OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **December 1, 2023**

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SUBJECT:	Minor Source General Permit for Oil and Gas Facilities (GP-OGF) 2022 GP-OGF (Version 2) Background Document

SECTION I. INTRODUCTION

The GP-OGF was replaced on July 1, 2022, (2022 GP-OGF). After initial implementation, it was determined that there were certain issues/aspects that needed to be addressed. Therefore, specific revisions were made to the 2022 GP-OGF and these revisions supersede any conditions in the 2022 GP-OGF. The following is a list of the changes and does not include typos and other administrative changes:

Changes to Appendix A (Construction, Operation, Maintenance, and Monitoring Requirements For Control Devices):

- NSCR/Oxidation Catalyst maximum allowed control efficiency was removed.
  - The specific maximum allowed control efficiencies for NSCR/Oxidation Catalyst listed were removed to allow flexibility for applicants who may have reduction efficiencies greater than the values indicated based on engine manufacturer data and control device manufacture guarantees. The applicants must provide the engine manufacturer data and control device manufacture guarantees to support the specific control efficiencies needed to meet the emission limits of the engines provided in the application.
  - The wording related to providing the manufacture guarantees was changed from “stated” to “provided” to represent the intent of the GP-OGF for the applicant to be required to provide the control device specifications in the application.

- Removed from the Requirements Section for NSCR/Oxidation Catalyst the requirement to document the O_2 concentration and changed the wording in the Requirements Section from NO_X and CO “concentrations” to “emissions”. The requirement to measure the diluent [O_2] gas concentration to determine emissions is addressed in the Portable Analyzer Guidance. The requirement in the GP-OGF is to determine compliance with the NO_X and CO emission limits provided in the application.

- Requirements for Glycol Dehydration Units and Amine Units.
  - Added wording to the Condenser Only Requirements Section for exemption from the requirement to install a temperature sensor and monitor the condenser outlet temperature if the applicant relies on an outlet condenser temperature equal to or greater than 100 °F. This is based on the average ambient temperature in Oklahoma of 70 °F plus 30 °F which a well-designed commercially available condenser is expected to be able to achieve.
  - Moved the exemption from the requirement to install a temperature sensor and monitoring the condenser outlet temperature if the uncondensed vapors are burned in a combustion device from the Condenser Only Requirements Section to the Condenser Plus Combustion Device Section. The Condenser Plus Combustion Device Section is the correct location for this condition.
  - Added wording that allowed use of a flare or an enclosed combustion device which is maintained and operated per manufacturer’s specifications to the Condenser Plus Combustion Device Section. Enclosed combustion devices were previously not

specifically mentioned in the section and this change incorporated the allowance of use of these types of combustion devices.

- Flares or enclosed combustion devices Requirements Section:
  - Added "enclosed combustion devices" to second bullet to clarify that the requirement was applicable to both flares and enclosed combustion devices.
  - Added "automatic ignition systems" to the third bullet as a separate compliance requirement for flares equipped with automatic ignition systems.

- Clarify that only one amine unit can be present to meet the GP modeling criteria for H_2S compliance.

- Reworded paragraph Part 1, Section III.C.1 of the 2022 GP-OGF to reflect fuel-burning equipment firing low sulfur diesel is not prohibited by the GP-OGF.

This General Permit has been developed to authorize construction and/or operation of facilities and limit potential emissions to 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
	Totals	**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 liquid petroleum gas (LPG) or natural gas with a maximum total sulfur content greater than 162 ppmv; or diesel fuel or No. 2 fuel oil with a total sulfur content greater than 0.05% by weight.

2. Stationary reciprocating engines burning diesel fuel with a total sulfur content greater than 15 ppm by weight.

3. 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 the 2022 GP-OGF.

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

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

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

7. Facilities with more than 1 amine unit.

8. 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.

9. 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.

10. 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).

11. 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.

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

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

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

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

16. 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.

The terms and conditions of the 2022 GP-OGF supersede all previous versions of the GP-OGF. All facilities constructing or operating under the previous GP-OGF dated December 18, 2008, will be subject to and must comply with the 2022 GP-OGF, including any revisions, within 24-months of July 1, 2022. During the 24-month transition period: (1) any facility constructing or operating under the previous GP-OGF (dated December 18, 2008, et. al.) and an existing Authorization must comply with the standards set forth therein; (2) the NOM for the previous GP-OGF may be used for those facilities wanting to maintain coverage under the previous GP-OGF; and (3) usage of the NOM from the 2022 GP-OGF automatically subjects the facility to the 2022 GP-OGF including any revisions upon submittal. For facilities that have conditions in their current authorization that conflict with the requirements of the 2022 GP-OGF, these facilities must obtain an individual minor source construction permit and then incorporate these conditions into a subsequently issued Authorization to Operate. All facilities will automatically be authorized as Class II facilities at the end of the transition period unless coverage as a Class I facility has been requested.

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.

As an alternative approach for compliance with the 12-month rolling total emission limits, facilities can calculate maximum projected actual emissions for all equipment based on specific oil and gas throughputs and hours of operation. The applicant then may use those 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 calculations have not been exceeded and where no other physical or operational changes have occurred.

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 (except for SO_2 at a facility with an amine unit). For facilities with an amine unit, SO_2 emissions will be based on a mass balance.

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 on 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, the emission factors provided in the application of NOM (usually based on AP-42) , and continuous hours of operation or actual hours of operation when appropriate monitoring is included.

The permit limits boilers and heaters to units less than 50 MMBtu/hr. Therefore, no short-term emission limitations or testing were required in the general permit.

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, the dry gas flow rate, 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. The dry gas flow rate shall be 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.

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, the gas flow rate, 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. The gas flow rate shall be 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. 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)

<table>
<tr><th>Maximum Allowed Control Efficiency</th><th>Requirements</th></tr>
<tr><td>Manufacture guarantee as provided in the application</td><td>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 and CO emissions 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.</td></tr>
</table>

Oxidation Catalyst

<table>
<tr><th>Maximum Allowed Control Efficiency</th><th>Requirements</th></tr>
<tr><td>Manufacture guarantee as provided in the application</td><td rowspan="2">Meet requirements listed above for NSCR except for AFRC.</td></tr>
<tr><td>Formaldehyde reduction ≤ CO reduction</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

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. • If the applicant relies on an outlet condenser temperature equal to or greater than 100 °F, then installation of the temperature sensor and monitoring of the condenser temperature is not required. • 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 additional controls.
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's 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. • 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.
≤ 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. • Utilize a flare or an enclosed combustion device 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 Balancing (Collection Efficiency)	
$\leq$ 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	
$\leq$ 98% for VOC's and HAP's	• Meet requirements of vapor balancing. • 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. • Flares and enclosed combustion devices 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 and/or automatic ignition systems 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]
<u>Part 2</u> 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 μg/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.
<u>Part 5</u> 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.
<u>Part 5</u> 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. These fuel sulfur contents are in compliance with this subchapter.

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]

<u>Part 3</u> 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.

<u>Part 3</u> 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.

<u>Part 3</u> 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.

<u>Part 3</u> 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.

<u>Part 7</u> 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.

<u>Part 7</u> 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

Subpart	Description	Applicable Equipment
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.

"Affected Facility" as defined in 40 CFR §60.2 of the General Provisions means with reference to a stationary source, any apparatus to which a standard is applicable. Each NSPS standard defines the affected facility.

"Affected Source" as defined in 40 CFR §63.2 of the General Provisions means the stationary source, the group of stationary sources, or the portion of a stationary source that is regulated by a relevant standard or other requirement established pursuant to Section 112 of the Clean Air Act. Each MACT standard defines the affected source.

"Appendix H Activities" means certain equipment or activities on the De Minimis Facilities list under OAC 252:100 Appendix H which warrant inclusion in the facility's emissions calculations 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 oil and natural gas facilities (Part 2 Section I, E).

"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)” include air emissions resulting from the maintenance, startup, or shutdown of equipment or facilities at a site and may include activities such as routine maintenance and other activities such as equipment blowdowns, pipeline pigging, or tank de-gassing.

[Note: MSS emissions are part of normal operation of a source and should be accounted for in planning, design, and implementation of operating procedures for process and control equipment. As such, MSS emissions should be included in Potential to Emit (PTE) calculations and are subject to applicable permitting requirements. Facility shall estimate MSS emissions to the extent that they are predictable and quantifiable.]

“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; (2) 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); (3) 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; (4) any modification to change emissions factors relied on in an application or a previous NOM; or (5) 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 upon submittal.

“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 was published in *The Oklahoman* on September 20, 2023, and in *The Tulsa World* on September 22, 2023. A copy of the draft permit was available for review on the Air Quality Section of the DEQ web page: *www.deq.ok.gov* during the public review period and was also available upon request. No comments were received.

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.

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/m³)

	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/m³) 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/m³)

	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/m³) 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/m^3)

	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/m^3); 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/m^3)

	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/m^3); 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" (≤ 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 ($\mu g/m^3$)
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 ($\mu g/m^3$)
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 ($\mu g/m^3$)
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.