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OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **October 12, 2022**

TO:	Lee Warden, P.E., Permits & Engineering Group Manager
THROUGH:	Richard Kienlen, P.E., Engineering Manager, New Source Permits Section
THROUGH:	Junru Wang, P.E., Existing Source Permits Section
FROM:	Alex Johnson, E.I., Existing Source Permits Section
SUBJECT:	Evaluation of Permit Application No. **2022-0107-C** VM Arkoma Stack, LLC Stanberry Gas Plant (SIC 1321/NAICS 211130) Facility ID No.: 19683 Section 17, Township 2N, Range 11E, Coal County, Oklahoma Latitude: 34.64100°N and Longitude: 96.16400°W Directions: From the intersection of State Hwy 31 and State Hwy 131 NE in Coalgate, OK, proceed north on State Hwy 31 for 3.55 miles to Grisso Road. Turn west and proceed 1 mile to N3850 Road. Turn north and proceed 0.25 miles to the facility.

SECTION I. INTRODUCTION

VM Arkoma Stack, LLC (VM Arkoma) has requested an individual minor source construction permit for their Stanberry Gas Plant in Coal County, Oklahoma. This permit authorizes the construction of one (1) amine unit and one (1) amine reboiler onto an inactive site with one (1) TEG dehydration unit, three (3) heaters including one (1) glycol reboiler, three (3) condensate tanks, one (1) produced water tank, and one (1) condensate flare.

This facility was previously authorized to operate under the General Permit for Oil and Gas Facilities (GP-O&GF) Authorization No. 2018-1250-O, issued on May 14, 2019. On April 1, 2021, this facility was shut down and the permit for the facility was canceled on May 19, 2021. VM Arkoma is requesting to install a new amine unit on the existing site in preparation to restart the site, tentatively planned for September 2022.

Based on data provided by VM Arkoma, the facility has uncontrolled emissions of 11.98 TPY NOx, 17.34 TPY CO, and controlled emissions of 51.14 TPY of VOC and 9.22 TPY HAPs, the most significant being 3.33 TPY n-hexane. Emissions from the facility are below the major source thresholds. This facility, therefore, qualifies for a "synthetic minor" permit because the controlled emissions of each of the criteria pollutants are below the major source threshold of 100 TPY and the HAP emissions are below the 10 TPY threshold for a single HAP and below the 25 TPY threshold for any combination of HAPs.

SECTION II. FACILITY DESCRIPTION

The facility is a natural gas processing facility comprised of an amine unit, a glycol dehydration unit, a cryogenic process, electric compression, and associated process equipment.

The inlet gas stream enters the facility through inlet separators. Up to 120-MMSCFD of the inlet gas stream is sent to the amine unit (AMINE-1) to sweeten the gas by removing CO_2 and H_2S. The amine unit includes an amine reboiler (H-4) to regenerate the rich amine. The amine unit acid gas stream is sent to a scavenger to control H_2S. After exiting the amine unit, sweetened gas is mixed with the inlet bypass gas and then flows to the triethylene glycol dehydration process (DEHY-1). The dehydration unit can process up to 230-MMSCFD of gas, and includes a glycol reboiler (H-2300) that regenerates the glycol.

Dehydrated gas flows to the cryogenic process, which includes a propane chiller, an expander, and a demethanizer tower. Natural gas liquids are stabilized in the demethanizer tower with heat from the cryo HMO heater (H-5712). The NGLs are then transported off-site via the sales pipeline. Residue gas from the cryogenic process is compressed by electric compressor engines before being sent to a sales line.

Condensate and produced water from the inlet separator and gas processing steps are sent to a condensate stabilizer and heated by hot oil provided by the regen gas heater (H-5711). Vapors from the condensate stabilizer are recycled back to the inlet. Stabilized condensate is stored in three atmospheric condensate tanks (TK-2300, TK-2350, and TK-2400). Produced water generated during the process is sent to one atmospheric produced water tank (TK-6100). Vapors generated in these tanks are captured with at least 98% efficiency and routed to the standard flare (FL-5100) for at least 98% combustion. NGLs from the condensate stabilizer are combined with NGL from the cryogenic plant and piped off-site.

Condensate and produced water are trucked off-site (CONDLOAD1 and PWLOAD1). Truck loading emissions are vented to the atmosphere. Fugitive emissions from equipment leaks (FUG), compressor blowdowns (CBD), and pig trap blowdowns (PBD) also occur.

SECTION III. EQUIPMENT

The following is a list of current equipment.

EU ID#	Equipment Type	Size/Rating	Manufacture Date
DEHY-1	TEG Dehydration Unit	230-MMSCFD	-
AMINE-1	Amine Unit	120-MMSCFD	-
H-2300	Glycol Reboiler	1.50-MMBTUH	-
H-5711	Regenerator Gas Heater	14.22-MMBTUH	-
H-5712	Cryo HMO Heater	24.10-MMBTUH	-

EU ID#	Equipment Type	Size/Rating	Manufacture Date
H-4	Amine Reboiler	7.00-MMBTUH	-
TK-2300	Condensate Tank	300-bbl	2018
TK-2350	Condensate Tank	300-bbl	2018
TK-2400	Condensate Tank	300-bbl	2018
TK-6100	Produced Water Tank	300-bbl	2018
CONDLOAD1	Condensate Loading	-	-
PWLOAD1	Produced Water Loading	-	-
FL-5100	Flare	0.33-MMBTUH(1)	-
FUG	Fugitive Emissions	-	-
CBD	Compressor Blowdowns	-	-
PBD	Pig Trap Blowdowns	-	-

(1) Maximum flare heat rating.

SECTION IV. FACILITY-SPECIFIC OR REPRESENTATIVE SAMPLE

TANKS

The facility submitted a Representative Sample in accordance with the guidance.

No.	All Sample Considerations	Yes	No
1	Is sample more than three (3) calendar years old?		X
If the above answer is yes, a new sample is required, or the sample shall be evaluated on a case-by-case basis.			

No.	Calculated Emission Considerations	Yes	No
2	For true minor and synthetic minor facilities, are VOC emissions more than 80 TPY and then do storage tank and truck loading VOC emissions account for more than 50% of facility-wide VOC emissions?		X
3	Are individual storage tank emissions, not controlled by a combustion device, more than 4 TPY VOC?		X
4	Are facility-wide emissions of a single HAP greater than 8 TPY or are total HAP emissions greater than 20 TPY? (Excluding HAP emissions from engines)		X
If any of the above answers are yes, a facility-specific sample is required.			

No.	Natural Gas Processing Plant Considerations	Yes	No
6d	Is the condensate treated in a condensate stabilizer prior to entering storage tanks or are storage tanks controlled by greater than 95% with a VRU and/or combustion device?	X	
If the above answer is no, a facility-specific sample is required.			

DEHYDRATION UNIT

Glycol Dehydrator Considerations	Yes	No
The facility submitted a facility-specific extended gas analysis of the inlet gas.		X(1)
The sample was no older than three (3) calendar years at the time of submittal.	X	

(1) A facility-specific sample is not required for a pre-construction permit.

AMINE UNIT

Amine Unit Considerations	Yes	No
The facility submitted a facility-specific extended gas analysis of the inlet gas.		X(1)
The facility submitted a facility-specific H_2S sampling of the inlet gas. The H_2S sampling can be a stain tube, lab analysis, or other approved method.		X(1)
The sample was no older than three (3) calendar years at the time of submittal.	X	

(1) A facility-specific sample is not required for a pre-construction permit.

FUGITIVES

Natural Gas Processing Plant Fugitive Considerations	Yes	No
The facility submitted a facility-specific sample of the inlet gas.		X(1)
The facility did not submit a liquid sample and assumed 100% VOC content for the liquid service components.	X	
The facility submitted a facility-specific sample of the VOC containing liquid.		X
The sample was no older than three (3) calendar years at the time of submittal.	X	

(1) A facility-specific sample is not required for a pre-construction permit.

SECTION V. EMISSIONS

All emissions calculations are based on continuous operation (8,760 hours per year), unless otherwise noted.

AMINE UNIT

Emission estimates from the amine, methyl diethanolamine (MDEA), unit's regenerator vent and flash tank are based on a ProMax analysis, an inlet gas analysis, and continuous operation.

Amine Unit

Parameter	Data
Type of Amine	MDEA
Inlet Gas Flow Rate, MMSCFD	120
Inlet Gas H_2S Concentration, ppmv	2.000
Outlet Gas H_2S Concentration, ppmv	0.002
Lean Amine Pump Design Capacity, gpm	100
Lean Amine Recirculation Rate Input, gpm	100
Amine Unit Inlet Gas Temperature, °F	57
Amine Unit Inlet Gas Pressure, psig	953.70
Amine Solution Concentration, wt. %	50

Parameter	Data
Regenerator Vent	
Control Method	Scavenger
H_2S Control Efficiency, %	98
Flash Tank	
Flash Tank Temperature, °F	104
Flash Tank Pressure, psig	85
Control Method	Recycle
VOC/H_2S Control Efficiency, %	100
Total Emissions, TPY	
VOC	7.80
H_2S, lb/hr	0.02
SO_2	--

DEHYDRATION UNIT

Emission estimates from the TEG dehydration unit's regenerator vent and flash tank are based on the Gas Research Institute (GRI) program GLYCalc Version 4.0, an inlet gas analysis and continuous operation. The dehydration unit is equipped with a flash tank on the rich glycol stream. Flash tank off-gasses are recycled/recompressed to the inlet. The dehydration unit's regenerator still vent is equipped with an air-cooled condenser, where vapors are captured. The vapors from the dehydration unit's regenerator still vent are routed through the condenser, with the uncondensed vapors from the condenser routed to the reboiler firebox when it is firing, or an in-stack glow plug when the reboiler is not firing. The dehydration unit's regenerator still vent emissions were calculated with a 98% overall control efficiency. Emissions from the regenerator vent include a safety factor of 10% to allow for variability in the composition of the natural gas stream.

Dehydration Unit

Parameter	Data
Type of Glycol	TEG
Dry Gas Flow Rate, MMSCFD	230.00
Glycol Pump Type	Electric
Lean Glycol Pump Design Capacity, gpm	40
Lean Glycol Recirculation Rate Input, gpm	40
Regenerator Vent	
Condenser Outlet Temperature, °F	120
Control Method	Condenser/Combustion(1)
Overall Control Efficiency, %	98
VOC Emissions, TPY	5.96
Flash Tank	
Flash Tank Temperature, °F	180
Flash Tank Pressure, psig	88
Control Method	Recycled/Recompressed
VOC Control Efficiency, %	100
VOC Emissions, TPY	--
Total Emissions, TPY	
VOC	6.55 (2)

Parameter	Data
Benzene	0.72
Toluene	0.90
Ethylbenzene	---
Xylene	0.19
n-Hexane	0.70
Total HAP	2.52

(1) Combusted in the reboiler or glow plug when the reboiler is not firing.
(2) Include a 10% safety factor (1+10%).

HEATERS/REBOILERS

Emission estimates for the heaters and reboilers at the facility are based on AP-42 (7/98), Section 1.4, Table 1.4-1 through Table 1.4-3 for small commercial boilers, the rating listed below, and a fuel heating value of 1,120-BTU/SCF. Heaters H-5711 and H-5712 are low NOx heaters.

Reboiler/Heater Emission Factors

EU ID#	NOx (lb/MMSCF)	CO (lb/MMSCF)	VOC (lb/MMSCF)
H-2300 – 1.50-MMBTUH	109.76	91.84	5.60
H-5711 – 14.22-MMBTUH	54.88	91.84	5.60
H-5712 – 24.10-MMBTUH	54.88	91.84	5.60
H-4 – 7.00-MMBTUH	109.76	91.84	5.60

Reboiler/Heater Emissions

EU ID#	NOx		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
H-2300	0.15	0.64	0.12	0.54	0.01	0.04
H-5711	0.70	3.05	1.17	5.13	0.08	0.34
H-5712	1.18	5.17	1.98	8.69	0.13	0.57
H-4	0.69	3.01	0.58	2.52	0.04	0.17

TANKS

Working and breathing emissions from the condensate and produced water tanks were calculated using AP-42 (11/19) Chapter 7.1. Flashing emissions from the produced water tank were calculated using BR&E's ProMax® 4.0, a representative liquid analysis, and the listed throughput. The condensate is stabilized before being sent to the tanks; therefore, they do not have any flashing emissions. Flash emissions at the produced water tank result as liquids under pressure enter the tank at atmospheric pressure. HAP emissions are calculated based on a representative sample of both the liquid and vapor streams that result in the flashing and separation of the inlet stream. Emissions from the storage tanks are routed to the tank flare (FL-5100) for control. To be conservative, working and breathing emissions for the produced water tank were calculated using 100% of the condensate properties.

Tank Emissions (per tank)

Parameter	TK-2300, TK-2350, and TK-2400 Data	TK-6100 Data
Throughput, gal/yr	1,890,700	919,800
Liquid in Tank(s)	Condensate/Oil	Produced Water
Working/Breathing Method/Tool	AP-42 (11/19) Chapter 7.1	AP-42 (11/19) Chapter 7.1
Flash Calculation Method/Tool	---	ProMax®
Working/Breathing Emissions, TPY	2.96	3.92
Flashing Emissions, TPY	---	0.66
Control Type	Flare	Flare
Capture Efficiency, %	98	98
Control Efficiency, %	98	98
Tank VOC Emitted at Tank, TPY	0.06	0.09
Tank VOC Emitted at Flare, TPY	0.06	0.09
Total VOC Emissions, TPY	0.12	0.18

LOADING

Emissions from loading condensate and produced water into tank trucks were estimated using AP-42 (6/08), Section 5.2, Equation 1, and the parameters listed in the table below. The vapor pressure, molecular weight, and temperature listed are from AP-42 (11/19), Section 7.1 defaults for Oklahoma City, Oklahoma and Crude Oil (RVP 10).

Loading Parameters and Emissions

Parameter	CONDLOAD1	PWLOAD1
Liquids Loaded	Condensate/Oil	Produced Water
Throughput, gal/yr	5,672,100	919,800
Saturation Factor	0.6	0.6
Temp., ^oF	61.81	61.81
TVP, psia	7.81	0.29
MW, lb/lbmol	50.00	18.78
VOC, wt.%	100	100
Emission Factor, lb/10^3 gal [(1)]	5.595	0.078
VOC Emitted at Truck, TPY	15.86	0.04

[(1)] Final factor considering any VOC reduction stated for methane/ethane.

FLARE

Emission factors of NO_X and CO are taken from AP-42 (2/18), Section 13.5. VOC emissions from the tank flare (FL-5100) are based on the emissions from the storage tanks with a 98% destruction efficiency.

Flare Combustion Emissions

EU ID#	Total Gas Combusted MMBTUH	Emission Factor lb/MMBTU		NO_X TPY	CO TPY
		NOx	CO		
FL-5100	0.33	0.068	0.310	0.10	0.45

Flare Emissions

EU ID#	Process Point(s)	VOC Emissions, TPY
FL-5100	Storage Tanks	0.27

FUGITIVES

Emissions from fugitive equipment leaks (FUG) are based on EPA's "Protocol for Equipment Leak Emission Estimates" (11/95, EPA-453/R-95-017), an estimated number of components, and the VOC (C_{3+}) content of the materials handled.

Fugitive Emissions

EU ID#	VOC, TPY
FUG	8.25

BLOWDOWNS

Blowdown emissions are based on an estimated number of events, an estimated volume of vapors released, and an estimated VOC content of the vapors from each type of activity.

Blowdown Emissions

EU ID#	Blowdown Type	VOC, TPY
CBD	Compressor Blowdowns	10.26
PBD	Pig Trap Blowdowns	0.72

FACILITY-WIDE EMISSIONS

For condensate tank emissions released at the flare, these emissions are represented at the flare.

EU ID #	Source	NO_X		CO		VOC		Total HAP
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	TPY
DEHY-1	230-MMSCFD TEG Dehydration Unit	-	-	-	-	1.50	6.55	2.52
AMINE-1	120-MMSCFD Amine Unit	-	-	-	-	1.78	7.80	3.44
H-2300	1.50-MMBTUH Glycol Reboiler	0.15	0.77(1)	0.12	0.65(1)	0.01	0.10(2)	0.01
H-5711	14.22-MMBTUH Regenerator Gas Heater	0.70	3.66(1)	1.17	6.16(1)	0.08	0.41(1)	0.11
H-5712	24.10-MMBTUH Cryo HMO Heater	1.18	6.20(1)	1.98	10.43(1)	0.13	0.68(1)	0.19
H-4	7.00-MMBTUH Amine Reboiler	0.69	3.61(1)	0.58	3.02(1)	0.04	0.20(1)	0.06
TK-2300	300-bbl Condensate Tank	-	-	-	-	0.01	5.99(3)	0.02
TK-2350	300-bbl Condensate Tank	-	-	-	-	0.01	5.99(3)	
TK-2400	300-bbl Condensate Tank	-	-	-	-	0.01	5.99(3)	
TK-6100	300-bbl Produced Water Tank	-	-	-	-	0.02	5.99(3)	0.01

EU ID #	Source	NOx		CO		VOC		Total HAP
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	TPY
CONDLOAD1	Condensate Loading	-	-	-	-	76.10	15.86	1.54
PWLOAD1	Produced Water Loading	-	-	-	-	1.84	0.10(2)	<0.01
FL-5100	0.33-MMBTUH Flare	0.10(2)	0.12(1)	0.12(1)	0.54(1)	0.10(2)	0.32(4)	0.03
FUG	Fugitive Emissions	-	-	-	-	1.88	8.25	0.79
CBD	Compressor Blowdowns	-	-	-	-	131.56	10.26	0.46
PBD	Pig Trap Blowdowns	-	-	-	-	27.81	0.72	0.03
Total Emissions		**2.82**	**14.36**	**3.97**	**20.80**	**242.88**	**75.21**	**9.22**

(1) Limit increased by 20% to allow for variance in operation.
(2) Limit increased to 0.10 to allow for variance in operation.
(3) Tanks conservatively limited to 5.99 tpy per tank to allow for variance in operation and keep the tanks exempt from NSPS OOOOa.
(4) Controlled tank emissions at the flare are included in emission limits of TK-2300, TK-2350, TK-2400, and TK-6100.

The total HAP emissions from the equipment at the facility are 9.22 TPY. Therefore, the individual and the total emissions of HAPs do not exceed the major source thresholds of 10/25 TPY.

SECTION VI. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the “Federal Regulations” section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration, Emission Inventory, and Annual Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. Required annual information (Turn-Around Document) shall be provided to Air Quality.

OAC 252:100-7 (Permits for Minor Facilities) [Applicable]
Subchapter 7 sets forth the permit application fees and the basic substantive requirements of permits for minor facilities. This project meets the conditions for a minor facility construction permit because there is no emission of any regulated pollutant of 100 TPY or more and HAP emissions do not exceed the 10/25 TPY threshold. As such, major source BACT consideration and public review are not required.

OAC 252:100-9 (Excess Emission Reporting Requirement) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for mitigation, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, and 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
Section 19-4 regulates emissions of particulate matter from fuel-burning equipment. Particulate emission limits are based on maximum design heat input rating. This subchapter specifies a PM emissions limitation of 0.6 lb/MMBTU from fuel-burning units with a rated heat input of 10 MMBTUH or less and a limit of 0.10 lb/MMBTU for units with a rated heat input of 10,000 MMBTUH or greater. For fuel-burning equipment with a capacity between 10 and 10,000 MMBTUH, this subchapter specifies a PM emission limitation based upon the heat input of the equipment and is calculated according to the following equations:

$E = 1.042808\ X^{-0.238561}$ For Units > 10 MMBTUH but < 1,000 MMBTUH
$E = 1.6\ X^{-0.30103}$ For Units > 1,000 MMBTUH but < 10,000 MMBTUH

Where: E = allowable total particulate matter emissions in pounds per MMBTU
X = the maximum heat input in MMBTU per hour.

The combustion units located at the facility are subject to this subchapter and will be in compliance as indicated below.

Equipment	Maximum Heat Input, (MMBtu/h)	Appendix C Emission Limit, (lb/MMBtu)	Potential Emission Rate, (lb/MMBtu)
H-2300	1.50	0.60	0.007
H-5711	14.22	0.55	0.007
H-5712	24.10	0.49	0.007
H-4	7.00	0.60	0.007

Section 19-12 limits emissions of particulate matter from industrial processes and direct-fired fuel-burning equipment based on their process weight rates. Since there are no significant particulate emissions from the nonfuel-burning processes at the facility compliance with the standard is assured without any special monitoring provisions.

OAC 252:100-25 (Visible Emissions and Particulate Matter) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The permit will require that any on-site equipment be fueled only with natural gas to ensure compliance with this requirement.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area; therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air concentration of H_2S emissions from any facility to 0.2 ppmv (24-hour average) at standard conditions which is equivalent to 283 µg /m^3. This facility submitted AERSCREEN modeling for the amine unit, incorporating terrain data and site-specific surface characteristics. AERSCREEN is a single-source model; therefore, impacts are directly related to emission rates. The submitted modeling indicated a 24-hour average ground level concentration of 191.9 µg/m^3, which is based off of a source emission rate of 4.683 lb/hr H_2S. However, the actual H_2S emission rate for the amine unit is 0.90 lb/hr. When considering this actual emission rate and multiplying it by the ratio of the modeled ground level concentration and the modeled emission rate, the resulting actual concentration is 36.88 µg/m^3. Based on this modeling and the modeling conducted for the general permit for oil and gas facilities, which included facilities that handle and treat "sweet" natural gas and store "sweet" crude oil or condensate, this facility is expected to be in compliance with the H_2S ambient air concentration limit.
Part 5 limits sulfur dioxide emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input averaged over 3 hours. For fuel gas having a gross calorific value of 1,000-BTU/SCF, this limit corresponds to fuel sulfur content of 1,203 ppmv. Gas produced from oil and gas wells having 162 ppmv or less total sulfur will ensure compliance with Subchapter 31. The permit requires the use of pipeline-grade natural gas or field gas with a maximum sulfur content of 162 ppmv for all fuel-burning equipment to ensure compliance with Subchapter 31.
Part 5 also limits hydrogen sulfide (H_2S) emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). Removal of H_2S in the exhaust stream, or oxidation to sulfur dioxide (SO_2), is required unless H_2S emissions do not exceed 0.3 lb/hr for a two-hour average. If this threshold is exceeded, H_2S emissions shall be reduced by a minimum of 95% of the H_2S in the exhaust gas. The permit requires the applicant to test the gas entering the facility to determine the H_2S concentration. The emissions from the amine unit's still vent are required to be directed to a H_2S scavenger system. During any calendar month that the amine unit is operated, the applicant is required to monitor the exhaust from the H_2S scavenger system at least once to ensure that the emissions do not exceed 0.3 lb/hr.
Part 5 requires removal or oxidation of H_2S from the exhaust gas of any new petroleum or natural gas process equipment. This part allows direct oxidation of H_2S to SO_2, without sulfur recovery, when the exhaust gas will contain no more than 100 lbs/hr SO_2 (2-hour average). Compliance

with the 100 lb/hr can be demonstrated by establishing that the acid gas stream contains 0.54 long tons per day (LTD) of sulfur (S) or less. An H_2S scavenger system treating gas at 4 ppmv after 100% conversion is 3.38 lb/hr SO_2 which assures that emissions are less than 100 lb/hr. This assures that as long as the facility is treating sweet gas, it will comply with this part. Oxidation of the H_2S must be conducted in a system that assures at least a 100% reduction of the H_2S in the exhaust gases and that is equipped with an alarm system to signal non-combustion of the exhaust gases. These requirements do not apply if H_2S emissions do not exceed 0.3 lb/hr.

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]
This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50-MMBTUH to emissions of 0.2 lb of NOx per MMBTU. There are no equipment items that exceed the 50-MMBTUH threshold.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
This facility has none of the affected sources: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5-psia at maximum storage temperature to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The condensate tanks at this facility are subject to this requirement.
Part 3 requires VOC loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling of tank trucks or trailers if the capacity of the vehicle is greater than 200 gallons. This facility does not have the physical equipment (loading arm and pump) to conduct this type of loading and is not subject to this requirement.
Part 5 limits the VOC content of coatings from any coating line or other coating operation. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment. The VOC emission is less than 100 pound per day and so is exempt.
Part 7 requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. The equipment at this location is subject to this requirement.
Part 7 requires all effluent water separator openings which receive water containing more than 200 gallons per day of any VOC, to be sealed or the separator to be equipped with an external floating roof or a fixed roof with an internal floating roof or a vapor recovery system. No effluent water separators are located at this facility.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Not Applicable]
This subchapter regulates TAC that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no AOC has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To

determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

SECTION VII. FEDERAL REGULATIONS

NSPS, 40 CFR Part 60 [Subparts Dc and OOOOa Applicable]
Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989, and that has a maximum design heat input capacity of between 10 MMBTUH and 100 MMBTUH. Heaters H-5711 and H-5712 are subject to the recordkeeping provisions for gas-fired units under this subpart.

Subpart Kb, Volatile Organic Liquid (VOL) Storage Vessels. This subpart regulates hydrocarbon storage tanks larger than 19,813-gallons capacity and built after July 23, 1984. The four 300-bbl storage tanks at the site have capacities less than the threshold, 19,813 gallons. Therefore, this subpart is not applicable.

Subpart GG, Stationary Gas Turbines. There are none at this facility.

Subpart VV, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOCMI). The equipment is not in a SOCMI plant.

Subpart KKK, Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. The facility was constructed after August 23, 2011, and is not subject to this subpart.

Subpart LLL, Onshore Natural Gas Processing: SO_2 Emissions. This subpart affects sweetening units and sweetening units followed by sulfur recovery units. The facility was constructed after August 23, 2011, and is not subject to this subpart.

Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. There are no compression ignition engines located at this facility.

Subpart JJJJ, Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart promulgates emission standards for all new SI engines ordered after June 12, 2006, and all SI engines modified or reconstructed after June 12, 2006, regardless of size. There are no SI engines at this facility, therefore this subpart does not apply.

Subpart OOOO, Crude Oil and Natural Gas Facilities. This subpart affects the following sources that commence construction, reconstruction, or modification after August 23, 2011, and on or before September 18, 2015:

(a) Each gas well affected facility, which is a single natural gas well.
(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals that is located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment.
(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment.
(d) Each pneumatic controller affected facility, which is:
    (1) For the oil production segment (between the wellhead and the point of custody transfer to an oil pipeline): a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 SCFH.
    (2) For the natural gas production segment (between the wellhead and the point of custody transfer to the natural gas transmission and storage segment and not including natural gas processing plants): a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 SCFH.
    (3) For natural gas processing plants: a single continuous bleed natural gas-driven pneumatic controller.
(e) Each storage vessel affected facility, which is a single storage vessel located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment, that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and has the potential for VOC emissions equal to or greater than 6 TPY.
(f) The group of all equipment, except compressors, within a process unit located at an onshore natural gas processing plant is an affected facility.
(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

This facility began construction after September 18, 2015. The storage tanks at this facility were manufactured after September 18, 2015. Therefore, this subpart does not apply.

Subpart OOOOa, Crude Oil and Natural Gas Facilities for which construction, modification, or reconstruction commenced after September 18, 2015. This subpart affects the following onshore affected facilities:

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing.
(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.
(d) Each pneumatic controller affected facility:
   (1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 SCFH.
   (2) Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.
(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 TPY as determined according to §60.5365a(e).
(f) The group of all equipment within a process unit located at an onshore natural gas processing plant is an affected facility. Equipment within a process unit of an affected facility located at onshore natural gas processing plants are exempt from this subpart if they are subject to and controlled according to Subparts VVa, GGG, or GGGa.
(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.
(h) Each pneumatic pump affected facility:
   (1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump.
   (2) For well sites, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump.
(i) The collection of fugitive emissions components at a well site, as defined in §60.5430a, is an affected facility, except as provided in § 60.5365a(i)(2).
(j) The collection of fugitive emissions components at a compressor station, as defined in § 60.5430a, is an affected facility.

This facility is a gas plant constructed after September 18, 2015, and is subject to the leak detection provisions of this subpart. The amine unit at this facility is potentially subject to this subpart due to having a sulfur recovery unit (H_2S scavenger), however, the design capacity is less than 2 LT/D, so it is only subject to the recordkeeping requirements of this subpart. There are no pneumatic controllers currently planned to be installed at this facility. The storage tanks were installed after September 18, 2015, but the applicant has requested federally enforceable limits of less than 6 TPY for the tanks at the facility (TK-2300, TK-2350, TK-2400, and TK-6100). Therefore, the storage tanks are not subject to this subpart. Federally enforceable limits for these tanks were previously established before the shutdown of this facility and are being carried over to this permit.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the pollutants subject to 40 CFR 61 (arsenic, asbestos, radionuclides, coke oven emissions, mercury, beryllium, vinyl chloride, and benzene) except for benzene. Subpart J affects process streams, which contain more than 10% benzene by weight. Benzene is present only in trace amounts in any product stream in this facility.

NESHAP, 40 CFR Part 63 [Subpart HH Applicable]
Subpart HH, Oil and Natural Gas Production Facilities. This subpart applies to affected sources that are located at facilities which are major and area sources of HAP. This facility is an area source

of HAP emissions. The only affected unit at an area source is the TEG dehydration unit. Even though the TEG dehydration unit at this facility is considered an affected area source it is exempt from the requirements of § 63.764(d)(2) since the actual average emissions of benzene from the glycol dehydration unit process vents to the atmosphere are less than 1 TPY, as determined by the procedures specified in § 63.772(b)(2). However, the facility must maintain records of the de minimis determination as required in § 63.774(d)(1). All applicable requirements have been incorporated into the permit.

Subpart HHH, affects Natural Gas Transmission and Storage Facilities that are major sources of HAP. Since this facility is a production facility and not a major source of HAP, this subpart does not apply.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines):

1) Stationary RICE located at an area source;
2) The following Stationary RICE located at a major source of HAP emissions:
   i) 2SLB and 4SRB stationary RICE with a site rating of ≤ 500 brake HP;
   ii) 4SLB stationary RICE with a site rating of < 250 brake HP;
   iii) Stationary RICE with a site rating of ≤ 500 brake HP which combust landfill or digester gas equivalent to 10% or more of the gross heat input on an annual basis;
   iv) Emergency or limited use stationary RICE with a site rating of ≤ 500 brake HP; and
   v) CI stationary RICE with a site rating of ≤ 500 brake HP.

No further requirements apply for engines subject to NSPS under this part. A stationary RICE located at an area source of HAP emissions is new if construction commenced after June 12, 2006. Based on emission calculations, this facility is an area source of HAP. There are no RICE at this facility, so this subpart does not apply.

Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters at major sources of HAPs. Because this facility is an area source of HAPs, this subpart does not apply.

Subpart JJJJJ, Industrial, Commercial, and Institutional Boilers. This subpart affects new and existing boilers located at area sources of HAP, except for gas-fired boilers. Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam or hot water. The reboilers and heaters at this facility meet the definition of gas-fired boilers and are not subject to this subpart.

SECTION VIII. COMPLIANCE

TIER CLASSIFICATION AND PUBLIC REVIEW
This application has been determined to be Tier I based on the request for a new minor NSR construction permit for a minor facility. Information on all permit actions is available for review by the public in the Air Quality Section of the DEQ web page: *www.deq.ok.gov.*

The draft permit will undergo public notice on the DEQ's web site as required in OAC 252:4-7-13(g). The public, tribal governments, and the EPA will have 30 days to comment on the draft permit. Permits available for public review and comment are found at this location: https://www.deq.ok.gov/permits-for-public-review/.

The applicant has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land used to accomplish the permitted purpose.

ENVIRONMENTAL JUSTICE REVIEW
All people should be protected from the impacts of environmental pollution regardless of race, national origin, or income. DEQ is committed to ensuring such protection through the development, implementation, and consistent enforcement of environmental laws and regulations.

Pending any public review indicated in this Section, AQD has determined that no communities with environmental justice concerns are impacted by the issuance of this permit. This determination is based on this permit qualifying as a minor source under OAC 252:100-7.

FEE PAID
A Minor Source Construction Permit application fee of $2,000 was paid on March 14, 2022.

INSPECTION
An inspection is not needed for a construction permit.

SECTION IX. SUMMARY

The facility has demonstrated the ability to comply with all applicable air quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues concerning this facility. Issuance of the operating permit is recommended, contingent on public review.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

VM Arkoma Stack, LLC **Permit No. 2022-0107-C**
Stanberry Gas Plant

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on March 10, 2022. The Evaluation Memorandum dated October 12, 2022, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction and continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Points of emissions and emission limitations for each point; unless otherwise stated, these limits are based on an averaging time of a 3-hour average for the hourly limits, and a 12-month rolling total for the annual limits:

EU ID #	Source	NO_X		CO		VOC	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
DEHY-1	230-MMSCFD TEG Dehydration Unit	-	-	-	-	-	6.55
AMINE-1	120-MMSCFD Amine Unit	-	-	-	-	-	7.80
H-2300	1.50-MMBTUH Glycol Reboiler	-	0.77(1)	-	0.65(1)	-	0.10(2)
H-5711	14.22-MMBTUH Regenerator Gas Heater	-	3.66(1)	-	6.16(1)	-	0.41(1)
H-5712	24.10-MMBTUH Cryo HMO Heater	-	6.20(1)	-	10.43(1)	-	0.68(1)
H-4	7.00-MMBTUH Amine Reboiler	-	3.61(1)	-	3.02(1)	-	0.20(1)
TK-2300	300-bbl Condensate Tank	-	-	-	-	-	5.99(3)
TK-2350	300-bbl Condensate Tank	-	-	-	-	-	5.99(3)
TK-2400	300-bbl Condensate Tank	-	-	-	-	-	5.99(3)
TK-6100	300-bbl Produced Water Tank	-	-	-	-	-	5.99(3)
CONDLOAD1	Condensate Loading	-	-	-	-	-	15.86
PWLOAD1	Produced Water Loading	-	-	-	-	-	0.10(2)
FL-5100	0.33-MMBTUH Flare	-	0.12(1)	-	0.54(1)	-	0.32(4)
CBD	Compressor Blowdowns	-	-	-	-	-	10.26
PBD	Pig Trap Blowdowns	-	-	-	-	-	0.72

(1) Limit increased by 20% to allow for variance in operation.
(2) Limit increased to 0.10 to allow for variance in operation.
(3) Tanks conservatively limited to 5.99 tpy per tank to allow for variance in operation and keep the tanks exempt from NSPS OOOOa.
(4) Controlled tank emissions at the flare are included in emission limits of TK-2300, TK-2350, TK-2400, and TK-6100.

2. The fuel-burning equipment shall be fired with pipeline grade natural gas or other gaseous fuel with sulfur content less than 162 ppmv. Compliance can be shown by the

following methods: for pipeline grade natural gas, a current gas company bill; for other gaseous fuel, a current lab analysis, stain-tube analysis, gas contract, tariff sheet, etc. Compliance shall be demonstrated at least once every calendar year.

3. The permittee shall be authorized to operate this facility continuously (24 hours per day, every day of the year, 8,760 hours).

4. The permittee shall comply with NSPS, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, including, but not limited to, the following.

a. § 60.40c Applicability and delegation of authority.
b. § 60.41c Definitions.
c. § 60.42c Standard for sulfur dioxide (SO_2).
d. § 60.43c Standard for particulate matter (PM).
e. § 60.44c Compliance and performance test methods and procedures for sulfur dioxide.
f. § 60.45c Compliance and performance test methods and procedures for particulate matter.
g. § 60.46c Emission monitoring for sulfur dioxide.
h. § 60.47c Emission monitoring for particulate matter.
i. § 60.48c Reporting and recordkeeping requirements.

5. The permittee shall comply with NSPS, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities, for all affected facilities located at this site for which construction, modified, or reconstructed after September 18, 2015, including, but not limited to, the following.

a. § 60.5360a What is the purpose of this subpart?
b. § 60.5365a Am I subject to this subpart?
c. § 60.5370a When must I comply with this subpart?
d. § 60.5375a What GHG and VOC standards apply to well affected facilities?
e. § 60.5380a What GHG and VOC standards apply to centrifugal compressor affected facilities?
f. § 60.5385a What GHG and VOC standards apply to reciprocating compressor affected facilities?
g. § 60.5390a What GHG and VOC standards apply to pneumatic controller affected facilities?
h. § 60.5393a What GHG and VOC standards apply to pneumatic pump affected facilities?
i. § 60.5395a What VOC standards apply to storage vessel affected facilities?
j. § 60.5397a What fugitive emissions GHG and VOC standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station?
k. § 60.5398a What are the alternative means of emission limitations for GHG and VOC from well completions, reciprocating compressors, the collection of fugitive emissions

components at a well site and the collection of fugitive emissions components at a compressor station?

l. § 60.5400a What equipment leak GHG and VOC standards apply to affected facilities at an onshore natural gas processing plant?
m. § 60.5401a What are the exceptions to the equipment leak GHG and VOC standards for affected facilities at onshore natural gas processing plants?
n. § 60.5402a What are the alternative means of emission limitations for GHG and VOC equipment leaks from onshore natural gas processing plants?
o. § 60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?
p. § 60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?
q. § 60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?
r. § 60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?
s. § 60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
t. § 60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?
u. § 60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, and storage vessel affected facilities?
v. § 60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?
w. § 60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, and affected facilities at onshore natural gas processing plants?
x. § 60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump and storage vessel affected facilities?
y. § 60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?
z. § 60.5420a What are my notification, reporting, and recordkeeping requirements?
aa. § 60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

bb. § 60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?
cc. § 60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
dd. § 60.5425a What parts of the General Provisions apply to me?
ee. § 60.5430a What definitions apply to this subpart?
ff. § 60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

6. The permittee shall comply with all applicable requirements of the NESHAP for Oil and Natural Gas Production, Subpart HH, for each affected dehydration unit including but not limited to the following:

a. An owner or operator of a glycol dehydration unit that meets the exemption criteria of §63.764(e)(1) shall maintain the records specified in §63.774(d)(1) for that glycol dehydration unit.

7. Throughput at the facility shall not exceed 5,672,100 gallons of condensate and 919,800 gallons of produced water (12-month rolling total). Emissions from the condensate and produced water tanks shall be routed to the condensate flare (FL-5100). The condensate and produced water tanks shall be bottom filled or operated with submerged fill pipes.

8. The glycol dehydration unit shall be installed and operated as follows:

(a) Maximum throughput of natural gas (monthly average) shall be no greater than 230-MMSCFD.
(b) Glycol circulation rate shall be 40.0 gallons/minute (GPM) or less.
(c) The glycol dehydrator still vent shall be equipped with a condenser.
(d) All emissions from the glycol dehydration unit's still vent shall be routed to the condenser, with the uncondensed vapors from the condenser routed to the reboiler firebox when it is firing, an igniter when the reboiler is not firing, or an approved, equally-effective (overall control efficiency of 98%) VOC/HAP emissions control system.
(e) The glycol dehydrator shall be equipped with a flash tank on the rich glycol stream.
(f) The off-gasses from the flash tank shall be routed to the process (i.e., facility inlet), or an approved, equally effective emission control system (100% control efficiency).
(g) The permittee shall monitor and record the lean glycol circulation rate at least once a month. When three consecutive months show no exceedance of the limit, the frequency may be reduced to quarterly. Upon any showing of non-compliance, the monitoring and recordkeeping frequency shall revert to monthly. With each inspection the lean glycol circulation rate shall be recorded as follows:

Circulation rate, as found (gal/min, strokes/min)	________
Circulation rate, as left (gal/min, strokes/min)	________
Date of inspection	________
Inspected by	________

The requirement to monitor and record glycol circulation rate shall not apply if the pump capacity does not exceed 40.0 GPM. If so, the manufacturer's rating or the performance data for the model of pump that verifies the maximum pump rate at any operational conditions shall be maintained and available for inspection.

9. The amine unit shall be installed and operated as follows:

(a) Maximum throughput of natural gas (monthly average) shall be no greater than 120-MMSCFD.
(b) Amine circulation rate shall be 100.0 gallons/minute (GPM) or less.
(c) The amine still vent shall be equipped with a H_2S scavenger.
(d) All emissions from the amine unit's still vent shall be routed to the H_2S scavenger.
(e) The amine unit shall be equipped with a flash tank on the rich amine stream.
(f) The H2S emissions from the H_2S scavenger system shall not exceed 0.3 lb/hr (two-hour average).
(g) During any calendar month that the amine unit is in operation, the permittee shall sample the exhaust gas from the H_2S scavenger system using a "stain tube" analysis or similar method, while the amine unit is operating, at least once during that calendar month, and shall calculate H2S emissions to demonstrate compliance with the 0.3 lb/hr limit.
(h) The off-gasses from the flash tank shall be routed to the process (i.e., facility inlet), or an approved, equally effective emission control system (100% control efficiency).
(i) At least once per calendar quarter, the permittee shall conduct tests for H2S concentrations in the inlet process gas to demonstrate that the H2S concentration is less than or equal to 4 ppmv to comply with OAC 252:100-31. A quarterly test may be conducted no sooner than 20 calendar days after the most recent test. Testing shall be conducted using a stain-tube (accurate to 0.1 ppmv), lab analysis, or an equivalent method approved by Air Quality. When four consecutive quarterly tests show the inlet concentration to be in compliance with the emissions limitations shown in the permit, then the testing frequency may be reduced to semi-annual testing. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test. Any showing of non-compliance with the limit reverts the frequency back to quarterly.
(j) The permittee shall monitor and record the lean amine circulation rate at least once a month. When three consecutive months show no exceedance of the limit, the frequency may be reduced to quarterly. Upon any showing of non-compliance, the monitoring and recordkeeping frequency shall revert to monthly. With each inspection the lean amine circulation rate shall be recorded as follows:

Circulation rate, as found (gal/min, strokes/min)	________
Circulation rate, as left (gal/min, strokes/min)	________
Date of inspection	________
Inspected by	________

The requirement to monitor and record glycol circulation rate shall not apply if the pump capacity does not exceed 100.0 GPM. If so, the manufacturer's rating or the performance data for the model of pump that verifies the maximum pump rate at any operational conditions shall be maintained and available for inspection.

10. The permittee shall calculate VOC emissions from compressor blowdowns on a monthly and 12-month rolling basis. The records of calculations shall include estimated discharge volumes and VOC content.

11. The permittee shall maintain records of operations as listed below. These records shall be maintained on-site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request.

(a) For the fuel(s) burned, the appropriate document(s) as described in Specific Condition No. 2.
(b) Facility condensate throughput (monthly and 12-month rolling total).
(c) Facility produced water throughput (monthly and 12-month rolling total).
(d) Lean glycol pump circulation rate (monthly / quarterly) if applicable, based on Specific Condition No. 8(g).
(e) Lean amine pump circulation rate (monthly / quarterly) if applicable, based on Specific Condition No. 9(j).
(f) Records of H_2S concentrations as required by Specific Conditions 9(g) and 9(i).
(g) Records of compressor blowdown volumes and resulting VOC emissions (monthly and 12-month rolling total) as required by Specific Condition No. 10.
(h) Natural gas throughput for both the glycol dehydration unit and the amine unit, MMSCFD (monthly average).
(i) Records required under NSPS 40 CFR Part 60, Subparts Dc and OOOOa.
(j) Records required under NESHAP 40 CFR Part 63, Subpart HH.

12. The permittee shall submit an application for an individual minor source operating permit within 180 days of commencement of operation of any emission source whose construction has been authorized by this permit.

PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2022-0107-C

VM Arkoma Stack, LLC,

having complied with the requirements of the law, is hereby granted permission to construct the Stanberry Gas Plant located in Section 17, Township 2N, Range 11E, Coal County, Oklahoma, and subject to the Standard Conditions dated February 13, 2020, and Specific Conditions, both attached.

In the absence of construction commencement, this permit shall expire 18 months from the date of issuance below, except as Authorized under Section B of the Standard Conditions.

DRAFT

Lee Warden, P.E.
Permits and Engineering Group Manager

Issuance Date

Scott A. Thompson
Executive Director

OKLAHOMA Environmental Quality

Kevin Stitt
Governor

VM Arkoma Stack, LLC
Attn.: Brandi Lowry
2575 Kelley Pointe Parkway
Edmond, OK 73013

Re: Construction Permit No. **2022-0107-C**
Stanberry Gas Plant
Facility ID No.: 19683
Section 17, Township 2N, Range 11E, Coal County, Oklahoma

Dear Ms. Lowry:

Enclosed is the permit authorizing construction of the referenced facility above. Please note that this permit is issued subject to standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed through DEQ's electronic reporting system by April 1st of every year. Any questions concerning the submittal process should be referred to the Emissions Inventory Staff at (405) 702-4100.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact the permit writer at alex.johnson@deq.ok.gov, or at (405) 702-4201.

Sincerely,

Lee Warden, P.E.
Permits and Engineering Group Manager
AIR QUALITY DIVISION

Enclosures

October 12, 2022

Cherokee Nation
Attn: Chuck Hoskin, Jr., Principal Chief
P.O. Box 948
Tahlequah, OK 74465

Re: Permit Application No. 2022-0107-C
VM Arkoma Stack, LLC, Stanberry Gas Plant (FAC ID 19683)
Coal County
Date Received: March 10, 2022

Dear Mr. Hoskin:

The Oklahoma Department of Environmental Quality (ODEQ), Air Quality Division (AQD), has received the Tier I application referenced above. A Tier I application requires AQD to provide a 30-day public comment period on the draft Tier I permit on the ODEQ website. Since the proposed project falls within your Tribal jurisdiction, AQD is providing this direct notice. This letter notification is in addition to email notifications provided to tribal contacts on record.

Copies of draft permits and comment opportunities are provided to the public on the ODEQ website at the following location:

https://www.deq.ok.gov/permits-for-public-review/

If you prefer a copy of the draft permit, or direct notification by letter for any remaining public comment opportunities, if applicable, on the referenced permit action, please notify our Chief Engineer, Phillip Fielder, by e-mail at phillip.fielder@deq.ok.gov, or by letter at:

Department of Environmental Quality, Air Quality Division
Attn: Phillip Fielder, Chief Engineer
P.O. Box 1677
Oklahoma City, OK, 73101-1677

Thank you for your cooperation. If you have any questions, I can be contacted at (405) 702-4237, and Mr. Fielder may be reached at (405) 702-4185.

Sincerely,

Lee Warden

Lee Warden, P.E.
Permits and Engineering Group Manager
AIR QUALITY DIVISION

Scott A. Thompson
Executive Director

OKLAHOMA Environmental Quality

Kevin Stitt
Governor

October 12, 2022

Chickasaw Nation
Attn: Bill Anoatubby, Governor
P.O. Box 1548
Ada, OK 74821

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Lee Warden, P.E.
Permits and Engineering Group Manager
AIR QUALITY DIVISION

MINOR SOURCE PERMIT TO OPERATE / CONSTRUCT
AIR POLLUTION CONTROL FACILITY
STANDARD CONDITIONS
(February 13, 2020)

A. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ) in accordance with and under the authority of the Oklahoma Clean Air Act. The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. This specifically includes compliance with the rules of the other Divisions of DEQ: Land Protection Division and Water Quality Division.

B. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-7-15(g)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-7-15(f)]

C. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-7-18(a)]

D. Unless specified otherwise, the term of an operating permit shall be unlimited.

E. Notification to the Air Quality Division of DEQ of the sale or transfer of ownership of this facility is required and shall be made in writing by the transferor within 30 days after such date. A new permit is not required. [OAC 252:100-7-2(f)]

F. The following limitations apply to the facility unless covered in the Specific Conditions:

1. No person shall cause or permit the discharge of emissions such that National Ambient Air Quality Standards (NAAQS) are exceeded on land outside the permitted facility. [OAC 252:100-3]
2. All facilities that emit air contaminants are required to file an emission inventory and pay annual operating fees based on the inventory. Instructions are available on the Air Quality section of the DEQ web page. *www.deq.ok.gov* [OAC 252:100-5]
3. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements. [OAC 252:100-9]
4. Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning subchapter. [OAC 252:100-13]
5. No particulate emissions from new fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lbs/MMBTU. [OAC 252:100-19]
6. No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. [OAC 252:100-25]
7. No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent

properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

8. No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lbs/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]
9. Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with an organic material vapor-recovery system. [OAC 252:100-37-15(b)]
10. All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

G. Any owner or operator subject to provisions of NSPS shall provide written notification as follows: [40 CFR 60.7 (a)]

1. A notification of the date construction (or reconstruction as defined under §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.
2. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in §60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
3. A notification of the actual date of initial start-up of an affected facility postmarked within 15 days after such date.
4. If a continuous emission monitoring system is included in the construction, a notification of the date upon which the test demonstrating the system performance will commence, along with a pretest plan, postmarked no less than 30 days prior to such a date.

H. Any owner or operator subject to provisions of NSPS shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility or any malfunction of the air pollution control equipment. [40 CFR 60.7 (b)]

I. Any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and other information required by this subpart recorded in a permanent file suitable for inspection. This file shall be retained for at least five years following the date of such measurements, maintenance, and records. [40 CFR 60.7 (f)]

J. Any owner or operator subject to the provisions of NSPS shall conduct performance test(s) and furnish to AQD a written report of the results of such test(s). Test(s) shall be conducted within 60 days after achieving the maximum production rate at which the facility will be operated, but not later than 180 days after initial start-up. [40 CFR 60.8]

Department of Environmental Quality (DEQ)
Air Quality Division (AQD)
Acronym List
9-10-21

ACFM Actual Cubic Feet per Minute
AD Applicability Determination
AFRC Air-to-Fuel Ratio Controller
API American Petroleum Institute
ASTM American Society for Testing and Materials

BACT Best Available Control Technology
BAE Baseline Actual Emissions
BBL Barrel(s)
BHP Brake Horsepower (bhp)
BTU British thermal unit (Btu)

C&E Compliance and Enforcement
CAA Clean Air Act
CAM Compliance Assurance Monitoring
CAS Chemical Abstract Service
CAAA Clean Air Act Amendments
CC Catalytic Converter
CCR Continuous Catalyst Regeneration
CD Consent Decree
CEM Continuous Emission Monitor
CFC Chlorofluorocarbon
CFR Code of Federal Regulations
CI Compression Ignition
CNG Compressed Natural Gas
CO Carbon Monoxide or Consent Order
COA Capable of Accommodating
COM Continuous Opacity Monitor

D Day
DEF Diesel Exhaust Fluid
DG Demand Growth
DSCF Dry Standard (At Standard Conditions) Cubic Foot (Feet)

EGU Electric Generating Unit
EI Emissions Inventory
EPA Environmental Protection Agency
ESP Electrostatic Precipitator
EUG Emissions Unit Group
EUSGU Electric Utility Steam Generating Unit

FCE Full Compliance Evaluation
FCCU Fluid Catalytic Cracking Unit
FEL Federally Enforceable Limit(s)
FESOP Federally Enforceable State Operating Permit
FIP Federal Implementation Plan
FR Federal Register

GACT Generally Achievable Control Technology
GAL Gallon (gal)
GDF Gasoline Dispensing Facility
GEP Good Engineering Practice
GHG Greenhouse Gases
GR Grain(s) (gr)

H_2CO Formaldehyde
H_2S Hydrogen Sulfide
HAP Hazardous Air Pollutants
HC Hydrocarbon
HCFC Hydrochlorofluorocarbon
HFR Horizontal Fixed Roof
HON Hazardous Organic NESHAP
HP Horsepower (hp)
HR Hour (hr)

I&M Inspection and Maintenance
IBR Incorporation by Reference
ICE Internal Combustion Engine

LAER Lowest Achievable Emission Rate
LB Pound(s) [Mass] (lb, lbs, lbm)
LB/HR Pound(s) per Hour (lb/hr)
LDAR Leak Detection and Repair
LNG Liquefied Natural Gas
LT Long Ton(s) (metric)

M Thousand (Roman Numeral)
MAAC Maximum Acceptable Ambient Concentration
MACT Maximum Achievable Control Technology
MM Prefix used for Million (Thousand-Thousand)
MMBTU Million British Thermal Units (MMBtu)
MMBTUH Million British Thermal Units per Hour (MMBtu/hr)
MMSCF Million Standard Cubic Feet (MMscf)
MMSCFD Million Standard Cubic Feet per Day
MSDS Material Safety Data Sheet
MWC Municipal Waste Combustor
MWe Megawatt Electrical

NA Nonattainment
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NESHAP National Emission Standards for Hazardous Air Pollutants
NH_3 Ammonia
NMHC Non-methane Hydrocarbon
NGL Natural Gas Liquids
NO_2 Nitrogen Dioxide
NOx Nitrogen Oxides
NOI Notice of Intent

NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
NSR	New Source Review
O_3	Ozone
O&G	Oil and Gas
O&M	Operation and Maintenance
O&NG	Oil and Natural Gas
OAC	Oklahoma Administrative Code
OC	Oxidation Catalyst
PAH	Polycyclic Aromatic Hydrocarbons
PAE	Projected Actual Emissions
PAL	Plant-wide Applicability Limit
Pb	Lead
PBR	Permit by Rule
PCB	Polychlorinated Biphenyls
PCE	Partial Compliance Evaluation
PEA	Portable Emissions Analyzer
PFAS	Per- and Polyfluoroalkyl Substance
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter with an Aerodynamic Diameter <= 2.5 Micrometers
PM_{10}	Particulate Matter with an Aerodynamic Diameter <= 10 Micrometers
POM	Particulate Organic Matter or Polycyclic Organic Matter
ppb	Parts per Billion
ppm	Parts per Million
ppmv	Parts per Million Volume
ppmvd	Parts per Million Dry Volume
PSD	Prevention of Significant Deterioration
psi	Pounds per Square Inch
psia	Pounds per Square Inch Absolute
psig	Pounds per Square Inch Gage
RACT	Reasonably Available Control Technology
RATA	Relative Accuracy Test Audit
RAP	Regulated Air Pollutant or Reclaimed Asphalt Pavement
RFG	Refinery Fuel Gas
RICE	Reciprocating Internal Combustion Engine
RO	Responsible Official
ROAT	Regional Office at Tulsa
RVP	Reid Vapor Pressure
SCC	Source Classification Code
SCF	Standard Cubic Foot
SCFD	Standard Cubic Feet per Day
SCFM	Standard Cubic Feet per Minute
SCR	Selective Catalytic Reduction
SER	Significant Emission Rate
SI	Spark Ignition
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SOx	Sulfur Oxides
SOP	Standard Operating Procedure
SRU	Sulfur Recovery Unit
T	Tons
TAC	Toxic Air Contaminant
TEG	Triethylene Glycol
THC	Total Hydrocarbons
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulates
TV	Title V of the Federal Clean Air Act
$\mu g/m^3$	Micrograms per Cubic Meter
US EPA	U. S. Environmental Protection Agency
VFR	Vertical Fixed Roof
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compound
VOL	Volatile Organic Liquid
VRT	Vapor Recovery Tower
VRU	Vapor Recovery Unit
YR	Year
2SLB	2-Stroke Lean Burn
4SLB	4-Stroke Lean Burn
4SRB	4-Stroke Rich Burn