/or testing deviations that may have affected the testing results.
- *Methodology* – A description of the sampling and analytical methodologies.
- *Sample Calculations* – Example calculations for each target parameter.
- *Field Data* – Copies of actual handwritten or electronic field data sheets.

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- *Quality Control Data* – Copies of all instrument calibration data and/or calibration gas certificates.
- *Process Operating/Control System Data* – Process operating, control system data (as provided by Lochbuie CS) to support the test results.

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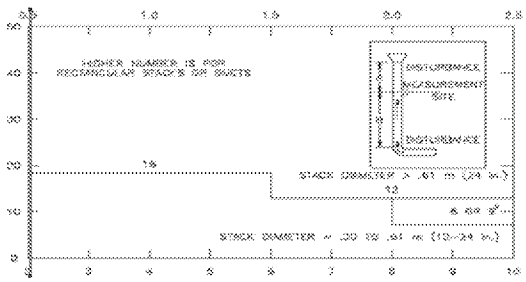
Appendix A

Method 1 Data

Location --
Source --
Project No. --
Date:

Stack Parameters

Duct Orientation:	Vertical	
Duct Design:	Circular	
Distance from Far Wall to Outside of Port:	--	in
Nipple Length:	--	in
Depth of Duct:	15.75	in
Width of Duct:	--	in
Cross Sectional Area of Duct:	1.35	ft^2
Equivalent Diameter:	--	in
No. of Test Ports:	2	
Distance A:	--	ft
Distance A Duct Diameters:	0.5	(must be > 0.5)
Distance B:	--	ft
Distance B Duct Diameters:	2.0	(must be > 2)
Minimum Number of Traverse Points:	16	
Actual Number of Traverse Points:	16	



CIRCULAR DUCT

LOCATION OF TRAVERSE POINTS

Number of traverse points on a diameter

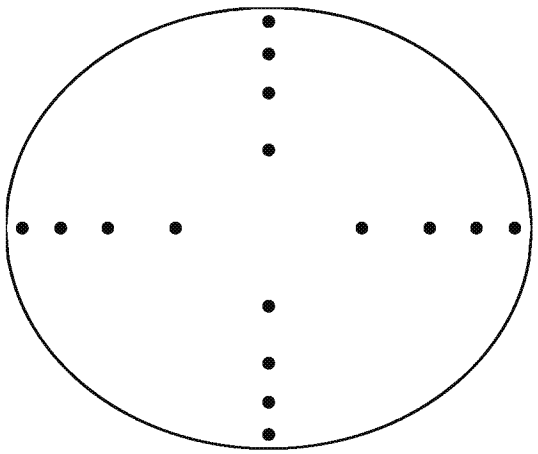
	2	3	4	5	6	7	8	9	10	11	12
1	14.6	--	6.7	--	4.4	--	3.2	--	2.6	--	2.1
2	85.4	--	25.0	--	14.6	--	10.5	--	8.2	--	6.7
3	--	--	75.0	--	29.6	--	19.4	--	14.6	--	11.8
4	--	--	93.3	--	70.4	--	32.3	--	22.6	--	17.7
5	--	--	--	--	85.4	--	67.7	--	34.2	--	25.0
6	--	--	--	--	95.6	--	80.6	--	65.8	--	35.6
7	--	--	--	--	--	--	89.5	--	77.4	--	64.4
8	--	--	--	--	--	--	96.8	--	85.4	--	75.0
9	--	--	--	--	--	--	--	--	91.8	--	82.3
10	--	--	--	--	--	--	--	--	97.4	--	88.2
11	--	--	--	--	--	--	--	--	--	--	93.3
12	--	--	--	--	--	--	--	--	--	--	97.9

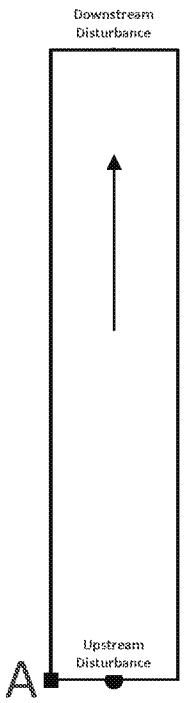
**Percent of stack diameter from inside wall to traverse point.*

Traverse Point	% of Diameter	Distance from inside wall	Distance from outside of port
1	3.2	0.50	--
2	10.5	1.65	--
3	19.4	3.06	--
4	32.3	5.09	--
5	67.7	10.66	--
6	80.6	12.69	--
7	89.5	14.10	--
8	96.8	15.25	--
9	--	--	--
10	--	--	--
11	--	--	--
12	--	--	--

Stack Diagram
A = -- ft.
B = -- ft.
Depth of Duct = 15.75 in.

Cross Sectional Area





Appendix B

Facility Name	Lochbuie CS	Lochbuie CS	Lochbuie CS	Lochbuie CS
Equip ID	C-210	C-211	C-212	C-213
Description	Cat 3606 A4	Cat 3606 A4	Cat 3606 A4	Cat 3516J
Site Rated HP	1875	1875	1875	1380
AIRS ID	123/9F74/001	123/9F74/002	123/9F74/003	123/9F74/004
Initial Start up Date	43502	43501	43475	43444
Manufacture Date	43160	43160	43101	42991
Serial Number	JFE00952	JFE00970	JFE00917	N6W00317
Contract Equip ID	148	149	143	157
Permit Number	17WE1195	17WE1195	17WE1195	17WE1195
Portable Test Period	Semi-Annual	Semi-Annual	Semi-Annual	Semi-Annual
1st Quarter 2019 Testing	Initial JJJJ	Initial JJJJ	Initial JJJJ	Initial JJJJ
Nox (tpy)	9.1	9.1	9.1	6.7
NOx (lb/hr)	2.1	2.1	2.1	1.53
CO (tpy)	2.8	2.8	2.8	2.7
CO (lb/hr)	0.64	0.64	0.64	0.62
VOC(tpy)	5.5	5.5	5.5	4.8

CONSTRUCTION PERMIT

Permit number: **17WE1195** **Issuance:** **1**

Date issued: March 20, 2018

Issued to: **Discovery DJ Services LLC**

Facility Name: Discovery Lochbuie Compressor and Pump Station
Plant AIRS ID: 123/9F74
Physical Location: SEC 21 T1N R65WE
County: Weld County
General Description: Natural Gas Compressor Station and Crude Oil Storage Facility

Equipment or activity subject to this permit:

Facility Equipment ID	AIRS Point	Equipment Description	Emissions Control Description
C-210	001	One (1) Caterpillar, G3606 A4, SN: TBD, natural gas-fired, Turbocharged aspiration, 4SLB reciprocating internal combustion engine, site rated at 1875 horsepower. This engine shall be equipped with a non-selective catalytic reduction (NSCR) system and air-fuel ratio control. This emission unit is used for natural gas compression.	Non-selective catalytic reduction (NSCR) system and air-fuel ratio control
C-211	002	One (1) Caterpillar, G3606 A4, SN: TBD, natural gas-fired, Turbocharged aspiration, 4SLB reciprocating internal combustion engine, site rated at 1875 horsepower. This engine shall be equipped with a non-selective catalytic reduction (NSCR) system and air-fuel ratio control. This emission unit is used for natural gas compression.	Non-selective catalytic reduction (NSCR) system and air-fuel ratio control
C-212	003	One (1) Caterpillar, G3606 A4, SN: TBD, natural gas-fired, Turbocharged aspiration, 4SLB reciprocating internal combustion engine, site rated at 1875 horsepower. This engine shall be equipped with a non-selective catalytic reduction (NSCR) system and air-fuel ratio control. This emission unit is used for natural gas compression.	Non-selective catalytic reduction (NSCR) system and air-fuel ratio control

C-213	**004**	One (1) Caterpillar, G3516J A4, SN: TBD, natural gas-fired, Turbocharged aspiration, 4SLB reciprocating internal combustion engine, site rated at 1380 horsepower. This engine shall be equipped with a non-selective catalytic reduction (NSCR) system and air-fuel ratio control. This emission unit is used for natural gas compression.	Non-selective catalytic reduction (NSCR) system and air-fuel ratio control
D-3101	**005**	One (1) Triethylene glycol (TEG) natural gas dehydration unit (make, model, serial number: TBD) with a design capacity of 20 MMscf per day. This emissions unit is equipped with two (2) Make and model TBD, glycol pump with a design capacity of 4.2 gallons per minute. This unit is equipped with a flash tank, reboiler and still vent.	Emissions from the still vent are routed to an enclosed flare (Point 007). Emissions from the flash tank are routed to an enclosed flare (Point 007).
D-3111	**006**	One (1) Triethylene glycol (TEG) natural gas dehydration unit (make, model, serial number: TBD) with a design capacity of 20 MMscf per day. This emissions unit is equipped with two (2) Make and model TBD, glycol pump with a design capacity of 4.2 gallons per minute. This unit is equipped with a flash tank, reboiler and still vent.	Emissions from the still vent are routed to an enclosed flare (Point 007). Emissions from the flash tank are routed to an enclosed flare (Point 007).
F-4101	**007**	One (1) enclosed process flare to control VOC and HAPs from the TEG dehydrators (Points 005 and 006)	Enclosed Process Flare
CB	**008**	Compressor blowdowns for the 4 compressor engines (Points 001-004)	None
FUG-2	**011**	Fugitives component leak emissions from the pump station	None
TK-1	**012**	One (1) 50,000 bbl external floating roof condensate storage tank	None
TL	**013**	Emissions associated with external floating roof tank landings for MSS activity	None
SR	**014**	Emissions associated with pipeline pigging MSS activity	None

(Points 001-004): These engines may be replaced with another engine in accordance with the temporary engine replacement provision or with the manufacturer and model submitted to the Division per Requirements to Self-Certify for Final Authorization in accordance with the permanent replacement provision of the Alternate Operating Scenario (AOS), included in this permit as Attachment A.

This permit is granted subject to all rules and regulations of the Colorado Air Quality Control Commission and the Colorado Air Pollution Prevention and Control Act (C.R.S. 25-7-101 et seq), to the specific general terms and conditions included in this document and the following specific terms and conditions.

REQUIREMENTS TO SELF-CERTIFY FOR FINAL AUTHORIZATION

1. YOU MUST notify the Air Pollution Control Division (the Division) no later than fifteen days of the latter of commencement of operation or issuance of this permit, by submitting a Notice of Startup form to the Division for the equipment covered by this permit. The Notice of Startup form may be downloaded online at www.colorado.gov/pacific/cdphe/other-air-permitting-notices. Failure to notify the Division of startup of the permitted source is a violation of Air Quality Control Commission (AQCC) Regulation Number 3, Part B, Section III.G.1. and can result in the revocation of the permit.

2. Within one hundred and eighty days (180) of the latter of commencement of operation or issuance of this permit, compliance with the conditions contained in this permit shall be demonstrated to the Division. It is the owner or operator's responsibility to self-certify compliance with the conditions. Failure to demonstrate compliance within 180 days may result in revocation of the permit. A self certification form and guidance on how to self-certify compliance as required by this permit may be obtained online at www.colorado.gov/pacific/cdphe/air-permit-self-certification. (Regulation Number 3, Part B, Section III.G.2.)

3. This permit shall expire if the owner or operator of the source for which this permit was issued: (i) does not commence construction/modification or operation of this source within 18 months after either, the date of issuance of this construction permit or the date on which such construction or activity was scheduled to commence as set forth in the permit application associated with this permit; (ii) discontinues construction for a period of eighteen months or more; (iii) does not complete construction within a reasonable time of the estimated completion date. The Division may grant extensions of the deadline. (Regulation Number 3, Part B, Section III.F.4.)

4. **Point 008:** Upon commencement of operation, the operator shall install a dedicated flow meter to monitor and record volumetric flow rate of natural gas vented from the compressor blowdown events covered by this permit.

5. The operator shall complete all initial compliance testing and sampling as required in this permit and submit the results to the Division as part of the self-certification process. (Regulation Number 3, Part B, Section III.E.)

6. **Points 001-006:** The following information shall be provided to the Division within fifteen (15) days of the latter of commencement of operation or issuance of this permit.

   - The reciprocating internal combustion engines manufacturer name, model number and serial number
   - The dehydrator manufacturer name, model number and serial number
   - The glycol circulation pump manufacturer name and model number

   This information shall be included with the Notice of Startup submitted for the equipment. (Reference: Regulation Number 3, Part B, III.E.)

7. The operator shall retain the permit final authorization letter issued by the Division, after completion of self-certification, with the most current construction permit. This construction permit alone does not provide final authority for the operation of this source.

EMISSION LIMITATIONS AND RECORDS

8. Emissions of air pollutants shall not exceed the following limitations. (Regulation Number 3, Part B, Section II.A.4.)

Monthly Limits:

Facility Equipment ID	AIRS Point	Pounds per Month				Emission Type
		PM2.5	NO_x	VOC	CO	
C-210	001	---	1,535	921	461	Point
C-211	002	---	1,535	921	461	Point
C-212	003	---	1,535	921	461	Point
C-213	004	---	1,130	814	452	Point
D-3101	005	---	---	963	---	Point
D-3111	006	---	---	963	---	Point
F-4101	007	---	904	---	1,805	Point
CB	008	---	---	738	---	Point
FUG-2	011	---	---	401	---	Fugitive
TK-1	012	---	---	1,767	---	Point
TL	013	---	---	243	---	Point
SR	014	---	---	190	---	Point

Note: Monthly limits are based on a 31-day month.

The owner or operator shall calculate monthly emissions based on the calendar month.

Facility-wide emissions of each individual hazardous air pollutant shall not exceed 1,359 pounds per month.

Facility-wide emissions of total hazardous air pollutants shall not exceed 3,398 pounds per month.

The facility-wide emissions limitation for hazardous air pollutants shall apply to all permitted emission units at this facility.

Annual Limits:

Facility Equipment ID	AIRS Point	Tons per Year				Emission Type
		PM2.5	NO_x	VOC	CO	
C-210	001	---	9.1	5.5	2.8	Point
C-211	002	---	9.1	5.5	2.8	Point
C-212	003	---	9.1	5.5	2.8	Point
C-213	004	---	6.7	4.8	2.7	Point
D-3101	005	---	---	5.7	---	Point
D-3111	006	---	---	5.7	---	Point
F-4101	007	---	5.4	---	10.7	Point
CB	008	---	---	4.4	---	Point
FUG-2	011	---	---	2.4	---	Fugitive
TK-1	012	---	---	10.4	---	Point
TL	013	---	---	1.5	---	Point
SR	014	---	---	1.2	---	Point

Note: See "Notes to Permit Holder" for information on emission factors and methods used to calculate limits.

Facility-wide emissions of each individual hazardous air pollutant shall not exceed 8.0 tons per year.

Facility-wide emissions of total hazardous air pollutants shall not exceed 20.0 tons per year.

The facility-wide emissions limitation for hazardous air pollutants shall apply to all permitted emission units at this facility.

During the first twelve (12) months of operation, compliance with both the monthly and annual emission limitations is required. After the first twelve (12) months of operation, compliance with only the annual limitation is required.

Compliance with the annual limits, for criteria and hazardous air pollutants, shall be determined on a rolling twelve (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permit holder shall calculate actual emissions each month and keep a compliance record on site or at a local field office with site responsibility for Division review.

9. **Points 005 & 006:** Compliance with the emission limits in this permit shall be demonstrated by running the GRI GlyCalc model version 4.0 or higher on a monthly basis using the most recent extended wet gas analysis and recorded operational values, including: gas throughput, lean glycol recirculation rate, condenser temperature, flash tank temperature and pressure, wet gas inlet temperature, and wet gas inlet pressure. Recorded operational values, except for gas throughput, shall be averaged on a monthly basis for input into the model and be provided to the Division upon request.

10. The owner or operator shall operate and maintain the emission points in the table below with the emissions control equipment as listed in order to reduce emissions to less than or equal to the limits established in this permit. The owner or operator shall operate this dehydration unit so as to prevent any emissions directly to the atmosphere. (Regulation Number 3, Part B, Section III.E.)

Facility Equipment ID	AIRS Point	Control Device	Pollutants Controlled
C-210	001	Non-selective catalytic reduction (NSCR) system and air-fuel ratio control	VOC, CO, Formaldehyde
C-211	002	Non-selective catalytic reduction (NSCR) system and air-fuel ratio control	VOC, CO, Formaldehyde
C-212	003	Non-selective catalytic reduction (NSCR) system and air-fuel ratio control	VOC, CO, Formaldehyde
C-213	004	Non-selective catalytic reduction (NSCR) system and air-fuel ratio control	VOC, CO, Formaldehyde
D-3101	005	Still Vent: Enclosed Flare	VOC and HAP
		Flash Tank: Enclosed Flare	VOC and HAP
D-3111	006	Still Vent: Enclosed Flare	VOC and HAP
		Flash Tank: Enclosed Flare	VOC and HAP

PROCESS LIMITATIONS AND RECORDS

11. This source shall be limited to the following maximum processing rates as listed below. Monthly records of the actual processing rates shall be maintained by the owner or operator and made available to the Division for inspection upon request. (Regulation Number 3, Part B, II.A.4.)

Process Limits

Facility Equipment ID	AIRS Point	Process Parameter	Annual Limit	Monthly Limit (31 days)
C-210	001	Consumption of natural gas as a fuel	109.1 MMscf/yr	9.3 MMscf/month
C-211	002	Consumption of natural gas as a fuel	109.1 MMscf/yr	9.3 MMscf/month
C-212	003	Consumption of natural gas as a fuel	109.1 MMscf/yr	9.3 MMscf/month
C-213	004	Consumption of natural gas as a fuel	88.4 MMscf/yr	7.5 MMscf/month
D-3101	005	Natural Gas Throughput	7,300 MMscf/yr	620 MMscf/month
D-3111	006	Natural Gas Throughput	7,300 MMscf/yr	620 MMscf/month
F-4101	007	Natural Gas Throughput	51.6 MMscf/yr	4.4 MMscf/month
CB	008	Blowdown Events	0.41 MMscf/yr	---
TK-1	012	Condensate Throughput	18,250,000 bbl/yr	1,550,000 bbl/month
TL	013	External Floating Roof Landing Events	2 events/yr	1 event/month
SR	014	Pigging Events	120 events/yr	11 events/month

Points 001 - 004: Fuel consumption shall be measured by one of the following methods: individual engine fuel meter or facility-wide fuel meter attributed to fuel consumption rating and hours of operation.

Points 005 & 006: The owner or operator shall monitor monthly process rates based on the calendar month. The volume of gas processed shall be measured by gas meter or by assuming the maximum design rate of the dehydrator unit of 20 MMscf/d.

During the first twelve (12) months of operation, compliance with both the monthly and annual throughput limitations is required. After the first twelve (12) months of operation, compliance with only the annual limitation is required.

Compliance with the annual throughput limits shall be determined on a rolling twelve (12) month total. By the end of each month a new twelve-month total is calculated based on the previous twelve months' data. The permit holder shall calculate throughput each month and keep a compliance record on site or at a local field office with site responsibility, for Division review.

12. **Points 005 & 006:** This unit shall be limited to the maximum lean glycol circulation rate of 4.2 gallons per minute. The lean glycol recirculation rate shall be recorded **weekly** in a log maintained on site and made available to the Division for inspection upon request. Glycol recirculation rate shall be monitored by one of the following methods: assuming maximum design pump rate, using glycol flow meter(s), or recording strokes per minute and converting to circulation rate. This maximum glycol circulation rate does not preclude compliance with the optimal glycol circulation rate (L_{opt}) provisions under MACT HH. (Reference: Regulation Number 3, Part B, II.A.4)

13. **Points 005 & 006:** On a monthly basis, the owner or operator shall monitor and record operational values including: flash tank temperature and pressure, wet gas inlet temperature and pressure. These records shall be maintained for a period of five years.

14. **Point 008:** Upon commencement of operation, the owner or operator shall continuously monitor and record the volumetric flow rate of natural gas vented from the compressor blowdowns using the flow meter. The owner or operator shall use monthly throughput records to demonstrate compliance with the process limits contained in this permit and to calculate emissions as described in this permit.

STATE AND FEDERAL REGULATORY REQUIREMENTS

15. The permit number and ten digit AIRS ID number assigned by the Division (e.g. 123/4567/001) shall be marked on the subject equipment for ease of identification. (Regulation Number 3, Part B, Section III.E.) (State only enforceable)

16. **Points 001 - 004:** Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes. Emission control devices subject to Regulation 7, Sections XII.C.1.d or XVII.B.2.b shall have no visible emissions. (Reference: Regulation No. 1, Section II.A.1. & 4.)

17. This source is subject to the odor requirements of Regulation Number 2. (State only enforceable)

18. Minor sources in designated nonattainment or attainment/maintenance areas that are otherwise not exempt pursuant to Regulation No. 3, Part B, Section II.D shall apply Reasonably Available Control Technology (RACT) for the pollutants for which the area is nonattainment or attainment/maintenance (Reference: Regulation No. 3, Part B, III.D.2.a). This requirement to apply RACT shall be satisfied by installing/implementing the following emission controls:

    a. Directed Inspection & Maintenance as described below shall satisfy the requirement to apply RACT.

        i. Auditory/visual/olfactory inspection (AVO) will be performed on a quarterly basis.

        ii. For each leak found in the AVO inspection, a gas detector may be used to determine the size of the leak. The gas detector shall be regularly calibrated. Component leaks greater than 10,000 ppm shall be managed in accordance with Item (vi) below, unless it is unfeasible to make the repair without shutting down the affected operation of the facility. Component leaks less than 10,000 ppm shall not require repair. For such component leaks that require a shutdown to be repaired, repair shall occur during the first shutdown of the affected operation after the leak is discovered.

        iii. For repair, valves adjacent to the equipment to be repaired will be closed if practicable, minimizing the volume released.

        iv. Repaired components shall be re-screened using AVO to determine if the leak is repaired.

        v. The following records shall be maintained for a period of two years:

            - The name of the site screened via AVO inspection and the name of the inspector.
            - Components evaluated with the gas detector.
            - Repair methods applied.

- Dates of the AVO inspections, gas detector calibrations, attempted repairs, successful repairs, repair delays, and post-repair screenings.

vi. Leaks shall be repaired as soon as practicable, but no later than 15 calendar days after detection, unless it is technically or operationally infeasible to make the repair within 15 calendar days. Records documenting the rationale shall be maintained if it is technically or operationally infeasible to make the repair within 15 calendar days.

19. **Points 005 & 006:** This source is subject to Regulation No. 7, Section XII.C General Provisions (State only enforceable). All condensate collection, storage, processing and handling operations, regardless of size, shall be designed, operated and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable. The operator shall comply with all applicable requirements of Section XII.

20. **Points 012 & 013:** This source is subject to Regulation Number 7, Section XII. The operator shall comply with all applicable requirements of Section XII and, specifically, shall:

    - Comply with the recordkeeping, monitoring, reporting and emission control requirements for condensate storage tanks

21. **Points 005 & 006:** This source is subject to Regulation Number 7, Section XII.H. The operator shall comply with all applicable requirements of Section XII and, specifically, shall:

    - Comply with the recordkeeping, monitoring, reporting and emission control requirements for glycol natural gas dehydrators; and
    - Ensure uncontrolled actual emissions of volatile organic compounds from the still vent and vent from any gas-condensate-glycol (GCG) separator (flash separator or flash tank), if present, shall be reduced by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. (Regulation Number 7, Section XII.H.1.)

22. **Points 001 - 004:** This equipment is subject to the control requirements for stationary and portable engines in the 8-hour ozone control area under Regulation No. 7, Section XVI.B.2. For lean burn reciprocating internal combustion engines, an oxidation catalyst shall be required.

23. **Points 005 & 006:** The combustion device covered by this permit is subject to Regulation Number 7, Section XVII.B.2 General Provisions (State only enforceable). If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Section XVII, it shall be enclosed; have no visible emissions during normal operations, as defined under Regulation Number 7, XVII.A.16; and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means approved by the Division, determine whether it is operating properly. This flare must be equipped with an operational auto-igniter according to the following schedule:

    - All combustion devices installed on or after May 1, 2014, must be equipped with an operational auto-igniter upon installation of the combustion device;
    - All combustion devices installed before May 1, 2014, must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

24. **Points 005 & 006:** The glycol dehydration unit covered by this permit is subject to the emission control requirements in Regulation Number 7, Section XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95% on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.

25. **Points 012 & 013:** This source is subject to the New Source Performance Standards, Standards of Performance for Volatile Organic Liquid Storage Vessels for which construction, reconstruction or modification commenced after July 23, 1984, Subpart Kb. This facility shall be subject to all provisions of this regulation, as stated in 40 C.F.R Part 60, Subparts A and Kb. (Regulation Number 6, Part A, Subparts A and Kb)

26. **Points 005 & 006:** The glycol dehydration unit at this facility is subject to National Emissions Standards for Hazardous Air Pollutants for Source Categories from Oil and Natural Gas Production Facilities, Subpart HH. This facility shall be subject to applicable area source provisions of this regulation, as stated in 40 C.F.R Part 63, Subpart A and HH. (Regulation Number 8, Part E, Subpart A and HH)

MACT HH Applicable Requirements	Area Source Benzene emissions exemption
§63.764 - General Standards	**§63.764 (e)(1)** - The owner or operator is exempt from the requirements of paragraph (d) of this section if the criteria listed in paragraph (e)(1)(i) or (ii) of this section are met, except that the records of the determination of these criteria must be maintained as required in §63.774(d)(1). **§63.764 (e)(1)(ii)** - The actual average emissions of benzene from the glycol dehydration unit process vent to the atmosphere are less than 0.90 megagram per year, as determined by the procedures specified in §63.772(b)(2) of this subpart.
§63.772 - Test Methods, Compliance Procedures and Compliance Demonstration	**§63.772(b)** - Determination of glycol dehydration unit flowrate or benzene emissions. The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate or benzene emissions to meet the criteria for an exemption from control requirements under §63.764(e)(1). **§63.772(b)(2)** - The determination of actual average benzene emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (b)(2)(i) or (b)(2)(ii) of this section. Emissions shall be determined either uncontrolled, or with federally enforceable controls in place. **§63.772(b)(2)(i)** - The owner or operator shall determine actual average benzene emissions using the model GRI-GLYCalc ™, Version 3.0 or higher, and the procedures presented in the associated GRI-GLYCalc ™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1); or **§63.772(b)(2)(ii)** - The owner or operator shall determine an average mass rate of benzene emissions in kilograms per hour through direct measurement using the methods in §63.772(a)(1)(i) or (ii), or an alternative method according to §63.7(f). Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.
§63.774 - Recordkeeping Requirements	**§63.774 (d)(1)** - An owner or operator of a glycol dehydration unit that meets the exemption criteria in §63.764(e)(1)(i) or §63.764(e)(1)(ii) shall maintain the records specified in paragraph (d)(1)(i) or paragraph (d)(1)(ii) of this section, as appropriate, for that glycol dehydration unit. **§63.774 (d)(1)(ii)** - The actual average benzene emissions (in terms of benzene emissions per year) as determined in accordance with §63.772(b)(2).

OPERATING & MAINTENANCE REQUIREMENTS

27. **Points 001 - 006:** Upon startup of these points, the owner or operator shall follow the most recent operating and maintenance (O&M) plan and record keeping format approved by the Division, in order to demonstrate compliance on an ongoing basis with the requirements of this

permit. Revisions to the O&M plan are subject to Division approval prior to implementation. (Regulation Number 3, Part B, Section III.G.7.)

COMPLIANCE TESTING AND SAMPLING

Initial Testing Requirements

28. **Points 005 & 006:** The owner or operator shall complete the initial extended wet gas analysis within one hundred and eighty days (180) of the latter of commencement of operation or issuance of this permit. The owner or operator shall use this analysis to calculate actual emissions, as prescribed in the Emission Limitation and Records section of this permit, to verify initial compliance with the emission limits. The owner or operator shall submit the analysis and the emission calculation results to the Division as part of the self-certification process. (Reference: Regulation Number 3, Part B, Section III.E.)

29. **Point 007:** The owner or operator shall demonstrate compliance with opacity standards, using EPA Reference Method 22, 40 C.F.R. Part 60, Appendix A, to determine the presence or absence of visible emissions. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one minute in any fifteen minute period during normal operation. (Regulation Number 7, Sections XVII.B.2. and XVII.A.16)

30. **Point 011:** Within one hundred and eighty days (180) of the latter of commencement of operation or issuance of this permit, the owner or operator shall complete the initial extended natural gas liquids analysis of liquids that are representative of volatile organic compound (VOC) and hazardous air pollutants (HAP) that may be released as fugitive emissions. This extended liquids analyses shall be used in the compliance demonstration as required in the Emission Limits and Records section of this permit. The operator shall submit the results of the liquids analyses and emission calculations to the Division as part of the self-certification process to ensure compliance with emissions limits.

31. **Points 012 & 013:** The owner or operator shall complete site specific sampling including a compositional analysis of the condensate routed to these storage tanks and an analysis to determine RVP and API gravity. Testing shall be in accordance with the guidance contained in PS Memo 05-01. Results of testing shall be used to determine site-specific emissions factors for VOC and Hazardous Air Pollutants using Division approved methods. Results of site-specific sampling and analysis shall be submitted to the Division as part of the self-certification and used to demonstrate compliance with the emissions factors chosen for this emissions point.

Periodic Testing Requirements

32. **Points 005 & 006:** The owner or operator shall complete an extended wet gas analysis prior to the inlet of the dehydration unit on an annual basis. Results of the wet gas analysis shall be used to calculate emissions of criteria pollutants and hazardous air pollutants per this permit and be provided to the Division upon request.

ADDITIONAL REQUIREMENTS

33. A revised Air Pollutant Emission Notice (APEN) shall be filed: (Regulation Number 3, Part A, II.C.)

- Annually by April 30th whenever a significant increase in emissions occurs as follows:

  For any criteria pollutant:

  For sources emitting **less than 100 tons per year**, a change in actual emissions of five (5) tons per year or more, above the level reported on the last APEN; or

  For volatile organic compounds (VOC) and nitrogen oxides sources (NO_x) in ozone nonattainment areas emitting **less than 100 tons of VOC or NO_x per year**, a change in annual actual emissions of one (1) ton per year or more or five percent, whichever is greater, above the level reported on the last APEN; or

For sources emitting **100 tons per year or more**, a change in actual emissions of five percent or 50 tons per year or more, whichever is less, above the level reported on the last APEN submitted; or

For any non-criteria reportable pollutant:

If the emissions increase by 50% or five (5) tons per year, whichever is less, above the level reported on the last APEN submitted to the Division.

- Whenever there is a change in the owner or operator of any facility, process, or activity; or
- Whenever new control equipment is installed, or whenever a different type of control equipment replaces an existing type of control equipment; or
- Whenever a permit limitation must be modified; or
- No later than 30 days before the existing APEN expires.

GENERAL TERMS AND CONDITIONS

34. This permit and any attachments must be retained and made available for inspection upon request. The permit may be reissued to a new owner by the APCD as provided in AQCC Regulation Number 3, Part B, Section II.B. upon a request for transfer of ownership and the submittal of a revised APEN and the required fee.

35. If this permit specifically states that final authorization has been granted, then the remainder of this condition is not applicable. Otherwise, the issuance of this construction permit does not provide "final" authority for this activity or operation of this source. Final authorization of the permit must be secured from the APCD in writing in accordance with the provisions of 25-7-114.5(12)(a) C.R.S. and AQCC Regulation Number 3, Part B, Section III.G. Final authorization cannot be granted until the operation or activity commences and has been verified by the APCD as conforming in all respects with the conditions of the permit. Once self-certification of all points has been reviewed and approved by the Division, it will provide written documentation of such final authorization. **Details for obtaining final authorization to operate are located in the Requirements to Self-Certify for Final Authorization section of this permit.**

36. This permit is issued in reliance upon the accuracy and completeness of information supplied by the owner or operator and is conditioned upon conduct of the activity, or construction, installation and operation of the source, in accordance with this information and with representations made by the owner or operator or owner or operator's agents. It is valid only for the equipment and operations or activity specifically identified on the permit.

37. Unless specifically stated otherwise, the general and specific conditions contained in this permit have been determined by the APCD to be necessary to assure compliance with the provisions of Section 25-7-114.5(7)(a), C.R.S.

38. Each and every condition of this permit is a material part hereof and is not severable. Any challenge to or appeal of a condition hereof shall constitute a rejection of the entire permit and upon such occurrence, this permit shall be deemed denied *ab initio*. This permit may be revoked at any time prior to self-certification and final authorization by the Air Pollution Control Division (APCD) on grounds set forth in the Colorado Air Quality Control Act and regulations of the Air Quality Control Commission (AQCC), including failure to meet any express term or condition of the permit. If the Division denies a permit, conditions imposed upon a permit are contested by the owner or operator, or the Division revokes a permit, the owner or operator of a source may request a hearing before the AQCC for review of the Division's action.

39. Section 25-7-114.7(2)(a), C.R.S. requires that all sources required to file an Air Pollution Emission Notice (APEN) must **pay an annual fee** to cover the costs of inspections and administration. If a source or activity is to be discontinued, the owner must notify the Division in writing requesting a cancellation of the permit. Upon notification, annual fee billing will terminate.

40. Violation of the terms of a permit or of the provisions of the Colorado Air Pollution Prevention and Control Act or the regulations of the AQCC may result in administrative, civil or criminal enforcement actions under Sections 25-7-115 (enforcement), -121 (injunctions), -122 (civil penalties), -122.1 (criminal penalties), C.R.S.

By:

Christopher Kester
Permit Engineer

Permit History

Issuance	Date	Description
Issuance 1	This Issuance	Issued to Discovery DJ Services LLC

Notes to Permit Holder at the time of this permit issuance:

1) The permit holder is required to pay fees for the processing time for this permit. An invoice for these fees will be issued after the permit is issued. The permit holder shall pay the invoice within 30 days of receipt of the invoice. Failure to pay the invoice will result in revocation of this permit. (Regulation Number 3, Part A, Section VI.B.)

2) The production or raw material processing limits and emission limits contained in this permit are based on the consumption rates requested in the permit application. These limits may be revised upon request of the owner or operator providing there is no exceedance of any specific emission control regulation or any ambient air quality standard. A revised air pollution emission notice (APEN) and complete application form must be submitted with a request for a permit revision.

3) This source is subject to the Common Provisions Regulation Part II, Subpart E, Affirmative Defense Provision for Excess Emissions During Malfunctions. The owner or operator shall notify the Division of any malfunction condition which causes a violation of any emission limit or limits stated in this permit as soon as possible, but no later than noon of the next working day, followed by written notice to the Division addressing all of the criteria set forth in Part II.E.1 of the Common Provisions Regulation. See: https://www.colorado.gov/pacific/cdphe/aqcc-regs

4) The following emissions of non-criteria reportable air pollutants are estimated based upon the process limits as indicated in this permit. This information is listed to inform the operator of the Division's analysis of the specific compounds emitted if the source(s) operate at the permitted limitations.

Facility Equipment ID	AIRS Point	Pollutant	CAS #	Uncontrolled Emissions (lb/yr)	Controlled Emissions (lb/yr)
C-210	001	Formaldehyde	50000	7,242	724
		Acetaldehyde	75070	1,030	1,030
		Acrolein	107028	633	633
		Methanol	67561	308	308
C-211	002	Formaldehyde	50000	7,242	724
		Acetaldehyde	75070	1,030	1,030
		Acrolein	107028	633	633
		Methanol	67561	308	308
C-212	003	Formaldehyde	50000	7,242	724
		Acetaldehyde	75070	1,030	1,030
		Acrolein	107028	633	633
		Methanol	67561	308	308
C-213	004	Formaldehyde	50000	11,460	933
		Acetaldehyde	75070	834	834
		Acrolein	107028	513	513
		Methanol	67561	250	250
D-3101	005	Benzene	71432	21,810	1,091
		Toluene	108883	24,428	1,221

		Ethylbenzene	100414	6,023	301
		Xylenes	1330207	11,654	583
		n-Hexane	110543	4,096	205
D-3111	006	Benzene	71432	21,810	1,091
		Toluene	108883	24,428	1,221
		Ethylbenzene	100414	6,023	301
		Xylenes	1330207	11,654	583
		n-Hexane	110543	4,096	205
CB	008	n-Hexane	110543	336	336
TK-1	012	n-Hexane	110543	298	298

Note: All non-criteria reportable pollutants in the table above with uncontrolled emission rates above 250 pounds per year (lb/yr) are reportable and may result in annual emission fees based on the most recent Air Pollution Emission Notice.

5) The emission levels contained in this permit are based on the following emission factors:

Points 001 - 003:

CAS	Pollutant	Emission Factors - Uncontrolled		Emission Factors - Controlled	
		lb/MMBtu	g/bhp-hr	lb/MMBtu	g/bhp-hr
	NOx	---	0.500	---	0.500
	CO	---	2.720	---	0.150
	VOC	---	1.500	---	0.300
50000	**Formaldehyde**	---	0.200	---	0.020
75070	**Acetaldehyde**	0.008	---	0.008	---
107028	**Acrolein**	0.005	---	0.005	---
67561	**Methanol**	0.0025	---	0.0025	---

Emission factors are based on a Brake-Specific Fuel Consumption Factor of 7500 Btu/hp-hr, a site-rated horsepower value of 1875, and a fuel heat value of 1130 Btu/scf.

Point 004:

CAS	Pollutant	Emission Factors - Uncontrolled		Emission Factors - Controlled	
		lb/MMBtu	g/bhp-hr	lb/MMBtu	g/bhp-hr
	NOx	---	0.500	---	0.500
	CO	---	2.430	---	0.200
	VOC	---	0.910	---	0.360
50000	**Formaldehyde**	---	0.430	---	0.035
75070	**Acetaldehyde**	0.008	---	0.008	---
107028	**Acrolein**	0.005	---	0.005	---
67561	**Methanol**	0.0025	---	0.0025	---

Emission factors are based on a Brake-Specific Fuel Consumption Factor of 7500 Btu/hp-hr, a site-rated horsepower value of 1380, and a fuel heat value of 1130 Btu/scf.

Points 005 & 006:

The emission levels contained in this permit are based on information provided in the application and the GRI GlyCalc 4.0 model. Controlled emissions are based on a flare control efficiency of 95%.

Combustion emissions from these points are accounted for in Point 007, the process flare controlling these points.

Point 007:

CAS #	Pollutant	Uncontrolled Emission Factors lb/MMBtu	Source
	NOx	0.138	TCEQ Flare Emission Factors
	CO	0.276	

Point 008:

CAS #	Pollutant	Uncontrolled Emission Factors lb/MMscf	Source
	VOC	21,527	Engineering Calculation
110543	n-Hexane	834.1	

Point 011:

The emission levels contained in this permit are based on the following emission factors:

Component	Gas Service	Heavy Oil	Light Oil	Water/Oil Service
Connectors	---	---	10	---
Flanges	---	---	100	---
Open-ended Lines	---	---	0	---
Pump Seals	---	---	3	---
Valves	---	---	50	---
Other*	---	---	9	---
VOC Content (wt. fraction)	---	---	100	---
Benzene Content (wt. fraction)	---	---	0.0038	---
Toluene Content (wt. fraction)	---	---	0.0096	---
Ethylbenzene (wt. fraction)	---	---	0.0043	---
Xylenes Content (wt. fraction)	---	---	0.0043	---
n-hexane Content (wt. fraction)	---	---	0.0260	---

*Other equipment type includes compressors, pressure relief valves, relief valves, diaphragms, drains, dump arms, hatches, instrument meters, polish rods and vents

TOC Emission Factors (kg/hr-component):

Component	Gas Service	Heavy Oil	Light Oil	Water/Oil Service
Connectors	2.0E-04	7.5E-06	2.1E-04	1.1E-04
Flanges	3.9E-04	3.9E-07	1.1E-04	2.9E-06

Open-ended Lines	2.0E-03	1.4E-04	1.4E-03	2.5E-04
Pump Seals	2.4E-03	NA	1.3E-02	2.4E-05
Valves	4.5E-03	8.4E-06	2.5E-03	9.8E-05
Other	8.8E-03	3.2E-05	7.5E-03	1.4E-02

Source: EPA-453/R95-017

Compliance with emissions limits in this permit will be demonstrated by using the TOC emission factors listed in the table above with representative component counts, multiplied by the VOC content from the most recent **liquids analyses.**

Point 012:

CAS #	Pollutant	Uncontrolled Emission Factors lb/bbl	Source
	VOC	0.00114	EPA TANKS 4.0.9d
110543	n-Hexane	0.0000163	

Point 013:

CAS #	Pollutant	Uncontrolled Emission Factors lb/event	Source
	VOC	1,425.1	AP-42

Point 014:

CAS #	Pollutant	Uncontrolled Emission Factors lb/event	Source
	VOC	18.55	AP-42

6) In accordance with C.R.S. 25-7-114.1, each Air Pollutant Emission Notice (APEN) associated with this permit is valid for a term of five years from the date it was received by the Division. A revised APEN shall be submitted no later than 30 days before the five-year term expires. Please refer to the most recent annual fee invoice to determine the APEN expiration date for each emissions point associated with this permit. For any questions regarding a specific expiration date call the Division at (303)-692-3150.

7) This permit fulfills the requirement to hold a valid permit reflecting the glycol dehydration unit and associated control device per the Colorado Oil and Gas Conservation Commission rule 805b(2)(B) when applicable.

8) This source is subject to 40 CFR, Part 60, Subpart OOOOa - Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015 (See June 3, 2016 Federal Register posting - effective August 2, 2016.) This rule has not yet been incorporated into Colorado Air Quality Control Commission's Regulation No. 6. A copy of the complete subpart is available at the Office of the Federal Register website at: https://www.federalregister.gov/documents/2016/06/03/2016-11971/oil-and-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources

9) This facility is classified as follows:

Applicable Requirement	Status
Operating Permit	Synthetic Minor/Major Source of: CO, VOC, & HAP
NANSR	Synthetic Minor/Major Source of: VOC
MACT HH	Major Source Requirements: Not Applicable Area Source Requirements: Applicable
MACT ZZZZ	Major Source Requirements: Not Applicable Area Source Requirements: Applicable

10) Full text of the Title 40, Protection of Environment Electronic Code of Federal Regulations can be found at the website listed below:

http://ecfr.gpoaccess.gov/

Part 60: Standards of Performance for New Stationary Sources		
NSPS	60.1-End	Subpart A - Subpart KKKK
NSPS	Part 60, Appendixes	Appendix A - Appendix I
Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories		
MACT	63.1-63.599	Subpart A - Subpart Z
MACT	63.600-63.1199	Subpart AA - Subpart DDD
MACT	63.1200-63.1439	Subpart EEE - Subpart PPP
MACT	63.1440-63.6175	Subpart QQQ - Subpart YYYY
MACT	63.6580-63.8830	Subpart ZZZZ - Subpart MMMMM
MACT	63.8980-End	Subpart NNNNN - Subpart XXXXXX

ATTACHMENT A
ALTERNATIVE OPERATING SCENARIOS
RECIPROCATING INTERNAL COMBUSTION ENGINES

1. Alternative Operating Scenarios

The following Alternative Operating Scenario (AOS) for the temporary and permanent replacement of natural gas fired reciprocating internal combustion engines has been reviewed in accordance with the requirements of Regulation No. 3., Part A, Section IV.A, Operational Flexibility-Alternative Operating Scenarios, Regulation No. 3, Part B, Construction Permits, and Regulation No. 3, Part D, Major Stationary Source New Source Review and Prevention of Significant Deterioration, and it has been found to meet all applicable substantive and procedural requirements. This permit incorporates and shall be considered a Construction Permit for any engine replacement performed in accordance with this AOS, and the owner or operator shall be allowed to perform such engine replacement without applying for a revision to this permit or obtaining a new Construction Permit.

1.1 Engine Replacement

The following AOS is incorporated into this permit in order to deal with an engine breakdown or periodic routine maintenance and repair of an existing onsite engine that requires the use of either a temporary or permanent replacement engine. "Temporary" is defined as in the same service for 90 operating days or less in any 12 month period. "Permanent" is defined as in the same service for more than 90 operating days in any 12 month period. The 90 days is the total number of days that the engine is in operation. If the engine operates only part of a day, that day shall count as a single day towards the 90 day total. The compliance demonstrations and any periodic monitoring required by this AOS are in addition to any compliance demonstrations or periodic monitoring required by this permit.

All replacement engines are subject to all federally applicable and state-only requirements set forth in this permit (including monitoring and record keeping).

The results of all tests and the associated calculations required by this AOS shall be submitted to the Division within 30 calendar days of the test or within 60 days of the test if such testing is required to demonstrate compliance with NSPS or MACT requirements.
Results of all tests shall be kept on site for five (5) years and made available to the Division upon request.

The owner or operator shall maintain a log on-site and contemporaneously record the start and stop date of any engine replacement, the manufacturer, date of manufacture, model number, horsepower, and serial number of the engine(s) that are replaced during the term of this permit, and the manufacturer, model number, horsepower, and serial number of the replacement engine. In addition to the log, the owner or operator shall maintain a copy of all Applicability Reports required under section 1.1.2 and make them available to the Division upon request.

1.1.1 The owner or operator may **temporarily** replace an existing engine that is subject to the emission limits set forth in this permit with an engine that is of the same manufacturer, model, and horsepower or a different manufacturer, model, or horsepower as the existing engine without modifying this permit, so long as the temporary replacement engine complies with all permit limitations and other requirements applicable to the existing engine. Measurement of emissions from the temporary replacement engine shall be made as set forth in section 1.2.

1.1.2 The owner or operator may **permanently** replace the existing engine with another engine with the same manufacturer, model, and horsepower engines without modifying this permit so long as the permanent replacement engine complies with all permit limitations and other requirements applicable to the existing engine as well as any new applicable requirements for the replacement engine. Measurement of emissions from the permanent replacement engine and compliance with the applicable emission limitations shall be made as set forth in section 1.2.

An Air Pollutant Emissions Notice (APEN) that includes the specific manufacturer, model and serial number and horsepower of the permanent replacement engine shall be filed with the Division for the permanent replacement

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engine within 14 calendar days of commencing operation of the replacement engine. The APEN shall be accompanied by the appropriate APEN filing fee, a cover letter explaining that the owner or operator is exercising an alternative operating scenario and is installing a permanent replacement engine, and a copy of the relevant Applicability Reports for the replacement engine. Example Applicability
Reports can be found at https://www.colorado.gov/pacific/cdphe/alternate-operating-scenario-aos-reporting-forms. This submittal shall be accompanied by a certification from the Responsible Official indicating that "based on the information and belief formed after reasonable inquiry, the statements and information included in the submittal are true, accurate and complete".

This AOS cannot be used for permanent engine replacement of a grandfathered or permit exempt engine or an engine that is not subject to emission limits.

The owner or operator shall agree to pay fees based on the normal permit processing rate for review of information submitted to the Division in regard to any permanent engine replacement.

1.2 Portable Analyzer Testing

Note: In some cases there may be conflicting and/or duplicative testing requirements due to overlapping Applicable Requirements. In those instances, please contact the Division Field Services Unit to discuss streamlining the testing requirements.

Note that the testing required by this Condition may be used to satisfy the periodic testing requirements specified by the permit for the relevant time period (i.e. if the permit requires quarterly portable analyzer testing, this test conducted under the AOS will serve as the quarterly test and an additional portable analyzer test is not required for another three months).

The owner or operator may conduct a reference method test, in lieu of the portable analyzer test required by this Condition, if approved in advance by the Division.

The owner or operator shall measure nitrogen oxide (NOX) and carbon monoxide (CO) emissions in the exhaust from the replacement engine using a portable flue gas analyzer *within seven (7) calendar days of commencing operation of the replacement engine.*

All portable analyzer testing required by this permit shall be conducted using the Division's Portable Analyzer Monitoring Protocol (ver March 2006 or newer) as found on the Division's web site at:
https://www.colorado.gov/pacific/sites/default/files/AP_Portable-Analyzer-Monitoring-Protocol.pdf

Results of the portable analyzer tests shall be used to monitor the compliance status of this unit.

For comparison with an annual (tons/year) or short term (lbs/unit of time) emission limit, the results of the tests shall be converted to a lb/hr basis and multiplied by the allowable operating hours in the month or year (whichever applies) in order to monitor compliance. If a source is not limited in its hours of operation the test results will be multiplied by the maximum number of hours in the month or year (8760), whichever applies.

For comparison with a short-term limit that is either input based (lb/mmBtu), output based (g/hp-hr) or concentration based (ppmvd @ 15% O2) that the existing unit is currently subject to or the replacement engine will be subject to, the results of the test shall be converted to the appropriate units as described in the above-mentioned Portable Analyzer Monitoring Protocol document.

If the portable analyzer results indicate compliance with both the NOX and CO emission limitations, in the absence of credible evidence to the contrary, the source may certify that the engine is in compliance with both the NOX and CO emission limitations for the relevant time period.

Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, if the portable analyzer results fail to demonstrate compliance with either the NOX or CO emission limitations, the engine will be considered to be out of compliance from the date of the portable analyzer test until a portable analyzer test indicates compliance with both the NOX and CO emission limitations or until the engine is taken offline.

1.3 Applicable Regulations for Permanent Engine Replacements

1.3.1 Reasonably Available Control Technology (RACT): Reg 3, Part B § II.D.2

All permanent replacement engines that are located in an area that is classified as attainment/maintenance or nonattainment must apply Reasonably Available Control Technology (RACT) for the pollutants for which the area is attainment/maintenance or nonattainment. Note that both VOC and NOX are precursors for ozone. RACT shall be applied for any level of emissions of the pollutant for which the area is in attainment/maintenance or nonattainment, except as follows:

In the Denver Metropolitan PM10 attainment/maintenance area, RACT applies to PM10 at any level of emissions and to NOX and SO2, as precursors to PM10, if the potential to emit of NOX or SO2 exceeds 40 tons/yr.

For purposes of this AOS, the following shall be considered RACT for natural gas fired reciprocating internal combustion engines:

VOC: The emission limitations in NSPS JJJJ
CO: The emission limitations in NSPS JJJJ
NOX: The emission limitations in NSPS JJJJ
SO2: Use of natural gas as fuel
PM10: Use of natural gas as fuel

As defined in 40 CFR Part 60 Subparts GG (§ 60.331) and 40 CFR Part 72 (§ 72.2), natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet.

1.3.2 Control Requirements and Emission Standards: Regulation No. 7, Sections XVI. and XVII.E (State-Only conditions).

Control Requirements: Section XVI

Any permanent replacement engine located within the boundaries of an ozone nonattainment area is subject to the applicable control requirements specified in Regulation No. 7, section XVI, as specified below:

Rich burn engines with a manufacturer's design rate greater than 500 hp shall use a non-selective catalyst and air fuel controller to reduce emission.

Lean burn engines with a manufacturer's design rate greater than 500 hp shall use an oxidation catalyst to reduce emissions.

The above emission control equipment shall be appropriately sized for the engine and shall be operated and maintained according to manufacturer specifications.

The source shall submit copies of the relevant Applicability Reports required under Condition 1.1.2.

Emission Standards: Section XVII.E - State-only requirements

Any permanent engine that is either constructed or relocated to the state of Colorado from another state, after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in the table below:

Max Engine HP	Construction or Relocation Date	Emission Standards in G/hp-hr		
		NO_X	CO	VOC
100<Hp<500	January 1, 2008	2.0	4.0	1.0
	January 1, 2011	1.0	2.0	0.7
500≤Hp	July 1, 2007	2.0	4.0	1.0
	July 1, 2010	1.0	2.0	0.7

The source shall submit copies of the relevant Applicability Reports required under Condition 1.1.2.

1.3.3 NSPS for stationary spark ignition internal combustion engines: 40 CFR Part 60, Subpart JJJJ

A permanent replacement engine that is manufactured on or after 7/1/09 for emergency engines greater than 25 hp, 7/1/2008 for engines less than 500 hp, 7/1/2007 for engines greater than or equal to 500 hp except for lean burn engines greater than or equal to 500 hp and less than 1,350 hp, and 1/1/2008 for lean burn engines greater than or equal to 500 hp and less than 1,350 hp are subject to the requirements of 40 CFR Part 60, Subpart JJJJ. An analysis of applicable monitoring, recordkeeping, and reporting requirements for the permanent engine replacement shall be included in the Applicability Reports required under Condition 1.1.2. Any testing required by the NSPS is in addition to that required by this AOS. Note that the initial test required by NSPS Subpart JJJJ can serve as the testing required by this AOS under Condition 1.2, if approved in advance by the Division, provided that such test is conducted within the time frame specified in Condition 1.2.

Note that under the provisions of Regulation No. 6. Part B, section I.B. that Relocation of a source from outside of the State of Colorado into the State of Colorado is considered to be a new source, subject to the requirements of Regulation No. 6 (i.e., the date that the source is first relocated to Colorado becomes equivalent to the manufacture date for purposes of determining the applicability of NSPS JJJJ requirements).

However, as of October 1, 2011 the Division has not yet adopted NSPS JJJJ. Until such time as it does, any engine subject to NSPS will be subject only under Federal law. Once the Division adopts NSPS JJJJ, there will be an additional step added to the determination of the NSPS. Under the provisions of Regulation No. 6, Part B, § I.B (which is referenced in Part A), any engine relocated from outside of the State of Colorado into the State of Colorado is considered to be a new source, subject to the requirements of NSPS JJJJ.

1.3.4 Reciprocating internal combustion engine (RICE) MACT: 40 CFR Part 63, Subpart ZZZZ

A permanent replacement engine located at either an area or major source is subject to the requirements in 40 CFR Part 63, Subpart ZZZZ. An analysis of the applicable monitoring, recordkeeping, and reporting requirements for the permanent engine replacement shall be included in the Applicability Reports required under Condition 1.1.2. Any testing required by the MACT is in addition to that required by this AOS. Note that the initial test required by the MACT can serve as the testing required by this AOS under Condition 1.2, if approved in advance by the Division, provided that such test is conducted within the time frame specified in Condition 1.2.

1.4 Additional Sources

The replacement of an existing engine with a new engine is viewed by the Division as the installation of a new emissions unit, not "routine replacement" of an existing unit. The AOS is therefore essentially an advanced construction permit review. The AOS cannot be used for additional new emission points for any site; an engine that is being installed as an entirely new emission point and not as part of an AOS-approved replacement of an existing onsite engine has to go through the appropriate Construction/Operating permitting process prior to installation.

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Appendix C

Alliance SOURCE TESTING

Location --
Source --
Project No. --
Run No.
Method --

Meter Pressure (Pm), in. Hg

$$Pm = Pb + \frac{\Delta H}{13.6}$$

where,

Pb	--	= barometric pressure, in. Hg
ΔH	0.000	= pressure differential of orifice, in H_2O
Pm	--	= in. Hg

Absolute Stack Gas Pressure (Ps), in. Hg

$$Ps = Pb + \frac{Pg}{13.6}$$

where,

Pb	--	= barometric pressure, in. Hg
Pg	--	= static pressure, in. H_2O
Ps	--	= in. Hg

Standard Meter Volume (Vmstd), dscf

$$Vmstd = \frac{17.647 \times Y \times Vm \times Pm}{Tm}$$

where,

Y	0.000	= meter correction factor
Vm	--	= meter volume, cf
Pm	--	= absolute meter pressure, in. Hg
Tm	--	= absolute meter temperature, °R
Vmstd	--	= dscf

Standard Wet Volume (Vwstd), scf

$$Vwstd = 0.04707 \times Vlc$$

where,

Vlc	--	= volume of H2O collected, ml
Vwstd	--	= scf

Moisture Fraction (BWSsat), dimensionless (theoretical at saturated conditions)

$$BWSsat = \frac{10^{6.37 - \left(\frac{2.327}{Ts + 265}\right)}}{Ps}$$

where,

Ts	--	= stack temperature, °F
Ps	--	= absolute stack gas pressure, in. Hg
BWSsat	--	= dimensionless

Moisture Fraction (BWSmsd), dimensionless (measured)

$$BWS = \frac{Vwstd}{(Vwstd + Vmstd)}$$

where,

Vwstd	--	= standard wet volume, scf
Vmstd	--	= standard meter volume, dscf
BWS	--	= dimensionless

Moisture Fraction (BWS), dimensionless

$$BWS = BWSmsd \text{ unless } BWSsat < BWSmsd$$

where,

BWSsat	--	= moisture fraction (theoretical at saturated conditions)
BWSmsd	--	= moisture fraction (measured)
BWS	--	= dimensionless

Molecular Weight (DRY) (Md), lb/lb-mole

$$Md = (0.44 \times \%\ CO_2) + (0.32 \times \%\ O_2) + (0.28\ (100 - \%\ CO_2 - \%\ O_2))$$

where,

CO_2	--	= carbon dioxide concentration, %
O_2	--	= oxygen concentration, %
Md	--	= lb/lb mol

Molecular Weight (WET) (Ms), lb/lb-mole

$$Ms = Md\ (1 - BWS) + 18\ (BWS)$$

where,

Md	--	= molecular weight (DRY), lb/lb mol
BWS	--	= moisture fraction, dimensionless
Ms	--	= lb/lb mol

Alliance SOURCE TESTING

Location --
Source --
Project No. --
Run No.
Method --

Average Velocity (Vs), ft/sec

$$Vs = 85.49 \times Cp \times (\Delta P^{1/2})\,avg \times \sqrt{\frac{Ts}{Ps \times Ms}}$$

where,

Cp	--	= pitot tube coefficient
$\Delta P^{1/2}$	--	= velocity head of stack gas, (in. H2O)$^{1/2}$
Ts	--	= absolute stack temperature, °R
Ps	--	= absolute stack gas pressure, in. Hg
Ms	--	= molecular weight of stack gas, lb/lb mol
Vs	--	= ft/sec

Average Stack Gas Flow at Stack Conditions (Qa), acfm

$$Qa = 60 \times Vs \times As$$

where,

Vs	--	= stack gas velocity, ft/sec
As	--	= cross-sectional area of stack, ft^2
Qa	--	= acfm

Average Stack Gas Flow at Standard Conditions (Qsw), scfm

$$Qsw = 17.647 \times Qa \times \frac{Ps}{Ts}$$

where,

Qa	--	= average stack gas flow at stack conditions, acfm
Ps	--	= absolute stack gas pressure, in. Hg
Ts	--	= absolute stack temperature, °R
Qsw	--	= scfm

Average Stack Gas Flow at Standard Conditions (Qsw), scfh

$$Qsw = 17.647 \times Qa \times 60 \times \frac{Ps}{Ts}$$

where,

Qa	--	= average stack gas flow at stack conditions, acfm
Ps	--	= absolute stack gas pressure, in. Hg
Ts	--	= absolute stack temperature, °R
Qsw	--	= scfh

Average Stack Gas Flow at Standard Conditions (Qsd), dscfm

$$Qsd = 17.647 \times Qa \times (1 - BWS) \times \frac{Ps}{Ts}$$

where,

Qa	--	= average stack gas flow at stack conditions, acfm
BWS	--	= moisture fraction
Ps	--	= absolute stack gas pressure, in. Hg
Ts	--	= absolute stack temperature, °R
Qsd	--	= dscfm

Dry Gas Meter Calibration Check (Yqa), dimensionless

$$Yqa = \frac{Y \cdot \left(\frac{\Theta}{Vm} \sqrt{\frac{0.0319 \times Tm \times 29}{\Delta H @ \times \left[Pb + \frac{\Delta H\ avg.}{13.6} \right] \times Md}} \sqrt{\Delta H}\ avg. \right)}{Y} \times 100$$

where,

Y	0	= meter correction factor, dimensionless
Θ	0	= run time, min.
Vm	--	= total meter volume, dcf
Tm	--	= absolute meter temperature, °R
ΔH@	0	= orifice meter calibration coefficient, in. H_2O
Pb	--	= barometric pressure, in. Hg
ΔH avg	0.000	= average pressure differential of orifice, in H_2O
Md	--	= molecular weight (DRY), lb/lb mol
$(\Delta H)^{1/2}$	0.000	= average squareroot pressure differential of orifice, (in. H_2O)$^{1/2}$
Yqa	--	= dimensionless

Alliance SOURCE TESTING

Location: _____
Source: _____
Project No.: _____
Run No./Method _____

Nitrogen Oxides Concentration @ 15% Oxygen (C_{NOxc15}), ppmvd @ 15% O_2

$$C_{NOxc15} = C_{NOx} \times \frac{20.9 - 15}{20.9 - C_{O2}}$$

where,

C_{NOx} _____ = NO_x concentration, ppmvd
C_{O2} _____ = O_2 concentration, %
C_{NOxc15} _____ = ppmvd @ 15% O_2

Nitrogen Oxides Emission Rate (ER_{NOx}), lb/hr

$$ER_{NOx} = \frac{C_{NOx} \times MW \times Qs \times 60 \times 28.32}{24.04 \times 1.0E + 06 \times 454}$$

where,

C_{NOx} _____ = NOx concentration, ppmvd
MW 46.0 = NOx (as NO2) molecular weight, g/g-mole
Qs _____ = stack gas volumetric flow rate at standard conditions, dscfm
ER_{NOx} _____ = lb/hr

Nitrogen Oxides Emission Factor (EF_{NOx}), g/hp-hr

$$EF_{NOx} = \frac{ER_{NOx} \times 454}{EBW}$$

where,

ER_{NOX} _____ = NOx emission rate, lb/hr
EBW _____ = engine brake work, HP
EF_{NOX} _____ = g/HP-hr

Alliance SOURCE TESTING

Location: _____
Source: _____
Project No.: _____
Run No./Method _____

Carbon Monoxide Concentration @ 15% Oxygen (C_{COc15}), ppmvd @ 15% O2

$$C_{COc15} = C_{CO} \times \frac{20.9 - 15}{20.9 - C_{O2}}$$

where,

C_{CO}	--	= CO concentration, ppmvd
C_{O2}	--	= O_2 concentration, %
C_{COc15}	--	= ppmvd @ 15% O_2

Carbon Monoxide Emission Rate (ER_{CO}), lb/hr

$$ER_{CO} = \frac{C_{CO} \times MW \times Qs \times 60 \times 28.32}{24.04 \times 1.0E+06 \times 454}$$

where,

C_{CO}	--	= CO concentration, ppmvd
MW	28.0	= CO molecular weight, g/g-mole
Qs	--	= stack gas volumetric flow rate at standard conditions, dscfm
ER_{CO}	--	= lb/hr

Carbon Monoxide Emission Factor (EF_{CO}), g/hp-hr

$$EF_{CO} = \frac{ER_{CO} \times 454}{EBW}$$

where,

ER_{CO}	--	= CO emission rate, lb/hr
EBW	--	= engine brake work, HP
EF_{CO}	--	= g/HP-hr

Alliance SOURCE TESTING

Location: _____
Source: _____
Project No.: _____
Run No./Method Method 25A

Total Hydrocarbons Concentration (C_{THC}) as (C3H8), ppmvd

$$C_{THC} = \frac{C_{THCw}}{1 - BWS}$$

where,

C_{THCw}	--	= THC concentration (as C3H8), ppmvw
BWS	--	= moisture fraction, unitless
C_{THC}	--	= ppmvd

NMVOC Concentration @ 15% Oxygen ($C_{NMVOCc15}$) (as C3H8), ppmvd @ 15% O2

$$C_{NMVOCc15} = C_{NMVOC} \times \frac{20.9 - 15}{20.9 - C_{O2}}$$

where,

C_{NMVOC}	--	= NMVOC concentration (as C3H8), ppmvd
C_{O2}	--	= O_2 concentration, %
$C_{NMVOCc15}$	--	= ppmvd @ 15% O_2

NMVOC Compounds Rate (ER_{NMVOC}) (as C3H8), lb/hr

$$ER_{NMVOC} = \frac{C_{NMVOC} \times MW \times Qs \times 60 \times 28.32}{24.04 \times 1.0E+06 \times 454}$$

where,

C_{NMVOC}	--	= NMVOC concentration (C3H8), ppmvd
MW	44.1	= molecular weight, g/g-mole
Qs		= stack gas volumetric flow rate at standard conditions, dscfm
ER_{NMVOC}	--	= lb/hr

NMVOC Emission Factor (EF_{NMVOC}) (as C3H8), g/hp-hr

$$EF_{NMVOC} = \frac{ER_{NMVOC} \times 454}{EBW}$$

where,

ER_{NMVOC}	--	= NMVOC emission rate (as C3H8), lb/hr
EBW	--	= engine brake work, HP
EF_{NMVOC}	--	= g/HP-hr

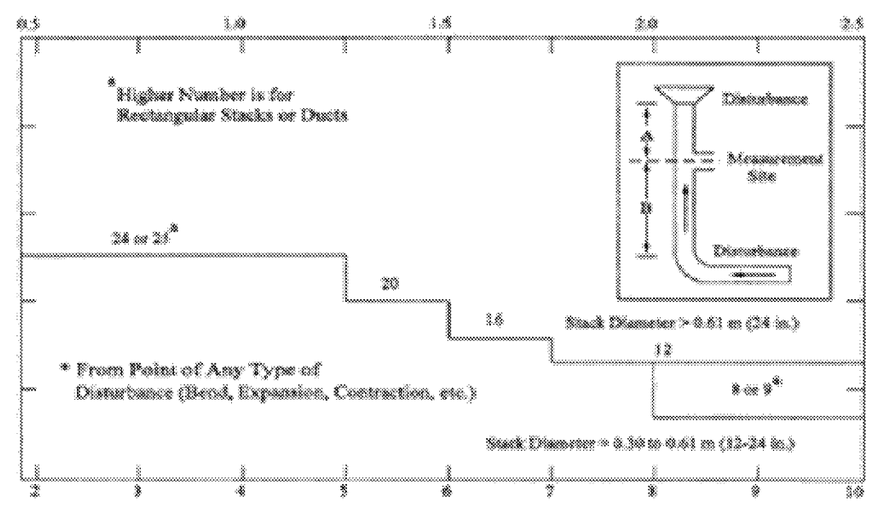
Appendix D

Method 1 Data

Location	0
Source	0
Project No.	0
Date:	

Stack Parameters

Duct Orientation:		
Duct Design:		
Distance from Far Wall to Outside of Port:	--	in
Nipple Length:	--	in
Depth of Duct:	--	in
Width of Duct:	--	in
Cross Sectional Area of Duct:	--	ft^2
Equivalent Diameter:	--	in
No. of Test Ports:	--	
Distance A:	--	ft
Distance A Duct Diameters:	--	(must be > 0.5)
Distance B:	--	ft
Distance B Duct Diameters:	--	(must be > 2)
Minimum Number of Traverse Points:	0	
Actual Number of Traverse Points:		



DUCT

LOCATION OF TRAVERSE POINTS

Number of traverse points on a diameter

	2	3	4	5	6	7	8	9	10	11	12
1	25.0	16.7	12.5	10.0	8.3	7.1	6.3	5.6	5.0	4.5	4.2
2	75.0	50.0	37.5	30.0	25.0	21.4	18.8	16.7	15.0	13.6	12.5
3	--	83.3	62.5	50.0	41.7	35.7	31.3	27.8	25.0	31.8	20.8
4	--	--	87.5	70.0	58.3	50.0	43.8	38.9	35.0	22.7	29.2
5	--	--	--	90.0	75.0	64.3	56.3	50.0	45.0	40.9	37.5
6	--	--	--	--	91.7	78.6	68.8	61.1	55.0	50.0	45.8
7	--	--	--	--	--	92.9	81.3	72.2	65.0	59.1	54.2
8	--	--	--	--	--	--	93.8	83.3	75.0	68.2	62.5
9	--	--	--	--	--	--	--	94.4	85.0	77.3	70.8
10	--	--	--	--	--	--	--	--	95.0	86.4	79.2
11	--	--	--	--	--	--	--	--	--	95.5	87.5
12	--	--	--	--	--	--	--	--	--	--	95.8

**Percent of stack diameter from inside wall to traverse point.*

Traverse Point	% of Diameter	Distance from inside wall	Distance from outside of port
1	16.7	--	--
2	50.0	--	--
3	83.3	--	--
4	--	--	--
5	--	--	--
6	--	--	--
7	--	--	--
8	--	--	--
9	--	--	--
10	--	--	--
11	--	--	--
12	--	--	--

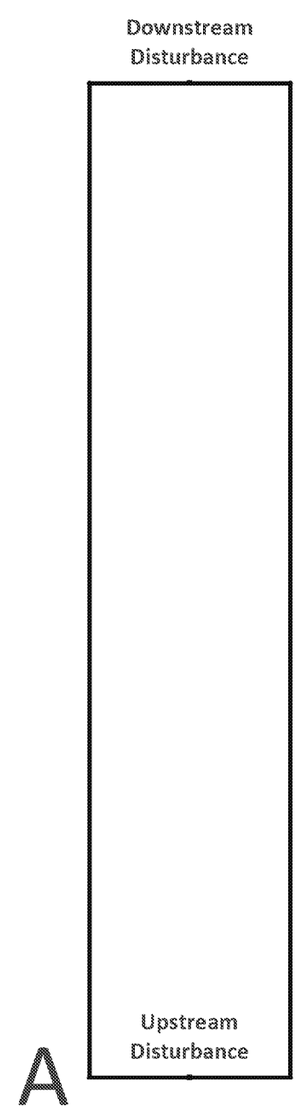
Stack Diagram

A = -- ft.

B = -- ft.

Depth of Duct = -- in.

Cross Sectional Area



Alliance SOURCE TESTING

Location --

Source --

Project No. --

Run No.	1		2		3	
Date			--		--	
Status	VALID		VALID		VALID	
Start Time						
Stop Time						
Leak Check						
Traverse Point	Δ P (in. WC)	Ts (°F)	Δ P (in. WC)	Ts (°F)	Δ P (in. WC)	Ts (°F)

					Average
Square Root of ΔP, (in. WC) $^{1/2}$	$(\Delta P)^{1/2}$	--	--	--	--
Average ΔP, in. WC	(ΔP)	--	--	--	--
Pitot Tube Coefficient	(Cp)	--	--	--	--
Barometric Pressure, in. Hg	(Pb)	--	--	--	--
Static Pressure, in. WC	(Pg)	--	--	--	--
Stack Pressure, in. Hg	(Ps)	--	--	--	--
Average Temperature, °F	(Ts)	--	--	--	--
Average Temperature, °R	(Ts)	--	--	--	--
Moisture Fraction	(BWS)	--	--	--	--
CO2 Concentration, %	(CO2)	--	--	--	--
O2 Concentration, %	(O2)	--	--	--	--
Molecuar Weight, lb/lb-mole (dry)	(Md)	--	--	--	--
Molecuar Weight, lb/lb-mole (wet)	(Ms)	--	--	--	--
Velocity, ft/sec	(Vs)	--	--	--	--
VFR at stack conditions, acfm	(Qa)	--	--	--	--
VFR at standard conditions, scfh	(Qsw)	--	--	--	--
VFR at standard conditions, scfm	(Qsw)	--	--	--	--
FR at standard conditions, dscfm	(Qsd)	--	--	--	--

Alliance SOURCE TESTING

Calibration Data

Location: -
Source: --
Project No.: --
Date: --

Parameter	O_2 - Outlet	CO - Outlet
Expected Average Concentration		
Span Between		
Low	-	-
High	-	-
Desired Span		
Low Range Gas		
Low	NA	NA
High	NA	NA
Mid Range Gas		
Low	-	-
High	-	-
High Range Gas		
Low	NA	NA
High	NA	NA
Actual Concentration (% or ppm)		
Zero	0.0	0.0
Low	NA	NA
Mid		
High	-	-
Response Time (seconds)		
Instrument Response (% or ppm)		
Zero		
Low	NA	NA
Mid		
High		
Performance (% of Span or Cal. Gas Conc.)		
Zero	-	-
Low	NA	NA
Mid	-	-
High	-	-
Status		
Zero	-	-
Low	NA	NA
Mid	-	-
High	-	-

Alliance SOURCE TESTING

Bias/Drift Determinations

Location: -
Source: --
Project No.: --

Parameter	O_2 - Outlet	CO_2 - Outlet
Run 1 Date --		
Span Value	-	-
Instrument Zero Cal Response	-	-
Instrument Mid Cal Response	-	-
Pretest System Zero Response	-	-
Posttest System Zero Response	-	-
Pretest System Mid Response	-	-
Posttest System Mid Response	-	-
Bias (%)		
Pretest Zero	-	-
Posttest Zero	-	-
Pretest Span	-	-
Posttest Span	-	-
Drift (%)		
Zero	-	-
Mid	-	-
Run 2 Date --		
Span Value	-	-
Instrument Zero Cal Response	-	-
Instrument Mid Cal Response	-	-
Pretest System Zero Response	-	-
Posttest System Zero Response	-	-
Pretest System Mid Response	-	-
Posttest System Mid Response	-	-
Bias (%)		
Pretest Zero	-	-
Posttest Zero	-	-
Pretest Span	-	-
Posttest Span	-	-
Drift (%)		
Zero	-	-
Mid	-	-
Run 3 Date --		
Span Value	-	-
Instrument Zero Cal Response	-	-
Instrument Mid Cal Response	-	-
Pretest System Zero Response	-	-
Posttest System Zero Response	-	-
Pretest System Mid Response	-	-
Posttest System Mid Response	-	-
Bias (%)		
Pretest Zero	-	-
Posttest Zero	-	-
Pretest Span	-	-
Posttest Span	-	-
Drift (%)		
Zero	-	-
Mid	-	-

Location: _____
Source: _____
Project No.: _____

Parameter	O_2	NOx
Make	--	--
Model	--	--
S/N		
Operating Range		
Cylinder Number ID		
LOW		
MID		
HIGH		

Location	--
Source	--
Project No.	--
Date	--

Spike Cylinder ID	--	Component
Spike Gas concentration	--	--
Tracer Cylinder ID	--	Component
Tracer Gas concentration	--	SF6
Instrument ID	0	

Direct Spike Values

Date	Time	File	Temperature (C)	Pressure	Spike (ppm)	Tracer (ppm)
				Average	--	--

Native Values

Date	Time	File	Temperature (C)	Pressure	Spike (ppm)	Tracer (ppm)
				Average	--	--

Spiked values

Date	Time	File	Temperature (C)	Pressure	Spike (ppm)	Tracer (ppm)
				Average	--	--

Dilution Factor

--

Calculated Spike

--

Spike Recovery

--

Location	--
Source	0
Project No.	--
Date	
Ethylene Cylinder ID	--
Concentration (ppmv)	--
Instrument ID	0

CTS 1	--	CTS 7	--	AVERAGE	--	Greatest Deviation from average	
CTS 2	--	CTS 8	--	MAX	--	--	
CTS 3	--	CTS 9	--	deviation	--		
CTS 4	--	CTS 10	--	MIN	--	Agreement with Assumed Pathlength	
CTS 5	--	CTS 11	--	deviation	--	--	
CTS 6	--	CTS 12	--			--	

CTS 1

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 7

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 2

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 8

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 3

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 9

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 4

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 10

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 5

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 11

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 6

Date	Time	File	Temperature (C	Pressure	Ethylene

CTS 12

Date	Time	File	Temperature (C	Pressure	Ethylene

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