OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM March 11, 2016

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SECTION I. INTRODUCTION

This General Permit has been developed to authorize construction and/or operation of facilities with potential emissions less than 100 tons/year (TPY) of a regulated pollutant in an attainment area, less than 100,000 TPY of CO_2e, less than 10 TPY of any single hazardous air pollutant (HAP), and less than 25 TPY of total HAP.

In addition, this permit will distinguish synthetic minor facilities with actual emissions below 79.99 TPY and those facilities with actual emissions equal to or above 80 TPY.

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	211111	Crude Petroleum and Natural Gas Extraction
1321	211112	Natural Gas Liquid Extraction
4612	48611	Pipeline Transportation of Crude Oil
4613	48691	Pipeline Transportation of Refined Petroleum Products
4922	48621	Pipeline Transportation of Natural Gas
5171	42271	Petroleum Bulk Stations and Terminals
5172	42272	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 permit. Permits issued to these facilities must address all air emissions from all sources at these facilities. Thus, this 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, and fugitive emission sources. 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 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 (2014)
1311	Crude Petroleum and Natural Gas Extraction	232	1663	5451
1321	Natural Gas Liquid Extraction	21	86	91
4612	Pipeline Transportation of Crude Oil	73	92	123
4613	Pipeline Transportation of Refined Petroleum Products	5	16	13
4922	Pipeline Transportation of Natural Gas	269	333	278
5171	Petroleum Bulk Stations and Terminals	11	14	24
5172	Petroleum and Petroleum Products Wholesalers (except Bulk Stations and Terminals)	8	12	5
	Total	**619**	**2216**	**5985**

SECTION II. DEFINITIONS

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

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

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

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

"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.

"Emissions Limited Engine" means any engine that has pound per hour emissions limitations specified under the conditions of an Authorization. Pound per hour emission limits shall be established for all engines located at a Class II facility and for all controlled engines; except for Certified Engines; except for Emergency Use Engines; except for engines subject to NSPS which have federally enforceable emission limits.

"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" means a written notice informing AQD of: (1) any modification or change of operations at the facility that would add a piece of equipment or a process that is subject to NSPS or NESHAP, or that would modify a piece of equipment or a process such that it becomes subject to NSPS or NESHAP, or that would change its facility classification (either from or to a True Minor Facility, a Class I Facility, or a Class II facility); or (2) any modification to add a storage tank with a capacity of 400 gallons or more storing VOC, a VOC Loading Operation, any combustion equipment, or any dehydration unit; or (3) any modification to change the hourly emissions limitations of an Emissions Limited Engine; or (4) any modification to add or remove a 6 TPY tank limit to address NSPS Subpart OOOO needs; or (5) any modification to add, modify, reconstruct, or replace an engine. Such notice shall contain calculations of the facility's new facility-wide potential to emit; the change in the facility's classification, if any; and the engine's potential to emit (g/hp-hr, lb/hr, and TPY) for all engines at the facility. Any emissions limits for NO_X and CO (lb/hr) cited in the latest Notice of Modification, for any Emissions Limited Engine, become permit limitations for that engine and an enforceable part of the existing Authorization to Operate. The permittee shall attach a copy of the latest Notice of Modification to a copy of the Authorization to Operate kept either on site, at a nearby manned facility, or at the nearest field office.

"Representative Extended Wet Gas Analysis" means an extended analysis (using GPA 2286 or similar approved methods) that provides speciated data for HAP components benzene, toluene, ethyl benzene, xylenes, and n-hexane. The sample must be representative of the maximum expected HAP content for normal operations of the glycol dehydrator or amine unit.

"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.

"True Minor Facility" means a facility that has the potential to emit, without controls, less than 80 TPY each of NO_X and CO.

"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).

"Voluntary Controls" means facilities not requesting the use of control devices for compliance with an emissions cap or federal limits.

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

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.

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 heat 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, ethyl benzene, xylene, and n-hexane) from rich glycol flash tank vents and glycol regenerator still vents.

Amine Units

Amine units are used to remove H_2S and CO_2 (acid gases) from natural gas or natural gas liquids. These units emit H_2S, CO_2, VOC, and HAP 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 that is listed as a de minimis facility under OAC 252:100, Appendix H. De minimis facilities are emission sources that do not require a minor permit unless located at an otherwise permitted facility. The Appendix H list is cited in the General Permit to identify activities/emissions units that are exempt primarily from monitoring and recordkeeping requirements. However, emissions from these activities/emissions units are required to be estimated for compliance with the facility-wide cap in the General Permit. A simplified method for estimating emissions from de minimis facilities is included in the permit.

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. 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, and lube oils.

Crude Oil

Significant emissions from the storage and loading of crude oil include VOC, hydrogen sulfide (H_2S), and the HAP listed in Table II-1. Crude oil contains other HAP, but they have higher molecular weights and the amount emitted is typically negligible compared to the HAP listed. The listed concentrations are the default HAP content values for crude oil in EPA TANKS 4.0.

Table II-1. Typical Crude Oil Maximum HAP Concentrations

Pollutant	CAS Number	Weight %
Benzene	71432	0.60
Toluene	108883	1.00
Ethyl benzene	100414	0.40
Xylenes	1330207	1.40
n-Hexane	110543	0.40

Condensate

Condensate, as defined in OAC 252:100-37-2, means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at normal operating conditions. VOC emissions from condensates may also include small amounts of benzene, toluene, ethyl benzene, and xylene (BTEX), and more significant amounts of n-hexane.

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 HAP; 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. EMISSIONS

A. POTENTIAL TO EMIT

The potential to emit (PTE) pollutants at a facility should be calculated using guidance contained in the DEQ "Potential to Emit Guidance", which is available on the DEQ website at www.deq.ok.gov. Note that facilities for which throughput is dependent on oil and gas field production may use the special procedures outlined in NESHAP 40 CFR, Subpart HH, for determining maximum facility throughput. In addition to the guidance above, start-up and shutdown related emissions , including but not limited to blowdowns and engine start-ups that utilize controls, shall be included in the facility PTE.

B. REGULATED AIR POLLUTANTS

NO_X, CO, VOC, SO_2, and PM_{10} are emitted from these facilities. NO_X and CO emissions from combustion sources can be significant and may require control for the facility to be a "synthetic minor" facility. Likewise, VOC emissions from storage tanks may also require control for the facility to be a "synthetic minor" facility. Emissions of SO_2 and PM_{10} are primarily from combustion sources and are typically much less than major source levels since most facilities combust natural gas with a total sulfur content of less than 20 grains/100 scf.

Storage Tanks

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. EPA and API have developed software packages (EPA TANKS and API E&P TANK) based on these working and breathing loss equations. The current version of E&P TANK can also provide estimates of flash losses from petroleum storage tanks. AQD has guidance which addresses acceptable methods for estimating VOC flash emissions from storage tanks: "Calculation of Flashing Losses/VOC Emissions from Hydrocarbon Storage Tanks."
(Current Link - http://www.deq.state.ok.us/aqdnew/resources/factsheets/FlashingLosses020916.pdf)

VOC Loading Operations

VOC emissions from the loading of tank trucks are generally estimated using AP-42 (1/95) Chapter 5.2.2.1.1, Equation 1 and Table 5.2-1 or other equivalent methods approved by Air Quality.

Combustion Equipment

Combustion 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. These pollutants can be estimated from emissions factors based on stack test data, manufacturer's data, or emission factors from AP-42, Chapters 1, 3, or 13. Stack test data or manufacturer's data are preferred methods for calculating potential NO_X and CO emissions from engines.

Combustion equipment also emits SO_2 due to the combustion of any sulfur compounds present in the fuel. Emission estimates should be based on a mass balance assuming 100% conversion of elemental sulfur in the fuel to SO_2. However, when combusting natural gas with total sulfur content of less than 20 gr/100 scf, emissions of SO_2 per MMBtu are much less than emissions of NO_X and CO; therefore, specific limits on SO_2 emissions are not required when combusting natural gas. The permit will limit the total sulfur content in liquid fuels to less than 0.05 wt% and will restrict the use of liquid fuels to Emergency Use Engines and engines rated at less than 50 horsepower, which will insure that SO_2 emissions remain below major source levels.

Emissions of PM_{10} are negligible and in compliance with OAC 252:100-19 for these sources when combusting natural gas. Compliance is also assured for liquid fuel combustion as demonstrated in Section IX.B.3.

Glycol Dehydration Units

Glycol dehydration units emit VOC from rich glycol flash tank vents and regenerator still vents. Potential VOC emissions from glycol dehydrator units can be estimated using the GRI-GLYCalc program (Version 4.0 or later), a process simulator program, or the Atmospheric Rich/Lean (ARL) Method. The emissions should be based on the potential to emit by assuming continuous operation using (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; a Representative Extended Wet Gas Analysis; the normal process operating temperature and pressure; the expected removal efficiency of any glycol still vent condenser at its maximum design temperature; and the maximum pump rate of the lean glycol circulation pump. 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. For combustion of gasses from a glycol still vent or flash tank in a reboiler, only 50% destruction efficiency shall be allowed.

Amine Units

Amine units emit VOC from the rich amine flash tank and regenerator still vents. Potential emissions can be estimated using the AMINE-Calc program, a process simulator program, and/or mass balance equations. The emissions should be based on the potential to emit by assuming continuous operation using the maximum throughput, a representative extended gas analysis or natural gas liquid analysis, the normal process operating temperatures and pressures, and the maximum pump rate of the lean amine circulation pump. Emissions from amine unit flash tanks are often controlled by routing the gases to the fuel gas system or by using a flare. Emissions from the regenerator still vent are often controlled by flaring or are vented to the atmosphere.

Fugitive Emission Sources

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.

C. HAZARDOUS AIR POLLUTANTS (HAP)

Significant amounts of HAP can be emitted from petroleum liquid storage tanks, VOC Loading Operations, engines, and glycol dehydration units. HAP emissions from heaters, boilers, flares, fugitive emission sources, and the storage of ethylene glycols and methanol are negligible for minor OGF.

Storage Tanks and VOC Loading Operations

HAP emissions from tanks storing petroleum liquids, other than condensate, can be estimated using the default crude oil HAP content in the EPA TANKS program or other methods that speciate the amount of HAP contained in the VOC emissions. VOC emissions from the storage and loading of condensate can contain significant amounts of HAP, especially n-hexane.

Combustion Equipment

Engines emit HAP including formaldehyde, acrolein, and acetaldehyde, with the most significant being formaldehyde. HAP emissions are generally estimated using manufacturer's data, the emission factors in AP-42 Chapter 3, or other industry generated data.

Glycol Dehydration Units

Glycol dehydration units emit HAP from rich glycol flash tank vents and regenerator still vents. Potential HAP emissions from glycol dehydrator units can be estimated using the GRI-GLYCalc program (Version 4.0 or later), a process simulator program, or the Atmospheric Rich/Lean (ARL) Method. The emissions should be based on the potential to emit by assuming continuous operation using (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; a Representative Extended Wet Gas Analysis; the normal process operating temperature and pressure; the expected removal efficiency of any glycol still vent condenser at its maximum design temperature; and the maximum pump rate of the lean glycol circulation pump.

Amine Units

Amine units emit HAP from rich amine flash tank vents and regenerator still vents. Potential HAP emissions from amine units can be estimated using the AMINE-Calc program or a process simulator program. The emissions should be based on the potential to emit by assuming continuous operation using the maximum throughput, a representative extended gas analysis or natural gas liquid analysis, the normal process operating temperatures and pressures, and the maximum pump rate of the lean amine circulation pump. Emissions from amine unit flash tanks are often controlled by routing the gases to the fuel gas system or by using a flare. Emissions from the regenerator still vent are often controlled by flaring or are vented to the atmosphere.

D. HYDROGEN SULFIDE

Some facilities store crude oils 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. Section I of Appendix A presents more detailed information on H_2S emissions from crude oil.

Glycol dehydration units that treat sour natural gas can emit H_2S from the regenerator still vent in significant amounts, although sour natural gas typically goes through an amine unit before dehydration. Amine units emit H_2S from rich amine flash tank vents and regenerator still vents. Potential H_2S emissions from amine units can be estimated using the methods from Appendix A.

E. GREENHOUSE GASES

Most of the facilities that meet emissions levels to qualify as a minor source under OAC 252:100-7 for regulated pollutants other than GHGs will not be affected by the GHG regulations. However, certain facilities may be impacted. Because of this, all facilities should take into consideration their GHG emissions when reviewing permit rule applicability. ODEQ is currently only requesting GHG emission estimates for minor source permit applications on a case-by-case basis, based on the equipment being proposed by the applicant. Should a facility determine there is a need to take an enforceable permit limit to avoid applicability of either the PSD or TV program, the facility should request such in a minor source construction permit application and any specific conditions required to ensure compliance with GHG emission limitations can then be incorporated into an Authorization to Operate. Once the enforceable limit is requested, the final permit would include GHG limits in terms of carbon dioxide equivalent (CO_2e), with appropriate monitoring and recordkeeping requirements.

SECTION V. PERMIT STRUCTURE

This general permit is designed for minor facilities (i.e., with actual emissions less than 100 TPY of a regulated pollutant in an attainment area, less than 100,000 TPY of CO_2e, less than 10 TPY of any single HAP, and less than 25 TPY of total HAP). The single 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 permit, or can obtain a minor source construction permit and then an Authorization to Operate under the permit, or can obtain an Authorization to Construct under the permit and then a minor source operating permit and pay all applicable fees. This should allow applicants the greatest flexibility for obtaining coverage under the 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 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 permit is formatted so that the first section establishes emissions limitations. Then specific conditions are given for each emissions unit allowed under the permit. Each section contains 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 NESHAP, are also incorporated as a specific condition for the permit. These emission unit-specific conditions, as required by Oklahoma regulations, are generally established in the Authorization to Construct under this permit, or by a minor source 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 hourly emissions limits on engines are required for compliance methods or TPY 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.

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 10 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.

SECTION VI. EMISSIONS LIMITATIONS

A. FACILITY-WIDE EMISSIONS CAP

Emissions limitations specified in the 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 hourly 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. A facility may take a facility-wide emissions cap for each regulated pollutant that is just below major source levels.

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 start-up 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 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 permit to assure compliance.

General EPA policy and preference is to not have emission compliance periods longer than one month, i.e., a 12-month rolling total is preferred for compliance with annual emissions limitations. Also, to demonstrate compliance with the facility-wide emissions caps, the permit requires the use of the hourly potential to emit for emissions from engines and glycol dehydration 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 already preauthorized by the permit (e.g., 40 CFR 60, Subparts A, Dc, K, Ka, Kb, GG, KKK, IIII, JJJJ, KKKK, or OOOO; or 40 CFR 63, Subpart HH for TEG units, Subpart ZZZZ for engines at area sources and Subpart BBBBBB for gasoline distribution bulk terminals, bulk plants and pipeline facilities at area sources). 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. To assure continuing compliance with these limits, the permittee must estimate emissions periodically, especially after a change at the facility, and maintain a current equipment inventory to document that such changes do not cause emissions to exceed the facility-wide cap. For certain modifications at the facility, the permittee must send in a Notice of Modification to AQD documenting that these items have been done.

B. HOURLY EMISSIONS LIMITATIONS ON ENGINES

Hourly emissions limitations are required for NO_X and CO for all engines (Emissions Limited Engines) unless the engine is an Emergency Use Engine; unless the engine is subject to an applicable short term federal standard such as NSPS, Subpart JJJJ; unless the engine could be considered an uncontrolled engine at a True Minor Facility but is using Voluntary Controls; or unless the engine is an Uncontrolled Engine located at a True Minor Facility. The hourly emissions limitations shall be based on manufacturer's data, EPA reference testing, or the latest revision of AP-42, Chapter 3. Appropriate safety factors may be applied. In addition, when federal reference testing is required and testing is not done under maximum representative operating conditions (i.e., less than 90% load), hourly emissions limits are required. If emissions testing is not available upon issuance of the Authorization to Operate and subsequent tests are reported to the agency demonstrating lower load testing, the permit may be reopened to incorporate appropriate hourly limits, only for the engines which that scenario applies.

H_2CO control efficiency shall be at or below the level requested for CO provided it is in compliance with the CO limit as required by the General Permit.

C. COMPLIANCE WITH THE CAP FOR STORAGE TANKS

The permittee will be required to maintain records of the type and capacity of all storage tanks at the facility with a capacity of 400 gallons or more that store VOC (as defined in OAC 252:100-1-3). In addition, the permittee will be required to include emissions of VOC and HAP from these storage tanks, based on actual throughputs, to demonstrate compliance with the facility-wide emissions cap for VOC and HAP. In addition, a facility may request a 5.99 TPY limit for any VOC storage tanks.

OAC 252:100-31-7 establishes an ambient air standard for H_2S emissions. H_2S emissions from storage tanks are of concern since these facilities may store/distribute crude oils with varying levels of H_2S content. Associated levels of H_2S are typically low, except for sour crude oils. To assure compliance with OAC 252:100-31, eligibility for the general permit will be restricted to those facilities that can demonstrate compliance with OAC 252:100-31-7 through permit eligibility restrictions and crude oil H_2S concentration limitations developed for the general permit and as presented in Appendix A.

D. COMPLIANCE WITH THE CAP FOR VOC LOADING OPERATIONS

The permittee will be required to include emissions of VOC and HAP from all loading operations, based on actual throughputs, to demonstrate compliance with the facility-wide emissions cap for VOC and HAP. Emissions of VOC and HAP from loading operations are typically low, when loading large volumes of liquid, loading emissions factors should be calculated using the procedures of AP-42 (1/95) Chapter 5.2.2.1.1, Equation 1 and Table 5.2-1 or other equivalent methods approved by Air Quality. Emissions of H_2S from VOC Loading Operations are expected to be negligible as demonstrated in Appendix A.

E. COMPLIANCE WITH THE CAP FOR COMBUSTION EQUIPMENT

Sulfur Dioxide Emissions

As shown in Appendix A, in order to demonstrate compliance with OAC 252:100-31 Part 2 and Part 5, the permit will have the following limits:

a. Total sulfur content in natural gas fuel of no more than 20 gr/100 scf.
b. Total sulfur content in liquid fuel of no more than 0.05% by weight.
c. Total installed fired duty from all combustion equipment, other than engines, is limited to 50 MMBtu/hr.

The total amount of engine horsepower that can be operated at a facility and still remain a minor source for NO_X and/or CO is about 5,000 horsepower (hp) for rich burn and 8,000 hp with lean burn engines. This inherent restriction and the limits listed above will limit potential SO_2 emissions to about 11 TPY for continuous operation of all combustion sources.

With the above permit restrictions, the potential to emit for SO_2 is limited to a maximum of less than 20 TPY for all combustion equipment at OGF and, therefore, no annual compliance calculations are required. The permit will restrict eligibility to those OGF with amine units that are not subject to OAC 252:100-31-26 unless a minor source construction permit is obtained and any specific conditions required to ensure compliance with SO_2 emission limitations are then incorporated into an Authorization to Operate.

NO_x and CO Emissions

To reduce the regulatory burden on the permittee and AQD, the general permit provides exemptions from hourly emissions limitations and periodic tests of NO_X and CO emissions from some engines. However, a one-time initial test of NO_X and CO emissions is required for these engines, except for Emergency Use Engines or engines subject to initial testing under NSPS, to demonstrate that the facility has potential to emit less than the facility-wide emissions cap for NO_X and CO. Also, the engines are always subject to unscheduled compliance testing by AQD. These exemptions include:

a. All Emergency Use Engines. This is present AQD policy.
b. All Uncontrolled Engines at a True Minor Facility. For the general permit, the emissions calculations for Uncontrolled Engines are based on the engine's potential to emit. An engine's potential to emit will be based on continuous operation, the engine's Maximum Rated Horsepower, and the highest manufacturers' emissions factors for any of the settings at which the engine can be operated, e.g., NO_X at "best economy" and CO at "best power". This is a conservative approach to emissions calculations. When combined with the 80 TPY potential emissions limit required for the facility to be classified as a True Minor Facility, there is ample room for variations in engine operations to ensure compliance with the facility-wide emissions caps.

c. All engines subject to an applicable federal short term emission limit such as NSPS, Subpart JJJJ.
d. All engines that are otherwise uncontrolled engines at a true minor facility but are nevertheless using a catalytic converter or an oxidation catalyst.

For all other Uncontrolled Engines, the general permit requires hourly emissions limitations and periodic testing of NO_X and CO emissions.

Compliance with NO_X and CO hourly emissions limits for emission limited engines using a control device (e.g., catalytic converters or oxidation catalyst), is not as straightforward, and is much more critical. Catalytic converters and oxidation catalysts typically have pollutant conversion efficiencies as high as 90 to 95% pollutant reduction. Thus, if the catalyst fails or is bypassed substantially through channeling, or, for three-way NSCR, if the AFRC 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 out of compliance. Therefore, hourly emissions limitations for NO_X and CO are required for Emissions Limited Engines. A specific condition requiring quarterly testing of NO_X and CO emissions from each Emissions Limited Engine is included in the permit. In addition, the permit will require monthly parametric monitoring to assure proper operation of the catalyst and AFRC (if applicable) and thus assure compliance between quarterly testing.

Engines subject to NSPS Subparts IIII or JJJJ which establishes enforceable short term emission limits, testing, and continuous compliance requirements are not subject to quarterly testing or hourly emission limits.

NO_X and CO emissions from heaters and boilers are much lower per MMBtu of fired duty than are emissions from engines. AP-42, Table 1.4-1 lists typical emission factors for natural gas combustion in small heaters (fired rating of less than 100 MMBtu/hr). NO_X emissions are approximately 100-lb/10^6 scf and CO emissions are approximately 84-lb/10^6 scf. With the permit limit of 50 MMBtu/hr on the total of all gas-fired combustion equipment, excluding engines and emergency relief flares, these emission factors give a PTE for NO_X of approximately 25 TPY and for CO of approximately 20 TPY. Therefore, no specific emission limitations or compliance demonstrations are required in the permit.

The permittee will be required to include emissions of NO_X and CO from all combustion equipment, based on actual operating hours, to demonstrate compliance with the facility-wide emissions cap for NO_X and CO.

VOC and PM_{10} Emissions

PM_{10} emissions from engines and other combustion equipment are typically only 1% (natural gas combustion) to 10% (from diesel engines) as much as NO_X and CO emissions; therefore, no specific limitations or compliance demonstrations are required in the permit for PM_{10}, other than restricting liquid fuel to either diesel or No. 2 fuel oil.

The permittee will be required to include emissions of VOC from all combustion equipment, based on actual operating hours, to demonstrate compliance with the facility-wide emissions cap for VOC.

HAP Emissions

Engines, lean-burn more so than rich-burn, can emit significant amounts of HAP, including formaldehyde, acrolein, and acetaldehyde, with 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 actual operating hours, to demonstrate compliance with the facility-wide emissions cap for HAP.

HAP emissions from the combustion of natural gas and liquid fuels combustion equipment such as heaters, boilers, flares, incinerators, and thermal oxidizers are negligible at minor OGF. For instance, the AP-42 factor for formaldehyde emissions from combustion of fuel oil is approximately 0.1% of the emission factor for NO_X. Therefore, emissions of HAP from heaters, boilers, flares, incinerators, and thermal oxidizers do not need to be included in the annual emissions calculated for compliance with the facility-wide cap for HAP.

F. COMPLIANCE WITH THE CAP FOR GLYCOL DEHYDRATION UNITS

The 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 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 permit when using the potential to emit; however, specific requirements in the permit are necessary to insure compliance when a condenser is used to control emissions and 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.

G. COMPLIANCE WITH THE CAP FOR AMINE UNITS

Hydrogen Sulfide and Sulfur Dioxide Emissions

Emissions of H_2S for amine units allowed under the permit are required to be controlled using a flare with a minimum control efficiency of 95%. Using a flare, H_2S is oxidized to SO_2. The major source threshold for SO_2 is around 3,200 SCFD of H_2S. The permit requires monitoring of the inlet gas H_2S concentration and throughput to keep the amount of SO_2 emitted below major source thresholds. Ambient impacts of H_2S when utilizing a flare to control emissions of H_2S are significantly lower than the ambient standard in OAC 252:100-31-7. At the H_2S throughput levels required to remain a minor source of SO_2 and including a required 95% control, H_2S

emissions are approximately 3 TPY. Therefore, no additional specific requirements to limit H_2S emissions from amine units are necessary.

Amine units processing natural gas or natural gas liquids from inlet gases containing less than 4 ppmv H_2S have also been shown to have impacts below the ambient standards in OAC 252:100-31-7. The maximum amount of natural gas processed by a single facility is generally much less than 300 MMSCFD. At 300 MMSCFD and 4 ppmv H_2S, uncontrolled emissions of H_2S from amine units would amount to 20 TPY. If these emissions were controlled using a flare and a 95% control efficiency, emissions of SO_2 would be equivalent to 35 TPY which is also significantly below the major source thresholds. Therefore, no additional specific requirements to limit H_2S or SO_2 emissions from amine units at a facility which process natural gas containing less than 4 ppmv H_2S are necessary.

VOC and HAP Emissions

Since the amine units allowed under the permit will be required to control emissions from the rich amine flash tank and the amine regeneration still vent to control emissions of H_2S, emissions of VOC and HAP will be negligible. Therefore, emissions of VOC and HAP from amine units after control do not need to be included in the annual emissions calculated for compliance with the facility-wide cap for VOC and HAP. No additional specific requirements to limit VOC and HAP emissions from amine units are necessary.

H. COMPLIANCE WITH THE CAP FOR FUGITIVE EMISSION SOURCES

The 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 and 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. However, since PSF > 300,000 barrels are major sources and ineligible for this permit, they are not included. The permit will require those facilities with K or Ka tanks (either subject to or grandfathered from the NSPS) 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.

I. CALCULATION OF ANNUAL EMISSIONS

For storage tanks and VOC Loading Operations, the emissions of VOC and HAP should be based on the actual annual liquid throughputs.

For an engine, the emissions will be based on the engine's potential to emit (which includes federally enforceable emission limits), including start-up and shutdown, or any hourly permit limits and the actual hours of operation. For all other combustion equipment, emissions should be based on the potential to emit of each pollutant, in TPY, adjusted for actual fired heat duty and actual annual operating hours, if known.

For glycol dehydration units, the emissions should be based on the unit's potential to emit in lb/hr and either assuming continuous operation or actual hours of operation if known.

For amine units, the emissions should be based on the unit's actual annual throughputs and either assuming continuous operation or actual hours of operation if known.

For fugitive emissions, the emissions should be based on an approximate fugitive component count and emissions factors approved by AQD.

Continuous operation of equipment must be assumed for the calculation of emissions for any emissions source for which the permittee has not kept records of actual hours of operation.

SECTION VII. 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 subject to an applicable requirement not included in this permit makes that facility ineligible for coverage under this permit unless a minor source construction permit is obtained and conditions from that permit are incorporated into an Authorization to Operate under this general 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, unless qualified as a de minimis facility under OAC 252:100, Appendix H, that are subject to:

    a. OAC 252:100-8 (Permits for Part 70 Sources)
    b. OAC 252:100-15 (Motor Vehicle Pollution Control Devices)
    c. OAC 252:100-17 (Incinerators)

d. OAC 252:100-23 (Cotton Gins)
e. OAC 252:100-24 (Grain, Feed, or Seed Operations)
f. OAC 252:100-35 (Control of Emissions of Carbon Monoxide)
g. 40 CFR Part 59 (National VOC Standards)
h. 40 CFR Part 82, Subparts B, D, E, G, and H (Stratospheric Ozone Protection)
i. 40 CFR Part 264 (Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities)

B. FACILITIES INELIGIBLE FOR AN AUTHORIZATION TO CONSTRUCT

The following facilities, unless qualified as a de minimis facility under OAC 252:100, Appendix H, are not eligible to obtain an Authorization to Construct under this permit, but may be eligible for coverage under an Authorization to Operate if they obtain a minor source construction permit and all relevant requirements and limitations in that permit are incorporated into the Authorization to Operate. .

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

2. Facilities storing/distributing crude oil that do not meet the following:

   a. Facilities that can demonstrate a maximum H_2S concentration of 135 ppmw for all categories of crude oil stored at the facility. Such demonstration must be documented using the methods outlined in Appendix A of this permit.

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

4. Facilities using a vapor-recovery/vapor disposal system, or other equipment of equal efficiency, as required by any part of OAC 252:100-37, Control of VOCs, or 100-39, Control of VOCs in Nonattainment Areas. Note that VOC storage vessels that are subject to equipment standards (e.g., a fixed roof in combination with an internal floating cover, an external floating roof, or a closed vent system and control device) in 40 CFR 60 Subparts K, Ka, or Kb are exempt from the requirements of 252:100-37-15(a) and (b). In addition, VOC storage vessels that are subject to the equipment standards for external floating roofs in 40 CFR 60 Subparts Ka or Kb are exempt from the requirements of 252:100-39-30.

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

6. 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. The rich amine flash tank can be routed to the fuel gas system or to a

flare. The amine regeneration still vent must be routed to a flare meeting the requirements of OAC 252:100-31-26. Facilities with amine units that process natural gas with an H_2S content greater than 4 ppmv or that do not control emissions from the rich amine flash tank and amine regeneration vent would require a site-specific determination of compliance with the H_2S ambient concentration limit of OAC 252:100-31-7.

7. Facilities with amine units that process more than 0.1276 LTPD of sulfur. Facilities with amine units that process more than 0.1276 LTPD of sulfur would be a major source for SO_2.

8. Facilities with "new fuel-burning equipment," as that term is defined in OAC 252:100-33, with a rated heat input of 50 MMBtu/hr or greater for one piece of equipment or a total of 50 MMBtu/hr or greater at the facility.

9. Facilities with emissions units subject to NSPS or NESHAP subparts other than the following:

   a. NSPS requirements under 40 CFR Part 60 Subpart A, Subpart Dc, Subpart K, Subpart Ka, Subpart Kb, Subpart GG, Subpart KKK, Subpart IIII, Subpart JJJJ, Subpart KKKK, Subpart OOOO, or
   b. NESHAP requirements under 40 CFR Part 61, or
   c. NESHAP requirements under 40 CFR Part 63, Subpart HH requirements for triethylene glycol dehydration units at area sources; any Subpart ZZZZ requirements for RICE at area sources; and Subpart BBBBBB requirements for gasoline distribution at bulk terminals, bulk plants and pipeline facilities at area sources.

10. 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.

11. Facilities that require a specific limitation(s) for a glycol dehydration unit in order to be a minor source, other than operation of a condenser on still vent emissions or the operation of a flare.

12. Facilities with the potential to emit more than 100,000 TPY CO_{2e} and would otherwise be considered a major source of GHG emissions.

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 VIII.B-Control Devices.

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. Facilities that are not in compliance with all applicable State and Federal air requirements may become eligible for coverage under this permit through submission of a compliance plan meeting the requirements of Part 3 of this Permit.

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 VIII. APPLICABLE RULES AND 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, 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. FACILITY-WIDE REQUIREMENTS

Oklahoma Air Pollution Control Rules

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

OAC 252:100-2 (Incorporation by Reference) [Applicable]
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 based on either emission inventories or allowable emissions.

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, including that a construction permit require the permittee to comply with all applicable air pollution rules, federal NSPS and NESHAP established under Sections 111 and 112 of the Federal Clean Air Act, and to not exceed ambient air quality standards. A construction permit and subsequent operating permit is required for new facilities and modification of existing facilities.
Part 4 establishes operating permit requirements and requires demonstration of compliance with the emission limits and air pollution control requirements of the construction permit. No specific emission limitation, work practice condition, or other emission standard, or criterion is specified in this subchapter.
Part 9 discusses applicability, general requirements, and registration requirements for facilities that are eligible for a permit by rule.

This permit assures compliance with this regulation using the following approach:
The permit is designed to allow minor facilities to fulfill the requirement to obtain an Authorization to Construct and an Authorization to Operate before starting construction and operation of an eligible facility, or for modifications to existing eligible facilities. A Notice of Intent (NOI) to Construct is required prior to commencing construction or installation of any new facility other than a de minimis facility. Coverage under the general permit is effective upon receipt of the NOI to Construct 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; or (3) a DEQ date stamped application, is acceptable documentation of receipt of the NOI. After construction is complete, an NOI to Operate must be submitted within 180 days of start-up.

The general permit has gone through Tier II review; therefore, only Tier I review will be provided for any Authorizations issued hereunder. In lieu of an Authorization to Construct, an applicant may obtain a minor source construction permit, and then apply for an Authorization to Operate under this permit. Permit conditions have been included in the permit that provide that conditions from a minor source construction permit can be incorporated into the Authorization to Operate as long as the conditions are equivalent to or more stringent than the corresponding conditions in the General Permit. 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 so as 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 permit also incorporates NSPS which contains initial and continuous compliance requirements and recordkeeping as well as reporting requirements. An initial compliance inspection of the facility may be conducted by the AQD prior to issuance of the Authorization to Operate. Conditions have also been included in the permit to require a compliance demonstration prior to issuance of an Authorization to Operate and continuing compliance demonstrations to assure that the source continues to meet applicable requirements. Compliance with the facility-wide emissions cap shall be determined by calculating the actual emissions from all emission units located at the facility. Such emissions estimates shall be calculated as specified in the specific conditions for each particular emissions unit, or for equipment not specified, using manufacturer's data, EPA approved emissions software, DEQ approved estimation methods, testing data, or the latest approved version of AP-42, Compilation of Air Pollution Emission Factors. Emissions limitations are required for those sources that have the potential to violate an applicable requirement. These limitations are established as part of the facility-wide emissions cap, not to equal or exceed 100 TPY of any regulated air pollutant for a Class II facility, or 80 TPY of any regulated pollutant for a Class I facility, nor to equal or exceed 10 TPY of any single HAP, or 25 TPY of all HAP. Specific conditions are also included in the permit to address any ambient air quality standards or NSPS and NESHAP requirements. Currently, under Oklahoma's State Implementation Plan (SIP), minor facilities are not required to demonstrate compliance with the NAAQS. However, a permit condition is included in the permit that requires the facility to meet the ambient air quality standards. The permit allows facilities that become subject to an NSPS or NESHAP to incorporate those requirements into an Authorization to Operate. A notice of intent to construct must be issued for the modification of an existing facility that is adding equipment subject to an NSPS or NESHAP not otherwise addressed in the permit or that is making modifications that require a case-by-case determination. After construction is complete, an NOI to Operate must be submitted within 180 days of start-up and a new Authorization to Operate will be issued. All other facility modifications may be constructed without a minor source construction permit, an Authorization to Construct, or a new Authorization to Operate. For certain modifications, the permittee must send a Notice of Modification to AQD within 10 days of the start of operation of the modification.

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, start-up, 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 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 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 permit.

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 permit assures compliance with this regulation using the following approach:
The only emissions units/activities with the potential for visible emissions are engines, especially liquid fueled engines. Most engines are natural gas fired. In addition, liquid fueled engines restricted to the fuels allowed in this permit have very little potential to violate these opacity requirements. Thus, periodic monitoring of opacity is not being required at any of these facilities. Ongoing operation and maintenance activities at the facility 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.

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 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 252:100-43 (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 permit assures compliance with this regulation using the following approach:
A standard condition is included which states that all required tests shall be made and the results calculated in accordance with test procedures described or referenced in the permit and approved by Air Quality. Permit specific conditions establish 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.

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. In addition, OAC 252:100-43 provides that any credible evidence may be used for the purpose of establishing whether a person has violated or is in violation of the State Implementation Plan (SIP).

Credible Evidence, 40 CFR Part 51 [Applicable]
This regulation clarifies that "any credible evidence," including data gathered from means other than the use of a specified "reference test method," can be used to prove an alleged emission limitation violation.

The permit assures compliance with this regulation using the following approach:
Conditions are included in the Standard Conditions of the permit to address the credible evidence requirements.

New Source Performance Standards (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.

The 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 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 permit requirements, e.g., equipment addition or change notifications. However, a timely submitted Notice of Modification shall suffice as a notice of the actual date of initial start-up, 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.

National Emission Standards for Hazardous Air Pollutants (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.

The permit assures compliance with this regulation using the following approach:
Conditions are included to address general notification, recordkeeping, emissions limitations, performance test, and monitoring requirements. Language in the 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 permit requirements, e.g., equipment addition or change notifications. However, a timely submitted Notice of Modification shall suffice as a notice of the actual date of initial start-up, 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 NESHAP (40 CFR 63.9)). Conditions specific to a particular NESHAP are included for each emissions unit that may be determined to be an affected unit.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subpart A and Subpart F Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to class I and class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H). Subparts A and F are potentially applicable to OGF facilities.

The permit assures compliance with this regulation using the following approach: Facilities subject to 40 CFR Part 82, Subparts B, C, D, E, G, and H are ineligible for an Authorization to Construct. A standard condition of the permit requires compliance with 40 CFR Part 82, Subparts A and F.

Subpart A identifies ozone-depleting substances and divides them into two classes. Petroleum liquid storage facilities may use one or more regulated refrigerants either in a process cooler or condenser, a building air conditioner, or in motor vehicles. Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs.

Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment, comply with the standards for recycling and emissions reduction. Conditions are included in the permit to address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; § 82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

Non-applicable Oklahoma and Federal Regulations

Table VIII-1 and Table VIII-2 list the Oklahoma Air Quality Rules and Federal 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 Rules

OAC 252:100-8	Permits for Major Sources	Not a major source
OAC 252:100-11	Alternative Emissions Reduction	Ineligible *
OAC 252:100-15	Mobile Sources	Not a covered source
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 VOC	Not a covered source
OAC 252:100-37, Part 7	Control of Specific Processes	Not a covered source
OAC 252:100-39, Part 7 Sections 40, 42, 43, 44-47, & 49	Emissions of VOCs in Nonattainment Areas and Former Non-Attainment Areas	Ineligible *

*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

Table VIII-2- Non-applicable Federal Regulations

40 CFR Part 52	Prevention of Significant Deterioration	Not applicable
40 CFR Part 59	Consumer/Commercial Products	Not a covered source
40 CFR Part 60	Subpart LLL, Onshore Natural Gas Processing: SO_2 Emissions	Ineligible *
40 CFR Part 61	NESHAP Subpart J, Equipment Leaks of Benzene	All process streams are below the 10% benzene by weight threshold
40 CFR Part 63	NESHAP Subpart HHH, Natural Gas Transmission and Storage Facilities Subpart EEEE, Organic Liquids Distribution (Non-Gasoline)	Only applicable to major sources of HAP
40 CFR Part 64	Compliance Assurance Monitoring	Not a major source
40 CFR Part 68	Chemical Accident Prevention	Ineligible *
40 CFR Part 82, Subpart B	Stratospheric Ozone for Servicing of MVACs	Ineligible *
40 CFR Part 82, Subpart C	Ban on Nonessential Products	Ineligible *
40 CFR Part 82, Subpart D	Stratospheric Ozone for Federal Procurement	Ineligible *
40 CFR Part 82, Subpart E	Stratospheric Ozone for Labeling of Ozone-Depleting Products	Ineligible *
40 CFR Part 82, Subpart G	Stratospheric Ozone for the Significant New Alternatives Policy Program	Ineligible *
40 CFR Part 82, Subpart H	Stratospheric Ozone for Halon Emissions Reduction	Ineligible *

*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. UNIT-SPECIFIC REQUIREMENTS

Storage Tank Requirements

Oklahoma Air Pollution Control Rules

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of hydrogen sulfide emissions from any new or existing source to 0.2 ppm for a 24-hour average (equivalent to 283 $\mu g/m^3$). The limitation 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.

The permit assures compliance with this regulation using the following approach:
Except for facilities that store crude oil, no significant emission of H_2S is expected from storage tanks at these facilities. Eligibility for an Authorization to Construct under the permit is restricted to those facilities that meet certain limitations as outlined in Appendix A. Facilities that store sour crude oil may apply for a minor source construction permit and then obtain an

Authorization to Operate under this permit. Appendix A documents compliance with Subchapter 31, Part 2 for facilities that meet the limitations. Any emission limitations or specific conditions necessary for compliance with Subchapter 31, Part 2 will be incorporated into the Authorization to Operate.

Facilities that store sour crude oil and which use a flare to convert H_2S emissions from the tanks to SO_2 are eligible for the permit.

OAC 252:100-37 (Control of VOCs) [Applicable]
Part 3 requires storage tanks (except pressure tanks) built after 12/28/74, and with a capacity of 400 gallons or more storing a VOC with a vapor pressure of 1.5 psia or greater under actual conditions, to be equipped with a submerged fill pipe or a vapor-recovery system.
Part 3 requires storage tanks (except pressure tanks) built after 12/28/74, with a capacity greater than 40,000 gallons to be equipped with a floating roof or a vapor-recovery system capable of collecting 85% or more of the uncontrolled VOCs.

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. These specific conditions require installation and operation of vapor-loss control devices, which, for storage tanks over 40,000 gallons, include a floating roof or a vapor recovery system. A permanent submerged fill pipe is required for storage tanks over 400 gallons. An Authorization to Construct is not allowed for a facility using a vapor-recovery/vapor disposal system as required by OAC 252:100-37-15(a)(2), or other equipment of equal efficiency, as required by 252:100-37-15(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.

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.

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.

Federal Regulations

New Source Performance Standards (NSPS), 40 CFR Part 60 [Applicable]

Subpart K, Standards of Performance for Storage Vessels for Petroleum Liquids. This subpart applies to storage vessels for petroleum liquids which have a storage capacity greater than 40,000 gallons and are not located at a drilling or production facility prior to custody transfer, and were constructed or modified between March 8, 1974, and May 19, 1978; and those similar vessels greater than 65,000 gallons which were constructed between June 11, 1973, and May 19, 1978. Those vessels storing liquids with a vapor pressure between 1.5 psia and 11.1 psia must be equipped with a floating roof, a vapor recovery system, or their equivalent. Those vessels storing liquids with a vapor pressure greater than 11.1 psia must be equipped with a vapor recovery system. Certain records are required to be kept for these facilities.

Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids. This subpart applies to storage vessels for petroleum liquids that have a storage capacity between 40,000 and 420,000 gallons which are not located at a drilling or production facility prior to custody transfer, and all storage vessels for petroleum liquids with a capacity greater than 420,000 gallons, which were constructed or modified after May 19, 1978. Those vessels storing liquids with a vapor pressure between 1.5 psia and 11.1 psia must be equipped with an external floating roof, a fixed roof with an internal floating roof, a vapor recovery system with 95% weight efficiency, or their equivalent. Those vessels storing liquids with a vapor pressure greater than 11.1 psia must be equipped with a vapor recovery system with 100% collection efficiency and vapor disposal system with 95% weight efficiency. Certain records and performance test are required for these facilities.

Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels). This subpart applies to vessels storing volatile organic liquids (VOL) with a capacity greater than or equal to 19,813 gallons that were constructed or modified after July 23, 1984. This subpart does not apply to storage vessels with a capacity greater than or equal to 39,894 gallons storing a liquid with a maximum true vapor pressure less than 0.51 psia or with a capacity between 19,813 gallons and 39,894 gallons storing a liquid with a maximum true vapor pressure less than 2.2 psia. Vessels with a capacity greater than or equal to 39,894 gallons storing a VOL with a maximum true vapor pressure between 0.75 psia and 11.1 psia or with a capacity between 19,813 gallons and 39,894 gallons storing a VOL with a maximum true vapor pressure between 4.0 psia and 11.1 psia, must be equipped with either a fixed roof in combination with an internal floating roof, an external floating roof, a closed vent system and control device, or their equivalent. Vessels with a capacity greater than or equal to 19,813 gallons storing a VOL with a maximum true vapor pressure greater than or equal to 11.1 psia must be equipped with a closed vent system and control device or their equivalent. Certain records are required to be kept for these facilities.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NSPS.

Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart was promulgated on August 16, 2012, and affects storage vessels located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment that commence construction, reconstruction, or modification after August 23, 2011, and have the potential for VOC emissions equal to or greater than 6 tpy. Storage vessel facilities are subject to standards of §60.5395. A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart. This subpart requires storage tanks with potential VOC emissions of six TPY or greater to reduce emissions by 95%.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements as specified in the NSPS.

VOC Loading Operations Requirements

Oklahoma Air Pollution Control Rules

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air concentration of hydrogen sulfide emissions from any facility to 0.2 ppm at standard conditions, 24-hour average (equivalent to 283 $\mu g/m^3$). The standard shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.

The permit assures compliance with this regulation using the following approach:
Emissions of H_2S from VOC Loading Operations are negligible (see Appendix A).

OAC 252:100-37 (Control of VOCs) [Applicable]
Part 3 requires VOC loading facilities built after 12/28/74, and with a throughput greater than 40,000 gal/day, to be equipped with a vapor collection and disposal system unless all tank trucks or trailers are bottom loaded with hatches closed.

Part 3 requires VOC loading facilities built after 12/28/74, and with a throughput less than 40,000 gal/day, to be equipped with a system for submerged filling of tank trucks or trailers which is installed and operated to maintain a 97 percent submergence factor.

The permit assures compliance with this regulation using the following approach:
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.

OAC 252:100-39 (VOCs in Non-attainment Areas) [Applicable]
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:
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.

Combustion Equipment Requirements

Oklahoma Air Pollution Control Rules

OAC 252:100-19 (PM Emissions from Fuel-burning Equipment) [Applicable]
Subchapter 19 requires that the maximum allowable emissions of particulate matter from engines and other combustion equipment not exceed the following amount:

Maximum Heat Input (MMBTU)	Allowable Total PM Emissions (lb/MMBTU)
Less than or equal to 10	0.60
10,000 or more	0.10

Allowable total PM emissions for units with a heat input of greater than 10 MMBTU but less than 10,000 MMBTU can be calculated using the formulas listed in OAC 252:100 Appendix C.

The permit assures compliance with this regulation using the following approach:
Eligibility for an Authorization to Construct under the permit is restricted to those facilities using liquid petroleum gas, natural gas with no greater than 162 ppmdv 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%. AP-42, Tables 3.2-1,-2, and -3 (7/00) list PM_{10} emissions from gas-fired internal combustion engines as 0.0447 lb/MMBtu for 2-stroke lean-burn engines, 0.009987 lb/MMBtu for 4-stroke lean-burn engines, and 0.01941 lb/MMBtu for 4-stroke rich-burn engines, which are in compliance for all heat input ranges. AP-42, Table 1.4-2 (7/98) lists total PM emissions from natural gas combustion as 0.0075 lb/MMBtu, which is in compliance with all heat input ranges. AP-42, Table 3.3-1 (10/96), lists gasoline fuel PM_{10} emissions as 0.10 lb/MMBtu, which is also in compliance for all heat input ranges. AP-42, Table 3.3-1 (10/96), lists diesel fuel PM_{10} emissions as 0.31 lb/MMBtu for engines rated less than 600-hp, which is also in compliance for all engines rated up to 600-hp. AP-42, Table 3.4-1 (10/96), lists diesel fuel PM_{10} emissions as 0.10 lb/MMBtu, which is also in compliance for all engines rated above 600-hp at all heat input ranges. AP-42, Table 1.3-1 (9/98) lists PM emissions from fuel oil combustion as [9.19S + 3.22] lb/10^3 gallons where S is the % sulfur by weight, which is equivalent to approximately 0.02628 lb/MMBtu and is in compliance for all heat input ranges. Thus, any diesel-fired engine eligible for this permit is in compliance with this subchapter.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity.

The permit assures compliance with this regulation using the following approach:
The only emissions units/activities with the potential for visible emissions are engines, especially liquid fueled engines. Most engines are natural gas fired. In addition, liquid fueled engines restricted to the fuels allowed in this permit have very little potential to violate these opacity requirements. Thus, periodic monitoring of opacity is not being required at any of these facilities. Ongoing operation and maintenance activities at the facility 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.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air concentration of hydrogen sulfide emissions from any facility to 0.2 ppm at standard conditions, 24-hour average (equivalent to 283 $\mu g/m^3$). The standard shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.
Part 5 limits SO_2 emissions from any new gas-fired fuel-burning equipment to 0.2 lb/MMBTU heat input for a three-hour average.
Part 5 limits SO_2 emissions from any new liquid-fired fuel-burning equipment to 0.8 lb/MMBTU heat input for a three-hour average

The permit assures compliance with this regulation using the following approach:
Eligibility for an Authorization to Construct under the permit is restricted to those facilities using liquid petroleum gas, natural gas with no greater than 20 grains/100 scf total sulfur content, or diesel or No. 2 fuel oil with a sulfur content less than 0.05% by weight. Appendix A documents compliance with Subchapter 31 for any engine eligible for the permit.

OAC 252:100-37 (Control of VOCs) [Applicable]
This subpart, as applied to engines, provides that all fuel-burning equipment shall be operated so as to minimize emissions of hydrocarbons or other organic materials. The equipment should be operated such that it is not overloaded, that it is properly cleaned and maintained, and that temperature and available air are sufficient to provide essentially complete combustion.

The permit assures compliance with this regulation using the following approach:
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.

Federal Regulations

New Source Performance Standards (NSPS), 40 CFR Part 60 [Applicable]

Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects Steam Generating Units (defined in the subpart) that commenced construction, modification, or reconstruction after June 9, 1989, and that have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. For Steam Generating Units burning natural gas or LPG, the only applicable Subpart Dc requirement is notification per 40 CFR § 60.48c(a) and records of the daily/monthly amount of fuel combusted per 40 CFR §60.48c(g).

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of this subpart.

Subpart GG, Standards of Performance for Stationary Gas Turbines. This subpart regulates NO_X and SO_2 emissions for gas turbines that commenced construction, modification, or reconstruction after October 3, 1977, with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel. These units are subject to the nitrogen dioxide emission limitations of §60.332, the sulfur dioxide emission limitations of §60.333, the requirements of §60.334(h) for fuel monitoring, and the test methods and procedures of §60.335. Monitoring of the fuel nitrogen content is not required if the owner or operator does not take a NO_X allowance for fuel-bound nitrogen. Also, monitoring of fuel sulfur content is not required when a gaseous fuel is fired in the turbine and the owner or operator demonstrates that the gaseous fuel meets the definition of "natural gas" using one of the methods in §60.334(h)(3)(i) or (ii). §60.331 defines "natural gas" as containing 20 grains or less of total sulfur per 100 standard cubic feet and is either composed of at least 70 percent methane by volume or has a gross caloric value between 950 and 1,100 Btu/scf. The fuel monitoring requirements of §60.334(b) are required for liquid fuels.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of this subpart.

<u>Subpart IIII</u>, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. This subpart regulates NO_X, particulate matter, CO, and Non-methane hydrocarbons (NMOC) from stationary compression ignition internal combustion engines (CI ICE) that commenced construction, modification, or reconstruction after July 11, 2005. Sulfur oxides (SO_X) will also be controlled through the use of low sulfur fuel. These units are subject to the emission standards of §60.4304 and §60.4205; the fuel requirements of §60.4207; compliance requirements of §60.4210 and §60.4211; and the testing methods of §60.4212 and §60.4213.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of this subpart.

<u>Subpart JJJJ</u>, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart promulgates emission standards for new SI engines ordered after June 12, 2006, that are manufactured after certain dates, and for SI engines modified or reconstructed after June 12, 2006. These units are subject to the emission standards of § 60.4233; the fuel requirements of §60.4235; compliance requirements of §60.4243; and the testing methods of §60.4244.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NSPS.

<u>Subpart KKKK</u>, Standards of Performance for Stationary Combustion Turbines. This subpart regulates NO_X and SO_2 emissions for turbines that commenced construction, modification, or reconstruction after February 18, 2005, with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the higher heating value of the fuel. These units are subject to the nitrogen dioxide emission limitations of §60.4320 and §60.4325, the sulfur dioxide emission limitations of §60.4330, the requirements of §60.4360, §60.4365, and §60.4370 for fuel monitoring, and the test methods and procedures of §60.4400, §60.4405, and §60.4415. Monitoring of fuel sulfur content is not required when natural gas is fired in the turbine and the owner or operator demonstrates that the natural gas contains 20 grains or less of total sulfur per 100 standard cubic feet.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NSPS.

<u>Subpart OOOO</u>, Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart affects each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals that is located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment as well as each reciprocating compressor affected facility, which is a single reciprocating compressor located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment that commence construction, reconstruction, or modification after August 23, 2011. A centrifugal or reciprocating compressor located at a well site, or an adjacent well site and servicing more than

one well site is not an affected facility under this subpart. Centrifugal compressor facilities are subject to the standards of §60.5380 and reciprocating compressor facilities are subject to the standards of §60.5385.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NSPS.

National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63 [Applicable]

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines). These units are subject to the emission and operating limits of §63.6601 through §63.6604; the requirements of §§63.6610 through §60.6630 for testing and initial compliance; and the notification, reports, and records requirements in §63.6645 through §63.6660.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NESHAP.

Glycol Dehydration Units Requirements

Oklahoma Air Pollution Control Rules

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of hydrogen sulfide emissions from any facility to 0.2 ppm at standard conditions, 24-hour average (equivalent to 283 $\mu g/m^3$). The standards 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. Glycol dehydrators treating sour natural gas have the potential to emit significant amounts of H_2S. Sour natural gas is typically treated in a sweetening unit prior to dehydration.

The permit assures compliance with this regulation using the following approach:
Eligibility for an Authorization to Construct is restricted to facilities that do not have glycol dehydration units which treat sour natural gas. Sour gas is natural gas containing greater than 4 ppmv 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.

OAC 252:100-42 (Toxic Air Contaminants) [Applicable]
Part 5 of OAC 252:100-41 was superseded by this subchapter. Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director.

The permit assures compliance with this regulation using the following approach:
No specific requirements are needed in this general permit for compliance with Subchapter 42. Those minor OGF that currently have permit specific conditions in order to demonstrate previous compliance with Subchapter 41 Part 5, may use the procedures for this general permit to request a modification for removal of those limitations.

Federal Regulations

National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63 [Applicable]

Subpart HH, Oil and Natural Gas Production Facilities. This subpart applies to TEG dehydration units affected emission points that are located at facilities that are major and area sources of HAPs and either process, upgrade, or store hydrocarbons prior to the point of custody transfer or prior to which the natural gas enters the natural gas transmission and storage source category. Facilities covered under OGF-GP are considered an "area" source of HAPs. TEG dehydration units with an actual annual average flow rate of less than 3 MMSCFD or less than 1 TPY of benzene emissions are exempt from control standards, but are subject to recordkeeping.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will have a specific condition requiring compliance with all applicable requirements for TEG units that are subject to NESHAP Subpart HH.

Amine Units Requirements

Oklahoma Air Pollution Control Rules

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air concentration of hydrogen sulfide emissions from any facility to 0.2 ppm at standard conditions, 24-hour average (equivalent to 283 $\mu g/m^3$). The standard shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.
Part 5, Section 31-26(1) 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.

Part 5, Section 31-26(2) acid gas streams with a sulfur content of greater than 0.54 LT/D or gas sweetening units or petroleum refinery process equipment which emit more than 100 lb/hr of SO_2 shall reduce the sulfur content prior to release to the ambient air by use of a sulfur recovery unit. The sulfur recovery unit shall meet the sulfur recovery efficiencies of OAC 252:100-31-26(2)(C-F).

The permit assures compliance with this regulation using the following approach:
Eligibility for an Authorization to Construct is restricted to facilities with amine units that process sweet natural gas. Sweet natural gas is natural gas with an H_2S content of 4 ppmv or less. Facilities with amine units that process 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. Appendix A documents compliance with the ambient standard of Subchapter 31 for amine units eligible for the permit. The permittee shall conduct testing of the inlet H_2S concentration at least quarterly to ensure compliance with OAC 252:100-31-7 H_2S ambient air concentration limit of 0.2 ppm (283 $\mu g/m^3$).

This 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.

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.

Federal Regulations

New Source Performance Standards (NSPS), 40 CFR Part 60 [Applicable]

Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart affects sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells that commence construction, reconstruction or modification after August 23, 2011. Sweetening unit facilities are subject to standards of §60.5405, §60.5406 and §60.5407. Facilities that have a design capacity less than 2 LT/D of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423(c), but are not required to comply with §§60.5405 through 60.5407 and §§60.5410(g) and 60.5415(g) of this subpart.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of the NSPS.

Subpart LLL, Natural Gas Production. This subpart affects sweetening units and sweetening units followed by a sulfur recovery unit located at an onshore natural gas processing plant that was constructed, reconstructed or modified after January 20, 1984, and on or before August 23, 2011. Sweeting unit facilities are subject to standards of §60.642, §60.643, §60.644, §60.645, §60.646, §60.647 and §60.648. Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.642(c), but are not required to comply with §§60.642 through 60.646 of this subpart. The provisions of this subpart do not apply to sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released into the atmosphere.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of the NSPS.

Fugitive Emission Sources Requirements

Oklahoma Air Pollution Control Rules

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of hydrogen sulfide emissions from any new or existing source to 0.2 ppm for a 24-hour average (equivalent to 283 $\mu g/m^3$). The limitation 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.

The permit assures compliance with this regulation using the following approach:
As shown in Appendix A, fugitive emissions of H_2S are negligible for the facilities eligible for this permit.

Federal Regulations

New Source Performance Standards (NSPS), 40 CFR Part 60 [Applicable]

Subpart KKK, Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This subpart requires leak detection and reporting (LDAR) for fugitive components and compressors at natural gas processing plants that were constructed, reconstructed, or modified after January 20, 1984.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of the NSPS.

Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution.
This subpart affects each pneumatic controller affected facility, which is a single continuous bleed gas-driven pneumatic controller operating at natural gas bleed rate greater than 6 scfh that

commence construction, reconstruction, or modification after August 23, 2011. Pneumatic controller facilities are subject to the standards of §60.5390 and §60.5402. This subpart also requires leak detection and reporting (LDAR) for equipment leaks at natural gas processing plants and is subject to the standards of §60.5400.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of the NSPS.

Control Devices

Control devices expected at Minor OGF include floating roofs, vapor-recovery systems, flares, 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). General permit requirements may be superseded by more stringent monitoring if a minor source construction permit is needed to develop other site-specific conditions to assure compliance with applicable state or federal rules.

The permit contains general requirements to insure compliance with the facility-wide emissions cap or unit specific limits when these control devices are used to reduce pollutant emissions. Facilities with a vapor-recovery system that is determined to be a control device are not eligible for an Authorization to Construct. Those facilities may obtain a minor source construction permit and incorporate any emission limitations and compliance requirements for these control devices in that construction permit into an Authorization to Operate.

OAC 252:100-37-15(a) specifies control requirements for storage tanks with a capacity above 40,000 gallons constructed after December 28, 1974. Such tanks shall be constructed with either (1) an external floating roof that consists of a pontoon type or double-deck type cover, or a fixed roof with an internal-floating cover; or (2) a vapor-recovery system that consists of a vapor-gathering system capable of collecting 85 percent or more of the uncontrolled VOCs; or (3) other equipment or methods that of equal efficiency and approved by the Division Director prior to installation. The permit requires compliance with OAC 252:100-37-15(a), except for petroleum or condensate stored, processed and/or treated at a drilling or production facility prior to lease custody transfer and except for methanol stored at drilling or production facilities, which is exempt per OAC 252:100-37-4(b).

Any VOC emissions from a storage vessel that are recovered and routed to a process through a VRU designed and operated as specified in §60.5365(e) are not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status. A properly installed and operated VRU is considered to recover 100% of the VOC emissions during the time the VRU is in use.

Maximum Allowed Control Efficiency	Requirements
Control Device : Flares or enclosed combustion device	

≤ 98% for VOC's, HAP's and H_2S	• Meet 40 CFR §60.18 requirements for minimum heating value and maximum flare tip velocities
	• Be operated with a flame present at all times by having a continuous pilot flame or an automatic ignition system
	  ▪ Presence of a flare 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 flare downtime shall be maintained
	• Monitors must be accurate to and calibrated at the frequency in accordance with manufacturers specifications
	• Be designed for the variability of the waste gas stream it controls

The permit requires compliance with 40 CFR 60.18 for any applicable flares used to control equipment subject to an NSPS or NESHAP. Acid gas flares are required to meet the requirements of OAC 252:100-31-26 and a minimum heat content of 300 BTU/SCF.

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.

Maximum Allowed Control Efficiency	Requirements
Control Device : Condenser	

≤ 90% for VOC's and HAP's	• Have exhaust temperature monitored at the outlet of the condenser
	  ▪ Exhaust temperature at 120° for a max efficiency of 90%
	  ▪ Monitored exhaust temperature monthly
	• Must be maintained and operated as specified by the manufactured or design engineering.
	• Not followed by further control such as reboilers, flares, or glowplugs. If such controls are installed, greater than 90% destruction may be applied if meeting the device requirements of the control selected.

Maximum Allowed Control Efficiency	Requirements
Control Device : Combustion device such as reboiler or heater	
$\leq$ 50% for VOC's and HAP's	• Have waste gas delivered to the flame zone/firebox
< 98% for VOC's and HAP's	• Must meet requirements to claim 90% destruction efficiency as described by the condenser table and • Have the waste gas pre-mixed with the primary fuel gas and used to fuel the device or • Routed to the facility inlet or • Utilize a glow plug and maintain per operators/manufacturer's instructions

The permit requires that nonselective catalytic reduction (NSCR) systems be constructed with an air-to-fuel ratio controller (AFRC) that operates on exhaust oxygen sensor control and with a sensor to measure the inlet temperature to the catalyst. The permit requires that oxidation catalyst systems be constructed, at a minimum, with a sensor to measure the inlet temperature to the catalyst. The permit must incorporate a CO lb/hr limit and require monitoring of carbon monoxide (CO) as a surrogate to assure compliance of H_2CO. Limit shall be based on manufacturer's uncontrolled CO emissions guarantee at 100% load reduced at an equal control rate as requested for H_2CO, not to exceed 90%. Any units subject to federal required monitoring are exempt from these requirements.

Maximum Allowed Control Efficiency	Requirements
Control Device : Catalytic converters	

Manufacture guarantee as stated in application (Not to exceed 90%)	• Use a portable analyzer to monitor nitrogen oxides, CO and oxygen concentration in the exhaust stream of the control device.
	  ▪ The portable analyzer shall be operated in accordance with the requirements of the latest AQD "Portable Analyzer Guidance" document or an equivalent method approved by the AQD.
	  ▪ Testing shall be performed quarterly
	• Monitoring device shall be installed to record the inlet flue gas temperature to the catalyst and be measured at least once daily.
	  ▪ Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or other written procedures that provide an adequate assurance that the device is calibrated accurately.

Maximum Allowed Control Efficiency	Requirements
Control Device : Oxidation Catalysts	
H_2CO reduction = CO reduction (Not to exceed 90%)	• Meet requirements listed above for catalytic converters.

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 252:2-15-41(c)(1). A request for an Authorization under this General Permit will typically be classified as Tier I, unless a compliance schedule required by OAC 252:100-8-5(e)(8)(B) is included, in which case it will be classified as Tier II.

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

SECTION X. SUMMARY

Applicants must demonstrate eligibility for coverage under this General Permit and that they are able to comply with applicable air quality rules and 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 Amine Units and Fuel Burning Equipment

SECTION I. INTRODUCTION

AERSCREEN (11126) was used to conduct modeling to determine compliance with the ambient standard for H_2S of OAC 252:100-31-7 for amine units, engines, and heaters/boilers. 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 specific scenario, 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 and cases were modeled in three locations 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, refer to the background information document entitled *GP-OGF Modeling of H_2S Sources* dated May 13, 2014.

SECTION II. AMINE UNITS

The AERSCREEN modeling conducted to determine compliance with OAC 252:100-31 was based on the following two (2) scenarios:

- Amine unit still vents with H_2S emission less than or equal to 0.3 lb/hr, and vented directly to the atmosphere without controls. Two cases for this scenario were developed related to amine units with the still vent routed directly to the atmosphere.
  - 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).

- Amine unit still vents with H_2S emission greater than 0.3 lb/hr, and flared (oxidized). Two cases were also developed for this scenario.

- 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.

AERSCREEN Amine Unit Modeling Scenario 1

Scenario 1 represents AERSCREEN modeling for amine unit still vents with H_2S emissions routed directly to the atmosphere with emissions of less than 0.3 lb/hr. The first case represents a facility with an amine unit which is used to treat sweet natural gas (less than or equal to 4 ppmv H_2S). The second case represents a facility with an amine unit which is used to treat sour natural gas (greater than 4 ppmv H_2S).

Scenario 1 AERSCREEN Input Parameters

Source Parameters	Case 1	Case 2
Type	Point	Point
Emission Rate (lb/hr)	0.3	0.3
Stack Height (ft)	10	10
Stack Diameter (ft)	0.5	0.33
Stack Flow (ACFM)	332	133
Stack Velocity (ft/s)	29	26
Stack Temperature (°F)	100	100

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

Scenario 1 AERSCREEN Results

Location 1	Case 1	Case 2
24-hr Concentration ($\mu g/m^3$)	242.3	290.4
Distance From Source (m)	18.0	16.0
Location 2	**Case 1**	**Case 2**
24-hr Concentration ($\mu g/m^3$)	191.9	213.4
Distance From Source (m)	23.0	21.0
Location 3	**Case 1**	**Case 2**
24-hr Concentration ($\mu g/m^3$)	198.7	231.4
Distance From Source (m)	20.0	23.0

The maximum modeled concentration for Case 1 is below the 0.2 ppm (283 $\mu g/m^3$) ambient air concentration limit. However, the maximum modeled concentration for Case 2 does exceed the 0.2 ppm (283 $\mu g/m^3$) ambient air concentration limit. Therefore, the general permit will exclude those facilities with uncontrolled amine units that process sour natural gas (> 4 ppmv H_2S).

AERSCREEN Amine Unit Modeling Scenario 2

Scenario 2 represents AERSCREEN modeling for amine unit still vents with H_2S emissions routed to a flare for oxidation assuming 95% control. The first case is based on an H_2S emission rate of 0.3 lb/hr before being flared. The second case is based on the major source threshold of 99 TPY (0.63 lb/hr) SO_2.

Scenario 2 AERSCREEN Input Parameters

Source Parameters	Case 1	Case 2
Type	Flare	Flare
Emission Rate (lb/hr)	0.015	0.63
Stack Height (ft)	25	25
Waste Gas Heat Content (BTUH)	1,127,658	135,788

The following table shows the AERSCREEN results for Scenario 2 at each of the three locations.

Scenario 2 AERSCREEN Results

Location 1	Case 1	Case 2
24-hr Concentration ($\mu g/m^3$)	1.0	154.5
Distance From Source (m)	232.0	180.0
Location 2	**Case 1**	**Case 2**
24-hr Concentration ($\mu g/m^3$)	0.2	38.2
Distance From Source (m)	95.0	517.0
Location 3	**Case 1**	**Case 2**
24-hr Concentration ($\mu g/m^3$)	0.2	31.4
Distance From Source (m)	82.0	533.0

The maximum modeled concentration for both cases is below the 0.2 ppm (283 $\mu g/m^3$) ambient air concentration limit.

SECTION III. ENGINES

The General Permit limits the sulfur content of fuel gas for engines to 162 ppmv. Therefore, this modeling scenario 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 3.02×10^{-4} lb/MMBTU. Three cases were developed for modeling small engines with a stack diameter of less than 1 foot, medium engines with a stack diameter equal to one foot, and large engines with a stack diameter greater than 1 foot.

Engine Specifications

Source Parameters	Case 1	Case 2	Case 3
Make	Arrow	White Superior	Cooper Bessemer
Model	VRG330	8G825	GMVA-10
Horsepower (Hp)	68	800	2,400
Heat Input (BTU/hp-hr)	7,300	7,750	8,000
MMBTUH	0.50	6.20	19.2

Engine AERSCREEN Input Parameters

Source Parameters	Case 1	Case 2	Case 3
Type	Point	Point	Point
Emission Rate (lb/hr)	1.51×10^{-4}	1.87×10^{-3}	5.80×10^{-3}
Stack Height (ft)	7.0	10	15
Stack Diameter (ft)	0.33	1.0	1.5
Stack Flow (ACFM)	238	3,738	8,263
Stack Velocity (ft/s)	45	79	78
Stack Temperature (°F)	970	1,340	825

The following table shows the AERSCREEN results for each engine modeling case at each of the three locations.

Engine AERSCREEN Results

Location 1	Case 1	Case 2	Case 3
24-hr Concentration (μg/m^3)	2.54×10^{-2}	8.01×10^{-2}	1.27×10^{-1}
Distance From Source (m)	20.0	18.0	285.00
Location 2	**Case 1**	**Case 2**	**Case 3**
24-hr Concentration (μg/m^3)	3.29×10^{-2}	9.12×10^{-2}	1.15×10^{-1}
Distance From Source (m)	19.0	28.0	46.0
Location 3	**Case 1**	**Case 2**	**Case 3**
24-hr Concentration (μg/m^3)	3.13×10^{-2}	9.86×10^{-2}	1.22×10^{-1}
Distance From Source (m)	25.0	24.0	41.0

The modeling results for the engines are all less than 1% of the standard; therefore, all engines combusting fuel with a sulfur content less than 162 ppmv are in compliance with the ambient air concentration limit.

SECTION IV. HEATERS AND BOILERS

The General Permit also limits the sulfur content of the fuel gas for heaters and boilers to 162 ppmv. Therefore, this modeling scenario 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 1.51×10^{-3} lb/MMBTU. Three cases were developed for modeling heaters/boilers with a heat input less than 1 MMBTUH, heaters/boilers with a heat input greater than or equal to 1 MMBTUH, and heaters/boilers with a heat input greater than or equal to 10 MMBTUH.

Heater/Boiler Specifications

Source Parameters	Case 1	Case 2	Case 3
MMBTUH	0.50	3.20	21.0

Heater/Boiler AERSCREEN Input Parameters

Source Parameters	Case 1	Case 2	Case 3
Type	Point	Point	Point
Emission Rate (lb/hr)	7.55×10^{-4}	4.83×10^{-3}	3.17×10^{-2}
Stack Height (ft)	8.0	21.9	33.0
Stack Diameter (ft)	0.50	1.30	2.30
Stack Flow (ACFM)	168	1,072	7,038
Stack Velocity (ft/s)	14	13	28
Stack Temperature (°F)	370	370	370

The following table shows the AERSCREEN results for each heater/boiler modeling case at each of the three locations.

Heater/Boiler AERSCREEN Results

Location 1	Case 1	Case 2	Case 3
24-hr Concentration (μg/m^3)	0.20	0.42	0.88
Distance From Source (m)	176.0	230.0	277.0
Location 2	**Case 1**	**Case 2**	**Case 3**
24-hr Concentration (μg/m^3)	0.19	0.13	0.23
Distance From Source (m)	20.0	56.0	83.0
Location 3	**Case 1**	**Case 2**	**Case 3**
24-hr Concentration (μg/m^3)	0.21	0.14	0.23
Distance From Source (m)	17.0	52.0	76.0

The modeling results for heater/boilers are all less than 1% of the standard; therefore, all heaters/boilers combusting fuel with a sulfur content less than 162 ppmv are in compliance with the ambient air concentration limit.

SECTION V. SUMMARY

Amine Units

Uncontrolled amine units with their still vents routed directly to the atmosphere have a potential to exceed the OAC 252:100-31-7 H_2S ambient air concentration limit of 0.2 ppm (283 μg/m^3). Based on Scenario 1, Case 2, outlined in Section II of this appendix, the general permit shall exclude uncontrolled amine units that treat sour natural gas (> 4 ppmv H_2S).

Amine units with their still vents routed to a flare are unlikely to exceed the OAC 252:100-31-7 H_2S ambient air concentration limit of 0.2 ppm (283 μg/m^3). Therefore, no specific limits need to be established in the general permit for amine units that route their still vents to a flare.

In order to ensure that only uncontrolled amine units that treat sweet natural gas are permitted under the general permit, the General Permit incorporates a limit of less than or equal to 4 ppmv H_2S in the inlet gas for uncontrolled amine units. Facilities with amine units treating sour natural gas (> 4 ppmv H_2S) 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 the H_2S ambient air concentration limit in OAC 252:100-31-7.

The general permit also incorporates monitoring and recordkeeping of the inlet H_2S concentration at least quarterly to ensure compliance with this limit. Controlled (flared) amine units are required to maintain these records for emission calculations.

Engines

Engines combusting fuel with a sulfur content less than 162 ppmv are unlikely to exceed the 0.2 ppm H_2S ambient air concentration limit in OAC 252:100-31-7. A fuel sulfur limit of 162 ppmv will ensure compliance with the ambient air concentration limit in OAC 252:100-31-7.

Heaters/Boilers

Heaters/boilers combusting fuel with a sulfur content less than 162 ppmv are unlikely to exceed the 0.2 ppm H_2S ambient air concentration limit in OAC 252:100-31-7. A fuel sulfur limit of 162 ppmv will ensure compliance with the ambient air concentration limit in OAC 252:100-31-7.

Facility Wide Compliance

The H_2S ambient air concentration of OAC 252:100-31-7 is applicable to each facility as a whole. Since most facilities will not have multiple amine units and the impacts from engines and heaters/boilers is so low, even if a facility was to be equipped with an amine unit and multiple engines and heaters/boilers, the facility as a whole would still be in compliance with the H_2S ambient air concentration limit.

Facilities with more than one uncontrolled amine unit treating sweet natural gas ($\leq$ 4 ppmv H_2S) could potentially exceed the H_2S ambient air concentration limit of 0.2 ppm. Therefore, facilities with more than one uncontrolled amine unit 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 the H_2S ambient air concentration limit in OAC 252:100-31-7.

DRAFT

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

OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY

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

In compliance with the provisions of the Oklahoma Clean Air Act, as amended (27A O.S., et seq.) and rules promulgated thereunder, operators of oil and gas facilities (OGF), as described under Part 1, Section III below, are hereby granted permission to construct/operate such facilities as specified in an Authorization to Construct/Operate (hereinafter referred to as an "Authorization") issued under this general permit by the Department of Environmental Quality (DEQ). Parts 1 through 4 and Appendices A through C of this permit specify emission limitations and standards that constitute applicable requirements, including state-only requirements, and include operational requirements and limitations necessary to assure compliance with all applicable air pollution rules. All OGF shall remain subject to the Oklahoma Clean Air Act, Okla. Stat. tit. 27A §§ 2-5-101 to -118 (2004) and the rules promulgated thereunder at Okla. Admin. Code ("OAC"), Air Pollution Control, Title 252, Chapter 100-1-1 to -47-14 (2015).

The owner or operator of an OGF may request that the facility be granted an Authorization in accordance with this general permit by submitting to the Air Quality Division (AQD) a DEQ Notice of Intent (NOI) Form and a complete set of General Permit Application Forms for an OGF. Eligible facilities may apply for coverage under this permit at any time during the permit term, noting on the applicable form whether the facility will have enforceable limits set below 80 TPY or 100 TPY. No facility, or part thereof, is authorized to construct or operate pursuant to the terms of this general permit unless an application for an Authorization using an NOI Form has been received by the AQD, or an Authorization has been issued for that facility.

Signed and issued this day, ____________________, 2016.

______________________ Eddie Terrill, Director

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Note: All terms written with initial capital letters are defined in Appendix C. Any reader of this permit should first read the definitions in Appendix C. Note that the term engine refers to both reciprocating internal combustion engines and gas-fired turbine engines.

PART 1 - REQUIREMENTS FOR GENERAL PERMIT

This permit is issued for the oil and gas facility (OGF) source category to establish (A) terms and conditions to implement applicable air pollution rules, (B) terms and conditions to implement applicable air pollution rules for specified categories of changes to those permitted sources, (C) terms and conditions for new requirements that apply to sources with existing permits, and (D) federally-enforceable caps on emissions. The permit is issued after finding that there are several permittees, permit applicants, or potential permit applicants who have the same or substantially similar operations, emissions, activities, or facilities; the permittees, permit applicants, or potential permit applicants emit the same types of regulated air pollutants; the operations, emissions, activities, or facilities are subject to the same or similar standards, limitations, and operating requirements; and the operations, emissions, activities, or facilities are subject to the same or similar monitoring requirements.

SECTION I. AUTHORITY

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

SECTION II. APPLICABILITY/EXEMPTIONS

Operators of a facility with potential emissions less than 100 TPY of regulated pollutant in an attainment area, less than 10 TPY of an individual hazardous air pollutant (HAP), and less than 25 TPY of total HAP, may use this general permit or obtain a minor source construction or operating permit. Facilities that are a permit exempt facility in accordance with OAC 252:100-7 are not required to obtain either a general permit or a minor source construction or operating permit.

SECTION III. ELIGIBILITY

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

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

1. New facilities.

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

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

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

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

2. Facilities with emissions units, unless qualified as a de minimis facility under OAC 252:100, Appendix H, that are affected sources subject to:

    a. OAC 252:100-8 (Permits for Part 70 Sources)
    b. OAC 252:100-15 (Motor Vehicle Pollution Control Devices)
    c. OAC 252:100-17 (Incinerators)
    d. OAC 252:100-23 (Cotton Gins)
    e. OAC 252:100-24 (Grain, Feed, or Seed Operations)
    f. OAC 252:100-35 (Control of Emissions of Carbon Monoxide)
    g. 40 CFR Part 59 (National VOC Standards)
    h. 40 CFR Part 82, Subparts B, D, E, G, and H (Stratospheric Ozone Protection)
    i. 40 CFR Part 264 (Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities)

C. The following facilities, unless qualified as a de minimis facility under OAC 252:100, Appendix H, are not eligible to obtain an Authorization to Construct under this permit, but may be eligible for coverage under an Authorization to Operate if they obtain a minor source construction permit and all relevant requirements and limitations in that construction permit are incorporated into the Authorization to Operate:

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

2. Facilities storing/distributing crude oil that do not meet all of the following.

    a. Facilities that can demonstrate a maximum H_2S concentration of 135 ppmw for all categories of crude oil stored at the facility. Such demonstration must be documented using the methods outlined in Appendix B of this permit.

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

4. Facilities using a vapor-recovery/vapor disposal system, or other equipment of equal efficiency, required by any part of OAC 252:100-37, Control of VOCs, or

OAC 252:100-39, Control of VOCs in Nonattainment Areas. Note that VOC storage vessels that are subject to equipment standards (e.g., a fixed roof in combination with an internal floating cover, an external floating roof, or a closed vent system and control device) in 40 CFR 60 Subparts K, Ka, or Kb are exempt from the requirements of OAC 252:100-37-15(a) and (b). In addition, VOC storage vessels that are subject to the equipment standards for external floating roofs in 40 CFR 60 Subparts Ka or Kb are exempt from the requirements of OAC 252:100-39-30.

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

6. 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. The rich amine flash tank can be routed to the facility inlet, fuel gas system, or to a flare meeting the requirements of OAC 252:100-31-26. The amine regeneration still vent must be routed to a flare meeting the requirements of OAC 252:100-31-26 or re-injected into oil-or-gas bearing geologic strata. Facilities with amine units that process natural gas with a H_2S content greater than 4 ppmv and amine units that process sweet natural gas with an H_2S content less than 4 ppmv 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 and the SO_2 1-hr NAAQS.

7. Facilities with amine units that process more than 0.1276 LTPD of sulfur. Facilities with amine units that process more than 0.1276 LTPD of sulfur would be a major source for SO_2.

8. Facilities with "new fuel-burning equipment," as that term is defined in OAC 252:100-33, with a rated heat input of 50 MMBtu/hr or greater for one piece of equipment or a total of 50 MMBtu/hr or greater at the facility.

9. Facilities with emissions units subject to NSPS or NESHAP subparts other than the following:

   a. NSPS requirements under 40 CFR Part 60 Subpart A, Subpart Dc, Subpart K, Subpart Ka, Subpart Kb, Subpart GG, Subpart KKK, Subpart IIII, Subpart JJJJ, Subpart KKKK, Subpart OOOO or
   b. NESHAP requirements under 40 CFR Part 61, or
   c. NESHAP requirements under 40 CFR Part 63, , Subpart HH requirements for triethylene glycol dehydration units at area sources; any Subpart ZZZZ requirements for RICE at area sources; and Subpart BBBBBB requirements for gasoline distribution bulk terminals, bulk plants and pipeline facilities at area sources.

10. 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 a 3-way catalyst (NSCR) or oxidation catalyst.

11. Facilities that require a specific limitation(s) for a glycol dehydration unit in order to be a minor source, other than operation of a condenser on still vent emissions or the operation of a flare.

12. Facilities with the potential to emit more than 100,000 TPY CO_{2e} and would otherwise be considered a major source of GHG emissions.

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 Appendix A.

D. 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. Facilities that are not in compliance with all applicable State and Federal air requirements may become eligible for coverage under this permit through submission of a compliance plan meeting the requirements of Part 3 of this Permit.

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

SECTION IV. AUTHORIZATIONS

An applicant for an Authorization under this General Permit may obtain coverage under this permit in one of the following ways.

A. An applicant proposing to construct a new facility that meets all of the eligibility requirements, excluding those facilities listed in Part 1, Section III.C, may apply for an Authorization to Construct by submitting an NOI Form and a complete set of General Permit Application Forms for an OGF, whether it be for a facility with enforceable limits set below 80 TPY or a facility with enforceable limits set below 100 TPY. Coverage under this permit is effective, and the permittee may commence construction, upon receipt by the DEQ of the NOI. 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; or (3) a DEQ date stamped application, is acceptable documentation of receipt of the NOI. The Authorization to Construct is issued by the DEQ after confirming that the application is administratively complete, the proper fee has been received, and that the facility is eligible for coverage under the permit.

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

C. An applicant proposing to obtain coverage under this permit for an existing, previously permitted facility, need only submit an application for an Authorization to Operate if the facility meets all of the eligibility requirements, including those listed in Part 1, Section III.C. Any of the relevant requirements and limitations in the existing operating permit, and any new specific conditions that may be necessary to insure compliance with applicable rules and regulations, may be incorporated into the Authorization to Operate under the General Permit.

D. An applicant proposing to obtain coverage under this permit for an existing facility, not previously permitted, need only submit an application for an Authorization to Operate if the facility meets all of the eligibility requirements, excluding those facilities listed in Part 1, Section III.C. If the facility meets the eligibility requirements listed in Part 1, Section III.C, the applicant may apply for an Authorization to Operate for the facility, and shall include fees for both a minor source construction permit and the Authorization to Operate. The AQD will make any determinations for specific conditions that need to be incorporated into the Authorization to Operate.

E. An applicant proposing to modify an existing facility (e.g., add, modify, reconstruct, or replace equipment or increase emissions) already covered by an Authorization to Operate under this general permit must meet the requirements specified in Part 4, Section II of this permit. Note that an applicant proposing to modify an existing facility need not obtain a new Authorization to Operate. However, if a minor source construction permit is required to make a modification as described under Part 1, Section III.C of this permit or if the facility is moving to a Class I or Class II status, i.e., above or below 80TPY, a new Authorization will be required.

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

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

SECTION V. PERMIT TERM

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

The DEQ shall establish, at the time this permit is modified, the terms and conditions under which existing Authorizations under this permit will be eligible for reauthorization under a modified general permit.

PART 2 – SPECIFIC CONDITIONS

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

Points of Emissions and Limitations for Each Point

SECTION I. Facility-Wide Emissions Cap

A. Emission limitations shall be established in each Authorization issued under this permit as a facility-wide emissions cap. The emission limitations must be less than 80% of major source levels for a Class I status or less than 100% of major source levels and not classified as a Class I facility for a Class II status.

B. In no case shall the permittee cause or allow the emission of any regulated air pollutant in such a concentration as to cause or contribute to a violation of ambient air quality standards or other applicable air pollution rules.

C. Compliance with these emission limitations shall be determined on a12-month rolling total basis. Emissions shall be calculated and documented in accordance with OAC 252:100-5-2.1(c) and (d), or as otherwise specified in this permit or an Authorization.

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

E. Start-up and shutdown emissions shall be included as part of the facility-wide emissions cap.

SECTION II. Storage Tanks

The following specific conditions apply to VOC storage tanks, including those which qualify as a de minimis facility under OAC 252:100, Appendix H.

Emission Calculations

A. To demonstrate compliance with Part 2, Section I.A of this permit, the permittee shall estimate annual emissions of VOC and HAP from all storage tanks with a capacity of 400 gallons or more that store VOC (as defined in OAC 252:100-1-3). Estimates of emissions of VOC and HAP from storage tanks shall be calculated in accordance with AP-42 Chapter 7 and/or EPA approved software programs. Flash emission calculations shall follow the procedures presented in the AQD Fact Sheet, "Calculation of Flashing Losses/VOC Emissions from Hydrocarbon Storage Tanks," and be based on actual annual throughputs. [OAC 252:100-43]

B. The permittee may estimate VOC and HAP emissions from storage of crude oil, slop oil, or oily water (condensate excluded) using AQD approved "default" factors listed in the current GP-OGF application forms.

Oklahoma Air Pollution Control Rules

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

D. VOC storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual storage conditions, except for petroleum or condensate stored, processed and/or treated at a drilling or production facility prior to lease custody transfer and except for methanol stored at drilling or production facilities, shall be equipped with a permanent submerged fill pipe or be bottom filled. [OAC 252:100-37-15 and OAC 252:100-39-41]

E. VOC storage tanks constructed after December 28, 1974, with a capacity greater than 40,000 gallons storing a liquid with a vapor pressure of 1.5 psia or greater under actual storage conditions, except for petroleum or condensate stored, processed and/or treated at a drilling or production facility prior to lease custody transfer and except for methanol stored at drilling or production facilities, shall be a pressure vessel capable of maintaining working pressures that prevent the loss of VOC to the atmosphere, or shall be equipped with an external floating roof that meets the standards of OAC 252:100-37-15 (a)(1). [OAC 252:100-37-15(a)]

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

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

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

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

    a. Are used to store waxy, high pour point crude oil;
    b. Have a capacity less than 422,675 gallons and are used to store produced crude oil or condensate prior to lease custody transfer;

c. Contain a petroleum liquid with a true vapor pressure less than 1.5 psia;
d. Contain a petroleum liquid with a true vapor pressure less than 4.0 psia, is of welded construction, and presently possesses a metallic-type shoe seal, a liquid-mounted foam seal, or a liquid-mounted liquid filled type seal;
e. Are of welded construction and are equipped with a metallic-type shoe primary seal and have a secondary seal from the top of the shoe seal to the tank wall (shoe-mounted secondary seal). [OAC 252:100-39-30(b)(2)]

Federal Regulations

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

1. Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids. This subpart applies to storage tanks that have a capacity greater than 40,000 gallons, but not exceeding 65,000 gallons, and commenced construction, or modification after March 8, 1974, and prior to May 19, 1978; and to storage tanks that have a capacity greater than 65,000 gallons and commenced construction or modification after June 11, 1973, and prior to May 19, 1978. [40 CFR 60.110 to 60.113]

   a. § 60.110 Applicability and designation of affected facility.
   b. § 60.111 Definitions.
   c. § 60.112 Standard for volatile organic compounds (VOC).
   d. § 60.113 Monitoring of operations.

2. Subpart Ka – Standards of Performance for Storage Vessels for Petroleum Liquids. This subpart applies to storage tanks that have a capacity greater than 40,000 gallons and commenced construction after May 18, 1978, and prior to July 23, 1984. [40 CFR 60.110a to 60.115a]

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

3. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels). This subpart applies to storage tanks that have a capacity greater than 19,812 gallons and commenced construction, reconstruction, or modification after July 23, 1984. [40 CFR 60.110b to 60.117b]

   a. § 60.110b Applicability and designation of affected facility.
   b. § 60.111b Definitions.
   c. § 60.112b Standard for volatile organic compounds (VOC).
   d. § 60.113b Testing and procedures.

e. § 60.114b Alternative means of emission limitation.
f. § 60.115b Reporting and recordkeeping requirements.
g. § 60.116b Monitoring of operations.

4. Subpart OOOO – Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart was promulgated on August 16, 2012 and affects storage vessels located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment that commence construction, reconstruction, or modification after August 23, 2011 and have the potential for VOC emissions equal to or greater than 6 tpy.

[40 CFR 60.5360 to 60.5430]

a. §60.5360 What is the purpose of this subpart
b. §60.5365 Am I subject to this subpart
c. §60.5370 When must I comply with this subpart
d. §60.5395 What standards apply to storage vessel affected facilities
e. §60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
f. §60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels, reciprocating compressors and centrifugal compressor wet seal degassing systems?
g. §60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?
h. §60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?
i. §60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
j. §60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel, centrifugal compressor and reciprocating compressor affected facilities?
k. §60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?
l. §60.5420 What are my notification, reporting, and recordkeeping requirements?
m. §60.5425 What part of the General Provisions apply to me?
n. §60.5430 What definitions apply to this subpart?

Recordkeeping

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

SECTION III. VOC Loading Operations

The following specific conditions apply to VOC Loading Operations.

Emission Calculations

A. The permittee shall estimate annual emissions of VOC and HAP from loading operations to demonstrate compliance with Part 2, Section I.A of this permit. Estimates of emissions of VOC from loading operations shall be calculated using the latest approved version of AP-42, "Compilation of Air Pollution Emission Factors," e.g., Chapter 5.2, equation 1, or an equivalent method approved by Air Quality and based on actual annual throughputs. [OAC 252:100-43]

B. The permittee may estimate VOC and HAP emissions from loading operations of crude oil, slop oil, oily water, and condensate using AQD approved "default" factors listed in the current GP-OGF application forms.

Oklahoma Air Pollution Control Rules

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

SECTION IV. Combustion Equipment

The following specific conditions apply to combustion equipment, including those that qualify as a de minimis facility under OAC 252:100, Appendix H.

Emission Calculations

A. The permittee shall estimate annual emissions of NO_X, CO, and VOC from all combustion equipment, and estimate annual emissions of formaldehyde (CH_2O) from engines, to demonstrate compliance with Part 2, Section I.A of this permit. For an engine, the annual emissions shall be calculated as either the engine's potential to emit (lb/hr) or the engine's permitted limit (lb/hr) of each pollutant, times the actual annual hours of operation, and converted to tons. For all other combustion equipment, the annual emissions shall be calculated based on actual annual hours of operation, maximum fired duty, and the emission factors that were used for the facility-wide emissions cap limitations established per Part 2, Section I.A or the latest revision of AP-42, and converted to tons. [OAC 252:100-43]

B. An emission factor considering add-on controls for CH_2O is acceptable when testing demonstrates continual compliance with the CO limits established in the authorization. [OAC 252:100-43]

C. Unless continuous operation (8,760 hours) is assumed for the calculation of actual emissions to demonstrate compliance with Part 2, Section I.A., the hours of operation of an engine or other combustion equipment shall be recorded with an hour meter, with a fuel meter recorded at least hourly, or monitored and recorded manually each day. If equipped with an hour meter, it must either be non-resettable or, if resettable, the date and hour each time the meter is reset must be maintained. [OAC 252:100-43]

Engine Emissions Tests (see Appendix D)

D. The permittee shall conduct an initial test of NO_X and CO emissions from any engine other than (1) an Emergency Use Engine, or (2) a natural gas-fired engine that has been certified to an emissions standard under NSPS Subpart JJJJ, or (3) an NSPS Subpart JJJJ applicable certified engine operated as a non-certified engine less than 100 HP. This test may be counted as the first quarterly test of an engine. Testing shall be conducted using EPA reference methods, if applicable, or a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD "Portable Analyzer Guidance" document, or an equivalent method approved by AQD. The permittee shall send AQD a copy of the initial test as part of the NOI to Operate application, or within 60 days of startup of a new, modified, reconstructed, or replacement Engine. [OAC 252:100-43]

E. Initially, a quarterly test of NO_X and CO emissions conducted within 10 percent of 100 percent peak (or the highest achievable) load is required for any uncontrolled Emissions Limited Engine not located at a True Minor Facility. At least once per calendar quarter, the permittee shall conduct tests of NO_X and CO emissions from the engine. Testing shall be conducted using a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD "Portable Analyzer Guidance" document, or an equivalent method approved by AQD. Testing is required for any engine that runs for more than 220 hours during that calendar quarter. A quarterly test may be conducted no sooner than 20 calendar days after the most recent test. When four consecutive quarterly tests show the engine in compliance with its hourly permit limits, the testing frequency may be reduced to semi-annual testing. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test.

Upon any showing of non-compliance with hourly permit limits, the testing frequency shall revert back to quarterly. [OAC 252:100-43]

F. For any controlled Emissions Limited Engine, the following requirements apply. [OAC 252:100-43]

1. Four-stroke rich-burn (4SRB) engines using NSCR catalyst shall be equipped with an Air to Fuel Ratio Controller (AFRC). The AFRC shall be inspected and maintained at least once a month to ensure that the controller is functioning properly, is not in alarm mode, and is being operated in accordance with manufacturers' recommendations. Replacement of the oxygen sensor(s) is required every 2,200 operating hours or less, or in accordance with manufacturers' recommendations, and replacement shall be documented in accordance with Part 4, Section IV.A. A maintenance log of all AFRC inspections, periods of operation in alarm mode, and engine or AFRC maintenance shall be kept. At least once per calendar quarter, the permittee shall conduct tests of NO_X and CO emissions from the engines. Testing shall be conducted using a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD "Portable Analyzer Guidance" document, or an equivalent method approved by AQD. Testing is required for any engine that runs for more than 220 hours during that calendar quarter. A quarterly test may be conducted no sooner than 20 calendar days after the most recent test.

2. At least once per calendar quarter, the permittee shall conduct tests of NO_X and CO emissions from any two-stroke and four-stroke lean-burn (2SLB and 4SLB) and compression ignition (CI) engine and gas turbine equipped with oxidation catalyst. Testing shall be conducted using a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD "Portable Analyzer Guidance" document, or an equivalent method approved by AQD. Testing is required for any engine that runs for more than 220 hours during that calendar quarter. A quarterly test may be conducted no sooner than 20 calendar days after the last test.

G. If any engine tested is not in compliance with its hourly permit limits, the permittee shall make the necessary adjustments to bring the engine into compliance and an excess emissions report shall be filed in accordance with the Standard Conditions, Part 4 Section III, of this permit.

H. For a new, reconstructed, or rebuilt [as that term is defined in 40 CFR §94.11(a) and (b)] Emissions Limited Engine, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine start-up (engine burn-in period) are not considered as excess emissions or violations of this permit.

Engine Addition, Modification, Reconstruction, or Replacement

I. Addition, modification, reconstruction, or replacement of an Emergency Use Engine is allowed at any time. The permittee shall keep a record of the date of the change; the new engine make, model, serial number, Maximum Rated Horsepower; and potential to emit (g/hp-hr, lb/hr, TPY).

J. Addition, modification, reconstruction, or replacement of any Uncontrolled Engine at a True Minor Facility is authorized under the following conditions.

1. The permittee shall send a Notice of Modification to AQD within 10 days of the start-up of the engine. The Notice of Modification shall include the date of the change; the new engine make, model, serial number, Maximum Rated Horsepower, intended hours of operation, fuel consumption (Btu/bhp-hr), stack flow (ACFM), stack temperature (°F), stack height (feet), and stack diameter (inches); potential to emit (g/hp-hr, lb/hr, and TPY); and a demonstration of compliance with the facility-wide emissions cap assuming operation of the new engine at its potential emissions rates for its intended hours of operation. Within 60 days of start-up, the permittee shall send to AQD a copy of an initial test of NO_X and CO emissions from the engine demonstrating that actual emission rates (lb/hr) are less than or equal to the potential emission rates (lb/hr) specified in the Notice of Modification. Testing shall be conducted using a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD "Portable Analyzer Guidance" document, or an equivalent method approved by AQD.

2. The permittee shall attach a copy of the Notice of Modification to a copy of the Authorization to Operate kept either on-site, at a nearby manned facility, or at the nearest field office per the recordkeeping requirements of Part 4, Section IV.A.

K. Addition, modification, reconstruction, or replacement of an Emissions Limited Engine is authorized under the following conditions.

1. The permittee shall send AQD a Notice of Modification within 10 days of the start-up of the engine. The Notice of Modification shall include the date of the change; the new engine make, model, serial number, Maximum Rated Horsepower, intended hours of operation, fuel consumption (Btu/bhp-hr), stack flow (ACFM), stack temperature (°F), stack height (feet), and stack diameter (inches); potential to emit (g/hp-hr, lb/hr, and TPY); NO_X and CO emission limits (lb/hr); and a demonstration of compliance with the facility-wide emissions cap assuming operation of the new engine at its potential emission rate (for VOC) and limited emission rates (for NO_X and CO) for its intended hours of operation.

2. The permittee shall comply with the hourly emission rates for NO_X and CO (lb/hr) cited in the Notice of Modification for that engine and those limitations shall become an enforceable part of the existing Authorization to Operate. The permittee shall attach a copy of the Notice of Modification to a copy of the Authorization to Operate kept either on-site, at a nearby manned facility, or at the nearest field office per the recordkeeping requirements of Part 4, Section IV.A.

3. The new engine is subject to periodic testing in accordance with Part 2, Section IV of this permit. A copy of the first emissions test shall be provided to AQD within 60 days of start-up of the added, modified, reconstructed, or replacement engine. The test report shall include the new engine make, model, serial number, Maximum Rated Horsepower, fuel consumption (Btu/bhp-hr), stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), proof the performance test was conducted with 10 percent of 100 percent peak load, and emissions rates (g/hp-hr, lb/hr, and TPY) at Maximum Rated Horsepower and continuous operation.

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

M. All fuel-burning equipment, including engines, shall at all times be properly operated and maintained in a manner that will minimize emissions of VOC. For heaters, temperature and available air shall be sufficient to provide essentially complete combustion. The permittee shall maintain maintenance records on engines to document compliance. [OAC 252:100-37-36]

N. Liquid fuel may be combusted only in Emergency Use Engines or in engines rated less than 50 horsepower. [OAC 252:100-31-25]

O. An Emergency Use Engine shall be equipped with a non-resettable hour meter. Operating hours for that engine shall not exceed 500 hours in any 12-month period. The permittee shall maintain a record of the operating hours for each Emergency Use Engine. [OAC 252:100-43]

Federal Regulations

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

1. Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects Steam Generating Units (defined in the subpart) that commenced construction, modification, or reconstruction after June 9, 1989, and that have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr.. [40 CFR 60.40c – 60.48c]

   a. §60.40c Applicability and delegation of authority
   b. §60.41c Definitions
   c. §60.42c Standards for sulfur dioxide (SO_2)
   d. §60.43c Standards for particulate matter (PM)
   e. §60.44c Compliance and performance test methods and procedures for sulfur dioxide

f. §60.45c Compliance and performance test methods and procedures for particulate matter
g. §60.46c Emission monitoring for sulfur dioxide
h. §60.47c Emission monitoring for particulate matter
i. §60.48c Reporting and recordkeeping requirements

2. Subpart GG - Standards of Performance for Stationary Gas Turbines. This subpart regulates NO_X and SO_2 emissions for gas turbines that commenced construction, modification, or reconstruction after October 3, 1977, with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel. [40 CFR 60.330 to 60.335]

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

3. Subpart IIII – Standards of Performance for Stationary Compressor Ignition Internal Combustion Engines. This subpart regulates NOX, particulate matter, CO, and Non-methane hydrocarbons (NMOC) from stationary compression ignition internal combustion engines (CI ICE) that commenced construction modification, or reconstruction after July 11, 2005. [40 CFR 60.4200 to 60.4219]

   a. §60.4200 Am I subject to this subpart
   b. §60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?
   c. §60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?
   d. §60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?
   e. §60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
   f. §60.4205 What emissions standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
   g. §60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine ?
   h. §60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?
   i. §60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model years?
   j. §60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
   k. §60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

l. §60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
m. §60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?
n. §60.4213 What test methods or other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?
o. §60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?
p. §60.4217 What engine standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?
q. §60.4218 What parts of the General Provisions apply to me?
r. §60.4219 What definitions apply to this subpart?

4. Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart promulgates emission standards for new SI engines ordered after June 12, 2006, that are manufactured after certain dates, and for SI engines modified or reconstructed after June 12, 2006.

[40 CFR 60.4230 to 60.4246]

a. §60.4230 Am I subject to this subpart?
b. §60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?
c. §60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?
d. §60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?
e. §60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?
f. §60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?
g. §60.4236 What is the deadline for importing or installing stationary SI ICE produced in previous model years?
h. §60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?
i. §60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP) or a manufacturer of equipment containing such engines?
j. §60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?

k. §60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?
l. §60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?
m. §60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?
n. §60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?
o. §60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?
p. §60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?
q. §60.4246 What parts of the General Provisions apply to me?
r. §60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines or a manufacturer of equipment containing such engines?
s. § 60.4248: What definitions apply to this subpart?

5. Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. This subpart regulates NO_X and SO_2 emissions for turbines that commenced construction, modification, or reconstruction after February 18, 2005, with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the higher heating value of the fuel. [40 CFR 60.4300 to 60.4420]

 a. §60.4300 What is the purpose of this subpart
 b. §60.4305 Does this subpart apply to my stationary combustion turbine
 c. §60.4310 What type of operations are exempt from these standards of performance
 d. §60.4315 What pollutants are regulated by this subpart
 e. §60.4320 What emissions limits must I meet for nitrogen oxides (NO_x)
 f. §60.4325 What emissions limits must I meet for NO_x if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?
 g. §60.4330 What emission limits must I meet for sulfur dioxide (SO_2)
 h. §60.4333 What are my general requirements for complying with this subpart?
 i. §60.4335 What are my general requirements for complying with this subpart
 j. §60.4335 How do I demonstrate compliance for NO_x if I use water or stream injection
 k. §60.4340 How do I demonstrate compliance for NO_x if I do not use water or steam injection

l. §60.4345 What are the requirements for the continuous emissions monitoring system equipment, if I choose to use this option?
m. §60.4350 How to I use data from the continuous emission monitoring equipment to identify excess emissions?
n. §60.4355 How to I establish and document a proper parameter monitoring plan
o. §60.4360 How to I determine the total sulfur content of the turbines' combustion fuel?
p. §60.4365 How can I be exempt for monitoring the total sulfur content of the fuel?
q. §60.4370 How often must I determine the sulfur content of the fuel?
r. §60.4375 What reports must I submit?
s. §60.4380 How are excess emissions and monitor downtime for NO_x?
t. §60.4385 How are excess emissions and monitoring downtime defined for SO_2?
u. §60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?
v. §60.4395 When must I submit my reports?
w. §60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_x?
x. §60.4405 How do I perform the initial performance test if I have chosen to install a NO_x-diluent CEMS?
y. §60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
z. §60.4415 How do I conduct the initial and subsequent performance tests for sulfur?
aa. §60.4420 What definitions apply to this subpart?

6. Subpart OOOO - Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart affects each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals that is located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment as well as each reciprocating compressor affected facility, which is a single reciprocating compressor located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment that commence construction, reconstruction, or modification after August 23, 2011. [40 CFR 60.5360 to 60.5430]

    a. §60.5360 What is the purpose of this subpart?
    b. §60.5365 Am I subject to this subpart?
    c. §60.5370 When must I comply with this subpart?
    d. §60.5380 What standards apply to centrifugal compressor affected facilities?
    e. §60.5385 What standards apply to reciprocating compressor affected facilities?
    f. §60.5385 What standards apply to centrifugal compressor affected facilities?
    g. §60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

h. §60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels, reciprocating compressors and centrifugal compressor wet seal degassing systems.
i. §60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?
j. §60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?
k. §60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
l. §60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel, centrifugal compressor and reciprocating compressor affected facilities?
m. §60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?
n. §60.5420 What are my notification, reporting, and recordkeeping requirements?
o. §60.5425 What part of the General Provisions apply to me?
p. §60.5430 What definitions apply to this subpart?

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

1. Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners or operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines).
[40 CFR 63.6580 to 63.6675]

a. § 63.6580 What is the purpose of subpart ZZZZ?
b. § 63.6585 Am I subject to this subpart?
c. § 63.6590 What parts of my plant does this subpart cover?
d. § 63.6595 When do I have to comply with this subpart?
e. § 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?
f. § 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?
g. § 63.6605 What are my general requirements for complying with this subpart?

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

Notification and Recordkeeping

R. The permittee shall maintain a record of any malfunction that prevents quarterly testing of NO_X and CO emissions from an Emissions Limited Engine and notify AQD of the malfunction that prevented testing within 30 days of the end of that quarter.

[OAC 252:100-43]

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

T. The permittee shall keep records that document each engine's maximum horsepower at International Organization for Standardization (ISO) or manufacturer's standard condition and maximum RPM, and any de-rating factors used to determine a site-rated maximum horsepower (e.g., site ambient conditions, jacket water temperature, compression load limitations, speed limitations of engine or driven equipment, etc.).

[OAC 252:100-43]

SECTION V. Glycol Dehydration Unit Process Vents

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

Emission Calculations

A. The permittee shall calculate emissions of VOC and HAP from glycol dehydration process vents to demonstrate compliance with Part 2, Section I.A of this permit. Estimates of emissions of VOC and HAP from any rich glycol flash tank vents or glycol regenerator still vents shall be calculated using either the GRI-GLYCalc program (Version 4.0 or later), a process simulator program, or the Atmospheric Rich/Lean (ARL) Method. The emission calculations shall be based on the potential to emit by assuming continuous operation using (1) the maximum design wet gas rate for the dehydrator unit, or (2) the maximum facility wet gas rate based on an inherent process limitation such as compressor horsepower or capacity limitations, or (3) the maximum facility wet gas rate based on an inherent limit on gas production, or (4) the average wet gas rate for the last 2 years plus a 20% safety factor; a Representative Extended Wet Gas Analysis; the normal process operating temperature and pressure; the expected removal efficiency of any glycol still vent condenser at its maximum design temperature; and the maximum pump rate of the lean glycol circulation pump. For combustion of gasses from a glycol still vent or flash tank in a reboiler only 50% destruction efficiency shall be allowed.
[OAC 252:100-43]

B. For facilities that have total potential HAP emissions from all dehydrator units above 80% of major source levels, based on the Representative Extended Wet Gas Analysis used in the permit application, the permittee shall sample and perform an extended wet gas analysis at least once each year for calculating compliance with the permit HAP limits per the procedures in paragraph A above. [OAC 252:100-43]

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C. If a condenser is used to control the emissions from the glycol still vent, then all of the still vent vapors must pass through the condenser. The condenser shall be designed to achieve the expected removal efficiency at the maximum expected condenser outlet temperature. 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. Recording of the condenser outlet temperature is not required if the uncondensed vapors are burned in a combustion device or recycled to the process.
[OAC 252:100-43]

Federal Regulations

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

1. Subpart HH - Oil and Natural Gas Production Facilities. This subpart applies to TEG dehydration units affected emission points that are located at facilities that are major and area sources of HAPs and either process, upgrade, or store hydrocarbons prior to the point of custody transfer or prior to which the natural gas enters the natural gas transmission and storage source category. Facilities covered under OGF-GP are considered an "area" source of HAPs. [40 CFR 63.760 to 63.775]

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

Recordkeeping

E. The permittee shall keep records demonstrating the method and data used for determining the maximum wet gas rate used to calculate the potential to emit from a glycol dehydrator per Part 2, Section V.A.; records of any required Representative Extended Wet Gas Analysis; and records of the GRI-GLYCalc printout or other emission calculation methods, including the condenser expected removal efficiency at its maximum design temperature. [OAC 252:100-43]

SECTION VI. Amine Units

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

Emission Calculations

A. The permittee shall calculate emissions of VOC and HAPS from rich amine flash tank and regenerator still vents to demonstrate compliance with Part 2, Section I.A of this permit. Potential emissions can be estimated using the AMINE-Calc program, a process simulator program, and/or mass balance equations. The emissions should be based on the potential to emit by assuming continuous operation using the maximum throughput, a representative extended gas analysis or natural gas liquid analysis, the normal process operating temperatures and pressures, and the maximum pump rate of the lean amine circulation pump. Emissions from amine unit flash tanks are often controlled by routing the gases to the fuel gas system or by using a flare. Emissions from the regenerator still vent are often controlled by flaring or are vented to the atmosphere.

Testing Requirements

The permittee shall conduct testing of the inlet H_2S concentration at least quarterly to ensure compliance with OAC 252:100-31-7 H_2S ambient air concentration limit of 0.2 ppm (283 $\mu g/m^3$).

Oklahoma Air Pollution Control Rules

B. Emissions from the rich amine flash tank are to be routed to a flare meeting the requirements of OAC 252:100-31-26, to the facility inlet, or to the fuel gas system. Emissions from the amine unit regenerator still vent are to be routed to a flare with a combustion efficiency of 95%.

C. Flares used to control emissions from the amine unit are to be equipped with an alarm system that will signal when there is no pilot flame.

Federal Regulations

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

1. Subpart OOOO –Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart affects sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells that commence construction, reconstruction or modification after August 23, 2011. [40 CFR 60.5360 to 60.5430]

   a. §60.5360 What is the purpose of this subpart?
   b. §60.5365 Am I subject to this subpart?
   c. §60.5370 When must I comply with this subpart?
   d. §60.5405 What standards apply to sweeting units at onshore natural gas processing plants?
   e. §60.5406 What test methods and procedures must I use for my sweeting units affected facilities at onshore natural gas processing plants
   f. §60.5407 What are the requirements for monitoring of emissions and operations from my sweeting unit affected facilities at onshore natural gas processing plants?
   g. § 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas-Tutwiler Procedure?
   h. §60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected

facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

i. §60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
j. §60.5420 What are my notification, reporting and recordkeeping requirements?
k. §60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
l. §60.5425 What part of the General Provisions apply to me?
m. §60.5430 What definitions apply to this subpart

2. Subpart LLL – Natural Gas Production. This subpart affects sweeting units and sweetening units followed by a sulfur recovery unit located at an onshore natural gas processing plant that was constructed, reconstructed or modified after January 20, 1984 and on or before August 23, 2011.

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

Recordkeeping

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

SECTION VII. Fugitive Emission Sources

The following specific conditions apply to fugitive VOC emission sources, unless qualified as a de minimis facility under OAC 252:100, Appendix H.

Emission Calculations

A. For any facility with a storage tank subject to, or grandfathered from, NSPS Subparts K, Ka or Kb, the permittee shall estimate annual emissions of VOC from fugitive emission sources to demonstrate compliance with Part 2, Section 1.A of this permit. Emissions of VOCs from fugitive sources shall be calculated using the factors in Table 2-4 (Oil and

Gas Production Operations) of EPA's *1995 Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)* or other methods approved by DEQ. [OAC 252:100-43]

Federal Regulations

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

1. Subpart KKK - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This subpart requires leak detection and reporting (LDAR) for fugitive components and compressors at natural gas processing plants that were constructed, reconstructed, or modified after January 20, 1984. [40 CFR 60.630 – 60.636]
   a. §60.630 Applicability and designation of affected facilities
   b. §60.631 Definitions
   c. §60.632 Standards
   d. §60.633 Exceptions
   e. §60.634 Alternate means of emission limitations
   f. §60.635 Recordkeeping requirements
   g. §60.636 Reporting requirements

2. Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart affects each pneumatic controller affected facility, which is a single continuous bleed gas-driven pneumatic controller operating at natural gas bleed rate greater than 6 scfh that commence construction, reconstruction, or modification after August 23, 2011. [40 CFR 60.5360 to 60.5430]

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

affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

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

Recordkeeping

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

SECTION VIII. Facility-wide Requirements

The following specific conditions apply facility-wide. [OAC 252:100-43]

Emission Calculations

A. For emission sources qualified as a de minimis facility under OAC 252:100, Appendix H, (other than storage tanks and combustion equipment), the permittee may calculate emissions or assume emissions are 5 TPY for each regulated pollutant emitted by each listed source. Emissions related to start-up and shutdown shall be included as part of the facility-wide total.

Oklahoma Air Pollution Control Rules

B. Gas-fired combustion equipment operated under this permit shall be fueled only with liquid petroleum gas (LPG) or natural gas with a maximum total sulfur content of 162 ppmvd. Compliance shall be demonstrated at least once annually and may be demonstrated by one of the following recordkeeping requirements.

[OAC 252:100-43]

1. For gaseous fuel, a current gas company bill or a current gas contract, tariff sheet, or transportation contract for the natural gas fuel which demonstrates that the maximum total sulfur content of the natural gas fuel does not exceed 20 grains/100 scf.

2. Technical data or gas sampling data demonstrating that the maximum total sulfur content of natural gas from the facility's production area does not exceed 20 grains/100 scf.

3. Representative fuel sampling data (including on-line analyzer data, lab analysis, or sampling by Draeger tubes), which show that the maximum total sulfur content of the natural gas fuel does not exceed 20 grains/100 scf. The fuel shall be sampled and results recorded once each calendar year.

C. Liquid-fired combustion equipment operated under this permit shall be fueled only with gasoline, diesel or No. 2 through No. 6 fuel oil. Liquid fuels are limited to a maximum of 0.05% sulfur by weight, except for CI ICE that are subject to 40 CFR Part 60 Subpart IIII and RICE that are subject to 40 CFR Part 60 Subpart JJJJ, which must use fuel that meets the more stringent requirements of those subparts (see Part II, Sections IV.P and IV.S). The permittee shall provide with the application a fuel composition analysis that shows total sulfur content. Thereafter, the permittee shall perform a fuel analysis that shows total sulfur content once per load received and shall maintain records of the required fuel sulfur analysis. A one-time certification of sulfur content of a grade of fuel, with subsequent receipts stating the fuel grade delivered from the supplier, is sufficient to document compliance with this requirement. A new certification shall be obtained from each new supplier. [OAC 252:100-43]

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

E. Emission units, and control devices associated with any emission units constructed under this permit, shall comply with all applicable requirements of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, and Appendix A of this permit. [OAC 252:100-43]

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

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

H. The permittee shall implement reasonable precautions or measures to minimize fugitive dust emissions from the handling, transporting or disposition of any substance or material which is likely to be scattered by the air or wind or is susceptible to being airborne or wind-borne. In addition, the permittee shall not cause or permit the discharge of any visible fugitive dust emissions beyond the property line in such a manner as to damage or to interfere with the use of adjacent properties, or to cause or contribute to the violation of ambient air quality standards. [OAC 252:100-29]

Recordkeeping

I. The permittee shall maintain records of emissions, including facility-wide 12-month rolling totals of NO_X, CO, VOC, and HAP emissions, and any compliance demonstrations required by this permit. An emissions record shall describe calculated emissions of regulated air pollutants from all emission units. This record shall include the emission unit identification number, control method used, operating hours, and other operating parameters as specified in specific conditions for each particular emission unit. A copy of the records or a summary including sample calculations shall be submitted with the application for an Authorization to Operate under this permit. [OAC 252:100-43]

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

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

PART 3 – SCHEDULE OF COMPLIANCE

Any facility reporting non-compliance in an application for Authorization under this permit must submit with such application a schedule of compliance for emission units or stationary sources that are not in compliance with all applicable air pollution rules.

A. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable air pollution rules for which the emission unit or stationary source is not in compliance.

B. This compliance schedule shall correspond to and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emission unit or stationary source is subject.

C. Any such schedule of compliance shall be supplemental to, and shall not sanction non-compliance with, the applicable air pollution rules on which it is based.

D. The approvable schedule of compliance may be incorporated into an Authorization if such is issued to the facility.

E. The permittee of a facility that is operating subject to a schedule of compliance shall submit to AQD progress reports at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones, or compliance required in the schedule of compliance and the dates when such activities, milestones, or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

Part 4 – STANDARD CONDITIONS

SECTION I. DUTY TO COMPLY

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

[OAC 252:100-7-15(e) and 7-18]

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

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

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

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

C. The permittee shall obtain a minor source construction permit for any modification described under Part 1, Section III.C of this permit. Facility modifications may be constructed without a new Authorization, or without a construction permit, provided that the modification will not increase emissions above the authorized limits (i.e., 80TPY or 100TPY depending on the Class. If the facility status will not be changed and a new authorization is not required then the permittee will only need to notify the DEQ in writing of the modification within 10 days following the start of operation.

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

D. The permittee shall apply for a new Authorization to Operate within 180 days of commencing operation of any modified facility authorized under a minor source construction permit or an Authorization to Construct issued under this permit, except for a de minimis facility under OAC 252:100, Appendix H. [OAC 252:100-7-18(a)]

E. The permittee shall apply for either a new Authorization to Operate or a relocation permit to relocate any portable source authorized under this permit. A facility must still meet the eligibility requirements of Part 1, Section III at the new location to use the general permit. [OAC 252:100-7-17]

F. An Authorization to Construct issued under this permit will terminate and become null and void if the construction is not commenced within 18 months of the issuance date, or if work is suspended for more than 18 months after it is commenced.
[OAC 252:100-7-15(f)]

SECTION III. REPORTING OF DEVIATIONS FROM PERMIT TERMS

In the event of any release which results in excess emissions, or when periodic compliance testing shows engine exhaust emissions in excess of the lb/hr limitations, the permittee shall comply with the provisions of OAC 252:100-9. [OAC 252:100-9]

SECTION IV. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep a permanent copy of the Authorization to Operate, with the latest Notice of Modification attached, either on-site, at a nearby manned facility, or at the nearest field office. The permittee shall keep records as specified in this permit and any Authorization issued under this permit, including a copy of all Notices of Modification. These records, including monitoring data and support information, shall be retained either on-site, at a nearby manned facility, or at the nearest field office for a period of at least five years unless a longer period is specified by an applicable rule or statute. Support information includes all original recordings for continuous monitoring instrumentation and copies of all reports required by this permit or the Authorization. Records may be maintained in paper, electronic, or computerized form.
[OAC 252:100-5-2.1(c); OAC 252:100-7-15; OAC 252:100-7-18]

B. Any owner or operator subject to provisions of NSPS shall provide written notification as follows. However, a Notice of Modification that is timely submitted (within 10 days of start-up) shall suffice for notification under items 1, 2, and 3. [40 CFR §60.7]

1. A notification of the date of when construction of an affected facility will be commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

2. A notification of the actual date of initial start-up of an affected facility postmarked within 15 days after such date.

3. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change.

4. If a continuous emission monitoring system is included in the construction, a notification of the date upon which the test demonstrating the system performance will commence, along with a pretest plan, postmarked no less than 30 days prior to such a date.

C. Any owner or operator subject to the provisions of NSPS shall maintain records of the occurrence and duration of any start-up or shutdown of the process containing such affected facilities, and shall record malfunctions in the operation of an affected facility or any malfunction of the air pollution control equipment, or any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR §60.7(b)]

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

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

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

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

H. The permittee shall submit to AQD a copy of all reports submitted to EPA as required by 40 CFR Part 60, 61, and 63 for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-4 and 41-15]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

Any Authorization issued after the effective date of a new or modified requirement or standard applicable to a unit located at the facility, may incorporate such requirement or standard, which shall supersede any corresponding permit requirement that is less stringent than the newer requirement or standard. [OAC 252:100-7-15(a); OAC 252:100-7-18]

SECTION VI. ANNUAL EMISSIONS INVENTORY AND FEE PAYMENT

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

SECTION VII. SEVERABILITY

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

SECTION VIII. PROPERTY RIGHTS

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

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

SECTION IX. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ upon receipt of a written request and within sixty (60) days of the request, unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, or revoking and reissuing or terminating the permit or to determine compliance with the permit or the Authorization. [27A O.S. Supp. 1999, § 2-5-105(18)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. Supp. 1999, § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

C. The transferor shall notify the AQD of the sale or transfer of ownership of this facility in writing not later than 30 days following the change in ownership. [Title 27A-2-5-112.G)]

SECTION X. DUTY TO SUPPLEMENT

The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in any information submittal, shall promptly submit such supplementary facts or corrected information. [OAC 252:100-4-7-8]

SECTION XI. REOPENING, MODIFICATION, AND REVOCATION

A. This permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the permittee for a permit or an Authorization modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated non-compliance does not stay any permit condition.
[27A O.S. Supp. 1999, § 2-5-112(B)(1)]

B. The permitting authority will reopen and revise or revoke this permit as necessary to remedy deficiencies if the DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable air pollution rules. [27A O.S. Supp. 1999, § 2-5-112(B)(3)]

C. Upon issuance of this permit, the terms and conditions of this updated Oil and Gas General Permit supersede all previous versions of the Oil and Gas General Permit. All Facilities constructing or operating under the previous Oil and Gas GP are subject to and must comply with this updated Oil and Gas GP, and must come into compliance with the provisions of this updated Oil and Gas GP within 24 months of its issuance date. During that 24-month compliance period, all facilities constructing or operating under the previous Oil and Gas GP must meet the minimum compliance standards set forth therein. [27A O.S. **Supp. 2004**, §2-5-112(B)(1)]

SECTION XII. INSPECTION AND ENTRY

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized officials of the DEQ to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1999, § 2-5-105 (18) for confidential information submitted to or obtained by the DEQ under this section).
[27A O.S. Supp. 1999, § 2-5-105]

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

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

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

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

SECTION XIII. DE MINIMIS FACILITIES

The permittee is hereby authorized to operate emission sources and/or conduct activities that are listed on the "De Minimis Facilities" list in OAC 252:100, Appendix H.

SECTION XIV. GENERAL PROVISIONS UNDER NSPS AND NESHAPS

The permittee shall comply with all applicable requirements of the corresponding General Provisions, as set forth in 40 CFR Part 60 Subpart A, 40 CFR Part 61 Subpart A, and 40 CFR Part 63 Subpart A, for all equipment constructed or operated under this permit subject to NSPS or NESHAP. [OAC 252:100-4]

SECTION XV. STRATOPHERIC OZONE PROTECTION 40 CFR PART 82

The permittee shall comply with all applicable requirements of 40 CFR Part 82 Subparts A through H for the use of ozone-depleting substances, especially regulated refrigerants; and the maintaining, servicing, and repairing of any equipment using such substances.

SECTION XVI. UPDATE OF AUTHORIZATION TO OPERATE

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

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

A. All control devices shall be constructed, operated, and maintained according to manufacturers' specifications, except as otherwise required by this permit, an Authorization, or applicable rules or statutes. Manufacturer's specifications shall be kept on-site or at the closest field office and made available to regulatory personnel upon request.

B. Non-selective catalytic reduction (NSCR) systems shall, at a minimum, be constructed with an Air-to-Fuel Ratio Controller (AFRC) that operates on exhaust oxygen sensor control, with a sensor to measure the inlet temperature to the catalyst.

C. Oxidation catalyst systems shall, at a minimum, be constructed with a sensor to measure the inlet temperature to the catalyst.

Maximum Allowed Control Efficiency	**Requirements**
Control Device : Catalytic converters	
Manufacture guarantee as stated in application (Not to exceed 90%)	• Use a portable analyzer to monitor nitrogen oxides, CO and oxygen concentration in the exhaust stream of the control device. ▪ The portable analyzer shall be operated in accordance with the requirements of the latest AQD "Portable Analyzer Guidance" document or an equivalent method approved by the AQD. ▪ Testing shall be performed quarterly • Monitoring device shall be installed to record the inlet flue gas temperature to the catalyst and be measured at least once daily. ▪ Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or other written procedures that provide an adequate assurance that the device is calibrated accurately.
Control Device : Oxidation Catalysts	
H_2CO reduction = CO reduction (Not to exceed 90%)	• Meet requirements listed above for catalytic converters.

D. Condensers shall be 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.

Maximum Allowed Control Efficiency	Requirements
Control Device : Condenser	
≤ 90% for VOC's and HAP's	• Have exhaust temperature monitored at the outlet of the condenser ▪ Exhaust temperature at 120° for a max efficiency of 90% ▪ Monitored exhaust temperature monthly • Must be maintained and operated as specified by the manufactured or design engineering. • Not followed by further control such as reboilers, flares or glowplugs. If such controls are installed, greater than 90% destruction may be applied if meeting the device requirements of the control selected.

Maximum Allowed Control Efficiency	Requirements
Control Device : Combustion device such as reboiler or heater	
≤ 50% for VOC's and HAP's	• Have waste gas delivered to the flame zone/firebox
< 98% for VOC's and HAP's	• Must meet requirements to claim 90% destruction efficiency as described by the condenser table and • Have the waste gas pre-mixed with the primary fuel gas and used to fuel the device or • Routed to the facility inlet or • Utilize a glow plug and maintain per operators/manufacturer's instructions

E. Flares shall be constructed with a sensor to measure temperature, designed to achieve the expected removal efficiency, and there must be a pilot flame present immediately before and during use.

APPENDIX B - DEMONSTRATION OF MAXIMUM H2S CONCENTRATION IN CRUDE OILS

For the general permit, a facility must demonstrate that the maximum H_2S concentration of any category of crude oil stored at the facility is no more than 135 ppmw. To do this, each category of crude oil handled at a facility shall be characterized by name using the standard terminology used in the petroleum industry to describe crude oils from specific locales and having similar characteristics, such as (but not limited to) "US-West Texas Sour," "US-Oklahoma Sour," "US-Mid Continent," "Kirkuk," "Hawkins," etc. A permit applicant may demonstrate the maximum expected H_2S concentration in each category of crude oil stored at the facility by one of three methods, subject to approval of AQD:

A. Certification by a responsible official in the permit application that only "sweet" crude oil is stored at the facility or that the maximum H_2S concentration of any "sour" crude oil stored at the facility is no more than 135 ppmw. "Sweet" crude oil is defined as having a total sulfur content of less than 0.5 wt%.

B. Documentation from a Crude Oil Assay Library or assays from the crude oil producer, seller, or buyer, that demonstrate that only "sweet" crude oil is stored at the facility or that the maximum H_2S concentration of any "sour" crude oil stored at the facility is no more than 135 ppmw.

C. Sampling by the applicant for H_2S concentration. Test methods may include UOP 163-89, ASTM D 5705 (the so-called "can test"), liquid phase H_2S analyzers, or lab certified liquid phase methods. For an initial compliance demonstration, one sample is required for each category of sour crude oil that requires sampling for compliance documentation, i.e., not demonstrated by A or B above. If the initial sample shows an H_2S concentration of 75 ppmw or less, then no more sampling is required for that category of sour crude oil. Otherwise, that category of crude oil must be sampled again, once each week for four weeks, and an average of the four samples calculated. If the average H_2S concentration is no more than 135 ppmv, compliance for that category of sour crude oil is demonstrated. This sampling procedure must be repeated in the future for any new category of sour crude oil stored at the facility that requires sampling for compliance with the 135 ppmw H_2S limit.

APPENDIX C - DEFINITIONS

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

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

"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 less than or equal to 500 hours per year.

"Emissions Limited Engine" means any engine that has pounds per hour emission limitations specified under the conditions of an Authorization. Pound per hour emission limits shall be established for all engines located at a Class II facility and for all controlled engines, except for engines subject to NSPS which have federally enforceable emission limits.

"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" means a written notice informing AQD of: (1) any modification or change of operations at the facility that would add a piece of equipment or a process that is subject to NSPS or NESHAP, or that would modify a piece of equipment or a process such that it becomes subject to NSPS or NESHAP, or that would change its facility classification (either from or to a True Minor Facility, a Class I Facility or a Class II facility); or (2) any modification to add a storage tank with a capacity of 400 gallons or more storing VOC, a VOC Loading Operation, any combustion equipment, or any dehydration unit; or (3) any modification to change the hourly emissions limitations of an Emissions Limited Engine; or (4) any modification to add, modify, reconstruct, or replace an engine. Such notice shall contain calculations of the facility's new facility-wide potential to emit; the change in the facility's classification, if any; and the engine's potential to emit (g/hp-hr, lb/hr, and TPY) for all engines at the facility. Any emissions limits for NO_X and CO (lb/hr) cited in the latest Notice of Modification, for any Emissions Limited Engine, become permit limitations for that engine and an enforceable part of the existing Authorization to Operate. The permittee shall attach a copy of the latest Notice of Modification to a copy of the Authorization to Operate kept either on site, at a nearby manned facility, or at the nearest field office.

"Representative Extended Wet Gas Analysis" means an extended analysis (using GPA 2286 or similar approved methods) that provides speciated data for HAP components benzene, toluene, ethyl benzene, xylenes, and n-hexane. The sample must be representative of the maximum expected HAP content for normal operations of the glycol dehydrator or amine unit.

"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.

"True Minor Facility" means a facility that has the potential to emit less than or equal to 80 TPY each of NO_X and CO.

"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 off-site or unloading of liquid VOC from a tank truck or trailer to a storage tank on-site. 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).

"Voluntary Controls" means facilities not requesting the use of control devices for compliance with emissions cap or federal limits.

APPENDIX D - SUMMARY OF ENGINE EMISSIONS TEST REQUIRMENTS

Engine Classification	One Time Initial Emissions Test?	Hourly Emission Limits?	Quarterly Emissions Tests?
All Emergency Use Engines	No	No	No
All Certified Engines	No	No	No
Uncontrolled Engines less than 100 HP	Yes	No	No
Uncontrolled Engines greater than 100 HP at a True Minor Facility	Yes	No	No. Must keep maintenance records for the engine.
All Other Uncontrolled Engines	Yes	Yes	Yes, initially. May go to semi-annual and then to annual upon consecutive tests demonstrating compliance.
All Other Controlled Emissions Limited Engines	Yes	Yes	Yes, plus monthly assurance monitoring (MAM) for rich-burn engines per Section IV.E of the specific conditions.