VOLUME II: CHAPTER 10

PREFERRED AND ALTERNATIVE METHODS FOR ESTIMATING AIR EMISSIONS FROM OIL AND GAS FIELD PRODUCTION AND PROCESSING OPERATIONS

September 1999

Prepared by:
Eastern Research Group, Inc.

Prepared for:
Point Sources Committee
Emission Inventory Improvement Program

DISCLAIMER

As the Environmental Protection Agency has indicated in Emission Inventory Improvement Program (EIIP) documents, the choice of methods to be used to estimate emissions depends on how the estimates will be used and the degree of accuracy required. Methods using site-specific data are preferred over other methods. These documents are non-binding guidance and not rules. EPA, the States, and others retain the discretion to employ or to require other approaches that meet the requirements of the applicable statutory or regulatory requirements in individual circumstances.

DISCLAIMER

The oil and gas field production and processing industry sector is one in which new emission estimation tools are rapidly being developed. Therefore, new tools may exist which are not addressed in this document. The reader should keep informed about new tools through the following websites:

- http://www.api.org
- http://www.gri.org
- http://www.epa.gov/ttn/chief

At the time of publication, however, the methodologies presented in this document are the best recommendations of the Emission Inventory Improvement Program Point Source Committee.

ACKNOWLEDGEMENT

This document was prepared by Eastern Research Group, Inc., for the Point Sources Committee of the Emission Inventory Improvement Program and for Roy Huntley of the Emission Factor and Inventory Group, U.S. Environmental Protection Agency. Members of the Point Sources Committee contributing to the preparation of this document are:

Denise Alston-Guiden, Galson Consulting
Dennis Beauregard, Emission Factor and Inventory Group, U.S. Environmental Protection Agency
Bob Betterton, Co-Chair, South Carolina Department of Health and Environmental Control
Paul Brochi, Texas Natural Resource Conservation Commission
Alice Fredlund, Louisiana Department of Environmental Quality
Gary Helm, Air Quality Management, Inc.
Martin Hochhauser, Allegheny County Health Department
Toch Mangat, Bay Area Air Quality Management District
Ralph Patterson, Wisconsin Department of Natural Resources
Jim Southerland, North Carolina Department of Environment and Natural Resources
Eitan Tsabari, Omaha Air Quality Control Division
Bob Wooten, North Carolina Department of Environment and Natural Resources

CONTENTS

Section **Page**

CONTENTS (CONTINUED)

CONTENTS (CONTINUED)

FIGURES AND TABLES

Figure **Page**

Tables **Page**

This page is intentionally left blank.

1

INTRODUCTION

The purposes of the preferred methods guidelines are to describe emission estimation techniques for stationary point sources in a clear and unambiguous manner and to provide concise example calculations to aid in the preparation of emission inventories. While emissions estimates are not provided, this information may be used to select an emission estimation technique best suited to a particular application. This chapter describes these procedures and recommends approaches for estimating emissions from most oil and gas field production and processing operations common throughout the United States. Additional sources may exist, which are not addressed in this chapter, such as cogeneration units, cooling towers, and non-road mobile sources (e.g., helicopters, and crew and supply boats). Depending on the purpose of the inventory, emissions from these additional sources should also be included. For procedures to estimate emissions from these sources, contact the state or local agency or EPA.

Section 2 of this chapter contains a general description of the oil and gas field production and processing operations source category, identifies common emission sources, and overviews available control technologies used in oil and gas field processing operations. Section 3 of this chapter provides an overview of available emission estimation methods.

Section 4 presents the preferred methods for estimating emissions from oil and gas field production and processing operations, while Section 5 presents the alternative emission estimation techniques.

It should be noted that the use of site-specific emission data is preferred over the use of industry-averaged data such as *AP-42* emission factors (EPA, 1995a). Depending upon available resources, site-specific data may not be cost effective to obtain. However, this site-specific data may be a requirement of the State Implementation Plan (SIP) and may preclude the use of other data.

Quality assurance (QA) and quality control (QC) procedures are described in Section 6. Coding procedures used for data input and storage are discussed in Section 7. Some states use their own unique identification codes, so industry personnel using this document should contact their state or local agency to determine the appropriate coding scheme to use. References are listed in Section 8. Appendix A provides an example data collection form to assist in information gathering prior to emissions calculations.

This page is intentionally left blank.

2

GENERAL SOURCE CATEGORY DESCRIPTION

This section provides a brief overview of most oil and gas field processing operations common throughout the United States. The reader is referred to the *Air Pollution Engineering Manual* (referred to as *AP-40*) and *AP-42, 5th Edition, January 1995*, for a more detailed discussion of these facilities.

Additional sources may exist, which are not addressed in this chapter, such as cogeneration units, cooling towers, and non-road mobile sources (e.g, helicopters, and crew and supply boats). In addition, equipment and emissions from off-shore operations, although not specifically addressed in this document, are believed to be similar to those from on-shore operations. Preferred and alternative emission estimation methodologies for off-shore sources are, therefore, expected to be the same as for on-shore sources. Depending on the purpose of the emission inventory, the inventory preparer should consider inclusion of emissions from these additional source types.

2.1 PROCESS DESCRIPTION

The petroleum industry is organized into the following four broad segments:

- Exploration and production;
- Transportation;
- Refining; and
- Marketing.

This chapter addresses only the field production and processing operations of the petroleum and natural gas industry found in the exploration and production (E&P) and transportation segments of the industry.

The oil and gas field production and processing operations begin with exploration to locate new sources of crude oil and natural gas. When potential sources are located, wells are drilled to confirm the presence of oil or gas and to determine whether the reserves are economically sufficient to support production.

During production, crude oil and/or natural gas is recovered from wells and prepared for transportation from the field. Trucks, rail cars, barges and tankers are used to transport domestic crude oil to refineries. Domestic crude oil can also be transported from the field to refineries by a complex network of pipelines. Natural gas, which may be produced alone or in combination with crude oil, often must be processed at a gas plant to make it suitable for consumer use (Rucker and Strieter, 1992).

Oil and gas field production and processing operations are primarily defined by the following types of emission activities:

- Exploration and production;
- Processing;
- Combustion;
- Storage and transport; and
- Wastewater.

2.1.1 EXPLORATION AND PRODUCTION

In the E&P segment of the industry, natural gas and crude oil are recovered from underground reservoirs. This industry segment encompasses exploration, well-site preparation, and drilling (Rucker and Strieter, 1992).

Seismic and other geophysical methods are used to locate subterranean formations that signal the potential presence of oil and gas reservoirs. When a likely formation is located, drilling is the only way to confirm that oil and gas are present (Rucker and Strieter, 1992).

Drilling operations include the activities necessary to bore through the earth's crust to access crude oil and natural gas resources. During drilling operations, specially formulated muds are circulated through the hole to remove cuttings from around the drill bit, to provide lubrication for the drill string, to protect the walls of the hole, and to control down-hole pressure. Cuttings are separated from the mud at the well surface as the mud is passed through shale shakers, desanders, desilters, and degassers. The mud flows to a tank for recycling, and the cuttings, which may be contaminated with hydrocarbons, are pumped to a waste pit for disposal (Rucker and Strieter, 1992).

Water and drilling muds from offshore operations can be discharged overboard if they meet various limitations and requirements set by EPA. If the water or drilling muds do not meet these limitations and requirements, they are brought back to land for onshore treatment or disposal.

When the desired well depth is reached, the well is completed by installing an outer annular casing. During this process a completion fluid (typically heavy salt water) is used to prevent premature gas/oil flow. Occasionally, the well formation pressure is greater than the completion fluid pressure and premature gas/oil flow or blowout occurs (GRI, 1994).

Well testing occurs at exploratory wells which have unknown reservoir potential. Testing occurs during well completion by measuring the potential gas or oil flow. Testing is conducted to determine the required specifications of the wellhead assembly. Gas vented during well testing is either flared or vented directly to the atmosphere (GRI, 1994). Oil extracted during well testing is collected in a storage tank.

Once a well has been completed and is producing crude oil or natural gas, an arrangement of high-pressure valves termed a "Christmas tree" is installed to control production. As the well ages, an artificial lift device may be needed to help bring product to the well surface (Rucker and Strieter, 1992).

2.1.2 PROCESSING

After extracting the hydrocarbons from the underground reservoirs, additional processing is conducted in the field to prevent corrosion and other problems in downstream handling and processing equipment (GRI, August 1994). The first processing step employed at many production facilities involves separating the oil, gas, and water produced by the well (Rucker and Strieter, 1992). The gas is separated from liquids either in a two-phase process, in which gas is typically separated from water, or in a three-phase separation operation, in which gas, water, and liquid hydrocarbons are separated. Three-phase separation is necessary when appreciable liquid hydrocarbons are extracted with the gas and water (GRI, 1994).

Separators can be vertical, spherical, or horizontal, and typically employ a series of baffles to separate the gas from the liquid hydrocarbons. A horizontal separator is used when the gas-to-liquid hydrocarbons ratio is large; a vertical separator is used when the gas-to-liquid hydrocarbon ratio is small; and a spherical separator is used when the gas-to-liquid hydrocarbon ratio is in the intermediate range. When wellhead pressures are high, a series of separators may be operated at sequentially reduced pressures (GRI, 1994).

Separators provide only one stage of separation, and, in many cases, additional water and gas separation from the oil emulsion streams may be required.

Oil Processing

Water in the oil can form an emulsion. This emulsion is broken using heat in heater treaters or electric energy in devices such as electrostatic coalescers. Cleaned oil flows from the emulsion breakers to crude oil storage tanks, prior to being transported to a pipeline, truck, rail car, barge, or tanker. The water that is recovered during emulsion breaking is often recycled through skimmers to recover remaining oil, filtered, and then stored in water tanks prior to underground injection or other discharge (Rucker and Strieter, 1992).

Natural Gas Processing

Glycol Dehydration. Glycol dehydration units are used to remove water from natural gas streams to prevent the formation of hydrates and corrosion in the pipeline. The natural gas stream is passed through a stream of triethylene glycol (TEG), diethylene glycol (DEG), or ethylene glycol (EG). Other forms of glycol, such as tetraethylene glycol, may also be used. At the point of contact, the glycol will absorb water and water vapor from the natural gas stream. During the absorption process, aromatic hydrocarbons including benzene, toluene, ethyl benzene and xylene (BTEX), hexane as well as other volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) present in the gas stream are absorbed along with the water vapor into the glycol stream. When the glycol is saturated with water, it is considered "rich glycol." The rich glycol is then sent to a glycol still for regeneration to remove water and liquid hydrocarbons. After regeneration, the glycol is considered "lean glycol" and is suitable for reuse (TNRCC, 1996).

Methanol Injection. Methanol is often added to natural gas as a hydrate point depressant and antifreeze. The methanol is injected using a gas-powered chemical injection pump, which uses gas pressure to drive the pump piston (GRI, 1994).

Particulate Removal. When solid impurities (particulates) are present in the raw natural gas, they are removed by passing the gas stream through a particulate filter, such as the common cartridge type filter (GRI, 1994).

Acid Gas Removal. The acid gases hydrogen sulfide (H_2S) and carbon dioxide (CO_2) corrode the pipeline and can cause safety problems if not removed from the natural gas stream. The gas stream must be freed of these contaminants, or "sweetened", before the gas can be transported for use (TNRCC, 1996). There are several processes available for removing the acid gases from the natural gas stream including:

- **Amine Based Process:** The most common method of acid gas removal (AGR), the amine process, utilizes aqueous solutions of diethanolamine (DEA), monoethanolamine (MEA), methyldiethanolamine (MDEA), and diglycolamine (DGA). The natural gas is processed through a stream of one of the previous amine solutions that will absorb H_2S, CO_2, and VOCs. After the amine solution is saturated with the acid gases, it is piped to the amine regenerator. The regenerator heats the amine solution and the acid gases are released (TNRCC, 1996).

- **Selexol Process:** This process uses the dimethylether of polyethylene glycol as a solvent, which has a high physical absorption capability for CO_2 and sulfur-based compounds including H_2S. In the presence of CO_2, the Selexol process can reduce the H_2S, carbonyl sulfide (COS) and mercaptan concentrations to 1 ppm, with the CO_2 content retained or reduced to any required level (GRI, 1994).

  The solvent is regenerated by flashing and/or stripping with steam or inert gas. The process vent stream from the flash tank usually has a high CO_2 concentration, and is typically flared to combust undesirable products such as H_2S, acid gases, and VOCs. The vent stream from the stripper column is either vented, flared, or sent to a sulfur recovery process.

- **Fixed Bed Sorption Process:** Fixed bed sorption, or molecular sieve gas sweetening, is typically used to treat liquified natural gas plant feed gases. Molecular sieves physically adsorb H_2S and/or CO_2, along with water, to sweeten and dehydrate the gas stream. With two or more adsorption beds, one bed is used to treat the feed gas stream while the other is regenerated by a heated gas stream (usually a slip stream of dry process gas). Generally, process heaters burning natural gas are used to heat the regeneration gas stream. The regeneration gas is usually recycled to the process after it has been cooled and any free water and sulfur compounds have been removed in an adsorber and flashed. The sour gas stream from the flash tank may be vented, incinerated, or sent to sulfur recovery (GRI, 1994).

- **Other Acid Gas Removal Processes:** Scavenging processes, such as iron sponge, are also used for acid gas removal, primarily where the H_2S content is relatively low. Other processes, such as the hot potassium carbonate-based Benfield process, are most often used for natural gas containing high concentrations of CO_2 (GRI, 1994). Other processes exist, but are used less frequently.

Sulfur Recovery. Exhaust gas from the sweetening process may be vented to a sulfur recovery process. There are two common methods of sulfur recovery:

- **Claus Sulfur Recovery Process:** The Claus sulfur recovery process is the most widely used technology for recovering elemental sulfur from sour gas (or sour crude oil). The Claus process is used to recover sulfur from the amine regenerator vent gas stream in plants where large quantities of sulfur are present (GRI, 1994). The Claus process consists of a multistage catalytic oxidation of H_2S. Each catalytic stage consists of a gas reheater, a catalyst chamber, and a condenser. The Claus process involves burning one-third of the H_2S with air in a reactor furnace to form sulfur dioxide (SO_2) and water. The remaining uncombusted two-thirds of the H_2S reacts with SO_2 to form elemental sulfur and water (EPA, 1995e).

- **Liquid Redox Sulfur Recovery Process:** Liquid redox sulfur recovery processes are liquid-phase oxidation processes which use a dilute aqueous solution of iron or vanadium to remove H_2S selectively by chemical absorption from sour gas streams. These processes can be used on relatively small or dilute H_2S streams to recover sulfur from the acid gas stream or, in some cases, they can be used in place of an acid gas removal (AGR) process. The mildly alkaline lean liquid scrubs the H_2S from the inlet gas stream, and the catalyst oxidizes the H_2S to elemental sulfur. The reduced catalyst is regenerated by contact with air in the oxidizer(s). Sulfur is removed from the solution by flotation or settling, depending on the process (GRI, 1994).

Hydrocarbon Recovery. Several processes are used in the industry to separate and recover non-methane hydrocarbons from natural gas (GRI, 1994):

- **Cryogenic Expansion:** In the cryogenic expansion process, the gas stream is initially treated by low-temperature separation to remove any residual water in the gas. The dehydrated gas is split, and part of the gas is cooled to -25° Fahrenheit (F) using residue gas. The remainder of the gas is chilled to 4°F using propane as the refrigerant. The split streams are combined and enter the high pressure separator where the cold liquid hydrocarbons are separated from the gas. The cold liquid hydrocarbons leave the high pressure separator and are reduced in pressure across a valve to lower the temperature to -45°F. This cold liquid hydrocarbon stream provides the heat sink for the upstream heat exchangers used to chill the incoming gas stream. After passing through these heat exchangers, the warm liquid enters the deethanizer (GRI, 1994).

  The gas stream from the high pressure separator is expanded to reduce the temperature to -85°F. This gas stream enters the low pressure separator where the hydrocarbon liquids are separated from the gas. The separated liquid stream is circulated as the coolant in the condenser on the deethanizer column and reintroduced as reflux to the deethanizer. The gas stream from the low pressure separator is used to further cool the overhead stream from the deethanizer, and then is combined with the deethanizer overhead stream. This combined gas stream is compressed to pipeline pressure (GRI, 1994). Figure 10.2-1 illustrates an example cyrogenic expansion process.

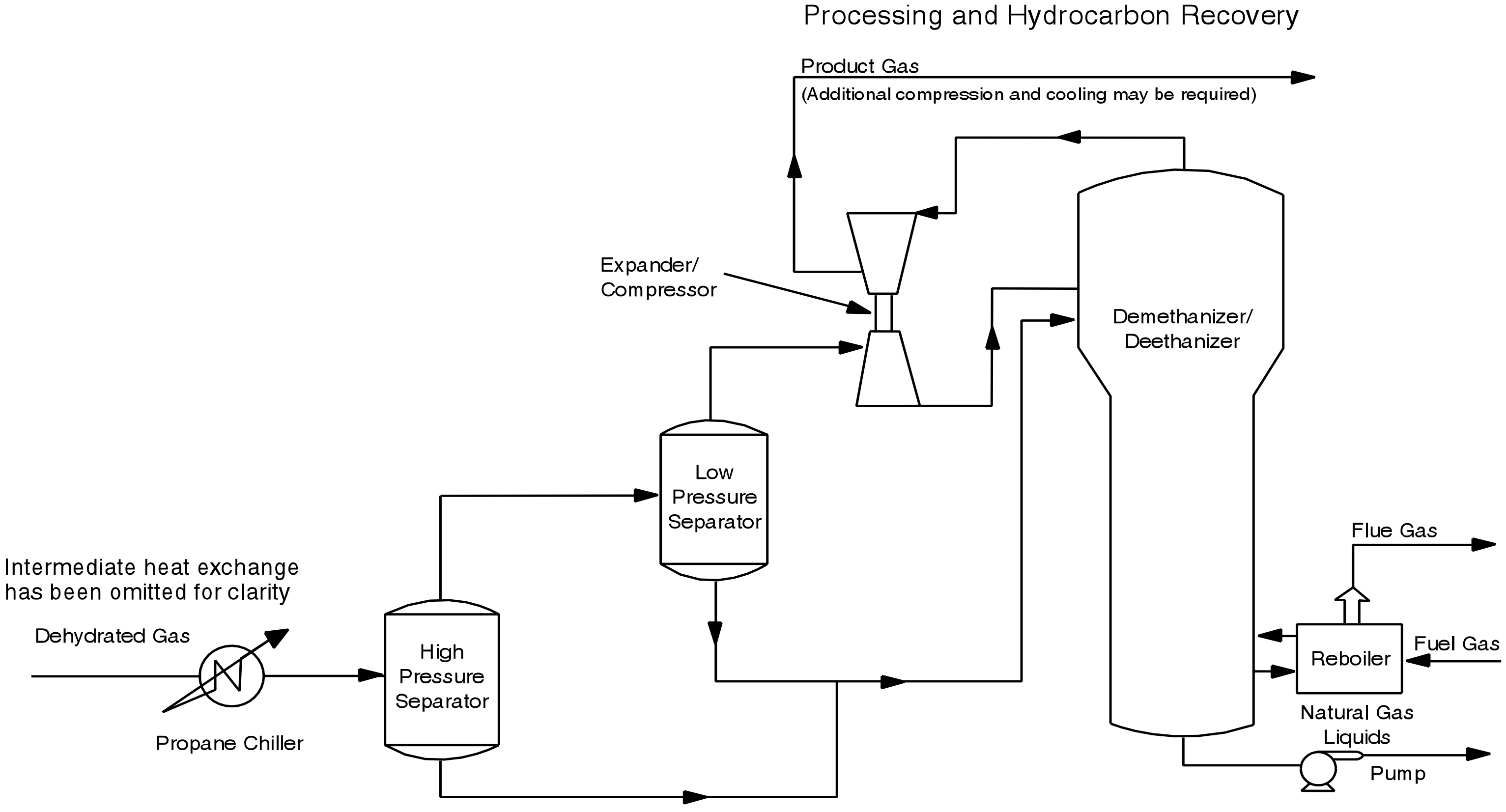

Figure 10.2-1 Cryogenic Expansion Process
(Source: GRI, 1994)

- **Refrigeration Process:** In the conventional refrigeration process, the inlet gas stream is initially contacted with a lean glycol solution to remove water from the gas stream. The gas/glycol stream is chilled to -30°F to separate the condensible liquid hydrocarbons from the dry gas stream. The liquid hydrocarbons are separated from the rich glycol solution and sent to a stabilizer, where the lighter gas stream is separated from the heavier liquid hydrocarbons. The rich glycol stream is regenerated to remove the absorbed water and recycled to the process (GRI, 1994).

- **Absorption Process:** In the absorption process, the wet field gas is contacted with an absorber oil in a packed or bubble tray column. Propane and heavier hydrocarbons are absorbed by the oil while most of the ethane and methane pass through the absorber. The enriched absorber oil is then taken to a fractionator where the absorbed propane and heavier hydrocarbons are stripped from the oil. The overhead gas product stream from the absorber is then compressed to pipeline pressure (GRI, 1994).

- **Adsorption Process:** The adsorption process utilizes two or more molecular sieve beds to adsorb all hydrocarbons except methane. The beds are used alternately, with one or more beds on-stream while the others are being regenerated by means of heat or steam which remove the adsorbed hydrocarbons. If steam is used, the steam/ hydrocarbon vapor stream is condensed and liquid hydrocarbons fed to a fractionation process where the various compounds are separated (GRI, 1994).

Pneumatic Devices. Pneumatic devices such as pressure and level controllers are used in gas field production operations to control field equipment. Natural gas is typically used as the pneumatic medium (GRI, 1994).

Blowdown. Equipment such as compressors is occasionally shutdown for emergencies and scheduled maintenance. Any gas remaining in the equipment and corresponding pipelines must be vented to reduce pressure prior to servicing. This process is called blowdown (GRI, 1994).

2.1.3 COMBUSTION

External Combustion. Boilers and heaters provide process heat and steam for many processes such as electric generation, glycol dehydrator reboilers, and amine reboiler units.

Internal Combustion Engines and Gas Turbines. Compressors are often used to transport natural gas from the field to processing plants. Reciprocating internal combustion engines (ICEs) or gas turbines are used to drive compressors. The inlet and outlet gas streams are passed through a scrubber/separator to remove any condensed liquids. The ICE or gas turbine driver combusts a slip stream of the gas being transported (GRI, 1994). ICEs and gas turbines also have many other purposes, such as compression of petroleum gases and refrigerants, electrical generation, and pump and crane operation.

Flares. Flares are often used to control VOC emissions and to convert H_2S and reduced sulfur compounds to SO_2. Flares can be used to control emissions from storage tanks, loading operations, glycol dehydration units, vent collection systems, and gas sweetening amine units (Boyer and Brodnax, 1996). Flares can also be used as a backup system for sulfur recovery units.

2.1.4 STORAGE AND TRANSPORT

Storage tanks are used to store crude oil, liquified natural gas (LNG), water or brine, process condensate, as well as other materials used or generated during the production of oil and natural gas. Crude oil is transported from production operations to refineries by tank trucks, rail cars, tankers, barges, and pipelines. Loading methods include splash loading, submerged pipe fill, and bottom loading. Natural gas is transported by pipeline.

Pipeline pigging operations are conducted to assist in product transfer and product separation, as well as for maintenance activities. A pig is a physical device which varies in size and shape and can be made of a variety of materials such as plastic, urethane foams, and rubber. Pigs can be solid, inflatable, foam, or made of a viscous gel. The specific design of a particular pig depends upon the pipeline as well as the purpose of the pigging operation (GRI, 1993).

Three types of pigging operations occur in pipelines at oil and gas field production and processing facilities: product transfer, product separation, and maintenance. Pigging following product transfer is used to remove residual product from the pipeline after loading occurs. Pigs can also be used for product separation to transport more than one product, such as oil, gas, or condensate as well as for maintenance activities such as pipeline cleaning, gauging, or dewatering. During pigging operations, a pig is inserted into the pipeline and is forced through the pipeline by a compressed gas, such as nitrogen. When the pig gets to the end of the line, it is trapped in a receiver. The gas is then bled off from behind the pig (TNRCC, 1998a; TNRCC, 1998b; GRI, 1993). Depending on the specific pigging operation, waste removed from the pipeline may also be an issue.

2.1.5 WASTEWATER

During oil and gas field production and processing operations, wastewater is generated from processes such as product separation and glycol dehydration. The wastewater may be treated on-site or it may be forwarded to an approved wastewater treatment facility.

Many types of units are used to treat, store, and transfer wastewater on-site. Some of these units include sumps, pits, storage tanks, brine tanks, and oil/water separators which may be in primary, secondary or tertiary treatment service.

2.2 EMISSION SOURCES

Emissions from oil and gas field processing operations result from both controlled (i.e., ducted) and uncontrolled sources. Section 7 of this chapter lists the source classification codes (SCCs) for these emission points. In addition to emissions from the sources described below, emissions result from process upsets such as pressure relief device releases due to over-pressure, and non-traditional sources such as cogeneration units, cooling towers and non-road mobile sources. In addition, equipment and emissions from off-shore operations, although not specifically addressed in this document, are believed to be similar to those from on-shore operations. Preferred and alternative emission estimation methodologies for off-shore sources are, therefore, expected to be the same as for on-shore sources. Depending on the purpose of the emission inventory, the inventory preparer should consider inclusion of emissions from these additional source types.

2.2.1 EXPLORATION AND PRODUCTION

Emission sources associated with exploration and production include exploration, well-site preparation, drilling, waste pits, blowouts, well testing, and gas/liquid separation. Fugitive dust and combustion emissions from exploration and well-site preparation result from vehicles, heavy equipment and engines and turbine operation.

Drilling operations are a significant source of short-term air pollutant emissions, which some states consider to be a temporary source. During drilling, gas may seep into the well bore and become dissolved or entrained in the drilling mud (EPA, 1977a). The gases are separated from the mud in a separator or degasser. Gases removed from the mud are either vented to the atmosphere or routed to a flare. Some states or local agencies may consider mud degassing a temporary source of emissions. Pollutants of concern are H_2S, CH_4, VOC and HAPs. The use of oil-based drilling muds also results in additional H_2S, CH_4, VOC and HAP emissions. When using oil-based drilling muds, the mud will be dispersed in oil rather than water. When the mud passes through the shale shaker, the oil vapors are exposed directly to the atmosphere (EPA, 1977a). Some state or local agencies may consider this a temporary source of emissions.

Waste pits storing hydrocarbon laden cuttings may be a source of VOC and HAP emissions. Well blowouts, although infrequent, are considered process upsets and can also be a source of VOC, HAP, and CH_4 emissions. Well testing can result in VOC, HAP and CH_4 emissions.

Emissions from gas/liquid separation processes include fugitive VOC and HAP from valves and fittings and from any operation upsets, such as pressure relief device releases due to over-pressure.

2.2.2 PROCESSING

Oil Industry

Emissions from heater treaters result from fuel combustion and include typical fuel combustion pollutants: carbon monoxide (CO), carbon dioxide (CO_2), nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter less than or equal to 10 microns in diameter (PM_{10}), particulate matter less than or equal to 2.5 microns in diameter ($PM_{2.5}$), VOC, lead, and HAPs. Equipment leaks from piping components (e.g., valves, flanges and connectors) also result in fugitive VOC and HAP emissions.

Gas Industry

Emissions associated with the glycol dehydration process may include vented emissions from the glycol dehydrator's flash tank as well as the glycol regenerator process vent. BTEX compounds, as well as hexane and other HAPs present in the gas, are carried with the rich glycol to the regenerator; thus the regenerator vent stream can be a major source of HAP emissions (GRI, 1994). Glycol regenerators either vent directly to the atmosphere or to vapor recovery or control systems.

The glycol regenerator reboiler typically fires natural gas and is also a potential source of HAP emissions. If the water is efficiently removed from the gas stream during the glycol dehydration process, the glycol regenerator reboiler can be used to thermally oxidize HAPs and VOCs emitted from the glycol regenerator process vent.[1] Gas-driven pumps often used in glycol units may produce HAP emissions. In most cases, the pump-driven gas is routed to the rich glycol stream upstream of the flash tank. Once the glycol reaches the flash tank or regenerator, the pump gas is separated with the gas from the absorber. Fuel combustion should be considered an emission source separate from the glycol regenerator reboiler. Other process-related sources of emissions include fugitive emissions from valves and fittings, and emissions from routine maintenance activities involving equipment depressurization (blowdown) or complete purging and filter replacement. Also, although DEG, TEG, and tetraethylene glycol are not listed HAPs, they may degrade at the high temperatures present in the regenerator to form compounds such as ethylene glycol, a listed HAP (GRI, 1994). If ethylene glycol is used, HAP emissions may be released.

---

[1] Water-cooled condensers are generally more efficient than air-cooled condensers when used in the glycol dehydration process.

VOC and HAP emissions from the methanol injection process include fugitive losses from the transfer line fittings and from the methanol storage tank. Also, the gas-powered chemical injection pumps vent gas directly to the atmosphere and could emit VOC or HAP compounds present in the gas (GRI, 1994).

Potential emissions of VOC and HAP from particulate removal result from fugitive losses from valves, flanges, or other connections, and vented emissions from periodic routine maintenance to repair or clean the filter. Disposal of the filter cartridges may also be a source of emissions due to the volatility of some VOC or HAP compounds (GRI, 1994).

During the gas sweetening/acid gas removal process, the amine unit is a potential source of SO_2, H_2S, VOC, HAP and CO_2 emissions. As the amine regenerator heats the amine solution, the acid gases are released through the amine still vent. The amine still vent can be vented directly to the atmosphere, to a flare or incinerator, or to a sulfur recovery unit (SRU) (TNRCC, 1996). Amine units designed to remove only CO_2 from the natural gas, generally, vent directly to the atmosphere. Amine units designed for the removal of H_2S and CO_2, generally, vent directly to a sulfur recovery unit.

During sulfur recovery, emissions sources in the Selexol process include the process vent streams, fugitive emissions from valves, flanges, and compressor seals, exhaust emissions associated with compressor operation and vented emissions due to periodic maintenance activities (GRI, 1994). Pollutants of concern are SO_2, H_2S, and HAPs.

Emission sources associated with the fixed bed sorption process potentially include the sour gas vent from the flash tank associated with molecular sieve bed regeneration, exhaust emissions from process heaters associated with the regeneration cycle, fugitive emissions, and vented emissions from maintenance activities (GRI, 1994).

Emission sources associated with the Claus sulfur recovery process include the tail gas stream, which is usually incinerated or which may be passed through a liquid redox sulfur recovery unit, fugitive emissions from equipment leaks, and emissions from maintenance activities. In addition, residual H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2) may also be released to the atmosphere from the recovered molten sulfur (GRI, 1994).

In the liquid redox sulfur recovery process, vent gases from the oxidizer vessel are a potential source of emissions. Emissions associated with fixed bed adsorption or molecular sieve dehydration include fugitive emissions and emissions from maintenance activities which are considered minor sources of HAP emissions. Process heaters are often used to heat the regeneration stream, with the burner vents from these heaters being potential sources of HAP emissions (GRI, 1994).

Emissions from the refrigerated absorption process include flue gas from the rich oil fractionator reboiler, exhaust emissions from the compressor driver (a reciprocating engine or a gas turbine), fugitive emissions, and emissions from maintenance activities.

Cryogenics plant emissions primarily include exhaust from the compressor driver, flue gas from the deethanizer reboiler, fugitive emissions, and emissions from maintenance activities.

Emissions associated with the refrigeration process include the glycol regenerator off-gas, which is typically vented to the atmosphere and may potentially contain BTEX, as well as hexane and other HAPs present in the gas. The flue gas stream from the glycol regenerator reboiler is also typically vented to the atmosphere and may be a source of emissions. Other sources of emissions include fugitive emissions and vented emissions due to maintenance activities.

Absorption process emissions include exhaust from the compressor driver, exhaust gas from the fractionator reboiler, fugitive emissions, and vented emissions due to maintenance activities.

Emissions associated with the adsorption process primarily include exhaust gas from the regenerator, fugitive emissions, and maintenance activities.

2.2.3 COMBUSTION

Boilers and heaters provide local process heat, process steam, steam for electric generation, glycol dehydrator reboilers, and amine reboiler units. Internal combustion engines and gas turbines have many other purposes, such as compression of petroleum gases, compression of refrigerants, electrical generation, and pump and crane operation. The pollutants of concern include NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, SO_2, CH_4, and CO_2. HAPs, primarily formaldehyde and acetaldehyde, are also potential pollutants from these combustion sources.

Flares convert potentially hazardous gases into less hazardous emissions. VOC, NO_x, CO, HAPs and CH_4 are the primary pollutants of concern with flares (TNRCC, 1996). If flares are used to oxidize H_2S and other reduced sulfur compounds, SO_2 will also be emitted. Depending on the level of conversion achieved, H_2S and other reduced sulfur compounds may also be emitted.

Auxiliary fuel combustion is also a source of emissions. Fuel used to fire specific process or control equipment such as flares and incinerators result in additional combustion emissions. Depending on the fuel fired, pollutants may include NO_X, CO, PM_{10}, $PM_{2.5}$, VOC, SO_2, CO_2, CH_4, and HAPs.

2.2.4 TRANSPORTATION

Emission sources related to transporting crude oil include loading losses and fugitive pipeline leaks. As crude oil is loaded into trucks, rail cars, barges, and tankers, vapors residing in the vapor space are pushed out of the cargo tank. Pipeline transmission of natural gas is also an emission source. Pollutants include VOC, HAPs, and CH_4 contained in the material.

Pigging operations are also a potential source of VOC, HAP, and CH_4 emissions if residual vapors are vented to the atmosphere rather than to a flare or incinerator. As the pig travels through the pipeline, residual vapors are pushed through the line as well. If the vapors are not routed to a control device, they escape through openings on the device such as hatches, doors, or vents. Emissions can be significant depending on the amount and vapor pressure of the product (TNRCC, 1998a). Depending on the gas used to push the pig, the bleed-off step can also result in VOC, HAP, or CH_4 emissions if the gas is not vented to a control device.

Depending on the purpose of the emission inventory, pigging emissions may need to be included. The inventory preparer should contact the state or local agency to identify the preferred methods to estimate emissions from pigging operations.

2.2.5 STORAGE TANKS

Storage tanks are used to store crude oil, LNG, water or brine, process condensate, as well as other materials used at oil and gas field processing facilities, and may be a potential source of VOC, HAP, CH_4 emissions. Emission losses from storage tanks in the oil and gas field processing industry include working losses, breathing losses, and flash losses. Working losses refer to the combined loss from filling and emptying the tank. Filling losses occur when the VOC contained in the saturated air are displaced from a fixed-roof vessel during loading. Emptying losses occur when air drawn into the tank becomes saturated and expands, exceeding the capacity of the vapor space. Breathing losses are the expulsion of vapor from a tank through vapor expansion caused by daily changes in temperature and pressure. Flash losses occur when fluids exiting vessels at pressures above atmospheric enter storage tanks operating at atmospheric pressure which are vented to the atmosphere. As the fluid pressure drops to atmospheric pressure, the gas which is entrained in the fluid is then released (TNRCC, 1996). Flash losses often exceed breathing and working losses (Boyer and Brodnax, 1996).

2.2.6 WASTEWATER

If open to the atmosphere, units used to treat, store and transfer wastewater on-site may also be potential sources of VOC, HAP, CH_4, and H_2S emissions. Some of these units that may be present at oil and gas field production and processing operations are sumps, pits, storage tanks, brine tanks, and oil/water separators.

2.2.7 FUGITIVES

Fugitive emissions (equipment leaks), are leaks from sealed surfaces associated with process equipment. Specific fugitive source types include various equipment components such as valves, flanges and connectors. Equipment specific to the oil and gas field production and processing operations which result in fugitive emissions include equipment such as heater treaters, separators, pipelines, wellheads and pump stations. Pneumatic devices such as gas actuated pumps and pressure/level controllers also result in fugitive emissions. Pollutants of concern include VOC, HAPs, CH_4 contained in the gas.

2.3 DESIGN AND OPERATING PARAMETERS AFFECTING EMISSIONS

In general, the primary factors affecting emissions and their estimation for sources in oil and gas field processing operations are:

- Oil/gas composition;
- Production rate/frequency of operation; and
- Type of control/recovery, if any.

The specific influence of each of these factors as well as other source specific parameters affecting emissions are discussed below.

Glycol dehydrator emissions will be affected by the composition of the natural gas, particularly the concentration of glycol-soluble hydrocarbons. As water is adsorbed into the glycol stream, so are some glycol-soluble hydrocarbons such as BTEX. The rich glycol stream flows to the reboiler for regeneration by heating to remove the water. Water and adsorbed hydrocarbons are released from the glycol during the regeneration (Boyer and Brodnax, 1996).

Emissions from gas sweetening units are influenced by the concentration of acid gases in the waste gas stream as well as the type of control or recovery process that follows the sweetening process. The greater the H_2S concentration in the sour gas, the greater the potential for H_2S emissions. In the amine gas sweetening process, the amine solution absorbs H_2S, CO_2, and VOCs. After the amine solution is saturated with the acid gases, the solution is piped to the amine regenerator. The regenerator heats the amine solution and the acid gases are released from the amine solution through the amine still vent. If emissions from the still vent are released directly to the atmosphere, H_2S, CO_2, and VOC emissions will be released. If amine still vent emissions are vented to a flare or incinerator, H_2S will be oxidized to SO_2 (TNRCC, 1996). Since the flare/incineration process converts the H_2S to SO_2, the greater the H_2S concentration in the tail gas, the greater the SO_2 emissions. Also, CO_2 in the waste gas stream can lower the

British thermal unit (BTU) content of the gas, thereby reducing the flare efficiency. Fuel gas can be added to the waste gas to increase the BTU content and increase the flame's temperature. The type of auxiliary fuel fired will also impact emissions. VOC emissions are also affected by the control efficiency of the flare or incinerator (Boyer and Brodnax, 1996). If the still vent emissions are vented to a SRU, the H_2S will be converted to elemental sulfur and SO_2 (TNRCC, 1996). The H_2S content of the tail gas, as well as the efficiency of the SRU, will affect SO_2 emissions.

Emissions resulting from flashing are impacted by the change in pressure to which the entrained gases are subjected as well as the volume, temperature, and composition of the material being transferred. Flash losses occur from tanks, gun barrels, and separators, as the fluid moves from the high pressure lines to atmospheric pressure. Under high pressure, the fluid can readily dissolve more gases. As pressures are released from the saturated fluid, the dissolved gases will be released (TNRCC, 1996). All other factors being equal, the greater the pressure drop, the greater the gas volume released per barrel of oil produced (Boyer and Brodnax, 1996). The composition of the fluid will also impact emissions.

Emissions from gas actuated pumps will be impacted by the gas composition, fuel supply pressure, discharge head (pressure), and the flow rate of the liquid pumped, since manufacturer pump curves estimate gas use based on these variables (Boyer and Brodnax, 1996).

The amount of gas vented by pressure and level controllers is dependent on the manufacturer, application, age, and orifice size. In general, controllers in liquid service have larger orifices than those in pressure service. Valves in liquid service are designed to quickly open or close to avoid throttling which can erode the valve seat and reduce the life of the valve (Boyer and Brodnax, 1996).

Factors affecting internal combustion engine and turbine emissions include engine type/design and size, fuel type and firing rate, and operating conditions, such as the air to fuel ratio.

Factors affecting blowdown emissions include maintenance schedules, line pressures, and the volume of gas relieved (TNRCC, 1996). More frequent maintenance results in more frequent gas relief. Also, since emissions are estimated using the Ideal Gas Law, the greater the line pressure and the volume of gas to be relieved, the greater the emissions.

Material transportation and loading losses are affected by the composition of the previous material transported and the current material to be loaded. If the empty cargo tank has not been cleaned, any vapors remaining in the tank will be expelled during the loading process. Also, the loading method will impact emissions. Splash loading will result in greater emissions than submerged pipe fill loading or bottom filling.

2.4 CONTROL TECHNIQUES

Control techniques and devices typically used in oil and gas field processing operations are described below and presented in Table 10.2-1. Control efficiency for a specific piece of equipment will vary depending on the type of equipment and quality of the maintenance/repair program at a particular facility.

2.4.1 CONTROL TECHNIQUES FOR VOC

VOC is probably the pollutant emitted in greatest quantities from oil and gas field processing operations. Flares are used as a method of controlling VOC emissions throughout these facilities when a flash tank is used in conjunction with a condenser. Vapor collection or header systems are commonly installed at oil and gas field processing operations to collect and route vapors to a flare or incinerator. Emissions from emergency and process vents (Boyer and Brodnax, 1996), loading operations (TNRCC, 1996), well casing gases (Rucker and Strieter, 1992), as well as other emission sources are typically routed to flares or incinerators. Control efficiencies of 98% for flares (Rucker and Strieter, 1992) and 99% or greater for incinerators can be achieved.

VOC emissions from emergency and process vents may also be routed to a vapor recovery compressor prior to pipeline injection (Boyer and Brodnax, 1996). Other devices that may be used to control VOC emissions from storage tanks and loading operations include vapor collection and vapor balance systems, carbon adsorption systems, and scrubbers (TNRCC, 1996). Submerged loading techniques will also help reduce VOC and HAP emissions. Another technique for reducing VOC and HAP emissions from storage tanks is the use of an internal floating roof.

Control methods for glycol dehydrators include condensers, flares, vapor recovery units, carbon adsorption, or combinations of these. Condenser efficiencies range from 35 to 98% depending on the type of condenser and the size of unit. Water-cooled condensers can achieve 85 to 98% efficiency. Air-cooled condenser efficiencies range from 35 to 98%. On smaller units, air cooled condensers are capable of achieving the upper end of this range, but efficiencies tend to decrease as the glycol dehydrator size increases. In addition, warmer climates may decrease the efficiency of air-cooled condensers. If the water is efficiently removed from the gas stream during the glycol dehydration process, the glycol regenerator reboiler can also be used to thermally oxidize VOC and HAP emissions from the glycol regenerator process vent. However, if the water is not efficiently removed from the gas stream during glycol dehydration, the glycol regenerator reboiler can become corroded resulting in inefficient combustion of VOC and HAP emissions.

TABLE 10.2-1

TYPICAL OIL AND GAS FIELD PROCESSING EMISSION CONTROL TECHNIQUES

Emission Sources	Pollutant	Control Technique	Typical
Glycol Dehydrators	VOC, HAPs	Condensers[a]	35-98[k]
		Flare[a]	98[b]
		Incinerator	99
		Reboiler[a,j,k]	c
		Vapor recovery systems	c
		Carbon adsorption[b]	c
Amine Still Vents	H_2S	Flare	98[b]
		Incinerator	99
		Sulfur recovery unit	c
Emergency and Process Vents	VOC, HAPs	Flare[a]	98[b]
		Incinerator	99
		Vapor recovery[a] compressor prior to injection	c
Mud Degassing	H_2S, CH_4	Flares[l]	98
	CH_4	Incinerators	99
		Vapor recovery systems[l]	c
Storage Tanks	VOC, HAPs	Flare[a]	98[b]
		Incinerator	99
		Vapor recovery[a] compressor prior to injection	c
		Internal floating roof	60-99[b]
		Vapor balance system	c
		Carbon adsorption	c
		Scrubbers	c
Loading Losses	VOC, HAPs	Submerged loading	58[b,d]
		Vapor recovery	85-95[b]
		Flare[e]	98[b]
		Incinerator[e]	99[b]
		Vapor balance system[e,f]	90[b]
		Carbon adsorption systems[e]	c
		Scrubbers[e]	c
Equipment Leaks	VOC	Leak detection and repair (LDAR)	c, g

TABLE 10.2-1

(CONTINUED)

Emission Sources	Pollutant	Control Technique	Typical
Pigging Operations	VOC, HAP, CH_4	Flares	98
		Incinerators	99
Internal Combustion Engines, Rich-burn	NO_x	Non-selective catalytic reduction[e]	c
		low emission combustion	c
Internal Combustion Engines, Lean-burn	NO_x	Selective catalytic reduction	c
		Torch ignition	c
		Chamber redesign	c
		Low emission combustion	c
Gas Turbines	NO_x	Water/steam injection[h]	c
		Selective catalytic reduction[h]	c
		Low-NO_x burner	c
Boilers/External Combustion Devices	NO_x	Low NO_X burners[i]	30-70[i]
		Flue gas recirculation[i]	50-75[i]
		Selective non-catalytic reduction[i]	25-40[i]
		Selective catalytic reduction[i]	80-90[i]

[a] Source: Boyer and Brodnax, 1996.

[b] Source: Rucker and Strieter, 1992.

[c] Control efficiency not documented; efficiency may vary depending on operational parameters of emission source and/or control technique.

[d] Emission reduction efficiency relative to splash filling.

[e] Source: TNRCC, 1996.

[f] For vapor balance systems, the loading loss saturation factors in AP-42 equation have this reduction built into the calculation. Control efficiency need only be factored in to the calculation if an uncontrolled emission estimation technique is applied.

[g] Efficiency of LDAR will vary based on source location (attainment area vs. nonattainment area), the I/M screening value for leakers, and the frequency of monitoring.

[h] Source: EPA, 1995a.

[i] Source: EPA, 1994a.

[j] The reboiler can be used to thermally oxidize VOC and HAP emissions if water is efficiently removed from the gas stream during the glycol dehydration process.

[k] Water-cooled condensers are generally more efficient than air-cooled condensers for removing water from the gas stream during the glycol dehydration process. On smaller units, air-cooled condensers are capable of achieving the upper end of this range, but efficiencies tend to decrease as glycol dehydrator size increases.

[l] Source: EPA, 1977b.

Leak detection and repair (LDAR) programs are used to reduce equipment leak emissions from components such as valves, pumps, and flanges. Leaking equipment is identified during periodic inspections with a VOC-detection device. The leaking equipment is logged on a maintenance schedule and mechanical adjustments are made to repair the leaks. The efficiency of this control procedure is affected by how often the inspections are conducted and how soon the repairs are made (some states assume specific LDAR control efficiencies provided certain program criteria are met). Leakless equipment has been developed to reduce fugitive emission losses from such equipment as valves and pump seals (Rucker and Strieter, 1992).

Flares can also be used to reduce VOC, HAP and CH_4 emissions collected during pigging operations.

2.4.2 CONTROL TECHNIQUES FOR H_2S

Flares and incinerators are used to convert H_2S in amine still vent streams to SO_2. SRUs also help reduce H_2S emissions from amine still vent streams.

2.4.3 CONTROL TECHNIQUES FOR COMBUSTION EMISSIONS

Water/steam injection, selective catalytic reduction (SCR), and low-NO_x burners are commonly used to reduce NO_x emissions from gas turbines. Some SCR systems utilize a CO catalyst which also reduces CO emissions.

NO_x abatement devices for rich-burn internal combustion engines primarily include non-selective catalytic reduction. Some rich-burn engines can also be prestratified charge engines. Lean-burn internal combustion engines use SCR, torch ignition or chamber redesign techniques to control NO_x emissions. Low emission combustion is also used on internal combustion engines.

Low NO_x burners, flue gas recirculation, and selective non-catalytic reduction are control options for boilers and other external control devices. Selective catalytic reduction can also be used. The reader is referred to Chapter 2 of this volume for more information on combustion sources.

3

OVERVIEW OF AVAILABLE METHODS

3.1 DESCRIPTION OF EMISSION ESTIMATION METHODOLOGIES

There are several methodologies available for calculating emissions from oil and gas field processing operations. The method used is dependent upon available data, available resources, and the degree of accuracy required in the estimate. In general, site-specific data is preferred over industry averaged data, such as *AP-42* emission factors, for accurate emissions estimates (EPA, 1995a). Each state may have a different preference or requirement and so it is suggested that the reader contact the appropriate state or local air pollution agency before deciding on which emission estimation methodology to use. This document evaluates emission estimation methodologies with respect to relative accuracy and does not mandate any emission estimation method. For purposes of calculating peak season daily emissions for State Implementation Plan inventories, refer to the Environmental Protection Agency's (EPA) *Procedures* manual (EPA, 1991a).

This section discusses the methods available for calculating emissions from oil and gas field processing operations and identifies the preferred method of calculation on a pollutant basis. The reader should not infer a preference based on the order emission estimation methodologies are listed in this section. A discussion of the sampling and analytical methods available for monitoring each pollutant is provided in Chapter 1, *Introduction to Stationary Point Source Emissions Inventory Development.*

Emission estimation techniques for auxiliary processes, such as use of EPA's TANKS program to calculate storage tank emissions, are also discussed in Chapter 1. For equipment leaks, the reader is referred to the emission estimation methodologies identified in Chapter 4, *Preferred and Alternative methods for Estimating Fugitive Emissions from Equipment Leaks*.

3.1.1 STACK SAMPLING

Stack sampling provides a "snapshot" of emissions during the period of the stack test. Stack tests are typically performed during either representative (i.e., normal) or maximum load conditions, depending upon the requirements of the state. Samples are collected from the stack using probes inserted through a port in the stack wall, and pollutants are collected in or on various media and sent to a laboratory for analysis. Emissions rates are then determined by multiplying the pollutant concentration by the volumetric stack gas flow rate. Because there are many steps in the stack sampling procedures where errors can occur, only experienced stack testers should perform such tests.

3.1.2 EMISSION FACTORS

Emission factors are available for many source categories and are based on the results of source tests performed at one or more facilities within an industry. Basically, an emission factor is the pollutant emission rate relative to the level of source activity. Chapter 1 of this volume contains a detailed discussion of the reliability, or quality, of available emission factors. EPA-developed emission factors for criteria and hazardous air pollutants are available in *AP-42*, the *Locating and Estimating Series* of documents, and the Factor Information REtrieval system (FIRE). Emission factors are also available from various industrial associations such as the American Petroleum Institute (API), the Gas Research Institute (GRI), and the Chemical Manufacturers Association (CMA). In addition, manufacturers often conduct research to develop emission factors for specific pieces of equipment. For a single facility, stack tests are usually preferable over emission factors, but for estimating emissions across a source category, emission factors can be used and may be the only reasonable means of estimating emissions due to the number of sources or lack of individual facility emission estimates.

3.1.3 CALCULATION PROGRAMS

Several calculation programs or theoretical “models” are available for use in estimating emissions from oil and gas field processing operations. Emission estimating programs/models are available for the following types of emission sources:

- Glycol dehydrators;
- Gas sweetening units;
- Emergency and process vents;
- Equipment leaks;
- External combustion devices;
- Internal combustion engines/gas turbines;
- Storage tanks;
- Flash losses; and
- Loading operations.

Inputs for programs/models generally fall into the following categories: chemical/physical properties of the material(s) involved (e.g., vapor pressure, vapor molecular weight), operating data (e.g., amount of material processed, operating hours), and physical characteristics/properties of the source (e.g., tank color, tank diameter).

The American Petroleum Institute (API) has developed the Exploration and Production Emissions Calculator (EPEC) and E&P TANK models. The EPEC model integrates user input, emissions calculations, and data summaries for many equipment types used in the oil and natural gas production industry (API, 1998). EPEC may be used to estimate emissions of VOC, HAPs, criteria pollutants, and other regulated pollutants.

The E&P TANK model was developed by the API and Gas Research Institute (GRI) and is designed to use site specific information to predict VOC and HAP emissions (flashing, working, and standing losses) from petroleum production field storage tanks (API, 1997).

GRI developed the GRI-HAPCalc model which estimates emissions from six major process units and from equipment leaks from the natural gas production industry. The GRI-HAPCalc model allows the use of *AP-42* emission factors, factors based on literature data, factors based on GRI data, and user-defined factors.

API, in collaboration with GRI, developed the AMINECalc model to estimate HAP and VOC emissions from amine-based sour gas and natural gas liquid sweetening unit.

When using any emission estimation model, the user should be cautious when collecting input data to make sure the correct data is collected and entered into the model. In addition, most models offer default values for some parameters if process-specific data is not available. While simplifying the data collection process, use of the defaults that are not appropriate for a particular unit may result in invalid or inaccurate emission estimates. In all cases, therefore, the user is encouraged to collect and use process-specific data to obtain the most accurate estimate that the model is capable of producing.

Also, depending on the purpose of the inventory, the user should check with the state or local agency to confirm the model is acceptable.

3.1.4 ENGINEERING CALCULATIONS

Various engineering calculations are also used to estimate emissions from oil and gas field processing operations. These calculations require data inputs similar to the calculation programs. Engineering calculations are available for the following sources:

- Emergency and process vents;

- Gas actuated pumps;
- Gas sweetening;
- Sulfur recovery units;
- Flares;
- Pneumatic devices;
- Mud degassing;
- Glycol dehydrators;
- Flash losses;
- Blowdown;
- Well blowouts;
- Well testing; and
- Loading losses

3.2 COMPARISON OF AVAILABLE EMISSION ESTIMATION METHODOLOGIES

Table 10.3-1 identifies the preferred and alternative emission estimation approach(es) for selected pollutants. Table 10.3-1 is ordered according to the relative accuracy of the emission estimation approach. The reader and the local air pollution agency must decide which emission estimation approach is applicable based on costs and air pollution control requirements in their area. The method chosen should also recognize the time specificity of the emission estimate and the data quality. The quality of the data will depend on a variety of factors including the number of data points generated, the representativeness of those data points, and the proper operation and maintenance of the equipment being used to record the measurements. In general, source tests are preferable over emission factors for estimating emissions from a specific source operating under specific conditions, but for emissions across a source category, emission factors can be used and may be the only reasonable means of estimating emissions due to the number of sources or lack of individual emission factors.

TABLE 10.3-1

SUMMARY OF PREFERRED EMISSION ESTIMATION METHODS FOR OIL AND GAS FIELD PROCESSING OPERATIONS

Emission Source	Pollutant[a]	Preferred Emission Estimation Approach Ordered by Accuracy[b]
Internal combustion engines	CO, NO_x, SO_2, VOC, $PM_{2.5}$, PM_{10}, HAPs, CH_4, CO_2	1. Measurement 2. EPA/state/other published emission factors
Gas turbines	NO_x CO, $PM_{2.5}$, PM_{10}, CH_4, CO_2	1. Measurement 2. EPA/state/other published emission factors
Boilers/External flame burners	VOC, SO_2, $PM_{2.5}$ PM_{10}, CH_4, CO_2, HAPs, NO_x, CO	(See Chapter 2 of this series)
Mud degassing	VOC, HAPs, CH_4, H_2S	Displacement equation
Shale shakers/oil-based muds	VOC, HAPs, CH_4, H_2S	EPA/State/other published emission factors
Glycol dehydrator	VOC, HAPs	1. GRI-GLYCalc emission model 2. Measurement 3. Rich/lean method
Gas sweetening - amine units venting to smokeless flare or tail gas incinerator	SO_2, H_2S	1. Displacement Equation/Stoichiometry 2. EPA/state/other published emission factors
	VOC, HAPs	Destruction and removal efficiency
Gas sweetening - amine units venting to atmosphere	CO_2, H_2S	1. Displacement Equation 2. Measurement 3. Rich/lean method
	VOC, HAPs	AMINECalc Model
Gas sweetening amine units venting to sulfur recovery unit	SO_2, H_2S, HAPs	1. Sulfur recovery efficiency 2. EPA/state/other published emission factor

TABLE 10.3-1

(CONTINUED)

Emission Source	Pollutant[a]	Preferred Emission Estimation Approach Ordered by Accuracy[b]
Emergency and process vents	VOC, HAPs, CH_4	Displacement Equation
Flares	NO_x, CO, CH_4	EPA/state/other published emission factors
	VOC, HAPs	Destruction and removal efficiency
	SO_2, H_2S	Displacement Equation/Stoichiometry
Gas actuated pumps	VOC, HAPs, CH_4	Displacement Equation
Loading losses	VOC, HAPs, CH_4	1. EPA published equations 2. Measurement
Pigging operations	VOC, HAPs, CH_4	Measurement
Pneumatic devices	VOC, HAPs, CH_4	1. Displacement Equation 2. EPA/state/other published emission factors
Storage tanks Working losses Breathing losses	VOC, HAPs, CH_4	1. TANKS model (See Chapter 1 of this series) 2. GRI-HAPCalc 3. E&P Tank
Storage tanks Flash losses	VOC, HAPs	See methods for “Flash losses” listed below.
Flash losses - black oil systems	VOC, HAPs	1. E&P Tank Model 2. EPEC Model 3. Vazquez-Beggs/Rollins, McCain, and Creeger Correlations
Flash losses - gas condensate systems	VOC, HAPs	EC/R algorithm or E&P Tank model[c]
Blowdown	VOC, HAPs, CH_4	Displacement Equation
Equipment leaks	VOC, HAPs, CH_4	(See Chapter 4 of this series)
Blowout	VOC, HAPs, CH_4	1. Displacement Equation
Well testing	VOC, HAPs, CH_4	Displacement Equation

[a] VOC = Volatile organic compounds; HAPs = Hazardous air pollutants.
[b] Preferred emission estimation approaches do not include considerations such as cost. The costs, benefits, and relative accuracy should be considered prior to method selection. Non-regulatory agency personnel are advised to check with their local air pollution control agency before choosing a preferred emission estimation approach.
[c] Nizich and EC/R, 1999, reference lists results of both methods.

3.2.1 STACK SAMPLING

Without considering cost, stack sampling is the preferred emission estimation methodology for NO_x, CO, VOC, total hydrocarbons (THC), $PM_{2.5}$, PM_{10}, metals, and speciated organics. EPA reference methods and other methods of known quality can be used to obtain accurate estimates of emissions at a given time for a particular facility. It should be noted, however, that stack sampling provides a snapshot of emissions at the test conditions and does not address variability over time.

3.2.2 EMISSION FACTORS

Due to their availability and acceptance in the industry, emission factors are commonly used to prepare emission inventories. The user should recognize that, in most cases, emission factors are averages of available industry-wide data, with varying degrees of quality, and may not be representative of individual facilities within that industry.

3.2.3 CALCULATION PROGRAMS

Calculation programs often provide a more accurate estimate than emission factors, although they may require considerably more effort in some cases. Because the program inputs require process specific information, the results are process specific estimates.

3.2.4 ENGINEERING CALCULATIONS

Similar to the calculation programs, engineering calculations often provide more accurate estimates than emission factors, although they may also require considerably more effort in some cases. Because the calculations are based on process specific information, the results are process specific estimates. Engineering calculations may be less accurate than emission factors since it may be necessary to make several assumptions when process specific data are not available.

This page is intentionally left blank.

4

PREFERRED METHODS FOR ESTIMATING EMISSIONS

This section describes the preferred methods for estimating emissions for specific types of sources typically found in oil and gas field processing operations and provides examples to illustrate the use of each calculation technique. For certain source types (e.g., material storage), the reader is referred to other documents or other chapters in this document for details on using the suggested methodology.

The reader is also referred to Chapter 4 of this series of documents for emission estimation methods for equipment leaks and to Chapter 2 of this series of documents for emission estimation methods for boilers. Emission estimation methods for wastewater sources can be found in Chapter 5 of this series of documents. In addition, equipment and emissions from off-shore operations, although not specifically addressed in this document, are believed to be similar to those from on-shore operations. Preferred and alternative emission estimation methodologies for off-shore sources are, therefore, expected to be the same as for on-shore sources. Depending on the purpose of the emission inventory, the inventory preparer should consider inclusion of emissions from these additional source types.

Table 10.4-1 lists the variables used in Equations 10.4-1 through 10.4-16.

4.1 EMISSION CALCULATIONS USING EMISSION FACTORS

Emission factors are commonly used to calculate emissions from oil and gas field processing operations. EPA maintains a compilation of emission factors in *AP-42* for criteria pollutants and HAPs (*AP-42*, *5th Edition*, January 1995). The Factor Information and REtrieval system (FIRE) (EPA, 1998) is a database containing *AP-42* emission factors as well as other emission factors that may be found in EPA documents such as the “Locating and Estimating” series for toxic pollutants. In addition, manufacturers often provide emission factors for specific equipment types. Emission factors for equipment leaks may be found in *Protocol for*

TABLE 10.4-1

LIST OF VARIABLES AND SYMBOLS

Variable	Symbol	Units
Emissions	E_x	Typically lb/hr of pollutant x
Emission factor	EF_x	Various
Activity, production or flow rate	Q	Various
Volume of fuel fired	V	Various
Heating value of the fuel	H	Various
Gas molecular weight	MW	lb/lb-mole
Mass fraction	X_x	lb x/total lb
Molar Volume of ideal gas	C	scf/lb-mole
Mole fraction of pollutant x in gas stream	Y_x	lb-mole x/total lb-mole
Molecular weight of pollutant x	MW_x	lb x/lb-mole x
Molecular conversion ratio of pollutant i to pollutant x	M_x	lb-mole x/lb-mole i
Equilibrium ratio for component x	K_x	lb-mole x (vapor)· lb-mole (liquid)/lb-mole x (liquid)· lb-mole (vapor)
Vapor pressure of component x at temperature T	$P_x(T)$	psia
Operating pressure	P	psia
Vapor pressure of material	P_v	pounds per square inch absolute (psia or atm)
Mole fraction of vapor flashed	Y_v	lb-mole (vapor)/lb-mole (liquid)
Density of condensate liquid	δ_{oil}	lb/gallon
Days per year operation	D	Days/year

TABLE 10.4-1

(CONTINUED)

Variable	Symbol	Units
Temperature	T	Various
Molecular weight of vapor	MW_v	lb/lb-mole
Loading loss saturation factor	S	Dimensionless
Arrival emission factor	C_A	lb/Mgal
Generated emission factor	C_G	lb/Mgal
Vapor growth factor	G	Dimensionless
Recovery/production factor	F_x	lb-mole x/lb-mole
Recovery efficiency	RE	%
Destruction and removal efficiency	DRE	%
Stack gas concentration	C_x	Mg/m^3 or ppmvd

Equipment Leak Emission Estimates (EPA-453/R-95-017, 1995h) and *Calculation Workbook for Oil and Gas Production Equipment Fugitive Emissions* (API, 1996).

Emission factors are the preferred emission estimation methodology for the following types of sources found in oil and gas field production and processing operations:

- Internal combustion engines/turbines;
- Flares; and
- Shale shakers.

Much work has been done to develop emission factors for HAPs, and AP-42 revisions include these factors (EPA, 1995a,b). Some states have developed their own HAP emission factors for certain source categories and require their use in any inventories including HAPs. In addition, industry organizations such as GRI and API have developed emission factors for HAPs as well as criteria pollutants for many sources which many key gas producing states recommend for use.

Refer to Chapter 1 of Volume III for a complete discussion of available information sources for locating, developing, and using emission factors as an estimation technique.

Emission factors developed from measurements for a specific source may sometimes be used to estimate emissions at other sites. For example, a company may have several units of similar model and size; if emissions were measured from one unit, an emission factor could be developed and applied to other similar units. It is advisable to consult with state/local agencies or the EPA prior to selection of an emission factor.

The basic equation for using an emission factor to calculate emissions is the following:

$$E_x = EF_x * Q \qquad (10.4\text{-}1)$$

where:

E_x = Emissions of pollutant x
EF_x = Emission factor of pollutant x
Q = Activity or production rate

It should also be noted that depending on the emission factor, activity rate, and desired emissions units, additional variables may need to be factored into the equation, such as sulfur content of the fuel, hours per year of operation, and conversion from pounds to tons. For some sources (e.g., combustion sources), emission factors may be based on the Btu fired rather than volume of fuel fired. The actual Btu firing rate can be calculated based on the volume of fuel fired and the heating value of the fuel using the following equation:

$$Q = V * H \qquad (10.4\text{-}2)$$

where:

Q = Activity or production rate to be used in equation 10.4-1
V = Volume of fuel fired
H = Heating value of the fuel

Calculations using emission factors are presented in Examples 10.4-1 through 10.4-4.

The EPEC model uses the emission factor method for estimating emissions from internal combustion engines, turbines, boilers, flares, and heater treaters. In some cases, the user has the choice of applying GRI or EPA AP-42 emission factors.

The GRI-HAPCalc model also uses the emission factor method to estimate HAP as well as criteria pollutant emissions from internal combustion engines, turbines, and external combustion devices. Users have the choice of emission factors based on GRI literature, GRI field tests, or EPA AP-42.

In all cases, it is advisable to consult with state/local agencies or the EPA prior to selection of an emission factor.

Example 10.4-1

Example 10.4-1 shows how potential hourly CO_2 emissions may be calculated for a 1 MMBtu/hr internal combustion engine firing natural gas. The CO_2 emission factor is from AP-42, Table 3.2-2. The heating value of the natural gas is 1,000 MMBtu/MMscf. At its rated capacity (1 MMBtu/hr) the fuel fire rate is 0.001 MMscf/hr. The engine operates for 4,000 hours per year.

EF_{CO2} = 110 lb/MMBtu
Q = 0.001 MMscf/hr
E_{CO2} = EF_{CO2} * Q
= 110 lb/MMBtu * 0.001 MMscf/hr * 1,000 MMBtu/MMscf = 110 lb/hr
= 110 lb/hr * 4,000 hr/yr = 440,000 lb/yr
= 440,000 lb/yr * ton/2,000 lb = 220 ton/yr
= 220 ton/yr

Example 10.4-2

Example 10.4-2 shows how potential hourly CO_2 emissions may be calculated for a gas turbine. The CO_2 emission factor is from Table 3.2-2 in AP-42. The heating value of the natural gas is 1,000 MMBtu/MMscf. The rated capacity of the turbine is 50 MMBtu/hr. The turbine is operated 2,500 hours per year.

EF_{CO2} = 110 lb/MMBtu
Q = 50 MMBtu/hr
E_{CO2} = EF_{CO2} * Q
= 110 lb/MMBtu * 50 MMBtu/hr = 5,500 lb/hr
= 5,500 lb/hr * 2,500 hr/yr = 13,750,000 lb/yr
= 13,750,000 lb/yr * ton/2,000 lb = 6,875 ton/yr
= 6,875 ton/yr

Example 10.4-3

Example 10.4-3 illustrates the use of emission factors to calculate CO emissions from a natural gas fired steam generator with rated capacity of 55 MMBtu/hr. At its rated capacity, the fuel fire rate is 0.055 MMscf/hr. The CO emission factor is from Table 1.4-2 in AP-42. The source is operated 8,760 hours per year.

Q = 0.055 MMscf/hr
EF_{CO} = 35 lb/MMscf
E_{CO} = $Q * EF_{CO}$
= 0.055 MMscf/hr * 35 lb/MMscf = 1.9 lb/hr
= 1.9 lb/hr * 8,760 hr/yr = 16,600 lb/yr
= 16,600 lb/yr * ton/2,000 lb = 8.3 ton/yr
= 8.3 ton/yr

The reader is referred to Chapter 3 of this volume for more information on steam generators.

Example 10.4-4

Example 10.4-4 shows how potential hourly NO_x emissions may be calculated for a smokeless flare. The NO_x emission factor is from the CMA flare study (CMA). The heat content of the inlet gas is assumed to be 1,030 MMBtu/MMscf, and the gas processing rate is assumed to be 0.0002 MMscf/hr for 8,760 hours per year.

EF_{NOx} = 0.1380 lb/MMBtu
V = 0.0002 MMscf/hr
H = 1,030 MMBtu/MMscf
Q = $V * H$
= 0.0002 MMscf/hr * 1,030 MMBtu/MMscf
= 0.206 MMBtu/hr
E_{NOx} = $EF_{NOx} * Q$
= 0.1380 lb/MMBtu * 0.206 MMBtu/hr = 0.0284 lb/hr
= 0.0284 lb/hr * 8,760 hr/yr = 249 lb/yr
= 249 lb/yr * ton/2,000 lb = 0.124 ton/yr
= 0.124 ton/yr

Example 10.4-5

Example 10.4-5 estimates VOC and HAP emissions from a shale shaker processing oil-based mud. The mud flow rate is 500 gal/min and oil-based drilling muds are used 8 days per year. The emission factor is 0.36 lb/Mgal (Mgal = 1,000 gallons) throughput (EPA, 1977b). The benzene content of the VOC is 25%.

Q = 500 gal/min
EF_{VOC} = 0.36 lb/Mgal
$X_{benzene}$ = 0.25 lb benzene/lb VOC
E_{VOC} = $Q * EF_{VOC}$
= 500 gal/min * 0.36 lbVOC/Mgal * Mgal/1,000 gal
= 0.18 lb VOC/min * 60 min/hr * 24 hr/day * 8 days/yr = 2,074 lb VOC/yr
= 2,074 lb VOC/yr * ton/2,000 lb * 1.037 ton VOC/yr
= 1.037 ton VOC/yr

$E_{benzene}$ = $E_{VOC} * X_{benzene}$
= 2,074 lb VOC/yr * 0.25 lb benzene/lb VOC
= 518 lb benzene/yr * ton/2,000 lb
= 0.26 ton benzene/yr

4.2 EMISSION CALCULATIONS USING EMISSION MODELS

Emission models are the preferred emission estimation technique for glycol dehydrators, storage tanks, flash losses from black oil systems, and VOC and HAP losses from amine-based gas sweetening units venting to the atmosphere. The models for each of these sources are discussed below. Depending on the purpose of the inventory, the user should check with the state or local agency to confirm the model is acceptable.

4.2.1 EMISSION MODEL FOR GLYCOL DEHYDRATORS

VOC and HAP emissions from glycol dehydrators can be estimated using the Gas Research Institute (GRI) model GRI-GLYCalc. GLYCalc provides users the option of applying thermodynamic equations or the Rich/Lean method to estimate emissions. The preferred method of estimating emissions is use of the GLYCalc thermodynamic equations. The Rich/Lean method is discussed later in Section 5.

The preferred method uses fundamental chemical engineering thermodynamics along with empirical data and correlations to make emissions estimates (GRI, 1997). The software is designed as a screening tool to determine if emissions from a unit are of concern. In addition, GRI-GLYCalc only estimates emissions from EG and TEG units (Boyer and Brodnax, 1996). Therefore, if a more accurate estimate is required, or if the unit is not an EG or TEG unit, an alternative emissions estimation method should be selected. For information to obtain GRI-GLYCalc contact GRI.

GLYCalc requires process-specific data to produce an accurate emission estimate. As with any emission estimation model, the user should be cautious when collecting this data to make sure the correct data is collected at the right point in the process line. In addition, models including GLYCalc offer default values for some parameters if process-specific data is not available. While simplifying the data collection process, use of defaults that are not appropriate for a particular unit may result in invalid or inaccurate emission estimates. In all cases, therefore, the user is encouraged to collect and use process-specific data to obtain the most accurate emission estimate.

In addition, recommended guidelines for using the GLYCalc model and a Glycol Inspection Checklist developed and used by the Louisiana Department of Environmental Quality are included as Appendix B. Specific process parameters are listed along with acceptable ranges and suggested guidelines when using the GLYCalc model and are based on data collected from the field. If the acceptable ranges or the suggested guidelines are not appropriate for a particular unit, the user should select an alternative emission estimation technique. The checklist identifies specific data requirements for use with the GLYCalc model (LADEQ, 1998b).

4.2.2 EMISSION MODEL FOR LIQUID MATERIAL STORAGE

The preferred method for calculating working and breathing losses from storage tanks is the use of equations presented in AP-42. EPA has developed a software package (TANKS) for calculating these types of emissions. The TANKS computer program is based upon API equations that were derived for petroleum products, such as, gasoline, diesel fuel, jet fuel and stable crude oil (crude oil without dissolved gasses in solution that could be flashed from solution at a lower pressure). The TANKS computer program is commonly used to quantify working and breathing loss emissions. TANKS has chemical, climatological and component loss factor databases, but still requires knowledge of data specific to tank design and operation. You should check with your local or state authority as to whether TANKS is required for your facility. The use of the TANKS program for calculating emissions from storage tanks is discussed in Chapter 1 of this volume, *Introduction to Stationary Point Source Emissions Inventory Development*. Flash losses from storage tanks can be estimated using several approaches identified later in this chapter (See Sections 4.2.3, 4.3.2, and 5.3).

4.2.3 E&P TANK EMISSION MODEL FOR FLASH LOSSES

Recommendations for preferred methodologies for flash losses are based upon information generated by EPA's Emission Standards Division during development of the Oil and Gas Production NESHAP and limited datasets used for model development and verification restricting model applicability and from information provided by API.

The preferred method for estimating VOC and HAP flash losses from petroleum production storage tanks in black oil systems is the E&P TANK Model. The preferred emission estimation methodologies for gas condensate systems are the EC/R algorithm and the E&P TANK Model. The EC/R algorithm is a more simplified method, however, either method is preferred. The EC/R algorithm is presented in Section 4.3.2.

The E&P TANK Model developed by API and GRI, can be used for either black oil or gas condensate systems. Black oil is a hydrocarbon (petroleum) liquid with a gas-to-oil ratio (GOR) less than 50 cubic meters (1,750 cubic feet) per barrel and an API gravity less than 40 degrees. Gas condensate is a hydrocarbon (petroleum) liquid with a GOR greater than or equal to 50 cubic meters (1,750 cubic feet) per barrel and an API gravity greater than or equal to 40 degrees (FR 2/6/98). The E&P TANK Model is valid for liquids with API gravity ranging from 15 to 68 degrees.

The E&P TANK Model estimates emissions by applying rigorous thermodynamic relationships based on vapor-liquid equilibrium conditions from the Peng-Robinson equation-of-state (Martino, 1997). Data requirements include liquid composition, separator temperature and pressure, Reid Vapor Pressure of the liquid, API gravity of the liquid and the liquid production rate. For more information or to obtain a copy of the E&P TANK model, contact API.

4.2.4 EMISSION MODEL FOR AMINE SWEETENING UNIT

The method for estimating VOC and HAP emissions from amine units for sweetening natural gas and natural gas liquids venting to the atmosphere is use of the AMINECalc model. Data requirements depend on the option selected for calculating emissions. The mass balance option requires flow rates of rich and lean amine streams and composition of rich amine stream exiting the absorption column. Gas process options require sour gas feed data, lean amine circulation rate, and number of absorber trays.

4.3 EMISSION CALCULATIONS USING ENGINEERING EQUATIONS

Use of engineering equations is the preferred technique for estimating emissions from emergency and process vents, gas actuated pumps, pressure/level controllers, blowdown, well blowouts, well testing, gas sweetening units, flash losses from gas condensate systems, transportation loading losses, sulfur recovery units and flares. Engineering equations are also preferred for non-amine gas sweetening units and TEG glycol dehydrators. These equations are discussed and illustrated below.

4.3.1 DISPLACEMENT EQUATION

Use of a displacement equation is the preferred method for estimating VOC, HAP, and CH_4 emissions from emergency and process vents, gas actuated pumps, pressure/level controllers, blowdown, well blowouts, and well testing. This displacement equation can also be used to estimate H_2S and CO_2 emissions from gas sweetening units venting to the atmosphere and for H_2S emissions from mud degassing operations. The following equations can be applied to estimate emissions when no chemical conversion occurs:

$$E_x = Q * MW * X_x * 1/C \qquad (10.4\text{-}3)$$

where:

E_x = Emissions of pollutant x
Q = Volumetric flow rate/volume of gas processed
MW = Molecular weight of gas
= Specific gravity of gas $*$ molecular weight of air
X_x = Mass fraction of pollutant x in gas
C = Molar volume of ideal gas, 379 scf/lb-mole at 60 degrees Fahrenheit and 1 atmosphere

Speciated VOC emissions are calculated using the following equation:

$$E_x = E_{VOC} * X_x \qquad (10.4\text{-}4)$$

where:

E_x = emissions of pollutant x;
E_{VOC} = total VOC, calculated using equation 10.4-3; and
X_x = mass fraction of species x in VOC.

For well blowouts, if the amount of gas processed is unknown, the references “Methane Emissions from the U.S. Petroleum Industry” (EPA, 1996) and “Atmospheric Emissions from Offshore Oil and Gas Development and Production” (EPA, 1977b) provide some background information that may be of use.

Calculations using equations 10.4-3 and 10.4-4 are presented in Examples 10.4-6 through 10.4-13.

Example 10.4-6

Example 10.4-6 shows how VOC and HAP emissions can be calculated from emergency and process vents using the displacement equation. The gas volume released is assumed to be 10,000 scf/yr, the molecular weight of the gas is assumed to be 21 lb/lb-mole, and the VOC weight fraction is assumed to be 0.2.

Q = 10,000 scf/yr
MW = 21 lb/lb-mole
X_{VOC} = 0.2 lb VOC/lb
C = 379 scf/lb-mole @ 60°F, 1 atm
E_{VOC} = $Q * MW * X_{VOC} * 1/C$
= 10,000 scf/yr * 21 lb/lb-mole * 0.2 lb VOC/lb * lb-mole/379 scf = 111 lb VOC/yr
= 111 lb VOC/yr * ton/2,000 lb = 0.055 ton VOC/yr
= 0.055 ton VOC/yr

Xylene content of the exhaust VOC is assumed to be 10% by weight.

X_{xylene} = 0.10 lb xylene/lb VOC
E_{VOC} = 111 lb/yr
E_{xylene} = $X_{xylene} * E_{VOC}$
= 0.10 lb xylene/lb VOC * 111 lb VOC/yr = 11.1 lb xylene/yr
= 11.1 lb xylene/yr * ton/2,000 lb = 0.0055 ton xylene/yr
= 0.0055 ton xylene/yr

Example 10.4-7

Example 10.4-7 shows how VOC and HAP emissions can be calculated from gas actuated pumps using the displacement equation. The gas volume consumed is determined from the manufacturer's pump curve and is assumed to be 2,000 scf/hr, the molecular weight of the gas is assumed to be 21 lb/lb-mole, and the VOC weight fraction is assumed to be 0.2. The pumps operate 4,000 hours per year.

Q = 2,000 scf/hr
MW = 21 lb/lb-mole
X_{VOC} = 0.2 lb VOC/lb
C = 379 scf/lb-mole @ 60°F, 1 atm

Example 10.4-7 (Continued)

E_{VOC} = Q * MW * X_{VOC} * 1/C
= 2,000 scf/hr * 21 lb/lb-mole * 0.2 lb VOC/lb * lb-mole/379 scf = 22.2 lb VOC/hr
= 22.2 lb VOC/hr * 4,000 hrs/yr = 88,654 lb VOC/yr
= 88,654 lb VOC/yr * ton/2,000 lb = 44.3 ton VOC/yr
= 44.3 ton VOC/yr

Benzene content of the exhaust VOC is assumed to be 20% by weight.

$X_{benzene}$ = 0.2 lb benzene/lb VOC
E_{VOC} = 88,654 lb/yr
$E_{benzene}$ = $X_{benzene}$ * E_{VOC}
= 0.20 lb benzene/lb VOC * 88,654 lb VOC/yr = 17,731 lb benzene/yr
= 17,731 lb benzene/yr * ton/2,000 lb = 8.87 ton benzene/yr
= 8.87 ton benzene/yr

Example 10.4-8

Example 10.4-8 shows how VOC and HAP emissions can be calculated from pressure and level controllers using the displacement equation. The gas volume released is determined by either obtaining the manufacturer's estimate or by assuming an average release rate per controller. For this example, the release rate is assumed to be 20 scf/hr. The molecular weight of the gas is assumed to be 21 lb/lb-mole, and the VOC weight fraction is assumed to be 0.1. The controllers are assumed to operate 8,760 hours per year.

Q = 20 scf/hr
MW = 21 lb/lb-mole
X_{VOC} = 0.1 lb VOC/lb
C = 379 scf/lb-mole @ 60°F, 1 atm
E_{VOC} = Q * MW * X_{VOC} * 1/C
= 20 scf/hr * 21 lb/lb-mole * 0.1 lb VOC/lb * lb-mole/379 scf = 0.11 lb VOC/hr
= 0.11 lb VOC/hr * 8,760 hr/yr = 971 lb VOC/yr
= 971 lb VOC/yr * ton/2,000 lb = 0.49 ton VOC/yr
= 0.49 ton VOC/yr

Example 10.4-8 (Continued)

Xylene content of the exhaust VOC is assumed to be 10% by weight.

X_{xylene} = 0.10 lb xylene/lb VOC
E_{VOC} = 971 lb/yr
E_{xylene} = $X_{xylene} * E_{VOC}$
= 0.10 lb xylene/lb VOC * 971 lb VOC/yr = 97.1 lb xylene/yr
= 97.1 lb xylene/yr * ton/2,000 lb = 0.049 ton xylene/yr
= 0.049 ton xylene/yr

Example 10.4-9

Example 10.4-9 calculates VOC and HAP emissions resulting from blowdown of a group of compressor engines. Blowdown occurs 4 times per year and the total volume of gas vented per event is 150 scf. The total annual volume of gas is 600 scf/yr. The molecular weight of the gas is 29.2 lb/lb-mole and the mass fraction of VOC in the gas is 0.3.

Q = 600 scf/yr
MW = 29.2 lb/lb-mole
X_{VOC} = 0.3 lb VOC/lb
C = 379 scf/lb-mole @ 60°F, 1 atm
E_{VOC} = $Q * MW * X_{VOC} * 1/C$
= 600 scf/yr * 29.2 lb/lb-mole * 0.3 lb VOC/lb * lb-mole/379 scf = 13.9 lb VOC/yr
= 13.9 lb VOC/yr * ton/2,000 lb = 0.007 ton VOC/yr
= 0.007 ton/yr

Gas analysis indicates benzene content of VOC is 25% by weight.

$X_{benzene}$ = 0.25 lb benzene/lb VOC
E_{VOC} = 13.9 lb/yr
$E_{benzene}$ = $X_{benzene} * E_{VOC}$
= 0.25 lb benzene/lb VOC * 13.9 lb VOC/yr = 3.5 lb benzene/yr
= 3.5 lb benzene/yr * ton/2,000 lb = 0.002 ton benzene/yr
= 0.002 ton benzene/yr

Example 10.4-10

Example 10.4-10 calculates methane emissions from well blowout using the displacement equation. During the year, 1 well blowout occurred which lasted for 2 days. The well production rate is 465,000 SCF/day. It is assumed that the daily gas production rate of the well for those 2 days is released to the atmosphere. The amount of gas released to the atmosphere, therefore, is 930,000 SCF (465,000 SCF/day * 2 days). The mass fraction of CH_4 in the gas is 0.90. The mass fraction of VOC in the gas is 0.10. The molecular weight of the gas is 22 lb/lb-mole

Q = 930,000 scf/yr
C = 379 scf/lb-mole @ 60°F, 1 atm
MW = 22 lb/lb-mole
X_{VOC} = 0.10
X_{CH4} = 0.90
E_{VOC} = Q * MW * X_{VOC} * 1/C

$$= 930{,}000\ \text{scf/yr} * 22\ \text{lb/lb-mole} * \frac{0.10\ \text{lb VOC}}{\text{lb}} * \frac{1\ \text{lb-mole}}{379\ \text{scf}}$$

= 5,398 lb VOC/yr * ton/2,000 lb
= 2.70 ton VOC/yr
E_{CH4} = Q * MW * X $_{CH4}$ * 1/C

$$= 930{,}000\ \text{scf/yr} * 22\ \text{lb/lb-mole} * \frac{0.90\ \text{lb } CH_4}{\text{lb}} * \frac{1\ \text{lb-mole}}{379\ \text{scf}}$$

= 48,586 lb CH_4/yr * ton/2,000 lb
= 24.3 ton CH_4/yr.

Example 10.4-11

Example 10.4-11 shows how VOC and HAP emissions can be estimated for well testing operations using the displacement equation. A total of 100 gas wells are tested each year and the total volume of gas vented is 285,000 scf/yr. The average VOC concentration of the vented gas is 0.15 lb VOC/lb. The average toluene concentration of the VOC is 0.25 lb toluene/lbVOC.

Q = 285,000 scf/yr
MW = 21 lb/lb-mole
X_{VOC} = 0.15 lb VOC/lb
$X_{toluene}$ = 0.25 lb toluene/lb

Example 10.4-11 (Continued)

C = 379 scf/lb-mole @ 60°F, 1 atm

E_{VOC} = $Q * MW * X_{VOC} * 1/C$

$$= 285{,}000 \text{ scf/yr} * 21 \text{ lb/lb-mole} * \frac{0.15 \text{ lb VOC}}{\text{lb}} * \frac{\text{lb-mole}}{379 \text{ scf}} * 2{,}369 \text{ lb VOC/yr}$$

$$= 2{,}369 \text{ lb VOC/yr} * \frac{\text{ton}}{2{,}000 \text{ lb}} = 1.2 \text{ ton VOC/yr}$$

= 1.2 ton VOC/yr

$E_{toluene}$ = $X_{toluene} * E_{VOC}$

= 0.25 lb toluene/lb VOC * 2,369 lb VOC/yr = 592 lb toluene/yr

$$= 592 \text{ lb toluene/yr} * \frac{\text{ton}}{2{,}000 \text{ lb}} = 0.30 \text{ ton toluene/yr}$$

= 0.30 ton toluene/yr

Example 10.4-12

Example 10.4-12 illustrates the calculation of CO_2 and H_2S emissions from an amine-based gas sweetening unit that vents to the atmosphere. The sour gas flowrate is 12.5 mmscf/day. The mass fraction of CO_2 and H_2S in the sour gas is 0.19 and 0.01, respectively. The molecular weight of the sour gas is 18.33 lb/lb-mole. The unit operates continuously for 200 days throughout the year.

Q = 12.5 mmscf/day

MW = 18.33 lb/lb-mole

X_{CO2} = 0.19 lb CO_2/lb

X_{H2S} = 0.01 lb H_2S/lb

C = 379 scf/lb-mole @ 60°F, 1 atm

E_{CO2} = $Q * MW * X_{CO2} * 1/C$

$$= 12.5 \text{ mmscf/day} * 18.33 \text{ lb/lb-mole} * \frac{0.19 \text{ lb } CO_2}{\text{lb}} * \frac{\text{lb-mole}}{379 \text{ scf}} * \frac{10^6 \text{ scf}}{\text{mmscf}}$$

= 114,865 lb CO_2/day * 200 days/yr * ton/ 2,000 lb = 11,486 ton CO_2/yr

= 11,486 ton CO_2/yr

E_{H2S} = $Q * MW * X_{H2O} * 1/C$

$$= 12.5 \text{ mmscf/day} * 18.33 \text{ lb/lb-mole} * \frac{0.01 \text{ lb } H_2S}{\text{lb}} * \frac{\text{lb-mole}}{379 \text{ scf}} * \frac{10^6 \text{ scf}}{\text{mmscf}}$$

= 6,046 lb H_2S/day * 200 day/yr * ton/2,000 lb = 605 ton H_2S/yr

= 605 ton H_2S/yr

Example 10.4-13

Example 10.4-13 estimates H_2S and CH_4 emissions from a drilling mud degassing operation. The volume of gas vented to the atmosphere is 10,000 ft^3. The mass fraction of H_2S and CH_4 in gas is 0.05 and 0.19, respectively. The molecular weight of the gas is 18.33 lb/lb-mole. The degassing operations occurred for four days.

Q = 10,000 scf/day
X_{CH4} = 0.19 lb CH_4/lb-mole
X_{H2S} = 0.05 lb H_2S/lb-mole
MW = 18.33 lb/lb-mole
C = 379 scf/lb-mole
E_{CH4} = Q * MW * 1/C * X_{CH4}

$$= 10{,}000\ \text{scf/day} * 18.33\ \text{lb/lb-mole} * \frac{\text{lb-mole}}{379\ \text{scf}} * \frac{0.19\ \text{lb}\ CH_4}{\text{lb}} = \frac{91.9\ \text{lb}\ CH_4}{\text{day}}$$

= 91.9 lb CH_4/day * 4 days/yr = 368 lb CH_4/yr
= 368 lb CH_4/yr * ton/2,000 lb = 0.184 ton CH_4/yr
= 0.184 ton CH_4/yr
E_{H2S} = Q * MW * 1/C * X_{H2S}

$$= 10{,}000\ \text{scf/day} * 18.33\ \text{lb/lb-mole} * \frac{\text{lb-mole}}{379\ \text{scf}} * \frac{0.05\ \text{lb}\ H_2S}{\text{lb}} = \frac{24.2\ \text{lb}\ H_2S}{\text{day}}$$

= 24.2 lb H_2S/day * 4 days/yr = 96.8 lb H_2S/yr
= 96.8 lb H_2S/yr * ton/2,000 lb = 0.048 ton H_2S/yr
= 0.048 ton H_2S/yr

For sources where a chemical conversion takes place, such as gas sweetening units venting to a flare or incinerator, the displacement equation can be used to estimate SO_2 and H_2S emissions, however, additional factors based on stoichiometry must be applied. The following equation can be applied to estimate SO_2 emissions from flares or incinerators where H_2S is converted to SO_2:

$$E_{SO_2} = Q * y_{H_2S} * \frac{1}{C} * M_{SO_2} * MW_{SO_2} \qquad (10.4\text{-}5)$$

where:

E_{SO2} = SO_2 emissions, lb/yr
Q = Volume of gas processed, scf/yr
y_{H2S} = Mole fraction of H_2S in inlet gas, lb-mole H_2S/lb-mole

C = Molar volume of ideal gas, 379 scf/lb-mole at 60 degrees Fahrenheit and 1 atmosphere

M_{SO2} = Molar conversion ratio from H_2S to SO_2, $\frac{\text{lb-mole } SO_2}{\text{lb-mole } H_2S}$

(Based on stoichiometry and assuming complete conversion of H_2S to SO_2, $M_{SO2} = 1$)

MW_{SO2} = Molecular weight of SO_2, lb SO_2/lb-mole SO_2

The residual H_2S emissions from this process can be estimated using the following equation:

$$E_{H_2S} = Q * y_{H_2S} * \frac{1}{C} * (1 - M_{SO_2}) * MW_{H_2S} \tag{10.4-6}$$

where:

E_{H2S} = H_2S emissions, lb/yr

Q = Volume of gas processed, scf/yr

y_{H2S} = Mole fraction of H_2S in inlet gas, lb-mole H_2S/lb-mole

C = Molar volume of ideal gas, 379 scf/lb-mole at 60 degrees Fahrenheit and 1 atmosphere

M_{SO2} = Molar conversion ratio from H_2S to SO_2, $\frac{\text{lb-mole } SO_2}{\text{lb-mole } H_2S}$

(Based on stoichiometry and assuming complete conversion of H_2S to SO_2, $M_{SO2} = 1$)

MW_{H2S} = Molecular weight of H_2S, lb H_2S/lb-mole H_2S

If the conversion of H_2S to SO_2 is completed, no residual H_2S emissions would result.

Example 10.4-14 illustrates the use of this equation.

Example 10.4-14

Example 10.4-14 shows how SO_2 and H_2S emissions can be calculated from a gas sweetening unit venting to a flare using the displacement equation and assuming 98% conversion of H_2S to SO_2. The gas volume released is 50,000 scf/yr, and the mole fraction of H_2S in the inlet gas is 0.2.

Q = 50,000 scf/yr
y_{H2S} = 0.2 lb-mole H_2S/lb-mole
C = 379 scf/lb-mole @ 60°F, 1 atm
M_{SO2} = 0.98 lb-mole SO_2/lb-mole H_2S
MW_{SO2} = 64 lb/lb-mole
E_{SO2} = $Q * y_{H2S} * 1/C * M_{SO2} * MW_{SO2}$

$$= 50{,}000 \text{ scf/yr} * 0.2 \text{ lb-mole } H_2S/\text{lb-mole} * \text{lb-mole}/379 \text{ scf} * 0.98 \frac{\text{lb-mole } SO_2}{\text{lb-mole } H_2S}$$

$$* 64 \text{ lb } SO_2/\text{lb - mole } SO_2 = 1{,}655 \text{ lb } SO_2/\text{yr}$$

= 1,655 lb SO_2/yr * ton/2,000 lb = 0.83 ton SO_2/yr
= 0.83 ton SO_2/yr

Residual H_2S emissions are calculated below.

E_{H2S} = $Q * y_{H2S} * 1/C * (1-M_{SO2}) * MW_{H2S}$
= 50,000 scf/yr * 0.2 lb-mole H_2S/lb-mole * lb-mole/379 scf * (1-0.98) * 34 lb H_2S/lb-mole H_2S
= 17.94 lb H_2S/yr * ton/2,000 lb = 0.00897 ton H_2S/yr
= 0.00897 ton H_2S/yr

4.3.2 EMISSION EQUATIONS FOR FLASH LOSSES FROM GAS CONDENSATE SYSTEMS

Recommendations for preferred methodologies for flash losses are based upon information generated by EPA's Emission Standards Division during development of the Oil and Gas Production NESHAP and limited datasets used for model development and verification restricting model applicability and from information provided by API.

The preferred methods for estimating flash losses from gas condensate systems are the EC/R algorithm and the E&P TANK Model. The EC/R algorithm is a more simplified method, however, either method is preferred. The E&P TANK Model is discussed in Section 4.2.3.

The EC/R algorithm calculates flash emissions based on the pressure drop of the process stream from the previous process vessel to a storage vessel and was derived from the behavior of the liquid stream based on changes in stream compositions and pressure (Akin and Battye, 1994).

This method assumes that the liquid and vapor streams reach equilibrium at standard temperature and pressure and that the storage tank is at standard temperature and pressure. The EC/R algorithm is valid for vapor pressure of liquid streams entering the storage tank between 1.6 atm and 5.1 atm. At vapor pressures less than 1.6 atm, flash losses can be assumed to approach zero. At vapor pressures greater than 5.1 atm, another method should be selected (see section 10.5.3). For more information on this method, see Akin and Battye, 1994. Procedures for applying the EC/R algorithm to estimate VOC and HAP emissions are described below. The first step in calculating flash losses from fixed-roof storage tanks in condensate systems is to estimate the equilibrium ratio. The equilibrium ratio (K_x) in a multi component mixture of liquid and vapor phases is defined as the ratio of the mole fraction of that component in the vapor phase to the mole fraction of that component in the liquid phase. The equilibrium ratio can be estimated using Raoult's law and assuming ideal solution behavior:

$$K_x = P_x\ (T)/P \qquad (10.4\text{-}7)$$

where:

K_x = Equilibrium ratio for component i, $\frac{\text{lb-mole component}_{i,V} * \text{lb-mole}_l}{\text{lb-mole component}_{i,l} * \text{lb-mole}_v}$

P_x (T) = Vapor pressure of component i at the condensate liquid storage tank temperature T, psia.

P = Pressure of the storage tank, psia

Then, estimate the mole fraction of vapor flashed using the following equation:

$$Y_v = 0.0523(P_v - 1.636) \qquad (10.4\text{-}8)$$

where:

Y_v = Mole fraction of vapor flashed, lb-mole$_v$/lb-mole$_l$

0.0523 = Coefficient, lb-mole $_v$/lb-mole$_l$ · atm

P_v = Total vapor pressure of the condensate liquid stream in the previous vessel, atm

1.636 = Total vapor pressure of the condensate liquid stream in the previous vessel at which the flashing losses approach zero, atm

Having estimated the equilibrium ratio and the mole fraction of vapor flashed, emissions can be calculated as follows:

$$E_x = K_x * Q * \delta_{oil} * X_x * Y_v * D * 42 \tag{10.4-9}$$

where:

E_x = Component x emissions, lb/year

K_x = Equilibrium ratio for VOC, $\frac{\text{lb-mole } X_V * \text{lb-mole}_l}{\text{lb-mole } X_l * \text{lb-mole}_v}$

Q = Volume of condensate liquid processed, bbl/day

δ_{oil} = Density of the condensate liquid, lb/gal

X_x = Mass fraction of component x in the condensate liquid, lb x/lb

Y_v = Mole fraction of vapor flashed, lb-mole$_v$/lb-mole$_l$

D = Days per year of operation, days/year

42 = Conversion from barrels to gallons

Example 10.4-15 illustrates the use of Equations 10.4-7 through 10.4-9.

Example 10.4-15

Example 10.4-15 calculates flash losses resulting from condensate entering a storage tank at a total vapor pressure of 3.82 atm and a temperature of 70°F. The VOC concentration of the condensate stream is 0.65 lb/lb. The benzene concentration of the condensate stream is 0.015 lb benzene/lb. At 70°F, the vapor pressure of VOC is 4.23 psia and the vapor pressure of benzene is 1.54 psia. The volume of condensate processed is 135 bbl/day, and the condensate density is 7.25 lb/gal. The storage tank is at standard temperature and pressure. This source operates 365 days per year.

$P_{voc}(T)$ = 4.23 psia or lb-mole VOC$_v$/lb-mole VOC$_l$

$P_{benzene}(T)$ = 1.54 psia or lb-mole benzene$_v$/lb-mole benzene$_l$

P = 14.7 psia

P_v = 3.82 atm

Q = 135 bbl/day

Example 10.4-15 (Continued):

δ_{oil} = 7.25 lb/gal
X_{voc} = 0.65 lb/lb
$X_{benzene}$ = 0.015 lb benzene/lb
D = 365 days/yr

Calculate the equilibrium ratios:

K_x = $P_x(T)/P$
K_{voc} = 4.23 psia/14.7 psia
= 0.288 lb-mole $VOC_v \cdot$ lb-$mole_l$/lb-mole $VOC_l \cdot$ lb-$mole_v$
$K_{benzene}$ = 1.54 psia/14.7 psia
= 0.105 lb-mole $benzene_v \cdot$ lb-$mole_l$/lb-mole $benzene_l \cdot$ lb-$mole_v$

Calculate the mole fraction of vapor flashed:

Y_v = 0.0523 * (P_v-1.636)
0.0523 lb-$mole_v \cdot$ atm/lb-$mole_l$ * (3.82 atm - 1.636 atm)
= 0.114 lb-$mole_v$/lb-$mole_l$

Calculate emissions:

E_{voc} = $K_{voc} * Q * \delta_{oil} * X_{voc} * Y_v * D * 42$

$$= 0.288\ \frac{\text{lb-mole VOC}_v \cdot \text{lb-mole}_l}{\text{lb-mole VOC}_l \cdot \text{lb-mole}_v} * 135\ \text{bbl/day}$$

* 7.25 lb/gal * 0.65 lb VOC/lb *

$$\frac{0.114\ \text{lb-mole}_v}{\text{lb-mole}_l} * 365\text{days/yr} * 42\ \text{gal/bbl}$$

$$* \frac{1\ \text{lb-mole VOC}_l}{1\ \text{lb-mole VOC}_v} = 320{,}202\ \text{lb/yr}$$

$$= 320{,}202\ \text{lb/yr} * \frac{\text{ton}}{2{,}000\ \text{lb}} = 160\ \text{ton/yr}$$

= 160 ton/yr

Example 10.4-15 (Continued):

$$E_{benzene} = K_{benzene} * Q * \delta_{oil} * X_{benzene} * Y_v * D * 42$$

$$= 0.105 * \frac{\text{lb-mole benzene}_v * \text{lb-mole}_l}{\text{lb-mole benzene}_l * \text{lb-mole}_v} * 135 \text{ bbl/day}$$

$$* 7.25 \text{ lb/gal} * 0.015 \text{ lb benzene/lb} *$$

$$* \frac{0.114 \text{ lb-mole}_v}{\text{lb-mole}_l} * 365 \text{days/yr}$$

$$* 42 \text{ gal/bbl} * \frac{1 \text{ lb-mole benzene}_l}{1 \text{ lb-mole benzene}_v} = 2{,}694 \text{ lb benzene/yr}$$

$$= 2{,}694 \text{ lb benzene/yr} * \text{ton}/2000 \text{ lb} = 1.35 \text{ ton benzene/yr}$$

$$= 1.35 \text{ ton benzene/yr}$$

4.3.3 EMISSION EQUATIONS FOR LOADING LOSSES

VOC emissions resulting from loading liquid materials into tank trucks and tank cars may be calculated using the following loading loss equation (EPA, 1995c).

$$E_{VOC} = 12.46 * \frac{S * P_V * MW_V * Q}{T} \qquad (10.4\text{-}10)$$

where:

E_{VOC} = VOC loading loss, lb/yr
S = Saturation factor, see Table 5.2-1 in AP-42
P_V = True vapor pressure of the material in the tank at temperature T, psia
MW_V = Vapor molecular weight, lb/lb-mole
Q = Volume of material loaded, Mgal/yr (Mgal = 1,000 gallons)
T = Temperature of material in the tank, °R.

Calculation of VOC emissions using Equation 10.4-10 is based on the following assumptions:

- The ideal gas law is applicable;
- The previous cargo that generated the vapors being displaced is the same as the liquid currently being loaded; and
- There is no mass or heat transfer from the loaded liquid to the previously existing vapors; only displacement is being modeled.

VOC emissions from the loading of crude oil into ships and ocean barges can be estimated using the following equation (which is presented in Section 5.2 of AP-42):

$$E_{VOC} = (C_A + C_G) * Q * X_{VOC} \qquad (10.4\text{-}11)$$

where:

E_{VOC} = Total loading loss, lb/yr
C_A = Arrival emission factor, contributed by vapors in the empty tank compartment before loading, lb/Mgal loaded. See Table 5.2-3 in AP-42.
C_G = Generated emission factor, contributed by evaporation during loading, lb/Mgal loaded. See equation 10.4-12.
Q = Volume of material loaded, Mgal/yr
X_{VOC} = Mass fraction of VOC in vapor, lb VOC/lb. Default per AP-42 is 0.85

The parameter C_G can be calculated using the following equation (per Section 5.2 in AP-42):

$$C_G = 1.84 * (0.44 * P_V - 0.42) * \frac{MW_V\, G}{T} \qquad (10.4\text{-}12)$$

where:

P_V = True vapor pressure of loaded crude oil, psia. See AP-42 Figure 7.1-5 and Table 7.1-2.
MW_V = Molecular weight of vapors, lb/lb-mole. See AP-42 Table 7.1-2.
G = Vapor growth factor, 1.02 (dimensionless)
T = Temperature of vapors, °R (°F + 460)

Examples 10.4-16 and 10.4-17 illustrate the use of these equations.

The EPEC model uses the *AP-42* method to estimate emissions from loading operations.

Example 10.4-16

Example 10.4-16 calculates loading losses resulting from splash loading crude oil into a tank truck in dedicated vapor balance service. Tank volume loaded is 100,000 gallons, liquid temperature is 70°F, true vapor pressure is 3.4 psia, and the molecular weight of vapors is 50 lb/lb-mole.

Q = 100 Mgal/yr
T = 70 + 460 = 530°R
P_V = 3.4 psia
MW_V = 50 lb/lb-mole
S = 1.00 (see AP-42, Table 5.2-1)
E_{VOC} = 12.46 * [S * P_v * MW_v * Q]/T
= 12.46 * [1.00 * 3.4 psia * 50 lb/lb-mole * 100 Mgal/yr]/530°R = 400 lb VOC/yr
= 400 lb VOC/yr * ton/2,000 lb = 0.2 ton VOC/yr
= 0.2 ton VOC/yr

Gas analysis indicates that 5% of the VOC by weight is benzene.

$E_{benzene}$ = E_{VOC} * $X_{benzene}$
= 400 lb VOC/yr * 0.05 lb benzene/lb VOC = 20 lb benzene/yr
= 20 lb benzene/yr * ton/2,000 lb = 0.01 ton benzene/yr
= 0.01 ton benzene/yr

Example 10.4-17

Example 10.4-17 estimates emissions from a loading operation which loads crude oil into a ship. The ship's previous cargo was volatile and the cargo tank was not cleaned. Vapor pressure of the crude oil to be loaded is 5.4 psia and the molecular weight of vapors is 50 lb/lb-mole. Vapor temperature is assumed to be at 75°F. Annual throughput under these conditions is 500,000 gallons. Mass fraction of VOC in vapor is 0.7.

C_A = 0.86 lb/Mgal (see AP-42, Table 5.2-3)
P_V = 5.4 psia
MW_V = 50 lb/lb-mole
T = 435°R
G = 1.02

Example 10.4-17 (Continued):

Q = 500 Mgal/yr
X_{VOC} = 0.7
C_G = 1.84 * (0.44 * P_V - 0.42) * [MW_V * G]/T
= 1.84 * (0.44 * 5.4 psia - 0.42) * [50 lb/lb-mole * 1.02]/435°R = 0.42 lb/Mgal
= 0.42 lb/Mgal
E_{VOC} = (C_A + C_G) * Q * X_{VOC}
= (0.86 + 0.42) * 500 Mgal/yr * 0.7 lb VOC/lb = 448 lb VOC/yr
= 448 lb VOC/yr * ton/2,000 lb = 0.22 ton VOC/yr
= 0.22 ton VOC/yr

Vapor analysis indicates the mass fraction of benzene in the VOC is 0.4.

$E_{benzene}$ = E_{VOC} * $X_{benzene}$
= 448 lb VOC/yr * 0.4 lb benzene/lb VOC = 179 lb benzene/yr
= 179 lb benzene/yr * ton/2,000 lb = 0.09 ton benzene/yr
= 0.09 ton benzene/yr

4.3.4 EMISSION EQUATIONS FOR SULFUR RECOVERY UNITS

H_2S and SO_2 emissions from the sulfur recovery process are dependent on the degree of sulfur recovery achieved. The following equations can be used to estimate uncontrolled SRU emissions:

$$E_{SO_2} = Q * y_{H_2S} * F_s * MW_S * \frac{1}{C} * \frac{MW_{SO_2}}{MW_S} * F_{SO_2} * \left(1 - \frac{RE}{100}\right) \qquad (10.4\text{-}13)$$

where:

E_{SO2} = SO_2 emission estimate, lb/hr
Q = Gas process rate, scf/hr
y_{H2S} = mole fraction of H_2S in inlet gas stream
F_S = Sulfur recovery factor (1 mole sulfur/mole H_2S)
MW_S = Molecular weight of sulfur
C = Molar volume of ideal gas, 379 scf/mole at 60 degrees Fahrenheit and 1 atmosphere
MW_{SO2} = Molecular weight of SO_2
F_{SO2} = SO_2 production factor (1 mole SO_2/3 moles S)
RE = Sulfur recovery efficiency, %

$$E_{H_2S} = Q * y_{H_2S} * F_s * MW_S * \frac{1}{C} * \frac{MW_{H_2S}}{MW_S} * F_{H_2S} * \left(1 - \frac{RE}{100}\right) \qquad (10.4\text{-}14)$$

where:

E_{H2S} = H_2S emission estimate, lb/hr
Q = Gas process rate, scf/hr
y_{H2S} = mole fraction of H_2S in inlet gas stream, mole H_2S/mole
F_S = Sulfur recovery factor, 1 mole sulfur/mole H_2S
MW_S = Molecular weight of sulfur, lb/mole
C = Molar volume of ideal gas, 379 scf/mole at 60 degrees Fahrenheit and 1 atmosphere
MW_{H2S} = Molecular weight H_2S, lb/mole
F_{H2S} = H_2S production factor, 2 mole H_2S/3 moles S
RE = Sulfur recovery efficiency

Example 10.4-18 illustrates the use of these equations.

Example 10.4-18

Example 10.4-18 calculates emissions from a Claus sulfur recovery unit processing 10,000 scf/hr gas with an inlet H_2S content of 20% by volume. The process operates 6,000 hours per year and has a sulfur recovery efficiency of 95%.

Q = 10,000 scf/hr
y_{H2S} = 0.20 lb-mole H_2S/lb-mole
F_S = 1 lb-mole S/lb-mole H_2S
MW_S = 32 lb S/lb-mole S
C = 379 scf/lb-mole @ 60°F, 1 atm

Example 10.4-18 (Continued)

MW_{H2S} = 34 lb H_2S/lb-mole H_2S
F_{H2S} = 2 lb-mole H_2S/3 lb-mole S
MW_{SO2} = 64 lb SO_2/lb-mole SO_2
F_{SO2} = 1 lb-mole SO_2/3 lb-mole S
RE = 95

$$E_{SO2} = Q * y_{H_2S} * F_S * MW_S * \frac{1}{C} * \frac{MW_{SO_2}}{MW_S} * F_{SO_2} * \left(1 - \frac{RE}{100}\right)$$

$$\frac{10{,}000\,\text{scf/hr} * \frac{0.20\,\text{lb-mole}\,H_2S}{\text{lb-mole}} * \frac{1\,\text{lb-mole}\,S}{\text{lb-mole}\,H_2S} * \frac{32\,\text{lb}\,S}{\text{lb-mole}\,S} * \frac{\text{lb-mole}}{379\,\text{scf}} * \frac{64\,\text{lb}\,SO_2}{\text{lb-mole}\,SO_2} * \frac{1\,\text{lb-mole}\,SO_2}{3\,\text{lb-mole}\,S} * \left(1 - \frac{95}{100}\right)}{\left(\frac{32\,\text{lb}\,S}{\text{lb-mole}\,S}\right)} = 5.63\ \text{lb}\ SO_2\ \text{hr}$$

= 5.63 lb SO_2/hr * 6,000 hr/yr = 33,780 lb SO_2/yr
= 33,780 lb SO_2/yr * ton/2,000 lb = 17 ton SO_2/yr
= 17 ton SO_2/yr

$$E_{H2S} = Q * y_{H_2S} * F_S * MW_S * \frac{1}{C} * \frac{MW_{H_2S}}{MW_S} * F_{H_2S} * \left(1 - \frac{RE}{100}\right)$$

$$\frac{10{,}000\ \text{scf/hr} * \frac{0.20\,\text{lb-mole}\,H_2S}{\text{lb-mole}} * \frac{1\,\text{lb-mole}\,S}{\text{lb-mole}\ H_2S} * \frac{32\,\text{lb}\,S}{\text{lb-mole}\ S} * \frac{\text{lb-mole}}{379\,\text{scf}} * \frac{34\,\text{lb}\,H_2S}{\text{lb-mole}\,H_2S} * \frac{2\,\text{lb-mole}\,H_2S}{3\,\text{lb-mole}\,S} * \left(1 - \frac{95}{100}\right)}{\left(\frac{32\,\text{lb}\,S}{\text{lb-mole}\,S}\right)} = 5.98\ \text{lb}\ H_2S/\text{hr}$$

= 5.98 lb H_2S/hr * 6,000 hr/yr = 35,880 lb H_2S/yr
= 35,880 lb H_2S/yr * ton/2,000 lb = 18 ton H_2S/yr
= 18 ton H_2S/yr

4.3.5 VOC AND HAP EMISSIONS FROM FLARES

The preferred approach for estimating VOC and HAP emissions from sources venting VOC and HAP emissions to flares is based on the gas processing rate and the destruction and removal efficiency (DRE) of the flare. The following equation can be applied:

$$E_X = Q * y_X * \frac{1}{C} * MW_X * \left(1 - \frac{DRE}{100}\right) \qquad (10.4\text{-}15)$$

where:

E_x = Emission estimate for pollutant x, lb/hr
Q = Gas process rate, scf/hr
y_x = Mole fraction of pollutant x in inlet stream, lb-mole x/lb-mole
C = Molar volume of ideal gas, 379 scf/lb-mole @ 60 degrees Fahrenheit
MW_x = Molecular weight of pollutant x
DRE = Destruction and removal efficiency, %

Example 10.4-19 illustrates the use of this equation.

Example 10.4-19

Example 10.4-19 calculates VOC and HAP emissions from a flare. The inlet gas process rate is 200 scf/hr and contains 25% VOC and 1% toluene, by volume. The flare operates 8,760 hours per year and is 98% efficient.

Q = 200 scf/hr
y_{VOC} = 0.25 scf VOC/scf
$y_{toluene}$ = 0.01 scf xylene/scf
C = 379 scf/lb-mole @ 60°F
MW_{VOC} = 50 lb/lb-mole
$MW_{toluene}$ = 92.13 lb/lb-mole
DRE = 98%

$$E_{VOC} = Q * y_{VOC} * \frac{1}{C} * MW_{VOC} \left(1 - \frac{DRE}{100}\right)$$

Example 10.4-19 (Continued)

$$= 200\,\text{scf} * 0.25\ \text{scfVOC/scf} * \frac{1\ \text{lb-mole VOC}}{379\ \text{scf VOC}} * \frac{50\ \text{lb VOC}}{\text{lb-mole VOC}} * \left(1 - \frac{98}{100}\right) = 0.132$$

= 0.132 lb VOC/hr * 8,760 hr/yr = 1,156 lb VOC/yr

= 1,156 lb VOC/yr * ton/2,000 lb = 0.58 ton VOC/yr

= 0.58 ton VOC/yr

$$E_{toluene} = Q * y_{toluene} * \frac{1}{C} * MW_{toluene} * \left(1 - \frac{DRE}{100}\right)$$

$$= 200\ \text{scf} * 0.01\ \text{scf toluene/scf} * \frac{1\ \text{lb-mole toluene}}{379\ \text{scf toluene}} * \frac{92.13\ \text{lb toluene}}{\text{lb-mole toluene}} * \left(1 - \frac{98}{100}\right) = 0.0097\ \text{lb toluene/hr}$$

= 0.0097 lb toluene/hr * 8,760 hr/yr = 85 lb toluene/yr

= 85 lb toluene/yr * ton/2,000 lb = 0.042 ton toluene/yr

= 0.042 ton toluene/yr

4.4 EMISSION CALCULATIONS USING STACK SAMPLING DATA

Stack sampling test reports often provide emissions data in terms of lb/hr or mg/m^3. Annual emissions may be calculated from these data using Equation 10.4-16. Stack tests performed under a proposed permit condition or a maximum emissions rate are likely to be higher than the emissions which would result under normal operating conditions. The emission testing should only be completed after the purpose of the testing is known. For example, emission testing for particulate emissions may be different than emission testing for New Source Performance Standards (NSPS) because the back-half catch portion of the sampling train (where condensable PM is caught) is not considered in the NSPS limits.

An example summary of a stack test is shown in Table 10.4-2. The table shows the results of three different sampling runs conducted during one test event. Pollutant concentration is multiplied by the exhaust gas volumetric flow rate to determine the emission rate in pounds per hour, as shown in Equation 10.4-16 and Example 10.4-20.

$$E_x = C_x * Q/35.3 * 60/454{,}000 \qquad (10.4\text{-}16)$$

where:

E_x = hourly emissions in lb/hr of pollutant x

C_x = stack gas concentration, mg/m^3
Q = stack gas volumetric flow rate, scfm
35.3 = conversion factor, 35.3 ft^3/m^3
60 = 60 min/hr
454,000 = conversion factor, 454,000 mg per pound

TABLE 10.4-2

TEST RESULTS

Parameter	Symbol	Run 1	Run 2	Run 3
Volumetric flow rate (scfm)	Q	300	292	297
Concentration of H_2S (mg/m^3)	C_{H2S}	652	665	657
H_2S emission rate (lb/hr)	E_{H2S}	0.73	0.73	0.73

Example 10.4-20

H_2S emissions are calculated using Equation 10.4-16 and the stack sampling data for Run 1 (presented in Table 10.4-2 are shown below). The unit is operated 8,760 hours per year.

$$
\begin{aligned}
E_{H2S} &= C_{H2S} * Q/35.3 * 60/454{,}000 \\
&= 652 \text{ mg/m}^3 * 300 \text{ scf/min}/(35.3 \text{ ft}^3/\text{m}^3) * (60 \text{ min/hr})/(454{,}000 \text{ mg/lb}) \\
&= 0.73 \text{ lb } H_2S/\text{hr} \\
&= 0.73 \text{ lb } H_2S/\text{hr} * 8{,}760 \text{ hrs/yr} = 6{,}415 \text{ lb } H_2S/\text{yr} \\
&= 6{,}415 \text{ lbs } H_2S/\text{yr} * \frac{\text{ton}}{2{,}000 \text{ lb}} = 3.2 \text{ ton } H_2S/\text{yr} \\
&= 3.2 \text{ ton } H_2S/\text{yr}
\end{aligned}
$$

5

ALTERNATIVE METHODS FOR ESTIMATING EMISSIONS

Alternative methods for estimating emissions from oil and gas field processing operations are presented in this section. Table 10.5-1 lists the variables used in Equations 10.5-1 through 10.5-6.

In addition, equipment and emissions from off-shore operations, although not specifically addressed in this document, are believed to be similar to those from on-shore operations. Preferred and alternative emission estimation methodologies for off-shore sources are, therefore, expected to be the same as for on-shore sources. Depending on the purpose of the emission inventory, the inventory preparer should also consider inclusion of emissions from these source types.

5.1 EMISSION CALCULATIONS USING EMISSION FACTORS

Emission factors are commonly used to calculate emissions from oil and gas field processing operations. EPA maintains a compilation of emission factors in *AP-42* for criteria pollutants and HAPs (*AP-42, 5th Edition*, January 1995). Emission factors for equipment leaks may be found in *Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017, 1995) and *Calculation Workbook for Oil and Gas Production Equipment Fugitive Emissions* (API, 1996). The Factor Information and Retrieval system (FIRE) (EPA, 1998) is a database containing AP-42 emission factors as well as other emission factors that may be found in EPA documents such as the "Locating and Estimating" series for toxic pollutants. In addition, manufacturers often provide emission factors for specific pieces of equipment.

Currently, emission factors are available as an alternative method for the following types of sources found in oil and gas field processing operations:

- SO_2 emissions from gas sweetening amine units venting to a smokeless flare or tail gas incinerator;
- SO_2 emissions from Claus sulfur recovery units; and

TABLE 10.5-1

LIST OF VARIABLES AND SYMBOLS

Variable	Symbol	Units
Emissions	E_x	Typically lb/hr of pollutant x
Emission factor	EF_x	Various
Activity, production or flow rate	Q	Various
Volume of fuel fired	V	Various
Heating value of the fuel	H	Various
Pollutant concentration	C_x	mg/m^3 or ppmvd
Rich sample pollutant x concentration	C_i	Various
Lean sample pollutant x concentration	C_o	Various
Molecular weight of pollutant	MW	lb/lb-mole
Molar volume of ideal gas	C	scf/lb-mole
Annual emissions of pollutant x	$E_{tpy,x}$	ton/yr
Annual operating hours	OpHrs	hour/yr
Gas/oil ratio	GOR	scf/ Stock tank barrel (STB)
API gravity	γ_o	API degrees
Solution gas specific gravity at actual temperature and pressure	γ_g	Dimensionless
Dissolved gas specific gravity at 100 psig	γ_{gc}	Dimensionless
Stock tank oil specific gravity	γ_{os}	Dimensionless
Operating pressure	P	Psia

TABLE 10.5-1

CONTINUED

Variable	Symbol	Units
Operating temperature	T	Various
Molecular weight of vapor	MW_v	lb/lb-mole
Mass fraction	X_x	lb x/total lb
Days per year operation	D	Days/year

- Pneumatic devices.

Much work has been done to develop emission factors for HAPs and AP-42 revisions have included these factors (EPA, 1995a,b). In addition, many states have developed their own HAP emission factors for certain source categories and require their use in any inventories including HAPs. Refer to Chapter 1 of Volume II for a complete discussion of available information sources for locating, developing, and using emission factors as an estimation technique.

Emission factors developed from measurements for a specific source may sometimes be used to estimate emissions at other sites. For example, a company may have several units of similar model and size; if emissions were measured from one unit, an emission factor could be developed and applied to other similar units. It is advisable to consult with state/local agencies or the EPA prior to selection of an emission factor.

The basic equation for using an emission factor to calculate emissions is the following:

$$E_x = EF_x * Q \qquad (10.5\text{-}1)$$

where:

E_x = Emissions of pollutant x
EF_x = Emission factor of pollutant x
Q = Activity or production rate

Depending on the emission factor, activity rate, and desired emissions units, additional variables may need to be factored into the equation, such as sulfur content of the fuel, hours per year of operation, and conversion from pounds to tons. For some sources (e.g., combustion sources), emission factors may be based on the Btu fired rather than volume of fuel fired. The actual Btu firing rate can be calculated based on the volume of fuel fired and the heating value of the fuel using the following equation:

$$Q = V * H \tag{10.5-2}$$

where:

Q = Activity or production rate to be used in equation 10.5-1
V = Volume of fuel fired
H = Heating value of the fuel

Calculations using emission factors are presented in Examples 10.5-1 through 10.5-3.

The EPEC model uses the emission factor method for estimating VOC, HAP, and criteria pollutant emissions from heater treaters and flares. In some cases, users have the choice of applying GRI or EPA AP-42 emission factors.

The GRI-HAPCalc model also uses the emission factor method to estimate HAP as well as criteria pollutant emissions from gas sweetening amine units. The gas sweetening emission factors are based on GRI field test data.

In all cases, it is advisable to consult with the state/local agencies or the EPA prior to selection of an emission factor.

Example 10.5-1

Example 10.5-1 shows how potential hourly SO_2 emissions may be calculated for a smokeless flare on an amine gas sweetening process with no sulfur recovery or sulfuric acid production present. The SO_2 emission factor is from AP-42, Table 5.3-1. H_2S content of the inlet gas is assumed to be 2.5% by volume, and the gas processing rate is assumed to be 200 scf/hr for 8,760 hours per year.

EF_{SO2} = 1,685 * S lb/10^6 scf gas processed
S = H_2S content of the sour gas entering the gas sweetening plant (volume %)
= 2.5
Q = 200 scf/hr

Example 10.5-1 (Continued)

$$\begin{aligned}
E_{SO2} &= EF_{SO2} * S * \text{gas processing rate} \\
&= 1{,}685 * 2.5 * 200 = 842{,}500 \text{ lb-scf/hr-}10^{6} \text{ scf} \\
&= 842{,}500 \text{ lb-scf/hr-}10^{6} \text{ scf} * 10^{6} \text{ scf}/1{,}000{,}000 \text{ scf} = 0.8425 \text{ lb/hr} \\
&= 0.8425 \text{ lb/hr} * 8{,}760 \text{ hr/yr} = 7{,}380 \text{ lb/yr} \\
&= 7{,}380 \text{ lb/yr} * \text{ton}/2{,}000 \text{ lb} = 3.69 \text{ ton/yr} \\
&= 3.69 \text{ ton/yr}
\end{aligned}$$

Example 10.5-2

Example 10.5-2 estimates SO_2 emissions from an uncontrolled 3-stage Claus sulfur recovery unit using emission factors. The SO_2 emission factor is from AP-42, Table 8.13-1. The unit produces 550 tons per year of sulfur.

$$\begin{aligned}
EF_{SO2} &= 188 \text{ lb/ton sulfur produced} \\
Q &= 550 \text{ ton/yr} \\
E_{SO2} &= EF_{SO2} * Q \\
&= 188 \text{ lb/ton sulfur} * 550 \text{ ton sulfur/yr} = 103{,}400 \text{ lb } SO_2\text{/yr} \\
&= 103{,}400 \text{ lb } SO_2\text{/yr} * \frac{\text{ton}}{2{,}000 \text{ lb}} = 51.7 \text{ ton } SO_2\text{/yr} \\
&= 51.7 \text{ ton } SO_2\text{/yr}
\end{aligned}$$

Example 10.5-3

Example 10.5-3 uses emission factors to estimate CH_4 emissions from pneumatic devices. The site estimates a total of 85,000 pneumatic devices. The emission factor is from "Methane Emissions from the U.S. Petroleum Industry" (EPA, 1996).

$$\begin{aligned}
Q &= 85{,}000 \text{ devices} \\
EF_{CH4} &= 345 \text{ scf } CH_4 \text{ /day/device} \\
E_{CH4} &= Q * EF_{CH4}
\end{aligned}$$

Example 10.5-3 (Continued)

$$= \quad 85{,}000 \text{ devices} * 345 \text{ scf } CH_4\text{/day/device}$$

$$= \quad 29{,}325{,}000 \text{ scf } CH_4\text{/day} * \frac{\text{lb mole } CH_4}{379 \text{ scf}} * \frac{16 \text{ lb } CH_4}{\text{lb-mole } CH_4} = 4{,}836 \text{ lb } CH_4\text{/day}$$

$$= \quad 4{,}836 \text{ lb } CH_4\text{/day} * 365 \text{ days/yr} = 1{,}765{,}110 \text{ lb } CH_4\text{/yr}$$

$$= \quad 1{,}765{,}110 \text{ lb } CH_4\text{/yr} * \frac{\text{ton}}{2{,}000 \text{ lb}} = 883 \text{ ton } CH_4\text{/yr}$$

$$= \quad 883 \text{ ton } CH_4\text{/yr}$$

5.2 EMISSION CALCULATIONS USING STACK SAMPLING DATA

Stack sampling test reports often provide emissions data in terms of lb/hr or mg/m^3. Annual emissions may be calculated from these data using Equations 10.5-3 or 10.5-4. Stack tests performed under a proposed permit condition or a maximum emissions rate are likely to be higher than the emissions which would result under normal operating conditions. The emission testing should only be completed after the purpose of the testing is known. For example, emission testing for particulate emissions may be different than emission testing for New Source Performance Standards (NSPS) because the back-half catch portion of the sampling train (where condensable PM is caught) is not considered in the NSPS limits.

5.2.1 STACK SAMPLING DATA FOR GAS SWEETENING PROCESSES

This section shows how to calculate emissions in lb/hr based on stack sampling data. Calculations involved in determining H_2S emissions from EPA Method 11 data are used as an example. The only available methods for sampling H_2S emissions are EPA Method 11, a stainless steel bomb or a portable gas chromatograph.

An example summary of a Method 11 test is shown in Table 10.5-2. The table shows the results of three different sampling runs conducted during one test event. Pollutant concentration is multiplied by the exhaust gas volumetric flow rate to determine the emission rate in pounds per hour, as shown in Equation 10.5-3 and Example 10.5-4.

$$E_x = C_x * Q/35.3 * 60/454{,}000 \qquad (10.5\text{-}3)$$

where:

E_x = hourly emissions in lb/hr of pollutant x
C_x = stack gas concentration, mg/m^3
Q = stack gas volumetric flow rate, scfm
35.3 = conversion factor, 35.3 ft^3/m^3
60 = 60 min/hr
454,000 = conversion factor, 454,000 mg per pound

TABLE 10.5-2

TEST RESULTS - METHOD 11

Parameter	**Symbol**	**Run 1**	**Run 2**	**Run 3**
Volumetric flow rate (scfm)	Q	300	292	297
Concentration of H_2S (mg/m^3)	C_{H2S}	652	665	657
H_2S emission rate (lb/hr)	E_{H2S}	0.73	0.73	0.73

Example 10.5-4

H_2S emissions are calculated using Equation 10.5-3 and the stack sampling data for Run 1 (presented in Table 10.5-2 are shown below). The unit is operated 8,760 hours per year.

$$\begin{aligned} E_{H2S} &= C_{H2S} * Q/35.3 * 60/454{,}000 \\ &= 652\ mg/m^3 * 300\ scf/min/(35.3\ ft^3/m^3) * (60\ min/hr)/(454{,}000\ mg/lb) \\ &= 0.73\ lb\ H_2S/hr \\ &= 0.73\ lb\ H_2S/hr * 8{,}760\ hrs/yr = 6{,}415\ lb\ H_2S/yr \\ &= 6{,}415\ lbs\ H_2S/yr * \frac{ton}{2{,}000\ lb} = 3.2\ ton\ H_2S/yr \\ &= 3.2\ ton\ H_2S/yr \end{aligned}$$

5.2.2 THE RICH/LEAN METHOD FOR GLYCOL DEHYDRATORS AND GAS SWEETENING AMINE UNITS

The rich/lean method can be used to estimate emissions from glycol dehydrators and gas sweetening amine units. The rich/lean method utilizes rich and lean sample data by applying them to either glycol or amine circulation rates. For glycol dehydrators, a rich glycol sample is obtained prior to the reboiler and after any flash tank. A lean glycol sample is taken prior to the contact tower (Boyer and Brodnax, 1996). The following equation can be used to calculate emissions from either glycol dehydrators or gas sweetening amine units venting to the atmosphere:

$$E_x = (C_i - C_o) * Q \qquad (10.5\text{-}4)$$

where:

E_x = Emissions of pollutant x
C_i = Rich sample pollutant x concentration
C_o = Lean sample pollutant x concentration
Q = Glycol or amine circulation rate

Examples 10.5-5 and 10.5-6 illustrate the use of this equation.

The EPEC model incorporates the Rich/Lean emissions estimation method for both glycol dehydrators and gas sweetening amine units. The GLYCalc model also provides users the option of applying the Rich/Lean method to estimate emissions from glycol dehydrators.

<u>Example 10.5-5</u>

Example 10.5-5 estimates benzene emissions from a glycol dehydrator with a glycol circulation rate of 5 gpm. Sample analyses indicate a rich glycol benzene concentration prior to the reboiler of 800 mg/L and a lean glycol benzene concentration prior to the contact tower of 100 mg/L. The dehydrator operates 8,760 hours per year.

C_i = 800 mg/L
C_o = 100 mg/L
Q = 5 gal/min
$E_{benzene}$ = $(C_i - C_o) * Q$

Example 10.5-5 (Continued)

$$= (800\,\text{mg/L} - 100\,\text{mg/L}) * 5\ \text{gal/min} * \frac{1{,}000\,\text{L}}{264\,\text{gal}}$$

$$* \frac{\text{lb}}{454{,}000\,\text{mg}} * 60\,\text{min/hr} = 1.75\ \text{lb benzene/hr}$$

$$= 1.75\ \text{lb benzene/hr} * \frac{8{,}760\ \text{hr}}{\text{yr}} = 15{,}348\ \text{lb benzene/yr}$$

$$= 15{,}348\ \text{lb benzene/yr} * \frac{\text{ton}}{2{,}000\ \text{lb}} = 7.67\ \text{ton benzene/yr}$$

$$= 7.67\ \text{ton benzene/yr}$$

Example 10.5-6

Example 10.5-6 estimates ethylbenzene emissions from a gas sweetening amine unit with an amine circulation rate of 8 gpm. Sample analyses indicate a rich amine ethylbenzene concentration of 600 mg/L and a lean amine ethylbenzene concentration of 300 mg/L. The amine unit operates 8,760 hours per year.

C_i = 600 mg/L
C_o = 300 mg/L
Q = 8 gal/min
$E_{ethylbenzene}$ = $(C_i - C_o) * Q$

$$= (600\,\text{mg/L} - 300\,\text{mg/L}) * 8\ \text{gal/min} * \frac{1{,}000\,\text{L}}{264\,\text{gal}}$$

$$* \frac{\text{lb}}{454{,}000\,\text{mg}} * 60\,\text{min/hr} = 1.20\ \text{lb ethylbenzene/hr}$$

$$= 1.20\ \text{lb ethylbenzene/hr} * \frac{8{,}760\ \text{hr}}{\text{yr}} = 10{,}525\ \text{lb ethylbenzene/yr}$$

$$= 10{,}525\ \text{ton ethylbenzene/yr} * \frac{\text{ton}}{2{,}000\ \text{lb}} = 5.26\ \text{ton ethylbenzene/yr}$$

$$= 5.26\ \text{ton ethylbenzene/yr}$$

5.3 EMISSION EQUATIONS FOR FLASH LOSSES

The dissolved Gas Oil Ratio (GOR) can also be used as an alternative method to estimate flash losses. The GOR can be estimated using either the Vazquez-Beggs Correlation or the Rollins, McCain, Creeger Correlation. Both techniques are detailed below (TNRCC, 1996).

5.3.1 VAZQUEZ-BEGGS CORRELATION

The Vazquez-Beggs correlation is an empirical correlation equation based on laboratory measured pressure-volume-temperature (PVT) data and is a function of pressure, temperature, oil gravity, and gas gravity (Martino, 1997). The Vazquez-Beggs correlation is valid for liquids with API gravity ranging between 15 and 68 degrees. The Vazquez-Beggs correlation is valid only within a set range of values. These values are listed below.

Parameters	**Range**
Vessel operating pressure, P	50 to 5250 (psia)
Vessel operating temperature, T	70 to 295 (degrees F)
Vessel gas/oil ratio, GOR	20 to 2070 (scf/STB)
API gravity, γ_o	16 to 58 API
Gas specific gravity at actual temperature and pressure, γ_g	0.56 to 1.18

The Vazquez-Beggs solution gas ratio correlation for a bubble point crude is shown below:

$$\mathrm{GOR} = C_1 * \gamma_{gc} * P^{C_2} * \exp\left[\frac{C_3 * \gamma_o}{T + 460}\right] \tag{10.5-7}$$

where:

GOR = Solution gas/oil ratio in vessel liquid, units are standard cubic feet per stock tank barrel (scf/STB)
C_1, C_2, C_3 = Empirical constants shown in table below
γ_{gc} = Dissolved gas specific gravity at 100 psig (See equation 10.5-8)
P = Vessel operating pressure, psia
exp = 2.718, the base “e” of the natural log system
γ_o = API gravity of stock-tank liquid
T = Vessel operating temperature, degrees Fahrenheit

Coefficient	API ≤ 30	API > 30
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.9310

If the gas specific gravity was not taken at 100 psig then, the gas specific gravity, for any pressure and temperature, may be referenced to 100 psig by using the following equation:

$$\gamma_{gc} = \gamma_g * \left[1.0 + \left(5.912 \times 10^{-5} * \gamma_o * T * \log\left[\frac{P}{114.7}\right]\right)\right] \tag{10.5-8}$$

where:

γ_{gc} = Dissolved gas specific gravity at 100 psig
γ_g = Solution gas specific gravity at actual separator pressure and temperature
P = Vessel operating pressure, psia
γ_o = API gravity of stock tank liquid
T = Vessel operating temperature, degrees Fahrenheit
log = 10, the base “10" of the standard log system

5.3.2 ROLLINS, MCCAIN, CREEGER CORRELATION

The Rollins, McCain, Creeger correlation is based on 301 black oil samples and is a function of the oil specific gravity, separator gas specific gravity, and separator temperature and pressure (Martino, 1997). The Rollins, McCain, Creeger correlation is applicable to oil with an API gravity range of 20 to 50 degrees.

The Rollins, McCain, Creeger correlation is valid within the following range of values:

Parameter	**Range**
Vessel gas/oil ratio, GOR	≥ 100.0 (scf/STB)
Vessel operating pressure, P	30 to 300 (psia)
Vessel operating temperature, T	65 to 140 (degrees F)
Stock tank oil specific gravity, γ_{os}	0.934 to 0.780

The following equation can be used to estimate GOR:

$$\log(GOR) = 0.4896 - 4.916 * \log(\gamma_{os}) + 3.469 * \log(\gamma_g) + 1.501 * \log(P) - 0.9213 * \log(T) \tag{10.5-9}$$

where:

GOR = Solution gas/oil ratio in vessel liquid, scf/STB
γ_{os} = Stock tank oil specific gravity
γ_g = Vessel gas specific gravity
P = Vessel operating pressure, psia
T = Vessel operating temperature, degrees Fahrenheit

The following equation can be used to estimate γ_{os}:

$$\gamma_{os} = 141.5/[131.5 + \gamma_o]$$

where:

γ_{os} = Stock tank oil specific gravity
γ_o = API gravity of stock tank liquid, API degrees

The EPEC model incorporates both the Vazquez-Beggs and the Rollins, McCain, Creeger correlations for estimating the dissolved gas oil ratio. In all cases, it is advisable to consult with state/local agencies or the EPA prior to selection of an emission estimation method.

Once the GOR has been found, the VOC emissions can be calculated as follows:

$$E_{VOC} = Q * GOR * 1/C * MW_v * X_{VOC} * D \tag{10.5-10}$$

where:

E_{VOC} = VOC emissions lb/year
Q = Volume of oil processed, bbl/day
GOR = Dissolved gas/oil ratio, scf/STB
C = Molar volume of ideal gas, 379 scf/lb-mole at 60 degrees Fahrenheit and 1 atmosphere
MW_v = Vapor Molecular weight, lb/lb-mole
X_{VOC} = Mass fraction of VOC in vapor, lb VOC/lb vapor
D = Days per year of operation

Examples 10.5-8 and 10.5-9 illustrate the use of equations 10.5-7 through 10.5-10.

<u>Example 10.5-8</u>

Example 10.5-8 uses the Vazquez-Beggs correlation to calculate flash losses resulting from oil entering a storage tank from a separator operating at 300 psia and 200°F. The API gravity of the oil is 30 API, the dissolved gas specific gravity at actual conditions is 0.75.

The oil transfer rate is 120 STB/day, the vapor molecular weight is 50 lb/lb-mole and the mass fraction of VOC in the vapor is 0.9. This source operates 365 days/yr.

P = 300 psia
T = 200°F
γ_o = 30
γ_g = 0.75
γ_{gc} = $\gamma_g * [1.0 + (5.912 \times 10^{-5} * \gamma_o * T * \log(P/114.7))]$
= $0.75 * [1.0 + (5.912 \times 10^{-5} * 30 * 200 * \log(300/114.7))]$
= 0.86
C_1 = 0.0362 at 30 API
C_2 = 1.0937 at 30 API
C_3 = 25.7240 at 30 API
MW = 50 lb/lb-mole
Q = 120 STB/day
X_{VOC} = 0.9
C = 379 scf/lb-mole @ 60°F, 1 atm
GOR = $C_1 * \gamma_{gc} * P^{C2} * \exp[C3 * \gamma_o/(T + 460)]$
= $0.0362 * 0.86 * (300)^{1.0937} * \exp[25.7240 * 30/(200 + 460)]$
= 51.31 scf/STB
E_{VOC} = $Q * GOR * (1/C) * MW * X_{VOC}$
= 120 STB/day * 51.31 scf/STB * (lb-mole/379 scf) * 50 lb/lb-mole * 0.9 lb VOC/lb
= 731.1 lb VOC/day * 365 days/yr
= 266,851 lb VOC/yr * ton/2,000 lb
= 133 ton VOC/yr

Gas analysis indicates benzene content is 5%of VOC by weight.

$E_{benzene}$ = $E_{VOC} * X_{benzene}$
= 266,851 lb VOC/yr * 0.05 lb benzene/lb VOC
= 13,343 lb benzene/yr * ton/2,000 lb
= 6.7 ton benzene/yr

Example 10.5-9

Example 10.5-9 uses the Rollins, McCain, Creeger correlation to calculate flash losses resulting from oil entering a storage tank from a gun barrel operating at 300 psia and 200°F. The API gravity of the oil is 30 API degrees, the dissolved gas specific gravity at actual conditions is 0.75. The oil transfer rate is 50 STB/day, the vapor molecular weight is 50 lb/lb-mole and the mass fraction of VOC in vapor is 0.85.

P = 300 psia
T = 200°F
γ_o = 30
γ_g = 0.75 @ 300 psia
MW = 50 lb/lb-mole
Q = 120 STB\day
X_{VOC} = 0.85
C = 379 scf/lb-mole @ 60°F, 1 atm
γ_{os} = $141.5/[131.5 + \gamma_o]$
= 141.5/[131.5 + 30]
= 0.876
log (GOR) = $0.4896 - 4.916 * \log(\gamma_{os}) + 3.469 * \log(\gamma_g) + 1.501 * \log(P) - 0.9213 * \log(T)$
= $0.4896 - 4.916 * \log(0.876) + 3.469 * \log(0.75) + 1.501 * \log(300) - 0.9213 * \log(200)$
= 1.94
GOR = $\log^{-1}(1.94)$
= 86.5 scf/STB
E_{VOC} = $Q * GOR * (1/C) * MW * X_{VOC}$
= 50 STB/day * 86.5 scf/STB * (lb-mole/379 scf) * 50 lb/lb-mole * 0.85 lb VOC/lb
= 485 lb VOC/day * 365 day/yr = 177,023 lb/yr
= 177,023 lb/yr * ton/2,000 lb
= 89 ton VOC/yr

Gas analysis indicates benzene content is 10% of VOC by weight.

$E_{benzene}$ = $E_{VOC} * X_{benzene}$
= 177,023 lb VOC/yr * 0.10 lb benzene/lb VOC
= 17,702 lb benzene/yr * ton/2,000 lb
= 8.85 ton benzene/yr

6

QUALITY ASSURANCE/QUALITY CONTROL

The consistent use of standardized methods and procedures is essential in the compilation of reliable emission inventories. QA and QC of an inventory is accomplished through a set of procedures that ensure the quality and reliability of data collection and analysis. These procedures include the use of appropriate emission estimation techniques, applicable and reasonable assumptions, accuracy/logic checks of computer models, checks of calculations, and data reliability checks. Figure 10.6-1 provides an example completeness checklist that could aid the inventory preparer at an oil and gas field production and processing facility. Volume VI, *QA Procedures*, of this series describes additional QA/QC methods and tools for performing these procedures.

Volume II, Chapter 1, *Introduction to Stationary Point Source Emission Inventory Development*, also presents recommended standard procedures to follow to ensure that the reported inventory data are complete and accurate. This section discusses the use of QC checklists, QA/QC procedures for specific emission estimation methods (e.g., emission factors), and the application of the Data Attribute Rating System (DARS).

6.1 GENERAL FACTORS INVOLVED IN EMISSION ESTIMATION TECHNIQUES

6.1.1 EMISSION FACTORS

The use of emission factors is straightforward when the relationship between process data and emissions is direct and relatively uncomplicated. When using emission factors, the user should be aware of the quality indicator associated with the value. Emission factors published within EPA documents and electronic tools have a quality rating applied to them. The lower the quality indicator, the less confidence EPA has in the data used to develop the factor and the more cautious the user should be using the emission estimate. When an emission factor for a specific source or category may not provide a reasonably adequate emission estimate, it is always better to rely on actual stack test data, where available. The reliability and uncertainty of using emission factors as

Item	**Y/N**	**Corrective Action (Complete if "N"; Describe, Sign, and Date)**
Have emissions from all sources been included? Potential sources include external flame burners/boilers, IC engines/turbines, flares, equipment leaks, glycol dehydrators, storage tanks, process piping, loading losses, flash losses, sulfur recovery units, heater treaters, blowout, separators, well heads, pipeline, pump stations, gas sweetening units, emergency and process vents, pigging operations, and pneumatic devices.		
Has an emission estimating technique been identified for each source?		
If toxic emissions are to be calculated using testing data, are the test methods approved?		
If toxic emissions are to be calculated using emission factors, are the emission factors from *AP-42* or FIRE?		
Have stack parameters been provided for each stack or vent that emits criteria or toxic air pollutants?		
If required by the state, has a site diagram been included with the emissions inventory? This should be a detailed plant drawing showing the location of sources/stacks with ID numbers for all processes, control equipment, and exhaust points.		
Have examples of all calculations been included?		
Have all assumptions been documented?		
Have references for all calculation methods been included?		
Have all conversions and units been reviewed and checked for accuracy?		

FIGURE 10.6-1

EXAMPLE EMISSION INVENTORY CHECKLIST FOR
OIL AND GAS FIELD PRODUCTION AND PROCESSING OPERATIONS

an emission estimation technique are discussed in detail in the QA/QC section of Chapter 1 of this volume and Chapter 4 of Volume VI.

6.1.2 EMISSION MODELS AND ENGINEERING EQUATIONS

The level of effort for using models and engineering equations is related to the complexity of the equations, the types of data that must be collected, and the diversity of products manufactured at a facility. Typically, the use of emission models involves making one or more conservative assumptions. As a result, their use may result in an overestimation of emissions. However, the accuracy and reliability of models can be improved by ensuring that data collected for emission calculations (e.g., material speciation data) are of the highest possible quality.

6.1.3 TESTING

Stack tests must meet quality objectives. Test data must be reviewed to ensure that the test was conducted under normal operating conditions, or under maximum operating conditions in some states, and that the data were generated according to an acceptable method for each pollutant of interest. Calculation and interpretation of accuracy for stack testing methods are described in detail in *Quality Assurance Handbook for Air Pollution Measurements Systems: Volume III, Stationary Source Specific Methods (Interim Edition)* (EPA, 1994b).

The acceptable criteria, limits, and values for each control parameter associated with manual sampling methods, such as dry gas meter calibration and leak rates, are summarized in tabular format in the QA/QC section of Chapter 1 of this volume. QC procedures for all instruments used to continuously collect emissions data are similar. The primary control check for precision of the continuous monitors is daily analysis of control standards.

6.2 DATA ATTRIBUTE RATING SYSTEM (DARS) SCORES

One measure of emission inventory data quality is the DARS score. Four examples are given here to illustrate DARS scoring using the preferred and alternative methods. DARS provides a numerical ranking on a scale of 0 to 1.0 for individual attributes of the emission factor and the activity data. Each score is based on what is known about the factor and activity data, such as the specificity to the source category and the measurement technique employed. The composite attribute score for the emissions estimate can be viewed as a statement of the confidence that can be placed in the data. For a complete discussion of DARS and other rating systems, see the *QA Procedures* (Volume VI, Chapter 4), and the QA/QC section of Chapter 1 of this volume.

Each of the examples below is hypothetical. A range is given where appropriate to cover different situations. Table 10.6-1 gives a set of scores for an estimate made with an *AP-42* emission factor. The activity data are assumed to be measured directly or indirectly. Table 10.6-2 shows scores

TABLE 10.6-1

DARS SCORES: EMISSION FACTORS (EF)

Attribute	Factor Score	Activity Score	Emissions Score	Factor Assumptions	Activity Assumptions
Measurement/ Method	0.90	0.80 - 1.0	0.72 - 0.90	Factor is based on intermittent measurements of intended pollutant and representative sampling over a range of loads.	Lower score reflects an activity rate derived from a surrogate that is indirectly related to the activity data (rather than a surrogate that has been directly related and measured); upper score reflects direct continuous measurement of activity.
Source Specificity	0.90	0.90	0.81	Factor was developed for a subset or a superset of the intended source category. Expected variability is low.	Activity data are very closely correlated to the emission activity.
Spatial Congruity	0.90	1.0	0.90	Factor was developed for a similar source.	Activity data are developed for and specific to the

TABLE 10.6-1

(CONTINUED)

Attribute	Factor Score	Activity Score	Emissions Score	Factor Assumptions	Activity Assumptions
Spatial Congruity (Continued)				Spatial variability is low.	source being inventoried.
Temporal Congruity	0.70	0.90	0.63	Factor was developed for a different period where the temporal variability is expected to be moderate to low.	Activity data are representative of the same temporal period as the inventory, but are based on an average of several repeated periods (activity data are an average of three years, inventory is for one year).
Composite Scores	0.85	0.90 - 0.95	0.76 - 0.81		

TABLE 10.6-2

DARS SCORES: EMISSION MODELS AND ENGINEERING EQUATIONS

Attribute	Factor Score	Activity Score	Emissions Score	Factor Assumptions	Activity Assumptions
Measurement/ Method	0.30	0.30 - 1.0	0.09 - 0.30	Factors (inputs to model or equation) are based on material balance, all/most end-points accounted for.	Lower score reflects an activity rate derived from engineering or physical principles. Upper score reflects direct, continuous measurement of activity.
Source Specificity	0.90 - 1.0	0.70 - 1.0	0.63 - 1.0	Lower score reflects inputs developed for a subset or superset of the intended category. Upper score reflects inputs developed specifically for the intended source.	Lower score reflects activity data for a similar process that is highly correlated to the emissions process. Upper score reflects activity data that represent the emission process exactly.
Spatial Congruity	1.0	1.0	1.0	Inputs were developed for and specific	Activity data are developed for and specific to the

TABLE 10.6-2

(CONTINUED)

Attribute	Factor Score	Activity Score	Emissions Score	Factor Assumptions	Activity Assumptions
Spatial Congruity (Continued)				to the given spatial scale.	source being inventoried.
Temporal Congruity	1.0	1.0	1.0	Model inputs were developed for and are applicable to the temporal period represented in the inventory.	Activity data are specific for the temporal period represented in the inventory.
Composite Scores	0.80 - 0.83	0.75 - 1.0	0.68 - .083		

developed from the use of emission models. Table 10.6-3 demonstrates scores determined for testing data.

These examples are given as an illustration of the relative quality of each method. If the same analysis were done for an actual site, the scores could be different but the relative ranking of methods should stay the same. Note, however, that if the source is not truly a member of the population used to develop the EPA correlation equations or the emission factors, these approaches are less appropriate and the DARS scores will drop.

If sufficient data are available, the uncertainty in the estimate should be evaluated. Qualitative and quantitative methods for conducting uncertainty analyses are described in the *QA Procedures* (Volume VI, Chapter 4).

TABLE 10.6-3

DARS SCORES: STACK SAMPLING

Attribute	Factor Score	Activity Score	Emissions Score	Factor Assumptions	Activity Assumptions
Measurement/ Method	0.70 - 0.90	0.90 - 1.0	0.63 - 0.90	Lower score reflects a small number of tests at typical loads; upper score represents numerous tests over a range of loads.	Lower score reflects direct, intermittent measurement of activity. Upper score reflects direct, continuous measurement of activity.
Source Specificity	1.0	1.0	1.0	Factor is developed specifically for the intended source.	Activity data represents the emission process exactly.
Spatial Congruity	1.0	1.0	1.0	Factor is developed for and is specific to the given spatial scale.	Activity data are developed for and specific to the inventory area.
Temporal Congruity	0.70 - 1.0	0.70 - 1.0	0.49 - 1.0	Lower score reflects a factor developed for a shorter time period with moderate to low temporal variability; upper score	Lower score reflects activity data representative of a short period of time; upper score represents activity data specific for the

TABLE 10.6-3

(CONTINUED)

Attribute	**Factor Score**	**Activity Score**	**Emissions Score**	**Factor Assumptions**	**Activity Assumptions**
Temporal Congruity (Continued)				reflects a factor developed for and applicable to the same temporal scale.	temporal period represented in the inventory.
Composite Scores	0.85 - 0.98	0.90 - 1.0	0.78 - 0.98		

7

DATA CODING PROCEDURES

This section describes the methods and codes available for characterizing emission sources at oil and gas field production and processing operations. Consistent categorization and coding will result in greater uniformity among inventories. In addition, the procedures described here will assist the reader who is preparing data for input to the Aerometric Information Retrieval System (AIRS) or a similar database management system. For example, the use of the Source Classification Codes (SCCs) provided in Table 10.7-1 are recommended for describing oil and gas field production and processing operations. Refer to the CHIEF for a complete listing of SCCs.

7.1 SOURCE CLASSIFICATION CODES

SCCs for oil and gas field production and processing operations are presented in Table 10.7-1. A brief description of each source listed in the table is given below.

7.1.1 PROCESS OPERATIONS

Process operations consist of well operations, separation, drilling, heating, sweetening, sulfur recovery, glycol dehydration, reboiler, and equipment leaks. The SCCs that correspond to these activities appear in Table 10.7-1 under the Oil Production, Natural Gas Production, Natural Gas Processing, Liquid Waste Treatment, Process Heaters, and Steam Generators source descriptions.

7.1.2 IN-PROCESS FUEL USE

In-process fuel use consists of internal combustion engines. The SCCs that correspond to these activities appear in Table 10.7-1 under the Internal Combustion Engines and Control Device Fuel source descriptions.

7.1.3 STORAGE TANKS

At oil and gas field production and processing facilities oil is stored in fixed roof, floating roof, or underground storage tanks. The SCCs that correspond to these activities appear in Table 10.7-1 under the Fixed Roof 67,000 Barrel Fuel Tanks: Standing Losses, Fixed Roof 250,000 Barrel Fuel Tanks: Standing Losses, Fixed Roof Fuel Tanks: Working Losses, Floating Roof 67,000 Barrel Fuel Tanks: Standing Losses, Floating Roof 250,000 Barrel Fuel Tanks: Standing Losses,

TABLE 10.7-1

SOURCE CLASSIFICATION CODES FOR OIL AND GAS PRODUCTION

Source Description	Process Description	SCC	Units
Process Emissions			
Oil Production	Miscellaneous Well: General	3-10-001-02	Wells/Year in Operation
	Wells: Rod Pumps	3-10-001-03	Wells/Year in Operation
	Crude Oil Sumps	3-10-001-04	Square Feet Sump Area/Year
	Crude Oil Pits	3-10-001-05	Square Feet Sump Area/Year
	Enhanced Wells, Water Reinjection	3-10-001-06	1000 Gallons Water
	Oil/Gas/Water/Separation	3-10-001-07	1000 Gallons Crude Transfer
	Evaporation from Liquid Leaks into Oil Well Cellars	3-10-001-08	Square Feet of Surface Area
	Site Preparation	3-10-001-21	100 Acres Prepared
	Drilling and Well Completion	3-10-001-22	Wells/Year Drilled
	Wellhead Casing Vents	3-10-001-23	Wells/Year in Operation
	Valves - General	3-10-001-24	1000 Barrels Oil Produced
	Relief Valves	3-10-001-25	1000 Barrels Oil Produced
	Pump Seals	3-10-001-26	1000 Barrels Oil Produced
	Flanges and Connections	3-10-001-27	1000 Barrels Oil Produced
	Oil Heating	3-10-001-28	1000 Barrels Oil Produced
	Gas/Liquid Separation	3-10-001-29	1000 Barrels Oil Produced
	Atmospheric Wash Tank (Second Stage of Gas-Oil Separation): Flashing Loss	3-10-001-32	1000 Gallons of Crude Oil Processed
	Waste Sumps - Primary Light Crude	3-10-001-40	1000 Barrels Oil Produced
	Waste Sumps - Primary Heavy Crude	3-10-001-41	1000 Barrels Oil Produced
	Waste Sumps - Secondary Light Crude	3-10-001-42	1000 Barrels Oil Produced
	Waste Sumps - Secondary Heavy Crude	3-10-001-43	1000 Barrels Oil Produced

TABLE 10.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
Oil Production (Continued)	Waste Sumps - Tertiary Light Crude	3-10-001-44	1000 Barrels Oil Produced
	Waste Sumps - Tertiary Heavy Crude	3-10-001-45	1000 Barrels Oil Produced
	Gathering Lines	3-10-001-46	1000 Miles of Pipeline
	Flares	3-10-001-60	1000 Barrels Oil Produced
	Processing Operations: Not Classified	3-10-001-99	1000 Barrels Produced
Natural Gas Production	Gas Sweetening: Amine	3-10-002-01	Million Cubic Feet Sour Gas Produced
	Gas Stripping Operations	3-10-002-02	Million Cubic Feet Gas Produced
	Compressor Operation	3-10-002-03	Million Cubic Feet Gas Processed
	Well Vents	3-10-002-04	Million Cubic Feet Gas Produced
	Flares	3-10-002-05	Million Cubic Feet Gas Produced
	Gas Lift	3-10-002-06	Million Cubic Feet Gas Produced
	Valves - General	3-10-002-07	Million Cubic Feet Gas Produced
	Sulfur Recovery Unit	3-10-002-08	Tons 100% Sulfur
	Site Preparation	3-10-002-21	100 Acres Prepared
	Drilling and Well Completion	3-10-002-22	Wells/Year Drilled
	Relief Valves	3-10-002-23	Million Cubic Feet Gas Produced
	Pump Seals	3-10-002-24	Million Cubic Feet Gas Produced
	Compressor Seals	3-10-002-25	Million Cubic Feet Gas Produced
	Flanges and Connections	3-10-002-26	Million Cubic Feet Gas Produced
	Glycol Dehydrator Reboiler Still Stack	3-10-002-27	Million Cubic Feet Gas Produced
	Glycol Dehydrator Reboiler Burner	3-10-002-28	Million Cubic Feet Gas Produced
	Gathering Lines	3-10-002-29	Million Cubic Feet Gas Produced
	Hydrocarbon Skimmer	3-10-002-30	Million Cubic Feet Gas Produced

TABLE 10.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
Natural Gas Processing	Glycol Dehydrators: Reboiler Still Vent: Triethylene Glycol	3-10-003-01	Million Cubic Feet Gas Produced
	Glycol Dehydrators: Reboiler Burner Stack: Triethylene Glycol	3-10-003-02	Million Cubic Feet Gas Produced
	Glycol Dehydrators: Phase Separator Vent: Triethylene Glycol	3-10-003-03	Million Cubic Feet Gas Produced
	Glycol Dehydrators: Ethylene Glycol: General	3-10-003-04	Million Cubic Feet Gas Produced
	Gas Sweetening: Amine Process	3-10-003-05	Million Cubic Feet Gas Produced
	Process Valves	3-10-003-06	Million Cubic Feet Gas Produced
	Relief Valves	3-10-003-07	Million Cubic Feet Gas Produced
	Open-ended Lines	3-10-003-08	Million Cubic Feet Gas Produced
	Compressor Seals	3-10-003-09	Million Cubic Feet Gas Produced
	Pump Seals	3-10-003-10	Million Cubic Feet Gas Produced
	Ranges and Connections	3-10-003-11	Million Cubic Feet Gas Produced
Liquid Waste Treatment	Flotation Units	3-10-005-01	Barrels Waste Liquid
	Liquid - Liquid Separator	3-10-005-02	Barrels Waste Liquid
	Oil - Water Separator	3-10-005-03	Barrels Waste Liquid
	Oil-Sludge-Waste Water Pit	3-10-005-04	Barrels Waste Liquid
	Sand Filter Operation	3-10-005-05	Barrels Waste Liquid
	Oil-Water Separation Wastewater Holding Tanks	3-10-005-06	Square Feet of Surface Area
Process Heaters	Distillate Oil	3-10-004-01	1000 Gallons Burned
	Residual Oil	3-10-004-02	1000 Gallons Burned
	Crude Oil	3-10-004-03	1000 Gallons Burned
	Natural Gas	3-10-004-04	Million Cubic Feet Burned
	Process Gas	3-10-004-05	Million Cubic Feet Burned

TABLE 10.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
Steam Generators	Distillate Oil	3-10-004-11	1000 Gallons Burned
	Residual Oil	3-10-004-12	1000 Gallons Burned
	Crude Oil	3-10-004-13	1000 Gallons Burned
	Natural Gas	3-10-004-14	Million Cubic Feet Burned
	Process Gas	3-10-004-15	Million Cubic Feet Burned
In-Process Fuel Use			
Internal Combustion Engines	Gas Turbines	2-02-002-01	Lb/MMBtu
	2-Cycle Lean Burn	2-02-002-52	Lb/MMBtu
	4-Cycle Lean Burn	2-02-002-53	Lb/MMBtu
	4-Cycle Rich Burn	2-02-002-54	Lb/MMBtu
Storage Tanks			
Fixed Roof 67,000 Barrel Fuel Tanks: Standing Losses	Grade 6 Oil	4-03-010-25	1000 Gallons Storage Capacity
	Grade 5 Oil	4-03-010-26	1000 Gallons Storage Capacity
	Grade 4 Oil	4-03-010-27	1000 Gallons Storage Capacity
	Grade 2 Oil	4-03-010-28	1000 Gallons Storage Capacity
	Grade 1 Oil	4-03-010-29	1000 Gallons Storage Capacity
Fixed Roof 250,000 Barrel Fuel Tanks: Standing Losses	Grade 6 Oil	4-03-010-65	1000 Gallons Storage Capacity
	Grade 5 Oil	4-03-010-66	1000 Gallons Storage Capacity
	Grade 4 Oil	4-03-010-67	1000 Gallons Storage Capacity
	Grade 2 Oil	4-03-010-68	1000 Gallons Storage Capacity
	Grade 1 Oil	4-03-010-69	1000 Gallons Storage Capacity
Fixed Roof Fuel Tanks: Working Losses	Grade 6 Oil	4-03-010-75	1000 Gallons Throughput
	Grade 5 Oil	4-03-010-76	1000 Gallons Throughput
	Grade 4 Oil	4-03-010-77	1000 Gallons Throughput
	Grade 2 Oil	4-03-010-78	1000 Gallons Throughput
	Grade 1 Oil	4-03-010-79	1000 Gallons Throughput

TABLE 10.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
Floating Roof 67,000 Barrel Fuel Tanks: Standing Losses	Grade 6 Oil	4-03-011-25	1000 Gallons Storage Capacity
	Grade 5 Oil	4-03-011-26	1000 Gallons Storage Capacity
	Grade 4 Oil	4-03-011-27	1000 Gallons Storage Capacity
	Grade 2 Oil	4-03-011-28	1000 Gallons Storage Capacity
	Grade 1 Oil	4-03-011-29	1000 Gallons Storage Capacity
Floating Roof 250,000 Barrel Fuel Tanks: Standing Losses	Grade 6 Oil	4-03-011-65	1000 Gallons Storage Capacity
	Grade 5 Oil	4-03-011-66	1000 Gallons Storage Capacity
	Grade 4 Oil	4-03-011-67	1000 Gallons Storage Capacity
	Grade 2 Oil	4-03-011-68	1000 Gallons Storage Capacity
	Grade 1 Oil	4-03-011-69	1000 Gallons Storage Capacity
Floating Roof Fuel Tanks: Working Losses	Grade 6 Oil	4-03-011-75	1000 Gallons Throughput
	Grade 5 Oil	4-03-011-76	1000 Gallons Throughput
	Grade 4 Oil	4-03-011-77	1000 Gallons Throughput
	Grade 2 Oil	4-03-011-78	1000 Gallons Throughput
	Grade 1 Oil	4-03-011-79	1000 Gallons Throughput
Bulk Plants			
Oil Field Storage of Crude	Fixed Roof Tank: Breathing Loss	4-04-003-01	1000 Gallons Storage Capacity
	Fixed Roof Tank: Working Loss	4-04-003-02	1000 Gallons Throughput
	External Floating Roof Tank with Primary Seals: Standing Loss	4-04-003-03	1000 Gallons Storage Capacity
	External Floating Roof Tank with Secondary Seals: Standing Loss	4-04-003-04	1000 Gallons Storage Capacity
	Internal Floating Roof Tank: Standing Loss	4-04-003-05	1000 Gallons Storage Capacity
Underground Tanks	Crude Oil RVP 5: Breathing Loss	4-04-004-07	1000 Gallons Storage Capacity

TABLE 10.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
Underground Tanks (Continued)	Crude Oil RVP 5: Working Loss	4-04-004-08	1000 Gallons Throughput
Fugitive Emissions			
Oil Production	Complete Well	3-10-001-01	Wells/Year in Operation
	Compressor Seals	3-10-001-30	Number of Seals
	Drains	3-10-001-31	Number of Drains
	Miscellaneous Fugitive Emissions	3-10--888-01 to -04	Process Unit - Year
	Miscellaneous Fugitive Emissions - Oil	3-10-888-05	1000 Barrels Feed Produced
Natural Gas Production	Valves	3-10-002-07	Million Cubic Feet Gas Produced
	Drains	3-10-002-31	Number of Drains
	Miscellaneous Fugitive Emissions - Gas	3-10-888-11	Million Cubic Feet Produced
Control Device Fuel			
Control Device Fuel	Afterburners - Distillate Oil No. 2	3-06-099-01	1000 Gallons Burned
Transportation and Marketing			
Tank Cars and Trucks	Gasoline: Submerged Loading, Normal Service	4-06-001-31	1000 Gallons Transferred
	Crude Oil: Submerged Loading, Normal Service	4-06-001-32	1000 Gallons Transferred
	Gasoline: Splash Loading, Normal Service	4-06-001-36	1000 Gallons Transferred
	Crude Oil: Splash Loading, Normal Service	4-06-001-37	1000 Gallons Transferred
	Gasoline: Submerged Loading, Balanced Service	4-06-001-41	1000 Gallons Transferred
	Crude Oil: Submerged Loading, Balanced Service	4-06-001-42	1000 Gallons Transferred

TABLE 10.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
Tank Cars and Trucks (Continued)	Gasoline: Splash Loading, Balanced Service	4-06-001-44	1000 Gallons Transferred
	Crude Oil: Splash Loading, Balanced Service	4-06-001-45	1000 Gallons Transferred
	Gasoline: Submerged Loading, Clean Trucks	4-06-001-47	1000 Gallons Transferred
	Crude Oil: Submerged Loading, Clean Trucks	4-06-001-48	1000 Gallons Transferred
Marine Vessels	Crude Oil: Loading Tankers	4-06-002-43	1000 Gallons Transferred
	Crude Oil: Loading Barges	4-06-002-48	1000 Gallons Transferred

Floating Roof Fuel Tanks: Working Losses, Oil Field Storage of Crude, and Underground Tanks source descriptions.

7.1.4 FUGITIVE SOURCES

Fugitive sources consist of wells, equipment leaks, and other miscellaneous sources. The SCCs that correspond to these activities appear in Table 10.7-1 under the Oil Production and the Natural Gas Production source descriptions.

7.1.5 TRANSPORTATION AND MARKETING

Transportation and marketing consists of loading materials onto trucks, barges, and tankers. The SCCs that correspond to these activities appear in Table 10.7-1 under the Tank Cars and Trucks and Marine Vessels source descriptions.

7.2 AIRS CONTROL DEVICE CODES

Control device codes applicable to oil and gas field production and processing operations are presented in Table 10.7-2. These should be used to enter the type of applicable emission control device into the AIRS Facility Subsystem (AFS). The "099" control code may be used for miscellaneous control devices that do not have a unique identification code.

TABLE 10.7-2

AIRS CONTROL DEVICE CODES

Control Device	Code
Gas Scrubber	013
Catalytic Afterburner	019
Catalytic Afterburner with Heat Exchanger	020
Direct Flame Afterburner	021
Direct Flame Afterburner with Heat Exchanger	022
Flaring	023
Sulfur Plant	045
Process Change	046
Vapor Recovery System	047
Catalytic Reduction	065
Tube and Shell Condenser	072
Refrigerated Condenser	073
Barometric Condenser	074
Conservation Vent	088
Bottom Filling	089
Conversion to Variable Vapor Space Tank	090
Conversion to Floating Roof Tank	091
Conversion to Pressurized Tank	092
Submerged Filling	093
Underground Tank	094
White Paint	095
Miscellaneous Control Devices	099

This page is intentionally left blank.

8

REFERENCES

API. 1998. *Emissions Estimation Sotware*. American Petroleum Institute. http://www.api.org/ehs/old%20rh/E&PTANK&EPEC.htm#EPEC. September 1998.

API. 1996. *Calculation Workbook for Oil and Gas Production Equipment Fugitive Emissions*. American Petroleum Institute, API Publication Number 4638. Washington, D.C.

API. 1995. *Emission Factors for Oil and Gas Production Operations.* American Petroleum Institute, API Publication Number 4615. Washington, DC.

Akin, Tom and William H. Battye, 1994. Memorandum to Martha E. Smith, U.S. Environmental Protection Agency. Environmental Consultants and Research, Incorporated. October 18, 1994. Durham, North Carolina.

Boyer, Brian E. and Kenneth Brodnax, 1996. *Oil and Gas Production Emission Factors and Estimation Methods*. Complete Oil Field Management and Maintenance, Inc., Lafayette, Louisiana, and Mobil Exploration and Production Company, Houston, Texas. Presented at the Emission Inventory: Key to Planning Permits, Compliance and Reporting Conference, Air and Waste Management Association, September 4-6, 1996, New Orleans, Louisiana.

Corbeille, Robert, 1997. *Hydrogen Sulfide Occurrences in the Gulf of Mexico, Outer Continential Shelf Operations*. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Regional Office, New Orleans.

EIIP. 1996. *Preferred and Alternative Methods for Estimating Air Emissions from Hot-Mix Asphalt Plants, Final Report*. Prepared for the Point Sources Committee, Emission Inventory Improvement Program under EPA Contract No. 68-D2-0160, Work Assignment No. 82. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina.

EPA. 1998. *Factor Information and Retrieval System (FIRE), Version 6.01.* Updated Annually. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

EPA. 1996. *Methane Emissions from the U.S. Petroleum Industry, Draft Report*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

EPA. 1995a. *Compilation of Air Pollutant Emission Factors. Volume I: Stationary Point and Area Sources, Fifth Edition, AP-42. Section 7.1, Organic Liquid Storage Tanks*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina.

EPA. 1995b. *Compilation of Air Pollutant Emission Factors. Volume I: Stationary Point and Area Sources, Fifth Edition, AP-42. Section 5.3, Natural Gas Processing*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina.

EPA. 1995c. *Compilation of Air Pollutant Emission Factors. Volume I: Stationary Point and Area Sources, Fifth Edition, AP-42. Section 5.2, Transportation and Marketing of Petroleum Liquids*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina.

EPA. 1995d. *Compilation of Air Pollutant Emission Factors. Volume I: Stationary Point and Area Sources, Fifth Edition, AP-42. Section 4.7, Waste Solvent Reclamation.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina.

EPA. 1995e. *Compilation of Air Pollutant Emission Factors. Volume I: Stationary Point and Area Sources, Fifth Edition, AP-42. Section 8.13, Sulfur Recovery*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina.

EPA. 1995f. *State Workbook, Methodologies for Estimating Greenhouse Gas Emissions, Second Edition*. U.S. Environmental Protection Agency, Office of Policy, Planning and Evaluation, EPA-230-B-95-001. Washington, D.C.

EPA. 1995g. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1994.* U.S. Environmental Protection Agency, Office of Policy, Planning and Evaluation, EPA-230-R-96-006. Washington, D.C.

EPA. 1995h. *Protocol for Equipment Leak Emission Estimates*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, EPA-453/R-95-017. Research Triangle Park, North Carolina.

EPA. 1994a. *Alternative Control Techniques Document - NO$_x$ Emissions from Industrial/Commercial/Institutional Boilers*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, EPA-453/R-94-022. Research Triangle Park, North Carolina.

EPA. 1994b. *Quality Assurance Handbook for Air Pollution Measurements Systems: Volume III, Stationary Source Specific Methods (Interim Edition).* U.S. Environmental Protection Agency, Office of Research and Development, EPA-600/R-94-038c. Washington, D.C.

EPA. 1994c. *Air Emissions Models for Waste and Wastewater.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, EPA-453/R-94-080A. Research Triangle Park, North Carolina.

EPA. 1991a. *Procedures for the Preparation of Emission Inventories for Carbon Monoxide and Precursors of Ozone. Volume I: General Guidance for Stationary Sources*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

EPA. 1991b. *Control Technologies for Hazardous Air Pollutants Handbook*. U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory, EPA-625/6-91/014. Research Triangle Park, North Carolina.

EPA. 1987. *Estimating Releases and Waste Treatment Efficiencies for the Toxic Chemical Release Inventory Form*. U.S. Environmental Protection Agency, Office of Pesticides and Toxic Substances, EPA-560/4-88-002. Washington, D.C.

EPA. 1977a. *Industrial Process Profiles for Environmental Use: Chapter 2, Oil and Gas Production Industry*. U.S. Environmental Protection Agency, Office of Research and Development, EPA-600/2-77-023b. Cincinnati, Ohio.

EPA. 1977b. *Atmospheric Emissions from Offshore Oil and Gas Development and Production.* U.S. Environmental Protection Agency. Research Triangle Park, North Carolina.

GRI. 1998. *GRI-HAPCalc™ and GRI-HAPData™ Software*. Gas Research Institute. http://www.gri.org/pub/content/apr/19980406/204648/hapcalc.html.

GRI. 1997. *GRI-GLYCalc™ Version 3.0 Computer Program*. Gas Research Institute. http://www.gri.org/tech/e+s/airprj.htm#aquevalmeth3.

GRI. 1994. *Preliminary Assessment of Air Toxic Emissions in the Natural Gas Industry, Phase I, Topical Report*. Gas Research Institute, GRI-94/0268. Chicago, IL.

GRI. 1993. *In-line Inspection of Natural Gas Pipelines, Topical Report*. Gas Research Institute, GRI-91/0365. Chicago, IL.

LADEQ. 1998a. Memorandum from Jim Courville to LADEQ. August 12, 1998.

LADEQ. 1998b. Memorandum from Mike Alegro to Regional Coordinators. July 17, 1998.

Martino, Paul, 1997. Petroleum Production Emission Estimating Techniques and Software. American Petroleum Institute. Washington, D.C. Presented at the Emission Inventory: Planning for the Future, October 28-30, 1997, Research Triangle Park, North Carolina.

Mian, M.A. 1992. *Petroleum Engineering Handbook for the Practicing Engineer, Volume I.* PennWell Publishing Company. Tulsa, Oklahoma.

Nizich, Greg and EC/R. 1999. Table 1. Comparison of Measured HAP Emissions to Emissions Predicted Using E&P TANK and EC/R Algorithm. U.S. Environmental Protection Agency, Emission Standards Division, Research Triangle Park, NC and Environmental Consulting and Research, Durham, NC, July 1999.

Rucker, J. Eldon and Robert P. Strieter, 1992. *The Petroleum Industry Air Pollution Engineering Manual, AP-40*. Air and Waste Management Association. Pittsburgh, Pennsylvania.

TNRCC. 1998a. *Determination of Applicable Requirements for Pigging Operations at Marine Transfer Facilities.* Texas Natural Resource Conservation Commission. http://www.tnrcc.state.tx.us/air/opd/state/115/211/irim08.htm.

TNRCC. 1998b. *Applicability of Vent Gas Control Rules to Pipeline Pigging Activities*. Texas Natural Resource Conservation Commission. http://www.tnrcc.state.tx.us/air/opd/state/115/121/rim07.htm

TNRCC. 1996. *Technical Guidance Package for Annual Air Emissions Inventory Questionnaires, Oil and Gas Industry, Draft*. Texas Natural Resource Conservation Commission. Austin, Texas.

APPENDIX A

EXAMPLE DATA COLLECTION FORMS

This page is intentionally left blank.

EXAMPLE DATA COLLECTION FORMS INSTRUCTIONS - OIL AND NATURAL GAS FIELD PRODUCTION AND PROCESSING OPERATIONS MANUFACTURING FACILITIES

1. These forms may be used as a work sheet to aid the plant engineer in collecting the information necessary to calculate emissions from oil and natural gas field production and processing operations. The information requested on the forms relate to the methods (described in Sections 3, 4, and 5) for quantifying emissions. These forms may also be used by the regulatory agency to assist in area wide inventory preparation.

2. The completed forms should be maintained in a reference file by the plant engineer with other supporting documentation.

3. If the information requested is unknown, write "unknown" in the blank. If the information requested does not apply to a particular unit or process, write "NA" in the blank.

4. If you want to modify the form to better serve your needs, an electronic copy of the form may be obtained through the EIIP on the Clearinghouse for Inventories and Emission Factors (CHIEF) system.

5. Collect all Manufacturer's Technical Data Sheets (TDSs) for all materials containing potential air contaminants that are used at the facility.

6. The plant engineer should maintain all material usage information and TDSs in a reference file.

EXAMPLE DATA COLLECTION FORM

FORM A: GENERAL INFORMATION

Facility/Plant Name:

SIC Code:

SCC:

SCC Description:

Location:

County:

City:

State:

Plant Geographical coordinates:
Latitude: ___________________
Longitude: ___________________
UTM Zone: ___________________
UTM Easting: ___________________
UTM Northing: ___________________

Contact Name:

Title:

Telephone Number:

EXAMPLE DATA COLLECTION FORM

FORM B: SOURCE INFORMATION

Unit ID:

Permit No.:

Location:

Unit Description:

Manufacturer:

Date Installed:

Date Modified:

Operating Schedule:

Hours/Day:

Days/Week:

Weeks/Year:

EXAMPLE DATA COLLECTION FORM

FORM C: CONTROL DEVICE INFORMATION

Unit ID:

Permit No.:

Location:

Pollutant Controlled:

Control Efficiency (Indicate source of information):

Type of Control Device:

☐ Baghouse

☐ Carbon Adsorber

☐ Condenser

☐ Flare

☐ Scrubbers (indicate type) ____________________________

☐ Thermal Incinerator

☐ Other (indicate type) ____________________________

Manufacturer:

Date Installed:

Date Modified:

Operating Schedule:

Hours/Day:

Days/Week:

Weeks/Year:

Source(s) Linked to this Control Device:

EXAMPLE DATA COLLECTION FORM

FORM D: STACK INFORMATION

Stack ID:

Unit ID:

Stack (Release) Height (ft):

Stack Diameter (inch):

Stack Gas Temperature (°F):

Stack Gas Velocity (ft/sec):

Stack Gas Flow Rate (ascf/min):

Source(s) Linked to this Stack:

EXAMPLE DATA COLLECTION FORM

FORM E: PRODUCTION INFORMATION

Product Name	**Year**	**Amount Produced (lb/yr)**

EXAMPLE DATA COLLECTION FORM

FORM F: DATA NEEDED FOR EMISSIONS FROM COMBUSTION OPERATIONS

Unit ID No.:	Fuel A	Fuel B	Fuel C	Comments
Fuel Type:				
Sulfur Content (%):				
Heating Value of Fuel (MMBtu/MMscf or MMBtu/Mgal):				
Maximum Hourly Fuel Use (units):				
Total Annual Fuel Use (units):				
Maximum Capacity (Million Btu/hr):				

Note: Complete this form for each unit.

EXAMPLE DATA COLLECTION FORM

FORM G: DATA FOR EMERGENCY AND PROCESS VENTS, GAS ACTUATED PUMPS, PRESSURE/LEVEL CONTROLLERS, BLOWDOWN, WELL BLOWOUTS, WELL TESTING, TRANSPORTATION LOADING LOSS, AND STORAGE TANK FLASH LOSS EMISSIONS

Equipment ID	**Volume of Gas Processed (scf/yr)**	**Molecular Weight of Gas**	**VOC Mass Fraction in Gas**	**VOC Constituent**	**VOC Constituent Mass Fraction in VOC**

EXAMPLE DATA COLLECTION FORM

FORM H: DATA FOR GAS SWEETENING/FLARE EMISSIONS

Equipment ID	Volume of Gas Processed (scf/yr)	Constituent	Mole Fraction of Constituent in Inlet Gas

EXAMPLE DATA COLLECTION FORM

FORM I: DATA FOR SULFUR RECOVERY UNIT EMISSIONS

Unit ID	Volume of Gas Processed (scf/hr)	Mole Fraction of H_2S in Inlet Stream	Sulfur Recovery Efficiency (%)

EXAMPLE DATA COLLECTION FORM

FORM J: DATA FOR EMISSIONS FROM FUGITIVE SOURCES (HEATER TREATERS, BLOWOUT, SEPARATORS, WELLHEADS, PIPELINE, PUMP STATIONS

Source Type	Number of Components or Events	Constituent

EXAMPLE DATA COLLECTION FORM

FORM K: DATA NEEDED FOR LOADING LIQUID MATERIALS INTO TANK TRUCKS AND TANK CARS

Volume of Material Loaded (Mgal/yr)	**Material**	**Type of Loading (submerged, splash, etc.)**	**True Vapor Pressure of Material Loaded (psia)**	**Vapor Molecular Weight**	**Temp. (°R)**	**Constituent**	**Constituent Mass Fraction**

EXAMPLE DATA COLLECTION FORM

FORM L: DATA NEEDED FOR EMISSIONS FROM LOADING CRUDE OIL INTO SHIPS AND BARGES

Volume of Material Loaded (Mgal/yr)	Material	Mass Fraction of VOC in Vapor	True Vapor Pressure of Material Loaded (psia)	Temp. of Vapors (°R)	Molecular Weight of Vapors	Constituent	Constituent Mass Fraction

EXAMPLE DATA COLLECTION FORM

FORM M: EMISSION RESULTS

Equipment ID:________________

Pollutant	Emission Estimation Method[b]	Emissions	Emissions Units	Emission Factor[c]	Emission Factor Units	Comments

[a] Pollutants include VOCs, PM/PM$_{10}$, H_2S, SO_2, NO_x, CO_2, CH_4, CO, and HAPs (list individually).

[b] Use the following codes to indicate which emission estimation method is used for each pollutant:

Emission Factor = EF
Mass Balance = MB
Other Method (indicate) = O

Emission Model = EM
Engineering Equation = EE
Stack Test = ST
Continuous Emission Monitoring Systems = (CEMS)

[c] Where applicable, enter the emission factor and provide full citation of the reference or source of information from where the emission factor came. Include edition, version, table and page numbers if *AP-42* is used.

APPENDIX B

LADEQ GUIDELINES AND INSPECTION CHECKLIST FOR GRI-GLYCALC MODEL

This page is intentionally left blank.

LADEQ GUIDELINES FOR GRI-GLYCALC MODEL[1]

Process Parameter	Guidelines
A. Wet Gas	
1. Temperature	Range: 80°F to 120°F
2. Pressure	Range: 850 psig to 1,400 psig
3. Water content	Always saturated
4 All data	Based on actual information
5. Sample	Must be obtained at inlet for analysis and include BTEX analysis
6. Composition	Always check composition if benzene mole % is less than 0.03; if below 0.03%, the sample may have been taken in the wrong location.
B. Dry Gas	
1. Flow rate	Range: 1.0 to 500 MMscf/day
2. Water content	Range: 2.0 to 7.0 lb H_2O/MMscf (never over 7.0)
C. Lean Glycol	
1. Circulation rate	Obtain from chart with strokes per minute information (gpm)
2. Water content	Range: 0.1 to 0.5 wt%
3. Lean glycol	Always use 3.0 gal/lb H_20
4. Pump type	Electric or gas driven with meter on electric pump
5. Pump gas ratio	Obtain from chart called gas composition
D. Flash Tank (Separator):	
1. Temperature	Range: 100.0 to 150.0°F
2. Pressure	Range: 30 to 70 psig
3. All data	Obtained from actual data at facility
E. Stripping gas	Normally none
F. Control device (if applicable)	
1. Condenser temperature	Range: 80 to 200°F; if steam is coming out, use 200°F; if water cooled, use 80°F
2. Condenser pressure	Always use 14.7 psia

---

[1] These guidelines are used by the Louisiana Department of Environmental Quality (LADEQ) and are based on data collected from the field.

LADEQ GLYCOL INSPECTION CHECKLIST

July 17, 1998

MEMORANDUM

TO: Regional Coordinators
Air Quality Compliance Division

FROM: Mike Algero
Surveillance Program Manager
Air Quality Compliance Division

SUBJECT: Glycol Inspection Checklist

The Air Quality Engineering Section has developed the following checklist for glycol units. Please review it with you staff.

When glycol dehydrators are inspected by your staff, the following information is needed to evaluate compliance using the Glycale software.

1. Inlet wet gas flow rate and composition (speciated for BTEX).
2. Temperature and pressure of glycol contact tower.
3. Glycol circulation - obtained by timing strokes of the glycol pump and converting to flow rate using pump vendor information obtained from facility. If circulation cannot be determined this way, then facility must provide other means of measuring flow, if Glycalc is to be used.
4. If the unit is controlled with a condenser, documentation that the annual average temperature of the condenser outlet is less than 110°F (as specified in 2116.F.3).

Please contact me if you have any questions.

MA/vh