General Permit Oil & Gas Facilities (GP-OGF)
Response to the Public Comments

The GP-OGF draft was finalized and was provided for public comment for an initial 30 day period. The public was notified by publication in the Daily Oklahoman and Tulsa World newspapers, posting to the AQD website, and direct notice by e-mail. The public review period began on August 17, 2020. During the 30-day comment period, AQD received a request for a 30-day extension. AQD approved this extension and the comment period ended on Oct. 16, 2020.

This response includes all comments and AQD's response. In addition to the response to comments below, AQD identified the items that needed better clarification in the GP-OGF. These clarifications are listed following:

Section I. Facility-Wide Requirements:

(1) emission cap has been updated to create clearer emission limits;
(2) reference to the "Representative Sample Guidance" was added;
(3) requirements for OAC 252:100-25 were added to clarify as an applicable standard; and
(4) Memo and permit have been updated with language to clarify that a facility will automatically be authorized as a Class II facility after the 24-month transition period, unless the facility has officially requested authorization as a Class I facility.

Section II. Storage Tanks:

(1) clarified to include emissions from produced water storage tanks and (2) added 5.9 TPY federally enforceable limits.

Section V. Emission limitations and calculation methods for compliance with the cap: Requirements for lb/hr emissions limits was adjusted to align with the testing requirements, which excludes Emergency Use Engines or engines rated less than or equal to 250-hp.

Section IX. Other Process Equipment: section was added to address applicable requirements for pneumatic controllers, naturals gas driven pumps, and …

Section X. MSS: section was added to address applicable requirements for MSS activities.

The GP-OGF has been updated to clarify how hydrogen sulfide Draeger tubes may be used to demonstrate compliance with the natural gas total sulfur limit of 10 grains/100 scf or 162 ppmv.

The GP-OGF has been clarified that equipment (engines/turbines) that otherwise required limits under the GP-OGF are not required for equipment on the De Minimis facilities list.

The GP-OGF has been updated to allow tank averaging as allowed in 40 CFR Section 60.5365a(e)(3) [NSPS OOOOa].

<u>1 - Altamira-US, LLC dated October 13, 2020:</u>

<u>Comment #1:</u> Page 2: Bullet 13 references Section VIIIC – Control Devices

There is no such definition or section in the memo or permit. It appears this section was inadvertently omitted. Altamira requests that once this section is added, the opportunity to comment on the draft language be provided.

<u>Response:</u> It appears that this comment was referring to Page 6; the reference has been corrected to Section VI - Control Efficiencies and Monitoring Requirements. The Permit correctly cites Appendix A.

<u>Comment #2:</u> Page 7: Definition of effluent water separator

The definition of effluent water separator is inconsistent with prior ODEQ guidance. The current draft language could be interpreted to mean that effluent water separators are produced water storage tanks. A letter from the Department to the Mid Continent Oil and Gas Association of Oklahoma, dated June 5, 2007, explicitly states that "produced water tanks that store water associated with the production, gathering, separation, and processing of crude oil would not be considered an effluent water separator." Altamira requests this be addressed, and the draft be updated to reflect the existing guidance.

<u>Response:</u> Guidance related to effluent water separators has been posted to the DEQ website. Based on this guidance, common produced water storage tanks relying solely on gravity are not considered effluent water separators.

<u>Comment #3:</u> Page 8: De Minimis Facilities

The OAC statute does not require recordkeeping or calculation of emissions from de minimis sources. It appears the draft permit is contradicting this requirement for the de minimis sources by offering a "simplified method" of calculation for inclusion in the facility-wide cap.

<u>Response:</u> Just for clarification, OAC is a reference to the Oklahoma Administrative Code (OAC) and is not part of the Oklahoma Statute.

The reference to de Minimis in Subchapter 7 refers to "De minimis facility" and was created to assist companies to determine if a facility was exempt from permitting entirely and not intended to exempt equipment from monitoring and recordkeeping at a permitted facility.

The previous General Permit required activities on the "De Minimis Facilities" list to be included when demonstrating compliance with the CAP. To ease the burden on industry, the previous General Permit created a "simplified method" that could be used when facilities calculated compliance with the CAP. Instead of specific monitoring and recordkeeping, the General Permit allowed the facility to substitute 5 TPY for each activity instead of utilizing monitoring, recordkeeping, and specific calculations to document associated emissions. The 5 TPY amount was used because the original De Minimis Facilities list was created on the basis of this 5 TPY threshold. The proposed version of the new General Permit did create some confusion related to the simplified method criteria. The proposed General Permit is being modified to clarify that this will continue to be an acceptable approach in addition to allowing a facility to utilize specific monitoring and recordkeeping to calculate actual emissions from any de minimis activities. This will provide more flexibility with regard to CAP compliance. In addition, DEQ also recognizes that many of the activities on the De Minimis Facilities list are negligible emission sources unrelated to the primary activity and as such, the proposed General Permit is specifying which De Minimis Activities should be included in demonstrating compliance with the facility-wide cap in the General Permit.

The following equipment or activities from the de minimis facilities list are required to be evaluated for compliance with the General permit cap and have been included in the Permit:

Storage Tanks

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

Blowdowns

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

Combustion Equipment

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

Fugitive Emission Sources

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

MSS

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

Miscellaneous

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

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

Wording in the GP-OGF memorandum and permit regarding De Minimis Facilities was modified as needed to implement them as indicated above.

<u>Comment #4:</u> Page 8: Liquids Stored

The memo provides HAP default for crude oil, but not condensate. Are there any guidelines, or defaults available for condensate?

<u>Response:</u> The previously listed default HAP concentrations were from EPA TANKS 4.0 and that program did not offer any guidance related to condensate. After further review, the default HAP concentrations for crude oil were determined to not be representative and should be determined as described in the Section V of the GP-OGF memorandum. As such, the reference to this has been removed from the General Permit and the paragraphs for crude oil and condensate on page 8 of the memorandum have been modified and combined. Due to the varying concentrations of HAP in crude oil and condensate, no default HAP contents are available.

<u>Comment #5:</u> Page 11: Facility-Wide CAP

Preparing annual emissions inventories are a significant effort and expense to our clients. The requirement to prepare 12 month rolling total emissions calculations amounts to monthly annual emissions inventories. Regulated entities track liquid throughputs and gas throughputs as part of standard industry process for accounting purposes. Could sources have the option of electing production limits for the compliance demonstration, in lieu, of calculating emissions? This appears to be allowed under the 1989 EPA "Guidance on Limiting Potential to Emit in New Source Permitting" document that the Department references as justification for the monthly and 12-month rolling facility-wide emissions calculations. This would integrate current processes at the various regulated entities and would be less of a cost burden. Note, the referenced document only discusses the need for limits on production and operation on a monthly and 12-month rolling basis, not emission calculations.

<u>Response:</u> Using production limits to limit PTE is certainly an acceptable approach under the guidance referenced. Based on the current structure of the GP, sources do not have the option of establishing or electing production limits in the permit without an individual minor source permit action as described in Part 1 Section III.C. To provide the most flexibility this GP was set up as a "CAP" permit, allowing facilities to have a wide range of equipment while processing various gases and liquids. This is the most common approach taken by permitting authorities when developing general permits.

Developing a general permit that relies on production limits is a viable alternative. However, in order to develop a general permit that takes this approach, AQD would be required to set production limits based on "worst-case analyses." These analyses would certainly require the GP to include very restrictive production limits and limit the GP usefulness. AQD believes the best approach is to move forward under the current structure as this new GP provides several additional flexibility options to the affected industry. As resources allow, AQD will consider developing a general permit that utilizes production type limits as the means to demonstrate compliance.

It should be noted that the neither the current GP nor this proposed GP prohibits a facility from doing worst case emission calculations and then simply monitoring monthly production rates to demonstrate that the monthly and 12-month rolling emission calculations are representative.

The GP-OGF has been modified to specifically clarify how facilities may utilize a "default" set of calculations that rely on specified monthly throughputs/production rates/hours of operation as part of their compliance demonstration. The facility could rely on these "default" calculations for each month in which actual throughputs/production rates/hours of operation were below the "default" levels and then utilize the associated emissions rates as representative of that month when calculating the 12-month rolling total.

<u>Comment #6:</u> Page 12: Facility-Wide Emissions CAP

It is noted 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." Currently a new GP-OGF construction application is required to obtain a federally enforceable limit (FEL) on any new storage tank immediately upon request. Will this new permit allow for a FEL without a construction permit?

<u>Response:</u> Facilities covered under the GP-OGF can install tanks and obtain an FEL through a NOM.

<u>Comment #7:</u> Page 12: Storage Tanks

The maximum capture efficiency for a control device is listed as 98%. Does this apply to tank batteries with a closed vent system and LDAR program under NSPS OOOOa? Emissions detected from a closed vent system during a LDAR inspection conducted in accordance with NSPS OOOOa, are considered a leak and could be cited by ODEQ compliance and enforcement if 2% were to occur. Additionally, the latest revisions to NSPS OOOOa requires 100% capture for closed vent systems for tanks requesting a FEL.

<u>Response:</u> Yes, the maximum capture efficiency for a control device of 98% does apply to tank batteries with a closed vent system and LDAR program under NSPS, Subpart OOOOa. LDAR inspections do not cover emissions from tanks when not in normal operation (i.e., when access hatches, sampling ports, pressure relief devices and gauge wells are open) and would not be cited by ODEQ compliance and enforcement. NSPS, Subpart OOOOa requires the closed vent system to be operated with no detectable emissions during normal operation, as determined using olfactory, visual, and auditory inspections or optical gas imaging inspections.

<u>Comment #8:</u> Page 12: Storage Tanks

The EPA TANKS program is no longer allowed per the ODEQ website. Therefore, Altamira request the proposed GP-OGF be updated to reference AP-42 Section 7. Additionally, API E&P TANK is no longer supported, and was not updated for the latest AP-42 changes to working and breathing losses. Should this be updated and removed as a reference as well, or limited to only flash calculations?

<u>Response:</u> The GP-OGF has been updated to reference the latest edition of AP-42 Section 7. Additionally, the GP-OGF has been updated to reflect that use of API E&P TANK should be limited to flash emission calculations or when used for working and breathing losses emissions should be adjusted to take into account changes in AP-42 Section 7.

<u>Comment #9:</u> Page 14: Boilers and Heaters

Does the 50 MMBtu/hr total for “all gas-fired combustion equipment” include turbines? Prior versions excluded reciprocating engines and turbines.

Response: The approach previously taken in the existing GP-OGF did apply to all fuel-burning equipment, excluding engines. The current GP-OGF meant to adjust the ineligible criteria to a per unit basis. As a result of this review, the word combined has been removed from the GP-OGF to reflect the intended applicability to individual pieces of equipment, which does include turbines.

<u>Comment #10:</u> Page 15: Glycol Dehydration Unit

Do the controls listed provide a FEL of 1 TPY Benzene under NESHAP HH? Or will this need to be requested under an individual minor source construction permit, and then incorporated into a GP-OGF operating permit?

Response: No, the GP-OGF does not incorporate a FEL of 1 TPY of benzene for exemption from NESHAP Subpart HH. The NESHAP does not require a FEL to be exempt from the regulation. Subpart HH only requires a facility to document that the actual average emissions of benzene from the glycol dehydration unit process vent are less than 1 TPY (0.90 megagram/year), as determined by the procedures specified in §63.772(b)(2), to be exempt from the requirements of 40 CFR §63.764. The GP-OGF incorporates the requirement to document emissions from dehydration unit are less than 1 TPY by incorporating Subpart HH into the GP-OGF. Therefore, there is no need to request a FEL of 1 TPY benzene.

Comment #11: Page 15: Glycol Dehydration Unit

Can you take a limit on strokes for a dehy pump under the GP-OGF construction application?

Response: No, there is no mechanism in the GP-OGF that allows a facility to take a limit on the dehydration unit pump in the Notice of Intent to Construct. However, a limit could be established in an individual construction permit and then incorporated into an authorization to operate under the GP-OGF.

Comment #12: Page 16: Fugitives

"…since PSF [petroleum storage facilities] > 300,000 barrels are major sources and ineligible for this permit, they are not included." That is factually incorrect, there are many, many PSFs with total capacities greater than 300,000 barrels that are NOT major sources.

Response: The referenced sentence is "factually incorrect" and has been removed from the GP-OGF memorandum. The reference to this source category, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, is to indicate which facilities are required to include fugitive emissions in determining whether they are a major source. The permit and memorandum have been revised to require these facilities to include fugitive emissions when demonstrating compliance with the cap.

Comment #13: Page 16: MSS

This permit will supersede prior permits, and add in MSS to count towards the facility-wide emission cap for VOC. Altamira believes the requirement to include MSS emissions in the facility-wide emissions cap is inconsistent with previous guidance provided by ODEQ and is conflict with OAC 252:100 Appendices H and J. Previous guidance from the Department, including the Potential to Emit Fact Sheet, dated June 2, 2003, and the Potential to Emit Guidance Document, dated February 7, 2012, state the following:

> "A final step in identifying emission units to include in calculating PTE is to them delete those activities identified as a "trivial activity" at OAC 252:100, Appendix J. Emissions from these activities need not be counted in determining your PTE."

40 CFR Part 70.2 Major Source (2) specifically states fugitive emissions shall not be considered in the determination of major source applicability for those sources not listed. Since sources covered by the GP-OGF are not among the listed sources under 40 CFR Part 70.2 definition of a major source, fugitive emissions cannot be considered when determining Title V applicability. Does the ODEQ consider blowdowns as fugitive emissions or secondary emissions?

Beyond blowdowns, which is specifically included in OAC 252:100 Appendix J as a de minimis activity, the draft GP-OGF does not contain any other examples of MSS activities. Please clarify exactly what MSS activities are to be included. Is there a minimum frequency of the activity or de minimis level below which the activities do not have to be included? Are secondary emissions considered to be MSS? Also, ODEQ has previously required site specific permits include roof landings and from floating roof tanks for changes of service but not for roof landings associated with other activities such as maintenance. Will that continue to be the case for the general permit?

Response: Please reference response to De Minimis Activities in Altamira comment #3.

The PTE fact sheet dated June 2, 2003 is no longer listed as an applicable guidance document so it is not reviewed further here. The PTE guidance document dated February 7, 2012 remains as a listed resource. While this document does reference Appendix J and gives some guidance with regard to trivial activities and PTE calculations, Appendix J was specifically created for facilities needing a Title V permit and is only referenced in Subchapter 8 in OAC 252:100-8. Appendix J activities can be excluded from certain Title V application requirements and permit specific limits. While referencing Appendix J in the PTE document may have created some confusion, the intent was to assist facilities in identifying certain activities that are not needed for PTE calculations. The majority of the items listed in Appendix J meet this criterion. ODEQ will review the need to refine this document.

ODEQ agrees that most of the facilities that requests coverage under the GP-OGF do not meet the criteria to include fugitive emissions to determine major source status. As such, these facilities would not need to include fugitive emissions for compliance with the CAP. This criterion has been better clarified in the updated GP-OGF.

Generally, ODEQ does not consider blowdown emissions as fugitive nor are they secondary emissions.

While blowdowns are addressed in Appendix J for certain situations, Appendix J is only referenced and used in Subchapter 8 of OAC 252:100 for the purpose of major source permitting. ODEQ has updated the MSS section of the GP-OGF to better assist the regulated industry in addressing these emissions.

Secondary emissions are defined in OAC 252:100-8 as:

"Secondary emissions" means, for purposes of Parts 7 and 9 of this Subchapter, emissions which occur as a result of the construction or operation of a major stationary source or modification, but do not come from the source or modification itself. Secondary emissions must be specific, well defined, quantifiable, and impact the same general areas as the source or modification which causes the secondary emissions. Secondary emissions may include, but are not limited to:

> (A) emissions from trains coming to or from the new or modified stationary source; and,
> (B) emissions from any offsite support facility which would not otherwise be constructed or increase its emissions as a result of the construction or operation of the major source or modification.

Potential to Emit is defined in OAC 252:100-1-3 means:

the maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable. Secondary emissions do not count in determining the potential to emit of a source.

Secondary emissions do not count in determining PTE of a source and are not required to be included when demonstrating compliance with the GP-OGF emissions CAP.

AQD has included emissions from roof landing for various purposes. These have usually been associated with maintenance activities but could include change of service. For the GP-OGF, emissions from roof landings associated with all activities would need to be included for GP-OGF CAP compliance.

<u>Comment #14</u>: Page 19: Vapor Collection for Loading

"Loading loss emissions routed to storage tanks shall be added to the storage tank emissions." There is no regulatory guidance in NSPS OOOOa that requires the inclusion of emissions not generated by the tanks in the calculation of 6 TPY.

> 40 CFR Part 60, §60.5365a (e) The potential for VOC emissions must be calculated using a generally accepted model or calculated methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this subsection.

AP-42 Section 7, is a generally accepted methodology for calculating tanks and there is no discussion on the inclusion of emissions generated by loading in the estimation of tank emissions. In fact, AP-42 contains a separate section for the calculation of loading emissions and considers them a separate process. Therefore, Altamira does not believe loading losses should be included in demonstrating compliance with the requested tank limits of less than 6 tpy.

Response: As indicated, when demonstrating the potential VOC emissions from storage tanks are less than the 6 TPY de minimis threshold for exemption from NSPS Subpart OOOOa, the potential VOC emissions from the storage tanks must be calculated using a generally accepted model or calculation methodology. The requirement to include emissions (vapors) that are captured and routed to the storage tank when using vapor balancing corrects the assumption of AP-42 Section 7 that when emptied the tank is filled with ambient air generally void of VOC rather than devising a way to address the AP-42 Section 7 saturation factor K_N. As the tank is filled, those vapors become part of the tank emissions. The separate AP-42 section for tank truck loading emissions is a separate process. However, the estimated collected (70%) emissions are approximately the same as the difference in emissions calculated using a saturation factor (K_N) of one (1) when calculating emissions from tanks using AP-42 Section 7. In addition, if the loading vapor collection system is not independent of any tank vapor collection system, the vapors collected from the loading operation can collect in the tank being emptied. Either way these vapors become part of the tank emissions and should be included in evaluating their emissions.

For further clarification, the GP-OGF has been modified to include an alternative calculation methodology for tank working loss emissions which allows using a turnover factor (K_N) set equal to 1 in lieu of adding loading emissions routed to the tank.

Comment #15: Page 21: Permits for Minor Facilities

"Coverage under the general permit is effective upon receipt of the NOI to construct by the AQD" and goes on to list three (3) options: (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 to Construct. Currently applications are being submitted via email and the online portal. Does that fall under (3)? Should this be updated to reflect receipt of digital copies rather than when the DEQ is able to physically stamp an application?

Response: A complete application is comprised of both approved forms and payment of application fees. We have updated the language to include the date of receipt of digital copies when accompanied by a receipt or confirmation of payment. Payments may be made through online portals when available, through electronic funds transfers, credit card payments via phone, and submission of paper checks.

Comment #16: Page 26 of the memorandum and Part 2 Section II.B of the draft permit

Both locations reference performing seal gap measurements, but no standards for an acceptable or non-compliance gap are included. What is the point of performing a seal gap measurement in the absence of a standard?

Response: The requirement for seal gap measurements on Page 26 of the GP-OGF memorandum are in reference to the requirements established under OAC 252:100-39 which requires petroleum liquid storage vessel with an external floating roof to measure the secondary seal gap annually in accordance with OAC 252:100-39-30(c)(1)(B)(iii). This standard specifies that seal closure devices must meet the following: The accumulated area of gaps exceeding 1/8 in. (0.32 cm) in width between the secondary seal and the vessel wall when the secondary seal is used in combination with a vapor mounted primary seal shall not exceed 1.0 $in.^2$/ft of vessel diameter (21.2 cm^2/m of vessel diameter). This shall be determined by physically measuring the length and width of all gaps around the entire circumference of the secondary seal in each place where a 1/8 in. (0.32 cm) uniform diameter probe passes freely between the seal and the vessel wall and summing the areas of the individual gaps.

The requirements of Part 2, Section II.B (now Section II.C) of the GP-OGF are in reference to ensuring that storage vessels with an external floating roof are properly operated and maintained while the GP-OGF cannot establish specific limits for the seals on these tanks. It can establish inspection and recordkeeping requirements which can then be used to demonstrate the operational effectiveness of the seals.

APPENDIX A

Comment #17: Page 1: Section I. Introduction

There is a reference to the "GP-OGF Modeling of H2S Sources," dated April 6, 2017, but we cannot find a copy of this document on the ODEQ website. Will it be made publicly available?

Response: Yes, although the majority of the "GP-OGF Modeling of H2S Sources" document was incorporated as Appendix A of the GP-OGF memorandum the referenced document will be provided along with the GP-OGF during the supplementary response to comment review period

PERMIT

Comment #18: Page 4: Section III, C (3)

This specific condition refers to a maximum H2S concentration of 6 ppmw for all categories of crude oil storage at the facility. Please clarify that this is intended for the vapor phase and not the liquid phase.

The general permit is intended to provide flexibility and expedite permitting for frequently permitted facilities. However, the significant drop in allowable H2S in crude oil from 135 ppmw to 6 ppmw will dramatically reduce the usefulness of the general permit for facilities that store different types of crude oil. It is understood that this limitation is based on modeling. But there are significant questions regarding the modeling. How was the H2S concentration in the liquid converted to a vapor concentration? What distance to the property line was assumed? Is reasonable to assume 99 TPY of emissions from a single floating tank when in reality it would take a large tank farm spread over a wide area to come even close to those emissions? Altamira respectively requests that this condition be revised for a sliding scale emissions based on the type of equipment being registered and additional parameters. TCEQ has a method such as this in both 30 TAC 106.352 (a-k) and the Non-Rule Standard Permit. These contain lookup tables and allow for facilities to conduct modeling to demonstrate compliance.

<u>Response:</u> The H2S 6 ppmw concentration limit for crude oil was established as a limit in the liquid phase based on modeling which indicated that H2S could significantly accumulate in the vapor phase using the 6 ppmw limit in the liquid phase and that the ambient impacts from those emissions could exceed the ambient H2S standard. Information related to the assumptions made are contained in the referenced modeling, which will be provided during the supplementary response to comment period. The modeling evaluated only a couple of scenarios to determine compliance with the H2S ambient standard. Evaluation of each possible scenario covered by the different types of facilities and equipment that could be located at all facilities which could be permitted under the GP-OGF is not a viable option given limited resources.

The TCEQ incorporates into their permit by rule (30 TAC §106.352(m)) tables which allow a facility to demonstrate compliance with the TCEQ H2S ambient standard by summing the calculated ambient impacts from each piece of equipment located at a facility based on generic modeling performed by the agency for each type of equipment (including size), stack height, and distance from property line. Although the methods used by TCEQ to generate the generic impacts for individual pieces of equipment were not reviewed, the comprehensive modeling and derivation of generic impacts were not evaluated as a method of compliance for the GP-OGF because it relies on a case-by-case determination for each facility. Rather, the GP-OGF allows facilities to get individual minor facility construction permits to address case-by-case determinations and then to apply for a GP-OGF to incorporate any requirements needed to demonstrate compliance with the ambient standard.

<u>Comment #19:</u> Page 11: OAC 252:100-39-30

This specific condition refers to storage tanks that "[h]ave a capacity less than 422,675 gallons…used to store product crude oil or condensate prior to lease custody transfer." Isn't the limit for this 10,000 bbls (420,000 gallons).

<u>Response:</u> No, the limit referred to in the specific condition should not be for tanks with a capacity of 10,000 barrels. This specific condition establishes the requirements from OAC 252:100-39-30(b)(2)(B) which specifically exempts petroleum liquid storage vessels that have capacities less than 422,675 gal (1,600 m^3) used to store produced crude oil and condensate prior to lease custody transfer. No changes were made to the GP-OGF as a result of this comment.

<u>Comment #20:</u> Page 11: OAC 252:100-37-15(a)

Mention should also be made of paragraphs 100:252-37-15(a)(2) and (3) so that operators have other common options available, such vapor recovery or internal floating roof tanks, or "other equipment or methods that are of equal efficiency for purposes of air pollution control." A strict reading of the draft language might not allow options such as vapor recovery systems or internal floating roofs.

<u>Response:</u> OAC 100:252-37-15(a)(2) and (3) were specifically excluded as compliance options for OAC 252:100-37-25 in the GP-OGF because they require case-by-case determinations. The GP-OGF allows facilities to get individual minor facility construction permits to address case-by-case determinations and then to apply for a GP-OGF to incorporate any requirements needed to demonstrate compliance with the applicable standard.

<u>Comment #21:</u> Section VIII is missing

Altamira requests that once this section is added, the opportunity to comment on the draft language be provided.

<u>Response:</u> Typographical error, Section IX Compressors has been relabeled Section VIII and Section X MSS has been relabeled Section IX.

<u>2 - Mark Webster dated September 2, 2020</u>

Comment #1: In Appendix B, Page 42

It states that the maximum concentration of H2S is no more than 10 ppmw but in the three methods for demonstrating the expected H2S concentration 6 ppmw is listed as the maximum. Is there a correlation between these two numbers or is only one of those values the limit?

<u>Response:</u> The reference to 10 ppmw is a typographical error that will be corrected in the final version of the GP-OGF.

<u>3 - DCP Operating Company, LP dated September 15, 2020</u>

<u>Comment #1:</u> Page 6: Section II. B. 13

Control efficiencies appear to be in Section VI and not Section VIII.

<u>Response:</u> This was a typographical error, the reference has been corrected from Section VIII to Section VI.

<u>Comment #2:</u> Page 10: Section IV.

A NOM should not trigger compliance with the new GP and instead allow the 24 month transition period under the existing GP for that site. If the GP transition estimates facilities need 24 months to comply with the new GP, that time frame should not be changed due to an engine replacement activity. This prohibits the flexibility to use the GP to Construct and move to the individual minor source operating permit as described on page 9, Section IV, paragraph 2.

<u>Response:</u> After review, AQD agrees that additional flexibility should be provided to those facilities wanting to be covered under the existing GP-OGF during the transition period. The GP-OGF has been updated to allow this flexibility.

<u>Comment #3:</u> Page 11: Section V.

A search of the AQD guidance section did not locate the "Representative Sampling Guidance" referred to in this paragraph. Please provide additional direction to locate this guidance.

Response: This guidance was uploaded to the DEQ website in September 2020.

Comment #4: Page 11: Section V. A.

The permit requires the calculation of actual facility-wide emissions, as a monthly, 12-month rolling total, to determine compliance with each facility-side emissions cap. Actual facility emission are calculated and reported in the annual Emission Inventories. These calculations and emission estimates should be the basis of compliance. The GP is requiring calculations of actual facility-wide emissions monthly. There is not a monthly emissions limit to determine compliance. While EPA prefers a rolling-12, this seems overly burdensome for a minor source to calculate monthly emissions for every site. This does not seem to meet the goal of reducing resources to comply with the GP and would likely resort in an increased use of the individual minor source permit which contains monthly monitoring requirements to demonstrate compliance. Demonstrating compliance with a throughput limit is much more efficient that calculating emissions for every source every month.

Response: Please see response to Altamira comment #5. With regard the monthly limit and compliance. Correct, the permit does not contain monthly limits as the GP relies on ton/year limits to limit the permit to synthetic minor status. However, a monthly demonstration of compliance with the CAP is required in order to meet EPA criteria for compliance with long term limits. This is the most flexible criteria EPA allows for a demonstration of compliance with a long-term CAP. AQD does not believe industry would prefer a daily or weekly type rolling total.

Comment #5: Page 12: Section V. A.

EPA policy and preference is to not have a compliance period longer than 1 month. A monthly compliance point such as dehy throughput is currently required by the GP. There is not a "preference" for the actual calculations e.g. a glycalc every month for every facility authorized under a GP. The calculations are more resource intensive rather than collecting a data point.

Response: Glycol dehydrator emissions are based on potential to emit and throughput criteria as detailed in the Glycol Dehydration Unit section. This method is more straight forward and eliminates the need for additional monitoring and recordkeeping if the permit allowed actual throughputs to be utilized. AQD's review found that utilizing the maximum throughputs outweighed the requirements of additional monitoring and recordkeeping related to use of actual throughputs. Facilities still have the option to get an individual minor source construction permit to establish requirements for utilizing actual throughputs for compliance with GP-OGF cap.

Comment #6: Page 12: Section V. B.

Maintaining records of tank throughput monthly is a reasonable, efficient data point. It continues to be unreasonable to also require monthly calculations. If a facility demonstrates that facility operation and a throughput of 500,000 gal/yr of condensate is below the cap, maintaining records of the throughput monthly will determine the compliance and does not force the onerous process of calculating the emissions for every source every month. To determine monthly HAP from actuals requires sampling adding to the time and resources required to determine monthly emissions where a monthly throughput would make the same determination.

Response: Please see responses to Altamira comment #5 and DCP comment #4.

Comment #7: Page 14: Section V. E. Glycol Dehydration

E. Glycol Dehydration Unit. Glycol Dehydration Unit.

Response: This was a typographical error and has been corrected.

Comment #8: Page 15: Section V. E. Glycol Dehydration

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

The 50% destruction efficiency for glycol still vent gases should specify the 50% destruction is after the condenser control efficiency has been considered.

For example:
For combustion of gasses from a glycol still vent or flash tank in a reboiler firebox, only a 50% destruction efficiency shall be allowed after the condenser control unless combined with other controls such as flares, glow plugs, fuel gas system, or inlet of facility. If such controls are installed, greater than 50% destruction may be applied as allowed under this general permit.

Response: The wording has been modified to include potential control of gases from a condenser.

Comment #9: Page 16: Section V. I. Maintenance, Startup and Shutdowns (MSS)

The general permit requires the permittee to estimate VOC emissions from any MSS activity and include those emissions in calculating compliance with the facility-wide emissions cap for VOC. In OAC 252:100-7-2(b) Requirements For Permits For Minor Facilities specifically exempts De Minimis Facilities listed under Appendix H. Appendix H includes MSS activities. Please clarify that this MSS emissions in Appendix H are exempt.

Response: The criteria under OAC252:100-7-2(b) was established as a permitting threshold for the entire facility. MSS activities are not exempted for permitted facilities. For additional information, see response to Altamira Comment #3.

Comment #10: Page 17: Section VI. Control Efficiencies and Monitoring Requirements

Limit shall be based on manufacturer's uncontrolled CO emissions guarantee at 100% load reduced at a control rate less than or equal to that requested for H2CO, not to exceed 93%.

1. Are current AP-42 Section 3.2 factors acceptable to the Division for emission calculations as specified in the NSCR table? Please clarify.

2. Maximum allowed control efficiency for CO should be based on the engine manufacturer's uncontrolled emissions or AP-42 and the requested CO limit. It is not clear what "manufacture guarantee" means as an acceptable method of determining the control efficiency in the Non-Selective Catalytic Reduction (NSCR) table. Since engines are being stack tested to demonstrate compliance with the limits, the engine manufacturer's guarantee uncontrolled and the requested limit should be sufficient to demonstrate the reduction is less than 90%

3. Please clarify the differences in reduction efficiencies for CO (90%) and H2CO (93%) and in the preceding paragraph and the tables.

Response: 1. The table is addressing manufacturer's guarantees of the control devices and doesn't establish the basis for emission factors. A reference to the manufacturer's uncontrolled emission factor of the preceding paragraph used to determine the surrogate CO emission limit should be based on the most representative data available, usually manufacturer's data. This paragraph has been update to allow other resources when manufacturer's data is not available.

2. The catalysts manufacturer's emission reduction guarantee is integral to create a practically enforceable limit.

3. The wording has been corrected from 93% to 90%.

Comment #11: Page 19: Section VI. Control Efficiencies and Monitoring Requirements: Vapor Collection for Loading

Please add a row for minimum standards for uncontrolled loading.

Response: This table establishes criteria for vapor collection during loading and does not need to include uncontrolled loading requirements. The only minimum standard for uncontrolled loading at certain facilities is submerged filling of the tank truck, as detailed in the permit itself.

Comment #12: Page 5: Part 1, Section III. C. 10

No. 10 of the facilities list that are not eligible states “Facilities that require a specific limitation(s) not otherwise addressed in order to maintain compliance with the cap.” The draft GP does not reference tank controls & a VRU operation. It is expected that since the GP does reference OOOO and OOOOa, that those “facilities” were intended to be covered. However the operation of tanks with a VRU is not identified in the proposed GP. Does this indicate that tank controls and operating equipment, such as a VRU, do not qualify for a GP to construct?

Response: VRUs are process equipment and not control devices and are not covered under the control device section. Specific limitations are not required for VRUs to limit the PTE of a unit but recordkeeping of use of VRU is required (Part 2, SECTION II.I). Requirements for commonly used controls for tanks are addressed in the permit.

Comment #13: Page 8: Part 2 – Specific Conditions, Section I. B.

Compliance with these emission limitations shall be determined at least monthly and be based on a 12-month rolling total. Annual emissions are calculated during emission inventories and are verified through semi-annual PEA testing. In addition, emission limits are verified by facility throughput and/or equipment hours of operation. A monthly calculation of the emissions prohibits utilization of a data point record as the compliance point, increases dramatically the time needed to calculate every emission point every month, and will likely result in a reduction in utilization of the GP with a preference to using the site-specific individual permit instead which increases ODEQs resource for application review.

Response: Please see responses to Altamira comment #5 and DCP comment #4.

Comment #14: Page 8: Part 2 – Specific Conditions, Section I. C.

If the facility throughput or equipment hours of operation can be used to constrain the facility so the cap isn’t exceeded, why can the same compliance points not be used on a monthly basis to demonstrate compliance? If hours of operation and throughput is suitable in one instance, it should be suitable in the monthly determination.

Response: The GP-OGF doesn’t contain throughput limits or limitations on hours of operation, the GP-OGF provides a cap on emissions and requires monthly demonstrations of compliance based on actual throughputs and hours of operations. Hours of operation and throughput are suitable for both monthly calculations and the 12-month rolling cap limit.

Comment #15: Page 9: Part 2 – Specific Conditions, Section I. I. 3 & J

Representative fuel sampling does not specify if the demonstration is required for emergency engines. Emergency engines are usually small and fired with commercially purchased fuels. It doesn’t seem to be feasible to also sample the emergency fuel commercially purchased.

Response: Sampling of commercially purchased fuels in not required in the GP-OGF. Current gas company bill or a current gas contract, tariff sheet, or transportation contract is required for the natural gas fuel or a one-time certification with subsequent receipts for liquid fuel.

<u>Comment #16:</u> Page 9: Part 2 – Specific Conditions, Section I. K.

This section does not specify how long records need to be retained. Generally for minor sites, records are required for 2 – 3 years. Please clarify the records retention period.

<u>Response:</u> Part 3, SECTION IV.A of the GP-OGF states records shall be kept for 5 years, unless a longer period is specified.

<u>Comment #17:</u> Page 10: Part 2 – Specific Conditions, Section I. N.

Maintenance, Startup, and Shutdown (MSS) emissions shall be included as part of the facility-wide emissions cap. Please clarify monthly and facility-wide 12-month rolling totals of NOx, CO, VOC and HAP emissions. A facility site-specific permit does not require monthly and 12-month rolling totals of emissions calculations. Instead, it is requested that facility throughputs be utilized that could then be used to calculate emissions when needed. Monthly calculations of NOx, CO, VOC, and HAP is very labor intensive and potentially eliminates utilization of the GP.

Response: ODEQ is unclear concerning the question regarding MSS as MSS is not specifically listed in this paragraph. However, MSS emissions are required to be included in the records when facilities calculate compliance with the GP-OGF CAP. EPA criteria does require monthly and 12-month rolling total calculations (as a minimum) when demonstrating compliance with a TPY limit.

Also, please see comment responses to Altamira comment #5 and DCP comment #4.

<u>Comment #18:</u> Page 15: Part 2 – Specific Conditions, Section II. I.

Section doesn't differentiate between > 400 gallons and < 400 gallons. This recordkeeping requirement needs to clarify what tanks are being required to have the record.

<u>Response:</u> The condition has been updated to clarify records are required for tanks with a capacity of 400 gallons or more in accordance with the requirements of Section II. A.

<u>Comment #19:</u> Page 16: Part 2 – Specific Conditions, Section IV. C.

The paragraph does not include electronic means of recording engine operating hours. There are methods of determining engine operation electronically by monitoring rpm for determining if an engine is running. An electronic determination should be an acceptable method of determining engine run hours remotely.

<u>Response:</u> The condition has been updated to allow electronic methods to measure hours of operation.

<u>Comment #20:</u> Page 17: Part 2 - Specific Conditions, Section IV. H. 2.

The NOM is required to be maintained as a paper copy. There should also be allowed an electronic copy.

<u>Response:</u> The wording has been updated to clarify the applicant shall maintain a copy but does not clarify the method.

<u>Comment #21:</u> Page 36: Part 3 - Standard Conditions, Section XI. C. 2 & 3

ODEQ has determined a transition period of 24 months as suitable. If during that time period, a change occurs that is allowed using a NOM, it should not automatically negate the 24 month transition period that ODEQ has determined is appropriate. Doing this could potentially cause companies to forego maintenance to their equipment in order to not trigger the immediate compliance with the new GP.

<u>Response:</u> The standard conditions have been modified to allow use of the NOM from the existing GP-OGF to maintain coverage under that permit or utilize the new NOM to obtain coverage under the new GP-OGF during the transition period.

<u>Comment #22:</u> Appendix A

No control efficiency has been introduced for tank controls.

<u>Response:</u> This section is a generic list of controls that may be utilized by normal equipment at oil and gas facilities. For tanks, flares or enclosed combustion devices are typically used to control emissions. As a result of this comment, AQD incorporated into Section II.A the maximum capture efficiency of 98% indicated in the memorandum and incorporated into the memorandum the reference to the control efficiencies of Appendix A.

<u>4 - Enable Midstream – 1st Set, dated September 11, 2020</u>

<u>Comment #1:</u> Page 3

NAICS Code was changed to 211130 in 2017 updates.

<u>Response:</u> The change has been incorporated to better clarify SIC and NAICS Codes.

<u>Comment #2:</u> Page 5

What is the basis for 162 ppmv of total sulfur? Minor source permits have historically been 343 ppmv. Does this mean individual minor source permits will also change?

<u>Response:</u> The 162 ppmv total sulfur is based on the NSPS, Subpart Ja combustion device fuel gas concentration short term limit (§60.102a(g)(1)(ii)).

Yes, minor source oil and gas permits have historically limited the fuel gas sulfur content to below the limit established in the definition of natural gas of 343 ppmv. However, based on changes to the NAAQS for SO_2 and dispersion modeling conducted to demonstrate compliance with the new 1-hour ambient standard, it was determined that the 343 ppmv fuel gas sulfur content was not conservative enough and a lower value was needed. Previously, oil and gas permits have also limited fuel gas sulfur contents to below the limit established for fuel gas combustion devices in NSPS, Subpart J of approximately 159 ppmv. The short term fuel gas limit of NSPS Subpart Ja was selected as a good alternative to the current permitting standard.

Yes, the fuel gas sulfur content limit for individual minor source oil and gas permits will also change to reflect the limits established in the new GP-OGF to ensure compliance with the SO_2 NAAQS.

Comment #3: Page 5

What is the basis for the 135 ppmv in 2016 Proposed GP-OGF to 6 ppmw in this draft?

Response: The basis for limiting the GP-OGF to facilities processing "sweet" crude oil or crude oil with a concentration of less than 6 ppmw H2S is the modeling conducted to demonstrate compliance with the H2S ambient standard summarized in Appendix A of the GP-OGF memorandum. The tank calculations in combination with the AERSCREEN model indicated that H2S contained in the crude oil accumulated in the vapor space above the crude oil and vented to the atmosphere from storage tanks storing "sour" crude oil have the potential to exceed the ambient standard of OAC 252:100-31-7(b). Therefore, to ensure compliance with the H2S ambient standard the GP-OGF was limited to facilities that process "sweet" crude oil.
Also, please refer to Altamira Comment #18.

Comment #4: Page 5

What is the basis for limiting glycol dehydration units to 4 ppm?

Response: The basis for limiting the GP-OGF to facilities with glycol dehydration units treating "sweet" natural gas or natural gas with less than 4 ppmv H2S is the modeling conducted to demonstrate compliance with the H2S ambient standard summarized in Appendix A of the GP-OGF memorandum. The GRI-GlyCalc model in combination with the AERSCREEN model indicated that H2S adsorbed by the glycol in the contact tower and released from the still vent from units treating "sour" natural gas have the potential to exceed the ambient standard of OAC 252:100-31-7(b). Therefore, to ensure compliance with the H2S ambient standard the GP-OGF was limited to facilities with glycol dehydration units that treat "sweet" natural gas.

Comment #5: Page 6: Criteria #10

Would a natural gas throughput or glycol pump recirculation rate limit be a specific limitation?

Response: Yes, a natural gas throughput or glycol pump recirculation rate limit would be a specific limitation that is required to be established in an individual construction permit.

Comment #6: Page 6: Incorrect Reference

Update the citation and wording reference.

Response: This reference has been corrected to Section VI. Control Efficiencies and Monitoring Requirements.

Comment #7: Page 6

What does this mean? How is this different from #10? What would be examples of something under this condition?

Response: Part 2 Section II.B.10 is requesting limits to maintain compliance with the facility-wide cap (e.g., additional control efficiency limit) while Part 2 Section II.B.14 is requesting limits that are not allowed under the GP-OGF (e.g., processing > 6ppm H_2S limit) but are not related to direct compliance with the emission cap.

Comment #8: Page 7

The way effluent water separator is defined here, it could be interpreted that produced water tanks are effluent water separators. We suggest adding language from June 5, 2007 ODEQ guidance letter to the Mid Continent Oil and Gas Association of Oklahoma that specifically excludes produced water storage tanks from oil & gas operations. See redline requested changes to paragraph.

Response: AQD has developed updated specific guidance on effluent water separators and this guidance has been posted to the DEQ website.

Comment #9: Page 8

This does not align with EPA's definition of fugitive emission sources within NSPS OOOO/OOOOa. Specifically, the NSPS OOOO/OOOOa definition of "fugitive emissions component" exempts "devices that vent as part of normal operations" (i.e. "natural gas-driven pneumatic controllers or natural gas-driven pumps").

Response: As a result of the comment submitted, the permit has been updated to better define fugitive sources and an additional section has been added to address other operations that are not currently identified or included as part of the GP-OGF.

Comment #10: Page 8

OAC 252:100, Appendix H does not require records for de minimis activities, so based on OAC regulations, how can industry be required to track emissions from these activities that are covered under OAC 252:100, Appendix H?

Additionally, where in the proposed GP-OGF is the referenced "simplified method for estimating emissions from the de minimis facilities"?

<u>Response:</u> Please see response to Altamira Comment #3.

<u>Comment #11:</u> Page 8

Typo, add “amines”

<u>Response:</u> Added.

<u>Comment #12:</u> Page 8

TANKS 4.0 is no longer supported. Does this reference need to change to AP-42? If TANKS 4.0 is no longer supported, where do the HAP content values come from?

<u>Response:</u> Please see response to Altamira Comment #4.

<u>Comment #13:</u> Page 10

This should be more specific as only facilities with “new fuel-burning equipment,” with a combined rated heat input of 50 MMBtu/hr or greater (excluding reciprocating engines) cannot obtain an Authorization to Construct per the Eligibility section.

<u>Response:</u> This statement is correct, new fuel-burning equipment with a rated heat input greater than 50-MMBtu/hr would be subject to OAC 252:100-33 and cannot obtain coverage under the GP-OGF without limits from an individual construction permit. Additionally, per Altamira Comment #9, the eligibility criteria has been corrected to only limit eligibility to units greater than 50-MMBtu/hr individually and not a combined rating.

<u>Comment #14:</u> Page 10

Enable appreciates increasing this from the current 10-day notification requirement.

<u>Response:</u> No response needed.

<u>Comment #15:</u> Page 11

Was this this guidance document finalized and approved? It is not on the ODEQ website and we were unaware that is was finalized.

<u>Response:</u> Yes, this was finalized and posted to the website in various locations as of September 15, 2020 with an implementation date of March 15, 2021.

<u>Comment #16:</u> Page 11

This is a significant impact to industry. It increases time, resources, costs, and recordkeeping burden by creating an emissions inventory every month for every permitted facility.

For example, many companies utilize consultants to prepare emissions inventories. Has ODEQ completed a budgetary analysis to determine the extra costs that this would cause companies to incur? Likewise, the increased workload for companies that do EIs in-house could potentially lead to an increased cost to hire more in-house staff.

Response: Please see response to Altamira comment #5 and DCP comment #4.

Comment #17: Page 12

Policy or Preference? If it is preference, this is not required. If is policy, where is this policy from?

Response: Please see response to Altamira comment #5 and DCP comment #4. This is long-standing EPA policy detailed in EPA's "Guidance on Limiting Potential-To-Emit," dated June 13, 1989.

Comment #18: Page 12

This is not how the emissions are reported for EI's. They are reported at the point they are emitted at (i.e. VOC emitted at the flare will be reported at the flare).

Response: This statement has no impact on how emissions are reported in EIs. This is simply clarifying that tank emissions emitted at a flare are part of the 5.99 TPY VOC limit a facility may elect to include in their application. For some facilities, EIs will not represent total tank emissions. Facilities should be aware their compliance demonstration and calculations should list total tank emissions (including those emitted at the flare) for compliance with the 5.99 TPY limit.

Comment #19: Page 12

Is the actual throughput determined by the same methodology as in NSPS OOOOa?

Response: Actual throughput is the actual tank throughput documented on a monthly basis. For any facility designed and operated as defined under NSPS Subpart OOOOa, the tank averaging methodology allowed under NSPS Subpart OOOOa is an acceptable method.

Comment #20: Page 12

Does this apply to controlled tank batteries that have an LDAR program on the CVS? These typically have 100% capture efficiencies.

Additionally, does C/E agree that leaks found utilizing an IR camera on a controlled tank battery are part of the 2% VOC allowed to be emitted?

<u>Response:</u> Yes, see response to Altamira comment #7. No, this 2% does not include leaks found during inspections required under NSPS Subpart OOOOa or any other regulations requiring leak testing utilizing an IR camera.

<u>Comment #21:</u> Page 12

Several typos

<u>Response:</u> Updated.

<u>Comment #22:</u> Page 12

TANKS 4.0 is no longer supported. Needs to be removed.

<u>Response:</u> Updated.

<u>Comment #23:</u> Page 12

TANKS 4.0 is no longer supported. Does this reference need to change to AP-42? If TANKS 4.0 is no longer supported, where do the HAP content values come from?

<u>Response:</u> Yes, the reference has been updated to AP-42. Please see Altamira comment #4.

<u>Comment #24:</u> Page 12

What is “significant”? This may be a big impact to industry as most do not currently permit or calculate actual HAPs for condensate tanks.

<u>Response:</u> Significant is not defined; it is used as a qualitative reference and does not indicate a specific quantity. The current permit requires facilities to demonstrate compliance with the HAP limits of 10/25 TPY and HAP emissions are required as part of the EI reporting and should not be a big impact to industry.

<u>Comment #25:</u> Page 13
Is this just EPA Reference Method stack test data or can PEA stack test data be used too?

<u>Response:</u> Yes, any PEA test that was conducted using appropriate EPA test methods can be used. Wording has been updated to clarify this point.

<u>Comment #26:</u> Page 13

Define annual? Is this calendar year, 8760 hours, 12-month rolling, etc.?

<u>Response:</u> Annual hours of operation is a reference to 8,760 hours of operation in terms of determining annual emissions. However, demonstration of compliance with the annual emissions limits is based on 12-month rolling totals.

<u>Comment #27:</u> Page 13

Define annual? Is this calendar year, 8760 hours, 12-month rolling, etc.?

<u>Response:</u> Annual hours of operation is a reference to 8,760 hours of operation in terms of determining annual emissions. However, demonstration of compliance with the annual emissions limits is based on 12-month rolling totals.

<u>Comment #28:</u> Page 13

According to Specific Condition section, this is "twice per calendar year." Please clarify.

<u>Response:</u> As specified in Part 2 Section IV.E of the GP-OGF, semi-annual is defined as twice per calendar year separated by at least 120 days.

<u>Comment #29:</u> Page 13

Since there are not testing requirements for uncontrolled engines, will there be short-term limits for uncontrolled engines?

<u>Response:</u> Short-term limits are required to be established for all engines in the application or NOM for use in demonstrating compliance with the facility-wide cap. Additionally, there are initial testing requirements on some uncontrolled engines.

<u>Comment #30:</u> Page 14

According to Specific Condition section, this is "twice per calendar year". Please clarify.

<u>Response:</u> Please see response to Enable Comment #28.

<u>Comment #31:</u> Page 14

Enable appreciates testing frequency being reduced.

<u>Response:</u> No response needed.

<u>Comment #32:</u> Page 14

What about NESHAP ZZZZ limits? Can that be used?

<u>Response:</u> It has been added.

<u>Comment #33:</u> Page 14

What is this just limited to engines older than 2000? Some smaller engines such as emergency generators do not have formaldehyde manufacturer's emission factors?

Response: If an applicant can demonstrate no manufacturer's data is available, the GP-OGF application will allow for use of other established emission factors.

Comment #34: Page 14

Formaldehyde, H2CO, and CH2O is used interchangeably throughout document. Can you make consistent throughout document?

Response: All references to CH_2O and H_2CO have been changed to formaldehyde.

Comment #35: Page 14

This is Section V. and Section V. of the Specific Conditions references Glycol Dehydrators. What is this supposed to be referencing?

Response: The references have been updated.

Comment #36: Page 14

According to the Eligibility section glycol dehys are limited to 4-ppm. Is this the case? It is not mentioned in this section similarly to the amine section below

Response: Please see response to Enable Comment #4.

Comment #37: Page 15

Would a natural gas throughput limit or glycol pump recirculation rate limit be a specific limitation?

Response: Please see response to Enable Comment #5.

Comment #38: Page 15

What if the dehy does not operate continuously?

Response: The GP-OGF was setup to use a PTE calculation method for glycol dehydration units rather than establishing recordkeeping and monitoring requirements for estimating actual emissions. This process has been utilized in the current GP-OFG and AQD is not aware that this methodology imposes significant restrictions in using the GP-OGF.

Comment #39: Page 16

It is unclear what this would be. Could you please provide examples?

<u>Response:</u> An example of other equipment for which other emission calculations would be required are vapor recovery towers routed to a flare when VRU equipment is down.

<u>Comment #40:</u> Page 16

Does this only apply to NSPS OOOOa VRUs referenced in the sentence above or all VRUs? If it is all VRUs, this is a significant burden on industry in order to comply with OOOOa standards on a non-applicable VRU.

<u>Response:</u> Yes, for the purposes of §60.5365a(e)(5)* in determining if a storage tank is a storage vessel affected facility, these requirements are applicable. Also, the common requirements listed in §60.5365a(e)(5) are criteria for well operated and maintained equipment and should not impose a significant burden on industry.

*Note: Due to revisions in the regulation, the reference to §60.5365a(e)(3) has changed to §60.5365a(e)(5).

<u>Comment #41:</u> Page 16

This is also an additional burden on industry. What is the regulatory basis for requiring this? This is not required in OAC rules. In the Industry/ODEQ GP-OGF meeting held in 2016 upon initial proposal of this revised GP-OGF, Phillip Fielder stated that Permitting will not make these emissions be included in the permit application. However, by including it C/E is going to want to see these emissions included in our actual emissions. We do not typically calculate maintenance, start-up, and shutdown emissions as part of Emissions Inventory submittals since there is no regulatory requirement to maintain records of these types of emissions since they are de minimis/insignificant.

<u>Response:</u> EPA's long held policy is that facility CAP permit emission limitations apply at all times. Permit limits may not be waived during periods of maintenance, startup, and shutdown. However, where the permitting authority has made an on-the-record determination that compliance with unit specific emission limitations is infeasible during startup, shutdown and maintenance, the permitting authority may establish secondary limits or work practices for those periods for said unit. Such secondary limits or work practices (such as a limitation on total startup and shutdown event time) must be justified and the permitting authority must ensure that all CAA permitting requirements are met.

ODEQ has historically included alternative limits for MSS related activities/events when specifically requested by the facility or when the agency has determined the need based on a case-by-case determination. The primary facility CAP limits apply at all times, unless these alternative limits are included in the facility permit. If alternative limits were included total facility emissions would still need to be below CAP limits.

To reduce confusion ODEQ is now clearly identifying MSS emissions as subject to the CAP.

It is correct that C/E will be reviewing emissions calculations with regard to MSS emissions.

Emissions inventory submittals require facilities to include “actual” emissions. MSS and malfunction emissions are included as “actual” emissions and should be included when the same can be reasonable estimated.

MSS emissions do not qualify as de minimis or insignificant for facilities with minor source permits under Subchapter 7. Also, please see response to Altamira comment #3.

De minimis and insignificant activities are not definitions used for the purpose of emissions inventory reporting; this has been stated in many annual outreach workshops put on by the Emissions Inventory Section. Emissions inventory submittals require facilities to include “actual” emissions. MSS and malfunction emissions are included as “actual” emissions and should be included in the inventory. Current EI policy on an emissions reporting threshold per process is on the EI Reporting Guidance - FAQ’s webpage. Furthermore, all supporting data for the inventory must be kept for at least 5 years, which would include all “actual” emissions.

Comment #42: Page 17

These emissions are included as de minimis emissions in OAC and no recordkeeping is required for these emissions. If no recordkeeping is required by OAC, how can you legally require these emissions to be reported? Any change in requiring these emissions needs to be based in rulemaking and not through guidance or permitting with no rulemaking supporting it.

Response: Please see response to Altamira Comment #3 and Enable Comment #41.

Comment #43: Page 17

This contradicts DEQ Potential to Emit Guidance doc that states to use the highest manufacturers’ emissions factors for any of the settings at which the engine can be operated. Please clarify.

Response: The guidance referred to is used to calculate potential-to-emit and is not associated with the methodology used here to establish the surrogate CO limit.

Comment #44: Page 17

Are you saying that CO emissions reduction can be less than H2CO? This is opposite of page 14 of Memo which states “H2CO control efficiency shall be at or below the efficiency requested for CO.”

Response: No, wording has been updated to better clarify the requirement.

Comment #45: Page 17

This is not consistent with the last sentence of the above paragraph which states up to 93% control. Please revise to not to exceed 93%.

<u>Response:</u> The 93% reference refers to the oxidation catalysts surrogate policy and this table establishes requirements for NSCR catalysts. As a note, the 93% above was a typographical error and has been corrected to a maximum of 90% reduction.

<u>Comment #46:</u> Page 17

According to Specific Condition in Permit below, this is "twice per calendar year." Please clarify. Is there an operating hour threshold in each semiannual period for which testing is required?

<u>Response:</u> Please see response to Enable Comment #28.

<u>Comment #47:</u> Page 17

This is not consistent with the last sentence of the above paragraph which states that CO must be less than H2CO. H2CO control efficiency needs to be less than or equal to CO control efficiency. Is there an example where you can take up to 93% control for H2CO as described here.

<u>Response:</u> Please see response to Enable Comment #44-45.

<u>Comment #48:</u> Page 18

Below control devices don't specify whether they are hooked to still vent or flash tank. Some are just for still vent typically, some are just for flash tank typically, and other can be both. Need to separate glycol dehy units from amine units.

<u>Response:</u> We understand that these types of units may have flash tank or still vent controls and some of these controls may be in series, but we don't see an issue with addressing controls in this manner. AQD is not aware of any issues related to listing potential controlled devices for these units in a single table. This table provides the flexibility for these controls to be on either still vent or flash tank.

<u>Comment #49:</u> Page 18

Amine Units do not typically have condensers installed as control devices. Need to specify below which control device applies to amine units and glycol dehy units or separate into different section.

<u>Response:</u> The table does not mandate condensers on amine units. Where these controls are viable and used in industry, the requirements of the table must be met.

<u>Comment #50:</u> Page 18

Why must you have a flash tank? Flash tank emissions are not routed to the condensers, only still vent emissions. There are instances where a glycol dehy does not have a flash tank, but does have a condenser. Are those dehys not equipped with a flash tank unable to obtain a GP-OGF?

<u>Response:</u> Based on API's GRI-GLYCalc guidance, units with condensers must have a flash tank to operate within the parameters of the GRI-GLYCalc. Also, AQD is not aware of many facilities using condensers without flash tanks, however facilities can apply for an individual minor source construction permit and then obtain coverage under the GP-OGF.

<u>Comment #51:</u> Page 18

Above, it states to calculate using GRI-GLYCalc. Based on GRI-GLYCalc controlled emissions, this can be higher than 98%. Sometimes up to >99% when untilze the condenser/combustion device controlled emissions selection in GRI-GLYCalc. For example, GRI-GLYCalc will use a 90% control from the condenser and then take 95% of the remaining emissions due to the combustion. This leads to an overall reduction efficiency of greater than 98%.

<u>Response:</u> The control efficiency listed in this section refers to additional control for combustion in addition to the control efficiency for the condenser. Although these combined control efficiency may lead to greater than 98% control, due to the uncertainty of the added control efficiency of in-stack igniters, we believe 98% is a reasonable estimate of these combined controls.

<u>Comment #52:</u> Page 19

Does this section apply to uncontrolled truck loading? If not, suggest combining this section with "Control Device: Vapor Balancing" section.

<u>Response:</u> No, this does not apply to uncontrolled truck loading. It is combined, please see first criteria under vapor balancing.

<u>Comment #53:</u> Page 19

Is this correct? In Appendix A of the Permit, this is "≤ 70% for VOC's and HAP's" and the next section is "n/a".

Which is correct? Appendix A of the Permit or this table in the Memo?

<u>Response:</u> Yes, there is no control efficiency listed for these requirements because they are combined with the controls listed below.

<u>Comment #54:</u> Page 19

What does this mean? Does this mean 70% of loading emissions shall be reported at tanks and 30% at loading rack?

Please provide an example of a scenario that this would occur.

Response: Yes, 70% of loading emissions shall be listed in the tank emissions calculations and 30% of emissions shall be listed in the loading emissions calculations. Please see response to Altamira's Comment #14.

Comment #55: Page 20

This is NSPS requirement. Is it ODEQ's intention to make all flares regardless of applicability to NSPS subject to NSPS standards? If so, does it require performance testing or obtaining a waiver?

60.18 does not apply to enclosed combustion devices.

Response: Yes, it was AQD's intention to make all flares subject to minimum heating values and maximum flare tip velocities of 40 CFR §60.18. No, the requirements listed here do not require performance testing or a waiver.

Correct, 40 CFR §60.18 does not apply to enclosed combustion devices, the requirements were revised to indicate they are only applicable to flares. As a result of this comment, the second criteria was modified to reflect it was applicable to both flares and enclosed combustion devices.

Comment #56: Page 20

Please clarify what is meant by "monitors"?

How does one demonstrate compliance with this? Please provide example/expectations of documents C/E would consider 'in compliance'.

Response: Monitors refers to pilot flame monitoring devices. Facilities should review manufacturer's specifications for specific details regarding proper ongoing maintenance to ensure accuracy and proper calibration. The monitoring wording has been updated for clarity. Because there are so many types of monitoring devices, it is difficult to provide guidance about what is needed to demonstrate compliance.

Comment #57: Page 21

What about applications submitted via the ePermitting System or electronically?

Response: Please see response to DCP comment #20.

Comment #58: Page 31

In the definition of NOM, Enable has requested the term 'electronically' be added as an option to the requirement to maintain a copy of the NOM with the current Authorization to Operate.

<u>Response:</u> AQD agrees that electronic records are a reasonable approach and have modified the definition of NOM to allow for keeping records electronically as part of the permit record.

<u>Comment #59:</u> Appendix A, Page 6

Why the difference in units of measurement for H2S (ppmv vs. ppmw)?

Why the large spread between the two cases? What happens with sulfur between 4ppm and 162ppm?

<u>Response:</u> The term ppmw was a typographical error and was changed to ppmv.

When developing the different scenarios to be modeled, these values were chosen based upon the applicable standards of natural gas sulfur content. AQD chose two scenarios to model based upon available time and resources. Based on the modeling, taking into account impacts from only the dehydration unit, the maximum concentration of H2S in the natural gas that would be in compliance with the H2S ambient standard is 46 ppmv. Including other sources would result in the H2S concentration being reduced.

Additionally, AQD is not aware that limiting the GP-OGF to sweet natural gas imposes significant restrictions in use of the GP-OGF.

Also, please see response to Altamira comment #18.

<u>Comment #60:</u> Appendix A, Page 6

Why the difference in units of measurement for H2S (ppmv vs. ppmw)?

Why the large spread between the two cases? What happens with sulfur between 4ppm and 162ppm?

<u>Response:</u> Please see response to Enable comment #59.

<u>Comment #61:</u> Appendix A, Page 7

Why is there a crude oil reference in the glycol dehy section?

<u>Response:</u> The reference to crude oil was a typographical error and has been changed to natural gas.

<u>Comment #62:</u> Appendix A, Page 7

Where does the 46 ppmw standard come from?

<u>Response:</u> The value was interpolated from the modeled values and given concentrations and should be 46 ppm**v**.

<u>Comment #63:</u> Appendix A, Page 7

Why the difference in units of measurement for H2S (ppmv vs. ppmw)?

Why the large spread between the two cases? What happens with sulfur between 4ppm and 162ppm?

<u>Response:</u> Please see response to Enable comment #59.

<u>Comment #64:</u> Appendix A, Page 7

Where does the 20 ppmw standard come from?

<u>Response:</u> The value was interpolated from the modeled values and given concentrations and should be 20 ppm**v**.

ENABLE'S PERMIT COMMENTS

<u>Comment #65:</u> Page 4

What is the basis for 162 ppmv of total sulfur? Minor source permits have historically been 343 ppmv. Does this mean individual minor source permits will also change?

<u>Response:</u> Please see response to Enable comment #2.

Yes, the default approach will use these limits but facilities always have the option to request higher concentrations based on a site-specific demonstration of compliance with the ambient standard.

<u>Comment #66:</u> Page 4

What is the basis for the decrease from 135 ppmw in 2016 Proposed GP-OGF to 6 ppmw in this draft?

<u>Response:</u> Please see response to Enable comment #3.

<u>Comment #67:</u> Page 4

What is the basis for limiting glycol dehydration units to 4 ppm?

<u>Response:</u> Please see response to Enable comment #4.

<u>Comment #68:</u> Page 5

Would a natural gas throughput limit or glycol pump recirculation rate limit be a specific limitation?

Please clarify.

Response: Please see response to Enable comment #5.

Comment #69: Page 5

What does this mean? How is this different from #10?

What would be examples of something under this condition?

Response: Please see response to Enable comment #7.

Comment #70: Page 8

This sentence was deleted since the 2016 draft; however, it needs to stay because otherwise this can be read that if you are at Class II status that you are also at Class I status. By re-inserting the previous proposed language it clarifies that you can either be Class I or Class II, not both.

Response: The permit allows facilities to select Class II even if emissions are at Class I levels. If a facility chooses coverage as a Class II facility, then it is not a Class I facility. No changes were made as a result of this comment.

The GP-OGF requires facilities to designate Class I or Class II, there is no option for a facility to be both.

Comment #71: Page 8

This is a significant impact to industry. It increases time, resources, costs, and recordkeeping burden by creating an emissions inventory every month for every GP permitted facility.

For example, many companies utilize consultants to prepare emissions inventories. Has ODEQ completed a budgetary analysis to determine the extra costs that this would cause companies to incur? Likewise, the increased workload for companies that do EIs in-house could potentially lead to an increased cost to hire more in-house staff.

Response: Please see response to Enable comment #16.

Comment #72: Page 8

This is also an additional burden on industry.

What is the regulatory basis for requiring this? This is not required in OAC rules.

In the Industry/ODEQ GP-OGF meeting held in 2016 upon initial proposal of this revised GP-OGF, Phillip Fielder stated that Permitting will not make these emissions be included in the permit application. However, by including it C/E is going to want to see these emissions included in our actual emissions.
We do not typically calculate maintenance, start-up, and shutdown emissions as part of Emissions Inventory submittals since there is no regulatory requirement to maintain records of these types of emissions since they are de minimis/insignificant.

Response: Please see response to Altamira comment #13.

Comment #73: Page 8

This citation allows use of EPA Reference Method stack tests which is contradictory to page 16 of this document.

Response: Please see response to Enable comment #25.

Comment #74: Page 9

What is the basis for 162 ppmv of total sulfur? Minor source permits have historically been 343 ppmv. Does this mean individual minor source permits will also change?

Response: Please see response to Enable comment #2.

Comment #75: Page 9

This may not be available for construction permit applications as facility/applicable equipment will not be constructed yet.

Response: The language has been updated to clarify only a compliance certification is required for the NOI to Construct.

Comment #76: Page 9

What would an example of these records be?

Response: The catalytic converter manufacturer often recommends periodic replacement of the oxygen sensor and the records of operation and maintenance would indicate the oxygen sensors were replaced according to manufacturer's specifications.

Comment #77: Page 10

Will AQD approved "default" factors no longer be allowed?

Response: Please see response to Altamira comment #4.

<u>Comment #78:</u> Page 15

Will AQD approved “default” factors no longer be allowed?

<u>Response:</u> Please see response to Altamira comment #4.

<u>Comment #79:</u> Page 16

Formaldehyde, H2CO, and CH2O is used interchangeably throughout the document. Can you make consistent throughout document?

<u>Response:</u> Please see response to Enable comment #34.

<u>Comment #80:</u> Page 16

For emissions calculation purposes, are we not allowed to use EPA Reference Method stack tests as allowed per OAC 252:100-5-2.1(d) and on page 8 above? This is approved method for annual emissions inventory. For ODEQ EI reporting, will we have one methodology for GP-OGF permits and a different methodology for all other permits?

In other words, do we have to use the same method to calculate actual emissions here that we do to calculate PTE as set forth on Page 13 of the Memorandum or can we use actual test data to calculate actual emissions and then compare this to the method used to calculate PTE to show compliance?

<u>Response:</u> For emission calculation purposes for compliance with the permit cap, short-term limits are based on those established in the application as detailed on page 13 of the memorandum. The methods used to establish limits in the application will include EPA Reference Method stack tests.

Yes, Emissions Inventory and demonstration of compliance with the GP-OGF may have different methodologies.

Please also see response to Enable comment #25.

<u>Comment #81:</u> Page 16

Will short-term limits be established for all engines, even the engines that testing is not required?

<u>Response:</u> Yes, please see response to Enable comment #29.

<u>Comment #82:</u> Page 16

Formaldehyde, H2CO, and CH2O is used interchangeably throughout the document. Can you make consistent throughout document?

<u>Response:</u> Please see response to Enable comment #34.

<u>Comment #83:</u> Page 16

Needs to be removed as testing is not done on a continual basis.

<u>Response:</u> Change has been accepted.

<u>Comment #84:</u> Page 16

Assuming this is what is meant by semiannual, please revise in Permit Memorandum section to be clear that semiannual = twice per calendar year.

<u>Response:</u> Please see response to Enable comment #28.

<u>Comment #85:</u> Page 16

Please confirm that an NSPS JJJJ EPA Reference Method test would be considered an equivalent method approved by AQD as is allowed for an initial test. See redline requested changes to paragraph.

<u>Response:</u> Change has been accepted.

<u>Comment #86:</u> Page 17

Enable requested 'electronically' to be added as a specified option for keeping records of NOMs.

<u>Response:</u> Please see response to Enable comment #58.

<u>Comment #87:</u> Page 17

Please clarify that initial tests are not required to be submitted to ODEQ within 60-days of startup as in previous GP-OGF.

<u>Response:</u> This permit does not require testing to be submitted within 60 days of engine startup. Part 2 Section IV.D indicates that initial testing must be **performed** within 60 days of engine startup.

<u>Comment #88:</u> Page 17

This is subjective. Please remove.

<u>Response:</u> Change has been accepted.

<u>Comment #89:</u> Page 22

Please clarify. How do we notify? Self-disclosure? As currently written, this could be a C/E issue.

Also, if it is semi-annual testing, why are we notifying within 30-days of the end of the quarter? Need to clearly define semiannual period or when notification is required to be submitted.

Response: The requirements for maintain a record is a compliance and enforcement issue. The notification would be a letter including reasons why testing could not be conducted. Additionally, the wording in Part 2 Section IV.O has been adjusted to the end of the semi-annual period.

Comment #89: Page 22

Please clarify that if we are assuming continuous operation, we are not required to maintain operating hour records.

Response: Part 2 Section IV.C and P indicate keeping records of hours of operation is only required for any engine where hours of operation are used to calculate annual emissions.

Comment #90: Page 22

If this is how we are showing compliance with the facility-wide emissions cap, should this be actual emissions or PTE? If it is supposed to be actual emissions, why are we required to use maximum dry gas rate and other PTE based inputs? If it is PTE, why would we need to maintain emissions monthly and on a 12-month rolling total?

Response: This section specifies methodologies for calculation of emissions from glycol dehydration units for compliance with the cap. These methodologies address dry gas flow rate and option (4) allows for use of actual throughput related to dry gas flow rate. Other parameters not otherwise specified in this paragraph also allow the use of values during normal operating conditions. The compliance method specified here does rely on some PTE inputs when doing glycol dehydrator emissions for compliance with the cap. This was initially created to reduce the recordkeeping requirements related to emissions from dehydration units. Dehydration emissions are a portion of total facility emissions and are needed for a full demonstration of compliance with the cap.

Please also see response to DCP comment #5.

Comment #91: Page 22

What if the dehy does not operate continuously? See comment directly above.

Response: The GP-OGF does not require records for when the glycol dehydrator is not operating. Please see response directly above.

Comment #92: Page 23

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

Response: Comment has been accepted.

Comment #93: Page 24

Same comment above. Are we required to show compliance using PTE or actual emissions?

Response: Please see response to Enable comment #90.

Comment #94: Page 24

Revised to be consistent with A. above.

Response: Comment has been accepted.

Comment #95: Page 24

If this is how we are showing compliance with the facility-wide emissions cap, should this be actual emissions or PTE? If it is supposed to be actual emissions, why are we required to use maximum dry gas rate and other PTE based inputs? If it is PTE, why would we need to maintain emissions monthly and on a 12-month rolling total?

Response: Please see response to Enable comment #90.

Comment #96: Page 24

What if the amine unit does not operate continuously? See comment directly above.

Response: Please see response to Enable comment #91.

Comment #97: Page 24

Suggest revising to 4 ppm or less of H_2S in natural gas as opposed to a modeling requirement. The 4 ppm or less of H_2S in natural gas should show compliance with the ambient air standard. See redline requested changes to paragraph.

Response: Comment has been accepted in Part 2 Section VI.B.

<u>Comment #98:</u> Page 24

D. below states that we can use thermal devices, but this condition states “flare”. Please clarify.

<u>Response:</u> Flare has been changed to thermal device to be consistent with the applicable rule.

<u>Comment #99:</u> Page 24

This section is duplicative of E.

<u>Response:</u> No, this is a separate regulatory requirement. This section is applicable for certain situations and applies; some requirements from Appendix A may overlap.

<u>Comment #100:</u> Page 24

C. above states that we can only use a flare, but this condition states “thermal devices”. Please clarify.

<u>Response:</u> Please see response to Enable comment #98.

<u>Comment #101:</u> Page 27

Revised to be consistent with A. above.

<u>Response:</u> Comment has been accepted.

<u>Comment #102:</u> Page 29

Misnumbered sections.

<u>Response:</u> Change has been made.

<u>Comment #103:</u> Page 34

Include option for electronic record keeping.

<u>Response:</u> Section has been updated to include electronic record keeping.

<u>Comment #104:</u> Page 34

Misnumbered sections.

<u>Response:</u> Change has been made.

<u>Comment #105:</u> Appendix A, Page 38

Need to remove redundancy. Either remove Control Device section from Permit or Memorandum.

Response: The memorandum is not enforceable and is used to explain the conditions set forth in the permit. We do not view this as being redundant.

Comment #106: Appendix A, Page 38

This is not consistent with the last sentence of the above paragraph which states up to 93% control. Please revise to not to exceed 93%.

Response: Please see response to Enable comment #45.

Comment #107: Appendix A, Page 38

According to Specific Condition in Permit below, this is "twice per calendar year". Please clarify.

Is there an operating hour threshold in each semiannual period for which testing is required?

Response: Please see response to Enable comment #46.

Comment #108: Appendix A, Page 38

This is not consistent with the last sentence of the above paragraph which states that CO must be less than H2CO.

H2CO control efficiency needs to be less than or equal to CO control efficiency. Is there an example where you can take up to 93% control for H2CO as described here?

Response: Please see response to Enable comment #47.

Comment #109: Appendix A, Page 39

Below control devices don't specify whether they are hooked to still vent or flash tank. Some are just for still vent typically, some are just for flash tank typically, and others can be both. Need to separate glycol dehy units from amine units.

Response: Please see response to Enable comment #48.

Comment #110: Appendix A, Page 39

Amine Units do not typically have condensers installed as control devices. Need to specify below which control device applies to amine units and glycol dehy units or separate into different section.

<u>Response:</u> Please see response to Enable comment #49.

<u>Comment #1118:</u> Appendix A, Page 39

Why must you have a flash tank? Flash tank emissions are not routed to the condensers, only still vent emissions. There are instances where a glycol dehy does not have a flash tank, but does have a condenser. Are those dehys not equipped with a flash tank unable to obtain a GP-OGF?

<u>Response:</u> Please see response to Enable comment #50.

<u>Comment #112:</u> Appendix A, Page 39

Above, it states to calculate using GRI-GLYCalc.

Based on GRI-GLYCalc controlled emissions, this can be higher than 98%. Sometimes up to >99% when utilize the condenser/combustion device controlled emissions selection in GRI-GLYCalc. For example, GRI-GLYCalc will use a 90% control from the condenser and then take 95% of the remaining emissions due to the combustion. This leads to an overall reduction efficiency of greater than 98%.

<u>Response:</u> Please see response to Enable comment #51.

<u>Comment #113:</u> Appendix A, Page 40

Does this section apply to uncontrolled truck loading? If not, suggest combining this section with "Control Device: Vapor Balancing" section.

<u>Response:</u> Please see response to Enable comment #52.

<u>Comment #114:</u> Appendix A, Page 40

Is this correct? In Section VI. Of the Memo, this is "n/a" and the next section is "≤ 70% for VOC's and HAP's".

Which is correct? Section VI. Of the Memo or this table in the Permit?

<u>Response:</u> Please see response to Enable comment #53.

<u>Comment #115:</u> Appendix A, Page 40

What does this mean? Does this mean 70% of loading emissions shall be reported at tanks and 30% at loading rack?

Please provide an example of a scenario that this would occur.

<u>Response:</u> Please see response to Enable comment #54.

<u>Comment #116:</u> Appendix A, Page 41

This is NSPS requirement. Is it ODEQ's intention to make all flares regardless of applicability to NSPS subject to NSPS standards? If so, does it require performance testing or obtaining a waiver?

60.18 does not apply to enclosed combustion devices.

<u>Response:</u> Please see response to Enable comment #55.

<u>Comment #117:</u> Appendix A, Page 41

Please clarify what is meant by "monitors"?

How does one demonstrate compliance with this? Please provide example/expectations of documents C/E would consider 'in compliance'.

<u>Response:</u> Please see response to Enable comment #56.

<u>Comment #118:</u> Appendix B, Page 42

Is it 6 ppmw or 10 ppmw?

<u>Response:</u> Please see response to Mark Webster comment #1.

<u>Comment #116:</u> Appendix C, Page 43

Need to remove redundancy. Either remove definition sections from Permit or Memorandum.

<u>Response:</u> Please see response to Enable comment #105.

<u>Comment #117:</u> Page 44

Include option for electronic record keeping.

<u>Response:</u> Section has been updated to include electronic record keeping.

<u>5 - PLAINS PIPELINE COMMENTS, dated October 15, 2020</u>

<u>Comment #1</u>

Reduction of Allowable H2S in Crude Oil from 135 ppmw to 6 ppmw.

<u>Comments:</u> <u>Reduces Flexibility.</u> The GP-OGF is a general permit that is intended to provide- and historically has provided-flexibility and an expedited permitting process to

facilities that could meet certain emission thresholds and other requirements. The significant drop in allowable H2S in the draft GP-OGF as compared to the prior versions of the GP-OGF, however, will dramatically reduce the usefulness and availability of the general permit for facilities that store different types of crude oil.

Concerns with Underlying Modeling. It is our understanding that this new limitation for H2S was based on the modeling conducted included as Appendix A to the draft GP-OGF. We have concerns about whether this modeling accurately reflects real world conditions. For example, there are certain assumptions that were not explained in the Appendix A modeling: How was the H2S concentration in the liquid converted to a vapor concentration? What distance to the property line was assumed? Are the assumptions of 99 tpy reasonable for a single floating roof tank when those emissions would more accurately reflect a large tank farm facility spread over a wide area? These assumptions are crucial to determine whether the modeling accurately reflects actual facility conditions and whether it is appropriate to reduce the allowable H2S threshold.

Modeling Alternative. Instead of a fixed reduction, Plains recommends that DEQ adopt a sliding scale based on registered emissions or the type of equipment being authorized. We would note that Texas did something similar to this in their Non- Rule Standard Permit for Oil and Gas Handling and Production Facilities, which includes impact analysis look-up tables based on parameters such as emission release height and distance to nearest off-property receptor as well as the ability to use screening modeling or dispersion modeling to demonstrate compliance. This more flexible emissions modeling and analysis allows for modeling that better reflects the conditions at the actual facility seeking coverage under the general permit.

Clarification of Liquid Phase. Regardless of the H_2S threshold, Plains recommends that the draft GP-OGF clarify that in all instances the ppmw limit on H_2S pertains to the liquid phase and not the vapor phase. For example, Appendix B to the draft GP-OGF (page 42) states:

> If the average H_2S concentration is no more than 6 **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 6 **ppmw** H_2S limit. (emphasis added).

Plains recommends that the "ppmv" should be corrected to "ppmw."

Response: Flexibility in developing a general permit is a goal, however regulatory requirements must be addressed that will inherently limit the flexibility of the general permit. Setting up the GP for compliance with ambient standards is a particularly difficult task when the general permit must consider worst-case assumptions in the model. At this time, AQD does not have information that indicates this requirement will dramatically reduce the usefulness and availability of the general permit for facilities that store different types of crude oil.

With regard to the request for a sliding scale, please see the response to Altamira comment #18.

The reference to 6 ppmv on page 42 in the General Permit was in error and has been corrected to 6 ppmw.

Comment #2

Estimate of Emissions Include Maintenance, Startup and Shutdown ("MSS") Activities

Comment: MSS Activities Should be Clarified. With DEQ proposing to include MSS activities within the GP-OGF emission estimates, Plains requests that the types of MSS activities that DEQ plans to include be clarified. What qualifies as MSS activities has varied considerably from state to state. It would therefore be helpful for DEQ to provide its interpretation of the types of MSS activities that should be evaluated in connection with the GP-OGF, and the regulated community and the public should have an opportunity to provide comments on that interpretation.

De Minimis Threshold or Activities. A de minimis emissions threshold or a clarification of activities that are considered to be de minimis would also be helpful so that the regulated community can better understand and comply with DEQ's MSS requirements under the GP-OGF.

Response: The GP-OGF has been updated to better clarify sources and/or activities expected to have MSS related emissions. ODEQ hopes this better defines these emissions. For De Minimis activities, please see Response to Altamira comment #3.

Comment #3

Statement in Memorandum - "However, since PSF [Petroleum Storage Facilities] > 300,000 barrels are major sources and ineligible for the permit, they are not included."

Comment: Inaccurate Statement regarding Petroleum Storage Facilities. The above statement on page 16 of the Memorandum (Section G, "Fugitive Emissions Source") is inaccurate. There are many Petroleum Storage Facilities with a total storage capacity greater than 300,000 barrels that are not major sources of air emissions. The conclusion of what is a major source or what can qualify for a general permit should be based on the appropriate potential to emit calculations for the facility and not exclusively limited to tank capacity. Furthermore, since GP-OGF qualifying facilities are permitted to be synthetic minor sources, there is no reason that the capacity should be limited to 300,000 barrels to be a minor source. Plains therefore recommends the above statement be clarified or struck from the draft.

Response: Please see response to Altamira comment #12.

6 - THE PETROLEUM ALLIANCE COMMENTS, dated October 15, 2020

Comment #1

The Requirement to Calculate Actual Facility-wide Emissions, as a Monthly, 12-month Rolling Total Presents a Significant Burden

The Alliance requests that the Department reconsider this provision as it will be a significant increase in the regulatory burden to industry with little-to-no environmental benefit. Companies are already required to calculate actual facility-wide emission totals and submit an emission inventory annually to the Department. Compiling and submitting an annual emission inventory is a significant exercise which requires substantial time and resources to complete, often utilizing internal staff as well as external consultants. This requirement essentially amounts to the creation of an emission inventory on a monthly basis, and the Alliance is concerned this requirement will cause companies to incur costs that have not been fully contemplated by the Department. For example, $10,000 annual emission inventory costs would become $120,000 based on calculating emissions on a 12 month rolling timeframe. Additionally, the 1989 EPA "Guidance on Limiting Potential to Emit in New Source Permitting" document that the Department references as justification for the monthly and 12-month rolling facility-wide emissions calculations only discusses the need for limits on production and operation on a monthly and 12-month rolling basis, not emissions calculations. Based on this, the Alliance believes compliance with the emission cap in this permit can be adequately demonstrated through the existing annual emission inventory requirement, along with periodic monitoring, work practices, and maintaining records of production and operating parameters such as throughput and hours of operation. If a regulated entity is complying with the production and operating rates submitted in the permit application, why would we need to calculate the emissions on a monthly basis in order to show compliance? Regulated entities already track the production and operating parameters on a monthly basis, the burden lies in having to calculate the emissions monthly. The Alliance respectfully requests, that regulated entities have the option to list production limits in the GP-OGF as part of the compliance demonstration, in lieu of, 12 month rolling emission calculations

<u>Response:</u> Please see responses to Altamira comment #5 and DCP comment #4. Monthly emission calculations are not comparable to submittal of an annual Emissions Inventory. In the response to Altamira comment #5, an alternative approach using throughputs for compliance was established.

<u>Comment #2</u>

Concerns with the Inclusion of Maintenance, Startup and Shutdown (MSS) Emissions in the Facility-side Emissions Cap

The Alliance believes the requirement to include MSS emissions in the facility-side emissions cap is inconsistent with previous guidance provided by the Department and is in conflict with OAC 252:100 Appendices H and J and 40 CFR Part 70.2. Previous guidance from the Department, including the Potential to Emit Fact Sheet, dated June 2, 2003, and the Potential to Emit Guidance Document, dated February 7, 2012, state the following:

"A final step in identifying emission units to include in calculating PTE is to them delete those activities identified as a "trivial activity" at OAC 252:100, Appendix J. Emissions from these activities need not be counted in determining your PTE."

40 CFR Part 70.2 states:

"(2)….The fugitive emissions of a stationary source shall not be considered in determining whether it is a major stationary source…unless the source belongs to one of the following categories…"

Since sources covered by the GP-OGF are not among the listed sources under 40 CFR Part 70.2 definition of a major source, fugitive emissions cannot be considered when determining Title V applicability. This is also indicated and shown in both of the Department's Potential to Emit documents listed above.

Beyond blowdowns, which is specifically included in OAC 252:100 Appendix J as a de minimis activity, the draft GP-OGF does not contain any other examples of MSS activities. The Alliance is concerned that many operators, if not most, have not been accounting for or tracking MSS activities as part of their permit or applicability determinations and are not currently set up to do so. Moreover, the requirement to comply with the new GP-OGF within 24 months (discussed in more detail below) could cast doubt on a facility's ability to qualify for continued coverage under the new GP-OGF, resulting in a significant re-permitting burden. The Alliance respectfully requests that references to MSS emissions be removed from the permit.

Response: Please see responses to Altamira comments #3 and #13 and Enable comment #41.

Comment #3

All Flares or Enclosed Combustion Devices should not be Required to meet 40 CFR 60.18 Requirements for Minimum Heating Value and Maximum Flare Tip Velocities

The Alliance does not believe it is appropriate, nor the Department's intent, that all flares and enclosed combustion devices meet the requirements of 40 CFR 60.18, unless specifically required by a New Source Performance Standard. The Alliance supports a requirement that a flare or enclosed combustion device be operated with a flame present at all times by having a continuous pilot flame or an automatic ignition system, along with a requirement to have a monitoring device to detect the presence of a flame when gas streams are present. Additionally, 40 CFR 60.18 does not apply to enclosed combustion devices, only flares.

Response: It was AQD's intent to have all flares meet the requirements of heating value and flare tip velocities in 40 CFR §60.18. These requirements are assumed to be a minimum requirement for a properly operated flare.

In relation to enclosed combustion devices, please see Enable comment #55.

Comment #4

The H2S Limits for Coverage Under the GP-OGF are too Restrictive when a Flare or Enclosed Combustion Device is Utilized as a Control Device

The Alliance does not see support within the modeling conducted by the Department to justify lowering the H_2S limits to 6 ppmw (from 135 ppmw) for crude oil and 4 ppmv (from 162 ppmv or 343 ppmv) for natural gas, particularly when a flare or enclosed combustion device is being used as a control device. While the GP-OGF is intended to provide flexibility and expedite permitting for facilities with the same or substantially similar operations and activities, the Alliance believes these limits would drastically decrease the ability of industry to utilize the GP-OGF for facilities that store different types of crude oil or process gas with an H_2S content greater than 4 ppmv. The Alliance requests that the Department continue to utilize the previous limits when flares, enclosed combustion devices, or other combustion devices are being utilized for emissions control. The Alliance is open to and would appreciate further discussion should the Department feel there is a basis for the more restrictive limits.

Response: Not all facilities are required to control emissions from storage tanks using a flare or enclosed combustion device. Modeling has to be based on worst-case scenarios, which was used to establish the concentrations indicated. Additionally, please see responses to Altamira comment #18, Enable comment #2, and Enable comment #4. The 4 ppmv H_2S limit is only applicable to gasses treated by an amine or glycol dehydration unit.

Comment #5

Produced Water Storage Vessels are not Effluent Water Separators

As currently defined, effluent water separator could be interpreted to include produced water storage vessels. A letter from the Department to the Mid Continent Oil and Gas Association of Oklahoma, dated June 5, 2007, explicitly states that “produced water tanks that store water associated with the production, gathering, separation and processing of crude oil would not be considered an effluent water separator”. The Alliance requests that this be clarified in the GP-OGF.

Response: Please see response to Altamira comment #2.

Comment #6

Including VOC Emissions from the Flare or Enclosed Combustion Device with Storage Tank Emissions Conflicts with DEQ’s Emission Inventory Guidance

The Alliance is concerned that the Department’s emission inventory guidance conflicts with the GP-OGF requirement to include the VOC emissions from the flare or enclosed combustion device with the VOC emissions from the storage vessels. The emission inventory guidance requires the emissions to be reported separately. This permitting guidance has not been clearly articulated to industry and there may be circumstances where companies have utilized the emission inventory guidance in determining the potential to emit from storage vessels. The Alliance requests that the Department utilize one consistent approach across both the permitting and emission inventory sections to avoid future confusion. The Alliance further requests that if the Department intends to stay with this requirement to combine the VOC emissions at the storage vessels, then the Department make it clear that applicability determinations made under the emission inventory or previous agency guidance need not be re-evaluated.

Response: For emission units that use a control device, emissions released at the control device are a part of the emission units' potential-to-emit. For an emission unit that has a specific limit, the emissions released at the control device need to be included for compliance with that limit.

Comment #7

Adding Loading Loss Emissions to Storage Tank Emissions Could Result in Noncompliance with current federally enforceable limits

Similar to the discussion above, the Alliance is concerned that guidance has been inconsistent or unclear regarding the inclusion of loading loss emissions with storage vessel emissions when vapor collection systems are being utilized. There is no regulatory guidance in NSPS OOOOa that requires the inclusion of emissions not generated by the tanks in the tank emissions estimates.

40 CFR Part 60.5365a (e) The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this subsection.

AP-42 Section 7, is a generally accepted methodology for calculating tanks and there is no discussion on the inclusion of emissions generated by loading in the estimation of tank emissions. In fact, AP42 contains a separate section for the calculation of loading emissions and considers them a separate process. Therefore, the Alliance does not believe loading losses should be included in the tank emissions and in demonstrating compliance with the requested tank limits of less than 6 tpy.

Response: Please see response to Altamira comment #14.

Comment #8

Vapor Collection Appears to be Required for all Crude/Condensate Loading Operations in the GP-OGF

The way the draft GP-OGF is currently worded, it appears that vapor collection is required for all loading operations. Based on communication with the Department, the Alliance understands that this was not the intent. The Alliance would appreciate clarification that vapor collection for loading is not required, and that the requirements set forth in the table in Appendix A, as well as Section VI of the Memorandum, only apply if vapor collection is utilized to remain under the facility-wide emission cap.

Response: Appendix A does not establish requirements for all facilities but only those facilities that use those types of controls. The GP-OGF does not mandate that loading operations use vapor collection.

Comment #9

It Appears that Facilities with VOC Loading Greater than 40,000 gallons/day are not Eligible for Coverage, Resulting in Minor Source Permits for Most New Wells

The Alliance is concerned with the wording in the draft GP-OGF that would appear to exclude from coverage most new wells that do not produce to a pipeline and require truck loading. Based on communication with the Department, however, the Alliance understands that this does not apply to petroleum stored, processed, treated, loaded, and/or transferred at a drilling or production facility prior to lease custody transfer. The Alliance requests that the Department make that exemption clear in the GP-OGF. The Alliance additionally requests that the GP-OGF allow for facilities that may load more than 40,000 gallons per day with the provision that the requirements of OAC 252:100-37-16 would apply.

Response: Production facilities are not subject to OAC 252:100-37-16 due to the exemption in OAC 252:100-37-4(b), "Petroleum or condensate stored, processed, treated, loaded, and/or transferred at a drilling or production facility prior to lease custody transfer is exempt from this Subchapter." The majority of the facilities covered under this GP-OGF would not be subject to OAC 252:100-37-16. The DEQ has initiated a rule change to clarify that compressor stations are not applicable to these requirements.

Comment #10

The Requirement to Comply with the New GP-OGF within 24 months may Result in Significant Re-permitting and Potentially Affect the Compliance Status of Facilities Permitted Under the Previous GP-OGF

Facilities currently permitted under the existing GP-OGF were not permitted with the newly required MSS, liquid loading limitations, H2S limits, Class I/II criteria, and emission control efficiency criteria. As a result, the Alliance is concerned that many facilities may no longer qualify for continued coverage under the GP-OGF, resulting in a significant burden to re-permit at considerable cost, and may also result in questions regarding a facility's compliance status. The Alliance requests that the new GP-OGF requirements only apply to new or modified facilities requesting coverage under the GP-OGF, and that facilities operating under the existing GP-OGF be allowed to continue operating under the 2008 version until the facility is modified or otherwise requires re-permitting.

Response: ODEQ has addressed each listed concern below but does not believe the items listed create any undo burden for a 24-month implementation.

MSS inclusion – there are no new specific requirements requiring any new physical change or process change. Emissions associated with MSS events simply need to be included in calculations to demonstrate CAP compliance
Liquid loading limitation – the GP-OGF does not contain any new loading limitations
H2S Limits – the new permit does contain reduced H2S limits. However, after reaching out to the industry it has been confirmed that the new limits will not impose a significant burden or reduction in GP-OGF usage. It should be noted that the GP-OGF is not designed for every facility.
Class I/II criteria – this criteria was incorporated specifically to assist industry. ODEQ believes industry would want to implement this sooner than later.
Emission control efficiency – new control efficiency limits are included in the new GP-OGF. However, most of these limits are limits ODEQ has historically accepted and not new. This GP-OGF has just been updated to specifically list the criteria for better enforceability and help industry understand the exact criteria allowed. ODEQ expects most existing facilities will meet the criteria upon issuance.

Comment #11
Engine Testing Performed in Accordance with 40 CFR 60, Subpart JJJJ Should Satisfy both Initial and Semi-annual Testing Requirements

In many cases, an initial test is performed utilizing a portable analyzer as the JJJJ test cannot be scheduled until after the 60-day due date, due in part to the 30-day test notification requirement. The Alliance requests that in those circumstances, the JJJJ test should also be sufficient to satisfy the semi-annual requirement for the subsequent test. Alternatively, initial testing could be required within the first 180 days of startup. This will allow the most efficient use of testing resources and be in alignment with EPA testing requirements as well as language in this draft permit stating: "In the first year of operation, any engine started after March 31st only requires one test regardless of hours operated."

Response: Yes, EPA reference method tests are allowed for the initial test and may be counted as the first semi-annual test of an engine. Additionally, please see response to Enable comment #85. The initial testing requirement has been changed to 180 days of startup.

Comment #12
Storage Tanks Can Only Claim 98% Capture Efficiency in Proposed GP-OGF

The proposed GP-OGF does not allow storage tanks to claim capture efficiencies greater than 98%. Specifically, storage tanks that are controlled using a closed-vent system (CVS) that is subject to LDAR or certified by an engineer in NSPS Subpart OOOO or OOOOa are required to meet 100% capture efficiency. The Alliance requests that language be added to recognize and allow these types of storage tank capture and control methods.

Response: Please see response to Altamira comment #7.

7 - Enable Midstream – 2nd Set, dated September 14, 2020

I'm unsure of the current status of the proposed new GP-OGF, but Enable Midstream would like to take this opportunity to make a comment if still possible. Specifically, on page 9 of the proposed GP-OGF, Section IV - Emissions, A - Potential to Emit, last sentence in the paragraph states *"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."* Additionally, there are several instances in the Memorandum and Permit where start-up and shutdown emissions are indicated to be included in determining facility-wide annual emissions. Our concern with blowdown related emissions being included in PTE was brought up during the workshop ODEQ put on several months ago and we were told that it was done to appease EPA.

Enable is unable to find anything within OAC or ODEQ published guidance documents that supports the assertion that blowdowns should be included in determining PTE. In fact, it would appear that OAC and ODEQ guidance documents show the exact opposite. Starting with the addition of Appendix J to OAC 252:100 in 1998, publication of ODEQ's Potential to Emit Fact Sheet dated June 2, 2003, and publication of ODEQ's Potential to Emit Guidance Document dated February 7, 2012, it has been ODEQ's position and our understanding that blowdowns are not to be included in determining PTE.

OAC 252:100 Appendix J (added to OAC in 1998)
When the proposed addition of Appendix J was first presented at the Air Quality Council meeting on 10/21/97 the specific language for blowdowns was the exact same as what was previously (and currently) shown in Appendix H:

- Emissions from the blowdown of compressors or other vessels containing natural gas or liquid hydrocarbons for the purpose of maintenance due to emergency circumstances.

Based on a December 19, 1997 ODEQ Memorandum to the Air Quality Council from David Dyke Interim Director Air Quality Division, additional revisions were proposed at the December 16, 1997 meeting which specifically included changing the wording about blowdowns in Appendix J, which is now codified in OAC. The changes redlined below show the exact intent of the clarified wording to specifically include emissions from the depressurization during startup, shut down, maintenance or emergencies of compressors (effectively making two distinct sentences, first half dealing with compressors and second half dealing with other vessels):

- Emissions from the ~~blowdown~~ depressurization during startup, shut down, maintenance or emergencies of compressors or other vessels containing natural gas or liquid hydrocarbons for the purpose of maintenance due to emergency circumstances.

ODEQ Potential to Emit Fact Sheet dated June 2, 2003
The last two sentences of the last paragraph on page 2 under Section 1 (Identify all emissions sources) states the following:

<u>Response:</u> Please see response to Altamira comments #3 and 13, DCP comment #9, Enable 1st Set comments #41, 42, and 72, and Petroleum Alliance comment #2.