# APPENDIX A—TECHNICAL SUPPLEMENTS

**Disclaimer**

The TCEQ has developed technical supplements for several common emission sources. The supplements are intended to provide guidance for determining and correctly reporting emissions from specific types of sources, and may not cover every source at the site. It is the responsibility of the owner or operator of a regulated entity to report the emissions from every source required to be included in its EI. See Chapter 1 for information on reporting requirements.

These supplements reflect how certain processes work and how they generate emissions. The supplements may change over time as a result of findings of scientific studies and as new information becomes available. The TCEQ greatly appreciates any data, information, or feedback that may improve these supplements.

The methods discussed in this appendix are intended as an aid in calculating emissions. Certain process or operational conditions may make alternate calculation methods equally acceptable if they are based upon, and adequately demonstrate, sound engineering principles or data. It is the responsibility of the owner or operator of a regulated entity to use the best available method to determine and report the emissions that accurately reflect the conditions at his or her site. Additional guidance regarding the acceptability of a given emissions determination method is available from the Emissions Assessment Section (EAS) at 512-239-1773.

## Miscellaneous VOC Sources

One of the goals of the TCEQ is to identify sources that are failing to report, or are underreporting, their VOC emissions. The sources that fall into this category include, but are not limited to, casing head gas releases, coking units, confined entry ventilation, and Merox units. The EPA has released a draft document titled *Emission Estimation Protocol for Petroleum Refineries* that is currently under review. Once finalized, this document may provide guidance on determining emissions from coking units and Merox units. The TCEQ is not aware of any additional specific guidance that is readily available to determine the emissions from these types of sources.

If any of the sources listed below are present at the site, the sources must be represented in the EI and the emissions must be determined and reported in the EI using the best available emission determination methodologies. All sources of actual VOC emissions must be accounted for in the emissions inventory according to the guidance in Chapter 3.

### *Casing Head Gas Releases*

*Casing head gas* is unprocessed natural gas and other hydrocarbon vapors that emerge at the casing head fitting when crude oil is pumped to the surface of a well. During normal operating conditions, the casing head

fitting is tight and no vapors leak into the atmosphere. When the casing head gas is vented, any emissions meeting EI reporting requirements must be reported in the EI.

## Coking Units

*Coking* is a method of severe thermal cracking used to break heavy, long-chained hydrocarbons into lighter products. The residual product of the coking process is a solid carbon substance called *petroleum coke*.

Petroleum coke is removed from the walls of a coke drum by *decoking* or *coke cutting*. During decoking (or coke cutting), VOC gases trapped in the coke will be released while creating hot spots and steam eruptions. Hydrocarbons may also be emitted during the associated cooling and venting of the coke drum prior to decoking.

## Confined Entry Ventilation

Confined entry usually occurs during inspection, repair, or maintenance. Before entry, gas hazards are controlled by purging, inerting, flushing, or ventilating the space as necessary. Examples of confined spaces include, but are not limited to, tanks, manholes, boilers, furnaces, vaults, pipes, trenches, tunnels, ducts, and bins.

If the seal of a confined space is broken and uncontrolled, the contaminants within the confined space may be released into the atmosphere. These emissions must be included in the EI. Consult Chapter 3 for information on collective sources to determine if these ventilation emission sources can be grouped in the EI.

## Merox Units

After mercaptan-rich hydrocarbon liquids are treated in a Merox unit, they are often placed in a storage tank. Inert gases may become trapped in this hydrocarbon liquid and can strip VOCs while vaporizing during storage, resulting in VOC emissions. The EPA TANKS program may not account for these additional emissions in the calculated emissions report.

If the liquid streams are warmer than ambient temperature, see Technical Supplement 6 for information on hot-product storage to determine the tank's routine emissions. Additional emissions from inert gas stripping must be calculated using sound engineering principles and data.

## Glycol Dehydration Operations

Glycol dehydration units are used to remove water from natural gas streams to prevent the formation of hydrates and corrosion in the pipeline. Once the glycol is saturated with water, the rich glycol is pumped to a glycol reboiler heater to be regenerated and reused. When the glycol is

heated, the VOCs (including BTEX and other HAPs) and water are boiled off and may be released to the atmosphere through the glycol still vent.

Whether the GRI-GLYCalc program or a material balance based on a rich-lean analysis is used to determine emissions, an extended gas analysis is necessary for an accurate determination. The wet gas must be sampled at a point in the process ahead of the glycol contactor. The gas analysis must be speciated for each chemical including, but not limited to BTEX and HAPs. For the rich-lean analysis, the rich glycol stream must be sampled at an appropriate location in the process to accurately assess the VOC content (e.g., after the glycol contactor but before the regenerator or reboiler). The lean glycol stream must be sampled at a point in the process after the regenerator or reboiler.

If the process operations include a flash tank, the flash tank emissions must be included in the EI. When properly used, data from either GRI-GlyCalc or sampling can account for VOC emissions from the flash tank. Controls for the flash tank vents, as well as the regenerator, can be accounted for in the GRI-GlyCalc program. Include the Aggregate Summary Emission Report in the sample calculations, which provides the information needed for review.

Flash tanks must be represented as individual sources in the emissions inventory if they are permitted separately from the glycol still or dehydrator unit. Use the Facility Information—VOC Process form to add the glycol flash tank structure to the inventory. For assistance, contact the EAS.

### *Amine Units in Carbon Dioxide Service*

Amine units in $CO_2$ service that are vented to the atmosphere can be a significant source of VOC emissions (including BTEX and other HAPs). Amine units are used to remove acidic gases including $CO_2$ from natural gas streams. Once the amine is saturated with acid gas, the rich amine is pumped to the amine regenerator to be recycled and the $CO_2$ may be vented to the atmosphere. Amine solutions can absorb VOCs (including BTEX and other HAPs) and release them to the atmosphere during the regeneration cycle. Current and accurate simulation methods, such as the PROSIM, ProMax, etc., to determine emissions or stack sampling must be used to ensure that speciated VOCs are reported from amine units in $CO_2$ service that are vented to the atmosphere. Recent research indicates that AMINECalc underestimates VOC emissions from amine units. VOC emissions from amine units should be determined using measured emissions data (preferred) or software models that accurately determine the VOC emissions.

## Technical Supplements

The following technical supplements are included in this appendix.

**Technical Supplement 1: Selected Combustion Sources** addresses common problems and concerns regarding internal combustion engines (turbines, reciprocating engines, gasoline and diesel industrial engines, and portable engines); external combustion sources burning natural gas; and combined-cycle turbines with heat-recovery steam generators.

**Technical Supplement 2: Cooling Towers** will help you determine the nature of the emissions from a cooling tower system, identify some of the methods that may be used to quantify those emissions, and correctly report the emissions in the annual EI.

**Technical Supplement 3: Equipment Leak Fugitives** contains guidance for determining and reporting emissions from piping components at industrial facilities resulting from leaking seals or connections.

**Technical Supplement 4: Flares** contains guidance for determining and reporting emissions from elevated flares.

**Technical Supplement 5: Marine Facilities** contains guidance for determining and reporting emissions from vessel cleaning, material transfer, and dockside sources such as particulate stockpiles, silos, VOC collection units, loading racks, and abatement devices.

**Technical Supplement 6: Aboveground Liquid Storage Tanks** explores stationary emissions from storage tank breathing and working losses, flashing losses, and landing losses. The supplement identifies some of the methods used to quantify those emissions.

# TECHNICAL SUPPLEMENT 1: SELECTED COMBUSTION SOURCES

**Technical Disclaimer**

This technical supplement is intended to help the preparer determine and correctly report emissions from combustion sources. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how combustion sources work, how emissions are generated, how combustion sources are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. The TCEQ greatly appreciates any data, information, or feedback that may improve the supplement.

The calculation methods represented are intended as an aid; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS at 512-239-1773.

## Introduction

This technical supplement addresses common problems and concerns with internal combustion engines (turbines, reciprocating engines, gasoline and diesel industrial engines, and portable engines); external combustion sources burning natural gas; and combined-cycle turbines with heat-recovery steam generators. For more information about these sources, or for information about combustion sources not covered in this supplement, consult the appropriate TCEQ new source review guides and the EPA's *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources* (publication number AP-42), continually updated.

## Internal Combustion Engines

### *Expected Contaminants*

Reported engine emissions must include all of the following:

- PM (contaminant code *10000*)
- $PM_{10}$ (contaminant code *20000*)
- $PM_{2.5}$ (contaminant code *39999*)
- VOCs (contaminant codes *50001* through *59998*)
- HAPs, such as formaldehyde, $\geq$ 0.1 tpy
- $NO_x$ (contaminant code *70400*)

- $SO_2$ (contaminant code *70510*)
- CO (contaminant code *90300*)

## Emissions Determination Methodologies

Emissions determination methodologies for all regulated pollutant emissions from internal combustion engines are accepted in the following order of preference:

- D (continuous emissions monitoring system or CEMS)
- F (predictive emissions monitoring system or PEMS)
- M (measured—stack test data)
- Q (portable analyzer test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- S (scientifically calculated)
- E (estimated)

Portable analyzers have their own determination methodology and must be coded "Q." Testing conducted with a portable analyzer does not qualify as stack testing; therefore, the emissions determination methodology must not be coded 'measured' ("M"). If the stack test results from an identical unit are used to determine the emissions, the emissions determination methodology must be coded 'estimated' ("E").

Note that material balance ("B") is not explicitly mentioned in the list because of its limited applicability in determining emissions from combustion sources, except $SO_2$. If these methodologies will not accurately represent a source's emissions, contact the EAS for further assistance.

## $SO_2$ Emissions

If any sulfur is present in a source's inlet gas, the source will emit sulfur dioxide as a product of combustion. CEMS, PEMS, and stack test data are the preferred methods, in descending order, for determining the $SO_2$ emissions. In lieu of using a vendor or AP-42 $SO_2$ emission factor, the $SO_2$ emissions must be determined using material balance based upon the combusted fuel's sulfur content.

## Particulate Emissions

Combustion sources emit particulate matter. Furthermore, particulate matter emitted from internal combustion engines has an aerodynamic diameter smaller than 2.5 microns. Thus, all particulate emissions from

these sources must be reported as $PM_{2.5}$, $PM_{10}$, and PM (total). See Chapter 4, "Speciating Particulate Matter," for more details.

Use AP-42 to determine internal combustion engine particulate matter emissions only if preferable data does not exist. *Please note:* Some confusion has arisen from AP-42's representation of three particulate emission factors: $PM_{10}$ (filterable), $PM_{2.5}$ (filterable), and PM (condensable). PM consists of condensable particulate matter and filterable particulate matter; therefore, the emissions from condensable particulates and from filterable particulates must be determined to calculate the cumulative particulate emissions.

However, summing these emission factors is not straightforward. Since all particulate matter emitted from internal combustion engines is $PM_{2.5}$ or smaller, the $PM_{10}$ (filterable) and $PM_{2.5}$ (filterable) emission factors are equivalent; those two factors represent the same set of particulate emissions. Therefore—for internal combustion engines only—obtain the cumulative PM emission factor by summing the AP-42 condensable emission factor and the AP-42 $PM_{10}$ filterable emission factor. Use this cumulative emission factor in conjunction with the appropriate annual activity rate to determine cumulative PM emissions. Report the total emissions obtained by this method under each of the following contaminant codes:

- PM (contaminant code *10000*);
- $PM_{10}$ (contaminant code *20000*); and
- $PM_{2.5}$ (contaminant code *39999*).

**Example:** Suppose that AP-42 shows the following emission factors for particulate matter from a certain type of engine:

$PM_{10}$ (filterable) = 0.0095 lb/MMBtu

$PM_{2.5}$ (filterable) = 0.0095 lb/MMBtu

PM (condensable) = 0.00991 lb/MMBtu

Then the correct particulate emission factor for this engine type would be the sum of the $PM_{10}$ (filterable) and the PM (condensable) factors, or 0.01941 lb/MMBtu. If the engine consumed 35,000 MMBtu of fuel during the year, then its particulate emissions would be:

$$PM = 0.0194 \ \frac{lb}{MMBtu} \times 35{,}000 \ \frac{MMBtu}{year} \times \frac{1 \ ton}{2000 \ lb} = 0.3395 \ tons/year$$

The correct way to report these emissions is shown in Table A-1.

**Table A-1. Reporting Particulate Emissions**

| Contaminant Code | Contaminant | Annual Emissions |
|---|---|---|
| 10000 | Part—unclassified | 0.3395 tons |
| 20000 | $PM_{10}$—unclassified | 0.3395 tons |
| 39999 | total $PM_{2.5}$ | 0.3395 tons |

## VOC Emissions

Determining, speciating, and reporting VOC emissions are not always straightforward. Please read the information in this section carefully. Although source-specific VOC data as detailed in the Emissions Determination Methodologies section above must be used to determine VOC emissions if available, in practice, it is possible to determine VOC emissions using a combination of stack test data, vendor data, and AP-42 emission factors. Each methodology is discussed separately in the following sections; each section contains methodology-specific speciation instructions.

### Stack Test Data

When using valid stack test data to determine VOC emissions, the results of the stack test must be verified to ensure that the test measured VOCs rather than total hydrocarbons. If it did measure VOCs, then the test data must be used to determine emissions; code the emissions with a determination methodology of "M."

If the stack test measured total hydrocarbons, the VOC emissions must be determined by multiplying the hydrocarbon emission factor by the following ratio: *AP-42 VOC emission factor / AP-42 total organic carbon (TOC) emission factor*. The determination methodology must be coded "S."

Because complex oxidation reactions occur in the combustion chamber that significantly alter the emissions composition, it is unacceptable to apply the inlet gas stream's VOC percentage to the stack test TOC emission factor to obtain a VOC emission factor.

### Vendor Data

When using vendor data to determine VOC emissions, verify that the vendor's emission factor refers to VOCs rather than total hydrocarbons. If it does, the VOC emissions must be calculated and the determination methodology must be coded "V." **Also, verify whether the vendor's emission factor accounts for formaldehyde and other aldehyde compounds.** If the factor excludes only formaldehyde, see the "Speciation" section that follows. If the factor excludes all aldehyde compounds, please contact the EAS.

If the emission factor determines the amount of total hydrocarbons, the VOC emissions must be determined by multiplying the hydrocarbon emission factor by the following ratio: *AP-42 VOC emission factor / AP-42 TOC emission factor*. The determination methodology must be coded "S."

Because complex oxidation reactions occur in the combustion chamber that significantly alter the emissions composition, it is unacceptable to apply the inlet gas stream's VOC percentage to the vendor's TOC emission factor to obtain a VOC emission factor.

### AP-42 Factors

AP-42 provides both VOC and TOC emission factors. Because complex oxidation reactions occur in the combustion chamber that significantly alter the composition of emissions, it is unacceptable to apply the inlet gas stream's VOC percentage to the AP-42 TOC emission factor to obtain a VOC emission factor.

When using an AP-42 emission factor to determine emissions, the most recent VOC emission factor must be used and the determination methodology must be coded "A."

### Speciation

To determine whether or not to speciate VOC emissions from an internal combustion engine, see Chapter 4.

If speciation is required for the emissions source, source-specific information, if available, must be used when calculating the speciated VOC emissions.

If no source-specific information about the VOC composition exists, the VOC emissions must be speciated using the AP-42 "trace organic compounds" emission factors that are graded "C" or better.

Note that the total VOC factor in AP-42 is simply the sum of the speciated emission factors. If a method for determining VOC emissions preferred over AP-42 is used to determine total VOC emissions, the ratio of the AP-42 speciated emission factor to the total AP-42 VOC emission factor must be applied to determine each individual species' emissions rate. This ensures that the total of the speciated emissions does not exceed the total VOC factor.

To determine the speciated emissions, divide each trace organic factor by AP-42's VOC emission factor to obtain the contaminant's speciation ratio. Multiply the source's total VOC emissions by each ratio to obtain that compound's emission rate. The speciated VOC emissions that are at least 0.1 ton must be reported; smaller rates may be included under *VOC—u* (contaminant code 50001).

If stack test data or vendor data are used to determine total VOC emissions, the determination methodology must be coded "S" for 'scientifically calculated'; the *VOC—u* emissions must be coded "M" or "V." If an AP-42 emission factor is used to determine the total VOC emissions, the determination methodology for all of the VOC pollutants must be coded "A."

***Example: Speciating VOCs using a vendor-supplied VOC emission factor that includes formaldehyde***

The total VOC emissions from a four-cycle lean burn compressor have been determined to be 11.2 tons. Assuming the composition of the exhaust VOCs is not known, the inlet-gas analysis cannot be used to speciate the VOC emissions, because complex oxidation reactions occur in the combustion chamber that alter the composition of emissions significantly. Therefore, the factors in AP-42 must be used to speciate the VOC emissions.

In AP-42, formaldehyde is one of the "trace organic compounds" that have an emission factor (0.0528 lb/MMBtu) with a grade C or better. The total VOC emission factor in AP-42 is 0.118 lb/MMBtu. To obtain formaldehyde's speciation ratio, divide the formaldehyde emission factor by the total VOC emission factor:

$$0.0528\frac{\text{lb}}{\text{MMBtu}} \div 0.118\frac{\text{lb}}{\text{MMBtu}} = 0.44746$$

Multiply the engine's total VOC emissions by this ratio to determine the formaldehyde emissions:

$$11.2\ \text{tons VOC} \times 0.44746 = 5.0115\ \text{tons formaldehyde}$$

If this calculation is performed for each trace organic compound with a factor graded C or better, there are 27 speciated emission rates that must be determined. However, only eight of those exceed the 0.1 ton threshold. The speciated emissions for these eight compounds must be reported in the EI and the remaining balance of the total VOC emissions must be reported under "VOC—unclassified," as shown in Table A-2.

Formaldehyde emissions are difficult to quantify using existing EPA reference methods. Typically a separate test for formaldehyde is needed to quantify these emissions. Therefore, some vendor-provided, as well as stack test, VOC emission factors exclude formaldehyde. In those cases, the formaldehyde must be accounted for in the VOC speciation calculations. Subtract the AP-42 formaldehyde factor from the AP-42

**Table A-2. Reporting VOC Emissions from Internal Combustion—Vendor Factor Includes Formaldehyde**

| Contaminant Code | Contaminant | Annual Emissions | Determination Methodology |
|---|---|---|---|
| 50001 | VOC—unclassified | 0.2240 ton | V |
| 51620 | acetaldehyde | 0.7935 ton | S |
| 51640 | acrolein | 0.4879 ton | S |
| 51680 | formaldehyde | 5.0115 tons | S |
| 51530 | methanol | 0.2373 ton | S |
| 56150 | methylcyclohexane | 0.1167 ton | S |
| 56600 | *n*-hexane | 0.1054 ton | S |
| 56750 | *n*-pentane | 0.2468 ton | S |
| 56775 | propane | 3.9769 tons | S |

VOC emission factor, and then divide each trace organic factor by the resulting amount according to the formula below:

$$E_{speciatedVOC} = \frac{EF_{AP-42\ speciatedVOC}}{EF_{AP-42totalVOC} - EF_{AP-42\ formaldehyde}} \times E_{totalVOC}$$

Where:

$E_{speciated\ \ VOC}$ = the tpy rate for a speciated VOC contaminant

$EF_{AP-42\ speciatedVOC}$ = the specific trace organic factor for the compound in AP-42

$EF_{AP-42totalVOC}$ = the AP-42 VOC emission factor

$EF_{AP-42\ formaldehyde}$ = the AP-42 formaldehyde factor

$E_{totalVOC}$ = the tpy total VOC determined using stack test data or vendor data

***Example: Using a vendor-supplied VOC emission factor that excludes formaldehyde***

In this case, a vendor supplied the total VOC factor and the formaldehyde factor. Total VOC emissions were determined to be 11.2 tons; formaldehyde emissions, 3.8 tons. Assuming the composition of the exhaust VOCs is not known, the inlet-gas analysis cannot be used to speciate the VOC emissions because complex oxidation reactions occur in the combustion chamber that alter the emissions composition significantly. Therefore, the emission factors in AP-42 must be used to speciate the

remaining VOC emissions. To obtain the speciation ratio, first subtract the AP-42 formaldehyde factor from the AP-42 total VOC factor:

$$0.118\frac{\text{lb}}{\text{MMBtu}} - 0.0528\frac{\text{lb}}{\text{MMBtu}} = 0.0652$$

Then divide each trace organic compound's emission factor by the adjusted VOC emission factor. The AP-42 emission factor for acetaldehyde is 0.00836 lb/MMBtu:

$$0.00836\frac{\text{lb}}{\text{MMBtu}} \div 0.0652\frac{\text{lb}}{\text{MMBtu}} = 0.1282$$

Multiply the engine's total VOC emissions by this ratio to determine the acetaldehyde emissions:

$$11.2 \text{ tons VOC} \times 0.1282 = 1.4358 \text{ tons acetaldehyde}$$

Only the trace organic compounds exceeding the 0.1 ton threshold must be reported in the EI, and the remaining balance of the total VOC emissions must be reported under "VOC—unclassified," as shown in Table A-3.

**Table A-3. Reporting VOC Emissions from Internal Combustion—Vendor Factor Excludes Formaldehyde**

| Contaminant Code | Contaminant | Annual Emissions | Determination Methodology |
|---|---|---|---|
| 50001 | VOC—unclassified | 0.4055 ton | V |
| 51620 | acetaldehyde | 1.4358 tons | S |
| 51640 | acrolein | 0.8829 ton | S |
| 51680 | formaldehyde | 3.8 tons | V |
| 51530 | methanol | 0.4294 ton | S |
| 56150 | methylcyclohexane | 0.2113 ton | S |
| 56600 | *n*-hexane | 0.1907 ton | S |
| 56750 | *n*-pentane | 0.4466 ton | S |
| 56775 | propane | 7.1975 tons | S |

## Ozone Season Emissions

Ozone season emissions must reflect an average daily emission rate. Do not report maximum daily emissions based on a design capacity and the assumption that the source operated 24 hours each day. For sources that run regularly throughout the ozone season, divide the total emissions during the ozone season (as designated in Chapter 4) by the number of days the source is operated. For sources that run intermittently during the ozone season (e.g., emergency generators that operate a few hours every couple of weeks), use a straight conversion of the annual tons per year to pounds per day.

# External Combustion Sources Burning Natural Gas

## *Expected Contaminants*

Reported boiler emissions must include all of the following:

- PM (contaminant code *10000*)
- $PM_{10}$ (contaminant code *20000*)
- $PM_{2.5}$ (contaminant code *39999*)
- VOCs (contaminant codes *50001* through *59998*)
- $NO_x$ (contaminant code *70400*)
- $SO_2$ (contaminant code *70510*)
- CO (contaminant code *90300*)

## *Emissions Determination Methodologies*

The appropriate emission determination methodologies for regulated pollutant emissions from boilers are, in order of preference:

- D (continuous emissions monitoring system)
- F (predictive monitoring system)
- M (measured—stack test data)
- Q (portable analyzer test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- S (scientifically calculated)
- E (estimated)

Portable analyzers have their own determination methodology and must be designated as "Q." Testing conducted with a portable analyzer does not qualify as stack testing; therefore, the emissions determination methodology must not be coded measured ("M"). If the stack test results from an identical unit are used to determine the emissions, the emissions determination methodology must be coded 'estimated' ("E").

If none of these methodologies accurately represent a source's emissions, contact the EAS for further assistance.

## *$SO_2$ Emissions*

If any sulfur is present in a source's inlet gas, the source will emit sulfur dioxide as a product of combustion. CEMS, PEMS, and stack test data is

the preferred order when identifying the determination methodology for $SO_2$ emissions. In lieu of using a vendor or AP-42 $SO_2$ emission factor, the $SO_2$ emissions must be determined using a material balance based upon the combusted fuel's sulfur content.

## Particulate Emissions

Combustion sources emit particulate matter. Furthermore, all of the particulate matter emitted from boilers as a result of combustion has an aerodynamic diameter smaller than 2.5. Hence, all particulate emissions from these sources must be reported as PM, $PM_{10}$, and $PM_{2.5}$.

Note that AP-42 provides three particulate emission factors: PM (total), PM (condensable), and PM (filterable). Use the PM (total) factor [which can also be obtained by summing the PM (condensable) and PM (filterable) factors] to determine boiler particulate emissions. Report these emissions as PM (contaminant code 10000), as $PM_{10}$ (contaminant code *20000*), and as $PM_{2.5}$ (contaminant code *39999*).

## VOC Emissions

Source-specific data for total VOC emissions as detailed in "Emissions Determination Methodologies" (above), if available, must be used to determine VOC emissions. Speciated VOC emissions may be determined using multiple methods, including stack test data, vendor data, or AP-42 emission factors, or a combination. Each methodology is discussed separately in the following sections, and is followed by instructions on speciation.

### CEMS Data

If available, CEMS data must be used to determine a source's total VOC emissions. Please see the guidance in Chapter 4 for more information.

If a CEMS measures total hydrocarbon emissions instead of VOC emissions, special attention is necessary to determine VOC emissions accurately. Please contact the EAS for assistance.

### Stack Test Data

When using stack test data to determine VOC emissions, verify that the test measured total VOCs rather than total hydrocarbons. If the test did measure VOCs, the results must be used to determine the VOC emissions and the determination methodology coded "M."

If the stack test measured total hydrocarbons, the VOC emissions will need to be determined by multiplying the hydrocarbon emission factor by the following ratio: *AP-42 VOC emission factor / AP-42 TOC emission factor*. The determination methodology must be coded "S." Because complex oxidation reactions occur in the combustion chamber that significantly alter the composition of emissions, it is unacceptable to

apply the inlet gas stream's VOC percentage to the stack test TOC emission factor to obtain a VOC emission factor.

### Vendor Data

When using vendor data to determine VOC emissions, verify that the vendor's emission factor refers to VOCs rather than total hydrocarbons. If it does, the VOC emissions can be calculated, and the determination methodology must be coded "V."

If the vendor's emission factor refers to total hydrocarbons, the VOC emissions must be determined by multiplying the hydrocarbon emission factor by the ratio: *AP-42 VOC emission factor / AP-42 TOC emission factor*. The determination methodology must be coded "S."

Because complex oxidation reactions occur in the combustion chamber that significantly alter the emissions composition, it is unacceptable to apply the inlet gas stream's VOC percentage to the vendor's TOC emission factor to obtain a VOC emission factor.

### AP-42 Factors

AP-42 provides both VOC and TOC emission factors. Because complex oxidation reactions occur in the combustion chamber that significantly alter the emissions composition, it is unacceptable to apply the inlet gas stream's VOC percentage to the AP-42 TOC emission factor to obtain a VOC emission factor.

When using an AP-42 emission factor to determine emissions, use the most recent emission factor and report the determination methodology as "A."

### Speciation

To determine whether to speciate VOC emissions from a natural gas-fired external combustion source, consult Chapter 4.

If speciation is required for the emissions source, source-specific information, if available, must be used when calculating the speciated VOC emissions.

If no source-specific information about the VOC composition exists, the VOC emissions must be speciated using the AP-42 "speciated organic compounds" emission factors that are graded "C" or better. Divide each of these factors by the AP-42 VOC emission factor to obtain the contaminant's speciation ratio. Then multiply the source's total VOC emissions by each contaminant's ratio to obtain that contaminant's emission rate. The remaining balance of the VOC emissions must be included in the "VOC—unclassified" emissions (contaminant code *50001*).

If stack test data are used to determine total VOC emissions, the determination methodology for the speciated emissions must be coded "S"

for ‘scientifically calculated’; the *VOC—u* emissions must be coded “M.” If AP-42 emission factors are used to determine total VOC emissions, the determination methodology must be coded “A.”

*Example:* Using stack test data, the VOC emissions from a boiler have been determined to be 43 tons. No information about the composition of the exhaust VOC emissions exists. Inlet gases were analyzed but, because complex oxidation reactions occur in the combustion chamber that alter the composition of emissions significantly, the results of the inlet gas analysis cannot be used to speciate the VOC emissions. The VOC emission factors in AP-42 must be used to speciate the VOC.

In AP-42, formaldehyde is one of the compounds that is graded C or better and the emission factor is 0.075 lb/MMscf. The total VOC emission factor in AP-42 is 5.5 lb/MMscf. To obtain formaldehyde’s speciation ratio, divide the formaldehyde emission factor by the total VOC emission factor:

$$0.075\frac{\text{lb}}{\text{MMscf}} \div 5.5\frac{\text{lb}}{\text{MMscf}} = 0.0136$$

Multiply the boiler’s total VOC emissions by this ratio to determine the formaldehyde emissions:

$$43 \text{ tons VOC} \times 0.0136 = 0.5864 \text{ ton formaldehyde}$$

Perform similar calculations for benzene and toluene. Report the boiler’s VOC emissions as shown in Table A-4.

**Table A-4. Reporting VOC Emissions from External Combustion**

| Contaminant Code | Contaminant | Annual Emissions | Determination Methodology |
|---|---|---|---|
| 50001 | VOC—unclassified | 42.3706 tons | M |
| 51680 | formaldehyde | 0.5864 ton | S |
| 52420 | benzene | 0.0164 ton | S |
| 52490 | toluene | 0.0266 ton | S |

# Combined-Cycle Turbines with Heat-Recovery Steam Generators

## *Structure*

Structural representation of cogeneration turbines with an associated duct burner, heat-recovery steam generator (HRSG), or boiler will vary, depending upon the operation of the units in question.

If the unit associated with the cogeneration turbine cannot operate independently from the turbine, represent the units as one facility–

emissions point path, noting in the path or facility comments that a duct burner or HRSG operates in conjunction with the turbine.

If the unit associated with the cogeneration turbine can operate independently from the turbine, as is the case for most boilers, represent the turbine as one facility and the associated unit as a separate facility. If both the turbine and the associated unit vent to the same emission point, create a common emission point for both facilities.

If the turbine vents to a separate emission point (that is **not** the emission point shared with the associated unit) when it operates independently, the emission point needs to be represented in the EI. Create two paths for the turbine, using one facility and two emission points: one for the separate turbine stack, and one for the stack shared with the associated unit. The path for the associated unit that vents to the shared stack must be represented in the EI.

## Expected Contaminants

These facilities' reported emissions must include all of the following:

- PM (contaminant code *10000*)
- $PM_{10}$ (contaminant code *20000*)
- $PM_{2.5}$ (contaminant code *39999*)
- VOCs (contaminant codes *50001* through *59998*)
- $NO_x$ (contaminant code *70400*)
- $SO_2$ (contaminant code *70510*)
- CO (contaminant code *90300*)
- $NH_3$ (contaminant code *70050*)

## Emissions Determination Methodologies

The appropriate emission determination methodologies for combined-cycle turbines are, in order of preference:

- D (continuous monitoring system)
- F (predictive monitoring system)
- M (measured—stack test data)
- Q (portable analyzer test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- S (scientifically calculated)
- E (estimated)

Portable analyzers have their own determination methodology and must be designated as "Q." Testing conducted with a portable analyzer does not qualify as stack testing; therefore, the emissions determination methodology must not be coded 'measured' ("M"). If the stack test results from an identical unit are used to determine the emissions, the determination methodology must be coded 'estimated' ("E").

If none of these methodologies accurately represent a source's emissions, contact the EAS for further assistance.

### $NO_x$ and CO Emissions

$NO_x$ and CO emissions from these sources are typically continuously monitored.

If stack test data is used to determine emissions from a combined-cycle turbine equipped with a duct burner, two data sets must be used to determine the emissions: one representing emissions with the duct burner on, and the other with the duct burner off. If two separate data sets do not exist or if another method is used to determine emissions, contact the EAS for guidance.

### Particulate, VOC, and $SO_2$ Emissions

For guidance on determining and speciating these emissions, see "Internal Combustion Engines" earlier in this supplement.

## Portable Engines

### Structure

A portable engine is an engine that is designed to be, and is capable of being, moved. It is considered a stationary source only if it remains at a single point or location for 12 or more consecutive months. Therefore, it may be subject to reporting requirements. While the portable engine itself may not be subject to the reporting requirements, emissions from any maintenance performed on the engine may need to be reported.

An engine that replaces another engine at a location and that is intended to perform the same or similar function is included in calculating the consecutive time period. A portable engine is represented in the EI the same way as an internal combustion engine and emissions are calculated in the same manner. Please refer to "Internal Combustion Engines," earlier in this supplement.

# TECHNICAL SUPPLEMENT 2: COOLING TOWERS

**Technical Disclaimer**

This technical supplement is intended to help determine and correctly report cooling tower emissions. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how cooling towers work, how they generate emissions, how they are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies conducted and as new information becomes available. The TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The methods represented are intended as an aid in calculating emissions; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. Additional guidance regarding the acceptability of a given emissions determination method is available from the EAS at 512-239-1773.

## Introduction

This technical supplement offers guidance on identifying, quantifying, and correctly reporting cooling tower emissions on the annual EI. It does not address devices such as fin-fan coolers and the cooling towers used exclusively in HVAC systems.

### *Definitions*

In this document, *cooling tower* refers to the equipment that, through the process of direct contact with atmospheric air, reduces the temperature of water used to cool either process equipment or process fluid streams. *Cooling tower heat exchange system* refers to the cooling tower and all associated heat exchangers, pumps, and ancillary equipment where water is used as a cooling medium to transfer heat from the process fluids to the water.

## Cooling Tower Structure

Each cooling tower in VOC service must be represented as a facility in the EI. For a multicell tower, represent the entire tower as a single facility.

To add a cooling tower in VOC service to the EI, use the Facility Information for Cooling Tower form. For cooling towers already in the EI, ensure that the appropriate facilities have a “cooling tower” group and profile and that all facility profile characteristics are complete. If a cooling tower facility has the incorrect group type, strike through the incorrect group type on the EI and write “cooling tower,” and update the facility by attaching a completed Facility Information for Cooling Tower

form to the EI; be sure to write "UPDATE FACILITY" across the top of the form.

Each cooling tower facility must have a **stack** type emissions point. This stack type emissions point must have:

- a stack diameter equal to the diameter
  - of the tower top for natural draft towers,
  - of the fan for mechanical draft towers, or
  - of an average fan for multicell towers;
- a stack velocity of 10–20 feet per second;
- a temperature ranging from ambient to 15 degrees Fahrenheit above ambient;
- a nonzero moisture content (generally between 5 to 10 percent); and
- no horizontal discharge, except for crossflow towers (possibly).

When a permit lists multiple fans in a multicell tower, use multiple stack emissions points attached to a single cooling tower facility.

# Cooling Tower Source Classification Codes

The cooling tower must be represented on the EI with an SCC of either *38500101* (for mechanical-draft cooling towers) or *38500102* (for natural-draft cooling towers).

# Expected Emissions

Cooling towers operate in such a manner that they may emit particulate matter, dissolved solids, or chemicals entrained in the cooling water. Cooling tower emissions fall into three categories: particulate matter, inorganic compounds, and VOCs. Any tower has the potential to emit all three of these emissions types in varying amounts, depending on its service.

## *Particulate Matter*

Particulate emissions result from the presence of minerals or any dissolved or suspended solids in the cooling water. Air flowing through the tower can entrain water droplets and carry them out of the cooling tower in a process referred to as *drift*. Once these drift droplets leave the tower and evaporate, they deposit dissolved or suspended solids as fine particulate matter ($PM_{10}$ or smaller).

Cooling towers are generally designed with drift eliminators—typically mesh or a series of angled slates placed above the water inlet. Note that, despite its name, a drift eliminator will reduce, but not eliminate, drift.

### *Inorganic Compounds*

Inorganic emissions may result from inorganic process fluids leaking into the cooling water or from water treatment chemicals or other additives used in the cooling water system. The air flowing through the tower may strip these inorganic compounds from the water, resulting in their emission to the atmosphere. Typical inorganic emissions may consist of chlorinated compounds, brominated compounds, or any other inorganic substance present in the cooling water.

### *Volatile Organic Compounds*

Although some VOC emissions may result from the stripping of organic water treatment chemicals, the primary sources of VOC emissions are hydrocarbon-containing process fluids leaked into the cooling water by components of the cooling tower heat exchange system. Once the hydrocarbon-contaminated cooling water reaches the tower, the VOCs either flash out of the water or are stripped out by the tower's air flow, resulting in VOC emissions.

## Emissions Determination

The process serviced by the cooling tower will largely determine how emissions must be determined and reported. For each contaminant type, determination methods and special concerns are discussed in the following sections.

### *Particulate Matter*

Some manufacturers provide drift factors that may help determine particulate emissions. If a vendor-supplied drift factor is used, the determination methodology must be coded "V" for 'vendor data.'

If no drift data are available from the manufacturer, determine particulate emissions using the appropriate factor from AP-42, Section 13.4. The determination methodology must be coded "A."

*Note:* AP-42 does not include factors for $PM_{2.5}$ emissions. Use the best available site-specific data and process knowledge to determine $PM_{2.5}$ emissions from cooling towers.

### *Inorganic Compounds*

Very little research has focused on inorganic compound emissions from cooling towers. Emissions resulting from water additives may be determined based on the additive's chemical characteristics, the amount of additive used, the volume of cooling water, and a scientifically based assumption about the percentage of additive stripped from the cooling water at the tower. The determination methodology must be coded "E" for 'estimated.'

# Volatile Organic Compounds

## Emissions Determination Methodologies: Order of Preference

The appropriate VOC emissions determination methodologies for cooling towers are, in order of preference:

- emissions data from a HRVOC monitoring system required by 30 TAC 115.764 (coded “H”)
- emissions data from a TCEQ-approved air-stripping method (coded “M”)
- emissions data from an approved monitoring and control program plan, other than an air-stripping method, on file with the TCEQ (coded “B”)
- emissions data from an unapproved monitoring and control program (coded “E”)
- the AP-42 **uncontrolled** VOC factor (coded “A”)

Emissions based on HRVOC monitoring systems required by 30 TAC 115.764 must be coded “H.” However, emissions determined using monitoring systems not required by 30 TAC 115.764 must be coded “B.”

The use of the AP-42 **controlled** VOC emission factor is **not** allowed. Detailed explanations of these emissions determination methodologies appear in the following sections.

## Emissions Determination Methodologies

If cooling water is used to cool VOC process streams, emissions will result from process fluid leaks into the cooling water, with one exception: if the cooling water is maintained at a pressure at least 5 psi greater than the process fluid pressure throughout the entire cooling tower heat exchange system. For such systems, heat-exchanger leaks do not generate VOC emissions from the cooling tower. For all other cooling tower heat exchange systems, where the cooling water is not maintained at a pressure at least 5 psi greater than the process fluid pressure throughout the entire cooling tower heat exchange system, use the following guidelines to determine emissions.

If VOC emissions are determined using an emission factor from Section 5.1 of AP-42, the uncontrolled emission factor (6 lb/MMgal) must be used. According to AP-42, the control indicated by the controlled emission factor (0.7 lb/MMgal) is technology that minimizes hydrocarbon leaks into the cooling water system and also monitors the cooling water for hydrocarbons. If a monitoring system allows for such control, then the associated data must be sufficiently detailed to allow for the derivation of an emission rate, either through a measurement of total VOCs or through testing for all VOC species present in the cooling water. If the monitoring system is insufficient to monitor and quantify hydrocarbons, the

"uncontrolled" VOC emission factor must be used. If the emissions are determined in this manner, the determination methodology must be coded "A."

Emissions determined based on measurements from an air-stripping method as outlined in the *TCEQ Sampling Procedures Manual*, Appendix P, are preferred. This document is available at <www.tceq.texas.gov/assets/public/implementation/air/sip/miscdocs/mgf/115/AppP.pdf >. When using such data to determine emissions, assume that VOCs were present at the measured concentration for the entire period between samples. If analytical test methods indicate that VOC measurements are below the minimum detection limit, the value equating to half of the detection limit must be used to calculate VOC emissions unless otherwise specified by a permit condition, TCEQ or federal rule, or commission order. This method applies to monitoring that determines the total VOC emission rate, either from a measurement of total VOCs or by a summation of measurements of all of the VOC species in the cooling water. Where only a select few of the possible VOCs present in the cooling water are measured, the AP-42 uncontrolled emission factor must be used to determine the total VOC emission rate from the cooling tower, and the measurements of the select VOC species (such as HRVOCs) must be speciated in the emissions reporting and subtracted from the total VOC emission rate derived from AP-42. Since this method measures the amount of air-strippable VOCs present in the cooling water, the determination methodology must be coded "M" (for 'measured').

Measured cooling water VOC concentrations and flow rate data may be used to determine the VOC emissions—assume that VOCs were present at the measured concentration for the entire period between samples. If analytical test methods indicate that VOC measurements are below the minimum detection limit, half of the detection limit must be used to calculate VOC emissions unless otherwise specified by a permit condition, TCEQ or federal rule, or commission order. This method applies to monitoring situations where a total VOC emission rate can be determined, either from a total VOC measurement or a summation of measurements of all of the VOC species in the cooling water. **Please note that the application of TOC or VOC concentration to water drift does not properly account for the VOC emissions stripping or flashing out of the water and must not be used.** Concentrations must be applied to the flow (circulation) rate data to determine emissions.

For cases where only a select few of the possible VOCs present in the cooling water are measured, the AP-42 uncontrolled emission factor must be used to determine the total VOC emission rate from the cooling tower, and the measurements of the select VOC species (such as HRVOCs) must be speciated in the emissions reporting and subtracted from the total VOC emission rate derived from AP-42. Since these methods measure the composition of chemicals in the cooling water rather than the amount of

emissions, the emissions are not determined by using measured data. The appropriate determination methodology will depend upon whether data are gathered by following an approved monitoring and control program plan on file with the TCEQ. If so, the determination methodology must be coded “B” for ‘material balance.’ If not, the determination methodology must be coded “E” for ‘estimated.’ Please note that, in the case of cooling towers, such estimates are preferred instead of the AP-42 emission factors.

If the air-strippable VOC concentration or cooling water VOC concentration is measured, but a large leak occurs between times of sampling events and no monitoring data are available for the period of the leak, then use the AP-42 uncontrolled emission factor to determine emissions for the leak period. If the beginning date and time when the leak began are not known, assume that the leak began immediately after the previous sample was taken. If the majority of annual emissions are determined using the measured data, the determination methodology must be reported as described in the preceding paragraph.

Note that the information from devices such as lower explosive limit detectors, chlorine residual measurements, and total organic carbon measurements do not qualify as adequate monitoring or control technology; therefore, the AP-42 controlled VOC emission factor must not be used.

## Annual and Ozone Season Rates

If measured data are available for a cooling tower, calculate the reported emissions using actual, rather than average, test data. Use test data from each sampling event to determine emissions released since the prior sampling event. Sum the emissions obtained from the different sampling periods to obtain the annual total. If analytical test methods indicate that VOC measurements are below the minimum detection limit (that is, undetected), then half of the detection limit must be used to calculate VOC emissions, unless otherwise specified by permit condition, TCEQ or federal rule, or commission order.

For example, suppose that tests are performed weekly to determine a cooling tower’s VOC emission rate. Using the test results from each week and the associated water flow for the seven days preceding the sample time, calculate the total emissions for each seven-day period during the year, then sum those weekly emissions to arrive at the annual total.

To obtain ozone season emission rates, use the same methodology but only sum the emissions from sampling periods that occurred during the ozone season months.

# Speciation

If samples were tested for VOCs, then use the measured data to speciate emissions. For more information on speciation requirements, see Chapter 4. For guidance regarding method detection limits and speciated compounds, follow the general guidance outlined in "Minimum Detection Limits," Chapter 4.

# Supporting Documentation

Include documentation with the EI that supports and validates the emissions reported in the inventory. The relevant supporting documentation for cooling towers includes, but may not be limited to, representative samples of the following types of data:

- VOC test results, especially from times when leaks were discovered;
- cooling water and process fluid pressure readings for systems that maintain cooling water at a pressure at least 5 psi greater than the process fluid pressure throughout the entire cooling tower heat exchange system;
- annual water treatment chemical usage data for all chlorinated or brominated chemicals;
- annual and daily flow rate for cooling water; and
- emission rates calculated from measured data.

# Issues of Special Concern

**What if I share a cooling tower with another company?**

Emissions must be reported by the owner or operator of the cooling tower. Please call the EAS for additional guidance about an individual situation.

**Are there any circumstances when I may use the AP-42 controlled VOC emission factor?**

No. According to AP-42, use of the "controlled" emission factor (0.7 lb/MMgal) is contingent upon the use of applicable control technology to minimize hydrocarbon leaks into the cooling water system and the monitoring of cooling water for hydrocarbons. If a monitoring system is sufficient to provide such "control," then the associated data must be sufficiently detailed to allow for the derivation of an emission rate. If the monitoring system is insufficient to provide data for determining emissions, then the system is insufficient to provide reliable "control" and so the "uncontrolled" VOC emission factor is appropriate for EI purposes.

**Must I report particulate matter emissions?**

Yes. While drift eliminators greatly reduce cooling tower drift, the drift droplets that do escape are so small and of such little mass that they can remain airborne for some time and travel a significant distance.

**My cooling tower's emission point is currently shown as a fugitive area. Must I change this?**

Yes. The cooling tower's emission point must be shown as a stack. For more information, see "Cooling Tower Structure" earlier in this supplement, as well as instructions for completing the Emission Point Information: Stack Profile form at <www.tceq.texas.gov/goto/ieas>.

**What does the cooling tower characteristic "HRVOC Service?" mean?**

Regardless of the county location of the regulated entity, if the cooling water cools any process equipment or process fluid stream containing over 5 percent by weight of aggregate highly reactive volatile organic compounds (HRVOCs—ethylene, propylene, all isomers of butene, and 1,3-butadiene), the cooling tower is considered to be in HRVOC service for EI purposes.

**If my cooling tower is used exclusively for comfort cooling and does not cool process fluids in a heat exchange system, how do I represent that on the EIQ?**

This information may be included in the comments field under the Facility Information portion of the EIQ for the cooling tower in question.

# References

Compilation of Air Pollutant Emission Factors. 1995. Vol. I: *Stationary Point and Area Sources.* 5th ed. AP-42. Research Triangle Park, NC: U.S. Environmental Protection Agency. Available online at: <www.epa.gov/ttn/chief/ap42/>. Accessed Nov. 4, 2012.

Perry, Robert H., et al. 1997. *Perry's Chemical Engineers' Handbook.* 7th ed. New York: McGraw-Hill.

# TECHNICAL SUPPLEMENT 3: FUGITIVE EMISSIONS FROM PIPING COMPONENTS

**Technical Disclaimer**

This technical supplement is intended to help determine and correctly report fugitive emissions from piping components. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how piping components work, how they generate emissions, how they are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. The TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The calculation methods represented are intended as an emissions calculation aid; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS at 512-239-1773.

## Introduction

This technical supplement offers guidance for identifying, determining, and correctly reporting fugitive emissions from piping components and associated equipment. It does not address emissions from cooling towers, oil-water separators, material stockpiles, loading operations, or other sources not related to piping components.

Please note that structural representation of piping components as a fugitive area in the EI is specifically addressed under "Issues of Special Concern" later in this supplement. For general guidance on this topic, consult Chapter 3, "Emissions Inventory Structure."

### *Definitions*

In this document, *traditional component types* refers to those component types traditionally considered and reported as sources of fugitive emissions from piping components: valves, connectors, pumps, compressor seals, relief valves, sampling connections, process drains, and open-ended lines. *Nontraditional component types* refers to component types traditionally not treated as sources of fugitive emissions from piping components, but identified as such by recent scientific studies. Examples include screwed fittings, liquid relief valves, agitators, heat exchanger heads, site glasses, bolted manways and hatches, blind flanges, caps and plugs, connectors, compression fittings, and metal-to-metal seals.

# Fugitive Component Structure

The emissions inventory structure of fugitive piping components will depend on the site. For sites that process or handle a single hydrocarbon or inorganic stream, such as a natural gas compressor station or a petroleum marketing terminal, the fugitive emissions from the entire plant's piping components must be represented by one facility–emissions point path. For sites that process or handle multiple hydrocarbon or inorganic streams with varying compositions, however, fugitive emissions must be reported by process area as detailed below. Please note that individual fugitive components must be grouped and reported as collective sources according to the guidance below as well as the section "Guidelines for Including Sources in Emissions Inventory Structure" in Chapter 3. Individual fugitive components are not considered individual facilities.

When separating fugitive areas into multiple facilities, if different process areas within a plant follow different leak detection and repair programs, each area must be represented by a separate path to avoid confusion. Also, since stream composition may differ greatly between processes and may necessitate the use of different calculation methodologies, fugitive emissions from separate processes must be reported under separate facilities. Consistent with these criteria, fugitive components—including valves, piping, flanges, and other components—must continue to be grouped together and reported under one FIN and not under individual FINs. For example, for a refinery with a process area for MTBE production, emissions determinations for the MTBE process area must use correlation equations or the SOCMI average emission factors, as they are more accurately determine emissions than the refinery factors. Separate facility–emissions point paths must represent the MTBE process area fugitives and the refinery fugitives.

# Expected Emissions

The fugitive emissions from piping components may include organic or inorganic compounds in a gaseous or liquid state, depending upon the composition of streams flowing through the associated piping components.

# Quantifying Fugitive Emissions from Piping Components

## *Introduction*

The fugitive emissions from piping components are determined using emission factors or equations statistically developed from component- and industry-specific sampling data. Methodologies will differ, depending upon whether a source is monitored using a VOC instrument detector or is

not monitored. For monitored sources, base determinations on correlation equations and the individual screening values obtained with the instrument. For unmonitored sources, base determinations on average emission factors.

For detailed information on available emission factors and determination methods, see the EPA documents *Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017) and "Preferred and Alternative Methods for Estimating Fugitive Emissions from Equipment Leaks" (Emissions Inventory Improvement Program Document Series, Volume II, Chapter 4, November 1996), as well as the TCEQ Air Permits technical guide for equipment leak fugitives available at <www.tceq.texas.gov/goto/nsr_elf>.

## Requirements for Determining Fugitive Emissions from Piping Components

Emissions from instrument-monitored components must be determined using the actual monitoring data gathered at a site. Most LDAR program permit conditions require the retention of screening value data for all monitored components. Therefore, most sites with a monitoring program will have the necessary data to use correlation equations to determine the fugitive emissions.

Specifically, if a regulated entity is required by permit condition, TCEQ rule, or commission order to retain screening value data for its monitored components, correlation equations must be used to determine emissions.

The TCEQ has previously allowed the use of LDAR reduction credits applied to the EPA's average emission factors for annual emissions determinations. However, using actual leaking component data, reflecting a site's actual leak fraction and LDAR program effectiveness, will allow for more accurate emission determinations than using average emission factors with LDAR reduction credits.

Since all monitored sources have individual screening values, the use of average emission factors with LDAR reduction credits to determine emissions from monitored components is not allowed. One exception is detailed under "Quantifying Emissions from Components Monitored by an Audio/Visual/Olfactory Inspection" later in this supplement.

## Emissions Determination Methodologies: Order of Preference

The appropriate methodologies for determining VOC emissions from piping components are, in order of preference:

- Unit-specific correlation equations developed using bagging data in accordance with EPA guidelines (code as "M")

- EPA correlation equations using screening values from an LDAR program (code as “A”)
- EPA industry-appropriate average factors (code as “A”)

The use of reduction credits (from a LDAR program) applied to the EPA’s average factors for EI purposes is no longer allowed, with few exceptions. One exception is detailed under “Quantifying Emissions from Components Monitored by an Audio/Visual/Olfactory Inspection” later in this supplement.

### Emission Factors

All emission factors discussed in this supplement are available in the PDF document titled *Emissions Factors for Equipment Leak Fugitive Components* on the EAS’s Web page at <www.tceq.texas.gov/goto/ieas>.

## Determining Emissions from Monitored Components

### Quantifying Emissions Using Correlation Equations

Emissions from monitored components must be determined using site-specific monitoring data. Specifically, correlation equations must be used to determine emissions when a permit condition, TCEQ rule, or commission order requires the retention of screening value data.

Correlation equations use an instrument-measured VOC concentration screening value to determine a component-specific emission rate. Screening value data are collected using a portable monitoring instrument to sample air from potential leak interfaces on individual pieces of equipment. Screening data must be collected in accordance with EPA Reference Method 21, as detailed in 40 CFR 60, Appendix A and *Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017), available at the EPA’s Web site at <www.epa.gov/ttnchie1/publications.html>.

To determine emissions, the screening value data are used either in industry-specific correlation equations developed by the EPA or in correlation equations developed by a company for a specific process unit. The EPA correlation equations are available in Protocol for Equipment Leak Emission Estimates and in the PDF document *Emissions Factors for Equipment Leak Fugitive Components* on the EAS’s Web page at <www.tceq.texas.gov/goto/ieas>. The EPA has approved separate correlation-equation sets for synthetic organic chemical manufacturing industry (SOCMI) components and petroleum industry components (including refineries, marketing terminals, and oil and gas production facilities).

The TCEQ accepts the use of correlation equations for screening values between zero and 100,000 parts per million. To determine emissions using correlation equations, consider each component's screening value (adjusted for the background concentration) as follows:

- Before using the screening value in the appropriate correlation equation, determine the screened stream's response factor and, if necessary, adjust the screening value according to the guidance in *Protocol for Equipment Leak Emission Estimates*.
- For each component with a nonzero and non-pegged screening value, enter the screening value into the applicable correlation equation to determine a mass emission rate. Sum the individual mass emission rates for each component to determine a total leak rate. Note that each individual screening value must be entered into the correlation equation to predict a component's leak rate. Averaged screening values must not be used to determine emissions.
- For each component with a screening value of zero, note that, although the correlations predict a leak rate of zero for screening values of zero, the EPA data suggest that this prediction is incorrect. The EPA has established a default zero leak rate factor that must be applied to each component whose screening value was zero.
- For each component with a pegged screening value, use the EPA-developed default 100,000 ppm pegged leak rate factor. Note that if a pegged value of 10,000 ppm is indicated (i.e., the instrument will not quantify the screening value between 10,000 ppm and 100,000 ppm), then use the default 100,000 ppm pegged leak rate factor—**not** the default 10,000 ppm rate factor.

This information is summarized in Table A-5.

Since a component's screening concentration may vary from one monitoring period to another, emissions for each period must be based upon each component's screening concentration for that period. These period-specific emission rates must then be summed to obtain an annual emissions rate. For example, if components are monitored quarterly, each component's quarterly screening value must be used to determine quarterly emissions, and then the quarterly emission rates summed to obtain the component's total annual emissions.

**Table A-5. Determining Emissions Using Correlation Equations**

| Screening value | Determine emissions using … |
|---|---|
| Zero | The default zero leak rate factor |
| Nonzero and nonpegged | The screening value in the applicable correlation equation |
| Pegged | The default 100,000 ppm pegged leak rate factor |

When determining a component's leak duration, it would be most conservative to assume that the component was leaking at the measured concentration for the entire period since last monitored. An acceptable engineering estimate would be that the component was leaking at the measured concentration for half the monitoring period, plus the time needed to repair the component. The TCEQ must approve any other method of determining leak durations.

When using the correlation equations to calculate emissions, the components must be monitored at least once during the year. Using monitoring data from a previous year to determine future emissions is a difficult process. If this is done, sound engineering assumptions to support the calculations must be provided with the EI.

Detailed information about correlation equations can be found in *Protocol for Equipment Leak Emission Estimates*.

### Unit-Specific Correlation Equations

If a regulated entity has developed its own set of unit-specific correlation equations for its equipment leak fugitive components, those equations may be used to determine emissions only if the equations, sampling procedures, and all related procedures and data comply with EPA Reference Method 21 and the guidance in *Protocol for Equipment Leak Emission Estimates*.

When using company-developed correlation equations, supply supporting documentation indicating the basis for these equations. Also, if the site-specific equations do not take into consideration components with screening values of zero, the TCEQ may require the use of the EPA's default zero leak rates. Likewise, if the site-specific equations do not include components with pegged screening values, the TCEQ may require the use of the EPA's pegged leak rates.

## *Quantifying Emissions from Components Monitored by an Audio/Visual/Olfactory Inspection*

For odorous or toxic inorganic compounds, an AVO inspection may be required by TCEQ rule, commission order, or permit condition. Generally, an AVO inspection program may only be applied to inorganic compounds that cannot be monitored by instrument. In limited instances, the AVO inspection program may be applied to extremely odorous organic compounds such as mercaptans. *Note:* the trace amounts of mercaptans present in natural gas are not sufficient to allow for an AVO inspection. However, a plant that manufactures mercaptans would be eligible, since the process streams contain a sufficient concentration of these compounds.

If no monitoring or screening data exist for AVO-monitored components, then average emission factors with AVO reduction credits applied can be used to determine emissions. To claim credit for this program, the

documentation must demonstrate that all elements of the program are in place and were followed.

AVO factors can be found in the PDF document titled *Emissions Factors for Equipment Leak Fugitive Components* on the EAS's Web page at <www.tceq.texas.gov/goto/ieas>.

Please note that an AVO inspection is different than a weekly physical inspection (a weekly walkthrough inspection). An AVO inspection is typically performed once per shift (every four to eight hours) versus once per week, and earns a reduction credit of up to 97 percent. A weekly walk-through inspection earns only a 30 percent reduction credit. An AVO inspection should be coded as "A" in the EIQ.

# Determining Emissions from Unmonitored Components

## *Emissions Determination Requirements*

Emissions from monitored components must be determined using actual monitoring data. However, for unmonitored components, average emission factors may still be used to quantify emissions.

## *Quantifying Emissions Using Average Factors*

Average emission factors are divided into four categories:

- SOCMI,
- oil and gas production,
- refinery, and
- petroleum marketing terminals.

Within each category, factors vary depending upon specific component type (connectors, valves, pumps, etc.) and material in service (light liquid, heavy liquid, gas-vapor, or water–light liquid). For components in liquid service, choose between a "heavy liquid" emission factor and a "light liquid" emission factor. Use the "heavy liquid" emission factor if the stream's vapor pressure is less than or equal to 0.044 psia at 68°F. If the stream's vapor pressure is greater than 0.044 psia at 68°F, use the appropriate "light liquid" emission factor.

Note that the average emission factors generally determine total hydrocarbon emissions. Therefore determine the total VOC emissions by multiplying the calculated emission rates by the stream's percentage by weight of VOC compounds.

The EPA average emission factors for the industry types described in the following sections can be found in *Protocol for Equipment Leak Emission*

*Estimates* (EPA-453/R-95-017), available at the EPA Web site at <www.epa.gov/ttn/chief/publications.html>.

### SOCMI Emission Factors

Use the SOCMI emission factors to determine the fugitive emissions from piping components at chemical plants or chemical processes within refineries. SOCMI emission factors are divided into three categories: SOCMI average emission factors, "SOCMI with ethylene" emission factors, and "SOCMI without ethylene" emission factors.

Use the SOCMI average emission factors, which were developed to represent fugitive emission rates from all chemical plants, for streams containing between 11 percent and 85 percent ethylene. For streams containing more than 85 percent ethylene, use the "SOCMI with ethylene" emission factors. For streams containing less than 11 percent ethylene, use the "SOCMI without ethylene" emission factors.

### Oil and Gas Production Emission Factors

The oil and gas production emission factors are based on data from piping component leaks from oil and gas production sites gathered by the American Petroleum Institute and evaluated by the EPA. These factors include four different equipment service categories: gas, heavy oil (less than 20° API gravity), light oil (greater than 20° API gravity), and water/light oil (water streams in light oil service with a water content between 50 percent and 99 percent).

### Refinery Emission Factors

Use refinery emission factors to determine the fugitive emissions from piping components for a refinery process. For a chemical process located within a refinery that is not specifically considered a refinery process (for example, an MTBE production unit), use the SOCMI factors, rather than the refinery factors, to calculate emissions.

### Petroleum Marketing Terminal Emission Factors

Use the emission factors for petroleum marketing terminals to determine the fugitive emissions from piping components at gasoline-distribution facilities that are one step removed from local gasoline stations and other end users. Do not use these emission factors to determine the fugitive emissions from loading racks at chemical plants and refineries; instead, use the appropriate SOCMI or refinery emission factors.

The use of these emission factors must be accompanied by an AVO program performed monthly. To claim credit for this program, the documentation must demonstrate that all elements of the program are in place and were followed. Because the petroleum marketing terminal emission factors include the appropriate reduction credit for the AVO inspection, no additional reductions may be taken.

If a monthly AVO inspection was not performed, use the refinery emission factors to determine emissions.

## *Quantifying Emissions from Components Exempt from Monitoring*

Some components may be exempt from monitoring requirements based on size, physical location at a facility, or low vapor pressure. Emissions from exempt components, like those from unmonitored components, **must** be calculated and reported. Since these components are not monitored, calculate their associated emissions based on average emission factors with no reduction credit applied. When calculating emission rates, inaccessible components and other unmonitored components must be clearly identified and separated from monitored components.

## *Quantifying Emissions Using Average Emission Factors with Emissions Reduction Credits*

Quantifying emissions using average emission factors with emissions reduction credits applied implies the use of a monitoring (LDAR) program. Most instrument-based LDAR program permit conditions will require the retention of screening value data. Since the use of such data in correlation equations provides more accurate emissions determinations, the use of average emission factors with applied emissions reduction credits to determine actual annual emissions rates is no longer allowed.

### Reduction Credit for Connector Monitoring

Because connector monitoring is not usually required, emission reductions are not typically claimed for these components. However, if a weekly physical inspection program is in place, a 30 percent emissions reduction credit applied to average emission factors is allowed. To claim credit for any such program, the documentation must demonstrate that all elements of the program are in place and were followed. If connectors are instrument monitored, the correlation equations must be used to determine emissions according to the guidance in this supplement. In these cases, no additional reduction credit for connector monitoring may be applied to the correlation equation.

## *Quantifying Emissions of Odorous or Toxic Inorganic Compounds*

The best method to determine the emissions of odorous or toxic inorganic compounds like chlorine ($Cl_2$), ammonia ($NH_3$), hydrogen sulfide ($H_2S$), hydrogen fluoride (HF), and hydrogen cyanide (HCN) would be to develop unit-specific correlation equations, as described in Section 2.3.4 of *Protocol for Equipment Leak Emission Estimates*. To develop these equations, it is necessary to use a monitoring instrument that could detect the inorganic compounds in question.

Note that it also would be necessary to use a monitoring instrument that could detect the inorganic compounds in question to apply either EPA-developed correlation equations or screening range emission factors. If monitoring data are not available, calculate uncontrolled fugitive emissions using the industry-specific emission factors discussed previously. Although these VOC emission factors were not developed specifically for use with inorganic compounds, they are presently the best data available for determining inorganic fugitive emissions from piping components.

## Quantifying Emissions for Nontraditional Components

Emissions from nontraditional piping sources must be calculated and included in all emissions inventories. While these sources have not historically been included, recent scientific studies and equipment monitoring have indicated that these components are a source of emissions.

Although component-specific emission factors do not exist for most nontraditional components, the TCEQ has identified appropriate substitute emission factors based on component, leak potential, and leak mechanism similarity. These emission factors are listed in Table A-6.

**Table A-6. Appropriate Substitute Factors for Nontraditional Components**

| To determine this nontraditional component's emissions ... | | ... use this factor. |
|---|---|---|
| Agitator | | Light liquid pump |
| Blind flange | | Flange |
| Bolted manway or hatch | | Flange |
| Cap or plug | | Flange |
| Compression fitting | | Flange |
| Connector | | Flange |
| Heat exchanger head: | unmonitored<br>monitored | Open-ended line<br>Flange correlation equation |
| Liquid relief valve | | Light liquid valve |
| Metal-to-metal seal | | Flange |
| Screwed fitting | | Flange |
| Site glass | | Flange times two |
| Pressurized railcar loading arm: | threaded connection<br>quick-connect coupler | 0.0214 lb/hr/component<br>0.0055 lb/hr/component |

The component-specific emission factors for pressurized railcar loading operations threaded connections and quick-connect couplers are listed in Table A-6 and must be applied when a pressurized railcar is connected to the loading system using a loading arm. The loading arm may consist of a combination of threaded and quick-connect components and each component must be included in the EI.

## *Special Considerations when Quantifying Emissions*

When determining fugitive emissions, the hours of operation and equipment design specifications need to be considered.

### Hours of Operation

Fugitive emission factors for piping components are independent of process unit throughput. Because emissions occur whenever material is in the line, regardless of process activity or downtime, all streams must be in service for 8,760 hours annually. Any exception to this service time would require that the lines be purged during process downtime.

### Equipment Design Specifications

Certain facility design specifications may eliminate or minimize the fugitive emissions from piping components. If components are designed as described in the following sections, apply the stated emissions reduction credit.

***Relief Valves*:** 100 percent control may be assumed if either of the following conditions is met.

- relief-valve vents are routed to a properly operating control device, or
- relief valves are equipped with a rupture disc and pressure-sensing device (between the valve and the disc) to monitor for disc integrity.

It is important to verify proper relief valve operation if one of these design specifications is not used. If a relief valve does not reseat properly, the resulting emissions must be determined and reported. Possible sources of emissions include storage tanks, pressure tanks, loading operations, reactors, and mixing vessels controlled by relief valves.

***Pumps*:** The following pump types are designed to be “leakless” and are eligible for a 100 percent control credit:

- canned pumps
- magnetic drive pumps
- diaphragm-type pumps
- pumps with double mechanical seals that use a barrier fluid at a higher pressure than the process fluid pressure

- pumps with double mechanical seals that vent the barrier fluid seal pot to a control device

***Valves*:** Take a 100 percent control credit for the following:

- bellows valves with bellows welded to both the bonnet and stem
- diaphragm-type valves
- seal-welded, magnetically actuated, packless, hermetically sealed control valves

***Connectors*:** Take a 100 percent control credit if the connections are welded together around their circumference so that the flanges cannot be unbolted.

***Compressors*:** Take a 100 percent control credit if a compressor is designed with enclosed distance pieces and if the crankcase vents to a control device.

***Double Mechanical Seals*:** Take a 75 percent control credit for any component employing double mechanical seals.

# Speciation

Use current gas or liquid process stream analysis (or both) to speciate the fugitive emissions from piping components. Remember to speciate HAP emissions greater than 0.1 tpy for all sources. In nonattainment counties, supply HRVOC speciation to 0.1 tpy. For more information about speciation requirements for the emissions inventory, see Chapter 4.

# Supporting Documentation

Include representative sample calculations for each fugitive area, including a list of the components where a 100 percent control credit has been applied with a footnote describing the specific control method. If screening range emission factors are used, the TCEQ may require the submission of supporting documentation to verify that a permitted monitoring program is not required to retain screening value data.

In addition, if more than 5 tons was emitted at a fugitive area during the year, complete and submit the Fugitive Data Form or submit the requested information in a similar format. The Fugitive Data Form and instructions can be downloaded at the EAS Web page <www.tceq.texas.gov/goto/ieas>.

# Issues of Special Concern

**May I put the whole plant's fugitive emissions from piping components under one facility and emissions point?**

In a relatively small plant that handles one hydrocarbon stream, such as a natural gas compressor station or a petroleum-marketing terminal, the fugitive emissions from the entire plant's piping components must be represented by one facility–emissions point path.

For larger plants, however, it is generally more appropriate to report fugitive emissions under more than one facility. There are two main items to consider when breaking fugitive areas into multiple facilities. First, if different process areas within a plant follow different leak detection and repair programs, each area must be represented by a separate path to avoid confusion. Second, since stream composition may differ greatly between processes and may necessitate the use of different calculation methodologies, fugitive emissions from separate processes must be reported under separate facilities.

As an example for a larger site, consider a refinery with a process area for MTBE production. Emissions determinations for the MTBE process area must use correlation equations or the SOCMI average emission factors, as they are more appropriate than the refinery factors. Separate facility–emissions point paths must represent the MTBE process area fugitives and the refinery fugitives.

**Do I have to report emissions from components that are exempt from monitoring (such as components less than 2 inches in diameter)?**

Yes. The emissions from all components must be determined and reported, regardless of monitoring exemptions based on size, physical location, or low vapor pressure. Since these components are exempt from monitoring, an approach based on determining average factors will typically be used and no reduction credits from monitoring may be applied.

**I have a unit that was shut down part of the year. Must I determine fugitive emissions from piping components for the entire year or just for the part of the year when the unit was operating?**

The fugitive emissions from piping components must be determined for the entire year (8,760 hours) unless the unit's lines were purged during the downtime.

**I want to use correlation equations to determine the fugitive emissions from piping components. May I get screening values for a certain percentage of components and use the average value to represent all other components?**

No. Correlation equations may only be used to determine emissions for those components with individual screening values. If screening values

are not determined for certain components, a different calculation methodology must be used for these unmonitored components.

**I have a crude oil storage and loading facility. May I use the emission factors for bulk terminals?**

No. If monitoring data for the fugitive components exist, then the monitoring data must be used to determine emissions in accordance with the guidance in this supplement.

In the absence of monitoring data, use the oil and gas production average emission factors to determine the emissions. The bulk terminal average emission factors were developed specifically for gasoline and gasoline product loading operations. For crude oil storage and loading, the oil and gas production emission factors would be more appropriate.

**I have an LDAR program. Is there any way to represent this on my emissions inventory?**

An LDAR program can be represented in the EI by adding a CIN with an abatement code of *800*. Since the LDAR reduction credits can no longer be applied to average factors for emissions determinations, a control efficiency for this type of CIN is not required.

**How do I find out if any new fugitive emission factors for piping components have been developed or approved by the TCEQ?**

Review the PDF document *Emissions Factors for Equipment Leak Fugitive Components*, available on the EAS's Web page at <www.tceq.texas.gov/goto/ieas>.

**Do I have to report emissions of nonreactive compounds?**

Nonreactive compounds like methylene chloride and acetone are still considered air contaminants and must be reported. This is particularly important if a nonreactive compound has an associated allowable emission rate. Nonreactive fugitive emissions from piping components must be calculated in the same way as VOC fugitive emissions.

**For my permit, I used the EPA's average emission factors with LDAR reduction credits to determine my fugitive emissions from piping components. Can I use this approach to report these emissions in the emissions inventory?**

No. All monitored components must either have limited data for leaking components or, preferably, have individual screening values. Since using this monitoring data with correlation equations or screening range emission factors will provide a more accurate determination of a site's emissions, the use of LDAR reduction credits applied to average emission factors for emissions determinations will not be allowed.

**I monitor my connectors only once every four years based on "skip period" provisions in my permit. For years where the connectors are**

**not monitored, should I use the average emission factors with no reductions applied to determine my emissions? Or can I apply the correlation equations using the data from the last monitoring period?**

Normally, the TCEQ would require components to be monitored at least once during the current inventory year to use the correlation equations. Using monitoring data from previous years to predict future emissions requires the assumption that component leaks will not grow in the future—a questionable engineering assumption that will likely result in underestimation of emissions.

In the case of "skip period" provisions in a permit, it is permissible to use data from the last monitoring period in the correlation equations. For future leaking components, use leaking component screening values **before** any repairs are done. Since there is a history of monitoring and monitoring will occur in the future, the snapshot (as it were) taken before repairs should reasonably mirror any future monitoring.

Because there is no way to determine the amount of time a component will leak in the future, the emissions must be determined conservatively by assuming any leaking component will do so for an entire year. If a different method is used to determine the emissions, document valid engineering assumptions to support the calculations.

**In the past, I used screening range (leak/no-leak) emission factors to determine emissions from my fugitive area. May I continue to use this method?**

The correlation equations must be used to determine emissions from the fugitive area if screening value data from a monitoring program are available.

If a monitoring program does not retain screening value data, emissions must be determined using the best available method. If the screening range emission factors are used to determine the emissions, supply valid engineering assumptions to support the calculations.

**The TCEQ accepts the use of the correlation equations for screening values between zero and 100,000 ppm. If my instrument indicates non-pegged screening values above 100,000 ppm, can I use the correlation equations for those readings?**

For EI purposes, the TCEQ currently accepts correlation equations as an acceptable method to determine emissions where the screening value is above 100,000 ppm.

**My site does not fit specifically into one of the four categories of EPA average emission factors. What emission factors should I use?**

The most representative emission factors must be used. For example, a chemical storage and loading facility would select the SOCMI emission factors instead of the "petroleum marketing terminal" or "oil and gas"

emission factors. Both the type of product and the type of process must be considered when selecting the most appropriate factor.

# References

Texas Commission on Environmental Quality. 2008. *Emissions Factors for Equipment Leak Fugitive Components.* TCEQ Industrial Emissions Assessment Section. Available online at: <www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/ef_elfc.pdf>. Accessed Nov. 4, 2013.

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———. 1996. *Preferred and Alternative Methods for Estimating Air Emissions from Equipment Leaks.* Vol. 2, chapter 4. Emissions Inventory Improvement Program Document Series. Available online at: <www.epa.gov/ttn/chief/eiip/techreport/volume02/ii04.pdf>. Accessed Nov. 4, 2013.

# TECHNICAL SUPPLEMENT 4: FLARES

**Technical Disclaimer**

This technical supplement is intended to help determine and correctly report flare emissions. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how flares work, how they generate emissions, how they are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. The TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The calculation methods represented are intended as an aid; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. If additional guidance is needed regarding the acceptability of a given emissions determination method, contact the EAS at 512-239-1773.

## Introduction

This technical supplement offers guidance on identifying, quantifying, and correctly reporting emissions from elevated flares in the annual EI.

This document does not address flare structural representation in the inventory. For guidance on this topic, consult Chapter 3.

### *Definitions*

In this supplement, *waste gas* refers to gas streams produced in the process unit and routed to the flare for destruction.

*Supplemental fuel* refers to the gas that mixes with waste gas prior to its arrival at the flare tip, ensuring the combustibility of the total gas stream.

*Flared gas* refers to the combination of waste gas and supplemental fuel.

*Pilot gas* refers to the gas routed to the flare tip to ensure flared gas ignition.

## TCEQ 2010 Flare Study

In the fall of 2010, TCEQ funded a research project on flare destruction and removal efficiency (DRE) at a flare-test facility. The results demonstrated that air-assisted and steam-assisted flares must operate within a very limited range of assist rates to achieve the assumed DRE of 98 percent or greater. This project also demonstrated that operating an assisted flare in compliance with 40 CFR 60.18 does not ensure that the flare will achieve 98 percent DRE. Flare assist rates and other operating information must be reviewed and assessed to determine whether a flare may be operating at assist ranges that do not achieve the 98 percent DRE,

in which case the flare DRE must be reduced accordingly when determining and reporting flare emissions in the EI. The final report and additional project information are at <www.tceq.texas.gov/goto/2010-flare-study>.

# Expected Emissions

Flare emissions will include, at a minimum, nitrogen oxides ($NO_x$), carbon monoxide (CO), and uncombusted flared gas compounds. In addition, if the flared gas contains sulfur-bearing compounds, emissions will also include sulfur dioxide ($SO_2$).

## *Products of Combustion*

Products of combustion include $NO_x$, CO, and $SO_2$. Flared and pilot gas heat outputs impact emission rates of $NO_x$ and CO. The sulfur content of both flared and pilot gases determines $SO_2$ emissions.

## *Compounds from Uncombusted Flared Gas*

The flare's destruction efficiency determines what fraction of the flared gas remains uncombusted. The uncombusted flared gas compounds are generally volatile organic compounds, but may also include $H_2S$, CO, ammonia, and other organic and inorganic compounds present in the flared gas.

# Emissions Determination

All determinations of flare emissions depend upon the flared gas flow rate and composition. Therefore, before specific emission calculations are discussed, the preferred methods for obtaining the actual flared gas flow rate and composition data will be addressed.

## *Flared Gas Flow Rate and Composition*

To determine the emissions from flares, the actual flow rate and the specific composition of the gas routed to the flare must be known. The generally preferred methods of obtaining data on flared gas flow rate and composition are, in order of preference:

- continuous monitoring with quality-assured instruments
- continuous monitoring with instruments that may not meet all quality-assurance tests
- periodic testing with instruments and laboratory analytical methods
- engineering determinations based on detailed process evaluation
- a one-time performance test conducted during the inventory year

For flares subject to Chapter 115, Subchapter H, relating to highly reactive volatile organic compounds, valid flow rate and composition

data required by 30 TAC 115.725–26 must be used to determine emissions for any portions of 2012 during which HRVOC monitors were installed and operational.

In the absence of monitoring data, selection of the most accurate method may sometimes require exercising scientific judgment. For example, when using the results of a one-time performance test, the test conditions must be compared to the flare's actual operating conditions during the inventory year to determine whether the test accurately represents the flare's performance. If test conditions do not accurately model flare operation, then engineering determinations based on detailed process evaluation may provide the best data.

## $NO_x$ and CO Emissions

To calculate $NO_x$ and CO emissions, the net heating value of the flared gas must be known. Using the actual short-term flared gas composition and flow rate data for the inventory year, calculate the net heating value of the flared gas and the total heat release for each short time period. Use these total heat release data, in conjunction with the appropriate emission factors listed below, to determine $NO_x$ and CO emissions for each time segment. Since the calculated net heating value of the gas and the assist gas type will determine the appropriate emission factors, carefully select the correct factors for each flare from Table A-7.

Calculate emissions using the most accurate data for the gas flow rate and composition available. (See "Flared Gas Flow Rate and Composition" earlier in this supplement for more information on preferred data.)

Regardless of the data's source, the determination methodology for $NO_x$ and CO emissions must be coded "A" for 'TCEQ-approved factor.'

**Table A-7. Flare Emission Factors**

| Contaminant | Assist Type | Waste Gas Stream Net Heating Value[a,b] | Emission Factor |
|---|---|---|---|
| $NO_x$ | Steam | High Btu | 0.0485 lb/MMBtu |
| | | Low Btu | 0.068 lb/MMBtu |
| | Air or Unassisted | High Btu | 0.138 lb/MMBtu |
| | | Low Btu | 0.0641 lb/MMBtu |
| CO | Steam | High Btu | 0.3503 lb/MMBtu |
| | | Low Btu | 0.3465 lb/MMBtu |
| | Air or Unassisted | High Btu | 0.2755 lb/MMBtu |
| | | Low Btu | 0.5496 lb/MMBtu |

[a] High Btu: > 1000 Btu/scf

[b] Low Btu: 192–1000 Btu/scf

For flares subject to the HRVOC regulations in Chapter 115, Subchapter H, use the net heating value data required by 30 TAC 115.725 and 115.726 to determine $NO_x$ and CO emissions for any portions of 2012 during which HRVOC monitors were installed and operational.

## *Uncombusted Flared Gas Emissions*

Uncombusted flared gas emissions usually include VOCs, $H_2S$, or both. Emissions calculations for these contaminants are based on the flared gas flow rate and composition, and the appropriate destruction efficiency, which depends upon the actual flare operation.

### Destruction Efficiencies

Flare destruction efficiency varies with assist gas flow rate, flame stability, operating conditions, flare tip size and design, the specific compounds being combusted, and gas composition. HRVOC regulations in 30 TAC 115 address flare operational requirements. If flare operations are consistent with Chapter 115, the destruction efficiencies specified in 30 TAC 115.725 may be used to determine VOC emissions.

Otherwise, if the flare met all applicable regulations, the appropriate destruction efficiencies from either an applicable permit or the destruction efficiencies in Table A-8—the maximum destruction efficiencies for EI purposes—may be used to determine flare emissions. For assisted flares, there is the potential for over-assisting the waste gas stream, and the destruction efficiency may be lower than either the permitted efficiency or the appropriate efficiencies contained in the Chapter 115 HRVOC regulations or Table A-8. Emissions determinations must be adjusted accordingly.

Of course, if the flare flame (not the flare pilot) is ever extinguished, the destruction efficiency for the period when the flame was out will be zero. The pilot combustion zone is separate from the flame combustion zone. Therefore, the flare flame can be extinguished while the flare pilots are still lit.

### Determining Emissions

When flow rate and composition data are available from continuous monitoring systems, they must be used to determine the uncombusted emissions. Otherwise process knowledge and engineering calculations must be used to determine emissions.

**Table A-8. Maximum Destruction or Removal Efficiencies for Emissions Inventory Determinations**

| Waste Stream Composition | Destruction or Removal Efficiency |
|---|---|
| VOC, $C_1$–$C_3$[a] | 99% |
| VOC, > $C_3$ | 98% |
| $H_2S$ | 98% |

[a] 99% reduction must only be applied for compounds containing no more than three carbons that contain no elements other than carbon and hydrogen in addition to the following compounds: methanol, ethanol, propanol, ethylene oxide, and propylene oxide.

Since continuous monitoring methods measure the gas composition before destruction by the flare rather than the amount of emissions released to the atmosphere, the determination methodology must not be coded "M" (for 'measured data') or "D" (for 'continuous emissions monitoring systems'). The determination methodology for uncombusted flared gas emissions must be coded "H" (for 'HRVOC monitoring') when the actual flow rate and composition of the gas routed to the flare are obtained through a continuous monitoring system required by 30 TAC 115.725–26. When the actual flow rate and composition of the gas routed to the flare are obtained through a continuous monitoring system not required by 30 TAC 115.725–26, the determination methodology must be coded "B" (for 'material balance') instead of "H." If the flow rate and composition of the gas routed to the flare are determined using process knowledge and engineering calculations, the determination methodology for uncombusted flared gas emissions must be coded "S" (for 'scientific calculation').

Since waste gas streams routed to a flare vary widely, emission factors cannot be used to determine uncombusted flared gas emissions.

## *$SO_2$ Emissions*

$SO_2$ emissions are calculated based on the amount of sulfur-bearing compounds in the flared gas and on the appropriate destruction efficiency, as discussed previously.

For example, assume that 100 pounds per hour of flared gas, composed of 80 percent butane and 20 percent $H_2S$, is burned in an unassisted flare. The hourly uncombusted flared gas emissions would be 1.6 pounds of butane and 0.4 pounds of $H_2S$. In addition, the flare creates $SO_2$ from the $H_2S$. Determine the $SO_2$ emissions as follows:

$$20\frac{\text{lb } H_2S}{\text{hour}} \times 0.98 \times \frac{\text{lb-mole}}{34 \text{ lb } H_2S} \times 64\frac{\text{lb } SO_2}{\text{lb-mole}} = 36.9\frac{\text{lb } SO_2}{\text{hr}}$$

Note that a 98 percent destruction efficiency was assumed, since the flare does not have the potential for over-assisting and the flare complied with all applicable regulations.

The determination methodology for $SO_2$ emissions must be coded "B" for 'material balance.'

## Annual and Ozone Season Rates

Typically, flared gas flow rate and composition are highly variable; therefore, calculations of flare emissions need to take this variability into consideration. In general, emission determinations must not be based on annual average conditions. Instead, calculate emissions for short time segments when flare flow rate and composition are relatively constant, and then sum those short-term emissions to obtain the actual annual total. For example, if hourly flow rates and composition data are available, then calculate hourly emissions (lb/hr) and sum all hourly rates to obtain the annual total. If only weekly data are available, then calculate weekly average emissions and sum those to obtain the annual total.

These principles are especially important for ozone season emission calculations. The actual short-term emissions calculated for the ozone season months must be used to develop the daily average ozone season emissions.

If no flow rate or composition data are available, engineering estimates must take into consideration annual process variations that might affect flared gas.

## Speciation of Uncombusted Flared Gas Compounds

Depending on the flare service, emissions of uncombusted flared gas could include carbon, nitrogen, and sulfur compounds.

At this time, the composition of the uncombusted flared gas is assumed to remain unchanged. Although complex oxidation reactions in the flare flame may alter the emissions composition, no definitive method exists to identify those new compounds. Thus, emission determinations must assume no change in the composition of the uncombusted gas.

For example, consider a flared gas flow rate of 100 pounds per hour of VOC with a composition by weight of:

- 20 percent toluene,
- 60 percent xylene, and
- 20 percent butane.

If the flare is not over-assisted and sufficient waste gas heating value, volume, and concentration are present to support combustion, then a 98 percent destruction efficiency may be used. Based on the flow rate, composition, and destruction efficiency, **total** VOC emissions would be 2 pounds per hour.

Since these emissions are assumed to be 20 percent toluene, 60 percent xylene and 20 percent butane by weight, speciated VOCs would be reported as:

- 0.4 pound per hour toluene,
- 1.2 pounds per hour xylene, and
- 0.4 pound per hour butane.

For flares subject to HRVOC regulations, determine speciated uncombusted flare gas emissions according to the requirements (including destruction efficiencies) outlined in 30 TAC 115.725.

## Supporting Documentation

Flare emissions depend heavily on a flare's destruction efficiency. Supply detailed sample calculations showing the basis of flare destruction efficiencies and emissions.

For each flare in HRVOC service, indicate "Yes" on the "HRVOC Service?" characteristic. Regardless of the county location of the regulated entity, if any individual gas stream routed to the flare contains more than 5 percent by weight of aggregate highly reactive volatile organic compounds (HRVOCs—ethylene, propylene, all isomers of butene, and 1,3-butadiene), the flare is considered to be in HRVOC service for EI purposes.

## Reporting Emissions from a Shared Flare

In some cases, process streams are sent off-site to a flare owned by a different regulated entity. The applicable structure, including the flare emission point and abatement device, must be included in the emissions inventory where the process equipment is located and the emissions are generated. However, the path emissions will be zero because the owner of the flare is required to report the combustion emissions generated by the flare and the non-combusted contaminants. A path comment should be included on the path emissions page identifying the shared flare's EPN and its air account number. Please call the EAS for additional guidance.

## References

Allen, David T., and Vincent M. Torres. 2011. *2010 TCEQ Flare Study Project: Final Report.* Draft. Austin: Center for Energy and Environmental Resources, University of Texas.

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U.S. Environmental Protection Agency. 1985. *Evaluation of the Efficiency of Industrial Flares: Flare Head Design and Gas Composition.* EPA report 600/2-85-106. Washington.

# TECHNICAL SUPPLEMENT 5: MARINE FACILITIES

**Technical Disclaimer**

This technical supplement is intended to help determine and correctly report emissions from marine facilities. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how marine facilities work, how they generate emissions, how they are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. The TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The calculation methods represented are intended as an emissions calculation aid; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS at 512-239-1773.

## Introduction

This technical supplement offers guidance on identifying, quantifying, and correctly reporting marine facility emissions on the annual EI. Marine facility emissions must be reported as part of the annual routine EI. The owner or operator of the onshore facilities does not own or operate the marine vessel itself, but does operate most of the activities resulting in vessel emissions while the vessel is docked. Therefore, the owner or operator of the onshore facilities is responsible for reporting dock and dockside marine vessel emissions in the annual EI. This is consistent with the long-standing approach of reporting truck loading and cleaning emissions in the truck terminal or cleaning facility owner's inventory.

Several categories of facilities are associated with marine operations, including:

- onshore process units or equipment performing a function associated with dockside marine vessels (e.g., solid-material stockpiles, silos, tanks, and abatement devices)
- the dock and all of its associated equipment (e.g., conveying lines, piping, valves, pumps, hoses, and blowers); and
- dockside marine vessel loading and unloading, cleaning and degassing, and abrasive blasting and painting. A marine vessel is considered dockside if it is in any way connected to the shore. This includes vessels connected to the dock, connected to a vessel that is connected to the dock, or connected directly to the land.

Because onshore process units and equipment are addressed elsewhere in *2012 Emissions Inventory Guidelines*, this technical supplement addresses only dock and dockside marine vessel emissions.

This supplement does not address the structural representation of marine operations in the inventory. For guidance, consult Chapter 3.

# Expected Emissions

Emissions associated with the dock and the dockside marine vessels, except for emissions from marine vessel engines, must be determined and reported in the annual EI. This includes any emissions from marine vessel–to–marine vessel transfers (i.e., lightering or barging).

A marine facility's emissions depend on the activity performed and the materials handled or used.

Dock emissions may include:

- fugitive particulate matter from conveying lines; and
- fugitive VOCs from equipment leak fugitives.

Dockside marine vessel emissions may include:

- VOCs from loading or unloading liquid bulk materials,
- VOCs from loading or unloading liquefied gaseous materials,
- particulate matter from loading or unloading solid bulk materials (including lightering or barging at the dock),
- VOCs from degassing and cleaning liquid vessel compartments, and
- particulate matter and VOCs from abrasive blasting and surface coating.

# Determining Emissions

The following sections address the key points related to the EI.

## *Loading and Unloading Bulk Liquid Materials*

Loading and unloading bulk liquid materials may result in emissions at the dock and at the vessel. Dock emissions result from equipment leak fugitives, while vessel emissions result from vapor displacement during liquid loading.

Determine dock fugitive emissions from piping components following the guidance in Technical Supplement 3: Fugitive Emissions from Piping Components. The determination methodology must be coded "A." The fugitive emissions must be determined for the entire period when VOCs were present in the dock piping.

Determine vessel emissions from liquid material loading and unloading using the method in AP-42, Chapter 5, or a material-balance method

that accounts for the potential variables noted in that chapter. The determination methodology must be coded either "A" or "B," accordingly.

If loading emissions are collected and abated, some emissions will escape collection and, additionally, some collected emissions will escape destruction. The uncollected emissions must be determined as noted above. The collected emissions that escape destruction at the abatement device must be determined using an appropriate destruction efficiency. The determination methodology must be coded "B."

During unloading operations, vapor in the receiving storage tank's vapor space is displaced, resulting in emissions that must be reported at the storage tank using storage tank emission calculations and following the general guidance.

After unloading operations, the liquid left in sumps can evaporate over time, resulting in emissions. Those emissions must be reported with the fugitive emissions from piping components using a material balance approach.

## Loading and Unloading Bulk Liquefied Gaseous Materials

Loading and unloading liquefied gases will result in fugitive VOC emissions from dock piping components, and may also result in vessel emissions from gas freeing and vessel conditioning.

When liquefied gaseous materials are transferred to or from a pressurized marine vessel compartment, emissions usually come only from dock piping components. For guidance on determining these emissions, consult Technical Supplement 3. The determination methodology must be coded "A." Fugitive emissions from piping components must be determined for the entire period when VOCs are present in the dock piping.

Emissions from a pressurized marine vessel compartment may result from two processes used to ensure safety and product quality: gas freeing and gas conditioning. *Gas freeing* is the evacuation of residual liquid ("heel") and vapor after unloading and prior to loading a new material. *Gas conditioning* displaces the residual nitrogen pad from the marine vessel compartment and saturates the vapor space with product vapor prior to loading. Calculate emissions from gas freeing or gas conditioning using the ideal-gas law and the actual pressure, concentration, and vessel volume data. Since the ideal-gas law is a first-order scientific principle, the determination methodology must be coded "S" for 'scientifically calculated.'

## Loading and Unloading Bulk Solid Materials

Fugitive dock emissions occur at the loading and unloading operations for bulk solid materials. During loading, emissions also occur from the

entrainment of solids during displacement of the vessel-compartment air space.

Material-transfer methods determine where and how particulate matter is emitted. Emissions from such transfer methods as pneumatic systems, clamshell buckets, drag chains, belt conveyors, manual operations, or a combination of these methods must be determined following the detailed guidance in AP-42.

If a material type is explicitly addressed in AP-42, the determination methodology must be coded "A." If the material type is not explicitly addressed, use the method for the most closely related material and report the determination methodology as "E" for 'estimated.'

## Degassing and Cleaning Vessel Compartments

Cleaning operations remove residual material from vessel compartments prior to change of service, maintenance, or repair. Depending on the vessel compartment's condition, as many as three steps in the process may result in emissions: degassing, deheeling, and cleaning. Determine emissions from degassing, deheeling, or cleaning using either saturation-test data or the ideal-gas law and the actual pressure, concentration, and vessel-volume data. If the ideal-gas law is used to determine emissions, the determination methodology must be coded "S" for 'scientifically calculated.'

If saturation test results are used to calculate degassing, deheeling, and cleaning emissions, the ambient temperature during the test must correspond to or be greater than the average ambient temperature for that year's ozone season. Similarly, all chemical vapor pressures used to calculate emissions must be the vapor pressures of the chemicals at the average ozone season temperature. Additionally, the test results can only be applied to chemicals that have an equivalent or lower vapor pressure than the tested chemical's vapor pressure.

If emissions are determined using saturation test results, the determination methodology must be coded "B" for 'material balance.' Submit summary test results with each year's EI, and include information such as the ambient temperature during testing and vapor pressures of the tested chemicals.

## Abrasive Blasting and Surface Coating

Building or repairing marine vessels and offshore platforms may involve abrasive blasting and painting operations. Abrasive blasting results in particulate matter emissions of the abrasive material and the old paint. Painting results in emissions of the VOCs that volatilize from the paint as it cures and particulate matter resulting from paint overspray. Determine these emissions according to AP-42.The determination methodology must be coded "A."

Since VOC and particulate emissions from coatings are determined based on the coating composition and the application equipment's transfer efficiency, the determination methodology must be coded "B" for 'material balance.'

# Annual and Ozone Season Emission Rates

Determine actual annual emissions following the guidance in this supplement. If the same material is handled throughout the year, then use annual material throughput and the guidance in this supplement to determine emissions. If materials vary, determine emissions from each individual operation using the guidance in this supplement and the following information:

- the amount and type of material processed;
- speciation of any VOC or particulate emissions;
- temperature, vapor pressure, molecular weight, and any other data necessary to determine emissions.

Report the resulting emission rates at the appropriate facility–emissions point paths as the annual emissions rates. Do not use average or typical operations data to determine actual annual emissions.

To obtain ozone season emission rates for each facility–emissions point path, first determine emissions (in pounds) that the facility generated and emitted during the ozone season months. Next, divide the resulting emissions rates by the number of days that the facility operated during those months. Report the resulting rates as the ozone season pound per day emissions rates for that facility–emissions point path. For more information, consult "Reported Emissions": "Ozone Season Emissions" in Chapter 4.

# VOC and Particulate Speciation

Speciation must follow the *2012 Emissions Inventory Guidelines* (this manual). In general:

- Emissions from bulk liquids and liquefied gaseous materials loading and unloading will be VOCs, with a composition corresponding to that of the material loaded or unloaded.
- Vessel gas freeing and conditioning emissions will be VOCs, with a composition corresponding to that of the previously loaded material or the material now being loaded.
- Emissions from loading solid bulk material will be particles of the material loaded.

- Degassing and cleaning emissions will be VOCs, with a composition corresponding to that of the material previously held in the vessel compartment.
- Abrasive blasting results in particulate matter emissions of the abrasive material and the old paint. Painting results in emissions of the VOCs that volatilize from the paint as it cures and particulate matter resulting from paint overspray.

# Supporting Documentation

To allow for the verification of reported emissions, include representative sample calculations with the EI submission. Supply the data used in these sample calculations, including:

- the amount and type of material processed during each operation, including the type and amount of material transferred between vessels at the docks;
- the date and time of the activity;
- temperature, vapor pressure, molecular weight, and other factors that affect emission determinations;
- material composition data, if the associated emissions (total or speciated) depend upon them; and
- all other information necessary to determine emissions.

# Issues of Special Concern

**May I omit my marine emissions from the annual inventory? Aren't these emissions included in the area source inventory?**

No. The area source inventory only includes emissions from ships in transit. Once a ship is docked, it is considered a stationary source. All non-engine emissions from a docked vessel must be reported in the point source inventory.

**Since I don't own the marine vessel, am I required to report its emissions in my inventory?**

Yes. The marine vessel is at the site supporting the business.

**What if I share a marine loading facility with another company?**

Emissions must be reported by the owner or operator of the marine loading facility. Please call the EAS for additional guidance about a particular situation.

**Should I report emissions generated when materials are transferred from one marine vessel to another while docked? (This is sometimes also called *lightering* or *barging*.)**

Yes. All emissions from vessels at the dock must be reported by the dock owner or operator.

# TECHNICAL SUPPLEMENT 6: ABOVEGROUND LIQUID STORAGE TANKS

**Technical Disclaimer**

This technical supplement is intended to help determine and correctly report emissions from aboveground liquid storage tanks. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how aboveground liquid storage tanks work, how they generate emissions, how they are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. The TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The calculation methods represented are intended as an emissions calculation aid; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS at 512-239-1773.

## Introduction

This technical supplement offers guidance on identifying, quantifying, and correctly reporting aboveground storage tank emissions in the annual EI. This document does not address underground storage tanks, open-top tanks, or devices such as separators, reactors, mixing vessels, or blend tanks. For more information on the common tank designs covered in this technical supplement, consult the current edition of Chapter 7 of *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* (AP-42).

This document does not discuss tank structural representation in the EI. For guidance on this topic, consult Chapter 3.

### *Guidance Available in This Supplement*

This supplement offers guidance on appropriate methodologies for determining emissions from storage tanks, EI reporting, and special considerations to be made when determining emissions. Specifically, it addresses:

- expected emissions from aboveground liquid storage tanks;
- quantifying emissions for breathing, working, flash, degassing, cleaning, and landing losses; and
- special considerations in determining emissions for certain situations involving storage tanks.

## Definitions

In this document, *breathing losses* will refer to the emissions that occur when vapors are expelled from the tank due to changes in temperature, barometric pressure, or both. Breathing losses are also known as *standing losses.*

*Cleaning* refers to the process of removing vapor, sludge, or rinsing liquid from a storage tank.

*Degassing* is the process of removing organic gases or vapors from a storage tank.

*Equation of state* refers to an equation relating the temperature, pressure, and volume of a system in thermodynamic equilibrium.

*Flash gas* refers to the gas or vapor that is generated when a gas or liquid stream experiences a decrease in pressure or an increase in temperature.

*Gas/oil ratio* (GOR) means the number of standard cubic meters of gas produced per liter of crude oil or other hydrocarbon liquid.

*Landing losses* refers to emissions that occur from floating-roof tanks whenever the tank is drained to a level where its roof rests on its deck legs (or other supports).

*Pigging* (and its variants) refers to deploying a mobile plug (known as a *pig*) through a pipeline to perform various activities such as pipeline cleaning, inspection, or product removal.

*Working losses* are emissions related to the movement of the liquid level in the tank. Working losses from fixed-roof tanks occur as vapors are displaced from the tank during tank filling and emptying. Working losses from floating-roof tanks occur as the liquid level (and therefore the floating roof) is lowered, causing the liquid on the exposed tank walls and fittings to evaporate.

# Expected Emissions

Storage tank emissions can include VOC, HAP, toxic, and inorganic emissions from flashing, landing, breathing, and working losses. Storage tank emissions may also include emissions from degassing, cleaning, and defective tank seals and fittings. All storage tank emissions, whether routine or not, must be quantified and reported in the EI.

## Associated Emissions

Equipment leaks and loading losses from trucks, railcars, tank cars, etc., are two other emissions sources generally associated with liquid storage operations.

Do not report fugitive emissions from piping components at the same facility–emissions point path where storage tank breathing and working

loss emissions are reported. The fugitive emissions from piping components must be reported at a separate path according to the guidance in Technical Supplement 3. To determine fugitive emissions from piping components, consult Technical Supplement 3.

Similarly, do not report truck, railcar, tank car, etc., loading operations associated with storage tanks at the same facility–emissions point path where the emissions are reported from storage tank breathing and working losses. The emissions from the loading rack and its related emissions must be reported at a unique facility–emissions point path. For further guidance on structural representation, consult "Loading Operations" in Chapter 3. For guidance on determining emissions from loading operations, consult the current version of AP-42, Chapter 5.2.

# Quantifying Storage Tank Emissions

## *Determining Emissions from Breathing and Working Losses*

Emissions from storage tanks occur because of evaporative losses of the liquid during storage (breathing losses) and as a result of changes in liquid level (working losses). Determining breathing and working loss emissions from liquid storage tanks must be consistent with the guidance in this document.

The current version of the TANKS program, the EPA's free software that calculates emissions from fixed-roof and floating-roof storage tanks, can be used to determine emissions for certain types of storage tanks in accordance with this document. The current version is available at <www.epa.gov/ttn/chief/software/tanks/index.html>. Previous versions of TANKS or AP-42, Chapter 7, must not be used for EI purposes.

### Annual and Ozone Season Emissions

Annual and ozone season breathing and working loss emissions can be determined by using the guidance outlined in AP-42, Chapter 7.

For tanks that store products at ambient temperatures, the current TANKS program can be used to determine annual emissions following the detailed guidance below. The "summary" or "detail" report types from the TANKS program must be included with the sample calculations. These reports include sufficient information to verify the emissions.

For tanks that store products at ambient temperature, annual emissions must be determined by generating a TANKS report and choosing the "monthly" time basis and selecting all 12 months of the year. This is more representative than choosing the "annual" time basis because it takes into account the monthly variations in meteorological data.

Due to higher average ambient temperatures during the ozone season, the vapor pressure of an organic liquid will increase; therefore, storage

tank emissions rates will be greater in the summer than in the winter. Ozone season emissions for tanks that store products at ambient temperature must be determined using the data for increased vapor pressure in the appropriate AP-42, Chapter 7, equations or a software program that uses the equations accurately. See "Key Considerations when Using TANKS 4.09D" below.

For heated storage tanks or tanks storing warmer-than-ambient stock (hot product), the current version of TANKS cannot determine annual or ozone season emissions accurately and cannot be used. Instead, annual and ozone season emissions for these tanks must be determined using the guidance and equations contained in AP-42, Chapter 7, or a software program that uses those equations accurately. For more details, see "Special Considerations when Quantifying Emissions" later in this chapter.

## Obtaining Accurate Emissions Determinations from TANKS

Accurate data input is essential to obtaining valid emissions determinations when using the TANKS program. The program has default settings for many input variables, including floating-roof tank fittings and speciation profiles for chemical mixtures. The default settings can result in inaccurate or invalid emissions determinations and the TCEQ will no longer accept their use for EI purposes. Therefore, the user must enter site-specific data to obtain the greatest accuracy. Specifically, for compounds whose physical properties can vary widely—such as condensate, mid-refined products, etc.—or for site-specific or proprietary compounds or chemical mixtures, enter specific chemical or mixture data into the TANKS program's chemical database; use these new chemical data to generate emissions reports. Default chemicals available in TANKS must not be used unless the default vapor pressure and composition of the product accurately represent the stored liquid's vapor pressure and composition. For example, the crude oil default in TANKS (RVP 5) does not typically represent the range of crude oils stored in tanks.

Similarly, detailed information on the number and physical characteristics of the tank fittings must be used in the "detailed" fittings selection in the "Physical Characteristics" portion of TANKS. The "typical" fittings selection is not accepted for emission determinations.

The program user's manual, available at <www.epa.gov/ttn/chief/software/tanks/>, contains detailed instructions for adding or modifying chemicals, chemical mixtures, and tank fittings, as well as general information on how to use the software.

### *Key Considerations when Using TANKS 4.09D*

In 2010, the EPA released version 2.0 of its *Emission Estimation Protocol for Petroleum Refineries*. Section 3 of that EPA document contains the following guidance for obtaining accurate emissions determinations using TANKS 4.09D:

- Site-specific conditions and material composition must be used to model and determine emissions from each tank. Default settings must not be used to determine emissions.
- The vapor pressure and composition of the stored material must be used to model and determine emissions from each tank. Unless the default parameters have been evaluated and are representative of the stored liquid, the defaults must not be used.
- The tank fittings selected for internal and external floating-roof tanks, including domed external floating-roof tanks, must be representative of the particular characteristics of each tank. Default settings must not be used.
- Tanks must be modeled, and emissions determined, using monthly parameters, including average monthly measured tank-liquid temperatures. In spite of selecting the monthly calculation option, the **annual** average liquid temperature is used for the calculations; therefore, TANKS will not sufficiently account for monthly emissions variations. TANKS 4.09D is not an acceptable method for calculating annual emissions for tanks with seasonal throughputs that vary significantly. For more information, see "Special Considerations When Quantifying Emissions" below.
- Emissions from floating-roof tanks containing liquids that are warmer than ambient temperature are underestimated using TANKS. In this case, equations from AP-42, Chapter 7, must be used directly. See "Heated Tanks" and "Tanks Receiving Hot Products" under "Special Considerations When Quantifying Emissions" below.
- TANKS does not determine emissions from tank roof landings. See "Determining Emissions from Landing Losses" below.

## *Determining Emissions from Flashing Losses*

Flashing losses occur when a liquid with entrained gases experiences a pressure drop or a temperature increase. As the liquid equalizes to a new steady state, some of the lighter compounds dissolved in the liquid are released or "flashed" from the liquid. Additionally, some of the compounds that are liquids at the initial pressure and temperature transform into a gas or vapor and are released or "flashed" from the liquid. As these gases are released, some of the other non-flashing compounds in the liquids may become entrained in these gases and will be emitted as the gases vaporize. Flashing loss emissions (*flash emissions*) increase as the pressure drop increases and as the amount of lighter hydrocarbons in the liquid increases. The temperature of both the liquids and the storage tank will also influence the amount of flash emissions.

From a process perspective, flash emissions from storage tanks generally occur when pressurized liquids are sent to storage at a lower pressure.

Specifically, flash emissions from storage tanks can occur at wellhead sites, tank batteries, compressor stations, gas plants, and "pigged" gas lines when pressurized gas and liquids are sent to atmospheric storage vessels. These flash emissions are vented to the atmosphere through a tank's pressure relief valve, hatch, or other openings, or alternatively may be routed to a control device. Flash emissions can also be associated with high-, intermediate-, and low-pressure separators, heater treaters, surge tanks, and accumulator operations; however, this supplement does not address emissions determinations for those sources.

While the composition of flash emissions varies, flash gas emissions include VOCs, HAPs, and toxics.

## Emissions Determination Methodologies: Order of Preference

Several different methods of determining flash emissions exist; however, there are specific constraints associated with each method. The most appropriate method for determining flash emissions will depend upon the site-specific process. Acceptable determination methods for a given process should be evaluated upon whether the process parameters are consistent with the method's development and underlying assumptions.

General orders of preference for black oil and gas condensate systems are listed below. However, for a given system, a more preferred method may not necessarily be applicable to a process based upon its specific parameters. Specific constraints for each method are explained in detail in the following sections. If the TCEQ determines that a determination method for a site-specific process is unfounded, then the TCEQ will require that the emissions determinations be recalculated using a more appropriate method.

Note that the TANKS program does **not** determine flash loss emissions, and cannot be used to determine losses from unstable or boiling stocks, or from mixtures of hydrocarbons or petrochemicals where the vapor pressure is not known or cannot be readily predicted.

### *Black Oil Systems*

"Black oil" is defined for EI purposes as heavy, low-volatility oil approximated by a GOR less than 1,750 cubic feet per barrel and an API gravity less than 40° per 40 CFR 63.761. The appropriate methodologies for determining flash emissions for black oil systems are, in general order of preference:

- direct measurement of emissions (code as "M");
- process simulator models (code as "S");
- the E&P TANK program (code as "O");
- Vasquez-Beggs or Rollins, McCain, and Creeger correlations, or software that uses these correlation equations (such as GRI-HAPCalc) (code as "O");

- the gas/oil ratio (GOR) method (code as “B”).

Please note that crude oil with an API gravity greater than 40° must be treated as gas condensate when determining flash emissions.

***Gas Condensate Systems***

“Gas condensate” is defined for EI purposes as a liquid hydrocarbon with an API gravity greater than or equal to 40° (and a specific gravity less than 0.8252) per the February 6, 1998, *Federal Register* notice. The appropriate methodologies for determining flash emissions for gas condensate systems are, in general order of preference:

- direct measurement of emissions (code as “M”)
- process simulator models (code as “S”)
- the E&P TANK program (code as “O”)
- the gas/oil ratio (GOR) method (code as “B”)

*Note:* For EI purposes, the Environmental Consultants and Research (EC/R) equation is not an acceptable method to determine flash emissions for gas condensate systems.

## Direct Measurement of Emissions

Direct measurement provides the most accurate results for evaluating flash gas flow rates and the composition of flash emissions; however, this method can be more costly than the other emissions determination methodologies discussed below.

## Process Simulator Models

Process simulators are computer models that use equations of state in conjunction with mass and energy balances to simulate petroleum processes for a variety of engineering purposes. Process simulator determinations generally are consistent with laboratory values, and therefore are expected to be more accurate when determining flash emissions than most other determination methods (except measurements). However, process simulators are costly, and can be complicated to use.

There are several different process simulators (HYSIM, HYSIS, WINSIM, PROSIM, etc.), each employing similar basic principles. While process simulators are primarily used in process design, these models can also determine and speciate flash emissions using the Peng-Robinson equation of state option. Although other equations of state are available in the model, the Peng-Robinson equation best suits flash emissions determinations.

Required inputs may include an extended pressurized condensate analysis as well as other parameters (for example, temperature, pressure, and flow) for the process being simulated. Unlike other flash determination methods, process simulators are not constrained by American Petroleum Institute

(API) gravity. Process simulators are appropriate for either black oil or gas condensate systems if detailed, accurate input data are available.

### E&P TANK Program

API and the Gas Research Institute developed the E&P TANK model. It predicts VOC and HAP emissions (flashing, working, and standing losses) from petroleum production field storage tanks. The E&P TANK program bases flash emissions determinations on the Peng-Robinson equation of state, and requires site-specific information to determine emissions rates. E&P TANK is best suited for upstream operations, such as stock tanks at wellheads and tank batteries common to several wellheads, although it will handle a broad range of API gravities (15°–68°).

The E&P TANK model allows the user to input compositional analyses from pressurized oil and gas samples to simulate flash generation in storage tanks. Specifically, the minimum inputs needed for the model are:

- separator oil or gas composition,
- separator temperature and pressure,
- sales oil API gravity and Reid vapor pressure (RVP),
- sales oil production rate, and
- ambient temperature and pressure.

Since separator oil or gas composition is a key input in the model, E&P TANK includes a detailed sampling-and-analysis protocol for separator oil or gas.

When “Low Pressure Oil” or “High Pressure Oil” is chosen, a default analysis is already entered. However, the company must input a site-specific extended analysis to achieve accurate emissions and emissions speciation.

The “Low Pressure Gas” option can be used to determine emissions if the following site-specific measurements and related data are available:

- laboratory analysis of a gas sample from the low pressure separator;
- laboratory analysis of the gas/oil ratio (GOR);
- laboratory analysis of hydrocarbon liquid produced (to obtain API gravity, RVP, and $C_7$–$C_{10+}$ characteristics); and
- tank specifications and location.

Documentation to support the GOR and other measurements must be included in the EI submission. A vapor sample of the sales gas is not acceptable for determining either a GOR or the compositional analysis of either the separator liquid or separator gas stream. GOR and measurement data from similar sites will not be accepted.

Additionally, the Geographical Database does not contain site-specific compositions and will not be accepted for Known Separator Stream Information. When the AP-42 model option is selected for working and standing losses, E&P TANK allows users to input detailed information about tank size, shape, liquid bulk temperature, and ambient temperatures; therefore, the software can produce more precise emissions determinations. This flexibility in model design allows use of the model to match site-specific information. However, the RVP Distillation Column model does not allow these specifications.

### Obtaining Accurate Emissions Determinations from the E&P TANK Program

Accurate data input is essential to obtaining valid emissions determinations when using E&P TANK Version 2. The program has default settings for many input variables, including a geographic-database option for crude oil. Using the default settings can result in inaccurate or invalid emissions determinations. Therefore, the user must use site-specific data to obtain the greatest accuracy.

If site-specific data are not available, then representative data that meet the following criteria must be used:

- the sample must have come from the same geological formation or reservoir,
- the API gravity of the sample must be within 3° of the actual material, and
- the process and treatment of the material must be the same.

Because the E&P TANK program determines **annual** emissions, use caution when determining **ozone season** emissions. Ozone season emissions can be determined by adjusting the annual inputs as shown in Table A-9.

Run the report and multiply the hourly rates by 24 to calculate the ozone season daily rates. Do not use the tons-per-year rates to determine ozone season emissions.

The E&P TANK software is available at <www.global.ihs.com>.

### Vasquez-Beggs Correlation Equation

The Vasquez-Beggs correlation equation was developed in 1980 as part of a University of Tulsa research project. More than 6,000 samples from oil fields worldwide were used in developing correlations to predict oil properties.

**Table A-9. Inputs for Calculating Ozone Season Emissions Using E&P TANK**

| Flowsheet Selection | Data Input | Parameters |
|---|---|---|
| Tank with Separator | Separator | Separator Temperature (°F): Average separator temperature during the ozone season. |
| | Flash Valve | Ambient Temperature (°F):* Average maximum ambient temperature during the ozone season. |
| | Sales Oil | Production Rate (bbl/day): Average daily production during the ozone season. |
| | | Days of Annual Operation (days/year): Number of operating days during the ozone season. |
| Stable Oil Tank | Stable Oil | NA |
| | Oil Tank | Meteorological Info: Choose the appropriate city from the drop-down menu. |
| | Sales Oil | Production Rate (bbl/day): Average production during the ozone season. |
| | | Days of Annual Operation (days/year): Number of operating days during the ozone season. |
| | | Bulk Temperature (°F): Average bulk temperature of the stock during the ozone season. |

*If not known, refer to the TCEQ's Texas Climatology Web page (<www.tceq.texas.gov/goto/climate>) or Weatherbase (<www.weatherbase.com/>).

The Vasquez-Beggs correlation equation determines the gas/oil ratio of a hydrocarbon solution from user-inputted variables; this GOR can then be used in conjunction with product and process parameters to determine flash emissions. This method was designed for gases dissolved in crude oils, and is most appropriate for use on upstream operations that handle black oil. This method is not valid for gas condensate systems; see "Emissions Determination Methodologies: Order of Preference" above for the appropriate methodologies to determine flash emissions from those sources.

The method requires eight input variables:

- stock-tank API gravity;
- separator pressure;
- separator temperature;
- gas specific gravity;
- volume of produced hydrocarbons;
- molecular weight of the stock-tank gas;
- the VOC fraction of the tank emissions; and
- atmospheric pressure.

The Vasquez-Beggs correlation equation determines the dissolved GOR of a hydrocarbon solution as a function of the separator temperature, pressure, gas specific gravity, and liquid API gravity. Flash emissions from the VOC storage tank are then determined by multiplying the GOR by the tank throughput, the molecular weight of the stock-tank gas, and the weight fraction of VOC in the gases.

Please note that the TCEQ only allows the Vasquez-Beggs correlations to be used for black oil systems (where the API gravity is less than 40°).

Programs such as GRI's HAPCalc model use the Vasquez-Beggs correlation equation to determine flash emissions; emissions determinations methods using such programs must be coded accordingly.

### EC/R Equation

The EC/R equation was designed to determine paraffin VOC emissions in higher proportion than in the default composition. The composition of stored condensate liquids deviates substantially from the composition used to derive the equation, and therefore the EC/R equation is not accepted for determining flash emissions.

### Gas/Oil Ratio (GOR) Method

The hydrocarbon liquid GOR can be determined by laboratory analysis of a pressurized sample collected upstream of the storage tank from the separator dump line (or from a similar apparatus). For more information, refer to Gas Processors Association Standard 2174-93. It gives details on sampling procedures for collecting a pressurized oil sample.

The flash emissions are then determined by multiplying the GOR by the throughput of the tank. An extended hydrocarbon analysis of the flash gas from the sample must also be conducted to identify the concentrations of the individual components of the tank's flash emissions. When such sampling is conducted, the GOR method is appropriate for either black oil or gas condensate systems.

### Griswold and Ambler GOR Chart Method

Please note that obtaining a GOR from sources such as the Griswold and Ambler GOR Chart is not an acceptable method for determining flash emissions for EI purposes. The Griswold-Ambler method cannot determine VOC emissions and cannot be used to determine the composition of flash emissions. In particular, it cannot distinguish between VOC and HAP emissions.

## *Determining Emissions from Landing Losses*

### Introduction

Landing losses occur from floating-roof tanks whenever a tank is drained to a level where its roof lands on its deck legs or other supports (including roof suspension cables). When a floating roof lands on its supports or legs, it creates a vapor space underneath the roof. Liquid remaining in the bottom of the tank provides a continuous source of vapors to replace those expelled by breathing (in the case of internal floating-roof tanks) or wind action (in the case of external floating-roof tanks). These emissions, referred to as standing idle losses, occur daily as long as the tank roof remains landed.

Additional emissions occur when incoming stock liquid fills a tank with a landed roof; the incoming liquid not only displaces those vapors remaining under the floating roof, but also generates its own set of vapors that are displaced during the filling process. These two types of emissions are collectively referred to as filling losses.

For a given roof landing event, total landing loss emissions are therefore the sum of the filling losses and the daily standing idle losses over the entire period that the roof remained landed. Landing losses are inherently episodic in nature, and must be determined each time a tank's floating roof is landed.

The EPA's TANKS program does not determine landing loss emissions as part of routine program operation. However, landing loss emissions may be determined using the guidance outlined in American Petroleum Institute Technical Report 2567, "Evaporative Loss from Storage Tank Floating Roof Landings" (API TR 2567). EPA has also incorporated this API guidance into AP-42, Chapter 7, "Liquid Storage Tanks," available at <www.epa.gov/ttn/chief/ap42/>.

The emissions determination method detailed in AP-42, Chapter 7, or a software program that uses these AP-42 equations accurately, is the preferred method for determining landing loss emissions.

### Floating-Roof Tank Designs

Tank design considerations will impact both standing idle and filling loss emissions. Therefore, AP-42, Chapter 7 separates floating-roof

tanks into the following three design categories for emissions determination purposes:

- internal floating-roof tanks (IFRTs) with a full or partial liquid heel,
- external floating-roof tanks (EFRTs) with a full or partial liquid heel, and
- IFRTs and EFRTs that drain dry.

AP-42, Chapter 7, contains standing idle and filling loss equations for each different tank category listed above. To accurately use these equations, classify the storage tank into one of the above categories. Use caution when classifying a tank as drain-dry. Both AP-42, Chapter 7, and API TR 2567 state that a tank is only a drain-dry tank if all of its free-standing liquid has been removed.

The following tank configurations qualify as tanks with a partial liquid heel, according to API TR 2567:

- tanks that drain to a sump that retains a liquid heel,
- tanks whose sumps have baffles or similar fittings that retain liquid, or
- flat-bottom tanks whose contents have been removed by a vacuum truck, since liquid typically will still remain in irregular surfaces along the tank bottom.

For each category of tank design listed above, AP-42, Chapter 7, publishes different saturation factors that have been validated through API field studies to use in the landing loss equations. These saturation factors represent the stratification of vapors in the vapor space underneath the floating roof; therefore, no modification to these saturation factors based upon tank shell height is necessary.

### Required Data for Determining Landing Loss Emissions

After correctly determining the tank type, collect the following information about the tank and its contents for each episode when the roof is landed:

- tank diameter
- tank color
- height of the vapor space under the floating roof
- height of the stock liquid
- atmospheric pressure at the tank’s location
- average temperature of the vapor and liquid below the floating roof
- physical and chemical properties of the stored liquid (such as density, molecular weight, and vapor pressure)

- physical and chemical properties of the liquid that the tank is refilled with, if different from the previously stored liquid
- number of days that the tank stands idle while its floating roof is landed

For a given tank, use this information in conjunction with the appropriate standing idle and filling loss equations to determine the emissions for each roof landing episode. The annual landing loss emissions can then be determined by summing the emissions from each episode occurring within a given calendar year. Emissions from each roof landing episode must be individually determined using accurate temperature data and stored liquid properties for the time of year when the roof landing occurred.

When using API TR 2567 or AP-42, Chapter 7, take care to avoid using certain default parameters that may not accurately reflect a given storage tank. For example, the daily vapor temperature range must be calculated from the appropriate equation presented within the document, instead of the default range being used.

Similarly, care must be taken using the "B" coefficient from Antoine's equation to calculate the $K_E$ term for certain chemical species. The form of Antoine's equation used within API TR 2567 and AP-42, Chapter 7 closely resembles the Clausius-Clapeyron equation, and "B" values for many chemical species are not readily available in the prescribed units of temperature and pressure. In certain cases, the $K_E$ term may have to be calculated using the original equation(s) as presented in AP-42, Chapter 7.

### Reporting Landing Loss Emissions within the Inventory

Landing losses for each storage tank must be reported on the appropriate path within the EI. If it is determined that landing loss emissions occurred due to normal, routine operation, report annual and ozone season emissions accordingly. For specific procedural guidance on reporting emissions in the EI, please consult Chapter 4.

## *Determining Emissions from Degassing and Cleaning*

Emissions from tank degassing and cleaning operations must be determined using site-specific knowledge and material balance equations. The liquid-heel method described in Section 11, "Startup and Shutdown," of the EPA's *Emission Estimation Protocol for Petroleum Refineries* <www.epa.gov/ttn/chief/efpac/protocol/index.html> is also acceptable.

Alternatively, the following methods developed by the EPA can be used to determine emissions.

### Degassing (Emptying) a Storage Tank

For a drain-dry fixed-roof tank, degassing emissions can be determined in accordance with API Technical Report 2568, *Evaporative Loss from the Cleaning of Storage Tanks.*

For a drain-dry floating-roof tank, degassing emissions can be determined in accordance with API Technical Report 2567, *Evaporative Loss from Storage Tank Floating Roof Landings*.

For either fixed- or floating-roof tanks with a liquid heel, the heel may be a continuing source of vapors that can generate emissions. Therefore, liquid-heel emissions must be accounted for when determining degassing emissions.

### Cleaning (Sludge Handling)

Emissions from the cleaning of tanks can be determined in accordance with API Technical Report 2568, *Evaporative Loss from the Cleaning of Storage Tanks*.

## Special Considerations when Quantifying Emissions

When determining storage tank emissions, the following must be considered.

### Pressure Tanks

Pressure tanks are designed to handle pressures significantly higher than atmospheric pressure. Two classifications of pressure tanks exist: low-pressure and high-pressure tanks. The API defines *low-pressure tanks* as those operating in the range of just above atmospheric pressure to 15 psig; *high-pressure tanks* are those operating at pressures above 15 psig.

High-pressure tanks are considered to be closed systems that prevent routine breathing and working loss emissions. However, routine fugitive emissions from piping components associated with high-pressure tanks, as well as any non-routine emissions, must be reported in the EI.

Low-pressure tanks can experience breathing and working losses. While these emissions are usually less than a similar atmospheric tank would experience, these emissions must be quantified and reported within the EI according to the guidance outlined in Chapters 3 and 4.

Since the TANKS program uses equations developed under atmospheric conditions, it does not accurately model emissions from low-pressure tanks. Instead, use AP-42, Chapter 7, equations directly to determine breathing and working losses from low-pressure tanks.

### Nitrogen-Blanketed Tanks

Typically, storage tanks are blanketed with nitrogen (or other inert materials) to reduce the risk of fire, to reduce water acquisition by hygroscopic materials, or to prevent corrosion. However, nitrogen blanketing of an atmospheric storage tank does not reduce the tank's breathing or working loss emissions (*note:* air is approximately 78 percent nitrogen by volume).

Therefore, when determining emissions from nitrogen-blanketed atmospheric storage tanks (whether the tank is of fixed roof or internal floating-roof design), no modifications to the AP-42 equations (or software programs using these equations) are required. The gas blanket will not affect emissions if the tank is operated near atmospheric pressure.

### Heated Tanks

For EI purposes, a *heated tank* is defined as a storage tank that is designed to store, and does store, product (including hot product) at a temperature above ambient temperature.

The current TANKS program, version 4.09D, contains several default routines that prevent it from properly applying the equations of AP-42 to heated fixed-roof tanks. For example, TANKS automatically sets the vapor-space temperature range for a heated tank equal to the liquid-surface temperature range. This assumption introduces a significant error for tanks that are designated as heated but which are not both well-insulated and equipped with high vent settings. Therefore, TANKS is no longer an acceptable option to determine emissions from heated tanks. Acceptable methods are the AP-42, Chapter 7, equations or a software program that uses those equations accurately.

### Tanks Receiving Hot Products

For EI purposes, *hot products* are materials with a temperature above the ambient temperature. For EI purposes, hot-product tanks are defined as unheated storage tanks that receive product above ambient temperature. When hot products are put into an unheated tank, ambient meteorological data cannot be used to properly determine the tank's emissions. TANKS 4.09D cannot determine emissions from tanks that receive warmer-than-ambient stock, but which are not heated, because it does not allow the user to enter key parameters such as the liquid bulk temperature. Therefore, TANKS 4.09D is not acceptable for calculating emissions from tanks storing hot products. Instead, AP-42, Chapter 7, equations or software that uses those equations accurately must be used to determine emissions. When using the AP-42, Chapter 7, equations to determine emissions, the elevated stock temperature must be used as the liquid bulk temperature.

### Sparging

In heated storage tanks, the stored liquid may be mixed using air injection (sparging). If constant air flows through the liquid, this air will exit the storage tank through the tank vents, generating VOC emissions. Currently, no commercial software or programs determine sparging emissions. Engineering calculations that account for air flow and volatility of the stored liquid and any cutter stock should be used to determine emissions.

### Tanks with Significant Monthly Throughput Variations

For storage tanks with throughputs that vary significantly with the seasons, the equations in AP-42, Chapter 7 or a software program that uses these equations accurately must be used to determine annual emissions.

### Tanks Storing Inorganic Liquids

Currently, methods developed exclusively for determining inorganic compound emissions from storage tanks do not exist. However, it is possible to use the TANKS program to determine storage tank emissions from inorganic liquids if the inorganic liquid has a measurable vapor pressure and if data are available for one of the vapor pressure options in the program's chemical database.

Although the equations used in the TANKS program were developed to determine evaporative losses from storage of organic liquids, they currently are the best available method for determining inorganic emissions from storage tanks.

### Tanks with a Liquid Heel

Use caution when classifying a tank as "drain dry." If the tank drains to a sump that retains a liquid heel, the API publishes saturation factors to use in the landing-loss equations in order to determine the resulting emissions, which cannot be assumed to be negligible.

Tanks with a liquid heel may generate emissions during degassing operations, tank cleaning, steam cleaning, and the use of vacuum trucks that are not currently accounted for by using conventional software programs, such as TANKS 4.09D.

### Oil Field Wellhead Tank Batteries

Companies that own or operate sites in the upstream oil and gas industry must determine VOC emissions from all wellhead tank batteries to determine if these sites meet the requirements for submitting an EI. Each storage tank in the wellhead battery will generate working, breathing, and flashing emissions. Please see Technical Supplement 6: Aboveground Storage Tanks, for guidance on determining storage tank emissions.

The TCEQ has developed a Material Throughput form specifically for oil field storage tanks and the form should be completed and include the production information for each tank.

### Produced Water Tanks

Produced water is generated during oil and gas exploration, production, transmission, and treatment, and typically stored on-site. It may contain various contaminants, including hydrocarbons that generate VOC emissions. Currently, specialized methods for determining emissions

from produced water storage tanks do not exist. However, these tanks are a potential source of VOC emissions that must be represented in the EI.

If VOCs are present in produced water, the VOCs may vaporize in the tank's headspace causing working, breathing, and flash losses. To determine working and breathing losses, it is possible to add a custom mixture in the TANKS program similar to the composition of the produced water stored in the tanks (e.g., a mixture of 99 percent water and 1 percent condensate) to determine the emissions.

Any VOCs entrained in water produced during oil and gas exploration and production could flash when transferred to atmospheric-pressure tanks due to pressure differentials. To determine flash losses, direct measurement of emissions and measurement of the amount of flash gas from a pressurized sample of produced water (similar to the GOR method) are the preferred methods for determining emissions. If neither of those methods is available, a process simulator may be able to determine emissions, provided an accurate sample composition and site-specific inputs are available.

### Winter Gas Blending

Some sites blend butane into gasoline during the fall and winter to increase the Reid Vapor Pressure (RVP) of the gasoline in a process called *winter gas blending* or gas butanizing. Butane emissions from this process must be determined and reported in the EI.

First, the normal working and breathing losses must be adjusted to account for the additional butane present in the gasoline. The RVP must be adjusted to match the actual RVP of the gasoline stored in the tank, and the gas mixture must reflect an increased butane component.

Next, if winter gas blending is carried out at the storage tank, additional butane emissions from the blending itself (separate from the working and breathing losses from the tank) must be determined and reported in the EI. The blending emissions can be determined using a material balance or from engineering knowledge of the blending process.

### Determining Emissions using Chemical Mixtures

For compounds whose physical properties can vary widely, such as condensate, or for site-specific or proprietary compounds or chemical mixtures, enter specific chemical or mixture data into the TANKS program's chemical database; use these new chemical data to generate emissions reports.

Additionally, data on chemical mixtures must be used to determine emissions from tanks where chemicals are combined. For example, when cutter stock is added to a heavy hydrocarbon storage tank, the cutter stock's composition must also be represented in the tank emission calculations by creating a mixture of both components.

### Default Chemical Properties in the TANKS program

Care is needed when choosing default chemical properties in the TANKS program. For chemicals whose properties can vary widely, specific site data must be used. For example, crude oil storage tanks must account for the actual vapor pressure instead of using the program's default "crude oil (RVP 5)" option. If the actual vapor pressure is not known, "gasoline (RVP 10)" must be selected to determine the emissions.

Additionally, for gasoline storage tanks, variations in product must be accounted for by using actual vapor pressure information for each month of the year. An average gasoline profile must not be used to determine the emissions.

## Speciation

If any source-specific information about storage tank VOC composition is available, use it to speciate the emissions. If the TANKS program is an acceptable determination method, it has several options for adding source-specific composition information in order to speciate emissions. Supply the composition data and any related information (such as test results, etc.) with the EI. For more information on speciation requirements, see Chapter 4.

## Supporting Documentation

Include documentation with the EI that supports and validates the emissions reported therein—including, but not limited to, representative samples of:

- calculations detailing the tank parameters (diameter, height, shell color, roof color, paint condition, shell construction, capacity, primary and secondary seals, fittings, and throughput rate);
- if the TANKS program is used, a report generated using the "detailed" report option;
- physical properties of each product, including liquid density, liquid molecular weight, vapor molecular weight, and vapor pressure;
- sampling analysis;
- all supporting data used to calculate the flash losses, including identification of the determination method, sample analysis, API gravity, density of liquid petroleum, gas/oil ratio, gas gravity, molecular weight of stock, and VOC percentage by weight of both the stored liquid and flash gas; and
- all other information necessary to determine emissions.

# For More Information

Additional guidance for storage tanks is available at the EPA's website: <www.epa.gov/ttn/chief/faq/tanksfaq.html>.

While those questions are not reproduced here due to space considerations, they address such topics as underground storage tanks, vapor-balanced tanks, tanks with roof geometries other than a cone or a dome, indoor storage tanks, and tanks storing a two-phase liquid.

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