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OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **December 7, 2021**

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SUBJECT:	Minor Source General Permit for Oil and Gas Facilities (GP-OGF) Background Document

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SECTION I. INTRODUCTION

This General Permit has been developed to authorize construction and/or operation of facilities with potential emissions less than 100 tons/year (TPY) of a regulated pollutant in an attainment area, less than 10 TPY of any single hazardous air pollutant (HAP), and less than 25 TPY of total HAPs. Facilities can meet the emissions limits by either operating as a minor facility, by limiting the emissions through controls, and/or documenting actual emissions are below the permit limits. In all cases, the permit provides for enforceable limits by requiring appropriate monitoring, recordkeeping, and emission calculations.

In addition, this permit will distinguish synthetic minor facilities with actual emissions below 80 TPY and those facilities with actual emissions equal to or above 80 TPY but below 100 TPY. The applicant can request limits of less than 80 TPY for NO_X, CO, PM_{10}, $PM_{2.5}$, VOC and SO_2.

The permit is limited to air pollutant emitting sources located at Oil and Gas Facilities (OGF) that are designed and operated for the production, gathering, processing, storage, and/or transportation of crude oil, refined petroleum products, natural gas, and natural gas liquids (NGL), including condensate. These facilities are typically categorized under the following SIC and NAICS codes:

SIC Code	NAICS Code	Industry
1311	211120	Crude Petroleum Extraction
1321	211130	Natural Gas Liquids
4612	486110	Pipeline Transportation of Crude Oil
4613	486910	Pipeline Transportation of Refined Petroleum Products
4922	486210	Pipeline Transportation of Natural Gas
5171	424710	Petroleum Bulk Stations and Terminals
5172	424720	Petroleum and Petroleum Products Wholesalers (except Bulk Stations and Terminals)

Facilities with the same or substantially similar operations and activities, which emit the same types of regulated air pollutants, and which are subject to the same or similar standards, limitations, operating requirements, and monitoring requirements can be covered under this general permit. Permits issued to these facilities must address all air emissions from all sources at these facilities. Thus, this general permit is designed to include those sources typically expected to be present at OGF, including storage tanks, VOC Loading Operations, combustion equipment (engines, heaters, boilers, and flares), glycol dehydration units, amine units, fugitive emission sources, and equipment and activities in De minimis facilities, as defined in OAC 252:100 Appendix H. Facilities with other sources of air emissions are not eligible for coverage under this permit, unless a minor source construction permit is obtained and the requirements of that permit are incorporated into an Authorization to Operate. For instance, some OGF may have amine units that require applicability review, compliance demonstrations, and/or specific conditions for compliance with OAC 252:100-31 and New Source Performance Standards (NSPS) Subpart LLL.

Table I-1 shows the approximate number of facilities located in Oklahoma that are potentially eligible for coverage under this permit.

TABLE I-1. OKLAHOMA MINOR OIL and GAS FACILITIES

SIC Code	Industry	Facilities Reporting To AQD Inventory (2003)	Facilities Reporting To AQD Inventory (2011)	Facilities Reporting To AQD Inventory (2018)
1311	Crude Petroleum and Natural Gas Extraction	232	1,663	8,696
1321	Natural Gas Liquids	21	86	50
4612	Pipeline Transportation of Crude Oil	73	92	118
4613	Pipeline Transportation of Refined Petroleum Products	5	16	10
4922	Pipeline Transportation of Natural Gas	269	333	259
5171	Petroleum Bulk Stations and Terminals	11	14	16
5172	Petroleum and Petroleum Products Wholesalers (except Bulk Stations and Terminals)	8	12	6
	Total	**619**	**2,216**	**9,155**

SECTION II. ELIGIBILITY

In order to provide the broadest coverage to applicants under this permit and to assure compliance with all applicable requirements, eligibility must be restricted to those minor facilities whose emission units are addressed in this permit. The permit has been developed for facilities designed and operated for the production, gathering, processing, storage, or transportation of crude oil, refined petroleum products, natural gas, and natural gas liquids (NGL), including condensate. Emission units identified as typically present at such a facility, and addressed in the permit, include storage tanks, VOC Loading Operations, engines and other combustion equipment, glycol dehydration units, amine units, and fugitive equipment components. In addition, those emission units identified as a De Minimis Facility, as defined in OAC 252:100 Appendix H, are also recognized as typically present at such a facility and are addressed in the permit. Any other emissions unit not addressed in this permit makes that facility ineligible for coverage under this permit.

A. INELIGIBLE FACILITIES

The following facilities are not eligible for coverage under this permit.

1. Facilities for which material facts were misrepresented or omitted from the application and the applicant knew or should have known of such misrepresentation or omission.

2. Facilities with emissions units that are subject to:

   a. OAC 252:100-8 (Permits for Part 70 Sources)
   b. OAC 252:100-17 (Incinerators)

B. FACILITIES INELIGIBLE FOR AN AUTHORIZATION TO CONSTRUCT

The following facilities are not eligible to obtain an Authorization to Construct under this permit, but may be eligible for coverage under an Authorization to Operate if they obtain a minor source construction permit and all relevant requirements and limitations in that permit are incorporated into the Authorization to Operate.

1. Facilities with combustion equipment fired with fuels other than liquid petroleum gas (LPG) or natural gas with a maximum total sulfur content greater than 162 ppmv; or stationary reciprocating engines burning liquid fuels other than gasoline, diesel fuel, or No. 2 fuel oil with a total sulfur content greater than 0.05% by weight.

2. Facilities storing/distributing crude oil that cannot demonstrate a maximum H_2S concentration of 6 ppmw for all categories of crude oil stored at the facility. Such demonstration must be documented using the methods outlined in Appendix A of this permit.

3. Facilities that use incinerators, regenerative or non-regenerative carbon absorbers, or catalytic systems to control emissions of H_2S.

4. Facilities with a VOC loading facility subject to OAC 252:100-37-16(a) or OAC 252:100-39-41.

5. Facilities with glycol dehydration units that process natural gas with an H_2S content greater than 4 ppmv.

6. Facilities with amine units under the following conditions: (1) that process natural gas with an H_2S content greater than 4 ppmv; or (2) that do not control emissions from the rich amine flash tank and amine regeneration vent. To be considered controlled, the rich amine flash tank can either be routed to the inlet, fuel gas system, or a flare. The amine regeneration still vent must be routed to a flare meeting the requirements of OAC 252:100-31-26. Facilities with amine units that process natural gas with an H_2S content greater than 4 ppmv, or that do not control emissions from the rich amine flash tank and amine regeneration vent, would require a site-specific determination of compliance with the H_2S ambient concentration limit of OAC 252:100-31-7.

7. Facilities with amine units that process more than 0.1276 long ton per day (LTPD) of sulfur. Facilities with amine units without sulfur recovery that process more than 0.1276 LTPD of sulfur would be a major source for SO_2.

8. Facilities with "new fuel-burning equipment," as that term is defined in OAC 252:100-33, with a rated heat input of 50 MMBtu/hr or greater (excluding reciprocating engines).

9. Facilities with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) control systems on any engine or other combustion source. These are control systems that require injection of ammonia, and do not include 3-way catalyst (NSCR) or oxidation catalyst.

10. Facilities that require a specific limitation(s) not otherwise addressed in order to maintain compliance with the cap.

11. Facilities located in an area that is federally designated as non-attainment.

12. Facilities that request an Alternative Emissions Reduction Authorization under OAC 252:100-11.

13. Facilities requesting control efficiencies above the levels allowed in Section VI- Control Efficiencies and Monitoring Requirements.

14. Facilities requesting unit specific limits not allowed or required under the general permit.

Conditions established in an individual minor source construction permit and incorporated into an Authorization to Operate may supersede conditions established in the GP-OGF, as long as the requirements that are incorporated are in compliance with all currently applicable rules and regulations.

The DEQ may not issue a permit authorization sought by an applicant that has not paid all money owed to the DEQ or is not in substantial compliance with the Environmental Quality Code, rules of the Board, and/or the terms of any existing DEQ permits and orders. The DEQ may impose specific conditions on the applicant to assure compliance and/or a separate schedule that the DEQ considers necessary to achieve required compliance.

The DEQ may refuse issuance of an Authorization to an applicant even though the facility meets the above eligibility criteria. In such a case, DEQ will provide to the facility a written explanation providing the reason(s) for the decision.

SECTION III. DESCRIPTION

A. EQUIPMENT

OGF typically have the following emission sources in common: storage tanks, VOC Loading Operations, combustion equipment (engines, heaters, boilers, and flares), glycol dehydration units, amine units, fugitive emission sources (pump seals, compressor seals, valves, flanges, connectors, pneumatic devices, and other components), and De Minimis Facilities as defined in OAC 252:100, Appendix H.

Storage Vessels and Effluent Water Separators

Crude oil production sites use tanks to store the produced crude oil prior to truck loading or pumping to pipelines. Crude oil trucking stations use tanks to store crude oil delivered from tank trucks, prior to the crude oil being pumped into pipelines. Breakout tanks are used at pipeline pump stations for surge capacity, sorting, measuring, rerouting, and temporary storage. Compressor stations and natural gas plants use tanks to store slop oil, oily water, and/or condensate prior to truck loading or unloading. Bulk stations and wholesale facilities store refined petroleum products prior to truck loading for delivery to retail stations or customers. Storage tanks emit VOC due to working and breathing losses and flash emissions from volatile liquids.

Effluent water separator is any vessel in which any VOC floating on, entrained in, or contained in water entering the vessel is physically separated and removed from the water prior to discharge of the water from the vessel. These units are not designed for long terms storage but are designed for the VOC/wastewater mixture to flow through the unit.

VOC Loading Operations

VOC is emitted from tank trucks being loaded (typically) or unloaded at a facility. The transferred liquids displace vapors present in the truck tank if loading or the storage vessel if unloading. These emissions may consist of vapors remaining from a previous cargo, or may be flashed from the liquid being loaded, or a combination of both. A controlled system may include “vapor balancing” whereby the displaced vapors are returned to the unloading truck tank, or the vapors from loading a truck tank may be routed back to the storage tank and then either recycled by compression back to the process or vented to a combustion device.

Combustion Equipment

The vast majority of OGF have one or more engine driven compressors, although large pumps at petroleum liquid storage facilities are typically driven by electric motors. Small heaters, such as crude oil heater treaters, small boilers, and glycol or molecular sieve regenerator heaters exist at many facilities. Flares, incinerators, and thermal oxidizers may also be present at some facilities. All combustion sources emit regulated air pollutants NO_X, CO, VOC, SO_2, and PM_{10}.

Glycol Dehydration Units

Both ethylene glycol (EG) and, more typically, triethylene glycol (TEG) dehydration units are used at many minor OGF. These units emit VOC and HAP (benzene, toluene, ethylbenzene, xylene, and n-hexane) from rich glycol flash tank vents and glycol regenerator still vents.

Amine Units

Amine units are used to remove hydrogen sulfide (H_2S) and CO_2 (acid gases) from natural gas or natural gas liquids. These units emit H_2S, CO_2, VOC, and HAPs from rich amine flash tank vents and amine regeneration still vents.

Fugitive Emission Sources

Equipment components such as pump seals, compressor seals, valves, flanges, connectors, open-ended lines, pneumatic control devices, and other components are the source of fugitive VOC emissions.

De Minimis Facilities

OGF often contain equipment and activities that are listed as De Minimis Facilities under OAC 252:100, Appendix H. Certain equipment or activities on the De Minimis Facilities list warrant inclusion in the emissions calculations for compliance with the emissions cap if located at a permitted facility. AQD evaluated the De Minimis Facilities list and determined the equipment or activities that need to be included for the facility-wide emissions cap are in the following list:

Storage Tanks

- Fuel/VOC storage tanks with less than 400 gallons capacity, or fuel/VOC storage tanks with less than 10,567 gallons capacity built after July 23, 1984, or tanks storing fuel/VOC that has a true vapor pressure at storage conditions less than 1.5 psia. This includes Fuel Oils Nos. 2 - 6, Nos. 2-GO - 4-GO, Diesel Fuel Oils Nos. 2-D - 4-D, and Kerosene.*
- Tanks containing separated water produced from oil and gas operations.
- Emergency use equipment, unless utilized in excess of 500 hours per year, and associated fuel storage tankage.*

Blowdowns

- Blowdown of compressors or other vessels containing natural gas or liquid hydrocarbons for maintenance due to emergency circumstances

Combustion Equipment

- Space heaters and boilers less than 10 MMBTU/hr heat input.**
- Emissions from non-natural gas fueled stationary internal combustion engines rated less than 50 hp output.**
- Emissions from gas turbines with less than 215 kilowatt rating of electric output.**
- Natural gas fueled internal combustion engines rated <150 hp and <20 years old.**
- Emergency use equipment, unless utilized in excess of 500 hours per year, and associated fuel storage tankage.*

Fugitive Emission Sources

- Pneumatic starters on reciprocating engines, turbines, compressors, or other equipment.*
- Instrument systems utilizing air or natural gas.*

MSS
- Pipeline maintenance pigging activities.
- General maintenance, upkeep, and replacement activities, including those which do not alter the capacity of process, combustion or control equipment nor increase regulated pollutant emissions, unless subject to NESHAP or NSPS.*
- Crude oil tank bottom reclaiming.*

Miscellaneous
- Vent emissions from gas streams used as buffer or seal gas in rotating pump and compressor seals.*
- Engine crankcase vents and equipment lubricating sumps.*

* In lieu of specific monitoring, recordkeeping, and calculations, the De Minimis Facilities activities designated with an asterisk (*) can use a simplified method of representing emissions by assuming emissions are 5 TPY for all emission units contained within the defined activity. For those activities designated with **, each emission unit within the defined activity can use a simplified method of representing emissions by assuming emissions are 5 TPY for each emission unit. For those activities requiring specific calculations or where a facility elects to not use the simplified method, the calculation methods specified in the individual sections shall be used.

B. LIQUIDS STORED

Petroleum liquids stored at these facilities generally include crude oil, slop oil, condensate, and any finished or intermediate liquid products manufactured or extracted in a petroleum refinery such as gasoline, diesel, fuel oil, jet fuel, and kerosene. Small amounts of petroleum liquids can be entrained in produced water. These facilities can also store ethylene glycols (EG, DEG, and TEG) and methanol for use in dehydrators, for engine cooling solutions, and for injection into refrigerant processes to control hydrate formation. Other stored liquids can include produced water, antifreeze, corrosion inhibitors, amines, and lube oils.

Crude Oil/Condensate/Produced Water

Emissions from the storage and loading of crude oil, condensate, and produced water include VOC, H_2S, and HAPs. VOC emissions from crude oil, condensate, and produced water include HAPs such as benzene, toluene, ethylbenzene, xylene (BTEX), and n-hexane. Condensate, as defined in OAC 252:100-37-2, means hydrocarbon liquid separated from natural gas which condenses due to changes in temperature and/or pressure and remains liquid at normal operating conditions. According to the Oklahoma Corporation Commission (OCC) condensate has an API gravity equal to or greater than 50 degrees.

Refined Petroleum Products

Refined petroleum products include, but are not limited to, the following: gasoline, diesel fuels, fuel oil, jet fuels, kerosene, and naphtha. These refined products can contain the same HAP as listed for crude oil.

Ethylene Glycols

Ethylene glycols (EG, DEG, and TEG) are HAPs; however, due to the low vapor pressure of these compounds and their water solutions, no emission calculations or specific requirements are necessary at minor OGF.

Methanol

Methanol is a HAP; however, due to its relatively low vapor pressure and typically small storage volumes, no emission calculations or specific requirements are necessary at minor OGF other than the requirement of a submerged fill pipe per OAC 252:100-37 Part 3, unless stored at a drilling or production facility for use on site (OAC 252:100-37-4(b)).

Amine

Amines (MEA, DEA, TEA, DGA, and MDEA) are VOC; however, due to the low vapor pressure of these compounds and their water solutions, no emission calculations or specific requirements are necessary at minor OGF.

SECTION IV. PERMIT STRUCTURE

This general permit is designed for minor facilities (i.e., with actual emissions less than 100 TPY of a non-HAP regulated pollutant in an attainment area, less than 10 TPY of any single HAP, and less than 25 TPY of total HAPs). The general permit can authorize both construction and operation, and can be used both for new sources and for modifications at existing sources. Major sources must obtain coverage under a major source construction permit and Part 70 permit.

The general permit is structured so that eligible facilities can obtain an Authorization to Construct and Authorization to Operate under the general permit, or can obtain an individual minor source construction permit and then an Authorization to Operate under the general permit, or can obtain an Authorization to Construct under the general permit and then an individual minor source operating permit and pay all applicable fees. This should allow applicants the greatest flexibility for obtaining coverage under the general permit. No site-specific determinations can be made in issuance of an Authorization to Construct under a general permit. However, once these site-specific determinations have been completed and drafted into an individual minor source construction permit as emissions limitations and/or specific conditions, they can then be incorporated into the Authorization to Operate under a general permit.

In addition, certain other options usually available by regulation had to be disallowed so that no site-specific determinations were made in issuance of an Authorization to Construct under the general permit. For example, facilities with amine units that have uncontrolled amine regeneration still vents and sour crude oil storage sites cannot obtain an Authorization to Construct because these types of facilities require a site-specific determination of compliance with the ambient H_2S standard of OAC 252:100-31-7. Also, facilities with “new fuel-burning equipment” subject to OAC 252:100-33 cannot obtain an Authorization to Construct. Alternate emissions reduction authorizations are not allowed under an Authorization to Construct under this permit, as these site-specific limitations require Air Quality Council approval. Similarly, several regulations allow exceptions from specific requirements "if approved by the Executive Director." These approvals also require a site-specific determination that cannot be reasonably made in issuance of an Authorization to Construct under this permit.

All conditions in the general permit have been derived directly from applicable requirements given in OAC 252:100, Air Pollution Control, as promulgated to implement the Oklahoma Clean Air Act. The general permit is formatted so that the first section establishes emissions limitations. Then specific conditions are given for each emissions unit allowed under the general permit. Each section may contain a list of emissions limitations, operational conditions, and monitoring and recordkeeping conditions developed to assure compliance with applicable requirements. Conditions to assure compliance with those state regulations that implement federal requirements; e.g., NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP), are also incorporated as a specific condition for the general permit. These emission unit-specific conditions, as required by Oklahoma regulations, are generally established in the Authorization to Construct under this general permit, or by a minor source individual construction permit, and then incorporated into a subsequently issued Authorization to Operate for the facility. Additionally, a section of standard conditions contain those requirements applicable to all minor facilities.

Specific numeric emissions limitations are usually required for sources that have the potential to exceed a threshold value or violate an applicable requirement. However, this general permit establishes those limitations as a facility-wide cap on emissions from the facility, rather than establishing limitations on individual emission units, except where emissions limits are required for compliance methods to avoid an otherwise applicable limit. The permit initially establishes a facility-wide emissions cap, which may include pre-approved changes foreseeable at the time of permit application. Certain modifications, e.g., adding, modifying, replacing equipment, changing fuels, or increasing operating hours of equipment, or adding or removing a unit specific TPY limit, are pre-approved so long as the facility remains in compliance with its facility-wide emissions cap and all other applicable notifications and recordkeeping.

This approach should greatly reduce the burden on both the permittee and AQD by eliminating the need for construction permits, permit modifications, or new Authorizations when making certain changes to the facility. Notification to DEQ within 15 days following the start of operation is required for certain specified changes that do not result in an exceedance of the facility-wide emissions cap.

Upon issuance of this permit, the terms and conditions of this updated GP-OGF supersede all previous versions of the GP-OGF and all facilities will automatically be authorized as Class II facilities. All facilities constructing or operating under the previous GP-OGF are subject to and must comply with this updated GP-OGF within 24-months of its issuance date. During the 24-month transition period: (1) any facility constructing or operating under the previous GP-OGF and existing Authorization must comply with the standards set forth therein; (2) the NOM for the existing GP-OGF may be used for those facilities wanting to maintain coverage under the existing GP-OGF; and (3) usage of the NOM of this GP-OGF automatically subjects the facility to this GP-OGF upon submittal. For facilities that have conditions in their current authorization that conflict with the requirements with this GP-OGF, these facilities must obtain an individual minor source construction permit and then incorporate these conditions into a subsequently issued Authorization to Operate.

SECTION V. EMISSION LIMITATIONS AND CALCULATION METHODS FOR COMPLIANCE WITH THE CAP

Equipment authorized by the general permit may require emission controls for the facility to be a "synthetic minor" facility. The general permit addresses common control types and methods and specifies approved efficiencies based on certain monitoring and recordkeeping requirements in Appendix A of the General Permit.

Various processes addressed below rely on representative gas and liquid analyses to determine emissions. DEQ has guidance that addresses criteria for accepting representative versus site-specific analyses: "Representative Sampling Guidance" found in the AQD guidance section of the DEQ website.

A. FACILITY-WIDE EMISSIONS CAP

Emissions limitations specified in the general permit are established from applicable federal and state requirements, or from a limitation that the source assumes to avoid an applicable requirement, or from limitations established in previously issued state or federal permits for the facility. Provided, however, that source assumed limitations and/or limitations from previously issued permits must be equivalent to or more stringent than the federal and state applicable requirements.

Because of the similarity of emissions and emissions units at minor OGF, specific numeric emissions limitations need not be developed for each emissions unit; except where emissions limits on engines are required for compliance methods as discussed below; except where tank TPY limits are required; or except where units have specific TPY limits.

The permit requires the calculation of actual facility-wide emissions, as a monthly, 12-month rolling total, to determine compliance with each facility-wide emissions cap. The facility-wide annual emissions must include emissions from each source located at the facility, including emissions related to maintenance, startup, and shutdowns. A direct comparison of the calculated emissions can then be compared to the permitted level to determine compliance with the specific condition in the general permit. In those cases where a numerical limitation is not specifically developed to demonstrate compliance, other methods (e.g., work practices, parametric monitoring, operational limits, modeling analyses, etc.) are required by the general permit to assure compliance.

General EPA policy and preference is to not have emission compliance periods longer than one month, i.e., a 12-month rolling total is preferred for compliance with annual emissions limitations. Also, to demonstrate compliance with the facility-wide emissions caps, the permit requires the use of conservatively high, short-term emission rates for some emission units, which can be significantly higher than actual emissions.

Note that facilities covered by a general permit are not required to obtain an Authorization to Construct when adding a piece of equipment subject to NSPS or NESHAP. An Authorization to Construct, and a new Authorization to Operate, is not needed for most other changes at the facility, so long as facility emissions after the change do not exceed the facility-wide cap. For certain modifications at the facility, the permittee must send in an NOM to AQD documenting that such changes do not cause emissions to exceed the facility-wide cap.

B. STORAGE TANKS AND EFFLUENT WATER SEPARATORS

The general permit allows a facility to request a VOC limit of 5.99 TPY for any storage tank. In addition to the facility-wide cap, the following methods are used to demonstrate compliance with the individual storage tank emission limit. VOC emissions emitted at the storage tanks and the flare or enclosed combustion device are included in this limit. Averaging of facility-wide throughput across tanks at a storage vessel battery, constructed, modified, or reconstructed after November 16, 2020, which consists of two or more storage vessels, is allowed if it meets all of the design and operational criteria specified in §60.5365a(e)(3).

The permittee will be required to maintain records of all storage tanks at the facility with a capacity of 400 gallons or more that store VOCs. The permittee will be required to calculate emissions of VOC and HAP from these storage tanks based on actual throughputs, a maximum capture efficiency of 98% when using a control device, the maximum allowed control efficiency in Appendix A of the GP-OGF, and the following methods.

The EPA document *Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations* (9/1999) provides guidelines for emission estimation techniques for stationary point sources. The preferred method of estimating working and breathing losses from storage tanks is the use of equations presented in AP-42, Chapter 7. AQD has guidance which addresses acceptable methods for estimating VOC flash emissions from storage tanks: “VOC Emissions/Flashing Losses from Hydrocarbon Storage Tanks” found in the AQD guidance section of the DEQ website. Storage tanks using vapor balancing during unloading shall include captured loading loss emissions in tank emissions or use the designated turnover factor K_N in working loss emissions calculations.

HAP emissions from tanks storing petroleum liquids, other than crude oil, condensate, and produced water can be estimated using the default HAP content in AP-42 Section 7.1 or other methods that speciate the amount of HAP contained in the VOC emissions. VOC emissions from the storage of crude oil, condensate, and produced water can contain significant amounts of HAPs, especially n-hexane and should be calculated based on representative sampling.

Some facilities store liquids containing varying levels of H_2S. Available information indicates that H_2S levels in crude oils are dependent upon the field and formation from which a particular crude oil is produced. Typical sweet crude oils contain zero to 6-ppm H_2S by weight. H_2S has a very high vapor pressure and stable (flashed and weathered from storage) sour crude oils handled by pipeline facilities will typically have much lower maximum H_2S concentrations than production facilities. Appendix A of this memorandum presents more detailed information on H_2S emissions from crude oil.

Emissions from effluent water separators can be calculated using similar methods to storage tanks.

C. VOC LOADING OPERATIONS

The permittee will be required to calculate emissions of VOC and HAP from all loading operations, based on actual throughputs. Emissions of H_2S from VOC loading operations are expected to be negligible as demonstrated in Appendix A.

VOC emissions from the loading of tank trucks are generally estimated using AP-42, Chapter 5.2.2.1.1, Equation 1 and Table 5.2-1 or other equivalent methods approved by Air Quality. AQD has guidance which addresses acceptable methods for estimating condensate and crude oil loading losses: "Estimating Condensate and Crude Oil Loading Losses from Tank Trucks" found in the AQD guidance section of the DEQ website.

D. COMBUSTION EQUIPMENT

Equipment such as engines, heaters, boilers, and flares, emit NO_X, CO, SO_2, VOC, and PM_{10} from the combustion and incomplete combustion of natural gas and liquid fuels. Based on the eligibility restrictions of the general permit, SO_2 and PM_{10} potential emissions will be below major source thresholds. Therefore, no demonstration of compliance with the cap is required for these pollutants.

Engines

The permittee will be required to calculate emissions of NO_X, CO, VOC, and HAPs from engines. Short-term (lb/hr) emission limits for NO_X, CO, and VOC are required to be established in the application for the general permit or NOM unless the engine is an Emergency Use Engine or an engine rated less than or equal to 250-hp.

NO_X, CO, and VOC short-term emission limits shall be estimated from emissions factors based on stack test data obtained from appropriate EPA test methods, manufacturer's data, NSPS Subparts IIII or JJJJ, NESHAP Subpart ZZZZ, or AP-42, Chapters 1 and 3. Annual emissions must be based upon the short-term limit and annual hours of operation.

The general permit requires initial and semi-annual testing for engines to demonstrate compliance with the short-term emission limits. To reduce the regulatory burden on the permittee and AQD, the general permit does not require testing for Emergency Use Engines or engines rated less than or equal to 250-hp.

Compliance with NO_X and CO hourly emissions limits for engines using a control device (e.g., catalytic converter or oxidation catalyst) is more critical. Catalytic converters and oxidation catalysts typically have pollutant conversion efficiencies as high as 90%. Thus, if the catalyst fails or is bypassed substantially through channeling, or, for three-way NSCR, if the AFR controller is not maintaining the appropriate amount of excess oxygen in the engine exhaust (typically less than 0.5% oxygen), a single engine could become a major source if operated for even a short period of time. A specific condition requiring semi-annual testing of NO_X and CO emissions from each non-emergency controlled engine greater than 250-hp is included in the GP-OGF.

Engines, lean-burn more so than rich-burn, emit HAPs, the most significant being formaldehyde. Estimates of potential formaldehyde emissions may be made using manufacturer's data, stack tests, or emission factors from AP-42, Chapter 3 (for engines older than model year 2000). The permittee will be required to include annual emissions of formaldehyde from all engines, based on annual operating hours, to demonstrate compliance with the facility-wide emissions cap for HAP. Compliance with the CO limit shall be used as a surrogacy for compliance with the formaldehyde limit. Formaldehyde control efficiency shall be at or below the efficiency requested for CO.

Boilers and Heaters

The permittee will be required to calculate emissions of NO_x, CO and VOC from all boilers and heaters based on rating, AP-42, Section 1.4, and continuous hours of operation.

With the permit limit of 50 MMBtu/hr on the total of all gas-fired combustion equipment (excluding reciprocating engines), emission factors found in AP-42 give an uncontrolled PTE for NO_X of approximately 25 TPY and for CO of approximately 20 TPY. Therefore, no short-term emission limitations or testing are required in the general permit for compliance with the cap.

HAP emissions from the combustion of natural gas and liquid fuels in equipment such as boilers and heaters are negligible at facilities covered by the GP-OGF. Therefore, emissions of HAP from boilers and heaters do not need to be included in the annual emissions calculated for compliance with the facility-wide cap for HAP.

Flares or enclosed combustion devices

The permittee will be required to calculate emissions of NO_x, and CO from all flares or enclosed combustion devices using heat input, emissions factors, and continuous hours of operation. The heat input shall be based on: (1) design capacity rating; (2) measured waste gas flow rate to the device; or (3) as calculated using the methodologies approved in this section. Emission factors shall be taken from manufacturer's data, TCEQ's document "Air Permit Technical Guidance for Chemical Sources: Flares & Thermal Oxidizers –RG-109 (draft) September 2000", or latest version of AP-42 Section 13.5.

The permittee will be required to calculate emissions of VOC and HAP from all units routed to the flares or enclosed combustion devices using the appropriate methods for those units in this section and 98% destruction efficiency as specified in Section VI of the memorandum.

E. GLYCOL DEHYDRATION UNIT

The general permit requires that the permittee estimate the potential to emit VOC and HAP from any glycol dehydration units and include those emissions in calculating compliance with the facility-wide emissions cap for VOC and HAP. Facilities that have potential HAP emissions from all dehydrator units, individual or combined, above 80% of major source levels are required to sample and perform an extended gas analysis on the wet gas once each year. No specific requirements to limit emissions from glycol dehydration units are necessary in the general permit when using the potential to emit; however, specific requirements have been incorporated into the general permit to ensure compliance when a condenser is used to control emissions and it is considered in the calculation of potential to emit. Facilities that require other limitations on a glycol dehydration unit in order to remain a minor source must obtain a minor source construction permit and any specific requirements in that permit can be included in an Authorization to Operate.

Emissions from glycol dehydration units are often controlled by using a condenser on the regenerator still vent and then venting to atmosphere or to the regenerator reboiler firebox, other heaters, or a flare. Emissions from rich glycol flash tank vents are often controlled by combustion or by recycling back to low-pressure inlet gas streams or fuel gas system. For combustion of gasses from a glycol still vent, flash tank, or condenser in a reboiler firebox, only 50% destruction efficiency shall be allowed unless combined with other controls such as flares, glow plugs, fuel gas system, or inlet of facility. If such controls are installed, greater than 50% destruction may be applied as allowed under this general permit.

Glycol dehydration units emit VOC and HAPs from rich glycol flash tank vents and regenerator still vents. Potential emissions from glycol dehydrator units can be estimated using the GRI-GLYCalc program (Version 4.0 or later), a process simulator program, or the Atmospheric Rich/Lean (ARL) Method. The emissions should be based on the potential to emit by assuming continuous operation using the dry gas flow rate based upon one of the following: (1) the maximum design dry gas rate for the dehydrator unit; or (2) the maximum facility dry gas rate based on an inherent process limitation such as compressor horsepower or capacity limitations; or (3) the maximum facility dry gas rate based on an inherent limit on gas production; or (4) the maximum annual average dry gas rate for the last 2 years plus a 20% safety factor; and an extended wet gas analysis, the normal process operating temperature and pressure, the expected removal efficiency of any control device, and the maximum pump rate of the lean glycol circulation pump.

F. AMINE UNIT

The general permit requires that the permittee estimate the potential to emit of VOC, HAP, and SO_2 from any amine unit and include those emissions in calculating compliance with the facility-wide emissions cap. Based on Appendix A, the amine units are required to control emissions from the rich amine flash tank and the amine regeneration still vent, and limit the inlet H_2S concentration to 4 ppmv. Therefore, no additional specific requirements to limit emissions from amine units are necessary.

Amine units emit VOC, HAPs, and SO_2 from the rich amine flash tank and regenerator still vents. Potential emissions can be estimated using the AMINE-Calc program, a process simulator program, and/or mass balance equations. The emissions should be based on the potential to emit by assuming continuous operation using the gas flow rate based upon one of the following: (1) the maximum design gas rate for the amine unit; or (2) the maximum facility gas rate based on an inherent process limitation such as compressor horsepower or capacity limitations; or (3) the maximum facility gas rate based on an inherent limit on gas production; or (4) the maximum annual average gas rate for the last 2 years plus a 20% safety factor; an extended gas analysis or natural gas liquid analysis, the normal process operating temperatures and pressures, and the maximum pump rate of the lean amine circulation pump. Emissions from amine unit flash tanks are often controlled by routing the gases to the fuel gas system or by using a flare. Emissions from the regenerator still vent are vented to the atmosphere or controlled by flaring.

G. FUGITIVE EMISSIONS SOURCE

The general permit will require that the permittee maintain an approximate fugitive equipment component inventory. Typically, OGF are not required to calculate fugitives to determine major source status. However, per EPA guidance documents, petroleum storage facilities (PSF) with a total storage capacity exceeding 300,000 barrels or any facility with a source category subject to an NSPS or NESHAP standard in effect prior to August 7, 1980, are required to include fugitive emissions for determination of major source status. The permit will require those facilities that have a total storage capacity exceeding 300,000 barrels or storage tanks that meet the source categories addressed by NSPS Subparts K or Ka to include fugitive VOC emissions in the emissions calculated for compliance with the facility-wide emissions cap for VOC.

Emissions of HAP from fugitive emission sources are negligible at minor OGF and do not need to be included in the emissions calculated for compliance with the facility-wide emissions cap for HAP. Emissions of H_2S are also negligible as demonstrated in Appendix A.

VOC emissions from fugitive equipment components are generally estimated using emission factors from EPA's *1995 Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)* or from other DEQ approved emissions factors, an approximate number of components, type of service, and percent VOC.

H. OTHER PROCESS EQUIPMENT

The general permit requires the permittee to calculate VOC emissions from other process equipment not previously listed (e.g., inlet separator routed to control device). The uncontrolled emissions shall be calculated using a process simulator program and/or mass balance equations.

Any VOC emissions from other process equipment that are recovered and routed to a process through a vapor recovery unit (VRU) designed and operated as specified in §60.5365a(e)(5) are not required to be included in the determination of VOC for purposes of determining compliance with emission limitations of the general permit. A properly installed and operated VRU is considered to recover 100% of the VOC emissions during the time the VRU is in use.

I. MAINTENANCE, STARTUP AND SHUTDOWN (MSS)

The general permit requires the permittee to estimate VOC emissions from any MSS activity and include those emissions in calculating compliance with the facility-wide emissions cap for VOC.

Some MSS emissions, such as blowdowns, can be estimated using mass balance equations, volume of gas vented, the number of events, and percent VOC.

SECTION VI. CONTROL EFFICIENCIES AND MONITORING REQUIREMENTS

Typical control options expected at OGF include floating roofs, vapor-recovery systems, flares, vapor balancing systems, and condensers to reduce VOC and HAP emissions, and catalytic converters on engines to reduce NO_X, CO, and VOC (primarily three-way NSCR) or CO and VOC (primarily oxidation catalyst). Higher control efficiencies may be established by obtaining an individual minor source construction permit and incorporating site-specific conditions into an authorization to operate to assure compliance.

The permit must incorporate a CO lb/hr limit and require monitoring of CO as a surrogate to assure compliance with formaldehyde limits. Limits shall be based on manufacturers' uncontrolled CO emissions guarantee at 100% load reduced using a control efficiency equal to or greater than the control rate requested for formaldehyde, not to exceed 90%. If manufacturers' data is not available, the most representative data available should be used, to include stack test data.

Non-Selective Catalytic Reduction (NSCR)

Maximum Allowed Control Efficiency	Requirements

Manufacture guarantee as stated in application (Not to exceed 90%)	• Must be maintained and operated as specified by the manufactured or design specifications.
	• Be constructed with an Air-to-Fuel Ratio Controller (AFRC) that operates on exhaust oxygen sensor control.
	• Use a portable analyzer to monitor NO_x, CO and O_2 concentration in the exhaust stream of the control device.
	  ▪ The portable analyzer shall be operated in accordance with the requirements of the latest AQD "Portable Analyzer Guidance" document or an equivalent method approved by the AQD.
	  ▪ Testing shall be performed semi-annually.

Oxidation Catalyst

<table>
<tr><th>Maximum Allowed Control Efficiency</th><th>Requirements</th></tr>
<tr><td>Manufacture guarantee as stated in application (Not to exceed 93%)</td><td rowspan="2">Meet requirements listed above for NSCR except for AFRC.</td></tr>
<tr><td>Formaldehyde reduction ≤ CO reduction (Not to exceed 90%)</td></tr>
</table>

The permit requires that condensers be properly operated, constructed with a temperature sensor in the outlet, and designed to achieve the expected removal efficiency at the maximum expected condenser outlet temperature, unless all vapor from the condenser is combusted or recycled to the process.

Glycol Dehydration Units and Amine Units

<table>
<tr><th>Maximum Allowed Control Efficiency</th><th>Requirements</th></tr>
<tr><td colspan="2">Control Device: Condenser Only</td></tr>
<tr><td>≤90% for VOC's and HAP's</td><td>Must be maintained and operated as specified by the manufactured or design specifications.
Unit must be equipped with a flash tank.
Constructed with a temperature sensor in the outlet.
The permittee shall inspect the condenser for proper operation and measure and record the condenser outlet temperature at least one day each month during daylight hours.
Installation of the temperature sensor and measuring and recording of the condenser outlet temperature is not required if the uncondensed vapors are burned in a combustion device or recycled to the process.
Not followed by further control such as reboilers, flares or in-stack ignitor. Greater than 90% reduction may be applied if meeting the device requirements of the control selected.</td></tr>
<tr><td colspan="2">Control Device: Recycled or Recompressed</td></tr>
<tr><td>≤ 100% for VOC's and HAP's</td><td>Have the flash tank stream pre-mixed with the primary fuel gas and used to fuel the device; or
Routed to the facility inlet.</td></tr>
</table>

Glycol Dehydration Units and Amine Units (cont.)

Maximum Allowed Control Efficiency	Requirements
Control Device: Combustion device such as reboiler or heater	
≤50% for VOC and HAP's	• Have still vent stream delivered to the flame zone/firebox.
≤ 95 % for VOC's and HAP's	• Have still vent stream delivered to the flame zone/firebox when firing; and • Delivered to an in-stack igniter when the firebox is not firing. • In-stack igniter must be maintained and operated per manufacturer's specifications.
Control Device: Condenser plus combustion device such as reboiler or heater	
≤ 95% for VOC's and HAP's	• Must meet requirements to claim 90% efficiency as described for a condenser; and • Have still vent stream delivered to the flame zone/firebox.
≤ 98% for VOC's and HAP's	• Must meet requirements to claim 90% efficiency as described for a condenser; • Have still vent stream delivered to the flame zone/firebox; and • Utilize an in-stack igniter which is maintained and operated per manufacturer's specifications.

The loading operations, vapor collection system, and vapor disposal system shall be operated in accordance with the following.

Vapor Collection for Loading

Maximum Allowed Control Efficiency	Requirements
Vapor Collection Systems	
n/a	• The tank trucks shall be bottom loaded with hatches closed (vapor tight) and the storage tank hatches and atmospheric vents shall be closed (vapor tight). • A vapor collection line shall be connected from the tank truck to the vapor collection system and shall route all vapors generated during loading to the vapor collection system. • All loading and vapor lines shall be equipped with fittings that make vapor-tight connections and which must be closed when disconnected or which close automatically when disconnected. • A means shall be provided to prevent VOC drainage from the loading device when it is removed from any tank truck or trailer, or to accomplish complete drainage before removal.

Vapor Collection for Loading (cont.)

Maximum Allowed Control Efficiency	Requirements
Vapor Balancing (Collection Efficiency)	
≤ 70% for VOC's and HAP's	• In addition to the requirements above, the tanks shall be equipped with a vapor pressure-vacuum vent valve that maintains a positive pressure setting during tank truck loading operations. • Loading loss emissions routed to the storage tanks shall be added to the storage tank emissions. In lieu of adding loading loss emissions to storage tanks, working loss emissions from the storage tanks being unloaded shall be calculated using a turnover factor (K_N) of 1.
Vapor Control	
≤ 98% for VOC's and HAP's	• Meet requirements of vapor balancing and • Control percentage only applies to vapors collected in vapor balancing and • The vapor disposal system shall route all vapors to a flare. Flares must meet requirements described in the flares or enclosed combustion device table.
Vapor Recovery	
100 % for VOC's and HAP's	• Control percentage only applies to vapors collected in vapor balancing and • Routed to the process stream or sales line.

Flares or Enclosed Combustion Devices

Maximum Allowed Control Efficiency	Requirements

≤ 98% for VOC's, HAP's and H_2S	• Flares must meet 40 CFR §60.18 requirements for minimum heating value and maximum flare tip velocities.
	• Be operated with a flame present at all times by having a continuous pilot flame or an automatic ignition system.
	  ▪ Presence of a pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame; and
	  ▪ Records of the pilot flame(s) outages and/or downtime shall be maintained.
	• Pilot flame monitors must be installed, operated, and calibrated in accordance with manufacturer's specifications.

SECTION VII. APPLICABLE REGULATIONS

Applicable rules and regulations are given below for each emission unit, and also for fugitive emissions authorized in this permit, including facility-wide requirements, storage tanks, VOC loading operations, combustion equipment, amine units, and glycol dehydration units. For brevity, only those applicable requirements that are specific to the particular emissions unit, and not addressed in the facility-wide requirements, are covered in each section.

A. Oklahoma Air Pollution Control

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]
The purpose of this Subchapter is to incorporate by reference applicable provisions of Title 40 of the Code of Federal Regulations listed in OAC 252:100, Appendix Q. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration, Emissions Inventory, & Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants.

This permit assures compliance with this regulation using the following approach:
A standard condition in the permit requires the permittee to file an annual emissions inventory and pay annual fees in accordance with OAC 252:100-5(2)(e).

Fugitive emissions are reportable as actual facility emissions. However, compliance with the limit of this permit does not include fugitive emissions except for those source categories that are a listed source category.

OAC 252:100-7 (Permits for Minor Facilities) [Applicable]
Part 1 includes definitions and subjects all permitting to the tiered Uniformed Permitting Act. Permits are required to meet public review requirements consistent with the Tier System given in the Uniform Permitting Act.
Part 2 establishes fees for construction and operating permits, Authorizations issued under General Permits, and applicability determinations.
Part 3 establishes construction permit categories and requirements. A construction permit is required for new facilities and modification of existing facilities. A general permit may be issued for an industry if there are a sufficient number of facilities that have the same or substantially similar operations, emissions, and activities that are subject to the same standards, limitations,

and operating and monitoring requirements. For general permits that provide for application through the filing of a notice of intent (NOI) to construct, authorization under the general permit is effective upon receipt of the NOI. Construction permits shall require compliance with all applicable air pollution rules, prohibit the exceedance of ambient air quality standards contained in OAC 252:100-3, and may establish permit conditions and limitations as necessary to assure compliance with all rules.
Part 4 establishes operating permit requirements. Emission limitations established and made a part of the construction permit are incorporated into and become enforceable limitations of the subsequently issued operating permit. Permit limitations in adjustment of, or in addition to, the facility's construction permit limitations may be made a condition of the facility's operating permit issuance.

This permit assures compliance with this regulation using the following approach:
For Part 1, the general permit has gone through Tier II review; therefore, Authorizations will only require Tier I review, without website notice in accordance with the Director's discretion under OAC 252:4-7-13(g)(10). Any part 70 source seeking an Authorization under the general permit, that once issued would qualify as a minor facility, requires a Tier II application.

For Part 2, the general permit requires remittance of the applicable fees.

For Part 3, the general permit is designed to allow minor facilities to fulfill the requirement to obtain an Authorization to Construct before starting construction of an eligible facility or for modifications to existing eligible facilities. Limitations are established as part of the facility-wide emissions cap of this general permit, not to equal or exceed the levels for Class I or Class II facilities. AQD has determined that a sufficient number of oil and gas facilities with the same or substantially similar operations and activities exist within the state of Oklahoma that require permitting, which creates the need to develop this general permit.

An NOI to Construct is required prior to commencing construction of a new facility or modification of an existing facility not covered under this general permit. Coverage under the general permit is effective upon receipt of the NOI to Construct application when accompanied by fee, a receipt, or other confirmation of payment by the AQD. The earliest of (1) a legible dated U.S. Postal Service postmark (private metered postmarks are not acceptable); (2) a dated receipt from a commercial carrier or the U.S. Postal Service; (3) a DEQ date stamped application; or (4) a date of receipt of a digital copy of an application is acceptable documentation of receipt of the NOI to Construct.

In lieu of an Authorization to Construct, an applicant may obtain an individual minor source construction permit. Certain facility modifications, as defined by the general permit, may be constructed without an individual minor source construction permit, an Authorization to Construct, or a new Authorization to Operate. For these modifications, the permittee must submit a Notice of Modification (NOM) form to AQD within 15 days of the start of operation of the modification.

This general permit requires compliance with all state and federal regulations which are evaluated in this Section of the memorandum.

For Part 4, after construction is complete, an application for an Authorization to Operate must be submitted within 180 days of startup. A condition has been included in the permit that allows conditions from an individual minor source construction permit to be incorporated into the Authorization to Operate. Operational conditions have been included in the permit to require a source to construct and operate all emission units and associated control equipment within a practical range of operating conditions to achieve, on a continuous basis, a level of emissions that complies with applicable requirements. Operating and compliance requirements, as well as monitoring and recordkeeping requirements for control devices, are specifically addressed in the permit. The Authorization to Operate does not make use of an NOI process, therefore, coverage under the general permit is not effective until the issuance of the Authorization to Operate. An applicant proposing to obtain coverage under this permit for an existing, previously permitted facility, need only apply for an Authorization to Operate.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
Subchapter 9 requires an owner or operator of a regulated facility to report all excess emissions from an air pollution source caused by malfunction, shutdown, startup, or regularly scheduled maintenance that are in violation of the applicable air pollution control rule, permit, or order of the DEQ. No specific emission limitation, standard, or criterion is specified in this subchapter.

The permit assures compliance with this regulation using the following approach:
Conditions are included in the standard conditions of the general permit that require compliance with this subchapter should excess emissions occur.

OAC 252:100-13 (Open Burning) [Applicable]
This subchapter prohibits open burning of refuse and other combustible material except in compliance with OAC 252:100-13-7 and 9. No specific emission limitation or criterion is specified in this subchapter. However, work practice conditions and standards are specified.

The permit assures compliance with this regulation using the following approach:
Subchapter 13 applies to all facilities. Therefore, the general permit includes a condition that requires compliance with this subchapter. However, open burning is not expected to take place at facilities covered under this permit. Therefore, no initial compliance demonstration or continuing monitoring, recordkeeping, or reporting requirements associated with this subchapter are included in the general permit.

OAC 252:100-19 (PM Emissions from Fuel-burning Equipment) [Applicable]
The purpose of this subchapter is to control the emission of particulate matter from fuel-burning units and industrial processes. This subchapter requires that the maximum allowable emissions of particulate matter from engines and other combustion equipment not exceed the limits listed in OAC 252:100 Appendix C.

The permit assures compliance with this regulation using the following approach:
The general permit is restricted to those facilities using liquid petroleum gas, natural gas with no greater than 162 ppmv total sulfur content, diesel fuel with a sulfur content less than 0.05% by weight, or No. 2 with a sulfur content less than 0.05 wt%. Usage of these fuels and AP-42 PM emission factors for engines and heaters will assure compliance with this subchapter.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
This subchapter states no person shall allow or permit the discharge of any fumes, aerosol, mist, gas, smoke, vapor, particulate matter, or any combination thereof, exhibiting greater than 20 percent equivalent opacity except for short-term occurrences. At no time may the opacity exceed 20 percent for one six-minute period in any consecutive 60 minutes nor more than three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity.

The general permit assures compliance with this regulation using the following approach:
The only emissions units/activities with the potential for visible emissions are flares and engines, especially liquid-fueled engines. Most engines are natural gas-fired. In addition, liquid-fueled engines restricted to the fuels allowed in this general permit have very little potential to violate these opacity requirements. Ongoing operation and maintenance activities at facilities should provide sufficient opportunities to allow owner/operators to identify and take corrective action to address any opacity exceedance. These activities, along with DEQ complaint and compliance activities, should be sufficient to assure compliance with this requirement. Thus, periodic monitoring of opacity is not being required at any of these facilities.

OAC 252:100-29 (Control of Fugitive Dust) [Applicable]
This subchapter prohibits any person from causing or allowing any fugitive dust source to be operated, or any substances to be handled, transported, or stored, or any structure constructed, altered, or demolished to the extent that such operation or activity may enable fugitive dust to become airborne and result in air pollution, without taking reasonable precautions to minimize or prevent pollution. Subchapter 29 further prohibits discharge of visible fugitive dust beyond the property line on which the emissions originated in such a manner as to damage or interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. A list of reasonable precautions is specified in this subchapter.

The general permit assures compliance with this regulation using the following approach:
Under normal operating conditions, these facilities have negligible potential to violate this requirement; 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 impacts of H_2S emissions from any facility to 0.2 ppm at standard conditions, 24-hour average (equivalent to 283 $\mu g/m^3$). The standard shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.
Part 5 limits SO_2 emissions from any new gas-fired fuel-burning equipment to 0.2 lb/MMBTU heat input and new liquid-fired fuel-burning equipment to 0.8 lb/MMBTU heat input, three-hour average.
Part 5 requires H_2S in the waste gas stream from any new petroleum or natural gas process equipment (constructed after July 1, 1972) to be reduced by 95% by removal or by being oxidized to SO_2. This requirement does not apply if a facility's emissions of H_2S do not exceed 0.3 lb/hr, two-hour average. The owner or operator is required to install, maintain, and operate an

alarm system that will signal a malfunction for all thermal devices used to control H_2S emissions from petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(1).

The general permit assures compliance with this regulation using the following approach:
Except for facilities that store sour crude oil, no significant emission of H_2S is expected from storage tanks at these facilities (see Appendix A). Eligibility for an Authorization to Construct under the permit is restricted to those facilities that do not store sour crude oil. Facilities that store sour crude oil may apply for a minor source construction permit and then obtain an Authorization to Operate under this permit. Any emission limitations or specific conditions necessary for compliance with Subchapter 31, Part 2 from the construction permit will be incorporated into the Authorization to Operate.

Emissions of H_2S from VOC Loading Operations are negligible (see Appendix A).

Eligibility for an Authorization to Construct under the permit is restricted to those facilities using liquid petroleum gas, natural gas with no greater than 10 grains/100 scf total sulfur content, or diesel or No. 2 fuel oil with a sulfur content less than 0.05% by weight. Appendix A documents compliance with Subchapter 31 for any engine eligible for the permit.

Eligibility for an Authorization to Construct is restricted to facilities that do not have glycol dehydration units which treat sour natural gas (see Appendix A). Sour gas is natural gas containing greater than 4 ppmv H_2S. Glycol dehydrators treating sour natural gas have the potential to emit significant amounts of H_2S. A facility that has a glycol dehydration unit which processes sour natural gas may apply for a minor source construction permit and then obtain an Authorization to Operate under this permit. Any emission limitations or specific conditions necessary for compliance with Subchapter 31, Part 2 from the construction permit will be incorporated into the Authorization to Operate.

Eligibility for an Authorization to Construct is restricted to facilities that only have a single amine unit, which treats sweet natural gas and/or liquids, and is controlled (see Appendix A). The general permit requires emissions from the rich amine flash tank to be routed to a flare or to the fuel gas system and the amine regenerator still vent to be routed to a flare with combustion efficiency of 95% or greater to the atmosphere. A facility that has multiple amine units or an amine unit which processes sour natural gas or which is uncontrolled may apply for a minor source construction permit and then obtain an Authorization to Operate under this permit. Any emission limitations or specific conditions necessary for compliance with Subchapter 31, Part 2 from the construction permit will be incorporated into the Authorization to Operate.

The permit also requires acid gas flares at petroleum and natural gas processing facilities to be equipped with an alarm system that will signal when there is no pilot flame.

The permit will also limit applicability of the permit to amine units which process less than 0.1276 long tons per day (LT/D), since at this level a facility would become a major source for SO_2.

As shown in Appendix A, fugitive emissions of H_2S are negligible for the facilities eligible for this permit.

OAC 252:100-37 (Control of VOCs) [Applicable]
Part 3 requires storage tanks (except pressure tanks) built after 12/28/74, and with a capacity of 400 gallons or more storing a VOC with a vapor pressure of 1.5 psia or greater under actual conditions, to be equipped with a submerged fill pipe or a vapor-recovery system.
Part 3 requires storage tanks (except pressure tanks) built after 12/28/74, with a capacity greater than 40,000 gallons to be equipped with a floating roof or a vapor-recovery system capable of collecting 85% or more of the uncontrolled VOCs.
Part 3 requires VOC loading facilities built after 12/28/74, and with a throughput greater than 40,000 gal/day, to be equipped with a vapor collection and disposal system unless all tank trucks or trailers are bottom loaded with hatches closed.
Part 3 requires VOC loading facilities built after 12/28/74, and with a throughput less than 40,000 gal/day, to be equipped with a system for submerged filling of tank trucks or trailers which is installed and operated to maintain a 97 percent submergence factor.
Part 7 provides that all fuel-burning equipment shall be cleaned, operated, and maintained to minimize emissions of VOCs. The equipment should be operated such that it is not overloaded and that temperature and available air are sufficient to provide essentially complete combustion.
Part 7 requires single-compartment or multiple-compartment VOC/water separators that receives effluent water containing 200 gallons per day or more of any VOC from any equipment processing, refining, treating, storing, or handling VOCs shall be totally enclosed, or equipped with an external floating roof, internal floating roof, or a vapor-recovery system. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. The oil removal devices shall be gas-tight except when manual skimming, inspection and/or repair is in progress.

The general permit assures compliance with this regulation using the following approach:
Specific operational conditions, based on this subchapter, are included in the general permit for storage tanks and effluent water separators.

Facilities with VOC loading facilities subject to OAC 252:100-37-16(a), load above 40,000 gal/day, are not eligible for an Authorization to Construct. Such facilities must obtain a minor source construction permit for these loading facilities and operational requirements developed in that construction permit must be incorporated into an Authorization to Operate. The permit requires compliance with OAC 252:100-37-16(b) for VOC Loading Operations.

Specific conditions are included in the permit that require that the permittee properly operate and maintain engines and associated control systems in a manner that will minimize emissions. Operational and maintenance records are required to be kept to document compliance with this requirement.

OAC 252:100-39 (VOCs in Non-Attainment and Former Non-attainment Areas) [Applicable]
Part 5 sets control requirements for petroleum liquid storage vessels equipped with external floating roofs, having capacities greater than 40,000 gallons and located in Tulsa and Oklahoma counties.

Part 7 requires that each VOC vessel with a capacity greater than 40,000-gal shall be a pressure vessel or shall be equipped with a floating roof or a vapor-recovery system that consists of a vapor-gathering system capable of collecting 90 percent by weight or more of the uncontrolled VOCs.
Part 7 requires that each VOC storage vessel with a nominal capacity greater than 400-gal and less than 40,000-gal shall be equipped with a submerged fill pipe or be bottom filled. The displaced vapors from each storage vessel with an average daily throughput of 30,000-gal or greater which stores VOCs shall be processed by a system that has a total collection efficiency no less than 90 percent by weight of total VOCs in the vapors.
Part 7 requires that each VOC storage vessel (located in Tulsa County only) with a nominal capacity greater than 2,000-gal and less than 40,000-gal, in addition to being equipped with a submerged fill pipe or being bottom loading, shall be equipped with a vapor control system.
Part 7 requires that each VOC loading facility with an annual throughput of 120,000 gallons or greater shall be equipped with a vapor-collection and/or disposal system. For facilities in Tulsa, stationary VOC loading facilities shall be checked annually in accordance with EPA Test Method 21, Leak Test. Leaks greater than 5,000 ppmv shall be repaired within 15 days. Facilities shall retain inspection and repair records for at least two years. Part 7 also specifies methods to be used to determine leakage from gasoline trucks and associated vapor control systems.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions, based on this subchapter, are included in the permit for storage tanks. Continuing compliance requires that the permittee perform routine inspections of all seal closure devices semi-annually; measure the secondary seal gap annually when the floating roof is equipped with a vapor-mounted primary seal; and maintain records of the types of volatile petroleum liquids stored, the true vapor pressure of the liquid as stored, and the results of the above inspections. An Authorization to Construct is not allowed for a facility using a vapor-recovery/vapor disposal system as required by 100-39-41(a)(2), 100-39-41(b)(2), or 100-39-41(c)(5), or other equipment of equal efficiency, as required by 100-39-41(a)(3). Such facilities must obtain a minor source construction permit for these vapor-recovery/vapor disposal systems and operational requirements developed in that construction permit must be incorporated into an Authorization to Operate. Thus, requirements do not need to be included in the general permit for vapor recovery/vapor disposal systems and their associated control devices.

Facilities with VOC loading facilities subject to OAC 252:100-39 are not eligible for an Authorization to Construct. Such facilities must obtain a minor source construction permit for these loading facilities and operational requirements developed in that construction permit must be incorporated into an Authorization to Operate.

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.

The general permit assures compliance with this regulation using the following approach:
A standard condition is included which states that all required tests shall be performed and the results calculated in accordance with test procedures described or referenced in the permit and approved by Air Quality. The general permit establishes minimum monitoring requirements for control devices associated with emission units addressed in this permit. In addition, testing must be performed as specified in 40 CFR Parts 51, 60, 61, 63, and 75, as applicable, unless otherwise specified in an Authorization under this permit.

Non-applicable Oklahoma Regulations

Table VIII-1 lists the Oklahoma Air Quality Regulations that are not applicable to facilities covered under this permit on a facility-wide basis. Rules applicable to a specific emission unit are listed separately.

Table VIII-1- Non-applicable Oklahoma Air Pollution Control Regulations

Rule	Description	Reason
OAC 252:100-8	Permits for Major Sources	Not a major source
OAC 252:100-11	Alternative Emissions Reduction	Ineligible *
OAC 252:100-17	Incinerators	Not a covered source
OAC 252:100-19-10 & 11	PM from Wood Waste Burning	Not a covered source
OAC 252:100-23	Cotton Gins	Not a covered source
OAC 252:100-24	Grain Elevators	Not a covered source
OAC 252:100-33	Nitrogen Oxides	Ineligible *
OAC 252:100-35	Carbon Monoxide	Not a covered source
OAC 252:100-37, Part 5	Control of VOCs	Not a covered source
OAC 252:100-39, Part 7 (except Section 41 *)	Emissions of VOCs in Nonattainment Areas and Former Non-Attainment Areas	Not a covered source
OAC 252:100-47	Existing Municipal Solid Waste Landfills	Not a covered source

*Ineligible for an Authorization to Construct. May be addressed in a minor source construction permit by specific conditions that are then incorporated into the Authorization to Operate

B. Federal Regulations

Certain state regulations require compliance with federally promulgated regulations. OAC 252:100-7-15(d) requires that construction permits include all applicable requirements, including NSPS and NESHAP.

NSPS, 40 CFR Part 60 [Applicable]

NSPS means a standard of emissions of air pollutants that reflects the degree of emission limitation achievable through the application of the best system of emission reduction that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements, the Administrator of EPA determines has been adequately demonstrated. NSPS apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication of the standard applicable to that facility. Certain notification, recordkeeping, emissions limitations, performance tests, and monitoring requirements are specified in these NSPS regulations.

Subpart	Description	Applicable Equipment
A	General Provisions	
Dc	Small Industrial-Commercial- Institutional Steam Generating Units	Boilers
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	Storage Tanks
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	Storage Tanks
Kb	VOL Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	Storage Tanks
GG	Stationary Gas Turbines	Turbines
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	Fugitives
LLL	SO_2 Emissions From Onshore Natural Gas Processing	Amine Units
IIII	Stationary Compression Ignition Internal Combustion Engines	Engines
JJJJ	Stationary Spark Ignition Internal Combustion Engines	Engines
KKKK	Stationary Combustion Turbines	Turbines
OOOO	Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015	Storage Tanks, Fugitives, Amine Units, Compressors
OOOOa	Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced after September 18, 2015	Storage Tanks, Fugitives, Amine Units, Compressors

The general permit assures compliance with this regulation using the following approach:
Conditions are included to address the NSPS general notification, recordkeeping, emissions limitations, performance test, and monitoring requirements. Language in the general permit emphasizes that NSPS notification and performance test requirements are separate, stand-alone,

and independent federal requirements that must be met in addition to any other general permit requirements, e.g., equipment addition or change notifications. However, a timely submitted NOM shall suffice as a notice of the actual date of initial startup, and as a notice of a physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies as required by an NSPS (40 CFR 60.7(a)). Conditions specific to a particular NSPS are included for each emissions unit that may be determined to be an affected unit.

NESHAP, 40 CFR Part 63 [Applicable]
NESHAP contains standards that regulate specific categories of stationary sources that emit one or more hazardous air pollutants. These standards require all owners or operators of major and area sources in certain source categories that are constructed or reconstructed to install generally achievable control technology (GACT) unless specifically exempted. Certain notification, recordkeeping, emissions limitations, performance tests, and monitoring requirements are specified in these NESHAP regulations.

Subpart	Description	Applicable Equipment
A	General Provisions	
HH	Oil and Natural Gas Production Facilities	Dehydration Units
ZZZZ	Stationary Reciprocating Internal Combustion Engines	Engines
CCCCCC	Gasoline Dispensing Facilities	Fugitives
JJJJJJ	Industrial, Commercial, and Institutional Boilers	Boilers

The general permit assures compliance with this regulation using the following approach:
Conditions are included to address NESHAP general notification, recordkeeping, emissions limitations, performance test, and monitoring requirements. Language in the general permit emphasizes that NESHAP notification and performance test requirements are separate, stand-alone, and independent federal requirements that must be met in addition to any other general permit requirements, e.g., equipment addition or change notifications. However, a timely submitted NOM shall suffice as a notice of the actual date of initial startup.

SECTION VIII. DEFINITIONS

The following definitions apply to this memorandum and general permit. All defined terms are written with initial capital letters in the memorandum and permit.

“Certified Engine” means any engine that has been certified by the EPA to meet emissions standards for the purposes of meeting an NSPS or NESHAP.

“Class I” means a facility that has an enforceable limit less than 80% of major source levels for each regulated air pollutant.

“Class II” means a facility that has an enforceable limit of less than 100% of major source levels for each regulated air pollutant and is not a Class I facility.

“Controlled Engine” means an engine, with or without an Air to Fuel Ratio Controller, that uses catalytic or oxidation catalyst control.

“Engine” means any reciprocating internal combustion engine or any gas-fired turbine.

“Emergency Use Engine” means any engine that drives an emergency power generator, peaking power generator, firewater pump, or other emergency use equipment, and operates no more than 500 hours per year.

“Extended Gas Analysis” means an extended analysis (using GPA 2286 or similar approved methods) that provides speciated data for HAP components benzene, toluene, ethylbenzene, xylenes, and n-hexane.

“Maintenance, Startup, and Shutdown (MSS)” refers to maintenance, startup, or shutdown; it does not include periods of malfunction.

“Maintenance” means the planned routine repair and upkeep of equipment.

“Malfunction” means a sudden and unavoidable breakdown of process or control equipment.

“Maximum Rated Horsepower” means an engine’s maximum horsepower at ISO or manufacturer’s standard conditions and maximum RPM, or an engine’s maximum horsepower at engine site conditions and maximum RPM.

“Notice of Modification (NOM)” means a written notice informing AQD of: (1) any modification or change of operations at the facility that would construct a piece of equipment or a process that is subject to NSPS or NESHAP, or that would modify or reconstruct a piece of equipment or a process such that it becomes subject to NSPS or NESHAP, or that would change its facility classification (either from a Class I Facility to a Class II facility or a Class II Facility to a Class I facility); or (2) any modification to add or replace a storage tank with a capacity of 400 gallons or more storing VOC, a VOC Loading Operation, any combustion equipment, any amine unit, or any dehydration unit; or (3) any modification to change emissions factors relied on in an application or a previous NOM; or (4) any modification to add or remove a federally enforceable limit (FEL) (e.g., 6 TPY limit on storage tanks). Such notice shall contain all information required in the NOM form. Any emissions limits requested in an NOM become an enforceable part of the existing Authorization to Operate. The permittee shall include a copy of any applicable NOM with the Authorization to Operate kept electronically or as a hard copy, either on-site, at a nearby manned facility, or at the nearest field office.

“Shutdown” means, generally, the cessation of operation of a source for any reason.

“Startup” means, generally, the setting in operation of a source for any reason.

“Synthetic Minor Facility” means a facility that has the potential to emit over major source levels of any regulated air pollutant but with controlled actual emissions below major source levels.

"Uncontrolled Engine" means an engine, with or without an Air to Fuel Ratio Controller, that has no catalytic or oxidation catalyst control.

"VOC Loading Operation" means loading liquid VOC into a tank truck or trailer for transportation offsite or unloading of liquid VOC from a tank truck or trailer to a storage tank onsite. A VOC Loading Operation does not have the physical equipment (loading arm and pump) to conduct the type of loading regulated by OAC 252:100-37-16 and 100-39-41 for VOC loading facilities, even though it may or may not use tank trucks or trailers that meet the requirements for delivery vessels in OAC:252-100-39-41(d).

SECTION IX. TIER CLASSIFICATION AND PUBLIC REVIEW

Processing of a new, modified, or renewed General Permit has been classified as Tier II based on OAC 252:4-7-33(c)(1). A request for an Authorization under this General Permit is classified as Tier I review, without website notice in accordance with the Director's discretion under OAC 252:4-7-13(g)(10). However, any part 70 source seeking an Authorization under the general permit, that once issued would qualify as a minor facility, requires a Tier II application.

A public notice of a 30-day public review period for the draft permit will be published in *The Tulsa World* and in *The Oklahoman*. A copy of the draft permit will be available for review at the Main Office of the Oklahoma Department of Environment Quality, 707 N. Robinson in Oklahoma City and in the Air Quality Section of the DEQ web page: *www.deq.ok.gov*.

SECTION X. SUMMARY

Applicants must demonstrate eligibility for coverage under this General Permit and that they are able to comply with applicable Air Quality regulations. Ambient air quality standards are not threatened at any of the sites eligible for coverage under this General Permit. Issuance of the permit is recommended, contingent upon public review.

APPENDIX A

Justification to Document Compliance with OAC 252:100-31 for H_2S

SECTION I. INTRODUCTION

AERSCREEN (16216r) was used to conduct modeling to determine compliance with the ambient standard for H_2S of OAC 252:100-31-7 for emission sources at oil and natural gas facilities to include: storage tanks, loading operations, combustion equipment (engines and heaters/boilers), glycol dehydration units, amine units, and fugitives. The ambient air quality standard is shown below.

> **252:100-31-7. Allowable hydrogen sulfide (H_2S) ambient air concentrations for new and existing sources**
> (b) **Hydrogen sulfide.** Emissions of H_2S from any facility shall not cause an ambient air concentration of H_2S greater than 0.2 ppm at standard conditions, 24-hour average.
> (c) **Exceptions.** The standards set in this section shall not apply to ambient air concentrations or impacts occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.

Each section identifies the type of source being modeled, the description of the different scenarios, and the individual cases within each scenario. The source data used in the AERSCREEN modeling was based on information obtained from AQD's Emission Inventory database. Each of the modeling scenarios were modeled in three locations (cases) which were determined to be representative of the varying terrain in the State of Oklahoma. For information related to the locations, development of each scenario, source type, or modeling input parameters for the storage tanks, amine units, engines and heaters/boilers, refer to the background information document entitled *GP-OGF Modeling of H_2S Sources* dated April 6, 2017. Information related to development of each scenario, source type, or modeling input parameters for the loading operations and fugitives are contained in this appendix.

SECTION II. STORAGE TANKS

For storage tanks, the AERSCREEN modeling conducted to determine compliance with OAC 252:100-31-7 was based on the following four (4) scenarios:

A. Storage Tank Modeling Scenario 1

- Vertical fixed roof storage tanks with VOC emission equal to 99 TPY, and vented directly to the atmosphere without controls. Two cases for this scenario were developed based on the concentration of H_2S in crude oil/condensate.
  - The first case is "sweet" crude oil (less than or equal to 0.5% by weight sulfur (S) & 6 ppmw H_2S).
  - The second case is "sour" crude oil (greater than 0.5% S & 135 ppmw H_2S).

The following table shows the AERSCREEN results for both cases at each of the three locations.

Vertical Fixed Roof Storage Tank AERSCREEN Results (μg/m^3)

	Case 1	Case 2
Location 1	55.9	1,258
Location 2	49.4	1,112
Location 3	51.1	1,150

The ambient impacts from Case 2 exceed the H_2S ambient air concentration limit (283 μg/m^3) at all three locations. Based on the modeling and only taking into account impacts from the storage tanks, the maximum concentration of H_2S in the crude oil that would be in compliance with the standard is 30 ppmw.

B. Storage Tank Modeling Scenario 2

- External floating roof storage tanks with VOC emissions equal to 99 TPY and vented directly to the atmosphere without controls. Two cases for this scenario were developed related to the concentration of H_2S in crude oil/condensate.
  - The first case is “sweet” crude oil (less than or equal to 0.5% S & 6 ppmw H_2S).
  - The second case is “sour” crude oil (greater than 0.5% S & 135 ppmw H_2S).

The following table shows the AERSCREEN results for both cases at each of the three locations.

External Floating Roof Storage Tank AERSCREEN Results (μg/m^3)

	Case 1	Case 2
Location 1	120.2	2,705
Location 2	13.4	301.6
Location 3	13.3	299.3

The ambient impacts from Case 2 exceed the H_2S ambient air concentration limit (283 μg/m^3) at all three locations. Based on the modeling and only taking into account impacts from the storage tanks, the maximum concentration of H_2S in the crude oil that would be in compliance with the standard is 14 ppmw.

C. Storage Tank Modeling Scenario 3

- Internal floating roof storage tanks with VOC emissions equal to 99 TPY and vented directly to the atmosphere without controls. Two cases for this scenario were developed related to the concentration of H_2S in crude oil/condensate.
  - The first case is “sweet” crude oil (less than or equal to 0.5% S & 6 ppmw H_2S).
  - The second case is “sour” crude oil (greater than 0.5% S & 135 ppmw H_2S).

The following table shows the AERSCREEN results for both cases at each of the three locations.

Internal Floating Roof Storage Tank AERSCREEN Results (µg/m^3)

	Case 1	Case 2
Location 1	60.6	1,364
Location 2	13.5	303.3
Location 3	13.8	310.6

The ambient impacts from Case 2 exceed the H_2S ambient air concentration limit (283 µg/m^3) at all three locations. Based on the modeling and only taking into account impacts from the storage tanks, the maximum concentration of H_2S in the crude oil that would be in compliance with the standard is 27 ppmw.

D. Storage Tank Modeling Scenario 4

- Storage tanks with VOC emissions equal to 400 TPY and vented to a flare. Two cases for this scenario were developed related to the concentration of H_2S in crude oil/condensate.
  - The first case is "sweet" crude oil (less than or equal to 0.5% S & 6 ppmw H_2S).
  - The second case is "sour" crude oil (greater than 0.5% S & 135 ppmw H_2S).

The following table shows the AERSCREEN results for both cases at each of the three locations.

Flared Storage Tank AERSCREEN Results (µg/m^3)

	Case 1	Case 2
Location 1	0.1	1.5
Location 2	<0.1	1.1
Location 3	<0.1	1.1

The ambient impacts from both cases are in compliance with the H_2S ambient air concentration limit (283 µg/m^3) at all three locations.

E. Summary

The maximum modeled concentrations for Scenarios 1, 2, and 3, Case 2 (uncontrolled "sour" crude oil tanks) are greater than the 0.2 ppm (283 µg/m^3) H_2S ambient air concentration limit. However, the maximum modeled concentrations for Scenarios 1, 2, and 3, Case 1 (uncontrolled "sweet" crude oil tanks) and Scenario 4, Case 1 and 2 (flared crude oil tanks) do not exceed the H_2S ambient air concentration limit. Therefore, the general permit will exclude those facilities that store "sour" (>0.5% S & 6 ppmw H_2S) crude oil.

Based on the modeling analyses, facilities with storage tanks storing "sour" crude oil would need a case-by-case analysis to demonstrate compliance with the H_2S ambient air concentration limit. Facilities processing "sour" crude oil may be eligible for coverage under an Authorization to Operate if they first obtain an individual minor source construction permit, which addresses all relevant requirements and limitations to demonstrate compliance with OAC 252:100-31-7.

In order to ensure that only facilities processing "sweet" crude oil are permitted under the general permit, the general permit must incorporate a requirement for each facility to identify the type of cure oil produced at the facility. The general permit incorporates monitoring and recordkeeping of the type of crude oil processed at the facility to ensure compliance with this requirement. Facilities should monitor the crude oil sulfur content and/or H_2S concentration to ensure that they remain eligible for the general permit.

SECTION III. LOADING OPERATIONS

For loading operations, the AERSCREEN modeling of a vertical fixed roof tank was used to determine compliance with OAC 252:100-31-7.

- Maximum hourly emissions for loading operations were based on loading a tank truck with a capacity of 11,600 gallons and the default AP-42 (7/2008), Section 5.2, emission factor for submerged loading of crude oil into a tank truck in dedicated normal service of 2 lb/1,000 gallons. Two cases for loading operations were developed based on the concentration of H_2S in crude oil/condensate.
    - The first case is "sweet" crude oil (less than or equal to 0.5% by weight sulfur (S) & 6 ppmw H_2S) with an H_2S/VOC emission ratio of 1,971 ppmw.
    - The second case is "sour" crude oil (greater than 0.5% S & 135 ppmw H_2S) with an H_2S/VOC emission ratio of 44,346 ppmw.

Vertical Fixed Roof Storage Tank AERSCREEN Results (μg/m^3)

	Case 1	**Case 2**
Location 1	57.4	1,291
Location 2	50.7	1,141
Location 3	52.4	1,180

The ambient impacts from Case 2 exceed the H_2S ambient air concentration limit (283 μg/m^3) at all three locations. Based on the modeling and only taking into account impacts from loading operations, the maximum concentration of H_2S in the crude oil that would be in compliance with the standard is 29 ppmw. Since the ambient impacts from loading "sour" crude oil exceed the H_2S ambient air concentration limit, the general permit will exclude those facilities that load "sour" (>0.5% S & 6 ppmw H_2S) crude oil.

Based on the modeling analyses, facilities with "sour" crude oil loading operations would need a case-by-case analysis to demonstrate compliance with the H_2S ambient air concentration limit. Facilities processing "sour" crude oil may be eligible for coverage under an Authorization to Operate if they first obtain an individual minor source construction permit, which addresses all relevant requirements and limitations to demonstrate compliance with the H_2S ambient air concentration limit of OAC 252:100-31-7.

SECTION IV. COMBUSTION EQUIPMENT

A. Engines

The general permit limits the sulfur content of fuel gas for engines (fuel-burning equipment) to 162 ppmv (10 gr/100 SCF). Therefore, the modeling to determine compliance with OAC 252:100-31-7 represents engines combusting fuel gas with an H_2S content of 162 ppmv and a combustion efficiency of 99%, which results in an emission factor of 1.43 x 10^{-4} lb/MMBTU. Three cases were developed for modeling engines: small engines with a stack diameter of less than a foot, medium engines with a stack diameter of equal to one foot, and large engines with a stack diameter greater than a foot. The following table shows the AERSCREEN results for all three cases at each of the three locations.

Engine AERSCREEN 24-hr Average Concentration (µg/m³)

	Case 1	Case 2	Case 3
Location 1	<0.1	0.1	0.1
Location 2	<0.1	<0.1	0.1
Location 3	<0.1	0.1	0.1

The maximum impact for engines is less than 0.1% of the standard (0.3 µg/m³); therefore, all engines combusting fuel with a sulfur content less than 162 ppmv are in compliance with the H_2S ambient air concentration limit.

B. Heaters/Boilers

The general permit limits the sulfur content of the fuel gas for heaters/boilers (fuel-burning equipment) to 162 ppmv (10 gr/100 SCF). Therefore, the modeling to determine compliance with OAC 252:100-31-7 represents heaters/boilers combusting fuel gas with an H_2S content of 162 ppmv and a combustion efficiency of 95%, which results in an emission factor of 7.13 x 10^{-4} lb/MMBTU. Three cases were developed for modeling heaters/boilers: heaters/boilers with a heat input less than one (1) MMBTUH, heaters/boilers with a heat input greater than or equal to one (1) MMTBUH, and heaters/boilers with a heat input greater than or equal to ten (10) MMBTUH. The following table shows the AERSCREEN results for all three cases at each of the three locations.

Heater/Boiler AERSCREEN 24-hr Average Concentration (µg/m³)

	Case 1	Case 2	Case 3
Location 1	0.2	0.3	0.4
Location 2	0.1	0.1	0.1
Location 3	0.1	0.1	0.1

The maximum impact for heater/boilers is about 0.1% of the standard (0.3 µg/m³); therefore, all heaters/boilers combusting fuel with a sulfur content less than 162 ppmv are in compliance with the H_2S ambient air concentration limit.

SECTION V. GLYCOL DEHYDRATION UNITS

The general permit does not specify specific controls for dehydration units. For dehydration units, the AERSCREEN modeling conducted to determine compliance with OAC 252:100-31-7 was based on the following three (3) scenarios:

A. Dehydration Unit Modeling Scenario 1

- Dehydration unit with a throughput of 10 MMSCFD and not equipped with a flash tank. The dehydration unit's still vent is vented directly to the atmosphere without controls. Two cases for this scenario were developed based on the concentration of H_2S in natural gas being treated.
  - The first case is "sweet" natural gas (less than or equal to 4 ppmv H_2S).
  - The second case is "sour" natural gas (greater than or equal to 162 ppmv H_2S).

The following table shows the AERSCREEN results for both cases at each of the three locations.

10 MMSCFD Dehydration Unit AERSCREEN Results (µg/m^3)

	Case 1	Case 2
Location 1	6.9	280.4
Location 2	0.7	30.0
Location 3	0.8	32.2

The ambient impacts from both cases are in compliance with the H_2S ambient air concentration limit (283 µg/m^3) at all three locations. However, the ambient impact from Case 2 at Location 1 has the potential to exceed the H_2S ambient air concentration limit (283 µg/m^3) when taking into account impacts from other sources.

B. Dehydration Unit Modeling Scenario 2

- Dehydration unit with a throughput of 30 MMSCFD and equipped with a flash tank. The dehydration unit's still vent and flash tank are vented directly to the atmosphere without controls. Two cases for this scenario were developed based on the concentration of H_2S in natural gas being treated.
  - The first case is "sweet" natural gas (less than or equal to 4 ppmv H_2S).
  - The second case is "sour" natural gas (greater than or equal to 162 ppmv H_2S).

The following table shows the AERSCREEN results for both cases at each of the three locations.

30 MMSCFD Dehydration Unit AERSCREEN Results (µg/m^3)

	Case 1	Case 2
Location 1	24.3	985.0
Location 2	2.9	119.1
Location 3	3.2	128.2

The ambient impact from Case 2 exceeds the H_2S ambient air concentration limit (283 μg/m^3) at Location 1. Based on the modeling and only taking into account impacts from the dehydration unit, the maximum concentration of H_2S in the natural gas that would be in compliance with the standard is 46 ppmv.

C. Dehydration Unit Modeling Scenario 3

- Dehydration unit with a throughput of 100 MMSCFD and equipped with a flash tank. The dehydration unit's flash tank is routed to the inlet or reboiler fuel gas system and the dehydration unit's still vent is vented through a condenser to the atmosphere. Two cases for this scenario were developed based on the concentration of H_2S in natural gas being treated.
  - The first case is "sweet" natural gas (less than or equal to 4 ppmv H_2S).
  - The second case is "sour" natural gas (greater than or equal to 162 ppmv H_2S).

The following table shows the AERSCREEN results for both cases at each of the three locations.

100 MMSCFD Dehydration Unit AERSCREEN Results (μg/m^3)

	Case 1	Case 2
Location 1	55.2	2,237
Location 2	9.7	394.6
Location 3	10.2	412.8

The ambient impacts from Case 2 exceed the H_2S ambient air concentration limit (283 μg/m^3) at all three locations. Based on the modeling and only taking into account impacts from the dehydration unit, the maximum concentration of H_2S in the natural gas being treated that would be in compliance with the standard is 20 ppmv.

D. Summary

The maximum modeled concentrations for Scenarios 2 and 3, Case 2 ("sour" natural gas) are greater than the 0.2 ppm (283 μg/m^3) H_2S ambient air concentration limit. The maximum modeled concentrations for Scenarios 1, 2, and 3, Case 1 ("sweet" natural gas) and Scenario 1, Case 2 ("sour" natural gas) do not exceed the H_2S ambient air concentration limit. However, the impacts from Scenario 1, Case 2 when combined with other facility impacts could exceed the H_2S ambient air concentration limit. Therefore, the general permit will exclude those facilities with dehydration units that treat "sour" (>4 ppmv H_2S) natural gas.

Based on the modeling analyses, facilities with dehydration units that treat "sour" (>4 ppmw H_2S) natural gas would need a case-by-case analysis to demonstrate compliance with the H_2S ambient air concentration limit. Facilities with dehydration units that treat "sour" (>4 ppmw H_2S) natural gas may be eligible for coverage under an Authorization to Operate if they first obtain an individual minor source construction permit, which addresses all relevant requirements and limitations to demonstrate compliance with OAC 252:100-31-7.

In order to ensure that only facilities with dehydration units only process “sweet” (≤ 4 ppmw H_2S) natural gas are permitted under the general permit, the general permit must incorporate a requirement for determining the H_2S content of gas treated by a facility with a dehydration unit. The general permit incorporates monitoring and recordkeeping of the H_2S content of the natural gas for facilities with dehydration units to ensure compliance with this requirement. Facilities with dehydration units should also continue to monitor the H_2S concentration of the natural gas to ensure that they remain eligible for the general permit.

SECTION VI. AMINE UNITS

For amine units, the AERSCREEN modeling conducted to determine compliance with OAC 252:100-31-7 was based on the following two (2) scenarios:

A. Amine Unit Modeling Scenario 1

- Amine unit still vents with H_2S emission less than or equal to 0.3 lb/hr. The amine unit still vent is vented directly to the atmosphere without controls. Two cases for this scenario were developed based on the concentration of H_2S in natural gas being treated.
  - The first case is a facility which treats “sweet” natural gas (less than or equal to 4 ppmv H_2S).
  - The second case is a facility which treats “sour” natural gas (greater than 4 ppmv H_2S (10 ppmv)).

The following table shows the AERSCREEN results for both cases at each of the three locations.

Uncontrolled Amine Unit AERSCREEN Results (μg/m^3)

	Case 1	Case 2
Location 1	384.0	539.4
Location 2	191.9	213.3
Location 3	198.8	231.1

The ambient impacts from Case 1 and Case 2 exceed the H_2S ambient air concentration limit (283 μg/m^3) at Location 1. However, the ambient impact from Case 2 at Location 3 also has the potential to exceed the H_2S ambient air concentration limit (283 μg/m^3) when taking into account impacts from other sources.

B. Amine Unit Modeling Scenario 2

- Amine unit still vents with H_2S emission greater than 0.3 lb/hr. and flared (oxidized). Two cases for this scenario were developed based on the concentration of H_2S in natural gas being treated.
  - The first case is based on the de minimis level of H_2S emissions 0.3 lb/hr being flared, assuming 95% control (0.015 lb/hr H_2S).
  - The second case is based on the maximum amount of SO_2 emissions for a minor source or the major source threshold. Assuming 95% control and 99 TPY (23.79 lb/hr) SO_2, this is equivalent to uncontrolled H_2S emissions of 0.63 lb/hr.

The following table shows the AERSCREEN results for both cases at each of the three locations.

Controlled Amine Unit AERSCREEN Results (μg/m^3)

	Case 1	Case 2
Location 1	0.9	246.9
Location 2	0.2	38.3
Location 3	0.2	31.1

The ambient impacts from both cases are in compliance with the H_2S ambient air concentration limit (283 μg/m^3) at all three locations. However, the ambient impact from Case 2 at Location 1 has the potential to exceed the H_2S ambient air concentration limit (283 μg/m^3) when taking into account impacts from other sources.

C. Summary

The maximum modeled concentration for Scenario 1, Case 1 and 2 are above the 0.2 ppm (283 μg/m^3) H_2S ambient air concentration limit at Location 1. Therefore, the general permit will exclude those facilities with uncontrolled amine units. The maximum modeled concentration for Scenario 2, Case 2 is within 80% of the H_2S ambient air concentration limit at Location 1. Therefore, the general permit will exclude those facilities with controlled amine units treating "sour" natural gas.

Based on the modeling analyses, facilities with uncontrolled amine units and controlled amine units treating "sour" natural gas would need a case-by-case analysis to demonstrate compliance with the H_2S ambient air concentration limit. Facilities with uncontrolled amine units or controlled amine units treating "sour" natural gas may be eligible for coverage under an Authorization to Operate if they first obtain an individual minor source construction permit, which addresses all relevant requirements and limitations to demonstrate compliance with OAC 252:100-31-7.

In order to ensure that only facilities with controlled amine units treating "sweet" ($\leq$ 4 ppmw H_2S) natural gas are permitted under the general permit, the general permit must incorporate a requirement for determining the H_2S content of gas treated by a facility with an amine unit and establish that all amine units must be flared. The general permit incorporates monitoring and recordkeeping of the H_2S content of the natural gas for facilities with amine units to ensure compliance with the requirement that the amine unit treat "sweet" natural gas. The general permit also establishes a requirement that facilities with amine units route the flash tank and still vent of the amine unit to a control device. Facilities with amine units should also continue to monitor the H_2S concentration of the natural gas to ensure that they remain eligible for the general permit.

SECTION VII. FUGITIVE EMISSION SOURCES

For fugitive emission sources, the AERSCREEN modeling used to determine compliance with OAC 252:100-31-7 was based on a 150 ft x 150 ft volume source emitting 5 TPY of VOC from components in gas and liquid service for a facility processing natural gas with a maximum H_2S concentration of 162 ppmv and "sweet" crude oil (less than or equal to 0.5% S & 6 ppmw H_2S).

The following table shows the AERSCREEN results for Scenario 1 at each of the three locations.

AERSCREEN 24-hr Average Concentrations (μg/m^3)

	Scenario 1
Location 1	0.1
Location 2	0.1
Location 3	0.1

The maximum modeled concentration is less than 1% of the standard; therefore, impacts from fugitive equipment leaks in gas service processing natural gas with a maximum H_2S concentration of 162 ppmv and in liquid service processing "sweet" crude oil or condensate are in compliance with the ambient air concentration limit.

SECTION VIII. SUMMARY

A. Storage Tanks

Storage tanks at facilities producing or handling "sweet" (<0.5% S & 6 ppmw H_2S) crude oil will have impacts below the H_2S ambient air concentration limit. Storage tanks at facilities producing or handling "sour (>0.5% S & 135 ppmw H_2S) crude oil have the possibility of exceeding the H_2S ambient air concentration limit. Limiting the general permit to facilities that produce or handle "sweet" crude oil will ensure compliance with OAC 252:100-31-7.

B. Loading Operations

Loading operations involving "sweet" (<0.5% S & 6 ppmw H_2S) crude oil at production sites and condensate at compressor stations will have impacts below the H_2S ambient air concentration limit Limiting the general permit to facilities that load "sweet" crude oil or condensate into tank trucks will ensure compliance with OAC 252:100-31-7.

C. Combustion Equipment

Engines and heaters/boilers combusting fuel with a sulfur content less than 162 ppmv have impacts of less than 0.1% of the H_2S ambient air concentration limit and will not contribute significantly to the facility wide impact. Limiting the fuel sulfur content of combustion equipment to 162 ppmv will ensure compliance with OAC 252:100-31-7.

D. Glycol Dehydration Units

Dehydration units processing “sweet” (≤ 4 ppmv H_2S) natural gas will have impacts below the H_2S ambient air concentration limit. Dehydration units processing “sour” (> 4 ppmv H_2S) natural gas have the possibility of exceeding the H_2S ambient air concentration limit. Limiting the general permit to facilities with dehydration units that processing “sweet” (≤ 4 ppmv H_2S) natural gas will ensure compliance with OAC 252:100-31-7.

E. Amine Units

Controlled amine units processing “sweet” (≤ 4 ppmv H_2S) natural gas will have impacts below the H_2S ambient air concentration limit. Uncontrolled amine units processing “sweet” (≤ 4 ppmv H_2S) natural gas and controlled amine units processing “sour” (> 4 ppmv H_2S) natural gas have the possibility of exceeding the H_2S ambient air concentration limit. Limiting the general permit to facilities with controlled amine units that processing “sweet” (≤ 4 ppmv H_2S) natural gas will ensure compliance with OAC 252:100-31-7.

F. Fugitive Emission Sources

Emissions from fugitive equipment leaks at facilities processing “sweet” crude oil, condensate, and natural gas containing less than 162 ppmv H_2S will have impacts of less than 0.1% of the H_2S ambient air concentration limit and will not contribute significantly to the facility wide impact. Limiting the general permit to facilities that process “sweet” crude oil, condensate, or natural gas containing less than 162 ppmv H_2S will ensure compliance with OAC 252:100-31-7.

G. Facility Wide Compliance

The H_2S ambient air concentration of OAC 252:100-31-7 is applicable to each facility as a whole. Since not each type of oil and gas facilities will have all of the emission sources which have been evaluated, a number of representative oil and gas facility types were established to evaluate the impacts from the whole facility for the types of emission sources usually located at those facilities.

Typical Emission Units Located at Specific Types of Facilities

Emission Units	Production Sites	Tank Battery	Compressor Station[1]	Transfer Station	Storage Facility
FR Storage Tank	X	X	X[2]	X	
IFR Storage Tank				X	X
EFR Storage Tank				X	X
Loading Operation	X	X	X[2]		
Combustion Equipment	X	X	X		
Dehydration Unit	X[3]		X		
Amine Unit	X[3]		X[3]		
Fugitive Sources	X	X	X	X	X

[1] - Compressor stations also represents gas plants since similar equipment is located at both.

[2] - Even though compressor stations will have FR storage tanks and loading operations, the liquids handled at compressor stations do not contain significant amounts of H_2S.

[3] - Most facilities will not have multiple dehydration units or amine units so the evaluation only takes into account impacts from a single dehydration unit or amine unit.

Cumulative H_2S Impact at a Production Site

Emission Units	Source Impact (μg/m^3)
FR Storage Tank [1]	55.9
Loading Operation [1]	57.4
Combustion Equipment [2]	1.0
Dehydration Unit [3]	55.2
Amine Unit [4]	0.9
Fugitive Sources	0.1
Total H_2S Impact	**170.5**

[1] - Based on "sweet" crude oil.

[2] - Based on maximum impact for engines and heaters/boilers and two engines and two heaters/boilers.

[3] - Based on maximum impact for a dehydration unit treating "sweet" natural gas.

[4] - Based on maximum impact of a controlled amine unit treating "sweet" natural gas.

Cumulative H_2S Impact at a Tank Battery

Emission Units	Source Impact (μg/m^3)
FR Storage Tank [1]	55.9
Loading Operation [1]	57.4
Combustion Equipment [2]	0.8
Fugitive Sources	0.1
Total H_2S Impact	**114.2**

[1] - Based on "sweet" crude oil.

[2] - Based on maximum impact for heaters/boilers and two heaters/boilers.

Cumulative H_2S Impact at a Compressor Station

Emission Units	Source Impact (μg/m^3)
FR Storage Tank [1]	55.9
Loading Operation [1]	57.4
Combustion Equipment [2]	2.2
Dehydration Unit [3]	55.2
Amine Unit [4]	0.9
Fugitive Sources	0.1
Total H_2S Impact	**171.7**

[1] - Based on "sweet" crude oil.

[2] - Based on maximum impact for engines and heaters/boilers and ten engines and three heaters/boilers.

[3] - Based on maximum impact for a dehydration unit treating "sweet" natural gas.

[4] - Based on maximum impact for a controlled amine unit treating "sweet" natural gas.

Transfer Station/Storage Facility

Emission Units	Source Impact (µg/m^3)
FR Storage Tank [1]	55.9
EFR Storage Tank [1]	120.2
IFR Storage Tank [1]	60.6
Fugitive Sources	0.1
Total H_2S Impact	**236.8**

[1] - Based on "sweet" crude oil.

Based on the modeling, the cumulative impact of the facilities is below the H_2S ambient air concentration limit. To ensure compliance with OAC 252:100-31-7, the general permit should exclude the following:

- Facilities that produce or handle "sour" crude oil;
- Facilities with uncontrolled amine units;
- Facilities with controlled amine units treating "sour" natural gas;
- Facilities with multiple amine units; and
- Facilities with glycol dehydration units treating "sour" natural gas.

These facilities may be eligible for coverage under an Authorization to Operate if they first obtain an individual minor source construction permit, where all relevant requirements and limitations demonstrate compliance with OAC 252:100-31-7.

DRAFT

AIR QUALITY
GENERAL PERMIT TO CONSTRUCT/OPERATE
OIL & GAS FACILITIES
(For Minor Facilities)
OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR QUALITY DIVISION
707 NORTH ROBINSON, P. O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

In compliance with the provisions of the Oklahoma Clean Air Act, as amended (27A O.S., et seq.) and rules promulgated thereunder, operators of oil and gas facilities (OGF), as described under Part 1, Section III below, are hereby granted permission to construct/operate such facilities as specified in an Authorization to Construct/Operate (hereinafter referred to as an "Authorization") issued under this permit by the Department of Environmental Quality (DEQ). Parts 1 through 3 and Appendices A through D of this permit specify emission limitations and standards that constitute applicable requirements, including state-only requirements, and include operational requirements and limitations necessary to assure compliance with all applicable air pollution rules. All OGF shall remain subject to the Oklahoma Clean Air Act, Okla. Stat. tit. 27A §§ 2-5-101 to -118 and the rules promulgated thereunder at Okla. Admin. Code ("OAC"), Air Pollution Control, Title 252, Chapter 100-1-1 to -47-14.

The owner or operator of an OGF may request that the facility be granted coverage under this permit by submitting to the Air Quality Division (AQD) a complete application that includes appropriate forms and fees for an OGF General Permit. Eligible facilities may apply for coverage under this permit at any time during the permit term, noting on the applicable form whether the facility will have enforceable limits set below 80 TPY or 100 TPY.

Signed and issued this day, ______________________, 2022.

_________________________ Kendal Stegmann, Division Director

Table of Contents

PART 1 - REQUIREMENTS FOR GENERAL PERMIT

This Permit is issued for the oil and gas facility (OGF) source category to establish (A) terms and conditions to implement applicable air pollution rules and regulations applicable to OGF, and (B) federally-enforceable limits (FEL)/caps on emissions. The Permit is issued after finding that there are a significant number of facilities that have the same or substantially similar operations, emissions, and activities that are subject to the same or similar standards, limitations, and operating and monitoring requirements.

SECTION I. AUTHORITY

This permit is developed in accordance with the provisions of OAC 252:100-7-15 and 100-7-18.

SECTION II. APPLICABILITY

This permit authorizes construction and/or operation of OGF with potential emissions less than 100 tons/year (TPY) of a regulated pollutant in an attainment area, less than 10 TPY of any single hazardous air pollutant (HAP), and less than 25 TPY of total HAPs.

SECTION III. ELIGIBILITY

A. This permit is limited to air pollutant emitting sources located at OGF that are designed and operated for the production, gathering, processing, storage, or transportation of crude oil, refined petroleum products, natural gas, and natural gas liquids (NGL), including condensate.

The following types of facilities are generally eligible for coverage under this permit:

1. New facilities.

2. Existing facilities, including those with previously issued minor source construction and/or operating permits, or those previously exempted from the requirement to obtain a permit.

3. Facilities existing prior to the effective date of any applicable standard that would have created specific quantifiable and enforceable emission rates.

B. The following facilities are not eligible for this permit:

1. Facilities for which material facts were misrepresented or omitted from the application and the applicant knew or should have known of such misrepresentation or omission.

2. Facilities with emissions units that are affected sources subject to:

a. OAC 252:100-8 (Permits for Part 70 Sources)

b. OAC 252:100-17 (Incinerators)

C. The following facilities are not eligible to obtain an Authorization to Construct under this permit, but may be eligible for coverage under an Authorization to Operate if they obtain a minor source construction permit and all relevant requirements and limitations in that construction permit are incorporated into the Authorization to Operate:

1. Facilities with combustion equipment fired with fuels other than liquid petroleum gas (LPG) or natural gas with a maximum total sulfur content greater than 162 ppmv; or stationary reciprocating engines burning liquid fuels other than gasoline, diesel fuel, or No. 2 fuel oil with a total sulfur content greater than 0.05% by weight.

2. Facilities storing/distributing crude oil that cannot demonstrate a maximum H_2S concentration of 6 ppmw for all categories of crude oil stored at the facility. Such demonstration must be documented using the methods outlined in Appendix B of this permit.

3. Facilities that use incinerators, regenerative or non-regenerative carbon absorbers, or catalytic systems to control emissions of H_2S.

4. Facilities with a VOC loading facility subject to OAC 252:100-37-16(a) or OAC 252:100-39-41.

5. Facilities with glycol dehydration units that process natural gas with an H_2S content greater than 4 ppmv.

6. Facilities with amine units under the following conditions: (1) that process natural gas with an H_2S content greater than 4 ppmv; or (2) that do not control emissions from the rich amine flash tank and amine regeneration vent. To be considered controlled, the rich amine flash tank can either be routed to the inlet, fuel gas system, or a flare. The amine regeneration still vent must be routed to a flare meeting the requirements of OAC 252:100-31-26. Facilities with amine units that process natural gas with an H_2S content greater than 4 ppmv, or that do not control emissions from the rich amine flash tank and amine regeneration vent, would require a site-specific determination of compliance with the H_2S ambient concentration limit of OAC 252:100-31-7.

7. Facilities with amine units that process more than 0.1276 long ton per day (LTPD) of sulfur. Facilities with amine units without sulfur recovery that process more than 0.1276 LTPD of sulfur would be a major source for SO_2.

8. Facilities with "new fuel-burning equipment," as that term is defined in OAC 252:100-33, with a rated heat input of 50 MMBtu/hr or greater (excluding reciprocating engines).

9. Facilities with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) control systems on any engine or other combustion source. These

are control systems that require injection of ammonia, and do not include 3-way catalyst (NSCR) or oxidation catalyst.

10. Facilities that require a specific limitation(s) not otherwise addressed in order to maintain compliance with the cap.

11. Facilities located in an area that is federally designated as non-attainment.

12. Facilities that request an Alternative Emissions Reduction Authorization under OAC 252:100-11.

13. Facilities requesting control efficiencies above the levels allowed in Appendix A of this Permit.

14. Facilities requesting unit specific limits not allowed or required under the general permit.

D. Conditions established in an individual minor source construction permit and incorporated into an Authorization to Operate, may supersede conditions established in the GP-OGF, as long as the requirements that are incorporated are in compliance with all currently applicable rules and regulations.

E. The DEQ may not issue a permit authorization sought by an applicant that has not paid all monies owed to the DEQ or is not in substantial compliance with the Environmental Quality Code, DEQ rules and the terms of any existing DEQ permits and orders. The DEQ may impose special conditions on the applicant to assure compliance and/or a separate schedule which the DEQ considers necessary to achieve required compliance.

F. The DEQ may refuse issuance of an Authorization to an applicant even though the facility meets the above eligibility criteria. In such a case, DEQ will provide to the facility a written explanation providing the reason(s) for the decision.

SECTION IV. AUTHORIZATIONS

An applicant requesting an authorization under this permit may obtain coverage in one of the following ways.

A. An applicant proposing to construct a new facility that meets all of the eligibility requirements, excluding those facilities listed in Part 1, Section III.C, may apply for an Authorization to Construct by submitting a complete Notice of Intent (NOI) to Construct application that includes the appropriate forms and fees for an OGF General Permit. Coverage under this permit is effective, and the permittee may commence construction, upon receipt by the DEQ of the NOI to Construct and fees or confirmation of fees received (a receipt) by the DEQ. The earliest of (1) a legible dated U.S. Postal Service postmark (private metered postmarks are not acceptable); (2) a dated receipt from a commercial carrier or the U.S. Postal Service; (3) a DEQ date stamped application; or (4) a date of receipt of a digital copy of an application is acceptable documentation of receipt of the NOI to Construct. A confirmation letter is issued by the DEQ after confirming that the application is administratively complete, the proper fee has been received, and that the facility is eligible for coverage under this permit.

B. An applicant proposing to construct a new facility that meets the eligibility requirements listed in Part 1, Section III.C, must apply for a minor source construction permit for the facility since a case-by-case determination is most likely required in order to establish enforceable limitations for some particular emission unit. All relevant requirements and limitations in the minor source construction permit can be incorporated into the Authorization to Operate under this permit.

C. An applicant proposing to obtain coverage under this permit for an existing, previously permitted facility, need only submit an application for an Authorization to Operate if the facility meets all of the eligibility requirements, including those listed in Part 1, Section III.C. Under this scenario, facilities that have not obtained authorization under an NOI to Construct, coverage under the GP-OGF is not effective until the issuance of the Authorization to Operate.

D. An applicant proposing to obtain coverage under this permit for an existing facility, not previously required to be permitted, need only submit an application for an Authorization to Operate, unless the facility is required to obtain an individual construction permit based on the criteria in Part 1, Section III.C. Under this scenario, facilities that have not obtained authorization under an NOI to Construct, coverage under the GP-OGF is not effective until the issuance of the Authorization to Operate.

E. An applicant proposing to modify an existing facility (e.g., add, modify, reconstruct, or replace equipment or increase emissions) already covered by an Authorization to Operate under this general permit must meet the requirements specified in Part 3, Section II of this permit. Note that an applicant proposing to modify an existing facility only needs to obtain a new Authorization to Operate if the change is not provided for in the definition of Notice of Modification (NOM). However, if a minor source individual construction permit is required to make a modification as described under Part 1, Section III.C of this permit, a new Authorization to Operate is required.

F. A new Authorization is not required to add or replace an engine, as long as the facility-wide emissions cap is not equaled or exceeded (80 TPY for Class I facilities or 100 TPY for Class II facilities) assuming operation of the new engine at its potential emission rates for its intended hours of operation. The addition or replacement of an engine shall be made in accordance with Paragraph H of Part 2, Section IV.

G. An applicant proposing to operate under an individual minor source permit for an existing facility already covered by an Authorization to Construct under this permit must meet the requirements for a minor source individual permit and submit the required applications forms and fees within the specified time frame. The fees include those required for the individual construction permit fee as well as individual operating permit fees.

SECTION V. PERMIT TERM

This permit shall remain valid and in effect unless it is modified or revoked in accordance with DEQ rules.

If this permit is modified, the DEQ shall establish the terms and conditions under which existing Authorizations under this permit will be authorized under the modified General Permit.

PART 2 – SPECIFIC CONDITIONS

Facilities shall be designed, constructed, and operated to meet the following terms and conditions, and any other applicable air pollution rules specified in this permit, the facility's Authorization, and any other requirements specified by rule or statute.

SECTION I. FACILITY-WIDE REQUIREMENTS

The following specific conditions apply facility-wide.

Emissions Cap

A. Emission limitations included here shall be applicable to each facility upon the submittal of an administratively complete application for a Notice of Intent to Construct or an issued Authorization to Operate. This general permit establishes emissions limitations for Class I and Class II facilities covered under this permit as a facility-wide emissions cap. Class II facilities shall limit actual emissions to less than the major source levels of 100 TPY of any regulated air pollutant or 10 TPY of a single HAP/25 TPY of any combination of HAP. Class I facilities shall limit actual emissions to less than 80% of the major source levels.

B. Compliance with these emission limitations shall be determined at least monthly and be based on a 12-month rolling total. As an alternative approach for compliance with the 12-month rolling total emission limits, facilities can calculate PTE for all equipment based on specific oil and gas throughputs and hours of operation. The applicant then may use those PTE calculations as the demonstration of compliance provided the throughputs and hours of operations (maintained on a monthly and 12-month rolling total) used in those PTE calculations have not been exceeded and where no other physical or operational changes have occurred.

C. The facility throughput and/or equipment hours of operation shall be constrained as necessary to not exceed any facility-wide emissions cap.

D. Maintenance, Startup, and Shutdown (MSS) emissions shall be included as part of the facility-wide emissions cap.

Emission Calculations

E. Actual emissions shall be calculated and documented in accordance with OAC 252:100-5-2.1(c) and (d), or as otherwise specified in this permit or an Authorization. Various processes rely on representative gas and liquid analyses to determine emissions. DEQ guidance addresses criteria for accepting representative versus site-specific analyses: “Representative Sampling Guidance” which is found in the AQD guidance section of the DEQ website. The emissions calculations required here shall include the items identified below that are contained in the De Minimis Facilities list in OAC 252:100, Appendix H.

Storage Tanks

- Fuel/VOC storage tanks with less than 400 gallons capacity, or fuel/VOC storage tanks with less than 10,567 gallons capacity built after July 23, 1984, or tanks storing fuel/VOC that has a true vapor pressure at storage conditions less than 1.5 psia. This includes Fuel Oils Nos. 2 - 6, Nos. 2-GO - 4-GO, Diesel Fuel Oils Nos. 2-D - 4-D, and Kerosene.*
- Tanks containing separated water produced from oil and gas operations.
- Emergency use equipment, unless utilized in excess of 500 hours per year, and associated fuel storage tankage.*

Blowdowns

- Blowdown of compressors or other vessels containing natural gas or liquid hydrocarbons for maintenance due to emergency circumstances

Combustion Equipment

- Space heaters and boilers less than 10 MMBTU/hr heat input.**
- Emissions from non-natural gas fueled stationary internal combustion engines rated less than 50 hp output.**
- Emissions from gas turbines with less than 215 kilowatt rating of electric output.**
- Natural gas fueled internal combustion engines rated <150 hp and <20 years old.**
- Emergency use equipment, unless utilized in excess of 500 hours per year, and associated fuel storage tankage.*

Fugitive Emission Sources

- Pneumatic starters on reciprocating engines, turbines, compressors, or other equipment.*
- Instrument systems utilizing air or natural gas.*

MSS

- Pipeline Maintenance Pigging Activities.
- General maintenance, upkeep, and replacement activities, including those which do not alter the capacity of process, combustion or control equipment nor increase regulated pollutant emissions, unless subject to NESHAP or NSPS.*
- Crude oil tank bottom reclaiming.*

Miscellaneous

- Vent emissions from gas streams used as buffer or seal gas in rotating pump and compressor seals.*
- Engine crankcase vents and equipment lubricating sumps.*

* In lieu of specific monitoring, recordkeeping, and calculations, the De Minimis Facilities activities designated with an asterisk (*) can use a simplified method of representing emissions by assuming emissions are 5 TPY for all emission units contained within the defined activity. For those activities designated with **, each emission unit within the defined activity can use a simplified method of representing emissions by assuming emissions are 5 TPY for each emission

unit. For those activities requiring specific calculations or where a facility elects to not use the simplified method, the calculation methods specified in the individual sections shall be used.

Oklahoma Air Pollution Control Rules

F. In no case shall the permittee cause or allow the emission of any regulated air pollutant in such a concentration as to cause or contribute to a violation of ambient air quality standards or other applicable air pollution rules. [OAC 252:100-3]

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

H. For all emissions units not subject to an opacity limit promulgated under 40 CFR Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

1. 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;
2. Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
3. An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
4. Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

I. The permittee shall take reasonable precautions to minimize or prevent pollution from the release of fugitive dust into the air by any operation or activity, as required under OAC 252:100-29. [OAC 252:100-29]

J. Gas-fired combustion equipment operated under this permit shall be fueled only with liquid petroleum gas (LPG) or natural gas with a maximum total sulfur content of 162 ppmv. Compliance shall be demonstrated at least once annually and may be demonstrated by one of the following recordkeeping requirements. [OAC 252:100-31 & -43]

1. For gaseous fuel, a current gas company bill or a current gas contract, tariff sheet, or transportation contract for the natural gas fuel that demonstrates the maximum total sulfur content of the natural gas fuel does not exceed 10 grains/100 scf.

2. Technical data or gas sampling data demonstrating that the maximum total sulfur content of natural gas from the facility's production area does not exceed 10 grains/100 scf.

3. Representative fuel sampling data (including in-line analyzer data, lab analysis, or sampling by Draeger tubes), that shows the maximum total sulfur content of the natural gas fuel does not exceed 10 grains/100 scf. If using hydrogen sulfide Draeger tubes to demonstrate compliance, the measured concentration of hydrogen sulfide must be less than 9 grains/100 scf or 146 ppmv.

K. Liquid-fired combustion equipment operated under this permit shall be fueled only with gasoline, diesel or No. 2 through No. 6 fuel oil. Liquid fuels are limited to a maximum of 0.05% sulfur by weight, except for engines that are subject to 40 CFR Part 60, Subparts IIII and/or JJJJ, which must use fuel that meets the more stringent requirements of those subparts (see Part 2, Sections IV.M and IV.N). The permittee shall certify in the NOI to Construct compliance with the standard and provide with the application for an Authorization to Operate a fuel composition analysis that shows total sulfur content. Thereafter, the permittee shall perform a fuel analysis that shows total sulfur content once per load received and shall maintain records of the required fuel sulfur analysis. A one-time certification of sulfur content of a grade of fuel, with subsequent receipts stating the fuel grade delivered from the supplier, is sufficient to document compliance with this requirement. A new certification shall be obtained from each new supplier.

[OAC 252:100-31 & -43]

L. Glycol dehydration units and amine units operated under this permit shall not process natural gas or natural gas liquids with a hydrogen sulfide concentration greater than 4 ppmv. Compliance shall be demonstrated at least once annually and may be demonstrated by one of the following recordkeeping requirements. [OAC 252:100-31 & -43]

1. A current gas contract, tariff sheet, or transportation contract that demonstrates the maximum hydrogen sulfide concentration of the natural gas or natural gas liquids does not exceed 4 ppmv (0.25 grains/100 scf).

2. Technical data or gas sampling data demonstrating the hydrogen sulfide concentration of natural gas or natural gas liquids from the facility's production area does not exceed 4 ppmv (0.25 grains/100 scf).

3. Representative sampling data (including on-line analyzer data, lab analysis, or sampling by Draeger tubes), that shows the hydrogen sulfide concentration of the natural gas or natural gas liquids does not exceed 4 ppmv (0.25 grains/100 scf).

M. Emission units, and control devices associated with any emission units constructed under this permit, shall comply with all applicable requirements of OAC 252:100-43, and Appendix A of this permit. Records of operation and maintenance procedures required by the manufacturer for any control devices used in Appendix A shall be kept

[OAC 252:100-43]

N. The permittee shall install, use, and maintain such monitoring equipment as specified in Appendix A of this permit, except as otherwise specified elsewhere in this permit or in an Authorization, or in applicable rules or statutes. [OAC 252:100-43]

O. The permittee shall document that all testing is conducted using methods specified in 40 CFR Parts 51, 60, 61, or 63, as applicable, or as otherwise specified in this permit or in an Authorization. A copy of these records shall be retained with the records containing the facility's test results. [OAC 252:100-43]

Recordkeeping

P. The permittee shall maintain records of emissions, including monthly and facility-wide 12-month rolling totals of NO_X, CO, VOC, and HAP emissions, and any compliance demonstrations required by this permit. When an amine unit is present, the permittee shall also maintain records of emissions, including monthly and facility-wide 12-month rolling totals of SO_2 emissions, and any compliance demonstrations required by this permit. An emissions record shall describe calculated emissions of regulated air pollutants from all emission units. This record shall include the emission unit identification number, control method used, operating hours, and other operating parameters as specified in specific conditions for each particular emission unit. [OAC 252:100-43]

Q. The permittee shall keep documents demonstrating the sulfur content of any fuel burned per paragraphs I and J of this section. [OAC 252:100-43]

R. The permittee shall maintain an equipment inventory. Such inventory shall be updated each time there is any change to any facility equipment (i.e., addition, removal, or replacement) that is subject to this permit, except for the fugitive components addressed in Section VII. The records shall include the equipment description, equipment serial or identification number, date of the change, description of the change, NSPS and/or NESHAP applicability, and a calculation of the potential to emit of the facility. A copy or summary of this record shall be provided with any application. If equipment is being added subject to NSPS or NESHAP that has not undergone the initial compliance demonstration as required by 40 CFR 60.8, the notification shall include a date and time for such required demonstration. [OAC 252:100-43]

SECTION II. STORAGE TANKS

The following specific conditions apply to VOC storage tanks (including produced water storage tanks).

Emission Calculations

A. To demonstrate compliance with Part 2, Section I of this permit, the permittee shall calculate actual emissions of VOC and HAP from all storage tanks with a capacity of 400 gallons or more that store VOCs (including produced water storage tanks). The permittee will be required to calculate emissions of VOC and HAP from these storage tanks based on actual throughputs, a maximum capture efficiency of 98% when using a control device, the maximum allowed control efficiency in Appendix A of the GP-OGF, and AP-42 Chapter 7 and/or AQD approved software programs. Flash emission calculations shall follow the procedures presented in the AQD guidance documents, "VOC

Emissions/Flashing Losses from Hydrocarbon Storage Tanks" and "Representative Sampling Guidance." Storage tanks using vapor balancing during unloading shall include captured loading loss emissions in tank emissions or use the designated turnover factor K_N in working loss emissions calculations. [OAC 252:100-43]

Federally Enforceable Limits

B. Emissions from individual storage tanks, as requested in the GP-OGF application or NOM, shall be limited to 5.9 TPY VOC. Compliance shall be demonstrated at least monthly based on a 12-month rolling total. [OAC 252:100-7-15(d)(3) & 252:100-7-18(f)(2)]

C. Averaging of facility-wide throughput across tanks at a storage vessel battery, constructed, modified, or reconstructed after November 16, 2020, which consists of two or more storage vessels, shall only be allowed if it meets all of the design and operational criteria specified below: [§60.5365a(e)(3)]

1. The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels;
2. The storage vessels must be equipped with a closed vent system that is designed, operated, and maintained to route the vapors back to the process or to a control device;
3. The vapors collected in (1) above must be routed back to the process or to a control device that reduces VOC emissions by at least 95.0 percent.

Oklahoma Air Pollution Control Rules

D. For all storage tanks equipped with an external floating roof (EFR) and with a capacity of more than 40,000 gallons, and that are not subject to an NSPS standard, the permittee shall perform routine inspections of all seal closure devices annually; measure the secondary seal gap annually when the floating roof is equipped with a vapor-mounted primary seal; and maintain records of the above inspections and maintenance or other repairs. [OAC 252:100-43]

E. 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 storage conditions, except for petroleum or condensate stored, processed and/or treated at a drilling or production facility prior to lease custody transfer and except for methanol stored at drilling or production facilities, shall be equipped with a permanent submerged fill pipe, be bottom filled, or have a vapor recovery system installed. [OAC 252:100-37-15 and OAC 252:100-39-41]

F. VOC storage tanks constructed after December 28, 1974, with a capacity greater than 40,000 gallons storing a liquid with a vapor pressure of 1.5 psia or greater under actual storage conditions, except for petroleum or condensate stored, processed and/or treated at

a drilling or production facility prior to lease custody transfer and except for methanol stored at drilling or production facilities, shall be a pressure vessel capable of maintaining working pressures that prevent the loss of VOC to the atmosphere, or shall be equipped with an external floating roof that meets the standards of OAC 252:100-37-15 (a)(1).
[OAC 252:100-37-15(a)]

G. The permittee shall comply with all applicable requirements set forth in OAC 252:100-39-30.

1. Any petroleum liquid storage vessel operated under this permit which is equipped with an external floating roof, has a capacity greater than 40,000 gallons, and is located in Tulsa or Oklahoma County, is required to meet the additional requirements of OAC 252:100-39-30, Petroleum Liquid Storage including, but not limited to:

   a. Standards of OAC 252:100-39-30(c)(1);
   b. Monitoring requirements of OAC 252:100-39-30(c)(2), and;
   c. Recordkeeping requirements of OAC 252:100-39-30(c)(3).

2. These requirements do not apply to petroleum liquid storage vessels that:

   a. Are used to store waxy, high pour point crude oil;
   b. Have a capacity less than 422,675 gallons and are used to store produced crude oil or condensate prior to lease custody transfer;
   c. Contain a petroleum liquid with a true vapor pressure less than 1.5 psia;
   d. Contain a petroleum liquid with a true vapor pressure less than 4.0 psia, is of welded construction, and presently possesses a metallic-type shoe seal, a liquid-mounted foam seal, or a liquid-mounted liquid filled type seal;
   e. Are of welded construction and are equipped with a metallic-type shoe primary seal and have a secondary seal from the top of the shoe seal to the tank wall (shoe-mounted secondary seal). [OAC 252:100-39-30(b)(2)]

H. If a control device is used to reduce emissions, the permittee shall comply with the requirements specified in Appendix A of this Permit. [OAC 252:100-43]

Federal Regulations

I. The permittee shall comply with all applicable requirements set forth in NSPS 40 CFR Part 60, including, but not limited to, the following.

1. Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. [40 CFR §§60.110 - 60.113]

   a. § 60.110 Applicability and designation of affected facility.
   b. § 60.111 Definitions.
   c. § 60.112 Standard for volatile organic compounds (VOC).

d. § 60.113 Monitoring of operations.

2. Subpart Ka – Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984. [40 CFR §§60.110a - 60.115a]

a. § 60.110a Applicability and designation of affected facility.
b. § 60.111a Definitions.
c. § 60.112a Standard for volatile organic compounds (VOC).
d. § 60.113a Testing and procedures.
e. § 60.114a Alternative means of emission limitation.
f. § 60.115a Monitoring of operations.

3. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. [40 CFR §§60.110b - 60.117b]

a. § 60.110b Applicability and designation of affected facility.
b. § 60.111b Definitions.
c. § 60.112b Standard for volatile organic compounds (VOC).
d. § 60.113b Testing and procedures.
e. § 60.114b Alternative means of emission limitation.
f. § 60.115b Reporting and recordkeeping requirements.
g. § 60.116b Monitoring of operations.
h. § 60.117b Delegation of authority.

4. Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced After August 23, 2011, and on or before September 18, 2015. [40 CFR §§60.5360 - 60.5430]

a. §60.5360 What is the purpose of this subpart?
b. §60.5365 Am I subject to this subpart?
c. §60.5370 When must I comply with this subpart?
d. §60.5375 What standards apply to gas well affected facilities?
e. §60.5395 What standards apply to storage vessel affected facilities?
f. §60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?
g. §60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
h. §60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels, reciprocating compressors and centrifugal compressor wet seal degassing systems?

i. §60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?
j. §60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?
k. §60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
l. §60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel, centrifugal compressor and reciprocating compressor affected facilities?
m. §60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?
n. §60.5420 What are my notification, reporting, and recordkeeping requirements?
o. §60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
p. §60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
q. §60.5425 What part of the General Provisions apply to me?
r. §60.5430 What definitions apply to this subpart?

5. Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015. [40 CFR §§60.5360a - 60.5430a]

   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. §60.5395a What VOC standards apply to storage vessel affected facilities?
   f. §60.5400a What equipment leak GHG and VOC standards apply to affected facilities at an onshore natural gas processing plant?
   g. §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?
   h. §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?

i. §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?
j. §60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?
k. §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?
l. §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?
m. §60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?
n. §60.5420a What are my notification, reporting, and recordkeeping requirements?
o. §60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?
p. §60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?
q. §60.5425a What part of the General Provisions apply to me?
r. §60.5430a What definitions apply to this subpart?

Recordkeeping

J. The permittee shall maintain records for all storage tanks with a capacity of 400 gallons or more that store VOC (as defined in OAC 252:100-1-3). The records shall include the tank identification number; date of manufacture; date of installation; tank capacity; type of tank; a description of the type of floating roof and seals if applicable; NSPS applicability; whether equipped with a submerged fill pipe or vapor recovery system; and the type of liquid stored. [OAC 252:100-43]

K. The permittee shall maintain records of throughput and emission calculations for each storage tank with a capacity of 400 gallons or more. [OAC 252:100-43]

SECTION III. VOC LOADING OPERATIONS

The following specific conditions apply to VOC loading operations.

Emission Calculations

A. The permittee shall calculate actual emissions of VOC and HAP from loading operations to demonstrate compliance with Part 2, Section I of this permit. Emission calculations shall follow the procedures presented in the AQD guidance document, "Estimating Condensate and Crude Oil Loading Losses from Tank Trucks." [OAC 252:100-43]

Oklahoma Air Pollution Control Rules

B. Each loading pipe handling a liquid with a vapor pressure of 1.5 psia or greater under actual storage conditions, except for petroleum or condensate stored, processed and/or treated at a drilling or production facility prior to lease custody transfer and except for methanol stored at drilling or production facilities, shall be equipped with a system for submerged filling of tank trucks or trailers which is installed and operated to maintain a 97% submergence factor. [OAC 252:100-37-16(b)]

C. If a control device is used to reduce emissions, the permittee shall comply with the requirements specified in Appendix A of this Permit. [OAC 252:100-43]

Recordkeeping

D. The permittee shall maintain records of throughput and emission calculations for all loading operations. [OAC 252:100-43]

SECTION IV. COMBUSTION EQUIPMENT

The following specific conditions apply to combustion equipment.

Emission Calculations

A. The permittee shall calculate actual emissions of NO_X, CO, and VOC from all combustion equipment, and calculate actual emissions of formaldehyde from engines, to demonstrate compliance with Part 2, Section I of this permit. For an engine, the emissions shall be calculated based on short-term limits (lb/hr) for each pollutant established in an application for an NOI to Construct, an application for an Authorization to Operate, or an NOM, times the actual hours of operation, and converted to tons. For all other combustion equipment, except flares and enclosed combustion devices, the emissions shall be calculated based on actual hours of operation, maximum fired duty, and the emission factors for each pollutant established in the application or NOM, and converted to tons. For flares and enclosed combustion devices, the emissions shall be calculated based on heat input determined by any one of the following: (1) design capacity rating; (2) measured waste gas flow rate to the device; or (3) as calculated using the methodologies approved in Part 2 of the GP-OGF; and the emission factors for each pollutant established in the application or NOM, and converted to tons. [OAC 252:100-43]

B. An emission factor considering add-on controls for formaldehyde is acceptable when testing demonstrates compliance with the CO limits. [OAC 252:100-43]

C. Unless continuous operation (8,760 hours) is assumed for the calculation of actual emissions to demonstrate compliance with Part 2, Section I, the hours of operation of an

engine or other combustion equipment shall be recorded with an hour meter, with a fuel meter recorded at least hourly, monitored and recorded manually each day, or electronic methods using measurements of parameters indicating total hours operated. If equipped with an hour meter or other similar measurement method, it must either be non-resettable or, if resettable, the date and hour each time the meter is reset must be maintained.
[OAC 252:100-43]

Engine Testing and Maintenance Requirements

D. The permittee shall conduct an initial test of NO_X and CO emissions from any engine other than (1) an Emergency Use Engine, or (2) any engine equal to or less than 250 horsepower (hp). The initial test must be performed within 180 days of engine startup. This test may be counted as the first semi-annual test of an engine. Testing shall be conducted using EPA reference methods, if applicable, or a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD "Portable Analyzer Guidance" document, or an equivalent method approved by AQD. [OAC 252:100-43]

E. At least twice per calendar year, the permittee shall conduct tests of NO_X and CO emissions from any controlled engine greater than 250 hp. Testing shall be conducted using EPA reference methods, if applicable, or a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD "Portable Analyzer Guidance" document, or an equivalent method approved by AQD. Testing is required for any engine that runs for more than 440 hours during a semi-annual period. Each semi-annual test shall be separated by at least 120 days. In the first year of operation, any engine started after March 31st only requires one test regardless of hours operated. [OAC 252:100-43]

F. Four-stroke, rich-burn (4SRB) engines using NSCR catalyst shall be equipped with an Air to Fuel Ratio Controller (AFRC). The AFRC shall be inspected and maintained at least once a month to ensure that the controller is functioning properly, is not in alarm mode, and is being operated in accordance with manufacturers' recommendations. Replacement of the oxygen sensor(s) is required every 2,200 operating hours or less, or in accordance with manufacturers' recommendations, and replacement shall be documented in accordance with Part 3, Section IV.A. A maintenance log of all AFRC inspections, periods of operation in alarm mode, and engine or AFRC maintenance shall be kept.
[OAC 252:100-43]

G. If any engine tested is not in compliance with its hourly permit limits, the permittee shall make the necessary adjustments to bring the engine into compliance and an excess emissions report shall be filed in accordance with Part 3 Section III, of this permit.

Engine Addition, Modification, Reconstruction, or Replacement

H. Addition, modification, reconstruction, or replacement of any engine is authorized under the following conditions.

1. The permittee shall send AQD an NOM within 15 days of the startup of the engine.

2. The permittee shall comply with the emission limits cited in the NOM for that engine and those limitations shall become an enforceable part of the existing Authorization to Operate. The permittee shall include a copy of the NOM kept electronically or as a hard copy, either on-site, at a nearby manned facility, or at the nearest field office per the recordkeeping requirements of Part 3, Section IV.A.

3. The engine is subject to initial and periodic testing requirements in accordance with Part 2, Section IV of this permit.

Oklahoma Air Pollution Control Rules

I. All fuel-burning equipment shall be operated to minimize emissions of VOC. Among other things, such operation shall assure, based on manufacturer's data and good engineering practices, that the equipment is not overloaded; that it is properly cleaned, operated, and maintained; and that temperature and available air are sufficient to provide essentially complete combustion. The permittee shall maintain maintenance records on engines to document compliance. [OAC 252:100-37-36]

J. Each engine shall have a permanent identification plate attached that shows the make, model number, and serial number. [OAC 252:100-43]

K. An Emergency Use Engine shall be equipped with a non-resettable hour meter. The permittee shall maintain a record of the operating hours for each Emergency Use Engine. [OAC 252:100-43]

L. If a control device is used to reduce emissions, the permittee shall comply with the requirements specified in Appendix A of this Permit. [OAC 252:100-43]

Federal Regulations

M. The permittee shall comply with all applicable requirements set forth in NSPS 40 CFR Part 60, including, but not limited to, the following.

1. Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. [40 CFR §§60.40c - 60.48c]

    a. §60.40c Applicability and delegation of authority
    b. §60.41c Definitions
    c. §60.42c Standards for sulfur dioxide (SO_2)
    d. §60.43c Standards 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

2. Subpart GG - Standards of Performance for Stationary Gas Turbines.
[40 CFR §§60.330 - §60.335]

a. §60.330 Applicability and designation of affected facility
b. §60.331 Definitions
c. §60.332 Standards for nitrogen oxides
d. §60.333 Standards for sulfur dioxides
e. §60.334 Monitoring of operations
f. §60.335 Test methods and procedures

3. Subpart IIII – Standards of Performance for Stationary Compressor Ignition Internal Combustion Engines. [40 CFR §§60.4200 - 60.4219]

a. §60.4200 Am I subject to this subpart
b. §60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?
c. §60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?
d. §60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?
e. §60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
f. §60.4205 What emissions standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
g. §60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?
h. §60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?
i. §60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model years?
j. §60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
k. §60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?
l. §60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
m. §60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?
n. §60.4213 What test methods or other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?
o. §60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

p. §60.4217 What engine standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?
q. §60.4218 What parts of the General Provisions apply to me?
r. §60.4219 What definitions apply to this subpart?

4. Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (SI-ICE). [40 CFR §§60.4230 - 60.4246]

   a. §60.4230 Am I subject to this subpart?
   b. §60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?
   c. §60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?
   d. §60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?
   e. §60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?
   f. §60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?
   g. §60.4236 What is the deadline for importing or installing stationary SI ICE produced in previous model years?
   h. §60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?
   i. §60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP) or a manufacturer of equipment containing such engines?
   j. §60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?
   k. §60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?
   l. §60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?
   m. §60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?
   n. §60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?
   o. §60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?
   p. §60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?
   q. §60.4246 What parts of the General Provisions apply to me?

r. §60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines or a manufacturer of equipment containing such engines?
s. § 60.4248: What definitions apply to this subpart?

5. Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. [40 CFR §§60.4300 - 60.4420]

a. §60.4300 What is the purpose of this subpart
b. §60.4305 Does this subpart apply to my stationary combustion turbine
c. §60.4310 What type of operations are exempt from these standards of performance
d. §60.4315 What pollutants are regulated by this subpart
e. §60.4320 What emissions limits must I meet for nitrogen oxides (NO_x)
f. §60.4325 What emissions limits must I meet for NO_x if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?
g. §60.4330 What emission limits must I meet for sulfur dioxide (SO_2)
h. §60.4333 What are my general requirements for complying with this subpart?
i. §60.4335 What are my general requirements for complying with this subpart
j. §60.4335 How do I demonstrate compliance for NO_x if I use water or stream injection
k. §60.4340 How do I demonstrate compliance for NO_x if I do not use water or steam injection
l. §60.4345 What are the requirements for the continuous emissions monitoring system equipment, if I choose to use this option?
m. §60.4350 How to I use data from the continuous emission monitoring equipment to identify excess emissions?
n. §60.4355 How to I establish and document a proper parameter monitoring plan
o. §60.4360 How to I determine the total sulfur content of the turbines' combustion fuel?
p. §60.4365 How can I be exempt for monitoring the total sulfur content of the fuel?
q. §60.4370 How often must I determine the sulfur content of the fuel?
r. §60.4375 What reports must I submit?
s. §60.4380 How are excess emissions and monitor downtime for NO_x?
t. §60.4385 How are excess emissions and monitoring downtime defined for SO_2?
u. §60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?
v. §60.4395 When must I submit my reports?
w. §60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_x?
x. §60.4405 How do I perform the initial performance test if I have chosen to install a NO_x-diluent CEMS?
y. §60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
z. §60.4415 How do I conduct the initial and subsequent performance tests for sulfur?
aa. §60.4420 What definitions apply to this subpart?

N. The permittee shall comply with all applicable requirements set forth in NESHAP 40 CFR Part 63, including, but not limited to, the following.

1. Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE).
[40 CFR §§63.6580 - 63.6675]

a. § 63.6580 What is the purpose of subpart ZZZZ?
b. § 63.6585 Am I subject to this subpart?
c. § 63.6590 What parts of my plant does this subpart cover?
d. § 63.6595 When do I have to comply with this subpart?
e. § 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?
f. § 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?
g. § 63.6605 What are my general requirements for complying with this subpart?
h. §63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?
i. § 63.6615 When must I conduct subsequent performance tests?
j. § 63.6620 What performance tests and other procedures must I use?
k. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
l. § 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?
m. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
n. § 63.6640 Ho do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?
o. § 63.6645 What notifications must I submit and when?
p. § 63.6650 What reports must I submit and when?
q. § 63.6655 What records must I keep?
r. § 63.6660 In what form and how long must I keep my records?
s. § 63.6665 What parts of the General Provisions apply to me?
t. § 63.6670 Who implements and enforces this subpart?
u. § 63.6675 What definitions apply to this subpart?

Recordkeeping

O. The permittee shall maintain a record of any malfunction that prevents semi-annual testing of NO_X and CO emissions and notify AQD within 30 days of the end of the semi-annual period of the malfunction that prevented testing. [OAC 252:100-43]

P. The permittee shall keep records of the actual annual hours of operation, in accordance with the methods in Part 2, Section IV.C for any engine or other combustion equipment for which actual hours of operation, instead of continuous operation, are used to calculate annual emissions. [OAC 252:100-43]

Q. The permittee shall keep records that document each engine's maximum horsepower at International Organization for Standardization (ISO) or manufacturer's standard conditions and maximum RPM, and any de-rating factors used to determine a site-rated maximum horsepower (e.g., site ambient conditions, jacket water temperature, compression load limitations, speed limitations of engine or driven equipment, etc.). [OAC 252:100-43]

SECTION V. GLYCOL DEHYDRATION UNIT PROCESS VENT

The following specific conditions apply to emissions from glycol dehydration unit process vents.

Emission Calculations

A. The permittee shall calculate emissions of VOC and HAP from glycol dehydration process vents to demonstrate compliance with Part 2, Section I.A of this permit. Estimates of emissions of VOC and HAP from any rich glycol flash tank vents or glycol regenerator still vents shall be calculated using either the GRI-GLYCalc program (Version 4.0 or later), a process simulator program, or the Atmospheric Rich/Lean (ARL) Method. The emissions should be based on the potential to emit by assuming continuous operation using the dry gas flow rate based upon one of the following: (1) the maximum design dry gas rate for the dehydrator unit; or (2) the maximum facility dry gas rate based on an inherent process limitation such as compressor horsepower or capacity limitations; or (3) the maximum facility dry gas rate based on an inherent limit on gas production; or (4) the maximum annual average dry gas rate for the last 2 years plus a 20% safety factor; and an extended wet gas analysis, the normal process operating temperature and pressure, the expected removal efficiency of any control device, and the maximum pump rate of the lean glycol circulation pump. Specific requirements for control devices and allowed control efficiencies are found in Appendix A of this Permit. [OAC 252:100-43]

B. For facilities that have total potential HAP emissions from all dehydrator units, individual or combined, above 80% of major source levels, based on the extended wet gas analysis used in the application for an NOI to Construct, an application for an Authorization to Operate, or an NOM, the permittee shall sample and perform an extended wet gas analysis at least once each year for calculating compliance with the permit HAP limits per the procedures in Subsection A of this Section. [OAC 252:100-43]

Oklahoma Air Pollution Control Rules

C. If a control device is used to reduce emissions, the permittee shall comply with the requirements specified in Appendix A of this Permit. [OAC 252:100-43]

Federal Regulations

D. The permittee shall comply with all applicable requirements set forth in NESHAP 40 CFR Part 63, including, but not limited to, the following.

1. Subpart HH - National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. [40 CFR §§63.760 - 63.775]

a. §63.760 Applicability and designation of affected source
b. §63.761 Definitions
c. §63.762 Affirmative defense for violations of emission standards during malfunction
d. §63.764 General standards
e. §63.765 Glycol dehydration unit process vents standards
f. §63.766 Storage vessel standards
g. §63.769 Equipment leak standards
h. §63.771 Control equipment requirements
i. §63.772 Test methods, compliance procedures, and compliance demonstrations
j. §63.773 Inspection and monitoring requirements
k. §63.774 Recordkeeping requirements
l. §63.775 Reporting requirements
m. §63.776 Implementation and enforcement
n. §63.777 Alternate means of emission limitation

Recordkeeping

E. The permittee shall keep records demonstrating the method and data used for determining the maximum wet gas rate used to calculate the potential to emit from a glycol dehydrator per Part 2, Section V.A.; records of any required extended wet gas analysis; and records of the GRI-GLYCalc printout or other emission calculation methods, including the requirements of Appendix A. [OAC 252:100-43]

SECTION VI. AMINE UNITS

The following specific conditions apply to emissions from amine units and regenerator still vents.

Emission Calculations

A. The permittee shall calculate emissions of VOC and HAPS from rich amine flash tank and regenerator still vents to demonstrate compliance with Part 2, Section I.A of this permit. The emissions should be based on the potential to emit by assuming continuous operation using the gas flow rate based upon one of the following: (1) the maximum design gas rate for the amine unit; or (2) the maximum facility gas rate based on an inherent process limitation such as compressor horsepower or capacity limitations; or (3) the maximum facility gas rate based on an inherent limit on gas production; or (4) the maximum annual average gas rate for the last 2 years plus a 20% safety factor; an extended gas analysis or natural gas liquid analysis, the normal process operating temperatures and pressures, and the maximum pump rate of the lean amine circulation pump. Specific requirements for control devices and allowed control efficiencies are found in Appendix A of this Permit. [OAC 252:100-43]

Testing Requirements

B. The permittee shall conduct testing, using acceptable methods, of the amine unit inlet natural gas H_2S concentration at least quarterly to ensure the H_2S concentration is 4 ppmv or less.

Oklahoma Air Pollution Control Rules

C. Emissions from the rich amine flash tank shall be routed to a thermal device with a combustion efficiency of 95%, to the facility inlet, or to the fuel gas system. Emissions from the amine unit regenerator still vent are to be routed to a thermal device with a combustion efficiency of 95%. [OAC 252:100-31-26(1)(A)]

D. The owner or operator shall install, maintain, and operate an alarm system that will signal a malfunction for all thermal devices used to control H_2S emissions from petroleum and natural gas processing facilities. [OAC 252:100-31-26(1)(B)]

E. If a control device is used to reduce emissions, the permittee shall comply with the requirements specified in Appendix A of this Permit. [OAC 252:100-43]

Federal Regulations

F. The permittee shall comply with all applicable requirements set forth in NSPS 40 CFR Part 60, including, but not limited to, the following.

1. Subpart LLL – Standards of Performance for SO_2 Emissions From Onshore Natural Gas Processing for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011. [40 CFR §§60.640 - 60.648]

   a. §60.640 Applicability and designation of affected facilities
   b. §60.641 Definitions
   c. §60.642 Standards for sulfur dioxide
   d. §60.644 Test methods and procedures
   e. §60.646 Monitoring of emissions and operations
   f. §60.647 Recordkeeping and reporting requirements
   a. §60.648 Optional procedure for measuring hydrogen sulfide in acid gas – Tutwiler Procedure

2. Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced After August 23, 2011, and on or before September 18, 2015.
[40 CFR §§60.5360 - 60.5430]

   a. §60.5360 What is the purpose of this subpart?
   b. §60.5365 Am I subject to this subpart?
   c. §60.5370 When must I comply with this subpart?
   d. §60.5375 What standards apply to gas well affected facilities?
   e. §60.5405 What standards apply to sweeting units at onshore natural gas processing plants?
   f. §60.5406 What test methods and procedures must I use for my sweeting units affected facilities at onshore natural gas processing plants
   g. §60.5407 What are the requirements for monitoring of emissions and operations from my sweeting unit affected facilities at onshore natural gas processing plants?
   h. § 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas-Tutwiler Procedure?
   i. §60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
   j. §60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
   k. §60.5420 What are my notification, reporting and recordkeeping requirements?
   l. §60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
   m. §60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
   n. §60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
   o. §60.5425 What part of the General Provisions apply to me?
   p. §60.5430 What definitions apply to this subpart

3. Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015. [40 CFR §§60.5360a - 60.5430a]

   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? §60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?
e. §60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?
f. §60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?
g. §60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?
h. §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?
i. §60.5420a What are my notification, reporting, and recordkeeping requirements?
j. §60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?
k. §60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?
l. §60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
m. §60.5425a What parts of the General Provisions apply to me?
n. §60.5430a What definitions apply to this subpart?
o. §60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

Recordkeeping

G. The permittee shall keep records demonstrating the method and data used for determining the maximum wet gas rate used to calculate the potential to emit from an amine unit per Part 2, Section VI.A.; records of any required extended gas analysis; and records of the AMINE-Calc Program printout or other emission calculation methods including the requirements of Appendix A of this Permit. [OAC 252:100-31]

SECTION VII. FUGITIVE EMISSION SOURCES

The following specific conditions apply to fugitive VOC emission sources.

Emission Calculations

A. For any facility that has a total petroleum storage capacity exceeding 300,000 barrels or meets the affected facility definition of NSPS Subparts K or Ka (including existing tanks), the permittee shall calculate actual annual emissions of VOC from fugitive emission sources to demonstrate compliance with Part 2, Section 1.A of this permit. Emissions of VOCs from fugitive sources shall be calculated using the factors in Table 2-4 (Oil and Gas Production Operations) of EPA's *1995 Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)* or other methods approved by DEQ. [OAC 252:100-43]

Federal Regulations

B. The permittee shall comply with all applicable requirements set forth in NSPS 40 CFR Part 60, including, but not limited to, the following.

1. Subpart KKK - Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011. [40 CFR §§60.630 – 60.636]

   a. §60.630 Applicability and designation of affected facilities
   b. §60.631 Definitions
   c. §60.632 Standards
   d. §60.633 Exceptions
   e. §60.634 Alternate means of emission limitations
   f. §60.635 Recordkeeping requirements
   g. §60.636 Reporting requirements

2. Subpart OOOO - Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced After August 23, 2011, and on or before September 18, 2015. [40 CFR §§60.5360 - 60.5430]

   a. §60.5360 What is the purpose of this subpart?
   b. §60.5365 Am I subject to this subpart?
   c. §60.5370 When must I comply with this subpart?
   d. §60.5375 What standards apply to gas well affected facilities?
   e. §60.5390 What standards apply to pneumatic controller affected facilities?
   f. §60.5400 What equipment leak standards apply to affected facilities at onshore gas processing plants?
   g. §60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore gas processing plants?
   h. §60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?
   i. §60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
   j. §60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary

reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

k. §60.5420 What are my notification, reporting and recordkeeping requirements?
l. §60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
m. §60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
n. §60.5425 What part of the General Provisions apply to me?
o. §60.5430 What definitions apply to this subpart?

3. Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015. [40 CFR §§60.5360a - 60.5430a]

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. §60.5395a What VOC standards apply to storage vessel affected facilities
e. §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?
f. §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?
g. §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?
h. §60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?
i. §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?
j. §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?
k. §60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?
l. §60.5420a What are my notification, reporting, and recordkeeping requirements?

m. §60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?
n. §60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?
o. §60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
p. §60.5425a What part of the General Provisions apply to me?
q. §60.5430a What definitions apply to this subpart?

Recordkeeping

C. The permittee shall maintain an approximate inventory record of fugitive emission sources at the facility. The record shall include the material handled for each fugitive source group, along with the following data sets for each fugitive component type: service (gas, heavy oil, light oil, and water/oil), component count, emission factor, and VOC content in weight percent. [OAC 252:100-43]

SECTION VIII. OTHER PROCESS EQUIPMENT

The following specific conditions apply to other process equipment not previously listed.

Emission Calculations

A. To demonstrate compliance with Part 2, Section I of this permit, the permittee shall calculate emissions of VOC and HAP from all process equipment. The permittee will be required to calculate emissions of VOC and HAP actual throughputs, the maximum allowed control efficiency in Appendix A of the GP-OGF, and AQD approved software programs or mass balance equations. Flash emission calculations shall follow the procedures presented in the AQD guidance documents, “VOC Emissions/Flashing Losses from Hydrocarbon Storage Tanks” and “Representative Sampling Guidance.”
[OAC 252:100-43]

Federal Regulations

B. The permittee shall comply with all applicable requirements set forth in NSPS 40 CFR Part 60, including, but not limited to, the following.

1. Subpart OOOO - Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced After August 23, 2011, and on or before September 18, 2015. [40 CFR §§60.5360 - 60.5430]

a. §60.5360 What is the purpose of this subpart?
b. §60.5365 Am I subject to this subpart?
c. §60.5370 When must I comply with this subpart?

d. §60.5375 What standards apply to gas well affected facilities?
e. §60.5380 What standards apply to centrifugal compressor affected facilities?
f. §60.5385 What standards apply to reciprocating compressor affected facilities?
g. §60.5390 What standards apply to pneumatic controller affected facilities?
h. §60.5395 What standards apply to storage vessel affected facilities?
i. §60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?
j. §60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?
k. §60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?
l. §60.5405 What standards apply to sweetening units at onshore natural gas processing plants?
m. §60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?
n. §60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?
o. §60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?
p. §60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
q. §60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels, reciprocating compressors and centrifugal compressor wet seal degassing systems?
r. §60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?
s. §60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?
t. §60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
u. §60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel, centrifugal compressor and reciprocating compressor affected facilities?
v. §60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?
w. §60.5420 What are my notification, reporting, and recordkeeping requirements?

x. §60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
y. §60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
z. §60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
aa. §60.5425 What part of the General Provisions apply to me?
bb. §60.5430 What definitions apply to this subpart?

2. Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015. [40 CFR §§60.5360a - 60.5430a]

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 VOC standards apply to well affected facilities?
e. §60.5380a What VOC standards apply to centrifugal compressor affected facilities?
f. §60.5385a What VOC standards apply to reciprocating compressor affected facilities?
g. §60.5390a What VOC standards apply to pneumatic controller affected facilities?
h. §60.5393a What 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 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 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. §60.5399a What alternative fugitive emissions 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: Equivalency with state, local, and tribal programs?
m. §60.5400a What equipment leak VOC standards apply to affected facilities at an onshore natural gas processing plant?
n. §60.5401a What are the exceptions to the equipment leak VOC standards for affected facilities at onshore natural gas processing plants?
o. §60.5402a What are the alternative means of emission limitations for VOC equipment leaks from onshore natural gas processing plants?
p. §60.5405a What standards apply to sweetening unit affected facilities?
q. §60.5406a What test methods and procedures must I use for my sweetening unit affected facilities?

r. §60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities?
s. §60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?
t. §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 at onshore natural gas processing plants and sweetening unit affected facilities?
u. §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?
v. §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?
w. §60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?
x. §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, equipment leaks at onshore natural gas processing plants and sweetening unit affected facilities?
y. §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?
z. §60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?
aa. §60.5420a What are my notification, reporting, and recordkeeping requirements?
bb. §60.5421a What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
cc. §60.5422a What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
dd. §60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities?
ee. §60.5425a What parts of the General Provisions apply to me?
ff. §60.5430a What definitions apply to this subpart?
gg. §60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

Recordkeeping

C. The permittee shall maintain records of throughput and emission calculations for each process equipment. [OAC 252:100-43]

SECTION IX. MSS

The following specific conditions apply to all MSS activities.

Emission Calculations

A. Fugitive MSS are required to be included for any facility with equipment that meets the definition of affected facility in NSPS Subparts K or Ka (including existing tanks). For these facilities, the permittee shall calculate annual emissions of VOC from fugitive emission sources to demonstrate compliance with Part 2, Section 1.A of this permit. MSS emissions shall be calculated using best available calculation methodologies. These emissions include but are not limited to:

1. Blowdowns and other venting activities (such as emissions related to pigging) can be calculated using mass balance equations (e.g., volume of gas vented, the number of events, and percent VOC).

2. Tank roof landing losses can be calculated using AP-42 Section 7.1.

General Requirements

B. The permittee shall establish and implement a maintenance plan to minimize emissions during routine or predicable startup, shutdown, and scheduled maintenance and shall operate in accordance with the procedures set forth in the maintenance plan.

C. The permittee shall install, maintain, and operate each affected emission unit, including any associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions of regulated air pollutants and considering the manufacturer's recommended operating procedures at all times, including periods of startup, shutdown, and maintenance. AQD will determine whether the permittee is using acceptable operating and maintenance procedures based on information available which may include, but is not limited to: monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the permitted source.

Recordkeeping

D. The permittee shall keep records of MSS emitting activity data necessary to calculate emissions and documentation of all periods of control device downtime.

PART 3 – STANDARD CONDITIONS

SECTION I. DUTY TO COMPLY

The permittee shall comply with all conditions of this permit and any Authorizations issued hereunder. This permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. Any permit non-compliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, for revocation of the approval to operate under the terms of this general permit, or for denial of an application to operate under the terms of this general permit.

[27A O.S. §2-5-112, OAC 252:100-7-15 and 7-18]

SECTION II. FACILITY MODIFICATIONS AND MODIFICATION OF AUTHORIZATIONS UNDER THE TERMS OF THE GENERAL PERMIT

A. An Authorization shall be corrected if any applicable emission limitation or standard is found to be absent or is found to be in error. Correction of an Authorization shall not change the Effective Date of the Authorization.

B. The permittee shall obtain a major source permit for any modification that would cause an existing facility to no longer be classified as a minor facility.

C. The permittee shall obtain a minor source construction permit for any modification described under Part 1, Section III.C of this permit. All other facility modifications may be constructed without a new Authorization, or without a construction permit, provided the applicant submits a notice of modification (NOM) when required. An NOM is required to be submitted to AQD within 15 days following startup.

D. The permittee shall apply for a new Authorization to Operate within 180 days of commencing operation of any modified facility authorized under a minor source construction permit or an Authorization to Construct issued under this permit.

[OAC 252:100-7-18(a)]

E. An Authorization to Construct issued under this permit will terminate and become null and void if the construction is not commenced within 18 months of the issuance date, or if work is suspended for more than 18 months after it is commenced.

[OAC 252:100-7-15(f)]

SECTION III. REPORTING OF DEVIATIONS FROM PERMIT TERMS

In the event of any release which results in excess emissions, the permittee shall comply with the provisions of OAC 252:100-9. [OAC 252:100-9]

SECTION IV. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep an electronic or hard copy of the Authorization to Operate, with all Notice of Modifications included, either on-site, at a nearby manned facility, or at the nearest field office. The permittee shall keep records as specified in this permit and any Authorization issued under this permit, including all Notice of Modifications. These records, including monitoring data and support information, shall be retained either on-site, at a nearby manned facility, or at the nearest field office for a period of at least five years unless a longer period is specified by an applicable rule or statute. Support information includes all original recordings for continuous monitoring instrumentation and copies of all reports required by this permit or the Authorization. Records may be maintained in paper, electronic, or computerized form. [OAC 252:100-5-2.1(c), and 100-43]

B. Any owner or operator subject to provisions of NSPS shall provide written notification as follows. However, a Notice of Modification that is timely submitted (within 15 days of startup) shall suffice. [40 CFR §60.7]

1. A notification of the date of when construction of an affected facility will be 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 the actual date of initial startup of an affected facility postmarked within 15 days after such date.

3. 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 40 CFR 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.

C. All testing must be conducted by methods approved by the Executive Director under the direction of qualified personnel. All tests shall be made and the results calculated in accordance with test procedures described or referenced in the permit and approved by Air Quality. [OAC 252:100-43]

D. The permittee shall document that all testing is conducted using methods specified in 40 CFR Parts 51 (SIP), 60 (NSPS), 61 (NESHAP), and 63 (MACT), as applicable, or as otherwise specified in this permit or in an Authorization. A copy of these records shall be retained with the facility's testing records. [OAC 252:100-43]

E. If the permittee monitors any pollutant more frequently than required by this permit, the results of this monitoring shall be included in the calculations used for determining compliance with the conditions of this permit. 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. [OAC 252:100-43-6]

F. The permittee shall submit to AQD a copy of all reports submitted to EPA as required by 40 CFR Part 60, 61, and 63 for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-2]

SECTION V. NEW APPLICABLE REQUIREMENTS

The permittee shall comply with any new state, NSPS, or NESHAP regulation that becomes applicable during the life of this permit. [OAC 252:100-2]

SECTION VI. ANNUAL EMISSIONS INVENTORY AND FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory, to include MSS and fugitive emissions, and shall pay annual fees based on emission inventories or allowable emissions. [OAC 252:100-5]

SECTION VII. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

SECTION VIII. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort or any exclusive privilege.

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued.

SECTION IX. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ upon receipt of a written request and within sixty (60) days of the request, unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, or revoking and reissuing or terminating the permit or to determine compliance with the permit or the Authorization. [27A O.S. § 2-5-105(17)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(17). Two copies of the application shall be submitted, one including clearly labeled confidential information, and the other a redacted version.

C. The transferor shall notify the AQD of the sale or transfer of ownership of this facility in writing not later than 30 days following the change in ownership.
[27A O.S. § 2-5-112(G) & OAC 252:100-7-2(f)]

SECTION X. DUTY TO SUPPLEMENT

The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in any information submittal, shall promptly submit such supplementary facts or corrected information. [OAC 252:100-7-2(c)(3)]

SECTION XI. REOPENING, MODIFICATION, AND REVOCATION

A. This permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the permittee for a permit or an Authorization modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated non-compliance does not stay any permit condition. [27A O.S. § 2-5-112(B)]

B. The permitting authority will reopen and revise or revoke this permit as necessary to remedy deficiencies if the DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable air pollution rules. [27A O.S. § 2-5-112(B)]

C. Upon issuance of this permit, the terms and conditions of this updated General Permit for Oil and Gas Facilities (GP-OGF) supersede all previous versions of the GP-OGF. All facilities constructing or operating under the previous GP-OGF are subject to and must comply with this updated GP-OGF within 24 months of its issuance date and all facilities will automatically be authorized as Class II facilities. [27A O.S. §2-5-112(B)]

1. During the 24-month transition period, any facility constructing or operating under the previous GP-OGF and existing Authorization must comply with the standards set forth therein.
2. During the 24-month transition period, the NOM for the existing GP-OGF may be used for those facilities wanting to maintain coverage under the existing GP-OGF. Using the NOM from this GP-OGF automatically subjects the facility to this GP-OGF upon submittal.
3. For facilities that have conditions in their current authorization that conflict with the requirements with this GP-OGF, these facilities must obtain an individual minor source construction permit and then incorporate these conditions into a subsequently issued Authorization to Operate.

SECTION XII. INSPECTION AND ENTRY

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized officials of the DEQ to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S.§ 2-5-105(17) for confidential information submitted to or obtained by the DEQ under this section). [27A O.S. § 2-5-105]

A. Enter upon the permittee's premises during reasonable/normal working hours where a source is located or emission-related activity is conducted, or where records must be kept under the conditions of the permit or the Authorization;

B. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit or the Authorization;

C. Inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit or the Authorization; and

D. Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or the Authorization.

SECTION XIII. GENERAL PROVISIONS UNDER NSPS AND NESHAPS

The permittee shall comply with all applicable requirements of the corresponding General Provisions, as set forth in 40 CFR Part 60 Subpart A, 40 CFR Part 61 Subpart A, and 40 CFR Part 63 Subpart A, for all equipment constructed or operated under this permit subject to NSPS or NESHAP. [OAC 252:100-2]

SECTION XIV. UPDATE OF AUTHORIZATION TO OPERATE

AQD reserves the right to require a facility to apply for an updated Authorization to Operate in order to clarify the Authorization based on a substantial number of Notices of Modification.

APPENDIX A – CONSTRUCTION, OPERATION, MAINTENANCE, AND MONITORING REQUIREMENTS FOR CONTROL DEVICES

A. Non-Selective Catalytic Reduction (NSCR)

Maximum Allowed Control Efficiency	Requirements

Manufacture guarantee as stated in application (Not to exceed 90%)	• Must be maintained and operated as specified by the manufactured or design specifications.
	• Be constructed with an Air-to-Fuel Ratio Controller (AFRC) that operates on exhaust oxygen sensor control.
	• Use a portable analyzer to monitor NO_x, CO and O_2 concentration in the exhaust stream of the control device.
	  ▪ The portable analyzer shall be operated in accordance with the requirements of the latest AQD "Portable Analyzer Guidance" document or an equivalent method approved by the AQD.
	  ▪ Testing shall be performed semi-annually.

B. Oxidation Catalyst

<table>
<tr><th>Maximum Allowed Control Efficiency</th><th>Requirements</th></tr>
<tr><td>Manufacture guarantee as stated in application (Not to exceed 93%)</td><td rowspan="2">• Meet requirements listed above for NSCR except for AFRC.</td></tr>
<tr><td>Formaldehyde reduction ≤ CO reduction (Not to exceed 90%)</td></tr>
</table>

C. Glycol Dehydration Units and Amine Units

Maximum Allowed Control Efficiency	Requirements
Control Device: Condenser Only	
≤90% for VOC's and HAP's	• Must be maintained and operated as specified by the manufactured or design specifications. • Unit must be equipped with a flash tank. • Constructed with a temperature sensor in the outlet. • The permittee shall inspect the condenser for proper operation and measure and record the condenser outlet temperature at least one day each month during daylight hours. • Installation of the temperature sensor and measuring and recording of the condenser outlet temperature is not required if the uncondensed vapors are burned in a combustion device or recycled to the process. • Not followed by further control such as reboilers, flares or in-stack ignitor. Greater than 90% reduction may be applied if meeting the device requirements of the control selected.
Control Device: Recycled or Recompressed	
≤ 100% for VOC's and HAP's	• Have the flash tank stream pre-mixed with the primary fuel gas and used to fuel the device; or • Routed to the facility inlet.
Control Device: Combustion device such as reboiler or heater	
≤50% for VOC and HAP's	• Have still vent stream delivered to the flame zone/firebox.
≤ 95 % for VOC's and HAP's	• Have still vent stream delivered to the flame zone/firebox when firing; and • Delivered to an in-stack igniter when the firebox is not firing. • In-stack igniter must be maintained and operated per manufacturer's specifications.
Control Device: Condenser plus combustion device such as reboiler or heater	
≤ 95% for VOC's and HAP's	• Must meet requirements to claim 90% efficiency as described for a condenser; and • Have still vent stream delivered to the flame zone/firebox.
≤ 98% for VOC's and HAP's	• Must meet requirements to claim 90% efficiency as described for a condenser; • Have still vent stream delivered to the flame zone/firebox; and • Utilize an in-stack igniter which is maintained and operated per manufacturer's specifications.

D. Vapor collection for loading

Maximum Allowed Control Efficiency	Requirements
Vapor Collection Systems	
n/a	• The tank trucks shall be bottom loaded with hatches closed (vapor tight) and the storage tank hatches and atmospheric vents shall be closed (vapor tight). • A vapor collection line shall be connected from the tank truck to the vapor collection system and shall route all vapors generated during loading to the vapor collection system. • All loading and vapor lines shall be equipped with fittings that make vapor-tight connections and which must be closed when disconnected or which close automatically when disconnected. • A means shall be provided to prevent VOC drainage from the loading device when it is removed from any tank truck or trailer, or to accomplish complete drainage before removal. • Vapor collection system shall be routed to either a vapor balancing or vapor control.
Vapor Balancing (Collection Efficiency)	
≤ 70% for VOC's and HAP's	• In addition to the requirements above, the tanks shall be equipped with a vapor pressure-vacuum vent valve that maintains a positive pressure setting during tank truck loading operations. • Loading loss emissions routed to the storage tanks shall be added to the storage tank emissions. In lieu of adding loading loss emissions to storage tanks, working loss emissions from the storage tanks being unloaded shall be calculated using a turnover factor (K_N) of 1.
Vapor Control	
≤ 98% for VOC's and HAP's	• Meet requirements of vapor collection system and • Control percentage only applies to vapors collected in vapor collection system and • The vapor collection system shall route all vapors to a flare. Flares must meet requirements described in the flares or enclosed combustion device table.
Vapor Recovery	
100 % for VOC's and HAP's	• Control percentage only applies to vapors collected in vapor balancing and • Routed to the process stream or sales line.

E. Flares or enclosed combustion devices

Maximum Allowed Control Efficiency	Requirements
≤ 98% for VOC's, HAP's and H_2S	• Flares must meet 40 CFR §60.18 requirements for minimum heating value and maximum flare tip velocities. • Flares must be operated with a flame present at all times by having a continuous pilot flame or an automatic ignition system. ▪ Presence of a pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame; and ▪ Records of the pilot flame(s) outages and/or downtime shall be maintained. • Pilot flame monitors must be installed, operated, and calibrated in accordance with manufacturer's specifications.

APPENDIX B - DEMONSTRATION OF MAXIMUM H_2S CONCENTRATION IN CRUDE OILS

For the general permit, a facility must demonstrate that the maximum H_2S concentration of any category of crude oil stored at the facility is no more than 6 ppmw. To do this, each category of crude oil handled at a facility shall be characterized by name using the standard terminology used in the petroleum industry to describe crude oils from specific locales and having similar characteristics, such as (but not limited to) "US-West Texas Sour," "US-Oklahoma Sour," "US-Mid Continent," "Kirkuk," "Hawkins," etc. A permit applicant may demonstrate the maximum expected H_2S concentration in each category of crude oil stored at the facility by one of three methods, subject to approval of AQD:

A. Certification by a responsible official in the permit application that only "sweet" crude oil is stored at the facility or that the maximum H_2S concentration of any "sour" crude oil stored at the facility is no more than 6 ppmw. "Sweet" crude oil is defined as having a total sulfur content of less than 0.5 wt%.

B. Documentation from a Crude Oil Assay Library or assays from the crude oil producer, seller, or buyer, that demonstrate that only "sweet" crude oil is stored at the facility or that the maximum H_2S concentration of any "sour" crude oil stored at the facility is no more than 6 ppmw.

C. Sampling by the applicant for H_2S concentration. Test methods may include UOP 163-89, ASTM D 5705 (the so-called "can test"), liquid phase H_2S analyzers, or lab certified liquid phase methods. For an initial compliance demonstration, one sample is required for each category of sour crude oil that requires sampling for compliance documentation, i.e., not demonstrated by A or B above. If the initial sample shows an H_2S concentration of 3 ppmw or less, then no more sampling is required for that category of sour crude oil. Otherwise, that category of crude oil must be sampled again, once each week for four weeks, and an average of the four samples calculated. If the average H_2S concentration is no more than 6 ppmw, compliance for that category of sour crude oil is demonstrated. This sampling procedure must be repeated in the future for any new category of sour crude oil stored at the facility that requires sampling for compliance with the 6 ppmw H_2S limit.

APPENDIX C - DEFINITIONS

The following definitions apply to this memorandum and general permit. All defined terms are written with initial capital letters in the memorandum and permit.

"Certified Engine" means any engine that has been certified by the EPA to meet emissions standards for the purposes of meeting an NSPS or NESHAP.

"Class I" means a facility that has an enforceable limit less than 80% of major source levels for each regulated air pollutant.

"Class II" means a facility that has an enforceable limit of less than 100% of major source levels for each regulated air pollutant and is not a Class I facility.

"Controlled Engine" means an engine, with or without an Air to Fuel Ratio Controller, that uses catalytic or oxidation catalyst control.

"Engine" means any reciprocating internal combustion engine or any gas-fired turbine.

"Emergency Use Engine" means any engine that drives an emergency power generator, peaking power generator, firewater pump, or other emergency use equipment, and operates no more than 500 hours per year.

"Extended Gas Analysis" means an extended analysis (using GPA 2286 or similar approved methods) that provides speciated data for HAP components benzene, toluene, ethylbenzene, xylenes, and n-hexane.

"Maintenance, Startup, and Shutdown (MSS)" refers to maintenance, startup, or shutdown; it does not include periods of malfunction.

"Maintenance" means the planned routine repair and upkeep of equipment.

"Malfunction" means a sudden and unavoidable breakdown of process or control equipment.

"Maximum Rated Horsepower" means an engine's maximum horsepower at ISO or manufacturer's standard conditions and maximum RPM, or an engine's maximum horsepower at engine site conditions and maximum RPM.

"Notice of Modification (NOM)" means a written notice informing AQD of: (1) any modification or change of operations at the facility that would construct a piece of equipment or a process that is subject to NSPS or NESHAP, or that would modify or reconstruct a piece of equipment or a process such that it becomes subject to NSPS or NESHAP, or that would change its facility classification (either from a Class I Facility to a Class II facility or a Class II Facility to a Class I facility); or (2) any modification to add or replace a storage tank with a capacity of 400 gallons or more storing VOC, a VOC Loading Operation, any combustion equipment, any amine unit, or any dehydration unit; or (3) any modification to change emissions factors relied on in an application or a previous NOM; or (4) any modification to add or remove a federally enforceable limit (FEL) (e.g., 6 TPY limit on storage tanks). Such notice shall contain all information required in the NOM form. Any emissions limits requested in an NOM become an enforceable part of the existing Authorization to Operate. The permittee shall include a copy of any applicable NOM with the Authorization to Operate kept electronically or as a hard copy, either on-site, at a nearby manned facility, or at the nearest field office.

"Shutdown" means, generally, the cessation of operation of a source for any reason.

"Startup" means, generally, the setting in operation of a source for any reason.

"Synthetic Minor Facility" means a facility that has the potential to emit over major source levels of any regulated air pollutant but with controlled actual emissions below major source levels.

"Uncontrolled Engine" means an engine, with or without an Air to Fuel Ratio Controller, that has no catalytic or oxidation catalyst control.

"VOC Loading Operation" means loading liquid VOC into a tank truck or trailer for transportation offsite or unloading of liquid VOC from a tank truck or trailer to a storage tank onsite. A VOC Loading Operation does not have the physical equipment (loading arm and pump) to conduct the type of loading regulated by OAC 252:100-37-16 and 100-39-41 for VOC loading facilities, even though it may or may not use tank trucks or trailers that meet the requirements for delivery vessels in OAC:252-100-39-41(d).

APPENDIX D - SUMMARY OF GP-OGF ENGINE EMISSIONS TEST REQUIRMENTS

Engine Classification	One Time Initial Emissions Test?	Semi-Annual Emissions Tests?
All Emergency Use Engines	No	No
Uncontrolled Engines Under 250-hp	No	No
Uncontrolled Engines Over 250-hp	Yes	No
Controlled Engines Under 250-hp	No	No
Controlled Engines Over 250-hp	Yes	Yes