OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

GUIDANCE DOCUMENT **February 9, 2016**

SUBJECT: Guidance on Estimating Flashing Losses and Guidance on Determining Representative Process Stream Composition Data for Oil and Gas Facilities

SECTION I. INTRODUCTION

The purpose of this guidance document is to update the Air Quality Division's (AQD's) "Calculation of Flashing Losses/VOC Emissions from Hydrocarbon Storage Tanks," issued on July 19, 2004. These revisions were prompted by a number of developments, including the establishment of control requirements and work practice standards for *storage vessel affected facilities* under New Source Performance Standards (NSPS), Subpart OOOO. This document is also intended to provide general guidance on characterizing process streams (e.g., natural gas, pressurized condensate, crude oil, etc.) to provide sufficiently representative data for the purpose of estimating emissions for new and existing facilities.

This document is intended only as general guidance. For special or difficult situations and problematic facilities, owner/operators are encouraged to contact the AQD permitting section for specific guidance.

What is a VOC?

VOC is an abbreviation that stands for Volatile Organic Compound. VOCs are components of hydrocarbon liquids such as crude oil and condensate. VOC means any compound of carbon (excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate) which participates in atmospheric photochemical reactions resulting in the formation of tropospheric ozone. In addition, there is a list of organic compounds that are excluded from being VOCs because they have negligible photochemical reactivity such as methane, ethane, and fluorinated and chlorinated hydrocarbons. The list of chemicals excluded from the definition of VOC is found in 40 CFR 51.100(s)(1). The Oklahoma Administrative Code (OAC) includes a definition of VOC in OAC 252:100-1-3.

SECTION II. BACKGROUND DISCUSSION AND GENERAL APPROACH

To estimate emissions from oil and gas facilities, the owner/operator of a facility must be able to characterize the composition of gas and liquid streams containing volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) with sufficient accuracy to determine applicability of state and federal regulations, and to select appropriate permit limits and emission controls. The intent of this guidance is to make it possible for owner/operators to have flexibility when selecting a method to characterize emissions, in order to achieve a satisfactory balance of cost and benefits. In certain cases, a simple, inexpensive method may be entirely appropriate, especially where that method has built-in conservative bias that will lead to an overestimate of

What are flashing losses and how do they contribute to VOC emissions from hydrocarbon storage tanks?

There are three types of emissions from hydrocarbon storage tanks: working losses, breathing losses, and flashing losses. All three types of losses generate gaseous emissions containing VOCs. Flashing losses occur when a liquid with dissolved and/or entrained gases goes from a higher pressure to a lower pressure. As the pressure on the liquid drops, some of the lighter compounds dissolved in the liquid are released or "flashed" and some of the compounds that are liquids at the initial pressure and temperature transform from a liquid into a gas/vapor and are also released or "flashed" from the liquid. As these gases are released, some of the heavier compounds in the liquids may become entrained in these gases and will be emitted with them. Flashing losses (and associated VOC emissions) are greater as the pressure drop increases and as the amount of lighter hydrocarbons in the liquid increases. The temperature of the liquids in the storage tank will also influence the amount of flashing losses. These flashing losses are then either vented to the atmosphere through the tank's pressure relief valve, hatch, or other opening, or they may be vented to a capture and/or control system. Flashing losses from hydrocarbon storage tanks include emissions of VOCs, HAPs, and toxic air contaminants (TACs).

emissions. In other cases, an owner/operator will need to use a more complex, rigorous method, and that method may require more expensive sampling of process streams, more detailed chemical analyses, and more time and expertise devoted to emissions estimations. Where the conservative bias of a simple method may indicate unacceptably high emissions, a more rigorous (but more complex and more expensive) alternative method may yield a more accurate, lower estimate of emissions.

It is the philosophy of the AQD to empower the owner/operator of a facility to use whatever method he or she believes is most appropriate, providing that the method chosen is adequate to the task of providing an estimate of emissions that both parties can be reasonably confident is sufficiently accurate.

Where do flashing losses from hydrocarbon storage tanks occur?

The main areas where tank flashing losses (and associated VOC emissions) occur are from storage tanks (at atmospheric pressure) located downstream from a pressurized vessel or process stream. This occurs at:

- Wellhead sites,
- Tank batteries,
- Compressors stations, and
- Gas plants.

Flashing losses also occur when natural gas lines are "pigged" (physically purged of condensate and water) and the recovered liquids are then sent to a storage vessel.

What are working and breathing losses from hydrocarbon storage tanks?

Working and breathing losses (and associated VOC emissions) from unpressurized hydrocarbon storage tanks occur in addition to flashing losses. Working losses are due to displacement of the vapors within the storage tank as a tank is filled. Breathing losses are due to displacement of vapors within the storage tank due to changes in the tank temperature and pressure throughout the day and throughout the year. Working and breathing losses can be estimated with the latest EPA TANKS program or its equivalent.

SECTION III. AN ITERATIVE APPROACH

Each facility will have a number of emission units and, for each type of unit, there may be a number of alternative methods which may be chosen to estimate emissions. For each unit, the owner/operator should follow a stepwise process, leading to an appropriate emissions estimate. For some units (e.g., fugitive emissions from valves, fittings, etc.), the process should be fairly simple. For other units (e.g., atmospheric storage tanks), the process may be more complex. An outline of the process is provided below.

Steps

1. Select a preliminary method for estimating emissions.
2. Gather data that are both (a) sufficiently representative of the facility and (b) adequate in providing all of the input parameters used in the estimation method chosen in Step 1.
3. Evaluate the data collected to determine whether the estimation method selected in Step 1 and data gathered in Step 2 are appropriate in combination.
4. Estimate emissions.
5. Apply an appropriate safety factor.
6. Evaluate the estimate with regard to regulatory thresholds, data quality, and reasonability. If the estimate is determined to be inadequate, consider selecting a different method for evaluation and repeat these steps.

This guidance document is intended to constrain the use of these estimation methods to ensure that, where systematic errors are introduced by the choice of estimation method, those errors result in conservative (high) estimations of emissions. Reducing this systematic error will typically require additional data to be collected and, often, more sophisticated estimation methods to be used.

When providing composition data of any type, it is essential that the applicant identify the source of the data. If the data provided were obtained from a nearby facility (e.g., another wellhead in the same well field), then the applicant must indicate the location were the sample was obtained. If data are submitted for a new facility and no site-specific data are available, it is essential that the applicant explain how the parameters were estimated. The following discussion presents guidelines for gathering and submitting representative data from (1) new facilities, prior to first construction, and (2) from facilities which are already operating.

New Facilities – Prior to First Construction

Estimating emissions prior to the construction of a new facility represents an obvious challenge, because there is no facility-specific data on the composition and characteristics of the gas and hydrocarbon liquids that will be produced and/or processed. It is the policy of the Oklahoma DEQ to provide the owner/operator considerable latitude in predicting the composition of various process streams and in estimating emissions prior to first construction, provided that the applicant provides a complete description of the assumptions used and the methods employed. In addition, it is essential that, when using data from a similar facility, the applicant indicate the location of the reference facility, the date the sample was collected, and a justification why the data set used is considered likely to be representative of the new facility. In some cases a single sample from a similar facility may be sufficient. In other cases, an applicant may choose to use an average value from a number of similar facilities. No matter which method is selected, it is critical that the applicant provide a complete description of that method.

Facilities Currently Operating

For existing facilities, the owner/operator will have access to additional facility-specific data. For oil and gas facilities that produce hydrocarbon liquids and natural gas for sale, the following data are required no matter which method is chosen by the applicant to estimate flashing emissions.

- The API gravity of hydrocarbons liquids produced for sale.
- The gas composition from the facility.
- The operating pressure and temperature of the process unit (often, but not always, a separator) immediately upstream of the atmospheric storage tanks.
- The production rate for hydrocarbon liquids and for natural gas.

Even if some of these data (e.g., API gravity of the hydrocarbon liquids) are not used in estimating emissions from the facility, the applicant is required to provide this information.

In addition to this information, the applicant must provide the appropriate facility-specific data required by the DEQ to support the use of whichever estimation method has been chosen to estimate flashing emissions.

SECTION IV. ESTIMATION METHODS AND INPUT PARAMETERS

An applicant may seek prior approval from the AQD to use any method to estimate emissions that the applicant thinks is suitable. While any reasonable method may ultimately receive approval for use, the AQD is more familiar with the following methods and the use (and restrictions on the use) of these methods is described in some detail in this guidance document:

1. The Vasquez-Beggs Equation
2. E&P Tank
3. Laboratory Gas-Oil Ratio (GOR)
4. Process Simulation Software
5. Direct Measurement

The order in which the estimation methods are listed is, generally, from the simplest method, requiring the least amount of site-specific testing to the most demanding method, requiring the greatest effort in gathering facility-specific data. Listing these methods in this order does not mean that the AQD prefers the Vasquez-Beggs Equation over any other approach. On the contrary, the AQD would prefer that applicants estimate emissions using direct measurement. However, the AQD recognizes that some applicants may prefer to begin with a simple method (with appropriately conservative defaults) before moving to more complex methods if warranted. On the other hand, other applicants may already plan to gather certain site-specific data (for example, detailed process stream composition data to aid in process design) and, where those data are available, the applicant may move directly to a more complex estimation method (e.g., a process simulator).

Whichever method is selected, the applicant must provide all supporting data used to calculate the emissions, including identification of the calculation method and specific constraints, a description of the sampling methods and conditions, and copies of lab sampling analyses. If any parameter used in estimating emissions is not based on facility-specific data (or on an AQD default value), the applicant must communicate that fact clearly. In addition, the applicant must provide a justification why the non-site-specific data is appropriate for use.

Facility type: oil or gas wellhead site, compressor station, or gas plant?

The original flashing guidance document was developed primarily for compressor stations. Compressor stations typically are equipped with unheated inlet separators and, for many such facilities, most of the hydrocarbon liquids are collected (and associated flashing emissions occur) during pigging operations. In addition, with the introduction of NSPS, Subpart OOOO, many applicants are concerned about estimating emissions from wellhead facilities and most of those facilities include heated separators. Further, gas plants may be equipped with condensate stabilizers, unheated separators, or other process vessels that ultimately direct hydrocarbon liquids to atmospheric storage tanks.

No matter what type of facility is under consideration, it is essential that (where required by a particular estimation method) an applicant gather pressurized hydrocarbon liquid samples under conditions which are most likely to generate flashing emissions. For compressor stations, that may well be during pigging operations. At wellhead sites, the hydrocarbon liquid may leave a heated separator. In cases where a separator is only heated during the winter months, it may be necessary to collect an unheated sample. In addition, it may be necessary to estimate emissions using different operating assumptions to reflect seasonal variations. That is, it may be necessary to use different hydrocarbon liquid storage temperatures under different scenarios to accurately represent changing field conditions throughout the year. Alternatively, an applicant may use a single, worst-case scenario for the entire year. This approach is appropriately conservative and simpler to execute and evaluate than an approach involving multiple seasonal scenarios.

For wellhead facilities using gas-lift compression and where an applicant has elected to use a method to estimate flash emissions that requires the collection of a pressurized hydrocarbon liquid sample, the applicant must sample the pressurized hydrocarbon liquid when the gas-lift compressor is in operation.

Whichever type of facility is being permitted and whatever the particular situation, it is incumbent on the applicant to communicate these issues clearly in the application submissions.

Vasquez-Beggs Equation (VBE)

The Vasquez-Beggs Equation is a simple method which, when using defaults provided by the AQD, requires very limited facility-specific data. Many applicants find its simplicity well-suited to performing a screening analysis to determine whether a more complex method should be used.

The VBE was developed in 1980 as part of a research project at the University of Tulsa. More than 6,000 samples from oil fields worldwide were used in developing correlations to predict oil properties. The VBE can be used as a default method to estimate potential flashing losses from hydrocarbon storage tanks. This equation has eight input variables: stock tank API gravity, separator pressure (psig), temperature (°F), gas specific gravity, volume of produced hydrocarbons (bbls/day), molecular weight of the stock tank gas (lb/lb•mole), VOC fraction of the tank emissions, and atmospheric pressure (psia). The VBE estimates the dissolved gas-oil ratio (GOR) of a hydrocarbon solution as a function of the separator temperature, pressure, gas specific gravity, and liquid API gravity. Flashing losses from the crude oil or condensate storage tank are then estimated by multiplying the GOR by the tank throughput, the stock tank gas molecular weight, and the weight fraction of VOCs in the gases. This method was designed for gases dissolved in crude oils, but, with proper defaults, it may be used for some condensates. The equation is available in a spreadsheet format (EXCEL®) and can be downloaded from the ODEQ website:

http://www.deq.state.ok.us/AQDnew/resources/VBE_Feb2016.xls

The following table provides the AQD defaults and notes regarding each input parameter. If an applicant chooses to use any non-default value, the applicant must provide an explanation why the facility-specific value was chosen as well as supporting documentation (e.g., an extended gas analysis for the stock tank gas.)

Input Parameters for the Vasquez-Beggs Equation
AQD Defaults and Additional Information

Parameter	Default Value	Notes
Stock tank API gravity (°API)	70	An applicant may use the default value for a construction permit for a new facility or the applicant may provide an estimate based on professional judgment. For an operating permit application, the applicant may use the default value or the facility-specific API gravity. Even if the applicant uses the default value for an operating permit, the applicant must also provide a facility-specific API gravity. A laboratory analysis or an oil sales ticket must be provided as supporting documentation. If the facility-specific API gravity is below 20°API, the applicant must use 20°API. If the facility-specific API gravity is above 60°API, the applicant may not use the VBE and must choose another method to estimate flashing emissions. It should be noted that the AQD default value (70°API) is higher than the maximum (measured) API gravity value allowed if an applicant wishes to use the VBE to estimate flashing emissions. This was done on purpose to yield a conservative estimate of flashing emissions.
Separator pressure (psig)	--	The applicant must use a facility-specific separator pressure. For a construction permit, this parameter must be estimated. If the separator pressure is below 35 psig, the applicant must use 35 psig for this parameter.
Separator temperature (°F)	60	The applicant may use the default or a facility-specific value. It should be noted that this is the temperature inside the process unit directly upstream of the storage tank. For separators that are heated seasonally, either the most conservative assumption must be used (the lowest temperature) or the VBE may be applied to estimate emissions during the different seasons, with those emissions summed to estimate annual emissions.

Input Parameters for the Vasquez-Beggs Equation
AQD Defaults and Additional Information

Parameter	Default Value	Notes
Separator gas gravity at initial conditions (unitless)	0.9	The applicant must use a value of 0.9 or higher to ensure that the emissions estimated are conservative.
Stock tank barrels of oil per day (BOPD)	--	The applicant must use a facility-specific value for the hydrocarbon liquids throughput. For a construction permit, this parameter must be estimated. Where this calculation is used to estimate potential to emit (PTE), the applicant should refer to AQD PTE guidance and the applicable NSPS or National Emissions Standards for Hazardous Air Pollutants (NESHAP). NSPS, Subpart OOOO provides guidance on estimating potential VOC emissions from tanks and NESHAP, Subparts HH and HHH provide guidance on the estimation of potential emissions of HAPs.
Stock tank gas molecular weight (lb/lb•mole)	60	The applicant may use the default or a facility-specific value. If the applicant chooses to use a facility-specific value, the applicant must obtain a sample of the storage tank flash gas and provide a laboratory report showing the results of an extended gas analysis. If the facility-specific stock tank molecular weight is below 60 lb/lb•mol, the applicant must still use 60 to ensure that the emissions estimated are conservative.
Mass fraction VOC (C_3+) of stock tank gas	0.8	The applicant may use the default or a facility-specific value. If the applicant chooses to use a facility-specific value, the applicant must obtain a sample of the storage tank flash gas and provide a laboratory report showing the results of an extended gas analysis. If the facility-specific VOC mass fraction is below 0.8, the applicant must still use 0.8 to ensure that the emissions estimated are conservative.
Atmospheric pressure (psia)	14.7	The applicant must use the default value.

E&P TANK

E&P TANK® is a software program designed for use on personal computers. E&P TANK® was developed in an effort to estimate the working, breathing and flashing components of hydrocarbon production tanks. The E&P TANK program is based on the Peng-Robinson (PR) equation of state (EOS). An EOS is a mathematical equation showing the relationships between thermodynamic variables such as pressure, temperature, and volume of a specific material in thermodynamic equilibrium. The minimum inputs needed for the model are separator oil composition, separator temperature and pressure, sales oil API gravity and Reid Vapor Pressure (RVP), sales oil production rate and ambient temperature and pressure. The program is set up so that the separator oil composition can be determined using an analysis of the low-pressure separator oil, high-pressure separator oil, or low-pressure separator gas, or using an analysis from the geographical database provided with the program. The database is sorted by geographic region, sales oil physical properties, and separator pressure and separator temperature. The AQD will allow the geographical database to be used only for applications for new construction and only if the selected case is a reasonable approximation of what is expected at the facility. In addition, an applicant choosing to use E&P TANK must use the low-pressure oil configuration and, for operating permits, must sample and analyze the hydrocarbon liquids leaving the process unit directly upstream from the atmospheric storage tanks. Using the inputs provided, the program estimates flashing losses as well as working and breathing losses from atmospheric storage tanks. This program was developed by the American Petroleum Institute (API) and users must obtain a license (and pay a fee) for its use. The AQD has been granted a non-commercial license and is able to replicate analyses provided by an applicant.

The following table provides a discussion of the input parameters used in the E&P TANK program. If an applicant chooses to use the E&P TANK program, the applicant must provide an explanation why each facility-specific input parameter value was chosen as well as supporting documentation (e.g., an extended composition analysis for the pressurized hydrocarbon liquids exiting the separator upstream of the atmospheric storage tank.)

Input Parameters for the E&P TANK Program

Parameter	Notes
Flowsheet selection	Select "Tank with Separator."
Known separator stream information	Select "Low Pressure Oil." If an applicant would prefer to use a different setting, the applicant must obtain prior approval from the AQD before submitting their E&P Tank output.
Control efficiency (%)	If the tanks are controlled, use an appropriate control efficiency. If an applicant is unsure what control efficiency value is appropriate for a particular site, the applicant should contact the AQD.
Model selection for W and S losses	Select "AP-42." Please note that the program must be run separately for each type of tank to get an accurate estimate of working and breathing losses.
Separator pressure (psig)	The applicant must use a facility-specific separator pressure. For a construction permit, this parameter must be estimated.
Separator temperature (°F)	The applicant must use a facility-specific value. It should be noted that this is the temperature inside the process unit directly upstream of the storage tank. For a construction permit, this parameter must be estimated. If the process unit directly upstream of the storage tanks is a separator which is heated seasonally, appropriate consideration must be given to seasonal temperature variations. The applicant should contact the AQD for guidance.
Low-pressure oil composition (mol %)	The applicant must gather a representative pressurized sample of the hydrocarbon liquids that leave the separator before being directed to an atmospheric storage tank. It is essential that the sample is obtained at the pressure it will leave the vessel and in a manner that preserves the composition of the liquid hydrocarbon mixture. This program requires that composition data be provided for hydrocarbon species up to C_{10}+, certain Hazardous Air Pollutants, and some dissolved (non-hydrocarbon) gases.
C_{10}+ characterization	The applicant may use either the E&P TANK program defaults (MW = 166.00 lb/lb-mol and SG = 0.899) or the applicant may incorporate facility-specific data if those data are available.
Ambient pressure (psia)	Use 14.7 psia.

Input Parameters for the E&P TANK Program

Parameter	Notes
Ambient temperature (°F)	Enter the tank inlet temperature. If the tank inlet temperature is not known, use the temperature of the separator immediately upstream of the atmospheric storage tank. Again, where upstream process vessels are heated only seasonally, temperature variations must be accounted for.
Tank and shell diameter (ft), height (ft), and cone roof slope (unitless)	Enter the measurement for each tank into the program for each run performed.
Average liquid height (ft)	Enter half the value of the tank height.
Breather vent pressure setting range (psi)	Enter 0.060 psi or the actual value if the setting is different than that.
Paint color and condition	Enter the appropriate data.
Paint factor (unitless)	The program will provide this value depending on the paint color and paint condition information provided.
Meteorological data	Select the city that is closest to the facility.
Sales oil production rate (bbl/day)	The applicant must use a facility-specific value for the hydrocarbon liquids throughput. For a construction permit, this parameter must be estimated. Where this calculation is used to estimate PTE, the applicant should refer to AQD PTE guidance and the applicable NSPS or NESHAP. NSPS, Subpart OOOO provides guidance on estimating potential VOC emissions from tanks and NESHAP, Subparts HH and HHH provide guidance on the estimation of potential emissions of HAPs.
Days of annual operation (days/year)	Use 365 unless circumstances warrant use of a different value. If a different value is used, adequate justification must be provided in the application.
Stock tank API gravity (°API)	For a construction permit for a new facility, the applicant must provide an estimate based on professional judgment. For an operating permit application, the applicant must use the facility-specific API gravity. A laboratory analysis or an oil sales ticket must be provided as supporting documentation.
Stock tank bulk temperature (°F)	Use 70°F for this parameter as a default. If the process vessel directly upstream of the tank is heated, then use an appropriate temperature which may depend on the typical length of time the liquids are stored as well as other site-specific and seasonal factors. The applicant should contact AQD for additional guidance.

Laboratory Gas-Oil Ratio (GOR)

Determination of the hydrocarbon liquid GOR can be obtained by collecting a pressurized sample upstream of the storage tank. The GOR is determined in the laboratory and is reported in standard cubic feet of flash gas per barrel of hydrocarbon liquid (scf/bbl). The flashing losses/emissions can then be determined by multiplying the GOR by the throughput of the tank, the molecular weight of the flash gas, and the mass fraction VOC in the flash gas. An extended hydrocarbon analysis of the flash gas from the sample must also be performed to identify the concentrations of the individual components of the tank's flash emissions and the molecular weight of the flash gas.

This is a simple method for estimating flash emissions; however, it is essential that the pressurized liquid sample be obtained properly to yield reliable results. The applicant must submit a description of the sampling procedure and a complete laboratory report when using this method.

Process Simulation Software

Process simulators are computer models that use an equation of state and mass and energy balances to simulate petroleum processes for a variety of engineering purposes. There are several different developers of process simulators and various simulation packages available (e.g., ProMax®, HYSIM®, HYSIS®, WINSIM®, PROSIM®, etc.). Each process simulator applies similar basic principles to develop stream data for various processes. Historically, process simulators were mainly used in process design and, in that capacity, they have been demonstrated to accurately predict natural gas and petroleum processes. Process simulators can also be used to estimate flash emissions and speciate these emissions. Required inputs may include an extended analysis of a sample of pressurized hydrocarbon liquids as well as other parameters (e.g., temperature, pressure, and flow) for the process being simulated. Process simulators are not constrained by the API gravity of a particular crude oil or condensate. This method of estimating potential flash emissions can be very expensive and complicated due to the need for additional stream sampling and analysis as well as the licensing cost for the software. However, proper use of a process simulator (when supported by representative sampling and analysis of key process streams) is expected to be more accurate in estimating flashing losses from hydrocarbon storage tanks than most other emissions estimation methods.

With regard to the process simulation software an applicant chooses to use, the AQD is willing to accept any valid method that is determined to be appropriate for the particular emission source and conditions. However, the AQD strongly prefers that applicants submit data from a proprietary simulator that the AQD has been granted a non-commercial license to use. Regardless of which process simulator an applicant chooses to use, each applicant is encouraged to contact the AQD prior to submitting an application to determine what additional information may be needed to ensure that the AQD may properly evaluate an applicant's submission. In addition, the AQD encourages software companies to consider providing non-commercial licenses to the AQD to facilitate evaluation of emissions estimates performed using that software. By having access to the process simulation software, the AQD may evaluate the applicant's application and supporting data more efficiently and expend fewer resources.

Direct Measurement

Actual testing of emissions from tanks can also be performed to determine flash emissions. Since there are no currently approved U.S. EPA reference methods that are developed specifically for measuring emissions from storage tanks, modified reference methods or other approved methods may be used to characterize and determine these emissions, with prior approval of the AQD. However, it should be noted that such testing is just a snapshot of the emissions and should be used in conjunction with a safety factor to establish emission limits.

Are there restrictions or limits to take into consideration when using any of the calculation methods?

Yes, the VBE is a relatively simple calculation method and it can be used for a general estimate of flashing losses from hydrocarbon storage tanks. However, if the VBE analysis results in flashing losses (without taking any controls into consideration) that are greater than 50 TPY (facility-wide), another more accurate method must be used. If using the more accurate emission estimation method shows that the simpler emission estimation method is conservative (that is, if the simpler method shows higher emissions), then either method can be used for permitting and reporting annual emissions.

Also, when using a process simulator, care should be exercised to ensure that the amount of lighter hydrocarbons (propane, ethane, and methane) remaining in the flash oil (hydrocarbon liquids remaining in the tank after flashing occurs) is not significant. If the simulation shows these components to represent more than 4% (by mole), additional scrutiny is warranted.

If a process simulator and the EPA TANKS program are used together to calculate flashing and working and standing losses (and associated VOC emissions) from a tank, respectively, it should be noted that the EPA TANKS program does not calculate emissions of lighter hydrocarbons that evolve from the liquids due to their low boiling points. The EPA TANKS program does not even allow entering compounds lighter than pentane. As stated in AP-42 (7/97), Section 7.1, “the equations are not intended to be used in estimating losses from unstable or boiling stocks or from mixtures of hydrocarbons or petrochemicals for which the vapor pressure is not known or cannot be readily predicted.” If the amount of the lighter hydrocarbons predicted to remain in the flash oil by the process simulator or other program is significant, another method should be investigated as an alternative for calculating the working and standing losses and associated emissions.

Each applicant should be advised that underestimating emissions (deliberately or even unintentionally) leaves the applicant open to a possible enforcement action.

SECTION V. REFERENCES

American Petroleum Institute, "E&P TANK, Version 3.0," API Publication 4697. https://www.eptanks.com/

Texas Commission on Environmental Quality, "Representative Analysis Criteria," revised February 2012. https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/rep-analysis-criteria.pdf.

U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Emission Inventory and Improvement Program, Volume I, Chapter 10, "Preferred and Alternative Methods for Estimating Emissions from Oil and Gas Filed Production and Processing operations," Research Triangle Park, North Carolina. 1999 http://www.epa.gov/ttn/chief/eiip/techreport/volume02/ii10.pdf

Vasquez, Milton and H. Dale Beggs, "Correlations for Fluid Physical Property Prediction," *Journal of Petroleum Technology*, June 1980, pp. 968-970.

Who Can I Contact for More Information?

For assistance, contact the Air Quality Division at (405) 702-4100 and ask to speak with a permit writer.

Oklahoma Department of Environmental Quality
Air Quality Division – Permitting Group
707 N. Robinson, Suite 4100
P.O. BOX 1677
Oklahoma City, Oklahoma 73101-1677