GREENHOUSE GAS EMISSIONS REPORTING FROM THE PETROLEUM AND NATURAL GAS INDUSTRY

BACKGROUND TECHNICAL SUPPORT DOCUMENT

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TABLE OF CONTENTS

1. Segments in the Petroleum and Natural Gas Industry

The U.S. petroleum and natural gas industry encompasses the production of raw gas and crude oil from wells to the delivery of processed gas and petroleum products to consumers. These segments, and everything in between, use energy and emit greenhouse gases (GHG). It is convenient to view the industry in the following discrete segments:

- Petroleum Industry – petroleum production, petroleum transportation, petroleum refining, petroleum terminals, and
- Natural Gas Industry –natural gas production, natural gas processing (including gathering and boosting), natural gas transmission and underground storage, liquefied natural gas (LNG) import and export terminals, and natural gas distribution.

Each industry segment uses common processes and equipment in its facilities, all of which emit GHG. Each of these industry segments is described in further detail below.

a. Petroleum Industry

Petroleum Production. Petroleum or crude oil is produced from underground formations. In some cases, natural gas is also produced from oil production wells; this gas is called associated natural gas. Production may require pumps or compressors for the injection of liquids or gas into the well to maintain production pressure. The produced crude oil is typically separated from water and gas, injected with chemicals, heated, and temporarily stored. GHG emissions from crude oil production result from combustion-related activities, and fugitive and vented emissions. Equipment counts and GHG-emitting practices are related to the number of producing crude oil wells and their production rates.

As petroleum production matures in a field the natural reservoir pressure is not sufficient to bring the petroleum to the surface. In such cases, enhanced oil recovery (EOR) techniques are used to extract oil that otherwise can not be produced using only reservoir pressure. In the United States, there are three predominant types of EOR operations currently used; thermal EOR, gas injection EOR, and chemical injection EOR. Thermal EOR is carried out by injecting steam into the reservoir to reduce the viscosity of heavy petroleum to allow the flow of the petroleum in the reservoir and up the production well. Gas injection EOR involves injecting of gases, such as natural gas, nitrogen, or carbon dioxide ($CO_{2)}$, to improve the viscosity of the petroleum and push it towards and up the producing well. Chemical injection EOR is carried out by injecting surfactants or polymers to improve the flow of petroleum and/or enhance a water flood in the reservoir. Emissions sources from EOR operations are similar to those in conventional petroleum production fields. However, additional emissions occur when carbon dioxide is used for recovery. This specific EOR operation requires pumps to inject supercritical CO_2 into the reservoir while compressors maintain the recycled CO_2's supercritical state. Venting from these two sources is a major source of emissions.

Petroleum Transportation. The crude oil stored at production sites is either pumped into crude oil transportation pipelines or loaded onto tankers and/or rail freight. Along the supply chain crude oil may be stored several times in tanks. These practices and storage tanks release GHG emissions, as well as emissions from combustion. Emissions are related to the amount of crude oil transported and the transportation mode.

Petroleum Refining Crude oil is delivered to refineries where it is temporarily stored before being fractionated by distillation and treated. The fractions are reformed or cracked and then blended into consumer petroleum products such as gasoline, diesel, aviation fuel, kerosene, fuel oil, and asphalt. These processes are energy intensive. Equipment counts and GHG gas emitting practices are related to the number and complexity of refineries. Subpart Y of the Final Mandatory Reporting Rule (MRR) published in the Federal Register on October 30, 2009, addresses refineries and hence is not discussed further in this document.

Petroleum products are then transported via trucks, rail cars, and barges across the supply chain network to terminals and finally to end users.

b. Natural Gas Industry

Natural Gas Production In natural gas production, wells are used to withdraw raw gas from underground formations. Wells must be drilled to access the underground formations, and often require natural gas well completion procedures or other practices that vent gas from the well depending on the underground formation. The produced raw gas commonly requires treatment in the form of separation of gas/liquids, heating, chemical injection, and dehydration before being compressed and injected into gathering lines. Combustion, fugitive, and vented emissions arise from the wells themselves, gathering pipelines, and all well-site natural gas treatment processes and related equipment and control devices. Determining emissions, equipment counts, and frequency of GHG emitting practices is related to the number of producing wellheads and the amount of produced natural gas. Further details are provided on the individual sources of GHG emissions in Appendix A.

Natural Gas Processing (including Gathering/Boosting stations) In this segment of the supply chain, natural gas from the petroleum and natural gas production segment is compressed and injected into gathering lines that transport it to natural gas processing facilities. In the processing facility, natural gas liquids and various other constituents from the raw gas are separated, resulting in "pipeline quality" gas that is compressed and injected into the transmission pipelines. These separation processes include acid gas removal, dehydration, and fractionation. All equipment and practices have associated GHG fugitive emissions, energy consumption-related combustion GHG emissions, and/or process control related GHG vented emissions. Equipment counts and frequency of GHG emitting practices are related to the number and size of gas processing facilities. Further details are provided on the individual sources of GHG emissions in Appendix A.

Natural Gas Transmission and Storage Natural gas transmission involves high pressure, large diameter pipelines that transport natural gas from petroleum and natural gas production sites and natural gas processing facilities to natural gas distribution pipelines or large volume customers such as power plants or chemical plants. Compressor station facilities containing large reciprocating and turbine compressors, move the gas throughout the U.S. transmission pipeline system. Equipment counts and frequency of GHG emitting practices are related to the number and size of compressor stations and the length of transmission pipelines.

Natural gas is also injected and stored in underground formations, or stored as LNG in above ground storage tanks during periods of low demand (e.g., spring or fall), and then withdrawn, processed, and distributed during periods of high demand (e.g., winter and summer). Compressors and dehydrators are the primary contributors to emissions from these underground and LNG storage facilities. Equipment counts and GHG emitting practices are related to the number of storage stations.

Imported LNG also requires transportation and storage. These processes are similar to above ground LNG storage and require compression and cooling processes. GHG emissions in this segment are related to the number of LNG import terminals and LNG storage facilities.

Further details are provided on the individual sources of GHG emissions for all of transmission and storage in Appendix A.

Natural Gas Distribution Natural gas distribution pipelines take high-pressure gas from the transmission pipelines at "city gate" stations, reduce and regulate the pressure, and distribute the gas through primarily underground mains and service lines to individual end users. Between the distribution mains and many off-shooting services are underground regulating vaults. GHG emissions from distribution systems are related to the pipelines, regulating stations and vaults, and customer/residential meters. Equipment counts and GHG emitting practices can be related to the number of regulating stations and the length of pipelines. Further details are provided on the individual sources of GHG emissions in Appendix A.

2. Types of Emissions Sources and GHGs

The three main GHGs that are relevant to the petroleum and natural gas industry are methane (CH_4), CO_2, and nitrous oxide (N_2O). This technical document will focus mainly on CH_4 and CO_2 emissions from fugitive and vented emissions. However, all three gases are taken into account when developing the threshold analysis.

Emissions from sources in the petroleum and gas industry can be classified into one of two types:

Combustion-related emissions

Combustion-related emissions result from the use of petroleum and natural gas as fuel in equipment (e.g., heaters, engines, furnaces etc) in the petroleum and gas industry. CO_2 is the predominant combustion-related emission; however, because combustion equipment is rarely 100 percent efficient, CH_4 and N_2O may also be emitted. For methodologies to quantify GHG emissions from combustion, please refer to Subpart C of the MRR.

Fugitive emissions and vented emissions

The Intergovernmental Panel on Climate Change (IPCC) and the Inventory of U.S. GHG Emissions and Sinks[1] (henceforth referred to as the U.S. GHG Inventory) define fugitive emissions to be both intentional and unintentional emissions from systems that extract, process, and deliver fossil fuels. Intentional emissions are emissions designed into the equipment or system. For example, reciprocating compressor rod packing has a certain level of emissions by design, e.g., there is a clearance provided between the packing and the compressor rod for free movement of the rod that results in emissions. Also, by design, vent stacks in petroleum and natural gas production, natural gas processing, and petroleum refining facilities release natural gas to the atmosphere. Unintentional emissions result from wear and

[1] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006, (April 2008), USEPA #430-R-08-005

tear or damage to the equipment. For example, valves result in natural gas emissions due to wear and tear from continuous use over a period of time. Also, pipelines damaged during maintenance operations or corrosion result in unintentional emissions.

However, defining fugitive emissions as unintentional and intentional led to a great deal of confusion in the initial rule proposal. Also, such a definition is not intuitive in that fugitive in itself means unintentional. Therefore, this document henceforth distinguishes fugitive emissions clearly from vented emissions.

Fugitive emissions are emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including but not limited to process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

This document includes methodologies to quantify fugitive and vented emissions of CO_2 and CH_4.

3. GHG Emissions from the Petroleum and Natural Gas Industry

The U.S. GHG Inventory provides estimates of fugitive and vented CH_4 and CO_2 emissions from all segments of the petroleum and natural gas industry. These estimates are based mostly on emissions factors available from two major studies conducted by EPA/Gas Research Institute (EPA/GRI)[2] for the natural gas segment and EPA/Radian[3] for the petroleum segment. These studies were conducted in the early and late 1990s respectively.

The EPA/GRI study used the best available data and somewhat restricted knowledge of industry practices at the time to provide estimates of emissions from each source in the various segments of the natural gas industry. In addition, this study was conducted at a time when CH_4 emissions were not a significant concern in the discussion about GHG emissions. Over the years, new data and increased knowledge of industry operations and practices have highlighted the fact that emissions estimates from the EPA/GRI study are outdated and potentially understated for some emissions sources. The following emissions sources are believed to be significantly underestimated in the U.S. GHG Inventory: well venting for liquids unloading; gas well venting during well completions; gas well venting during well workovers; crude oil and condensate storage tanks; centrifugal compressor wet seal degassing venting; and flaring.

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[2] EPA/GRI (1996) *Methane Emissions from the Natural Gas Industry*. Prepared by Harrison, M., T. Shires, J. Wessels, and R. Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a.
[3] EPA (1996) *Methane Emissions from the U.S. Petroleum Industry (Draft)*. Prepared by Radian. U.S. Environmental Protection Agency. June 1996.

The understatement of emissions in the U.S. GHG Inventory were revised using publicly available information for all sources, except crude oil and condensate storage tanks and flares, where no new reliable data are available[4]. Appendix B provides a detailed discussion on how new estimates were developed for each of the four underestimated sources. Table 1 provides a comparison of emissions factors as available from the EPA/GRI study and as revised in this document. Table 2 provides a comparison of emissions from each segment of the natural gas industry as available in the U.S. GHG Inventory and as calculated based on the revised estimates for the four underestimated sources.

Table 1: Comparison of Emissions Factors from Four Updated Emissions Sources

Emissions Source Name	EPA/GRI Emissions Factor (CH_4 – metric tons/year)	Revised Emissions Factor (CH_4 – metric tons/year)
1) Well venting for liquids unloading	1.02	11
2) Gas well venting during completions		
Conventional well completions	0.02	0.71
Unconventional well completions	0.02	177
3) Gas well venting during well workovers		
Conventional well workovers	0.05	0.05
Unconventional well workovers	0.05	177
4) Centrifugal compressor wet seal degassing venting	0	233

1. Conversion factor: 0.01926 metric tons = 1 Mcf

[4] EPA did consider the data available from two new studies, TCEQ (2009) and TERC (2009). However, it was found that the data available from the two studies raise several questions regarding the magnitude of emissions from tanks and hence were not found appropriate for any further analysis until the issues are satisfactorily understood and/ or resolved by the authors and covered parties.

Table 2: Comparison of Process Emissions from each Segment of the Natural Gas and Petroleum Industries

Segment Name	U.S. GHG Inventory[1] Estimate for Year 2006 ($MMTCO_2e$)	Revised Estimate for Year 2006 ($MMTCO_2e$)
Production[2]	90.2	186.4
Processing	33.1	31.7
Transmission and Storage	38.3	64.0
Distribution	24.7	25.3

1. U.S. EPA (2008) *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006.*

2. *Production includes fugitive and vented emissions from both the natural gas and petroleum sectors' onshore and offshore facilities.*

After revising the U.S. GHG Inventory for the four updated sources, fugitive CH_4 and CO_2 emissions from the petroleum and natural gas industry were 307.4 million metric tons of CO_2 equivalent ($MMTCO_2e$) in 2006. Overall, the natural gas industry emitted 257.2 of CH_4 and 23.6 $MMTCO_2e$ of CO_2 in 2006. Total CH_4 and CO_2 emissions from the petroleum industry in 2006 were 26.3 $MMTCO_2e$ and 0.3 $MMTCO_2e$ respectively.

Petroleum Segment

Crude oil production operations accounted for over 97 percent of total CH_4 emissions from the petroleum industry. Crude oil transportation activities accounted for less than one half of a percent of total CH_4 emissions from the oil industry. Crude oil refining processes accounted for slightly over two percent of total CH_4 emissions from the petroleum industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the petroleum refineries. The United States currently estimates CO_2 emissions from crude oil production operations only in the U.S. GHG Inventory. Research is underway to include other larger sources of CO_2 emissions in future inventories.

Natural Gas Segment

Emissions from natural gas production accounted for approximately 66 percent of CH_4 emissions and about 25 percent of non-energy CO_2 emissions from the natural gas industry in 2006. Processing facilities accounted for about 6 percent of CH_4 emissions and approximately 74 percent of non-energy CO_2 emissions from the natural gas industry. CH_4 emissions from the natural gas transmission and storage segment accounted for approximately 17 percent of emissions, while CO_2 emissions from natural gas transmission and storage accounted for less than one percent of the non-energy CO_2 emissions from the natural gas industry. Natural gas distribution segment emissions, which account for approximately 10 percent of CH_4 emissions from natural gas systems and less than one percent of non-energy CO_2 emissions, result mainly from fugitive emissions from gate stations and pipelines.

4. Methodology for Selection of Industry Segments and Emissions Sources Feasible for Inclusion in a Mandatory GHG Reporting Rule

It is important to develop criteria to help identify GHG emissions sources in the petroleum and natural gas industry most likely to be of interest to policymakers. To identify sources for inclusion in a mandatory GHG reporting rule, two preliminary steps were taken; 1) review existing regulations to identify emissions sources already being regulated, and 2) review existing programs and guidance documents to identify a comprehensive list of emissions sources for potential inclusion in the proposed rule.

The first step in determining emissions sources to be included in a mandatory GHG reporting rule was to review existing regulations that the industry is subject to. Reviewing existing reporting requirements highlighted those sources that are currently subject to regulation for other pollutants and may be good candidates for addressing GHG emissions. The second step was to establish a comprehensive list of emissions sources from the various existing programs and guidance documents on GHG emissions reporting. This provided an exhaustive list of emissions sources for the purposes of this analysis and avoided the exclusion of any emissions sources already being monitored for reporting under other program(s). Both of these steps are described below.

a. Review of Existing Regulations

The first step was to understand existing regulations and consider adapting elements of the existing regulations to a mandatory reporting rule for GHG emissions. At this time, there are three emissions reporting regulations and six emissions reduction regulations in place for the petroleum and natural gas industry, including one voluntary reporting program included in the Code of Federal Regulations. This table also includes EPA's Final Mandatory Reporting Rule, which requires certain oil and gas facilities to report their combustion-related emissions. Table 3 provides a summary of each of these nine reporting and reduction regulations.

Table 3: Summary of Regulations Related to the Petroleum and Natural Gas Industry

Regulation	Type	Point/ Area/ Major/ Mobile Source	Gases Covered	Segment and Sources
EPA 40 CFR Part 98 Final Mandatory Reporting of Greenhouse Gases Rule	Mandatory Emissions Reporting	Point, Area, Biogenic	CO_2, CH_4, N_2O, HFCs, PFCs, , SF_6, NF_3, and HFE	All facilities that emit 25,000 metric tons or more per year of GHG.
EPA 40 CFR Part 51 – Consolidated Emissions Reporting	Emissions Reporting	Point, Area, Mobile,	VOCs, NOx, CO, NH_3, PM_{10}, $PM_{2.5}$	All segments of the petroleum and natural gas industry
DOE 10 CFR Part 300 – Voluntary GHG Reporting	Voluntary GHG Reporting	Point, Area, Mobile	CO_2, CH_4, N_2O, HFCs, PFCs, , SF_6, and CFCs	All segments of the petroleum and natural gas industry

EPA 40 CFR Part 60, Subpart KKK	NSPS[2]	Point	VOCs	Onshore processing plants; sources include compressor stations, dehydration units, sweetening units, underground storage tanks, field gas gathering systems, or liquefied natural gas units located in the plant
EPA 40 CFR Part 60, Subpart LLL	NSPS[2]	Point	SO_2	Onshore processing plants; Sweetening units, and sweetening units followed by a sulfur recovery unit
EPA 40 CFR Part 63,, NESHAP[1],, Subpart HHH	MACT[3]	Point (Glycol dehydrators, natural gas transmission and storage facilities)	HAPs	Glycol dehydrators
EPA 40 CFR Part 63, NESHAP[1], Subpart HH	MACT[3]	Major and Area (petroleum and natural gas production, up to and including processing plants)	HAPs	Point Source - Glycol dehydrators and tanks in petroleum and natural gas production; equipment leaks at gas processing plants Area Source - Triethylene glycol (TEG) dehydrators in petroleum and natural gas production
EPA 40 CFR Part 63, NESHAP[1], –Subpart YYYY	MACT[3]	Major and Area (Stationary Combustion Turbine)	HAPs	All segments of the petroleum and natural gas industry
EPA 40 CFR Part 63, NESHAP[1], Subpart ZZZZ	MACT[3]	Major and Area (Reciprocating Internal Combustion Engines)	HAPs	All segments of the petroleum and natural gas industry
Notes: [1]National Emission Standards for Hazardous Air Pollutants [2]New Source Performance Standard [3]Maximum Allowable Control Technology				

Table 3, indicates that only DOE 10 CFR Part 300 includes the monitoring or reporting of CH_4 emissions from the petroleum and natural gas industry. However, this program is a voluntary reporting program and is not expected to have a comprehensive coverage of CH_4 emissions. Although some of the sources included in the other regulations lead to CH_4 emissions, these emissions are not reported. The MACT regulated sources are subject to Part 70 permits which require the reporting of all major HAP emission sources, but not GHGs. GHG emissions from petroleum and natural gas operations are not systematically monitored and reported; therefore these regulations and programs can not serve as the foundation for a mandatory GHG emissions reporting rule.

b. Review of Existing Programs

The second step was to review existing monitoring and reporting programs to identify all emissions sources that are already monitored under these programs. Six reporting programs and six guidance documents were reviewed. Table 4 summarizes this review, highlighting monitoring points identified by the programs and guidance documents.

Table 4 shows that the different monitoring programs and guidance documents reflect the points of monitoring identified in the U.S. GHG Inventory, which are consistent with the range of sources covered in the 2006 IPCC Guidelines. Therefore, the U.S. GHG Inventory was used to provide the initial list of emissions sources for determining the emissions sources that can be potentially included in the proposed rule.

The preliminary review provided a potential list of sources, but did not yield any definitive indication on the emissions sources that were most suitable for potential inclusion in a reporting program. A systematic assessment of emissions sources in the oil and natural gas industry was then undertaken to identify the specific emissions sources (e.g., equipment or component for inclusion in a mandatory GHG reporting rule.

Table 4: Summary of Program and Guidance Documents on GHG Emissions Monitoring and Reporting

Reporting Program/Guidance	Source Category (or Fuel)	Coverage (Gases or Fuels)	Points of Monitoring	Monitoring Methods and/or GHG Calculation Methods*
2006 IPCC Guidelines for National GHG Inventory, Volume 2, Chapter 4	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	Oil and natural gas systems fugitive equipment leaks, evaporation losses, venting, flaring, and accidental releases; and all other fugitive emissions at oil and natural gas production, transportation, processing, refining, and distribution facilities from equipment leaks, storage losses, pipeline breaks, well blowouts, land farms, gas migration to the surface around the outside of wellhead casing, surface casing vent bows, biogenic gas formation from tailings ponds and any other gas or vapor releases not specifically accounted for as venting or flaring	Accounting/ reporting methodologies and guidelines Companies choose a base year for which verifiable emissions data are available. The base year emissions are used as an historic control against which the company's emissions are tracked over time. This ensures data consistency over time. Direct measurement of GHG emissions by monitoring concentration and flow rate can also be conducted. IPCC methodologies are broken down into the following categories: - Tier I calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and default industry segment emission factors - Tier II calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and country-specific industry segment emission factors or by performing a mass balance using country-specific oil and/or gas production information Tier III calculation-based methodologies for estimating emissions involve "rigorous bottom-up assessment by primary type of source (e.g. evaporation losses, equipment leaks) at the individual facility level with appropriate accounting of contributions from temporary and minor field or well-site installations. The calculation of emissions is based on activity data and facility-specific emission factors
AGA - Greenhouse Gas Emissions Estimation Methodologies, Procedures, and Guidelines	Gas – Distribution	CH_4, non-combustion CO_2 and other GHG gases	Segment-level counts, equipment discharges (i.e. valves, open-ended lines, vent stacks), and segment	Equipment or segment emissions rates and engineering calculations Tier I, II (IPCC) - facility level emissions rates

for the Natural Gas Distribution Sector			capacities, facility counts and capacities	Tier III (IPCC) - equipment emissions rates for intentional emissions, process level emissions rates, and process/equipment level emissions rate
API - Compendium of GHG Emissions Estimation Methodologies for the Oil and Gas Industry	Gas and Petroleum – all segments	CH_4, non-combustion CO_2	Equipment discharges (e.g. valves, open-ended lines, vent stacks), vent stacks for equipment types, tank PRV/vents, and facility input	Equipment or segment emissions rates and engineering calculations Tier II (IPCC) - facility level emissions rates Tier III (IPCC) - equipment emissions rates for intentional emissions, process level emissions rates, tank level emissions rates, and process/equipment level emissions rate (BY SEGMENT)
California Climate Action Registry General Reporting Protocol, March 2007	All legal entities (e.g. corporations, institutions, and organizations) registered in California, including petroleum and gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in indirect and direct emission of GHG gases for the entity	Provides references for use in making fugitive calculations The CCAR does not specify methodology to calculate fugitive emissions
California Mandatory GHG Reporting Program	Petroleum – Refineries	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in CH_4 and CO_2 fugitive emissions for petroleum refineries	Continuous monitoring methodologies and equipment or process emissions rates CO_2 process emissions can be determined by continuous emissions monitoring systems. Methods for calculating fugitive emissions and emissions from flares and other control devices are also available
DOE Voluntary Reporting of Greenhouse Gases Program (1605(b))	Petroleum and Gas- All Segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in direct and indirect emissions of GHG gases for the corporation or organization	Direct, site-specific measurements of emissions or all mass balance factors Mass-balance approach, using measured activity data and emission factors that are publicly documented and widely reviewed and adopted by a public agency, a standards-setting organization or an industry group Mass-balance approach, using measured activity data and other emission factors

				Mass balance approach using estimated activity data and default emissions factors.
EU ETS 1st and 2nd Reporting Period	Petroleum – Refining	Non-combustion CO_2	Hydrogen production	Engineering calculations Operators may calculate emissions using a mass-balance approach
INGAA - GHG Emissions Estimation Guidelines for Natural Gas Transmission and Storage, Volume 1	Gas - Transmission/Storage	CH_4, non-combustion CO_2	Segment-level counts, equipment discharges (i.e. valves, open-ended lines, vent stacks), and segment capacities, facility counts and capacities	Equipment or segment emissions rates Tier I (IPCC)- segment level emissions rates from intentional and unintentional releases Tier II - equipment level emissions rates for intentional releases Tier II (IPCC) – facility and equipment level emissions rates for unintentional leaks Engineering calculation methodologies for: - Pig traps - Overhauls - Flaring
IPIECA - Petroleum Industry Guidelines for Reporting GHG Emissions	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	Refers to API Compendium points of monitoring: Equipment discharges (e.g. valves, open-ended lines, vent stacks), vent stacks for equipment types, tank PRV/vents, and facility input	Tiers I, II, and III (IPCC) definitions and reporting methods for all fugitive and vented GHG emissions in the oil and gas industry
New Mexico GHG Mandatory Emissions Inventory	Petroleum refineries	CO_2 reporting starts 2008 , CH_4 reporting starts 2010	Equipment discharges (e.g. valves, pump seals, connectors, and flanges)	- 2009 reporting procedures will be made available in 10/2008

The Climate Registry (General Reporting Protocol for the Voluntary Reporting Program), 2007	All legal entities (e.g. corporations, institutions, and organizations) including petroleum and gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in emission of GHG gases for the entity	Continuous monitoring methodologies and equipment or process emissions rates Measurement-based methodology monitor gas flow (continuous, flow meter) and test methane concentration in the flue gas. Calculation-based methodologies involve the calculation of emissions based on activity data and emission factors
Western Regional Air Partnership (WRAP)	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in emission of GHG gases for the entity	Provides quantification methods for all sources from all sectors of the petroleum and gas industry considered in the rule. Quantification methods are typically engineering equation; however, parameters for the equations in several cases require measurement of flow rates, such as from well venting
World Resources Institute/ World Business Council for Sustainable Development GHG Protocol Corporate Standard, Revised Edition 2003	Organizations with operations that result in GHG (GHG) emissions e.g. corporations (primarily), universities, NGOs, and government agencies. This includes the oil and gas industry	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in direct and indirect emission of GHG gases for the corporation or organization	Provides continuous monitoring methodologies and equipment or process emissions rates Companies need to choose a base year for which verifiable emissions data are available and specify their reasons for choosing the year. "The base year emissions are used as an historic datum against which the company's emissions are tracked over time. Emissions in the base year should be recalculated to reflect a change in the structure of the company, or to reflect a change in the accounting methodology used. This ensures data consistency over time." Direct measurement of GHG emissions by monitoring concentration and flow rate can be conducted. Calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and emission factors

c. Selection of Emissions Sources for Reporting

When identifying emissions sources for inclusion in a mandatory reporting rule, two questions need addressing. The first is defining a facility. In other words, what physically constitutes a facility? The second is determining which sources of emissions should a facility report? Including or excluding sources from a mandatory reporting rule without knowing the definition of a facility is difficult. Therefore, both the facility definition and emissions source inclusion (or exclusion) were studied independently and finally reviewed together to arrive at a conclusion.

i. Facility Definition Characterization

Typically, the various regulations under the Clean Air Act (CAA) define a facility as a group of emissions sources all located in a contiguous area and under the control of the same person (or persons under common control). This definition can be easily applied to onshore natural gas processing and petroleum refining facilities since the operations are all located in a clearly defined boundary. Onshore natural gas transmission compressor stations also can be clearly identified using this definition. However, this definition does not as directly lend itself to onshore petroleum and natural gas production, onshore natural gas transmission pipelines and natural gas distribution, and petroleum transportation sectors.

Petroleum and natural gas production facilities can be very diverse in arrangement. Sometimes crude oil and natural gas producing wellheads are far apart with individual equipment at each wellhead. At other times several wells in close proximity are connected to common pieces of equipment. The choice of whether multiple wells are connected to common equipment depends on factors such as distance between wells, production rate, and ownership and royalty payment. New well drilling techniques such as horizontal and directional drilling allow for multiple wellheads to be located at a single location (or pad) from where they are drilled to connect to different zones in the same reservoir. Therefore, finding a single definition of a facility that can be applied to all of onshore petroleum and natural gas production can be challenging. In addition, there are several hydrocarbon resource ownership and operational equipment ownership issues relating to the onshore petroleum and natural gas production segment. In many cases, the mineral rights are not necessarily owned by the land owner. This is prevalent mostly in the western half of the United States where the Bureau of Land Management owns major portions of the minerals rights whereas the lands are held by private owners. Also, multiple operators commonly operate in a single production operation. For example, in the onshore production segment, multiple operators are responsible for different equipment in the same field under different ownership.

An alternative to a physical facility definition is the use of a corporate level reporter definition. In such a case the corporation that owns or operates petroleum and natural gas production operations could be required to report. Here the threshold for reporting could require that an individual corporation sum up GHG emissions from all the fields it is operating in and determine if its total emissions surpass the threshold. There is a precedent in subpart NN of the Final Mandatory Reporting Rule (MRR) for corporate reporting, where local distribution companies are required to report the volumes of natural gas that they sell to end customers. See Appendix E for further discussion of this issue.

Natural gas transmission and petroleum transportation pipelines run over several hundred thousand miles in the United States. There are no identifiers (or markers) that can be used to readily assign a portion of the pipelines as a single facility. Moreover, emissions sources in pipelines are spread across large geographical areas making it difficult to use the common definition available from the CAA. The natural gas distribution segment has issues similar to the onshore natural gas transmission segment in defining facilities for the extensive pipeline network. The meters and regulators in the distribution segment are mainly in small underground vaults in urban areas. Individually defining each vault as a facility is again impractical owing to the size and expected magnitude of emissions from a single vault. It may also not be immediately obvious to include multiple vaults to define a facility, as they are not in a contiguous area. However, similar to the onshore production segment, local distribution companies could potentially report at a corporate level. The precedence for this type of reporting already exists under the Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements under CFR Title 49 Section 191.11. See Appendix E for further discussion of this issue.

Gathering pipelines collect produced natural gas from petroleum and natural gas fields and direct it to either processing plants, transmission systems, or in some cases directly to end use customers via distribution system. The definitional issue with gathering pipelines is similar to transmission and distribution systems in that pipelines cannot be physically demarcated into a facility. However, there is an additional issue in regard to gathering pipelines. Unlike other segments of the petroleum and natural gas industry, gathering systems may be owned by producers, processing plants, transmission companies, local distribution companies, or independent gathering companies. Therefore, it is difficult to assign this portion of onshore production to one particular segment. One option is to require gathering pipelines to be reported as an emissions source. The other option is to have a separate segment assigned to gathering pipelines. See Appendix F for further discussion on the options.

ii. Selection of Potential Emissions Sources for Reporting

Given that there are over 160 emissions sources in the petroleum and natural gas industry, it is important to target sources which contribute significantly to the total national emissions for the industry. This avoids an excessive reporting burden on the industry, but at the same time enables maximum coverage for emissions reporting. The selection of emissions sources for potential inclusion in the proposed rulemaking was conducted in three steps.

Step 1: Characterize Emissions Sources

The U.S. GHG Inventory was used as the complete list of sources under consideration for inclusion in a reporting rule. The U.S. GHG Inventory was also used to provide all relevant emissions source characteristics such as type, number of sources across industry segments, geographic location, emissions per unit of output, total national emissions from each emissions source, and frequency of emissions. Also, information included in the U.S. GHG Inventory and the Natural Gas STAR Program technical studies was used to identify the different monitoring methods that are considered the best for each emissions source. If there are several monitoring methods for the same source, with equivalent capabilities, then the one with lower economic burden was considered in the analysis.

Step 2: Identify Selection Criteria and Develop Decision Tree for Selection
There are several factors that impact the decision on whether an emissions source should be included for reporting. A discussion of the factors follows below.

- *Significant Contribution to U.S. GHG Inventory* – Emissions sources that contribute significant emissions can be considered for potential inclusion in the rule, since they increase the coverage of emissions reporting. Typically, in oil and natural gas facilities, 80 percent or more of the facility emissions are reported to be from approximately 10 percent of the emissions sources. This is a good benchmark to ensure the adequate coverage of emissions while reducing the number of emissions sources required for reporting thus, keeping the reporting burden to a minimum. Emissions sources in each segment of the natural gas and petroleum industry can be sorted into two main categories: (1) top sources contributing to 80 percent of the emissions from the segment, and (2) the remaining sources contributing to the remaining 20 percent of the emissions from that particular segment. This can be easily achieved by determining the emissions contribution of each emissions source to the segment it belongs to, listing the emissions sources in a descending order, and identifying all the sources at the top that contribute to 80 percent of the emissions. Appendix A provides a listing of all emissions sources in the U.S. GHG Inventory and a breakdown of the top emissions sources and their contributions to their respective segment emissions.

- *Type of Emissions* – The magnitude of emissions per unit or piece of equipment typically depends on the type of emissions. Vented emissions per unit source are usually much higher than fugitive emissions from a unit source. For example, emissions from compressor blowdown venting for one compressor are much higher than fugitive emissions from any one unit component source on the compressor. The burden from covering emissions reporting from each unit source (i.e. dollar per ton of emissions reported) is typically much lower in the case of venting sources in comparison to fugitive emissions sources when the same monitoring method is used. Therefore, vented sources could be treated separately from fugitive sources for assessment of monitoring requirements.

- *Best Practice Monitoring Method(s)* – Depending on the types of monitoring methods typically used, a source may or may not be a potential for emissions reporting. There are four types of monitoring methods as follows:

    - Continuous monitoring – refers to cases where technologies are available that continuously monitor either the emissions from a source or a related parameter that can be used in estimating emissions. For example, continuous monitoring meters can determine the flow rate and in line analyzers can determine the composition of emissions from a process vent.

- Periodic monitoring – refers to monitoring at periodic intervals to determine emissions from sources. For example, leak detection and measurement equipment can be used on a recurring basis to identify and measure an emissions rate from equipment.
- Engineering calculations – refers to estimation of emissions using engineering parameters. For example, emissions from a vessel emergency release can be estimated by calculating the volume of the emitting vessel.
- Emissions factors – refers to utilizing an existing emissions rate for a given source and multiplying it by the relevant activity data to estimate emissions. For example, emissions per equipment unit per year can be multiplied by the number of pieces of equipment in a facility to estimate annual emissions from that equipment for the facility.

- *Accessibility of emissions sources* – Not all emissions sources are directly accessible physically for emissions detection and/or measurement. For example, connectors on pipelines, pressure relief valves on equipment, and vents on storage tanks may be out of direct physical reach and could require the use of bucket trucks or scaffolding to access them. In such cases requiring emissions detection and measurement may not always be feasible. Also, such requirements could pose health and safety hazards or lead to large cost burden. The accessibility of emissions sources has to be considered when addressing monitoring requirements.

- *Geographical dispersion of emissions sources* – The cost burden for detecting and measuring emissions will largely depend on the distance between various sources. For example, visiting individual onshore petroleum and natural gas production wells spread across large distances for emissions surveys will require excessive travel time and result in a large cost burden. Compressors at compressor stations on the other hand are located in close proximity.

- *Applicability of Population or Leaker Emission factors* – When the total emissions from all leaking sources of the same type are divided by the total count of that source type then the resultant factor is referred to as population emissions factor. When the total emissions from all leaking sources of the same type are divided by the total count of leaking sources for that source type then the resultant factor is referred to as leaker emissions factor. For example, in a emissions detection and measurement study if 10 out of 100 valves in the facility are found leaking then:

    - the total emissions from the 10 valves divided by 100 is referred to as population emissions factor
    - the total emissions from the 10 valves divided by 10 is referred to as leaker emissions factor

  The implication of these two types of emissions factor is as follows. The proposed rule could potentially ask for emissions detection only with the corresponding application of a leaker emissions factor. In such a case the burden for actual measurement is avoided. In addition, the use of leaker emissions factors will provide an estimate of "actual" emissions as opposed to the use of population emissions factor where the emissions from each facility can only be a "potential" of emissions.

Based on the criteria outlined above, a decision process was developed to identify the potential sources that could be included in a reporting rule. Figure 1 shows the resulting decision tree that includes these criteria and supported the decision-making process. The cost for monitoring from each emissions source varies greatly for oil and gas production and hence will have to be dealt with in addition to the decision tree. The decision process provided in Figure 1 was applied to each emissions source in the natural gas segment of the U.S. GHG Inventory. The petroleum onshore production segment has emissions sources that either are equivalent to their counterparts in the natural gas onshore segment or fall in the 20 percent exclusion category. Only CH_4 emissions were taken into consideration for this exercise given that, for most sources, fugitive CO_2 emissions are negligible in comparison to CH_4 emissions from the same sources. Appendix A summarizes the results of this analysis and provides guidance on the feasibility of each of the monitoring options discussed previously.

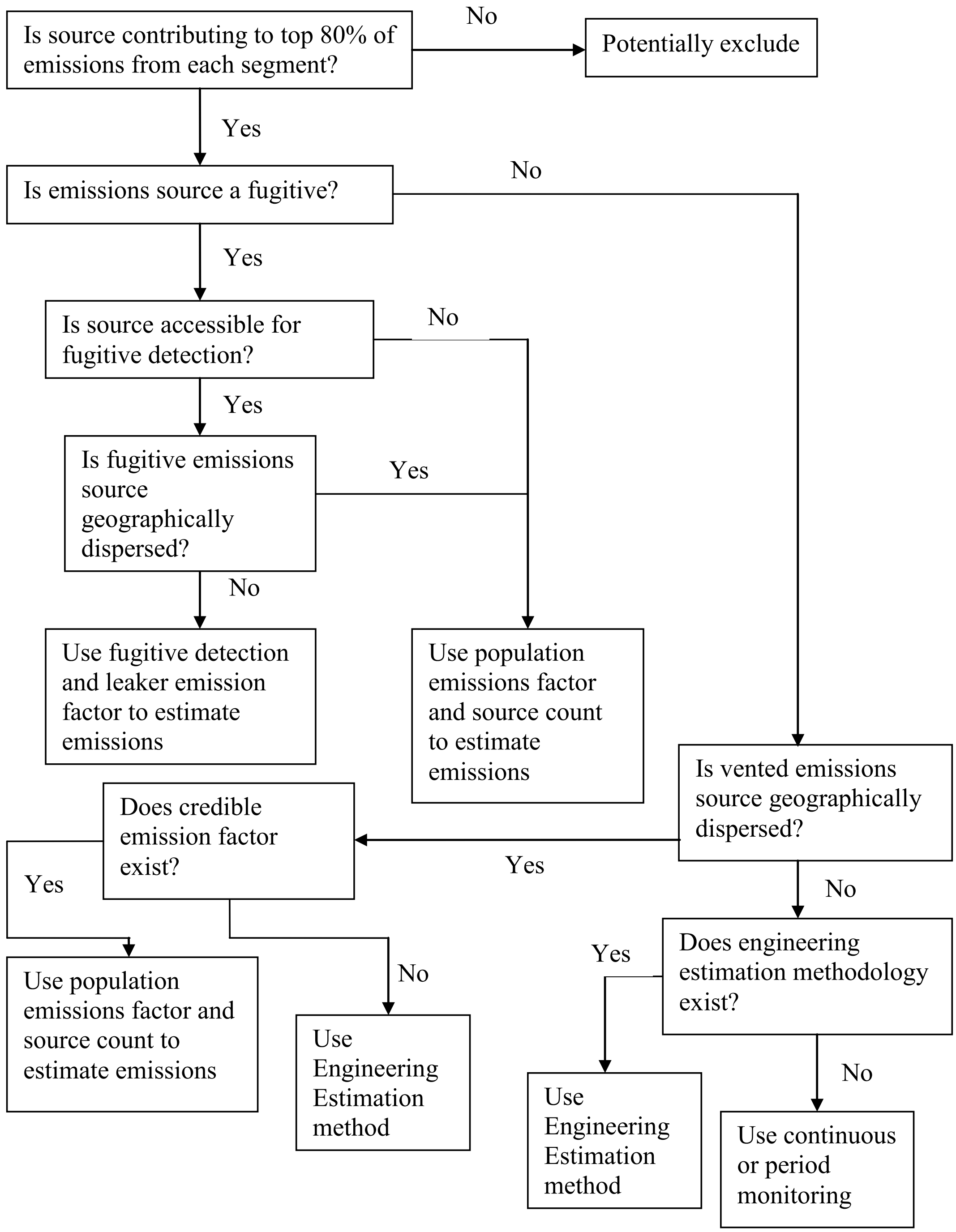

Figure 1: Decision Process for Emissions Source Selection

iii. Address Sources with Large Uncertainties

The natural gas and petroleum industry inventories are based on a U.S. EPA and Gas Research Institute Study[5] published in 1996. There are several estimates of emissions factors for emissions sources that do not correctly reflect the operational practices of today. Hence in some cases the estimates either under or over count volume of emissions from these sources. From anecdotal evidence from the industry, it is believed that emissions from some sources may be much higher than currently reported in the U.S. GHG Inventory. In most cases sufficient information is not publicly available to make changes to the national Inventory estimates. In other cases where public data are available, it is often incomplete and does not represent the industry at a national level. The decision tree was not necessarily ideal for sources known to be over- or underestimated in current inventories, which use existing emission factors. Therefore, the decision tree was overridden for these sources. The sources for consideration under this exception are:

- Condensate and oil storage tanks
- Natural gas well workovers
- Natural gas well completions
- Natural gas well blowdowns
- Centrifugal compressor wet seals
- Flares

In addition, the U.S. GHG Inventory includes CH_4 and CO_2 emissions from natural gas engines and turbines, as well as petroleum refineries. Emissions from these sources were not considered further here because methods for calculating and reporting emissions from these sources are addressed in the background technical support documents for Stationary Combustion described in Subpart C of the Final Mandatory Reporting Rule (MRR) and Petroleum Refineries described in Subpart Y of the Final Mandatory Reporting Rule (MRR) respectively.

iv. Identify Sources to be Included

Based on the understanding of facility definitions for each segment of the oil and gas industry and the identification of potential sources for inclusion in a mandatory reporting rule, the potential segments and sources to be included were identified. A brief analysis for each segment is as follows;

- *Onshore Petroleum and Natural Gas Production Segment* – Onshore petroleum and natural gas production is an important segment for inclusion in a GHG reporting program, due to its relatively large share of emissions. However, in order to include this segment, it is important to clearly articulate how to define the facility and identify who is the reporter. For some segments of the industry, identifying a facility is straightforward since there are clear physical boundaries and ownership structures

[5] U.S. Environmental Protection Agency/ Gas Research Institute, Methane Emissions from the Natural Gas Industry, June 1996.

Onshore production operations are a challenge for emissions reporting using the conventional facility definition of a "contiguous area" under a common owner/ operator. EPA proposes to define a hydrocarbon producing basin as a facility and all operators report their emissions on a basin level. In such a case, the company (or corporation) operating in multiple fields in the same basin can report at the basin level. The operator could be the company or corporation holding the required state or federal permit for drilling or operating. Reporting emissions from <u>all</u> potential emissions sources at a basin level would substantially increase reporting burden but the complexity of reporting requirements would be substantially reduced. Another possible alternative is to define a production field as a facility. In such cases, the company (or corporation) operating in the field can report emissions. However, such field level definition can result in lower coverage than basin level reporting, since fields are typically a segment of a basin.

In addition to basin and field level reporting, one alternative option is identifying a facility as an individual well pad, including all stationary and portable equipment operating in conjunction with that well, including drilling rigs with their ancillary equipment, gas/liquid separators, compressors, gas dehydrators, crude oil heater-treaters, gas powered pneumatic instruments and pumps, electrical generators, steam boilers and crude oil and gas liquids stock tanks. This definition was analyzed with available data including four cases to represent the full range of petroleum and natural gas well pad operations:

- Case 1 (highest well pad emissions): Drilling and completion of an unconventional gas well early in the year with the well producing the remainder of the year with a full complement of common, higher process emissions equipment on the well pad including a compressor, glycol dehydrator, gas pneumatic controllers, and condensate tank without vapor recovery. We assumed that unconventional well completion does not employ "Reduced Emissions Completion" practices.

- Case 2 (second highest well pad emissions): Drilling and completion of a conventional gas well early in the year with the well producing the remainder of the year with a full complement of common, higher process emissions equipment on the well pad including a compressor, glycol dehydrator, gas pneumatic controllers, and condensate tank without vapor recovery.

- Case 3 (third highest well pad emissions): Drilling and completion of a conventional oil well early in the year with the well producing the remainder of the year with a full complement of common, higher process emissions equipment on the well pad including an associated gas compressor, glycol dehydrator, gas pneumatic controllers, chemical injection pump, an oil heater-treater, and a crude oil stock tank without vapor recovery.

- Case 4 (fourth highest well pad emissions): Production at an associate gas and oil well (no drilling) with a compressor, dehydrator, gas pneumatics, oil heater/treater and oil stock tank without vapor recovery.

Facility definitions identifying a single wellhead as a facility could significantly increase the number of reporters to a program, and potentially raise implementation issues.

One way to reduce the reporting burden, due to the large number of sources, would be to focus on the largest contributors to GHG emissions. From the EPA Natural Gas STAR experience in mitigating methane emissions in the onshore petroleum and natural gas production segment, the major contributors to emissions from the onshore production segment are easily identifiable. These emissions sources are not reflected as major sources in the U.S. GHG Inventory as the inventory estimates are based on a 1992 measurement study[5] that, in the case of these sources, was based on limited data. Based on current knowledge of the petroleum and natural gas industry, the following seven emissions sources are known to be the major contributors to the total petroleum and natural gas production segment emissions: natural gas driven pneumatic valve and pump devices, well completion releases and flaring, well blowdowns, well workovers, crude oil and condensate storage tanks, dehydrator vent stacks, and reciprocating compressor rod packing. With a basin level, field level, or well-head level facility definition, onshore production segment operators or companies could report emissions from the seven major emissions sources listed above.

- *Offshore Petroleum and Natural Gas Production Segment* – All of the production activities offshore take place on platforms. These platforms can be grouped into two main categories; wellhead platforms and processing platforms. Wellhead platforms consist of crude oil and/ or natural gas producing wellheads that are connected to processing platforms or send the hydrocarbons onshore. Processing platforms consist of wellheads as well as processing equipment such as separators and dehydrators, in addition to compressors. All platforms are within a confined area and can be distinctly identified as a facility. Since all sources are within a small area on and around the platform, all sources of emissions on or associated with offshore platforms could be monitored and reported.

- *Onshore Natural Gas Processing Segment* – There are two types of operations in the processing segment of the natural gas industry; gathering/ boosting stations and processing facilities. Gathering/ boosting stations typically collect gas from several producing zones, dehydrate the natural gas and compress it for transportation to onshore natural gas processing plants. Processing facilities further process the gas to remove hydrogen sulfide (H_2S) and/ or CO_2 in the natural gas, if any, separate the higher hydrocarbons (ethane, propane, butane, pentanes, etc.) from the natural gas and compress the natural gas to be injected into the onshore natural gas transmission segment. Both gathering/ boosting stations and natural gas processing facilities have a well defined boundary within which all processes take place. All emissions sources in a processing plant could be monitored and included in a mandatory GHG reporting rule, including associated gathering and boosting stations.

- *Onshore Natural Gas Transmission Segment* – Transmission compressor stations are the largest source of emissions on transmission pipelines and meet the conventional definition of a facility. Given the relatively large share of emissions from the compressor station, as compared to the pipeline segments between transmission compressor stations, the station may be the most logical place to capture emissions from this segment. Natural gas transmission also involves high pressure, large diameter pipelines that transport gas long distances from field production and natural gas processing facilities to natural gas distribution pipelines or large volume customers such as power plants or chemical plants. The magnitude of transmission pipeline emissions in the U.S. Inventory is 0.07% of the total national emissions. Also, the Department of Transportation in Title 49 CFR Part 192 Section 706 requires that all natural gas transmission lines perform leakage surveys at least two to four times every calendar year. Section 711 of the same regulation requires operators to make permanent repairs to discovered leaks when feasible. Therefore, EPA is not proposing to include reporting of fugitive emissions from natural gas pipeline segments between compressor stations, or crude oil pipelines and tank terminals in the supplemental rulemaking can potentially be excluded because of the dispersed nature of the fugitive emissions, and the fact that once fugitives are found, they are generally fixed quickly. One possible option is that each segment facility that operates gathering pipelines report emissions from their gathering lines.

- *Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Segments* – All operations in an underground natural gas storage facility (except wellheads), LNG storage facility, and LNG import and export facilities are confined within defined boundaries. In the case of underground natural gas storage facilities, the wellheads are within short distances of the main compressor station such that it is feasible to monitor them along with the stations themselves. All three segments could be included in a mandatory reporting rule.

- *Natural Gas Distribution Segment* – The distribution segment meter and regulation vaults are identifiable as a facility. However, the magnitude of emissions from a single vault is not significant. Although vaults collectively contribute to a significant share of emissions from the natural gas industry nationally, it may not be possible to group multiple vaults as a single facility as they are not in a contiguous area. Also, emissions from vaults and pipelines are usually quickly dealt with given the safety concerns in a gas distribution segment. This might not allow any time for monitoring of leaks.

  Another option for including distribution sector is adapting the facility definition from the fuels reporting regulation for natural gas reporting from distribution companies. This subpart of the MRR defines a local distribution company (LDC) as a facility and the threshold is applied at the company level. Using this definition will avoid all the issues discussed earlier since geographical demarcation of the facility will no more be an issue.

- *Petroleum Transportation Segment* – All the sources in the petroleum transportation segment were excluded as a result of the decision process. Hence, this segment may not be amenable to inclusion in a reporting program.

Table 5 provides a list of each segment and a corresponding facility definition. It also provides a listing of all sources that can be monitored and could be reported as part of a mandatory GHG reporting rule.

Table 5: Segment Specific Facility Definition

Segment	Facility Definition	Potential Emission Sources for Inclusion
Onshore Petroleum and Natural Gas	Onshore petroleum and natural gas production facility means all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code. Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility.	Acid gas removal (AGR) vent stacks, centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, dehydrator vent stacks, flare stacks, natural gas driven pneumatic pumps, non-pneumatic pumps, open-ended lines (OELs), pump seals, pipeline fugitive emissions, natural gas driven pneumatic manual valve actuator devices, natural gas driven pneumatic valve bleed devices, reciprocating compressor rod packing, storage tanks, separators, well clean-ups/blowdowns, vessel blowdowns/venting, meters/piping, pipeline leaks, pipeline venting, wellhead fugitives, well completions, coal bed methane fugitives, heaters, separators.
Offshore Petroleum and Natural Gas Production	Offshore petroleum and natural gas production facility means any platform structure, either floating in the ocean or lake, or fixed on the ocean or lake bed, that houses equipment to extract hydrocarbons from the ocean or lake floor and transports it to storage or transport vessels or transports onshore. In addition, offshore production facilities include secondary platform structures and floating storage tanks connected to the platform structure by a pipeline. Production facilities connected to each other via causeways are one	Acid gas removal (AGR) vent stacks, centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, dehydrator vent stacks, flare stacks, natural gas driven pneumatic pumps, non-pneumatic pumps, open-ended lines (OELs), pump seals, offshore platform pipeline fugitive emissions, platform fugitive emissions, natural gas driven pneumatic

	facility.	manual valve actuator devices, natural gas driven pneumatic valve bleed devices, reciprocating compressor rod packing, storage tanks, separators, well clean-ups/blowdowns, vessel blowdowns/venting, meters/piping, pipeline leaks, pipeline venting.
Onshore Natural Gas Processing	Natural gas processing facilities are plants designed to separate and recover natural gas liquids (NGLs)or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO2 separated from natural gas streams for Enhanced Oil Recovery (EOR), carbon sequestration projects or other commercial applications. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flow lines or intra-facility gathering lines or compressors) as feed to the natural gas processing facilities are considered a part of the processing facility. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of the natural gas processing facility. All petroleum and natural gas equipment associated with petroleum and natural gas wells are not considered a part of the natural gas processing	AGR vent stacks, blowdown vent stacks, centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, dehydrator vent stacks, open-ended lines (OELs), natural gas driven pneumatic manual valve actuator devices, natural gas driven pneumatic valve bleed devices, processing facility fugitive emissions, reciprocating compressor rod packing, storage tanks, non-pneumatic pumps, meters/piping, pipeline leaks, station venting and M&R
Onshore Natural Gas Transmission	Onshore natural gas transmission compression facility means any permanent combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage facilities. In addition, transmission compressor station includes equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Each owner or operator	Centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, dehydrator vent stacks, OELs, natural gas driven pneumatic manual valve actuator devices, natural gas driven pneumatic valve bleed devices, reciprocating compressor rod packing, storage tanks, transmission station fugitive emissions, meters/piping, pipeline

	engaged in gas transmission compression, who also operates gas gathering pipelines, shall report emissions for these pipelines.	leaks, CBM Powder River, AGR vent stacks, vessel blowdown, station venting, and M&R.
Underground Natural Gas Storage	Underground natural gas storage facility means a subsurface facility, including but not limited to; depleted gas or oil reservoirs and salt dome caverns, utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas; processes and operations that may be located at a natural gas underground storage facility (including, but are not limited to, compression, dehydration and flow measurement); and all the wellheads connected to the compression units located at the facility.	Centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, dehydrator vent stacks, OELs, pump seals, natural gas driven pneumatic manual valve actuator devices, natural gas driven pneumatic valve bleed devices, reciprocating compressor rod packing, storage tanks, storage station fugitive emissions, storage wellhead fugitive emissions, meters/piping, pipeline leaks, vessel blowdowns/venting, pipeline venting, station venting, and M&R.
LNG Storage	LNG storage facilities means an onshore facility that stores LNG in above ground storage vessels, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.	Centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, OELs, LNG storage station fugitive emissions, reciprocating compressor rod packing, meters/piping, pipeline leaks, pneumatic device vents, vessel blowdowns/venting, pipeline venting, station venting, and M&R.
LNG Import and Export	LNG import facility means onshore or offshore facilities that receive imported LNG via ocean transport, store it in storage tanks, re-gasify it, and deliver re-gasified natural gas to a natural gas transmission or distribution system. LNG export facility means onshore or offshore facilities that receive natural gas, liquefy it, store it in storage tanks, and send out the LNG via ocean transportation, including to import facilities in the United States.	Centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, OELs, LNG storage station fugitive emissions, reciprocating compressor rod packing, meters/piping, pipeline leaks, pneumatic device vents, vessel blowdowns/venting, pipeline venting, station venting, and M&R.
Natural Gas Distribution	A natural gas distribution facility is a Local Distribution Company (LDC) that owns or operates distribution pipelines, not interstate pipelines or intrastate pipelines, and metering and regulating stations, that physically deliver natural gas to end users and that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems.	Main cast iron pipeline fugitives, main unprotected steel pipeline fugitives, main protected steel pipeline fugitives, main plastic protected steel pipeline fugitives, service unprotected steel pipeline fugitives, service protected steel pipeline fugitives, service plastic pipeline fugitives, service copper pipeline fugitive, city gate station fugitives, customer meter fugitives, pressure relief valves, pipeline blowdowns, mishaps.

5. Options for Reporting Threshold

For each segment in the petroleum and natural gas industry identified above as amenable to a reporting program, four thresholds were considered for emissions reporting as applicable to an individual facility; 1,000 metric tons of CO_2 equivalent (mtCO_2e) per year, 10,000 mtCO_2e, 25,000 mtCO_2e, and 100,000 mtCO_2e. A threshold analysis was then conducted on each segment to determine which level of threshold was most suitable for each industry segment. CH_4, CO_2, and N_2O emissions from each segment were included in the threshold analysis.

a. Threshold Analysis

For each segment, a threshold analysis was conducted to determine how many of the facilities in the segment exceed the various reporting thresholds, and the total emissions from these impacted facilities. This analysis was conducted considering fugitive and vented CH_4 and CO_2 emissions, and incremental combustion CH_4, CO_2, and N_2O emissions. Incremental combustion emissions are those combustion emissions not already reported under Subpart C of the MRR, but are required to be reported because their process emissions. The fugitive and vented emissions estimates available from the U.S. GHG Inventory were used in the analysis. However, the emissions estimates for four sources, well venting for liquids unloading, gas well venting during well completions, gas well venting during well workovers, and centrifugal compressor wet seal degassing venting from the U.S. GHG Inventory were replaced with revised estimates developed as described in Appendix B. Incremental combustion emissions were estimated using gas engine methane emissions factors available from the GRI study, back calculating the natural gas consumptions in engines, and finally applying a CO_2 emissions factor to the natural gas consumed as fuel. N_2O emissions were also calculated similarly. In the case of offshore petroleum and natural gas production platforms combustion emissions are already available from the GOADS 2000 study analysis and hence were directly used for the threshold analysis. It must be noted that the threshold analysis for the rule includes all fugitive and vented emissions but only incremental combustion emissions. Due to these reasons the total emissions from the threshold analysis does not necessarily match the U.S. GHG Inventory for all segments of the petroleum and natural gas industry. A detailed discussion on the threshold analysis is available in Appendix C.

The general rationale for selecting a reporting threshold is to identify a level at which the incremental emissions reporting between thresholds is the highest for the lowest incremental increase in number of facilities reporting between the same thresholds. This would ensure maximum emissions reporting coverage with minimal burden on the industry. For example, for onshore production the emissions reporting coverage is 67 percent and the corresponding reporting facilities coverage is 2 percent for a threshold of 100,000 mtCO_2e per year. The incremental emissions and facilities coverage is 14 and 2 percent (81 percent minus 67 percent and 4 percent minus 2 percent), respectively, for a 25,000 mtCO_2e per year threshold. However, at the next reporting threshold level of 10,000 mtCO_2e per year the incremental emissions and entities coverage is 6 and 5 percent, respectively. It can be seen that the incremental coverage of emissions decreases but the coverage of facilities increases.

Table 6 provides the details of the threshold analysis at all threshold levels for the different segments in the oil and gas industry.

Table 6: Threshold Analysis for the Oil and Gas Industry Segments

Source Category	Threshold Level	Total National Emissions	Number of Facilities	Emissions Covered: Process Emissions ($mtCO_2e/year$)	Combustion CO_2 Emissions (mt/year)	Total Emissions (tons $mtCO_2e/yr$)	Percent	Facilities Covered: Number	Percent
Onshore Natural Gas Production Facilities (Basin)	100,000	277,798,737	27,993	131,978,112	55,197,177	187,175,289	67%	466	2%
	25,000	277,798,737	27,993	154,932,641	69,294,918	224,227,559	81%	1,232	4%
	10,000	277,798,737	27,993	164,072,922	78,317,926	242,390,849	87%	2,413	9%
	1,000	277,798,737	27,993	174,457,309	94,391,220	268,848,529	97%	10,604	38%
Offshore Petroleum and Natural Gas Production Facilities	100,000	11,261,305	3235	3,217,228	25,161	3,242,389	29%	4	0.1%
	25,000	11,261,305	3235	4,619,175	500,229	5,119,405	45%	58	2%
	10,000	11,261,305	3235	5,515,419	1,596,144	7,111,563	63%	184	6%
	1000	11,261,305	3235	6,907,812	3,646,076	10,553,889	94%	1192	37%
Onshore Natural Gas Processing Facilities	100,000	33,984,015	566	24,846,992	27,792	24,874,783	73%	130	23%
	25,000	33,984,015	566	29,551,689	1,677,382	31,229,071	92%	289	51%
	10,000	33,984,015	566	30,725,532	2,257,443	32,982,975	97%	396	70%
	1000	33,984,015	566	31,652,484	2,331,531	33,984,015	100%	566	100%
Onshore Natural Gas Transmission Facilities	100,000	64,059,125	1,944	34,511,094	7,834	34,518,927	54%	433	22%
	25,000	64,059,125	1,944	51,527,832	6,155,313	57,683,144	90%	1,145	59%
	10,000	64,059,125	1,944	53,554,302	9,118,603	62,672,905	98%	1,443	74%
	1,000	64,059,125	1,944	54,117,187	9,934,474	64,051,661	100%	1,695	87%
Underground Natural Gas Storage Facilities	100,000	9,713,029	397	3,548,988	0	3,548,988	37%	36	9%
	25,000	9,713,029	397	6,570,369	1,276,239	7,846,609	81%	133	34%
	10,000	9,713,029	397	7,283,058	1,685,936	8,968,994	92%	200	50%
	1,000	9,713,029	397	7,745,028	1,951,505	9,696,532	100%	347	87%
LNG Storage Facilities	100,000	2,113,601	157	669,503	25,956	695,459	33%	4	3%
	25,000	2,113,601	157	1,712,240	188,552	1,900,793	90%	33	21%
	10,000	2,113,601	157	1,826,546	204,297	2,030,842	96%	41	26%
	1,000	2,113,601	157	1,859,880	237,094	2,096,974	99%	54	34%
LNG Import Facilities[1]	100,000	315,888	5	314,803	0	314,803	100%	4	80%
	25,000	315,888	5	314,803	0	314,803	100%	4	80%
	10,000	315,888	5	314,803	0	314,803	100%	4	80%
	1,000	315,888	5	315,048	840	315,888	100%	5	100%
Natural Gas Distribution Facilities	100,000	25,258,347	1,427	18,470,457	0	18,470,457	73%	66	5%
	25,000	25,258,347	1,427	22,741,042	0	22,741,042	90%	143	10%
	10,000	25,258,347	1,427	23,733,488	0	23,733,488	94%	203	14%
	1,000	25,258,347	1,427	24,983,115	0	24,983,115	99%	594	42%

1. The only LNG export facility in Alaska has not been included in this analysis.

Note: Totals may not add exactly due to rounding. Fugitive and vented emissions in the threshold analysis are a sum of facility level emissions for each segment. Hence the total fugitive and vented emissions from each segment may not match the U.S. GHG Inventory.

As discussed above, alternative definitions of facility for onshore petroleum and natural gas production could be considered. One alternative option is applying the threshold at the facility level. Table 7 provides the results of the threshold analysis for a field level facility definition.

Table 7. Emissions coverage and entities reporting for field level facility definition

Threshold Level[2]	Emissions Covered		Facilities Covered	
	Metric tons CO_2e/year	Percent	Number	Percent
100,000	99,776,033	38%	305	0%
25,000	144,547,282	55%	1,253	2%
10,000	169,160,462	64%	2,846	3%
1,000	242,621,431	92%	39,652	48%

Four different scenarios were also considered above for applying thresholds at individual well pads. Table 8 below illustrates the average emissions for each scenario and the number of facilities that have emissions equal to or greater than that average. So, for example, in case 1, average emissions are 4,927 tons CO_2e/well pad. A threshold would have to be set as low as appropriately 5,000 tons CO_2e/well pad to capture even 6% of emissions from onshore oil and gas production. For the other cases, the threshold would have to be set lower than the thresholds considered for other sectors of the mandatory GHG reporting rule to capture even relatively small percentages of total emissions. In all cases, the number of reporters is higher than would be affected under the field or basin level options.

Table 8: Alternate Well-head Facility Definitions

	Case 1	Case 2	Case 3	Case 4
Average emissions (tons CO_2e / well pad)	4,927	700	700	370
Number of Reporters	3,349	38,949	66,762	166,690
Covered Emissions (metric tons CO2e)	16,498,228	40,943,092	50,572,248	87,516,080
Percent Coverage	6%	16%	19%	33%

The petroleum and natural gas industry may be somewhat unique when calculating facility emissions to be applied against a threshold for reporting. Finalized source categories in the MRR excluded the calculation and reporting of emissions from portable equipment. This was one option considered for the petroleum and natural gas industry. However, given that portable equipment is so central to many of the operations in the oil and natural gas industry and such a large contributor to emissions for the industry, particularly for onshore petroleum and natural gas production, one might consider requiring reporting and calculation of portable equipment emissions from this source category. If these emissions were excluded from the threshold calculation, a large number of facilities may fall below the threshold, preventing the collection of significant data from the industry that would be beneficial to the development of future climate policies and programs. Although lowering the threshold, but excluding portable equipment emissions could address this issue, data are not available to disaggregate stationary and portable combustion emissions from total combustion emissions in order to support an analysis to lower the threshold.

6. Monitoring Method Options

a. Review of Existing Relevant Reporting Programs/ Methodologies

To determine applicability of the different monitoring methods available, existing programs and guidance documents were reviewed. All of the program and guidance documents provide direction on estimating CH_4 and/ or CO_2 emissions. All documents in general provide emissions rate (emissions factors) that can be used to estimate emissions and in some cases refer to continuous emissions monitoring. Table 4 provided a summary of the programs and guidance documents reviewed.

b. Potential Monitoring Methods

Depending on the particular source to be monitored in a facility, several of the currently available monitoring methods for estimating emissions could be used.

i. Fugitive Emissions Detection

Traditional fugitive emission detection technologies like the Toxic Vapor Analyzer (TVA) and the Organic Vapor Analyzer (OVA) are appropriate for use in small facilities with few pieces of equipment. However, comprehensive leak detection in large facilities can be cumbersome, time consuming, and in many cases costly. But new infrared remote fugitive emissions detection technologies are currently being used in the United States and internationally to efficiently detect leaks across large facilities. Considering these factors, one of the following two technologies can be used to detect leaks in facilities depending on suitability;

Infrared Remote Fugitive Emissions Detectors

Hydrocarbons in natural gas emissions absorb infrared light. The infrared remote fugitive emissions detectors use this property to detect leakages in systems. There are two main types of detectors; a) those that scan the an area to produce images of fugitive emissions from a source, and b) those that point or aim an IR beam towards a potential source to indicate presence of fugitive emissions.

An IR camera scans a given area and converts it into a moving image of the area while distinctly identifying the location where infrared light has been absorbed, i.e. the fugitive emissions source. The camera can actually “see” fugitive emissions. The advantages of IR cameras are that they are easy to use, very efficient in that they can detect multiple leaks at the same time, and can be used to do a comprehensive survey of a facility. The main disadvantage of an IR camera is that it involves substantial upfront capital investment depending on the features that are made available. Therefore, these cameras are most applicable in facilities with large number of equipment and multiple potential leak sources or when purchased at the corporate level, and then shared among the facilities, thereby lowering costs.

Aiming devices are based on infrared laser reflection, which is tuned to detect the interaction of CH_4 and other organic compounds with infrared light in a wavelength range where CH_4 has strong absorption bands but do not visually display an image of the fugitive emissions. Such devices do not have screens to view the fugitive emissions, but pin point the location of the emissions with a visual guide (such as a visible pointer laser) combined with an audible alarm when CH_4 is detected. These devices are considerably less expensive than the camera and also can detect fugitive emissions from a distance (i.e. the instrument need not be in close proximity to the emissions). More time is required for screening, however, since each equipment (or component) has to be pointed at to determine if it is leaking. Also, if there are multiple leaks in the pathway of the IR beam then it may not accurately detect the right source of emissions.

Method For IR instruments that visually display an image of fugitive emissions, the background of the emissions has to be appropriate for emissions to be detectable. Therefore, the operator should inspect the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions to identify all emissions. For other IR detection instruments, such as those based on IR laser reflection, instruments would have to monitor potential emissions sources along all joints and connection points where a potential path to the atmosphere exists. For example, a flange can potentially have fugitive emissions along its circumference and such surfaces will have to be monitored completely by tracing the instrument along each surface.

Calibration The minimum detectable quantity of fugitive emissions depends on a number of factors including manufacturer, viewing distance, wind speed, gas composition, ambient temperature, gas temperature, and type of background behind the fugitive emissions. For best survey results, fugitive emissions detection can be performed under favorable conditions, such as during daylight hours, in the absence of precipitation, in the absence of high wind, and, for active laser devices, in front of appropriate reflective backgrounds within the detection range of the instrument. Fugitive emissions detection and measurement instrument manuals can be used to determine optimal operating conditions to help ensure best results.

Toxic Vapor Analyzer (or Organic Vapor Analyzer)

TVAs and OVAs consist of a flame ionization detector that is used to detect the presence of hydrocarbon and measure the concentration of the fugitive emissions. It consists of a probe that is moved close to and around the potential emissions source and an emissions detection results in a positive reading on the instrument monitoring scale. The concentration can be used in conjunction with correlation equations to determine the leak rate. However, concentration is not a true measure of an emission's magnitude. Therefore concentration data from TVAs and OVAs, for the purposes of the rule, may be best suited for screening purposes only. The advantage of these instruments is that they have lower costs than IR cameras and several facilities conducting Leak Detection and Repair (LDAR) programs might already have these instruments, thereby reducing capital investment burden. But these instruments screen very slowly given that each potential emissions source has to be individually and thoroughly circumscribed less than 1 centimeter from the potentially leaking joints or seals.

Method TVAs and OVAs can be used for all fugitive emissions detection that is safely accessible at close-range. For each potential emissions source, all joints, connections, and other potential paths to the atmosphere would be monitored for emissions. Due to residence time of a sample in the probe, there is a lag between when an emission is captured and the operator is alerted. To pinpoint the source of the fugitive emission, upon alert the instrument can be slowly retraced over the source until the exact location is found.

Calibration Method 21 guidance can be used to calibrate the TVA or OVA using guidelines from *Determination of Volatile Organic Compound Leaks* Sections 3, 6, and 7.

ii. Emissions Measurement

A. Direct Measurement

Three types of technologies can be used where appropriate to measure or quantify the magnitude of emissions.

High Volume Sampler

A high volume sampler consists of a simple fixed rate induced flow sampling system to capture the emissions and measure its volume. The emissions and the air surrounding the emissions source are drawn into the instrument using a sampling hose. The instrument measures the flow rate of the captured volume of air and emissions mixture. A separate sample of the ambient air is taken by the instrument to correct for the volume of ambient air that is captured along with the emissions.

High volume samplers have moderate costs and have a maximum capacity for measuring up to 30 leaking components per hour with high precision at 0.02 percent methane. This allows for reduced labor costs and survey times while maintaining precise results. For this reason, high volume samplers are considered the preferred and most cost-effective measurement option for emissions within their maximum range. However, large component emissions and many vent emissions are above the high volume sampler capacity and therefore warrant the use of other measurement instruments.

Method A high volume sampler is typically used to measure only emissions for which the instrument can intake the entire emissions from a single source. To ensure proper use of the instrument, a trained technician can conduct the measurements. The technician will have to be conversant with all operating procedures and measurement methodologies relevant to using a high volume sampler, such as positioning the instrument for complete capture of the emissions without creating backpressure on the source. If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then anti-static wraps or other aids can to be used to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual. The attachments help capture the emissions from different points on the source allowing the measurement of the emission by the high volume sampler.

Calibration The instrument can be calibrated at 2.5% and 100% CH_4 by using calibrated gas samples and by following the manufacturer's instructions for calibration.

Meters

Several types of meters measure natural gas flows and can be used for measurement of emissions from sources where the volume of emissions are large like in vent stacks.

> *Rotameter* **–** A rotameter consists of a tapered calibrated transparent tube and a floating bob inside to measure emissions. To measure emissions a rotameter is placed over an emissions source (typically vents and open ended lines) and the emissions pass through the tube. As the emissions move through the tube it raises the floating bob to indicate the magnitude of emissions on the calibrated scale. Rotameters are most advantageous to use in cases where the emissions are very large. The disadvantage though is that it can only be used on leaks where the entire emissions can be captured and directed through the rotameter.
>
> *Turbine Meter* –To measure emissions a turbine meter is placed over an emissions source and the emissions pass through the tube. As the emissions move through the tube it spins the turbine; the rate at which the turbine spins indicates the magnitude of emissions. Like rotameters, turbine meters are most advantageous to use in cases where emissions are very large. The disadvantage is that it can only be used on emissions that can be entirely captured and directed through the meter.
>
> *Hotwire Anemometer* – Hotwire anemometers measure emissions velocity by noting the heat connected away by the emissions. The core of the anemometer is an exposed hot wire either heated up by a constant current or maintained at a constant temperature. In either case, the heat lost to emissions by convection is a function of the emissions velocity. Hotwire anemometers are best for measuring vents and open ended lines of known cross-sectional area and do not require complete capture of emissions. Hot wire anemometers have low levels of accuracy since they measure velocity that is converted into mass emissions rate.
>
> *Pitot Tube Flow Meter* – A simple pitot tube is a right angled tube open at one end and closed at the other. The closed end is connected to a transducer to measure pressure of the inflowing emissions. The open end is aligned parallel to the direction of emissions flow. Emissions are directed into the tube so that the pressure required to

bring the air inside the tube to stagnation is measured. The difference in pressure between the interior of the pitot tube and the surrounding air is measured and converted to an emissions rate. Pitot tube flow meters can be used when the cross-sectional area of an emitting vent or open ended line is known, or when the entire emission can be directed into the tube. The pitot tube flow meter measures pressure differential that is converted to mass emissions rate.

Vane Anemometer – A vane anemometer channels the emissions over a rotating vane that in turn rotates a fan to measure the velocity of emissions. The number of revolutions of the fan are detected and measured and converted to a flow velocity. Using the cross section of flow of the emissions, the volumetric flow rate of emissions can be estimated. A vane anemometer is best used for lines that have known cross-sectional areas. The disadvantage is if the flow direction of the emissions changes with respect to the axis of rotation of the vanes, it can result in errors in velocity and flow rate estimation.

Method To ensure accurate measurements when using metering (e.g. rotameters, turbine meters, and others), all emissions from a single source will have to be channeled directly through the meter. An appropriately sized meter can be used to prevent the flow from exceeding the full range of the meter and conversely to have sufficient momentum for the meter to register continuously in the course of measurement.

Calibration The meters can be calibrated using either one of the two methods provided below:

(A) Develop calibration curves by following the manufacturer's instruction.

(B) Weigh the amount of gas that flows through the meter into or out of a container during the calibration procedure using a master weigh scale (approved by the National Institute of Standards and Technology (NIST) or calibrated using standards traceable by NIST) that has a very high degree of accuracy. Determine correction factors for the flow meter according to the manufacturer's instructions, record deviations from the correct reading at several flow rates, plot the data points, compare the flow meter output to the actual flow rate as determined by the master weigh scale and use the difference as a correction factor.

Calibrated Bagging

A calibrated bag made of anti-static material is used to enclose an emissions source to completely capture all the leaking gas. The time required to fill the bag with emissions is measured using a stop watch. The volume of the bag and time required to fill it is used to determine the mass rate of emissions. Calibrated bags have a very high accuracy, since all the emissions are captured in the measurement.

Calibrated bags are the lowest cost measurement technique, and can measure up to 30 leaking components in an hour, but may require two operators (one to deploy the bag, the other to measure time inflation). It is a suitable technique for emission sources that are within a safe temperature range and can be safely accessed. The speed of measurement is highly dependent on the emissions rate and the results are susceptible to human error in enclosing the emission source and taking the measurement data, leading to lower precision and accuracy. For those sources outside the capacity of high volume samplers and within the limitations of bagging, this would be a second best choice for quantification.

Method Calibrated bags (also known as vent bags) can be used only where the emissions are at near-atmospheric pressures and the entire emissions volume can be captured for measurement. Using these bags on high pressure vent stacks can be dangerous. For conducting measurement the bag is physically held in place by a trained technician, enclosing the emissions source, to capture the entire emissions and record the time required to completely fill the bag. Three measurements of the time required to fill the bag can be conducted to estimate the emissions rates. The average of the three rates will provide a more accurate measurement than a single measurement.

Calibration To ensure accurate results, a technician can be trained to obtain consistent results when measuring the time it takes to fill the bag with emissions.

All of the emissions measurement instruments discussed above measure the flow rate of the natural gas emissions. In order to convert the natural gas emissions into CO_2 and CH_4 emissions, speciation factors determined from natural gas composition analysis must be applied. Another key issue is that all measurement technologies discussed require physical access to the emissions source in order to quantify emissions.

B. Engineering Estimation

Several emissions sources do not require physical measurement of the emissions using a measurement instrument. For example, emissions to the atmosphere due to emergency conditions from vessels or other equipment and engineered emissions from equipment like pneumatic devices can be estimated or quantified using engineering calculations. This is referred to as engineering estimation. These sources are outlined below along with relevant engineering estimation methods that can be used to estimate GHG gas emissions from each source.

1. Natural Gas Driven Pneumatic Pumps

Fugitive emissions from natural gas driven pneumatic pumps can be calculated using data obtained from the manufacturer for natural gas emissions per unit volume of liquid pumped at operating pressures. This information is available from the pump manufacturer in their manuals. Operators can maintain a log of the amount of liquids pumped annually for individual pneumatic pumps and use the following equation for calculating emissions:

$$E_{s,n} = F_s * V \qquad \textbf{Equation 1}$$

where,

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet per year

F_s = Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at operating pressure" in scf/gallon at standard conditions, as provided by the manufacturer

V = Volume of liquid pumped annually in gallons/year

If manufacturer data for a specific pump is not available, then data for a similar pump model of the same size and operational characteristics can be used to estimate emissions. As an alternative to manufacturer data on pneumatic pump natural gas emissions, the operator can conduct a one-time measurement to determine natural gas emissions per unit volume of liquid pumped using a calibrated bag for each pneumatic pump, when it is pumping liquids.

2. Natural Gas Driven Pneumatic Manual Valve Actuators

Emissions from natural gas driven pneumatic manual valve actuators can be calculated using data obtained from the manufacturer for natural gas emissions per actuation. Operators can maintain a log of the number of manual actuations annually for individual pneumatic devices and use the following equation:

$$E_{s,n} = A_s * N \qquad \textbf{Equation 2}$$

where,

$E_{s,n}$ = natural gas emissions at standard conditions

A_s = natural gas driven pneumatic valve actuator natural gas emissions in "emissions per actuation" units at standard conditions, as provided by the manufacturer.

N = Number of times the pneumatic device was actuated through the reporting period

As an alternative to manufacturer data, the operator could conduct a one-time measurement to determine natural gas emissions per actuation using a calibrated bag for each pneumatic device.

3. Natural Gas Driven Pneumatic Bleed Devices

Pneumatic devices typically fall in two categories; low bleed devices and high bleed devices. Low bleed devices are devices that bleed less than 6 scf of natural gas per hour. Given the vast difference in bleed rates, low bleed devices contribute to a small portion of the total emissions from pneumatic devices nationally. Therefore, it may be feasible to provide an emissions factor approach for low bleed pneumatic devices to reduce burden. Following are two different options for high and low bleed pneumatic devices.

Emissions from a natural gas pneumatic high bleed device venting can be calculated using a specific pneumatic device model natural gas bleed rate during normal operation as available from the manufacturer. If manufacturer data for a specific device is not available then data for a similar size and operation device can potentially be used to estimate emissions. The natural gas emissions for each bleed device can be calculated as follows;

$$E_{s,n} = B_s * T \qquad \textbf{Equation 3}$$

where,

$E_{s,n}$	=	Annual natural gas emissions at standard conditions, in cubic feet
B_s	=	Natural gas driven pneumatic device bleed rate volume at standard conditions in cubic feet per minute, as provided by the manufacturer
T	=	Amount of time in minutes that the pneumatic device has been operational through the reporting period

Emissions from natural gas pneumatic low bleed device venting can be calculated using emissions factor as follows;

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \qquad \textbf{Equation 4}$$

where,

$Mass_{s,i}$	=	Annual total mass GHG emissions in metric tons per year at standard conditions from all natural gas pneumatic low bleed device venting at the facility, for GHG i
Count	=	Total number of natural gas pneumatic low bleed devices at the facility
EF	=	Population emission factors for natural gas pneumatic low bleed device venting listed in Appendix K for onshore petroleum and natural gas production, onshore natural gas transmission, and underground natural gas storage facilities, respectively
GHG_i	=	for onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas; for other facilities GHG_i equals 1
$Conv_i$	=	conversion from standard cubic feet to metric tons CO_2e; 0.000404 for CH_4, and 0.00005189 for CO_2
24 * 365	=	conversion to yearly emissions estimate

4. Acid Gas Removal (AGR) Vent Stacks

AGR vents consist of both CO_2 and CH_4 emissions. CO_2 emissions from AGR units can be reliably estimated using mass balance approach or one of the standard simulation software packages. CH_4 emissions can only be estimated using simulation software packages. It must be noted, however, that CH_4 emissions from AGR vents are insignificant, 0.06 percent of the total volume of CO_2 and CH_4 emissions. The mass balance approach has the advantage of being usable in systems that use membrane, molecular sieves, or absorbents other than amines; simulation software packages currently do not provide an option for these types of technologies.

Operators can calculate emissions from acid gas removal vent stacks using simulation software packages, such as ASPEN™ or AMINECalc™. Different software packages might use different calculations and input parameters to determine emissions from an acid gas removal units. However, there are some parameters that directly impact the accuracy of emissions calculation. Therefore, any standard simulation software could be used assuming it accounts for the following operational parameters:

- Natural gas feed temperature, pressure, and flow rate;
- Acid gas content of feed natural gas;
- Acid gas content of outlet natural gas;
- Unit operating hours, excluding downtime for maintenance or standby;
- Emissions control method(s), if any, and associated reduction of emissions;
- Exit temperature of natural gas; and
- Solvent pressure, temperature, circulation rate, and weight.

CO_2 emissions from AGR unit vent stacks can be calculated as follows;

$$E_{a,CO2} = (V_1 * \%Vol_1) - (V_2 * \%Vol_2) \qquad \textbf{Equation 5}$$

where,

$E_{a,CO2}$	=	Annual volumetric CO_2 emissions at ambient condition, in cubic feet per year
V_1	=	Metered total annual volume of natural gas flow into AGR unit in cubic feet per year at ambient condition
$\%Vol_1$	=	Volume weighted CO_2 content of natural gas into the AGR unit
V_2	=	Metered total annual volume of natural gas flow out of the AGR unit in cubic feet per year at ambient condition
$\%Vol_2$	=	Volume weighted CO_2 content of natural gas out of the AGR unit

Sometimes AGR units have a continuous gas analyzer in which case they can be used to determine $\%Vol_1$ and $\%Vol_2$. In addition, there are gas processing plants that capture CO_2 for EOR or carbon sequestration projects. In such cases, the emissions E_{CO2} can be adjusted downward to account for the percentage of total emissions captured.

5. Blowdown Vent Stacks

Emissions from blowdown vent stacks can be calculated using the total volume between isolation valves (including all natural gas-containing pipelines and vessels) and logs of the number of blowdowns for each piece of equipment using the following equation:

$$E_{a,n} = N * V_v$$ **Equation 6**

where,

$E_{a,n}$	=	Annual natural gas venting emissions at ambient conditions from blowdowns in cubic feet
N	=	Number of blowdowns for the equipment in reporting year
V_v	=	Total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves in cubic feet

6. Dehydrator Vent Stacks

There are two predominant types of technologies that are used to dehydrate natural gas. The first type is the most prevalent and uses liquid tri-ethylene glycol for dehydration, typically referred to as glycol dehydrators. The second type of dehydrators use solid desiccants to extract water from natural gas. For glycol dehydrators, when contacted with natural gas for dehydration, the glycol absorbs some amount of natural gas, which is released as emissions during its regeneration. Standard simulation software packages that use some form of equilibrium analysis can estimate emissions from such liquid glycol type dehydrators. On the other hand, in desiccant dehydrators the solid desiccant itself does not absorb any significant quantities of natural gas. But emissions result when the desiccant dehydrator is opened to the atmosphere for the regeneration of the desiccant, which results in the release of natural gas trapped in the desiccant dehydrator vessel. Hence, for desiccant dehydrators standard simulation software packages cannot be used. However, calculative methods can be used to determine emissions from solid desiccant type dehydrators. The two monitoring methods for the two different types for dehydrators are as below.

Emissions from a dehydrator vent stack can be calculated using a simulation software package, such as GLYCalc™. There may be several other simulation packages, such as Aspen HYSYS, that can also estimate emissions from glycol dehydrators. However, GLYCalc™ is the most widely used software and referenced by several State and Federal agencies in their programs and regulations; see Appendix H for further details. Different software packages might use different calculations and input parameters to determine emissions from dehydration systems. However, there are some parameters that directly impact the accuracy of emissions calculation. Therefore, any standard simulation software could be used provided it accounts for the following operational parameters:

- Feed natural gas flow rate;
- Feed natural gas water content;
- Outlet natural gas water content;
- Absorbent circulation pump type(natural gas pneumatic/ air pneumatic/ electric);
- Absorbent circulation rate;
- Absorbent type: including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG);
- Use of stripping natural gas;
- Use of flash tank separator (and disposition of recovered gas);
- Hours operated; and
- Wet natural gas temperature, pressure, and composition.

For dehydrators that use desiccant emissions can be calculated from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using the following equation:

$$E_{s,n} = \frac{(H * D^2 * P * P_2 * \%G * 365 days / yr)}{(4 * P_1 * T * 1{,}000 cf / Mcf)}$$ **Equation 7**

where,

$E_{s,n}$	=	Annual natural gas emissions at standard conditions
H	=	Height of the dehydrator vessel (ft)
D_v	=	Inside diameter of the vessel (ft)
P_1	=	Atmospheric pressure (psia)
P_2	=	Pressure of the gas (psia)
P	=	pi (3.14)
$G_{\%}$	=	Percent of packed vessel volume that is gas
T	=	Time between refilling (days)

Some dehydrator vented emissions are sent to a flare. Annual emissions from dehydrator vent stacks to flares can be calculated using the methodology under section 8 for flares. Alternatively, a simple combustion efficiency factors, such as 98 percent, can be used in conjunction with a CO_2 emissions factor for natural gas to estimate emissions from glycol dehydrator vents to flare stack.

7. EOR injection pump blowdown.

EOR operations use pumps to inject supercritical phase CO_2 into reservoirs. For maintenance, these pumps may be blown down to release all the supercritical phase CO_2. The volume of CO2 released to during such blow down practices can be calculated using the total volume between isolation valves (including, but not limited to, pipelines, compressors and vessels).The emissions can be calculated using the following equation.

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3}$$ **Equation 8**

where,

$Mass_{c,i}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume in cubic meters of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/m^3. Use an appropriate standard method published by a consensus-based standards organization to determine density of super critical EOR injection gas.

GHG_i = mass fraction of GHG*i* in critical phase injection gas

C. Emission Factors

The EPA/ GRI and EPA/Radian studies provide emissions factors for almost all the emissions sources in the petroleum and natural gas industry. These can potentially be used to estimate emissions for reporting under the rule. However, the emissions factors are not necessarily reliable for all the emissions sources. The emissions factors were developed more than a decade ago when the industry practices were much different from now. In many cases the emissions factors were developed using limited sample data and knowledge about the industry's operations. Also, the introduction of many emissions reduction technologies are not reflected in the emissions factor estimates. However, the two studies provide a wealth of raw data that can be potentially used to revise the estimate in conjunction with any new data that is now publicly available.

D. Combination of Direct Measurement and Engineering Estimation

Emissions from several sources can be estimated using a combination of direct measurement and engineering estimation. Direct measurement can provide either a snapshot of the emissions in time or information on parameters that can be used for using a calculative method to estimate emissions. Following are options for using such a combination of monitoring methods to estimate emissions.

8. Flare stacks

Flares typically burn two types of hydrocarbon streams; continuous and intermittent. Continuous streams result from vented emissions from equipment such as glycol dehydrators and storage tanks. Intermittent streams result from such sources as emergency releases from equipment blowdown. It must be noted that most of these streams, continuous or intermittent, can be covered using monitoring methods already provided on an individual emissions source level.

Flare emissions in general can be monitored using one of the following monitoring methods

Method 1:

Many facilities, such as in the processing sector, may already have a continuous flow monitor on the flare. In such cases, the measured flow rates can be used when the monitor is operational, to calculate the total flare volumes for the reporting year.

Method 2:

One option is to require the estimation of all streams of hydrocarbons going to the flare at an individual emissions source level. Here engineering calculation and other methods described for different sources in this Section can be used to estimates of volume flare gas

Method 3:

When the flare stream is mostly continuous, a flow velocity measuring device (such as hot wire anemometer, pitot tube, or vane anemometer) can be inserted directly upstream of the flare stack to determine the velocity of natural gas sent to flare. The GHG volumetric emissions at actual conditions can then be calculated as follows.

$$E_{a,i}(un - combusted) = V_a * (1 - \eta) * X_i \quad \textbf{Equation 9}$$

$$E_{a,CO2}(combusted) = \sum_j \eta * V_a * Y_j * R_j \quad \textbf{Equation 10}$$

$$E_{a,i} = E_{a,i}(combusted) + E_{a,i}(un - combusted) \quad \textbf{Equation 11}$$

where,

$E_{a,i}$*(un-combusted)*	=	Contribution of annual un-combusted emissions from flare stack in cubic feet, under ambient conditions
$E_{a,CO2}$*(combusted)*	=	Contribution of annual emissions from combustion from flare stack in cubic feet, under ambient conditions
$E_{a,i}$*(total)*	=	Total annual emissions from flare stack in cubic feet, under ambient conditions
V_a	=	Volume of natural gas sent to flare in cubic feet, during the year
η	=	Percent of natural gas combusted by flare (default is 98 percent)
X_i	=	Concentration of GHG_i in gas to the flare
Y_j	=	Concentration of natural gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus).
R_j	=	Number of carbon atoms in the natural gas hydrocarbon constituent *j*; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus)

In some cases the facility may have a continuous gas composition analyzer on the flare. Here the compositions from the analyzer can be used in calculating emissions. If an analyzer is not present then a sample of the gas to the flare stack can be taken every quarter to evaluate the composition of GHGs present in the stream. The natural gas composition analyses can be conducted using ASTM D1945-03. It must be noted that for processing plants there are two distinct streams of natural gas with significant differences in composition. The natural gas stream upstream of the de-methanizer can be expected to have higher C2+ components as opposed to the stream downstream of the de-methanizer. In addition, the CO_2 content in natural gas can change significantly after acid gas removal. Finally, processing plants may send pure streams of separated hydrocarbons such as ethane, propane, butane, iso-butane, or pentanes plus to the flare during an emergency shutdown of any particular equipment. Such variations in hydrocarbon streams being sent to the flare would have to be accounted for in the monitoring methodology.

9. Compressor wet seal degassing vents

In several compressors, the wet seal degassing vents emit flash gas from degassed oil straight into or close to the compressor engine exhaust vent stack. The temperatures at the degassing vent exit are very high due to the proximity to the engine exhaust vent stack. In such cases, emissions can be estimated using a flow velocity measuring device (such as hot wire anemometer, pitot tube) or a flow rate measurement device such as vane anemometer, which can be inserted directly upstream of the degassing unit vent exit to determine the velocity or flow rate of gas sent to the vent. If a velocity measuring device is used then the volume of natural gas sent to vent can be calculated from the velocity measurement using the manufacturer manual for conversion. Annual emissions can be estimated using meter flow measurement as follows:

$$E_{a,i} = MT * T * M_i * (1 - B)$$ **Equation 12**

where,

$E_{a,i}$	=	Annual GHG_i (either CH_4 or CO_2) volumetric emissions at ambient conditions
MT	=	Meter reading of gas emissions per unit time
T	=	Total time the compressor associated with the wet seal(s) is operational in the reporting year
M_i	=	Mole percent of GHG_i in the degassing vent gas
B	=	percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system or recycle to fuel gas system

A sample representative of the gas to the degassing vent can be taken every quarter to evaluate the composition of GHGs present in the stream using ASTM D1945-03. Some facilities may send their degassing vent vapors to a flare or to fuel use. The monitoring method will have to account for this.

10. Reciprocating compressor rod packing venting

There are three primary considerations for emissions from rod packing on reciprocating compressors. First, the rod packing case may or may not be connected to an open ended line or vent. Second, the rod packing may leak through the nose gasket in addition to the emissions directed to the vent. And third, the emissions from rod packing will vary depending on the mode of operation of the reciprocating compressor – running, standby and pressurized, or standby and de-pressurized.

If the rod packing case is connected to an open ended line or vent then emissions from the rod packing case can be estimated using bagging or high volume sampler. Alternatively, a temporary meter such as vane anemometer or permanent meter such as orifice meter can be used to measure emissions from rod packing vents.

If the rod packing case is open to the atmosphere then the emissions from the rod packing case will be mingled with the emissions from the nose gasket. The emissions from an open rod packing case usually will migrate to the distance piece (dog house), and if the distance piece is enclosed then this emissions will migrate to the engine crank case, before being emitted to the atmosphere. There are two possible options to monitor these emissions. The first option is to use an emissions factor for rod packing along with a population count. The second option is to require fugitive emissions detection and measurement to determine the exact location and volume of emission.

Typically, rod packing emissions vary with the mode of operation of the compressor. The emissions are highest when the compressor is operating and lower when they are in standby pressurized mode. When the compressor is standby de-pressurized there might be some migration of natural gas from the unit isolation valve through the rod packing. But this is for the most part, negligible. Hence to correctly characterize annual emissions from rod packing, estimation of emissions at two compressor modes, operating and standby pressurized, may be required.

11. Storage tanks

Emissions from storage tanks can be estimated using one of the following three methods.

Method 1:

In the case of storage tanks, emissions rates are not constant; and thus, a one-time measurement may not provide accurate emissions rates for the entire reporting period. To accurately estimate emissions from storage tanks, it is necessary to conduct a one-time measurement during a cycle of operation that is representative of the tank operations through the year. The following equation can be used to calculate GHG emissions:

$$E_{a,h} = Q \times ER \qquad \textbf{Equation 13}$$

where,

$E_{a,h}$ = hydrocarbon vapor emissions at ambient conditions, in cubic meters

Q = storage tank total annual throughput, in barrels

ER = measured hydrocarbon vapor emissions rate per throughput (e.g. meter/barrel)

ER can be estimating using the following procedure:

- The hydrocarbon vapor emissions from storage tanks can be measured using a flow meter for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.
- The throughput of the storage tank during the test period can be recorded.
- The temperature and pressure of hydrocarbon vapors emitted during the test period can be recorded.
- A sample of hydrocarbon vapors can be collected for composition analysis.

Method 2:

A second method is to use simulation software such as E&P Tank (GEO-RVP) to estimate vented emissions from storage tanks. Therefore, any standard simulation software could be used assuming it accounts for the following operational parameters:

- Feed liquid flow rate to tank;
- Feed liquid API gravity;
- Feed liquid composition or characteristics;
- Upstream (typically a separator) pressure;
- Upstream (typically a separator) temperature;
- Tank or ambient pressure; and
- Tank or ambient temperature;
- Sales oil API gravity;
- Sales oil production rate;
- Sales oil Reid vapor pressure;

Method 3:

A third method for storage tank vented emissions quantification is use of the Vasquez-Beggs equation. This correlation equation provides an estimate of the gas-to-oil ratio for flashing tank vapors; however, it does not provide the GHG of the vapors, so composition analysis of tank vapors is still required. Equation 14 demonstrates the use of this correlation equation:

$$GOR = A \times G_{fg} \times \left(P_{sep} + 14.7\right) \times \exp\left(\frac{C \times G_{oil}}{T_{sep} + 460}\right) \qquad \textbf{Equation 14}$$

where,

GOR	=	ratio of flash gas production to standard stock tank barrels of oil produced, in standard cubic feet/barrel (barrels corrected to 60°F)
G_{fg}	=	Specific gravity of the tank flash gas, where air = 1. A suggested default value for G_{fg} is 1.22
G_{oil}	=	API gravity of stock tank oil at 60°F
P_{sep}	=	Pressure in separator (or other vessel directly upstream), in pounds per square inch gauge
T_{sep}	=	Temperature in separator (or other vessel directly upstream of the tank), °F
A	=	0.0362 for G_{oil} </= 30°API, or 0.0178 for G_{oil} > 30°API
B	=	1.0937 for G_{oil} </= 30°API, or 1.187 for G_{oil} > 30°API
C	=	25.724 for G_{oil} </= 30°API, or 23.931 for G_{oil} > 30°API

Sometimes one or more emissions source vents may be connected to the storage tank. In such cases the emissions from these sources will be commingled with the emissions from the storage tank. In addition, two phase separators directly upstream of the storage tank may not have a vortex breaker. This can lead to channeling of natural gas from the separator to the storage tank. All these multiple scenarios mean that only Method 1 could potentially capture such miscellaneous sources connected to the storage tank. If, however, Method 1 is performed at a time when say the separator is not vortexing then even Method 1 may not capture the emissions from the miscellaneous emissions sources connected to the storage tank. Hence there is no single method that can identify these variations in storage tank emissions that represent multiple sources. These data are available from two recent studies provided by the Texas Commission on Environmental Quality (2009) and the Texas Environment Research Consortium (2009) that highlight this fact. A potential option to correct such scenarios where other emissions sources are connected to the storage tank or if the separator is vortexing is to use multipliers on emissions estimated from Methods 1 and 2 above. Two such potential multipliers are as below,

(i) The emissions for sales oil less than 45 API gravity can be multiplied by 3.87
(ii) The emissions for sales oil equal to or greater than 45 API gravity can be multiplied by 5.37

Details on the development of these multipliers are available in Appendix J.

Storage tanks in the onshore natural gas transmission segment typically store the condensate from the scrubbing of pipeline quality gas. The volume of condensate is typically low in comparison to the volumes of hydrocarbon liquids stored in the upstream segments of the industry. Hence the emissions from condensate itself in the transmission segment are insignificant. However, scrubber dump valves often get stuck due to debris in the condensate and can remain open resulting in natural gas loss via the open dump valve. This natural gas then flows through the storage tank. The only potential option to measuring emissions from scrubber dump valves is to monitor storage tank emissions to determine if the emissions do not subside and become negligible. If the scrubber dump valve is stuck and leaking natural gas to the tank then the emissions will be visibly significant and will not subside to inconspicuous volumes. If the scrubber dump valve functions normally and shuts completely after the condensate has been dumped then the storage tank emissions should subside and taper off to insignificant quantities; this will happen because once the condensate has flashed the dissolved natural gas there will not be significant emissions from the storage tank. If persistent and significant emissions are detected then a measurement may be required using a temporary meter.

Storage tank vapors captured using vapor recovery systems or sent to flares will have to be accounted for in the above method.

12. Well testing venting and flaring

During well testing the well usually is flowing freely and the produced hydrocarbons are typically vented and/ or flared. A gas to oil ratio is often determined when conducting well testing. This information can be reliably used to estimate emissions from well testing venting using the equation below:

$$E_{s,n} = GOR * FR * D \qquad \textbf{Equation 15}$$

where,

$E_{s,n}$	=	Annual volumetric natural gas emissions from well testing in cubic feet under ambient conditions
GOR	=	Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities
FR	=	Flow rate in barrels of oil per day for the well being tested
D	=	Number of days during the year, the well is tested

When well testing emissions are sent to a flare then the emissions estimated above should be adjusted to reflect the combustion emissions.

13. Associated gas venting and flaring

Often times when onshore petroleum production fields are located in a remote location, the associated gas produced is sent to a vent or flare. This is because the associated natural gas is stranded gas, meaning that it is not economical to send the usually low volumes to the market via a pipeline system. In such cases the emissions can be estimated using the volume of oil produced and the corresponding gas to oil ratio as following;

Vented associated natural gas emissions can be estimated using the following equation,

$$E_{a,n} = GOR * V \qquad \textbf{Equation 16}$$

where,

$E_{a,n}$	=	Annual volumetric natural gas emissions from associated gas venting under ambient conditions, in cubic feet
GOR	=	Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities
V	=	Total volume of oil produced in barrels in the reporting year

When well testing emissions are sent to a flare then the emissions estimated above will have to be adjusted to reflect the combustion emissions.

14. Hydrocarbon liquids dissolved CO_2

Onshore petroleum production that uses EOR with CO_2 injection results in the production of petroleum that has significant amounts of CO_2 dissolved in it. This CO_2 is usually separated from the liquid petroleum component, and re-injected in a closed loop system (although this CO_2 might be eventually recovered when the EOR operation at the site is closed). However, the liquid portion of petroleum still contains dissolved CO_2, since separation usually takes place at higher than ambient pressure. Most of this CO_2 is then released in a storage tank where the CO_2 flashes out of the liquid hydrocarbons. But even after this stage some amount of CO_2 remains entrapped in the liquid hydrocarbons and is lost to the atmosphere during the transportation and processing phases.

The amount of CO_2 retained in hydrocarbon liquids after flashing in tanks can be determined by taking quarterly samples to account for retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. The emissions from this hydrocarbon dissolved CO2 can be estimated using the following equation,

$$Mass_{s,\,CO2} = S_{hl} * V_{hl} \qquad \textbf{Equation 17}$$

where,

$Mass_{s,\,CO2}$	=	Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids beyond tankage, in metric tons.
S_{hl}	=	Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.
V_{hl}	=	Total volume of hydrocarbon liquids produced in barrels in the reporting year.

15. Produced water dissolved CO_2

EOR operations often use water injection techniques to push the CO_2 soaked petroleum through the reservoir and up the production well. This water, like the liquid petroleum, contains dissolved CO_2, since CO_2 readily dissolves in water. This produced water is re-circulated for injection into the reservoir. However, often it may be sent through tankage to avoid a two phase flow of CO_2 and water through the injection pumps. In such cases the CO_2 dissolved in the water is flashed to the atmosphere in the storage tank.

These emissions can be determined similar to hydrocarbon dissolved CO_2 by sampling the water on a periodic basis. To determine retention of CO_2 in produced water immediately downstream of the separator where hydrocarbon liquids and produced water are separated the following equation can be used.

$$Mass_{s,\,CO2} = S_{pw} * V_{pw} \qquad \textbf{Equation 18}$$

where,

$Mass_{s,\,CO2}$	=	Annual CO_2 emissions from CO_2 retained in produced water beyond tankage, metric tons.
S_{pw}	=	Amount of CO_2 retained in produced water in metric tons per barrel, under standard conditions.
V_{pw}	=	Total volume of produced water produced in barrels in the reporting year.

EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without any leakage to the atmosphere could be exempted from reporting.

16. Well venting for liquids unloading

There are three potential methods to estimate well venting emissions from liquids unloading. Method 1 requires installation of a flow meter temporarily for developing an emissions factor. Method 2 requires a transient pressure spike engineering analysis across the vent pipe during one well unloading event. Method 3 uses an engineering calculation method that uses the well's physical parameters to estimate emissions. Each of the three options is discussed below.

Method 1:

For each unique well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter can be installed on the vent line used to vent gas from the well (e.g. on the vent line off the separator or a storage tank). An emissions factor can be estimated as an average flow rate per minute of venting calculated for each unique tubing diameter and producing horizon/formation combination in each producing field. The emission factor can be applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, multiplied by the number of minutes of venting of all wells of the same tubing diameter and producing horizon/formation combination in that field. A new factor can be determined periodically to track field declining formation pressure and flow potential.

Method 2:

For each unique well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, an engineering analysis of the transient pressure spike across the vent line for well unloading events can be conducted. An emissions factor as an average flow rate per minute of venting can then be calculated through such an analysis. This emissions factor can be applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, multiplied by the number of minutes of venting all wells of the same tubing diameter and producing horizon/formation combination in that field. A new emission factor can be determined periodically to track field declining formation pressure and flow potential. Emissions from well venting for liquids unloading can be calculated using the following equation,

$$E_{s,n} = T * X * EF \qquad \textbf{Equation 19}$$

where,

$E_{s,n}$ = Annual natural gas emissions at standard conditions

T = Amount of time of well venting

X	=	Concentration of GHG *i* in gas vented.
EF	=	Emission factor developed using the transient pressure spike

For wells that have a plunger lift installed on a timer or programmable logic controller that vent to the atmosphere and automatically closes the vent valve when the plunger is received at the well head, an equation calculating the volume of gas in the tubing string calculated at sales pipeline pressure can be used. This equation is unique for each category of wells with the same well depth and tubing size. The emissions factor can be estimated by multiplying the tubing cross-sectional area by the tubing string length from wellhead to the bottom resting location of the plunger, corrected for sales line pressure and average gas flowing temperature.

Method 3:

The Natural Gas STAR Lessons Learned – Installing Plunger Lift Systems in Gas Wells (available at <http://epa.gov/gasstar/documents/ll_plungerlift.pdf>) provides an engineering estimation method in its Appendix. This method uses physical characteristics of the well that are usually well known. Using this method, emissions from well venting for liquids unloading can be calculated using the following equation:

$$E_{s,n} = \{(0.37\times10^{-3}) * CD^2 * WD * SP * V\} + \{SFR*HR\}$$ **Equation 20**

where,

$E_{s,n}$	=	Annual natural gas emissions at standard conditions, in cubic feet/year
0.37×10^{-3}	=	*{pi(3.14)/4}/{(14.7*144) psia converted to pounds per square feet}*
CD	=	Casing diameter (inches)
WD	=	Well depth (feet)
SP	=	Shut-in pressure (psig)
V	=	Number of vents per year
SFR	=	Sales flow rate of gas well in cubic feet per hour
HR	=	Hours that the well was left open to the atmosphere during unloading

17. Gas well venting during well completions and workovers

There are two methods to estimate emissions from gas well venting during well completions and workovers. Method 1 requires the installation of a recording flow meter on the vent line to the atmosphere or to a flare. Method 2 is an engineering calculation based on the pressure drop flow across the well choke. Method 3 uses the production of the well to determine emissions.

Method 1:

A recording flow meter can be installed on the vent line to the atmosphere or to a flare during each well unloading event. This one time reading can be extrapolated to yearly emissions based on the time taken for completion or workover and the number of times the well is worked over (if more than once per year). Such emissions factors can be developed for representative wells in a field on a yearly basis. During periods when gas is combusted in a flare, the carbon dioxide quantity can be determined from the gas composition with an adjustment for combustion efficiency. This method can also be used when phase separation equipment is used and requires the installation of a recording flow meter on the vent line to the atmosphere or to a flare.

Emissions from gas well venting during well completions and workovers from hydraulic fracturing can be calculated using equation 21 below;

$$E_{s,n} = T * FR \qquad \textbf{Equation 21}$$

where,

$E_{s,n}$	=	Annual natural gas vented emissions at ambient conditions in cubic feet
T	=	Cumulative amount of time in hours of well venting during the year
FR	=	Flow rate in cubic feet per hour, under ambient conditions

Method 2:

Using pressures measured before and after the well choke, an engineering calculation of the average flow rate across the choke can be done. Using engineering judgment and the total time that flow across the choke is occurring, the total volume to the atmosphere or a flare during the back-flow period can be estimated. This one time reading can be extrapolated to yearly emissions based on the time taken for completion or workover and the number of times the well is worked over (if more than once per year). Such emissions factors can be developed for representative wells in a field on a yearly basis.

Method 3:

A quick and least burdensome method to determine emissions from well venting during completions and workovers is to use the daily gas production rate to estimate emissions using the following equation,

$$E_{s,i} = V * T * GHG_i \qquad \textbf{Equation 22}$$

where,

$E_{s,i}$	=	Annual GHG emissions in cubic feet at standard conditions from gas well venting during conventional well completions or workovers

V	=	Daily gas production rate, in cubic feet per minute
T	=	Cumulative amount of time of well venting in minutes during the year
GHG_i	=	for onshore petroleum and natural gas production facilities, fraction of GHG_i, CH_4 or CO_2, in produced natural gas

c. Leak detection and leaker emission factors

For fugitive emissions sources that are standard components such as connectors, valves, meters, etc. emissions can be estimated by conducting a fugitive emissions detection program and applying a leaker emissions factor to those sources found to be emitting. The following Equation 23 can be used for this purpose.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \textbf{Equation 23}$$

where,

$E_{s,j}$	=	Annual total volumetric GHG emissions at standard conditions from a fugitive source
$Count$	=	Total number of this type of emission source found to be leaking
EF	=	Leaker emission factor for specific sources listed in Appendix J.
GHG_i	=	for onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in feed natural gas; for other facilities GHG_i equals 1
T	=	Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours

Leaker emissions factors are available for specific sources for onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities, liquefied natural gas import and export facilities, and natural gas distribution facilities. These leaker emissions factors and a discussion on their development are available in Appendix K.

d. Population Count and Emission Factors.

For fugitive emissions that are geographically dispersed or where the cost burden is an issue emissions can be estimated using the population count of emissions sources and a corresponding population emissions factor. Such an option may be most feasible for emissions sources with gas content greater than 10 percent CH_4 plus CO_2 by weight since otherwise the emissions factors may overestimate overall GHG emissions. Emissions from all sources listed in this paragraph of this section can be calculated using the following equation.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \textbf{Equation 24}$$

where,

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from each fugitive source
Count	=	Total number of this type of emission source at the facility
EF	=	Population emission factor for specific sources listed in Appendix K.
GHG_i	=	for onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities GHG_i equals 1
T	=	Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours

Population emissions factors are available for specific sources for onshore petroleum and natural gas production facilities, onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities, liquefied natural gas import and export facilities, and natural gas distribution facilities. These population emissions factors and a discussion on their references are available in Appendix L.

e. Method 21

This is the authorized method for detecting volatile organic carbon (VOC) emissions under Title 40 CFR The method specifies the performance of a portable VOC emission detection instrument with a probe not exceeding one fourth inch outside diameter, used to slowly circumscribe the entire component interface where fugitive emissions could occur. The probe must be maintained in close proximity to the interface; otherwise it could be damaged by rotating shafts or plugged with ingested lubricants or greases. In most cases, it can be no more than 1 centimeter away from the leak interface. Method 21 does not specify leak definitions; they are defined within specific subparts of the Title 40 CFR. Method 21 also allows certain alternative fugitive emissions detection methods, such as soap solutions (where the fugitive emissions source is below the boiling point and above the freezing point of the soap solution, does not have areas open to the atmosphere that the soap solution cannot bridge, and does not have signs of liquid leakage). Method 21 does not specify any emissions mass or volumetric quantification methods, but only specifies an emissions concentration expressed in parts per million of combustible hydrocarbons in the air stream of the instrument probe. This leak detection data has been used by state emission inventories with "leaker" factors developed by the Synthetic Organic Chemicals Manufacturing Industry (SOCMI)[6] to estimate the quantity of VOC emissions. SOCMI factors were developed from petroleum refinery and petrochemical plant data using Method 21. SOCMI factors adjusted for methane content are considerably lower than the methane factors proposed in this rule, which were developed from more recent studies of gas processing plants and compressor stations.

Performance standards for remote leak sensing devices, such as those based on infrared (IR) light imaging, or laser beams in a narrow wavelength absorbed by hydrocarbon gases, were promulgated in the general provisions of EPA 40 CFR Part 60. This alternate work practice (AWP) permits leak detection using an instrument which can image both the equipment and leaking gas for all 40 CFR 60 subparts that require monitoring under Method 21.

Although leak detection with Method 21 or the AWP in their current form in conjunction with leaking component emission factors may not be the best suited for all mandatory reporting, the principle could potentially be adopted for estimating emissions from minor sources such as fugitive emissions from components. Emissions can be detected from sources (including those not required under Method 21, i.e. not within arm's reach) using AWP procedures for the optical gas imaging instrument, and applying leaker emissions factors available from studies conducted specifically with methane emissions in its scope. This will be easier for industry to adapt to and also avoid the use of Synthetic Organic Chemical Manufacturing Industry correlation equations or leak factors developed specifically for different industry segments (i.e. petroleum refineries and chemical plants). This method will also result in the estimation of real emissions, as opposed to potential emissions from population emissions factor calculations.

f. Portable VOC Detection Instruments for Leak Measurement

As discussed above under Method 21, portable VOC detection instruments do not quantify the volumetric or mass emissions. They quantify the concentration of combustible hydrocarbon in the air stream induced through the maximum one fourth inch outside diameter probe. Since these small size probes rarely ingest all of the fugitive emissions from a component leak, they are used primarily for fugitive emissions detection. EPA provides emissions quantification guidelines, derived from emissions detection data, for using portable VOC detection devices. One choice of instrument emissions detection data is referred to as

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[6] EPA (1995). *Protocol for Equipment Leak Emission Estimates.* Research Triangle Park, NC. Publication No. EPA-453/R-95-017. Online at: http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf

"leak/no-leak", where equipment is determined to be leaking when the portable instrument indicates the provided leak definition. Different leak definitions are specified within the subparts of the Clean Air Act. Subpart KKK of 40 CFR Part 60 defines "leakers" for natural gas processing facilities as components with a concentration of 10,000 ppm or more when measured by a portable leak detection instrument. Components that are measured to be less than 10,000 ppm are considered "not leaking." Hence, these quantification tables have a "no-leak" emission factor for all components found to have emissions rates below the leak definition, and "pegged" emission factors for all components above the leak definition. Alternatively, the "stratified" method has emission factors based on ranges of actual leak concentrations below, at and above the leak definition. Portable leak detection instruments normally peg at 10,000 ppm, and so are unsuitable for use with the "stratified" quantification factors. For the proposed rule, fugitive emissions detection by more cost-effective screening technologies in conjunction with leaker emission factors are considered a better approach to emissions quantification than the labor intensive Method 21.

g. Mass Balance for Quantification

There are mass balance methods that could be considered to calculate emissions from a reporting program. This approach would take into account the volume of gas entering a facility and the amount exiting the facility, with the difference assumed to be emitted to the atmosphere. This is most often discussed for emissions estimation from the transportation segment of the industry. For transportation, the mass balance is often not recommended because of the uncertainties surrounding meter readings and the large volumes of throughput relative to fugitive emissions. The mass balance approach may, however, be feasible in cases where the volume of emissions is significantly large and recognizable as meter readings. One such source is an acid gas recovery unit where the volume of CO_2 extracted from natural gas is significant enough to be registered in a compositional difference of the natural gas and can be determined using mass balance.

h. Gulf Offshore Activity Data System program (GOADS)

The Mineral Management Service conducts a comprehensive activity data collection effort under its Gulf Offshore Activity Data System program (GOADS). This requires all petroleum and natural gas production platforms located in the Federal Gulf of Mexico (GoM) to report their activities to MMS once in every four years. The activity data reported includes counts of emissions sources, volumes of throughputs from several pieces of equipment, fuel consumption by combustion devices, and parametric data related to certain emissions sources such as glycol dehydrators. This activity data is then converted into emissions estimates by MMS and reported subsequently by MMS. The MMS summary report provides estimates of GHG emissions in the GoM as well as a detailed database of emissions from each source on platform in the GoM. The EPA could potentially use this data reported by the GOADS program. However, since the data are only collected once every four years, EPA will not receive new emissions information for every reporting period. This means that between MMS reporting periods if a new platform is commissioned, an old platform is de-commissioned, new equipment is installed on existing platforms, or operating levels of platforms change then this information will not get recorded and reported for periods when MMS GOADS is not being conducted. Finally, the MMS GOADS program does not collect information from platforms in the GoM under State jurisdiction, as well as platform in the Pacific and Alaskan coasts. These platforms not under GOADS purview will not have existing data to report if GOADS reporting were to be adopted by EPA.

i. Additional Questions Regarding Potential Monitoring Methods

There are several additional issues regarding the potential monitoring methods relevant to estimating fugitive and vented emissions from the petroleum and natural gas industry.

i. Source Level Fugitive Emissions Detection Threshold

This document does not indicate a particular fugitive emissions definition or detection threshold requiring emissions measurement. This is because different fugitive emissions detection instruments have different levels and types of detection capabilities, i.e. some instruments provide a visual image while others provide a digital value on a scale (not necessarily directly related to mass emissions). Hence the magnitude of actual emissions can only be determined after measurement. This, however, may not serve the purpose of a reporting rule, which is to limit the burden by focusing only on significant sources of emissions. A facility can have hundreds of small emissions (as low as 3 grams per hour) and it might not be practical to measure all of them for reporting.

There are, however, two possible approaches to overcome this issue, as follows; provide an instrument performance standard such that any source determined to be emitting per the instrument is considered an emissions source, or provide a threshold value for the emitter such that any source below the threshold magnitude is not considered an emitter.

Instrument Performance Standards

Performance standards can be provided for fugitive emissions detection instruments and usage such that all instruments follow a minimum common detection threshold. Alternatively, the AWP to Detect Leaks from Equipment standards for optical gas imaging instruments recently adopted by EPA can potentially be proposed. In such a case, all detected emissions from components subject to the proposed rule may require measurement and reporting. This avoids the necessity of specifying performance standards.

Method 21 instrumentation technology has been used for over 30 years to detect leaks. The approach uses gas concentration measurement of air and combustible gas drawn into the tip of a probe manually circumscribed on or within one centimeter along the entire potential seal surface or center of a vent to detect fugitive emissions. This original practice is required for certain regulated components that are reachable with the hand-held leak detection instrument used while standing on the ground or fixed platform accessible by stairs (i.e. does not require climbing ladders, standing on stools or use of bucket-lift trucks to access components). In a study conducted by API at seven California refineries[7] with over five years of measured data (11.5 million data points), it was found that 0.13 percent of the components contributed over 90 percent of the controllable emissions (i.e. fugitive or vented emissions that can be mitigated once detected). Given the fact that only a small number of sources contribute to the majority of emissions, it is important for this proposed supplemental rule to detect and quantify leaking sources beyond the scope of Method 21.

In a typical Method 21 program the costs of conducting emissions detection remain the same during each recurring study period. This is because the determination of whether a potential source is emitting or not is made only after every regulated source is screened for emissions as described above. The OVA/TVA requires the operator to physically access the emissions source with the probe and thus is much more time intensive than using the optical gas imaging instrument. Optical gas imaging instruments were found to be more cost effective for leak detection for the proposed supplemental rule as these instruments are able to scan hundreds of source components quickly, including components out of reach for an OVA/TVA.

The EPA Alternative Work Practice (AWP) promulgated the use of optical gas imaging instruments that can detect in some cases emissions as small as 1 gram per hour. The AWP requires technology effectiveness of emissions statistically equivalent to 60 grams/hour on a bi-monthly screening frequency, i.e. the technology should be able to routinely detect all emissions equal to or greater than 60 grams/hour. EPA determined by Monte Carlo simulation that 60 grams/hour leak rate threshold and bi-monthly monitoring are equivalent to existing work practices (Method 21). To implement the technology effectiveness, the AWP requires that the detection instrument meet a minimum detection sensitivity mass flow rate. For the purposes of the proposed supplemental rule, such a performance standard could be adapted for the detection of natural gas emissions with methane as the predominant component (it should be noted that Method 21 is specifically meant for VOCs and HAPs and not for methane). A detailed discussion on the available instruments and standards for methane emission detection and quantification are presented in Appendix O.

Fugitive Emissions Threshold

One alternative to determining an emission source is to provide a mass emissions threshold for the emitter. In such a case, any source that emits above the threshold value would be considered an emitter. For portable VOC monitoring instruments that measure emission concentrations a concentration threshold equivalent to a mass threshold can be provided. However, the concentration measurement is converted to an equivalent mass value using SOCMI correlation equations, which were developed from petroleum refinery and petrochemical plant data. As discussed above, these SOCMI factors are not proposed for this supplemental rule. In the case of an optical imaging instrument, which does not provide the magnitude of emissions, either concentration or mass emissions, quantification would be required using a separate measurement instrument to determine whether a source is an emitter or not. This could be very cost prohibitive for the purposes of this rule.

[7] Hal Taback Company *Analysis of Refinery Screening Data*, American Petroleum Institute, Publication Number 310, November 1997.

ii. Duration of Fugitive Emissions

Fugitive emissions by nature occur randomly within the facility. Therefore, there is no way of knowing when a particular source started emitting. If the potential monitoring method requires a one time fugitive emissions detection and measurement, then assumptions will have to be made regarding the duration of the emissions. There are several potential options for calculating the duration of emissions. If a component fugitive emission is detected, total emissions from each source could be quantified under one of the following three scenarios: 1) if a facility conducts one comprehensive leak survey each reporting period, applicable component leaker emissions factors could be applied to all specific component emissions sources and emissions quantified based on emissions occurring for an entire reporting period; 2) if a facility conducts two comprehensive leak surveys during a single reporting period, applicable component leaker emissions factors could be applied to all component emissions sources. If a specific emission source is found not leaking in the first survey but leaking in the second survey, emissions could be quantified from the date of the first leak survey conducted in the same reporting period forward through the remainder of the reporting period. If a specific emissions source is found leaking in the first survey but is repaired and found not leaking in the second survey, emissions could be quantified from the first day of the reporting period to the date of the second survey. If a component is found leaking in both surveys, emissions could be quantified based on an emission occurring for an entire reporting period; 3) if a facility conducts multiple comprehensive leak surveys during the same reporting period, applicable component leaker emissions factors could be applied to component emissions sources. Each specific source found leaking in one or more surveys is quantified for the period from a prior finding of no leak (or beginning of the reporting period) to a subsequent finding of no leak (or end of the reporting period). If a component is found leaking in all surveys, emissions could be quantified based on an emissions occurring for an entire reporting period.

iii. Fugitive and Vented Emissions at Different Operational Modes

If a reporting program relies on a one time or periodic measurement, the measured emissions may not account for the different modes in which a particular technology operates throughout the reporting period. This may be particularly true for measurements taken at compressors. Fugitive emissions from a compressor are a function of the mode in which the compressor is operating: i.e. offline pressurized, or offline de-pressurized. Typically, a compressor station consists of several compressors with one (or more) of them on standby based on system redundancy requirements and peak delivery capacity. When a compressor is taken offline it may be kept pressurized with natural gas or de-pressurized. When the compressor is offline and kept pressurized, fugitive and vented emissions result from closed blowdown valves and reciprocating compressor rod packing leaks, respectively. When the compressor is offline and depressurized, fugitive emissions result from leaking isolation valves. When operating, compressor vented emissions result from compressor seals or rod packing and other components in the compressor system. In each of the compressor modes the resultant fugitive and vented emissions are significantly different. One potential approach to address this issue is that operators measure emissions for each mode the compressor is operated in and the period of time during the reporting period at which the compressor is in the different modes to account for the varying levels of fugitive and vented emissions. However, this will increase the reporting burden. Measurements will have to be taken at each mode of compressor operation and the time that the equipment is in various operational modes would also have to be tracked.

A similar issue exists with tanks where the operational parameters change more dynamically than compressors. The amount of throughput through tanks varies continuously as new hydrocarbon liquids are introduced and stored liquids are withdrawn for transportation. Unlike other equipment, the operational level of tanks cannot be categorized into a fixed and limited number of modes. This makes it all the more challenging to characterize emissions from storage tanks. One option is to require operators to use best judgment and characterize a few different modes for the storage tanks and make adjustments to the monitored emissions accordingly. A detailed discussion on the issue of operational modes, their impact on emissions monitoring, and potential options for monitoring emissions from emissions sources with varying modes of operation are can be found in Appendix M.

iv. Natural Gas Composition

When measuring fugitive and vented emissions using the various measurement instruments (high volume sampler, calibrated bags, and meters measure natural gas emissions) or using engineering estimation for vented emissions, only flow rate is measured or calculated and the individual CH_4 and CO_2 emissions are estimated from the natural gas mass emissions using natural gas composition appropriate for each facility. For this purpose, the monitoring methodologies discussed above would require that facilities use existing gas composition estimates to determine CH_4 and CO_2 components of the natural gas emissions (flare stack and storage tank vented emissions are an exception to this general rule). These gas composition estimates are assumed to be available at facilities. But this may or may not be a practical assumption. In the absence of gas composition, periodic measurement of the required gas composition for speciation of the natural gas mass emissions into CH_4 and CO_2 mass emissions could be a potential option.

In addition, GHG components of natural gas may change significantly in the facilities during the reporting period and different sources in the same facility may be emitting different compositions of natural gas. This is most prevalent in onshore production, offshore production and natural gas processing facilities. One potential option is to apply an average composition across all emissions sources for the reporting facility. Another option is to apply specific composition estimates across similar streams in the same facility. For example, in processing, the natural gas composition is similar for all streams upstream of the de-methanizer. The same is true of all equipment downstream of the de-methanizer overhead. For onshore production and offshore production monthly or quarterly samples can be taken to account for the variation in natural gas being produced from different combinations of production wells throughout the reporting period. See Appendix N for a detailed discussion on this issue.

v. **Physical Access for Leak Measurement**

All emissions measurement techniques require physical access to the leaking source. The introduction of remote leak detection technologies based on infrared (IR) light absorption by hydrocarbon gas clouds from atmospheric leaks makes leak detection quicker and possible for sources outside of arms reach from the ground or fixed platforms. Fugitive emissions from flanges, valve stems, equipment covers, etc. are generally smaller than emissions from vents. Fugitive emissions are expensive to measure where they are not accessible within arms reach from the ground or a fixed platform. For these inaccessible sources, the use of emission factors for emissions quantification may be appropriate. Vent stacks are often located out of access by operators for safety purposes, but may represent large emission sources. Where emissions are detected by optical gas imaging instruments, emissions measurement may be cost-effective using the following source access techniques:

- Short length ladders positioned on the ground or a fixed platform where OSHA regulations do not require personnel enclosure and the measurement technique can be performed with one hand;
- Bucket trucks can safely position an operator within a full surround basket allowing both hands to be used above the range of ladders or for measurement techniques requiring both hands;
- Relatively flat, sturdy roofs of equipment buildings and some tanks allow safe access to roof vents that are not normally accessible from fixed platforms or bucket trucks;
- Scaffolding is sometimes installed for operational or maintenance purposes that allow access to emission sources not normally accessible from the ground, fixed platforms and out of reach of bucket trucks.

Accessibility issues and these potential solutions are discussed in more detail in Appendix G.

7. Procedures for Estimating Missing Data

It is possible that some companies would be missing data necessary to quantify annual emissions. In the event that data are missing, potential procedures to fill the data gap are outlined below and are organized by data type.

In general, although there is always the possibility of using a previous years' data point to replace missing data in the current reporting year, this is not ideal since varying operating conditions can dramatically impact emissions estimates. Where using previous years' data are not desirable, then a reporting rule might require 100% data availability. In other words, there would be no missing data procedures provided. If any data were identified as missing, then there would be an opportunity to recollect the emissions data over the course of the current reporting period.

a. Emissions Measurement Data

Measured data can be collected by trained engineers using a high volume sampler, meter, or calibrated bag. Over the course of the data collection effort, some of the measured emissions rates could get lost temporarily or permanently due to human error, or storage errors such as lost hard-drives and records. If measured data is missing then the field measurement process may have to be repeated within the reporting period. If this proves to be impossible and the company clearly certifies that they lost the data and can justify not repeating the survey within the given reporting period, then the previous reporting period's data could be used to estimate fugitive emissions from the current reporting period.

b. Engineering Estimation Data

Engineering estimations rely on the collection of input data to the simulation software or calculations. A potential procedure for missing input data is outlined below for each type of input parameter.

- Operations logs. If operating logs are lost or damaged for a current reporting period, previous reporting period's data could be used to estimate emissions. Again, using previous years' data are not as desirable as there could be significant differences from year to year based on operating conditions.
- Process conditions data. Estimating vented emissions from acid gas removal vent stacks, blowdown vent stacks, dehydrator vent stacks, natural gas driven pneumatic valve bleed devices, natural gas driven pneumatic pumps, and storage tanks requires data on the process conditions (e.g., process temperature, pressure, throughputs, and vessel volumes). If, for any reason, these data are incomplete or not available for the current reporting period, field operators or engineers could recollect data wherever possible. If this data cannot be collected, then relevant parameters for estimation of emissions can be used from previous reporting period. However, where possible current reporting period parameters should be used for emissions estimation due to the reasons listed above.

c. Emissions Estimation Data for Storage Tanks and Flares

Emissions from storage tanks and flares might require a combination of both direct measurement and engineering estimation to quantify emissions. In such cases the storage tank emissions calculation requires the measurement of "emissions per throughput" data. If this data is missing then the previous year's estimate of "emissions per throughput" measured data could be used with current period throughput of the storage tank to calculate emissions.

Calculating emissions from flares requires the volume of flare gas measured using a meter. If these data are missing then the flare gas in the current reporting period could be estimated by scaling the flare gas volume from previous reporting period by adjusting it for current period throughput of the facility.

d. Emissions Estimation Data Using Emissions Factors

If population emissions factors are used then the only data required is activity data. In such a case missing data should be easily replaceable by undertaking a counting exercise for locations from which the data is missing. Alternatively, previous reporting period activity data can be used to fill in missing data. However, if facility and/ or equipment modifications have resulted in increase or decrease in activity data count then this may not be a feasible approach.

If leaker emissions factors are used then activity data will have to be collected using some form of fugitive emissions detection. In such case, missing data may not be easily replaceable. Previous period reported activity data may be used but it may not be representative of current period emissions. A detection survey to replace missing data may be warranted.

8. QA/QC Requirements

a. Equipment Maintenance

Equipment used for monitoring, both emissions detection and measurement, should be calibrated on a scheduled basis in accordance with equipment manufacturer specifications and standards. Generally, such calibration is required prior to each monitoring cycle for each facility. A written record of procedures needed to maintain the monitoring equipment in proper operating condition and a schedule for those procedures could be part of the QA/QC plan for the facility.

An equipment maintenance plan could be developed as part of the QA/QC plan. Elements of a maintenance plan for equipment could include the following:

- Conduct regular maintenance of monitoring equipment.
    - Keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures;
    - Keep a record of all testing, maintenance, or repair activities performed on any monitoring instrument in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring instrument and records of any corrective actions associated with a monitor's outage period.

b. Data Management

Data management procedures could be included in the QA/QC Plan. Elements of the data management procedures plan are as follows:

- Check for temporal consistency in production data and emission estimate. If outliers exist, can they be explained by changes in the facility's operations, etc.?
    - A monitoring error is probable if differences between annual data cannot be explained by:
        - Changes in activity levels,
        - Changes concerning monitoring methodology,
        - Changes concerning change in equipment,

- Changes concerning the emitting process (e.g. energy efficiency improvements).[8]

- Determine the "reasonableness" of the emission estimate by comparing it to previous year's estimates and relative to national emission estimate for the industry:
    - Comparison of emissions by specific sources with correction for throughput, if required,
    - Comparison of emissions at facility level with correction for throughput, if required,
    - Comparison of emissions at source level or facility level to national or international reference emissions from comparable source or facility, adjusted for size and throughput,
    - Comparison of measured and calculated emissions.[9]

- Maintain data documentation, including comprehensive documentation of data received through personal communication:
    - Check that changes in data or methodology are documented

c. Calculation checks

Calculation checks could be performed for all reported calculations. Elements of calculation checks could include:

- Perform calculation checks by reproducing a representative sample of emissions calculations or building in automated checks such as computational checks for calculations:
    - Check whether emission units, parameters, and conversion factors are appropriately labeled,
    - Check if units are properly labeled and correctly carried through from beginning to end of calculations,
    - Check that conversion factors are correct,
    - Check the data processing steps (e.g., equations) in the spreadsheets,
    - Check that spreadsheet input data and calculated data are clearly differentiated
    - Check a representative sample of calculations, by hand or electronically,
    - Check some calculations with abbreviated calculations (i.e., back of the envelope checks),
    - Check the aggregation of data across source categories, business units, etc.,

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[8] Official Journal of the European Union, August 31, 2007. Commission Decision of 18 July 2007, "Establishing guidelines for the monitoring and reporting of GHG emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council. Available at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2007:229:0001:0085:EN:PDF.

[9] Official Journal of the European Union, August 31, 2007. Commission Decision of 18 July 2007, "Establishing guidelines for the monitoring and reporting of GHG emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council. Available at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2007:229:0001:0085:EN:PDF.

- When methods or data have changed, check consistency of time series inputs and calculations.[10]

9. Reporting Procedure

The following reporting requirements could be considered for a mandatory reporting rule;

a) Some fugitive emissions by nature occur randomly within the facility, therefore, where emissions are reported on an annual basis, it may not be possible to determine *when* the fugitive emissions began. As discussed in more detail in Section I ii, under these circumstances, annual emissions could be determined assuming that the fugitive emissions were continuous from the beginning of the reporting period or from the last recorded not leaking in the current reporting period and until the fugitive emissions is repaired or the end of the reporting period.

(b) There are potentially hundreds (and in some cases) thousands of emissions sources in a facility. Typically, from practical experience in the Natural Gas STAR Program 10 percent of the potential emissions sources have been found to be emitting the large majority of the emissions. Reporting of such large numbers of emissions estimates may not be practical. One way to minimize the reporting burden would be to have facilities report emissions at the individual source type level, i.e. emissions from each source type can be reported in the aggregate. For example, a facility with multiple reciprocating compressors may report emissions from all reciprocating compressors as an aggregate number. The disadvantage to this approach would be that there would not be a distinction in the reported data between vented emissions and fugitive emissions. Although such distinctions may be of interest to the reporter, as different mitigation opportunities may exist for intentional and unintentional releases, it may not be necessary for the integrity of a reporting program, and therefore aggregate reporting may be sufficient.

(c) Due to the point-in-time nature of direct measurements, reports of annual emissions levels should take into account equipment operating hours according to standard operating conditions and any significant operational interruptions and shutdowns, to convert direct measurement to an annual figure.

(d) The facilities that cross the potential threshold for reporting could report the following information to EPA;

(1) Emissions monitored at an aggregate source level for each facility, separately identifying those emissions that are from standby sources. In several onshore natural gas processing plants CO_2 is being capture for Enhanced Oil Recovery operations. Therefore, these CO_2 emissions may have to be separately accounted for in the reporting.

[10] U.S. EPA 2007. Climate Leaders, Inventory Guidance, Design Principles Guidance, Chapter 7 "Managing Inventory Quality". Available at http://www.epa.gov/climateleaders/documents/resources/design_princ_ch7.pdf.

(2) Activity data, such as the number of sources monitored, for each aggregated source type level for which emissions will be reported.

(3) The parameters required for calculating emissions when using engineering estimation methods.

10. Verification of Reported Emissions

As part of the data verification requirements, the owner or operator could submit a detailed explanation of how company records of measurements are used to quantify fugitive and vented emissions measurement within 7 days of receipt of a written request from EPA or from the applicable State or local air pollution control agency (the use of electronic mail can be made acceptable).

Appendix A: Segregation of Emissions Sources using the Decision Process

The tables provided in this appendix represent the outcome of the decision process used to identify a starting list of potential sources that can be included in the proposed rule. The decision process was applied to each emission source in the natural gas segment of the U.S. GHG Inventory. The petroleum onshore production segment has emission sources that either are equivalent to their counter-parts in the natural gas onshore production segment or fall in the exclusion category. Petroleum transportation was not analyzed further due to the level of emissions and refineries are treated separately in Subpart Y.

Sources Contributing to 80% of Fugitive and Vented Emissions from Each Sector

Source	Offshore Production	Onshore Production	Processing	Transmission	Storage	LNG Storage	LNG Import and Export	Distribution
Separators		4%						
Meters/Piping		4%						
Small Gathering Reciprocating Comp.		2%						
Pipeline Leaks		7%						
CBM Powder River		2%						
Pneumatic Device Vents		43%	0.26%	12%	13%			
Gas Pneumatic Pumps		9%	0.49%					
Dehydrator Vents	2%	3%	3%					
Well Clean Ups (LP Gas Wells)/ Blowdowns		7%						
Plant/Station/ Platform Fugitives	4%		5%		16%	14%	3%	
Reciprocating Compressors			48%	40%	45%	54%	14%	
Centrifugal Compressors	22%		16%	8%	6%	19%	4%	
Acid Gas Removal Vents			2%					
Vessel Blowdowns/Venting			6%					
Routine Maintenance/Upsets - Pipeline venting				10%				
Station venting				8%			2%	
M&R (Trans. Co. Interconnect)				4%				
Pipeline Leaks Mains								36%
Services								16%
Meter/Regulator (City Gates)								37%
Residential Customer Meters								
Flare stacks	1%							
Non-pneumatic pumps	0.03%							
Open ended lines	0.005%							
Pump seals	0.41%							
Storage tanks	50%							
Wellhead fugitive emissions					4%			
Well completions		0.0004%						
Well workovers		0.04%						

NOTE: Pink cells represent sources that were included over riding the decision tree process. Blue cells represent sources that are not present in the respective segments. Green cells represent sources that are not explicitly identified in the U.S. GHG Inventory; however, these sources may potentially be found in the respective segments. Blank cells are sources in the U

Inventory of Methane Emissions from Natural Gas Systems

PRODUCTION OFFSHORE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Amine gas sweetening unit	0.2	80	0.01%	0.0001%	NE	c	c	a	n
Boiler/heater/burner	0.8	332	0.05%	0.0002%		c	d	a	n
Diesel or gasoline engine	0.01	6	0.001%	0.000004%		c	d	a	n
Drilling rig	3	1,134	0.17%	0.001%		c	d	a	n
Flare	24	9,583	1.47%	0.01%		c	c	b	n
Centrifugal Seals	358	144,547	22%	0.10%		a	a	a	b
Connectors	0.8	309	0.05%	0.0002%		b	b	b	b
Flanges	2.38	960	0.15%	0.001%		b	b	b	b
OEL	0.1	32	0.005%	0.00002%		b	b	b	b
Other	44	17,576	2.70%	0.01%		b	b	b	b
Pump Fugitive	0.5	191	0.03%	0.0001%		b	b	a	b
Valves	19	7,758	1%	0.01%		b	b	b	b
Glycol dehydrator	25	9,914	2%	0.01%		c	c	b	n
Loading operation	0.1	51	0.01%	0.00004%		c	d	a	n
Separator	796	321,566	49%	0.23%		c	c	b	b
Mud degassing	8	3,071	0.47%	0.002%		c	d	a	n
Natural gas engines	191	77,000	12%	0.05%					
Natural gas turbines	3	1,399	0.22%	0.001%					
Pneumatic pumps	7	2,682	0.41%	0.002%		c	b	a	b
Pressure/level controllers	2	636	0.10%	0.0005%		c	b	a	b
Storage tanks	7	2,933	0.45%	0.002%		c	c	a	n
VEN exhaust gas	121	48,814	8%	0.03%		c	c	b	n

NOTES: Leak Detection: a – Yes and cost effective; b – Yes but cost burden c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

PRODUCTION ONSHORE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Normal Fugitives									
Gas Wells									
Non-associated Gas Wells (less Unconventional)	2,682	1,083,539	2%	0.77%	376784	b	b	b	b
Unconventional Gas Wells	69	27,690	0.06%	0.02%	35440	a	b	b	b
Field Separation Equipment					0				
Heaters	1,463	591,023	1%	0.42%	89720	a	b	b	b
Separators	4,718	1,906,206	4%	1%	247919	b	b	b	b
Dehydrators	1,297	524,154	1%	0.37%	37925	a	b	b	b
Meters/Piping	4,556	1,840,683	4%	1%	315487	b	b	b	b
Gathering Compressors					0				
Small Reciprocating Comp.	2,926	1,182,062	2%	1%	28490	a	a	b	b
Large Reciprocating Comp.	664	268,133	0.54%	0.19%	112	a	a	b	b
Large Reciprocating Stations	45	18,178	0.04%	0.01%	14	a	a	b	b
Pipeline Leaks	8,087	3,267,306	7%	2%	392624	b	b	b	n
Vented and Combusted									
Drilling and Well Completion									
Completion Flaring	0	188	0.00%	0.00%	597	c	c	c	n
Well Drilling	96	38,946	0.08%	0.03%	35600	c	c	a	y
Coal Bed Methane									
Powder River	2,924	1,181,246	2%	1%	396920	c	c	a	n
Black Warrior	543	219,249	0.44%	0.16%		c	c	a	n
Normal Operations									
Pneumatic Device Vents	52,421	21,178,268	43%	15%		c	b	a	b
Chemical Injection Pumps	2,814	1,136,867	2%	0.81%		c	b	a	b
Kimray Pumps	11,572	4,674,913	9%	3%		c	b	a	n
Dehydrator Vents	3,608	1,457,684	3%	1%		c	c	a	n
Condensate Tank Vents									
Condensate Tanks without Control Devices	1,225	494,787	1%	0.35%		c	c	a	b
Condensate Tanks with Control Devices	245	98,957	0.20%	0.07%		c	d	a	b
Compressor Exhaust Vented									
Gas Engines	11,680	4,718,728	9%	3%					
Well Workovers									
Gas Wells	47	18,930	0.04%	0.01%		c	d	b	y
Well Clean Ups (LP Gas Wells)	9,008	3,639,271	7%	3%		c	d	a	n
Blowdowns									
Vessel BD	31	12,563	0.03%	0.01%		c	d	a	n
Pipeline BD	129	52,040	0.10%	0.04%		c	d	a	b
Compressor BD	113	45,648	0.09%	0.03%		c	d	a	n
Compressor Starts	253	102,121	0.20%	0.07%		c	d	a	n
Upsets									
Pressure Relief Valves	29	11,566	0.02%	0.01%		c	d	b	n
Mishaps	70	28,168	0.06%	0.02%		c	d	b	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

GAS PROCESSING PLANTS	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Normal Fugitives									
Plants	1,634	660,226	5%	0.47%		a	a	b	b
Recip. Compressors	17,351	7,009,755	48%	5%		a	a	b	b
Centrifugal Compressors	5,837	2,358,256	16%	2%		a	a	b	b
Vented and Combusted									
Normal Operations									
Compressor Exhaust									
Gas Engines	6,913	2,792,815	19%	2%					
Gas Turbines	195	78,635	1%	0.06%					
AGR Vents	643	259,592	2%	0.18%		c	c	a	n
Kimray Pumps	177	71,374	0.49%	0.05%		c	b	a	b
Dehydrator Vents	1,088	439,721	3%	0.31%		c	c	a	n
Pneumatic Devices	93	37,687	0.3%	0.03%		c	b	a	b
Routine Maintenance									
Blowdowns/Venting	2,299	928,900	6%	1%		c	d	a	n

Notes:

<u>Leak Detection</u>: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
<u>Direct Measurement</u>: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
<u>Engineering Estimate</u>: a – Exists; b – does not exist.
<u>Accessible Source</u>: y – Yes; n – No; b – Both.

TRANSMISSION	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Fugitives									
Pipeline Leaks	166	67,238	0.17%	0.05%		a	c	a	n
Compressor Stations (Transmission)									
Station	5,619	2,270,177	6%	2%		a	a	b	b
Recip Compressor	38,918	15,722,907	40%	11%		a	a	b	b
Centrifugal Compressor	7,769	3,138,795	8%	2%		a	a	b	b
M&R (Trans. Co. Interconnect)	3,798	1,534,238	4%	1%		a	a	b	b
M&R (Farm Taps + Direct Sales)	853	344,646	1%	0.25%		b	b	b	b
Vented and Combusted									
Normal Operation									
Dehydrator vents (Transmission)	105	42,329	0.11%	0.03%		c	c	a	n
Compressor Exhaust									
Engines (Transmission)	10,820	4,371,314	11%	3%					
Turbines (Transmission)	61	24,772	0.06%	0.02%					
Generators (Engines)	529	213,911	0.55%	0.15%					
Generators (Turbines)	0	60	0.0002%	0.00004%					
Pneumatic Devices Trans + Stor									
Pneumatic Devices Trans	11,393	4,602,742	12%	3%		c	b	a	b
Routine Maintenance/Upsets									
Pipeline venting	9,287	3,752,013	10%	3%		c	d	a	b
Station venting Trans + Storage									
Station Venting Transmission	7,645	3,088,575	8%	2%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

STORAGE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Fugitives									
Compressor Stations (Storage)									
Station	2,801	1,131,492	16%	1%		a	a	b	b
Recip Compressor	8,093	3,269,454	45%	2%		a	a	b	n
Centrifugal Compressor	1,149	464,354	6%	0.33%		a	a	b	n
Wells (Storage)	695	280,891	4%	0.20%		a	a	b	y
Vented and Combusted									
Normal Operation									
Dehydrator vents (Storage)	217	87,514	1%	0.06%		c	c	a	n
Compressor Exhaust									
Engines (Storage)	1,092	441,108	6%	0.31%					
Turbines (Storage)	9	3,680	0.05%	0.003%					
Pneumatic Devices Trans + Stor									
Pneumatic Devices Storage	2,318	936,324	13%	1%		c	b	a	b
Station venting Trans + Storage									
Station Venting Storage	1,555	628,298	9%	0.45%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

LNG STORAGE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
LNG Storage									
LNG Stations	552	222,824	14%	0.16%		b	b	b	b
LNG Reciprocating Compressors	2,084	842,118	54%	1%		b	b	b	b
LNG Centrifugal Compressors	715	288,756	19%	0.21%		b	b	b	b
LNG Compressor Exhaust									
LNG Engines	172	69,632	5%	0.05%					
LNG Turbines	1	261	0.02%	0.0002%					
LNG Station venting	306	123,730	8%	0.09%		c	d	a	n

LNG IMPORT AND EXPORT TERMINALS	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
LNG Import Terminals									
LNG Stations	22	8,880	3%	0.01%		b	b	b	b
LNG Reciprocating Compressors	105	42,347	14%	0.03%		b	b	a	b
LNG Centrifugal Compressors	27	10,820	4%	0.01%		b	b	a	b
LNG Compressor Exhaust									
LNG Engines	586	236,647	78%	0.17%					
LNG Turbines	3	1,370	0.45%	0.001%					
LNG Station venting	12	4,931	2%	0.004%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.
Export Terminals are not currently included in the U.S. GHG Inventory, therefore they were not included in this analysis. There is currently only one export terminal, located in Alaska.

DISTRIBUTION	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Normal Fugitives									
Pipeline Leaks									
Mains - Cast Iron	9,222	3,725,675	14%	3%		a	b	b	n
Mains - Unprotected steel	6,515	2,632,209	10%	2%		a	b	b	n
Mains - Protected steel	1,422	574,529	2%	0.41%		a	b	b	n
Mains - Plastic	6,871	2,775,759	10%	2%		a	b	b	n
Total Pipeline Miles			36%	7%					
Services - Unprotected steel	7,322	2,957,970	11%	2%		a	b	b	n
Services Protected steel	2,863	1,156,473	4%	1%		a	b	b	n
Services - Plastic	315	127,210	0.47%	0.09%		a	b	b	n
Services - Copper	47	19,076	0.07%	0.01%		a	b	a	n
Total Services			16%	3%					
Meter/Regulator (City Gates)			37%	7%					
M&R >300	5,037	2,034,986	7%	1%	3,198	a	a	b	b
M&R 100-300	10,322	4,170,101	15%	3%	12,325	b	b	b	b
M&R <100	249	100,480	0.37%	0.07%	6,587	a	c	b	b
Reg >300	5,237	2,115,726	8%	2%	3,693	a	a	b	b
R-Vault >300	25	9,976	0.04%	0.01%	2,168	a	a	b	b
Reg 100-300	4,025	1,625,929	6%	1%	11,344	b	b	b	b
R-Vault 100-300	8	3,247	0.01%	0.002%	5,097	a	c	b	b
Reg 40-100	306	123,586	0.45%	0.09%	33,578	b	b	b	b
R-Vault 40-100	23	9,115	0.03%	0.01%	29,776	b	b	b	b
Reg <40	17	6,690	0.02%	0.005%	14,213	b	b	b	b
Customer Meters									
Residential	5,304	2,142,615	8%	2%	37017342	b	b	a	y
Commercial/Industry	203	81,880	0.30%	0.06%	4231191	b	b	a	y
Vented									
Rountine Maintenance									
Pressure Relief Valve Releases	63	25,346	0.09%	0.02%		c	d	b	n
Pipeline Blowdown	122	49,422	0.18%	0.04%		c	d	a	n
Upsets									
Mishaps (Dig-ins)	1,907	770,405	3%	1%		c	d	b	n

NOTES: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

Appendix B: Development of revised estimates for four U.G. GHG Inventory emissions sources

Well Completion and Workover Venting

This discussion describes the methods used to estimate total U.S. methane emissions from well completion and workover venting. For the purposes of this estimate, it is assumed that all unconventional wells are completed with hydraulic fracturing of tight sand, shale or coal bed methane formations (i.e. completions involving high rate, extended back-flow to expel fracture fluids and sand proppant, which also leads to greater gas venting or flaring emissions than conventional well completions). It is understood that not all unconventional wells involve hydraulic fracturing, but some conventional wells are hydraulically fractured, which is assumed to balance the over-estimate.

►*Estimate the Number of Gas Wells Completed*
The data in Exhibit B-1 was extracted from EPA (2008)[11].

Exhibit B-1. 2007 Natural Gas Wells

Year	Approximate Number of Onshore Unconventional Gas Wells	Approximate Number of Onshore Conventional Gas Wells	Total Number of Gas Wells (both conventional and unconventional)
2006	35,440	375,601	411,041
2007	41,790	389,245	431,035

Exhibit B-1 was used to calculate that there was a net increase of 19,994 wells (both conventional and unconventional) between 2006 and 2007. Each of these wells is assumed to have been completed over the course of 2006. EPA (2008) also estimates that 35,600 gas wells were drilled in 2006. This includes exploratory wells, dry holes, and completed wells. EPA (2008) also indicates that 19,994 of those natural gas wells were drilled and completed. The difference between the 35,600 drilled and 19,994 new wells is 15,606 wells, which we assume are replaced for shut-in or dry holes. This analysis assumed that 50% of those remaining 15,606 wells were completed. Thus, the total number of gas well completions, both conventional and unconventional, was estimated to be 27,797 wells in 2006.

$$19{,}994\,wells + \left(50\% \times \left(35{,}600\,wells - 19{,}994\,wells\right)\right) = 27{,}797\,wells$$

That is 78% of the total gas wells drilled in 2006. We assumed this same percentage of completed wells applies to the year 2007. EPA (2008) estimates 37,196 gas wells were drilled in 2007, so applying this completion factor, 78% of 37,196 wells equals 29,043 gas wells completed in 2007.

►*Estimate the Number of Conventional and Unconventional Well Completions*

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[11] EPA. *U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990 – 2007*. Available online at: <http://epa.gov/climatechange/emissions/usgginv_archive.html>.

Exhibit B-1 shows a net increase of 6,350 unconventional wells from 2006 to 2007. This is 32% of the 19,994 net increase in all wells over that period. It was assumed that 32% of the estimated 29,043 well completions in 2007 (see previous section) were unconventional wells. The remaining gas well completions were assumed to be conventional wells. These results are summarized in Exhibit B-2. This analysis also assumed that all unconventional wells require hydraulic fracture upon completion.

Exhibit B-2. 2007 Completions Activity Factors

2007 Conventional Well Completions	19,819
2007 Unconventional Well Completions	9,224

►*Estimate the Number of Conventional and Unconventional Well Workovers*

GRI (1996)[12] provides activity data for 1992 on conventional workovers. It reported that 9,324 workovers were performed with 276,014 producing gas wells. This activity data was projected to 2007 using the ratio of 2007 producing gas wells to 1992 producing gas wells; as shown in Exhibit 3:

Exhibit B-3. Calculation of 2007 Conventional Workover Activity Factor

$$2007 Conventional Workovers = 1992 Conventional Workovers \times \frac{2007 Gas Wells}{1992 Gas Wells}$$

$$2007 Conventional Workovers = 9{,}324 workovers \times \frac{431{,}035 wells}{276{,}014 wells}$$

Unconventional gas wells were assumed to be re-fractured once every 10 years. Thus, the number of unconventional gas well workovers was 10% of the existing unconventional well count in 2007.

The resulting activity factors for conventional and unconventional gas well workovers are summarized in Exhibit B-4.

Exhibit B-4. Summary of 2007 Workover Activity Factors

2007 Conventional Well Workovers	$9{,}324 workovers \times \frac{431{,}035 wells}{276{,}014 wells} =$	14,569
2007 Unconventional Well Workovers	$10\% \times 41{,}790 wells =$	4,179

►*Estimate the Emission Factor for Conventional Well Completions*

[12] GRI. *Methane Emissions from the Natural Gas Industry*. 1996. Available online at: <http://epa.gov/gasstar/tools/related.html>.

GRI (1996) estimated that conventional well completions emit 0.733 Mcf of methane each. GRI (1996) assumed that all completion flowback was flared at 98% combustion efficiency and the produced gas was 78.8% methane by volume. This analysis estimated the amount of gas sent to the flare by dividing the reported GRI factor by the 2% un-combusted gas. The resulting emission factor for conventional well completions was **36.65 Mcf of methane/completion**.

►*Estimate the Emission Factor for Conventional Well Workovers*
The GRI (1996) emission factor for well completions was accepted for this analysis. That emission factor is **2.454 Mcf of methane/workover** for conventional wells.

►*Estimate the Emission Factor for Unconventional Well Completions*
The emission factor for unconventional well completions was derived using several experiences presented at Natural Gas STAR technology transfer workshops.

One presentation[13] reported that the emissions from all unconventional well completions were approximately 45 Bcf using 2002 data. The emission rate per completion can be back-calculated using 2002 activity data. API *Basic Petroleum Handbook*[14] lists that there were 25,520 wells completed in 2002. Assuming Illinois, Indiana, Kansas, Kentucky, Michigan, Missouri, Nebraska, New York, Ohio, Pennsylvania, Virginia, and West Virginia produced from low-pressure wells that year, 17,769 of those wells can be attributed to onshore, non-low-pressure formations. The Handbook also estimated that 73% (or 12,971 of the 17,769 drilled wells) were gas wells, but are still from regions that are not entirely low-pressure formations. The analysis assumed that 60% of those wells are high pressure, tight formations (and 40% were low-pressure wells). Therefore, by applying the inventory emission factor for low-pressure well cleanups (49,570 scf/well-year[11])approximately 5,188 low-pressure wells emitted 0.3 Bcf .

$$40\% \times 12{,}971 wells \times \frac{49{,}570 scf}{well} \times \frac{1 Bcf}{10^9 scf} \approx 0.3 Bcf$$

The remaining high pressure, tight-formation wells emitted 45 Bcf less the low-pressure 0.3 Bcf, which equals 44.7 Bcf. Since there is great variability in the natural gas sector and the resulting emission rates have high uncertainty; the emission rate per unconventional (high-pressure tight formation) wells were rounded to the nearest thousand Mcf.

$$\frac{44.7 Bcf}{60\% \times 12{,}971 wells} \times \frac{10^6 Mcf}{Bcf} \approx 6{,}000 Mcf / completion$$

The same Natural Gas STAR presentation[12] provides a Partner experience which shares its recovered volume of methane per well. This analysis assumes that the Partner recovers 90% of the flowback. Again, because of the high variability and uncertainty associated with

[13] EPA. *Green Completions*. Natural Gas STAR Producer's Technology Transfer Workshop. September 21, 2004. Available online at: <http://epa.gov/gasstar/workshops/techtransfer/2004/houston-02.html>.
[14] API. *Basic Petroleum Data Handbook*. Volume XXIV, Number 1. February, 2004.

different completion flowbacks in the gas industry, this was estimated only to the nearest thousand Mcf – 10,000 Mcf/completion.

A vendor/service provider of "reduced emission completions" shared its experience later in that same presentation[12] for the total recovered volume of gas for 3 completions. Assuming that 90% of the gas was recovered, the total otherwise-emitted gas was back-calculated. Again, because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was rounded to the nearest hundred Mcf – 700 Mcf/completion.

The final Natural Gas STAR presentation[15] with adequate data to determine an average emission rate also presented the total flowback and total completions and re-completions. Because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was rounded to the nearest 10,000 Mcf – 20,000 Mcf/completion.

This analysis takes the simple average of these completion flowbacks for the unconventional well completion emission factor: **9,175 Mcf/completion**.

►*Estimate the Emission Factor for Unconventional Well Workovers ("re-completions")*
The emission factor for unconventional well workovers involving hydraulic re-fracture ("re-completions") was assumed to be the same as unconventional well completions; calculated in the previous section.

►*Estimate the Total National Emissions (disregarding reductions)*
The estimated activity factors were multiplied by the associated emission factors to estimate the total emissions from well completions and workovers in the U.S. for 2007. This does not reflect reductions due to control technologies such as flares or bringing portable treatment units onsite to perform a practice called "reduced emission completions". The results are displayed in Exhibit B-5 below.

Exhibit B-5. Summary of Results: U.S. Completion and Workover Venting 2007

Activity	Activity Factor	Emission Factor	Total U.S. Emissions
Conventional Gas Well Completions	19,819 completions	36.65 Mcf/completion	~0.7 Bcf
Conventional Gas Well Workovers	14,569 workovers	2.454 Mcf/workover	<< 1 Bcf
Unconventional Gas Well Completions	9,224 completions	9,175 Mcf/completion	~85 Bcf
Unconventional Gas Well Workovers	4,179 workovers	9,175 Mcf/workover	~38. Bcf
Note: The emission factors and calculated emissions as presented in this table were rounded independently.		**TOTAL:**	**~120 Bcf**

[15] EPA. *Reducing Methane Emissions During Completion Operations*. Natural Gas STAR Producer's Technology Transfer Workshop. September 11, 2007. Available online at: <http://epa.gov/gasstar/documents/workshops/glenwood-2007/04_recs.pdf>.

The final U.S. emissions were rounded to **120 Bcf**.

Well Blowdown Venting for Liquid Unloading

This discussion describes the methods used to estimate total U.S. methane emissions from low-pressure well blowdowns for liquid unloading.

►*Estimate the Fraction of Conventional Wells that Require Liquid Unloading*

This analysis assumed that the survey of 25 well sites conducted by GRI (1996) for the base year 1992 provides representative data for the fraction of conventional wells requiring unloading. That is, 41.3% of conventional wells required liquid unloading.

►*Calculate Emissions per Blowdown*

This analysis used a fluid equilibrium calculation to determine the volume of gas necessary to blow out a column of liquid for a given well pressure, depth, and casing diameter. The equation for this calculation is available in an EPA, Natural Gas STAR technical study[16]. The equation is displayed in Exhibit B-6.

Exhibit B-6. Well Blowdown Emissions for Liquid Unloading

$$V_v = \left(0.37 \times 10^{-6}\right) \times D^2 \times h \times P$$

where,

V_v	=	Vent volume (Mcf/blowdown)
D	=	casing diameter (inches)
h	=	well depth (feet)
P	=	shut-in pressure (psig)

A combination of GASIS[17] and LASSER[18] databases provided well depth and shut-in pressures for a sample of 35 natural gas basins. The analysis assumed an average casing diameter of 10-inches for all wells in all basins.

►*Estimate the Annual Number of Blowdowns per Well that Require Unloading*

For wells that require liquid unloading, multiple blowdowns per year are typically necessary. A calibration using the equation in the previous section was performed using public data for the shared experiences of two Natural Gas STAR Partners.

[16] EPA. *Installing Plunger Lift Systems in Gas Wells: Lessons Learned from Natural Gas STAR Partners*. October, 2003. Available online at: <http://epa.gov/gasstar/documents/ll_plungerlift.pdf>.
[17] DOE. *GASIS, Gas Information System*. Release 2 – June 1999.
[18] LASSER™ database.

One Partner reported that it recovered 4 Bcf of emissions using plunger lifts with "smart" automation (to optimize plunger cycles) on 2,200 wells in the San Juan basin[19]. Using the data for San Juan basin in the equation in Exhibit B-6 required approximately 51 blowdowns per well to match the 4 Bcf of emissions.

Another Partner reported that it recovered 12 MMcf of emissions using plunger lifts on 19 wells in Big Piney[16]. Using information for the nearest basin in the equation in Exhibit B-6 required approximately 11 blowdowns per well to match the 12 MMcf of emission.

The simple average of 31 blowdowns per well requiring liquid unloading was used in the analysis to determine the number of well blowdowns per year by basin.

►*Estimate the Percentage of Wells in Each Basin that are Conventional*
GASIS and LASSER provided approximate well counts for each basin and GRI provided the percentage of conventional wells requiring liquid unloading for 35 sample basins. However, many of those basins contain unconventional wells which will not require liquid unloading. EIA posts maps that display the concentration of conventional gas wells in each basin[20], the concentration of gas wells in tight formations by basin[21], and the concentration of coal bed methane gas wells by basin[22]. These maps were used to estimate the approximate percentage of wells that are conventional in each basin. These percentages ranged from 50% to 100%.

►*Estimate Emissions from 35 Sample Basins*
The total well counts for each basin were multiplied by the percentage of wells estimated to be conventional for that basin to estimate the approximate number of conventional wells in each of the basins. The resulting conventional well counts were multiplied by the percentage of wells requiring liquid unloading, as estimated by the GRI survey (41.3%). The number of wells in each basin that require liquid unloading were multiplied by an average of 31 blowdowns/well to determine the number of well blowdowns for each basin. The emissions per blowdown, as calculated using the equation in Exhibit B-6, were then multiplied by the number of blowdowns for each basin to estimate the total well venting emissions from each of the 35 sample basins due to liquid unloading. Using the GRI estimate that the average methane content of production segment gas is 78.8% methane by volume, the total methane emissions from the sample of 35 basins were calculated to be 149 Bcf.

►*Extrapolate Sample Data to Entire U.S.*
The sample of 35 gas well basins represented only 260,694 conventional gas wells. EPA's national inventory[23]. estimated that there were 389,245 conventional gas wells in 2007. The

[19] EPA. *Natural Gas STAR Partner Update: Spring 2004*. Available online at: <http://epa.gov/gasstar/documents/partner-updates/spring2004.pdf>.
[20] EIA. *Gas Production in Conventional Fields, Lower 48 States*. Available online at: <http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm>.
[21] EIA. *Major Tight Gas Plays, Lower 48 States*. Available online at: <http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm>.
[22] EIA. *Coal Bed Methane Fields, Lower 48 States*. Available online at: <http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm>.
[23] EPA. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006*. Available online at http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

emission estimates were extrapolated to the entire nation by the ratio of the conventional gas wells. The final resulting emissions from gas well venting due to liquid unloading were estimated to be **223 Bcf**.

This estimate does not include emission reductions from control methods such as plunger lifts, plunger lifts with "smart" automation, or other artificial lift techniques.

Appendix C: Development of threshold analysis

As the main text has pointed out the oil and natural gas sector includes hundreds, and in some cases thousands, of players, many of them with few emission sources as well as ones with over 160 emission sources. Requiring all participants to report would impose a large burden on the industry and also on EPA. A rule-of-thumb, substantiated by survey work, is that 80 percent of the emissions come from 10 percent of the analysis. Therefore, a threshold analysis was performed so that the large emitters would be identified and small insignificant emitters could be excluded from the reporting requirement.

Threshold Analysis for Onshore Production

The following points lay out the methodology for the threshold analysis for the onshore oil and natural gas production segment

- Threshold analysis for onshore (including EOR) production sector was estimated per unique operator per basin.
- The oil and gas production volumes per operator per basin were obtained from the LASSER™ database 2006. The total onshore oil and gas production process and combustion (CH_4 and CO_2) emissions estimated in the U.S. GHG Inventory 2006 were apportioned to each operator based on the oil or gas production volumes.
- The U.S. GHG Inventory emissions estimates for the following sources were revised: well completions, well unloading, and well clean-ups. Natural Gas STAR emission reductions reported by partners from these sources are higher than the current inventory emission estimates. As a result emissions from these sources are currently under-estimated in the inventory. The methodology used to revise these emissions estimates can be found in Appendix B. In addition, emissions from storage tanks and flares as estimated in the U.S. GHG Inventory were included for the threshold analysis. These sources also have Natural Gas STAR reductions that are higher than the emissions estimates in the inventory. However, though these source emissions estimates were included, no new estimates were developed for lack of publicly available data.
- The combustion emissions from the following sources were estimated separately as they are not included in the U.S GHG Inventory: heater-treater, well drilling (oil and gas), dehydrator reboiler, and acid gas removal (AGR) units.
    - **Heater-Treaters Combustion:** The total national combustion emissions from heater-treaters were calculated by estimating the total fuel required to increase the temperature by 10^oF of total oil produced in 2006. CO_2 and N_2O combustion emission factor for natural gas from the API compendium 2004 was used to estimate the total national CO_2 and N_2O emissions. The total emissions were apportioned to the operators based on their oil production volumes.
    - **Dehydrator and AGR Combustion:** The total national combustion emissions from dehydrators and AGR units were estimated by applying the fuel consumption factor of 17 Mcf of natural gas/ MMcf of gas throughput,

obtained from the EPA's Lesson Learned 2006, *Replacing Gycol Dehydrators with Desiccant Dehydrator*. The total national throughput was assumed to be equal to the total national gas produced obtained from the EIA. CO_2 and N_2O combustion emission factor for natural gas from the API compendium 2004 was used to estimate the total national CO_2 and N_2O emissions. The total emissions were apportioned to the operators based on their gas production volumes.
    - **Well Drilling Combustion:** The total national combustion emissions from well drilling was estimated by multiplying the emissions per well drilled with the national number of oil and gas wells drilled in the year 2006. The emissions per well was estimated by assuming the use of two 1500 hp diesel engines over a period of 90 days to drill each well. CO_2 and N_2O combustion emission factor for diesel from the API compendium 2004 was used to estimate the total national CO_2 and N_2O emissions. The total emissions were apportioned to different states based on the percentage of rigs present in the state. The number of rigs per state was obtained from Baker Hughes. The total oil and gas well drilling combustion emissions per state was apportioned to each operator in the state based on their oil and gas volumes respectively.
- The total barrels of oil produced per field and operator using EOR operations was obtained from the OGJ (2006) *EOR/Heavy Oil Survey*.
- The total make-up CO_2 volume required for EOR operations was estimated using 0.29 metric tons CO_2/ bbl oil produced from EOR operations obtained from DOE, *Storing CO_2 with Enhanced Oil Recovery*. The total recycled CO_2 volumes per operator was estimated using a factor of 0.39 metric tons CO_2/bbl estimated from DOE, *Storing CO_2 with Enhanced Oil Recovery.*
- The equipment count for EOR operations was estimated by apportioning the U.S. GHG Inventory activity factors for onshore petroleum production to each field using the producing well count or throughput (bbl) based on judgment. E.g. the total number of compressors in the US used in EOR onshore production operations per field was estimated by using the ratio of the throughput per field to the national throughput and multiplying it by the total number of national compressors in onshore operations.
- The emission factors in the U.S. GHG Inventory and the re-estimated activity factors for EOR operations were used to estimate total methane emissions by volume for EOR operations. This volume was adjusted for methane composition (assumed to be 78.8% from GRI) to estimate the natural gas emissions from EOR operations. The composition of 97% CO_2 and 1.7% CH_4 was applied to the total natural gas emissions to estimate CO_2 and CH_4 emissions from vented, fugitive and combustion sources covered in the U.S. GHG Inventory . 97% CO_2 and 1.7% CH_4 composition was obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology.*
- The following EOR emissions sources are not covered in the U.S. GHG Inventory and therefore were estimated separately:
    - Recycled injection CO_2 dehydrator vented emissions
    - Recycled injection CO_2 compressor - vented and combustion emissions
    - CO_2 injection pumps - combustion and vented emissions

- Water injection pumps – combustion emissions
- Orifice meter - vented emissions from calibration

Emissions from the above mentioned sources were calculated in the following manner:

- **Recycled CO_2 Dehydrator**: The number of dehydrators per EOR field was estimated by using the ratio of gas throughput to the number of dehydrators indicated in the GRI report and multiplying it by the recycled CO_2 volumes. The recycled dehydrator vented emissions were estimated using readjusted U.S. GHG Inventory emission factor. The GRI methane emission factor was divided by 78.8% methane composition to calculate the natural gas emission factor. The natural gas emission factor was adjusted to EOR operation using the critical density of CO2. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology* was used to estimate emissions.
- **Recycled CO_2 Injection compressor**: The recycled CO_2 injection compressor fuel gas requirement was estimated using an assumed value of 65 kWhr/metric ton CO2 injected. The assumption was based on the DOE study, *Electricity use of EOR with Carbon dioxide*. It is assumed that only 50% of the injected CO2 requires natural gas powered compressors. CH_4 and CO_2 combustion emissions were estimated by applying API compendium relevant combustion emission factors to the fuel gas used by each operator. The fuel gas consumption was estimated using the horsepower requirements of engines per operator. N_2O (CO_2e) combustion emissions were estimated by applying API compendium N_2O combustion emission factors to the fuel gas used by each plant. The number of compressor per field was estimated using an assumed number of 12 hp/ bbl of EOR produced oil. This number was obtained from *Enhanced Recovery Scoping Study* conducted by the state of California. It is assumed that a typical compressor used in EOR operations is 3000 hp. This number is obtained from DOE study, *Electricity use of EOR with Carbon dioxide*. The compressor blowdown emissions was estimated assuming one blowdown event per year, the estimated number of compressors per field, and compressor blowdown emission factor obtained from the U.S GHG inventory. The compressor blowdown emission factor was adjusted for critical CO_2 density, CO_2 and CH_4 gas composition. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology* was used to estimate emissions. .
- **CO2 Injection pumps**: The supercritical CO_2 injection pumps are assumed to be electrically driven and therefore have no combustion emissions. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (*CO_2*EOR) Injection Well Technology* was used to estimate emissions. The pump blowdown emissions were estimated assuming an internal diameter of 12 inches and length of 30 feet with a 50% void volume. The pipe length between the blowdown valve and unit valve was assumed to be 10 feet with a diameter of 5.38 inches. It is assumed that the pump and pipeline vent gas equivalent to their volume once a year during blowdown operations. The number of supercritical pumps required per field was estimated by assuming that the EOR operations use pumps with 600 hp with a throughput of 40 Mcf/day. These pump specifications were obtained from an unnamed Natural Gas STAR Partner.
- **Water injection pumps**: The injection pump fuel gas requirement was estimated using an assumed value of 6 kWhr/bbl of oil produced. The assumption was based on

the DOE study, *Electricity use of EOR with Carbon dioxide*. It is assumed that only 50% of the injection pumps are natural gas powered. CH_4 and CO_2 combustion emissions were estimated by applying API compendium (2004) relevant combustion emission factors to the fuel gas used by each operator. The fuel gas consumption was estimated using the horsepower requirements of engines per operator. N_2O (CO_2e) combustion emissions were estimated by applying API compendium N_2O combustion emission factors to the fuel gas used by each plant.

- **Orifice Meter Vented Emissions**: It is assumed that there are 5 orifice meters for each field based on data provided by an unnamed Natural Gas STAR Partner. The orifice meters are assumed to be calibrated once per year during which the volume of meter is vented to the atmosphere. The orifice meters are assumed to be 8 inches in diameter and 12 feet in length. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology* was used to estimate emissions.
- The total emissions per operator were calculated by summing up all the process and combustion emissions for EOR operations and onshore production.
- Each operators was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
    - IF(operator total emissions > 1000) then reporting
    - IF(operator total emissions > 10000) then reporting
    - IF(operator total emissions > 25000) then reporting
    - IF(operator total emissions >100000) then reporting

Threshold Analysis for Offshore Production

- Federal GOM offshore platforms, by their complex ID, and their corresponding CO_2 combustion and fugitive emissions (CO_2e), CH_4 fugitive emissions (CO_2e), CH_4 vented emissions (CO_2e), and N_2O combusted emissions (CO_2e) for the year 2000 was obtained from the MMS Goads Summary Access File "Final GOADS Emissions Summaries"
- The ratio of 2006 to 2000 Gulf of Mexico offshore productions was calculated and applied to the emissions from each platform to estimate emissions for the year 2006.
- The total number of GOM offshore production platforms was obtained from the MMS website.
- Each platform was assigned a "1" or "0" based on if it crossed an emissions threshold by running the following logic checks:
    - IF(operator total emissions > 1000) then reporting
    - IF(operator total emissions > 10000) then reporting
    - IF(operator total emissions > 25000) then reporting
    - IF(operator total emissions >100000) then reporting
- The total number of state platforms (Alaska and Pacific) was obtained from the Alaska Division of Oil and Gas and *Emery et al*[24] respectively. The number of state and federal offshore oil and gas wells for GOM, Pacific, and Alaska was obtained from the LASSER™ database. The ratio of federal GOM oil and gas wells to federal

[24] http://www.icess.ucsb.edu/iog/pubs/DrifterSimulationsFinal_v5.pdf

platforms and the number of state offshore oil and gas wells were used to estimate the state GOM platform count.

- The ratio of gas to oil platforms was obtained from the U.S GHG Inventory 2006. All the state offshore platforms were assumed to be shallow water platforms.
- The state offshore fugitive, vented and combustion emissions were estimated by applying the ratio of state to federal platforms and multiplying it by the federal offshore fugitive, vented, and combustion emissions.
- The percentage of platforms that fall within each emissions threshold (1000, 10,000, 25,000 and 100,000 metric tons CO_2e) for the federal GOM offshore was calculated and applied to the estimated state fugitive, vented, and combustion emissions to calculate the volume of state offshore emissions that fall within each threshold.
- The number of state platforms that fall within each category was estimated by taking the ratio of federal emissions to platform count within each threshold and multiplying it by the state emissions covered by each threshold.
- The emissions from state and federal offshore platforms were summed up to estimate the total emissions from offshore operations

Threshold Analysis for Processing

- US gas processing plants, plant throughputs, and equipment count per plant were obtained from the OGJ (2006). 2005 and 2006 emissions are assumed to be the same on a plant basis as the total national throughput from 2005 to 2006 did not change significantly and were 45,685 MMcf/d and 45,537.4 MMcf/d respectively as indicated by the U.S. GHG Inventory
- CH_4 and CO_2 process emissions (CO_2e) per facility were estimated by multiplying the equipment count per plant (activity factor) obtained from the Gas Processing Survey with their corresponding emission factors obtained from GRI/ EPA 1996 reports. The national processing sector average composition (CH_4 and CO_2 content) of natural gas was obtained from GTI and applied to the GRI emission factors. Emission factor for centrifugal compressor degassing seals was obtained from Bylin et al[25].
- CH_4, CO_2 and N_2O combustion emissions (CO_2e) were estimated by applying CH_4,CO_2 and N_2O API compendium relevant combustion emission factors to the fuel gas used by each plant. The fuel gas consumption was estimated using the horsepower requirements of engines and turbines per plant.
- N_2O combustion emissions (CO_2e) were estimated by applying API compendium N_2O combustion emission factors to the fuel gas used by each plant.
- The different emissions per plant was summed up to provide total emissions (CO_2e)
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
    - IF(operator total emissions > 1000) then reporting
    - IF(operator total emissions > 10000) then reporting
    - IF(operator total emissions > 25000) then reporting

[25] Bylin, Carey (EPA), et. al (2009) *Methane's Role in Promoting Sustainable Development in Oil and Natural Gas Industry*. <presented at 24th World Gas Conference>

- IF(operator total emissions >100000) then reporting

- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.
- The resulting O&M and capital costs from the cost burden analyses were entered for each facility in the spreadsheet. The sum of the product of O&M or capital costs and the logic checks described above provides the total cost burdens for each reporting threshold. Dividing the total cost burdens by the number of reporting facilities (calculated above) provides the average facility cost burdens at each reporting threshold.

Threshold Analysis for Transmission

- "Facility" in the natural gas transmission segment is defined as a compressor station. Data for individual compressor stations on interstate transmission pipelines are reported to FERC Form 2[26], and data for compressor stations on intrastate pipelines were obtained from EIA through personal contact. However, the data collected for intrastate pipelines were incomplete.
- For intrastate pipeline facilities that did not have the number of compressor stations listed, it was assumed that each facility has one compressor. The compressor horsepower per intrastate pipeline was estimated by multiplying design throughput per intrastate pipeline with the ratio of total interstate pipeline compressor horsepower (engine and turbine) to the total interstate design throughput.
- The FERC data, supplemented with intrastate data and assumptions, list pipeline states, names, designed throughput capacity, and in some cases the type of compressor (centrifugal, reciprocating, and/or electric), and the installed horsepower for each station.
- In cases where the installed reciprocating horsepower is provided, it was used for installed engine capacity (Hp). In cases where the installed capacity was provided, but the type of compressor was not specified, the analysis assumes that 81% of the installed capacity is reciprocating. In cases where the provided installed capacity is both centrifugal and reciprocating, it is assumed that 81% is for engines. The 81% assumption is the ratio of reciprocating compressor engine capacity in the transmission sector to centrifugal turbine drivers for 2006 taken from the U.S. GHG Inventory
- The ratio of reciprocating compressor engine driver energy use (MMHphr, EPA[28]) to interstate station design throughput capacity (MMcfd, FERC[27]) was calculated. Then, the reciprocating compressor energy use for each station was assigned by multiplying the installed station throughput capacity by the ratio calculated previously in this bullet.
- In cases where the installed centrifugal horsepower is provided, it was used directly for installed turbine capacity (Hp). In cases where the installed capacity was

[26] FERC. *Form 2 Major and Non-major Natural Gas Pipeline Annual Report.* Available online at: <http://www.ferc.gov/docs-filing/eforms/form-2/data.asp#skipnavsub>.

provided, but the type of compressor was not specified, the analysis assumes that 19% of the installed capacity is centrifugal. In cases where the provided installed capacity is both centrifugal and reciprocating, it is assumed that 19% is for turbines. The 19% assumption is the ratio of centrifugal compressor turbine capacity in the transmission sector to reciprocating engine drivers taken from the U.S. GHG Inventory.

- The ratio of centrifugal compressor engine driver energy use (MMHphr, EPA[28]) to interstate station design throughput capacity (MMcfd, FERC[27]) was calculated. Then, the reciprocating compressor energy use for each station was assigned by multiplying the installed station throughput capacity by the ratio calculated previously in this bullet.
- The total emissions for 2006, both vented and fugitive methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total fugitive and vented emissions were allocated to each facility based on its portion of the segment's total station throughput capacity, as shown in the following equation:

Station "*i*" process emissions = $\dfrac{StationCapacity_i}{\sum_i StationCapacity} \times TotalInventoryEmissions$

- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

  EF_{CO2} = 719 metric tons CO_2e/MMHphr
  EF_{N20} = 5.81 metric tons CO_2e/MMHphr
  $Emissions_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times$ Compressor $energy_i$ (MMHphr)
- The total emissions for each facility were calculated by summing the calculated process and the combustion emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.

Threshold Analysis for Underground Storage

- "Facility" in the underground natural gas storage segment is defined as storage stations and the connected storage wellheads. Underground storage data by operator are collected in form EIA-176[27].

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[27] EIA. *EIA-176 Query System*. Available online at:
<http://www.eia.doe.gov/oil_gas/natural_gas/applications/eia176query_historical.html>.

- The data collected in EIA-176 contained each underground storage operator, field, and location as well as the storage capacity and maximum daily delivery.
- The total compressor energy use in 2006 for the underground storage segment was estimated in the U.S. GHG Inventory. This total energy use, in millions of horsepower hours (MMHphr), is allocated to each facility based on its portion of the segment's total maximum daily delivery capacity; as described in the following equation:

$$\text{Compressor energy}_i \text{ (MMHphr)} = \frac{MaximumDailyDelivery_i}{\sum_i MaximumDailyDelivery} \times TotalSegmentMMHphr$$

Where, index "*i*" denotes an individual facility

- The total process emissions for 2006, both vented and fugitive methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total process emissions were allocated to each facility based on its portion of the segment's total maximum daily delivery capacity, using the same methods as compressor energy use.
- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

  EF_{CO2} = 719 metric tons CO_2e/MMHphr

  EF_{N20} = 5.81 metric tons CO_2e/MMHphr

  $\text{Emissions}_{CO2 \text{ or } N20} = EF_{CO2 \text{ or } N20} \times \text{Compressor energy}_i$ (MMHphr)
- The total emissions for each facility were calculated by summing the calculated process and the combustion emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.

Threshold Analysis for LNG Storage

- "Facility" in LNG storage segment is defined as LNG storage plants (peak shaving or satellite). Data for each peak shaving facility is provided in *The World LNG Source Book – An Encyclopedia of the World LNG Industry*. Summary data for all satellite facilities is estimated in ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. GHG Inventory.
- The data reported in *The World LNG Source Book – An Encyclopedia of the World LNG Industry* includes the operator, liquefaction capacity, storage capacity, vaporization design capacity for each individual peak shaving plant.
- U.S GHG Inventory reports that in addition to peak shaving plants there are approximately 100 satellite facilities with a total storage capacity of 8.7 Bcf. The ICF memo also provides several key assumptions that will be discussed at the appropriate locations below.
- The total liquefaction compressor energy use for the segment was estimated using the methods and assumptions detailed in the ICF background memo for EPA's U.S. GHG Inventory. LNG company contacts provided the memo's assumption that 750 MMHphr are required for liquefaction for each million cubic feet per day of liquefaction capacity. It assumes the liquefaction takes place over a 200-day "fill" season. It assumes that approximately 50% of compressors are driven by gas-fired engines or turbines. EIA provides the LNG storage additions for 2006 on its website, totaling 38,706 MMcf. Thus, the total liquefaction energy use for the segment was calculated using the following formula:

$$\text{LEU} = \frac{38{,}706 MMcf}{200 days} \times \frac{750 Hp}{1 MMcfd} \times \frac{24 hours}{day} \times 200 days \times 50\% \times \frac{1 MMHphr}{1{,}000{,}000 Hphr}$$

where,

LEU = total liquefaction energy use for the segment, gas fired (MMHphr)

- The total calculated liquefaction compressor energy use was apportioned to individual facilities based on their share of the total liquefaction capacity for the segment, as shown in the following equation:

$$\text{Facility "i" liquefaction MMHphr} = \frac{LC_i}{\sum_i LC} \times TotalSegmentMMHphr$$

Where "i" indexes facilities and LC = liquefaction capacity.

- Storage capacity, provided in gallons by *The World LNG Source Book – An Encyclopedia of the World LNG Industry*, was converted to million cubic feet with a conversion factor of 1 gallon of LNG = 81.5 standard cubic feet of natural gas.
- Boil-off liquefaction compressor energy use was calculated using assumptions outlined in the U.S GHG Inventory. The memo assumes that 0.05% of storage capacity boils off and is recovered by vapor recovery compressors and liquefied. These compressors must operate all year and require the same 750 Hp per 1 MMcfd liquefied. The boil-off liquefaction compressor energy use was thus estimated for each facility using the following equation:

$$\text{FBEU}_i = \frac{SC_i \times 0.05\%}{365 days} \times \frac{750 Hp}{MMcfd} \times \left(365 days \times \frac{24 hours}{day}\right) \times \frac{MMHphr}{1{,}000{,}000 Hphr}$$

where,

FBEU_i	=	Facility "i" boil-off liquefaction compressor energy use (MMHphr)
SC	=	Facility "i" storage capacity (MMcf)

- Vaporization and send-out compressor energy use was also calculated based on assumptions from the U.S GHG Inventory. It estimates that with an average send-out pressure of 300 psia and inlet pressure of 15 psia, using 2-stage compression, a satellite facility requires 1.86 MMHphr for each MMcfd of send-out. The send-out period lasts all year, unlike the "fill" season. The memo also estimates that 75 Bcf of gas were sent out from peak shaving facilities compared to 8.7 Bcf from satellite facilities in 2003. This equates to 89.6% of send-out coming from peak shaving plants in 2003; the analysis assumes the same is true for 2006. EIA[28] provides that in 2006, total LNG withdrawals were 33,743 MMcf. The send-out compressor energy use by all peak shaving plants in the segment was calculated using the following equation:

$$\text{Total send-out energy use} = \frac{33{,}743 MMcf}{365 days} \times \frac{1.86 MMHphr}{MMcfd} \times 89.6\%$$

- Send-out compressor energy use was apportioned to each peak shaving facility by its share of the total peak shaving segment's send-out capacity; using the same method as apportioning liquefaction energy use. (See liquefaction bullet).
- The 100 satellite facilities were assumed to be equal size and capacity. That is, 8.7 Bcf storage capacity, all of which is sent out each year. It was assumed that satellite facilities have no liquefaction, except for that which is necessary for boil-off. We performed the above analysis on the "average" satellite facility to estimate its energy use and emissions. The only difference was that 10.4% of EIA reported LNG withdrawals was attributed to the satellite facilities.
- The total process emissions for 2006, both vented and fugitive methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total emissions were allocated to each facility based on its portion of the segment's total storage capacity, using the same methods as apportioning liquefaction and send-out compressor energy use.
- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

  EF_{CO2} = 719 metric tons CO_2e/MMHphr
  EF_{N20} = 5.81 metric tons CO_2e/MMHphr
  $\text{Emissions}_{CO2 \text{ or } N20} = EF_{CO2 \text{ or } N20} \times \text{Compressor energy}_i$ (MMHphr)

[28] EIA. *Liquefied Natural Gas Additions to and Withdrawals from Storage*. Available online at: <http://tonto.eia.doe.gov/dnav/ng/ng_stor_lng_dcu_nus_a.htm>.

- The total emissions for each facility were calculated by summing the calculated fugitive, vented, and combustion emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered by each threshold.
- Satellite facilities crossed the 1,000 and 10,000-metric ton reporting threshold, but fell well short of the 25,000-metric ton threshold.

Threshold Analysis for LNG Import Terminals

- "Facility" in the LNG import segment is defined as the import terminals. Data is available for this on the FERC website[29]. It provides the owner, location, capacity, and 2006 import volumes for each LNG terminal.
- ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. Inventory assumptions were used to estimate liquefaction, boil-off liquefaction, and send-out compressor energy use for each of the LNG import terminals.
- It was assumed that import terminals do not have liquefaction capacity.
- Boil-off liquefaction compressor energy use was calculated using assumptions outlined in ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. Inventory. The memo assumes that 0.05% of capacity boils off and is recovered by vapor recovery compressors and liquefied. These compressors must operate all year and require the same 750 Hp per 1 MMcfd liquefied. The boil-off liquefaction compressor energy use was thus estimated for each facility using the following equation:

$$FBEU_i = \frac{IV_i \times 0.05\%}{365 days} \times \frac{750 Hp}{MMcfd} \times \left(365 days \times \frac{24 hours}{day}\right) \times \frac{MMHphr}{1{,}000{,}000 Hphr}$$

  where,

  $FBEU_i$ = Facility "i" boil-off liquefaction compressor energy use (MMHphr)

  IV_i = Facility "i" import volume (MMcf)

- Vaporization and send-out compressor energy use was also calculated based on assumptions from ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. GHG Inventory. It estimates that with an average send-out pressure of 300 psia and inlet pressure of 15 psia, using 2-stage

[29] FERC. *Import Terminals*. Available online at: <http://www.ferc.gov/industries/lng.asp>.

compression, satellite facilities require 1.86 MMHphr for each MMcfd of send-out. The following equation estimates the energy use at each facility:

$$\text{Facility "i" send-out energy use} = \frac{IV_i}{365 days} \times \frac{1.86 MMHphr}{MMcfd}$$

- The total process emissions for 2006, both vented and fugitive methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total process emissions were allocated to each facility based on its portion of the segment's total import volume, using the following equation:

$$\text{Facility "i" process emissions} = \frac{IV_i}{\sum_i IV} \times InventorySegmentEmissions$$

where,

IV_i = import volume and "i" represents individual facilities

- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

  EF_{CO2} = 719 metric tons CO_2e/MMHphr

  EF_{N20} = 5.81 metric tons CO_2e/MMHphr

  $Emissions_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times$ Compressor $energy_i$ (MMHphr)
- The total emissions for each facility were calculated by summing the calculated process and the combustion emissions.
- Since there were only 5 active import terminals, all were assumed to be "medium" in size.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered by each threshold.

Threshold Analysis for Distribution

- "Facility" in the natural gas distribution segment is defined as the local distribution company (LDC). The Department of Transportation (DOT)[30] provides a set of data that contains distribution main pipelines miles by pipeline materials and distribution service counts by pipeline material for each LDC.
- Fugitive CO_2 and CH_4 emissions from distribution mains were evaluated for each facility by multiplying its pipeline data by the appropriate emission factor, summarized in the table below, from the U.S GHG Inventory.

[30] DOT. *2006 Distribution Annuals Data*. Available online at: <http://www.phmsa.dot.gov/pipeline/library/data-stats>.

Exhibit C-8: LDC's Fugitive Emissions Emission Factor

Pipeline Type/Material	Fugitive GHG Emission Factor
Mains – Unprotected Steel	110 Mcf/mile/year
Mains – Protected Steel	3.07 Mcf/mile/year
Mains – Plastic	9.91 Mcf/mile/year
Mains – Cast Iron	239 Mcf/mile/year
Services – Unprotected Steel	1.70 Mcf/service/year
Services – Protected Steel	0.18 Mcf/service/year
Services – Plastic	0.01 Mcf/service/year
Services – Copper	0.25 Mcf/service/year

- The total miles of mains pipelines of all materials were summed for each LDC.
- The total emissions from metering and regulating (M&R) stations for 2006, both vented and fugitive methane and non-energy CO_2, were estimated by EPA U.S GHG Inventory. These total emissions were allocated to each facility based on its portion of the segment's total import volume, using the following equation:

$$\text{Facility “i” M\&R emissions} = \frac{MM_i}{\sum_i MM} \times InventorySegmentEmissions$$

where,

MM = total miles of mains pipeline, and "i" represents individual facilities

- There are no combustion emissions from the LDCs covered in the rule.
- The total emissions for each facility were calculated by summing the calculated pipeline fugitives and M&R station emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.

Appendix D: Analysis of potential facility definitions for onshore petroleum and natural gas production

The purpose of this appendix is to determine the barriers in using a physical definition of a facility for the onshore petroleum and natural gas production segment. The paper also discusses a potential alternative to a physical definition by using a corporate level reporter definition.

A. **Facility Definition:** Any production sector reporting configuration will need specific definitions on what constitutes a facility. There are no definitions currently for the production sector in the initial rule proposal.

i. Field level – A field may be defined by either physically aggregating certain surface equipment, referred to as physical field definition. Or the field may be defined by demarcation of geographical boundaries, referred to as Geographic field definition.

Physical field definition:
The challenge in defining a field as a facility is to recognize a common structure through the oil and gas production operations. Such a definition can be achieved by identifying a point in the system upstream of which all equipment can be collectively referred to as a field level facility. All oil and gas production operators are required by law to meter their oil and gas production for paying royalties to the owner of the gas and taxes to the state, referred to as the lease meter. All equipment upstream of this meter can be collectively referred to as a facility.

There is no precedence for such a definition in the CAA. It must be noted, however, that the facility definitions commonly used in the CAA pertain specifically to pollutants whose concentration in the ambient atmosphere is the deciding factor on its impact. This is not necessarily true of GHGs that have the same overall impact on climate forcing irrespective of how and where they occur.

Geographic field definition:
An alternative to the lease meter field level definition is to use the EIA Oil and Gas Field Code Master[31] to identify each geological field as a facility. This definition is structurally similar to the corporate basin level definition, i.e. it uses geological demarcations to identify a facility rather than the above ground operational demarcation.

ii. Basin level – The American Association of Petroleum Geologists (AAPG) provides a geologic definition of hydrocarbon production basins which are

[31] EIA Oil and Gas Field Master – 2007, http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/field_code_master_list/current/pdf/fcml_all.pdf

referenced to County boundaries. The United States Geological Survey (USGS) also provides such a definition, which is different than the AAPG definition. The AAPG definition identified by the “geologic province code” is most commonly used by the industry and can be used to report emissions from each basin. The individual counties in each state are allocated to different geologic province codes and therefore there is no ambiguity in associating an operation with the relevant basin (geologic province code). An operation physically located on a basin as defined by the AAPG can be identified with that particular basin, irrespective of which basins the wells are producing from. (Well pads may have multiple wells producing from different fields and zones in a reservoir, and possibly different basins as well).

B. **Level of Reporting:** It is important to clearly distinguish the level of reporting- i.e., the facility level or the corporate level. The level of reporting is where the threshold level is applied and thus determination on whether reporting is required. In some cases, the owner or operator of the facility itself is the reporter and in other cases it is the overall company that is the reporter. For example, in subpart NN of the MRR published on September 22, 2009, reporting for natural gas sent to the end use customers is at the local distribution company, and not the individual physical locations (or facilities) that send the natural gas into the economy. Alternatively, in subpart MM of the initial rule proposal, the owner or operator of the individual refinery is the reporter as opposed to the company owning multiple refineries.

For the purposes of onshore petroleum and natural gas production reporting can be at either the facility level or the corporate level. If the level of reporting is at the corporate level, it could still be required that data be reported for individual facilities.

Petroleum and natural gas production companies are identified uniquely by the Internal Revenue System (IRS). Also, the CAA defines the ‘‘owner or operator’’ as meaning any person who owns, leases, operates, controls, or supervises a stationary source. In general, operational control for a facility means the authority to introduce and implement operating, environmental, health and safety policies, and therefore would be the entity who potentially reports under the rule. In circumstances where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control.

C. Qualitative Analysis of Facility Options

The following qualitative evaluation provides a discussion on the advantages and disadvantages of using any of the three reporting level definitions, based on expert opinion.

i. Ease of practical application of reporter and facility definitions

1) Field level facility definition – In this case the physical demarcation of field level by aggregating field equipment is difficult to implement. On the other hand, field level definition based on boundaries identified by the EIA Oil and Gas Field Code Master should be easy to implement, since the classification if widely used in the industry.

   Physical Field Definition:
   There are no standard guidelines or operational practices on how many wells can be connected to one lease meter. The choice of whether multiple wells are connected to the same lease meter depends on; the well spacing, number of owners of leases, volume of hydrocarbons produced per well, geographical boundaries, and ease of operation. Therefore, such a definition will lead to facilities of all kinds of sizes; at one extreme several well pads with multiple wells could be connected to one lease meter, while at the other extreme where situation demands only one well with no equipment could directly be connected to a lease meter. In addition there will be thousands of facilities that will be under purview.

   Any lease meters located upstream of a compression system will exclude compressors from the facility definition. This means that the required threshold for emissions reporting may not be reached due to exclusion of the fugitive emissions as well as the combustion emissions from compressors.

   Geographic field definition:
   The EIA publishes its Field Code Master on a yearly basis. Also, the classification system is widely used in the industry. Hence such a definition should be easy to implement.

2) Basin level facility definition - Basin level definition is more practical to implement given that operational boundaries and basin demarcations are clearly defined. Furthermore, more emissions will be captured under this facility definition than the field level or well level definitions.

3) Corporate reporting -
   It can be difficult to identify who the corporation is that would be responsible for reporting. If the corporation can be readily identified and defined then applying a field level facility definition using the EIA field classification or basin level facility definition using AAPG classification becomes practical.

ii. Coverage that can be expected from each definition type

1) Field level facility definition – This definition (both physical and geographical) provides the highest level of detail possible on emissions sources. However, any field level definition along with a 25,000 metric tons CO_2e/year threshold for reporting could potentially exclude a large portion of the U.S. oil and gas operations. Hence only a portion of the entire emissions from the U.S. oil and gas operations will get reported.

2) Basin level facility definition - Basin level information will throw light on the difference in patterns of emissions from sources both as a result of being located in different basins and as a result of different operational practices in different companies. This definition will result in the reporting of a significant portion of the emissions for the identified sources from the entire U.S. onshore oil and gas operations.

3) Corporate reporting - This definition will result in reporting of a significant portion of the emissions for the identified sources from the entire US onshore oil and gas operations. Since the reporting will be at a company level, variations in emissions from sources due to location on different basins may not be evident. However, if corporate national level reporter definition is used in addition to field and/or basin level reporting then all possible patterns in emissions will be evident.

D. Data Sources for Research and Analysis

i. Clean Air Act
ii. United States Geological Survey
iii. Natural Gas STAR Technical Documents
iv. EPA National GHG Inventory
v. DOE GASIS database
vi. Lasser® database
vii. Energy Information Administration
viii. Oil & Gas Journal
ix. HARC - VOC Emissions from Oil and Condensate Storage Tanks
x. State Oil and Gas Commissions

Appendix E: Analysis of potential facility definitions for local distribution companies

The purpose of this appendix is to investigate options for defining reporting facilities within the local distribution sector as well as discuss emissions sources to be reported and the associated coverage.

A. Issue Identification and Clarification

i. **LDC Facility Definition:** A potential parallel for defining the distribution sector for the GHG Reporting rule is adapting the definition available from Section NN of the Final Mandatory Reporting Rule (MRR) published on September 22, 2009.

   The Clean Air Act (CAA) does not put forth any definition for a facility in the natural gas distribution sector. This is to be expected as there are few sources of hazardous air pollutants in the natural gas distribution sector; the primary stationary emissions from this sector are fugitive and vented methane emissions. Only Section 112 (n) (4) (A) mentions natural gas pipeline facilities within the CAA and it states that emissions from compressor or pump stations shall not be aggregated with other units to determine whether they are major sources. As there are no compressor stations or pump stations within local natural gas distribution systems, this would potentially not effect any facility definition.

   In developing an appropriate definition for a reporting entity within the local natural gas distribution sector, a number of sources were examined to determine if there are any existing facility definitions in use. The Pipeline and Hazardous Materials Safety Administration (PHMSA) in the Department of Transportation collects data from the distribution sector on pipeline incidents and mileage. CFR Title 49 Section 191.11[32] requires that "each operator of a distribution pipeline system shall submit an annual report for that system". Section 191.3 defines a pipeline system as:

   > *Pipeline or Pipeline System means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.*

   Data on pipeline mileage, number of services, leaks, and other incidents is reported to the PHMSA by individual LDCs. Larger holding companies that operate distribution systems in different areas do not report as one large entity; each system reports separate data to the PHMSA.

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[32] Code of Federal Regulations Title 49. "Transportation of Natural and Other Gas By Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports." Available online at http://www.access.gpo.gov/nara/cfr/waisidx_02/49cfr191_02.html

The Climate Registry supports a voluntary GHG emissions reporting system in North America. The Climate Registry proposes that "For purposes of reporting, each pipeline, pipeline system, or electricity T&D system should be treated as a single facility"[33]. This definition indicates that an entire distribution system operated by an LDC would report GHG emissions as one entity to The Climate Registry.

The final MRR requires that all LDCs report CO_2 emissions which would result from the complete combustion of natural gas delivered to end users. The rule defines LDCs as:

> *Local Distribution Companies are companies that own or operate distribution pipelines, not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems.*

These various sources imply that LDCs are accustomed to reporting data from the pipeline systems that they operate. If GHG emissions from the natural gas distribution sector are required to be reported, it would be easiest to have emissions reported at the LDC level as this is consistent with the final MRR as well as other data reporting mechanisms. It is important to note that often one company may own several LDCs under different names. In such a case, it is important to determine at what level the company has to report.

B. Evaluation Criteria and Approach

i. Qualitative Analysis

A qualitative evaluation below provides a discussion on the advantages and disadvantages of using a LDC reporting level definition, using the following criteria;

1) Boundary limitations.

   As some holding companies operate multiple LDCs, often in close proximity, it may be difficult to define distinct boundaries between the systems that do not double-count or under-count GHG emissions. The data collected by the PHMSA appears to have addressed boundary issues for these large holding companies. The boundary specifications used by LDCs to report to the PHMSA can be potentially used to eliminate any confusion in the boundaries between LDCs owned by the same holding company.

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[33] The Climate Registry. "General Reporting Protocol". Page 38. Available online at http://www.theclimateregistry.org/downloads/GRP.pdf

Another issue that needs to be addressed for the boundary definition is DOT's definition of distribution pipelines versus transmission pipelines. In some cases, pipelines operated by LDCs are considered transmission pipelines rather than distribution pipelines. CFR Title 49 §192.5 provides the definition of a transmission line which can cover certain pipelines that are operated by an LDC. For example, a large company may operate a length of pipeline that delivers natural gas from an interstate transmission line to their distribution center. Along that length of pipeline there may be individual farm taps or industrial customers that pull gas directly from the transmission line with their own regulator to step down pressure. Because these end-users are not part of the distribution system, the initial rule proposal would need to clarify if any emissions from the equipment used to step down pressure and meter gas going to these customers would fall under the distribution sector or transmission sector.

2) Ease of practical application of definition.

   Annual reports collected by the Pipeline and Hazardous Materials Safety Administration (PHMSA) demonstrate that the definition of a distribution pipeline system can be applied to the industry to achieve nationwide data reporting.

3) Coverage that can be expected from LDC facility definition type.

   Defining a distribution pipeline system as a reporting entity in an equivalent fashion as in CFR Title 49 191.3 should include all distribution operations as tracked in the U.S. GHG Inventory. The number of entities that trigger the reporting threshold will depend largely upon the size of the system. A top-down estimate of fugitive emissions from LDCs based on both LDC data tracked by the PHMSA, as well as on emission factors from the *Inventory of US Greenhouse Gas Emissions and Sinks*[34], indicates that 11% of LDCs would emit fugitive emissions in excess of the 25,000 metric tons CO_2e threshold. Emissions from these LDCs would make up over 90% of fugitive emissions from all sources in the natural gas distribution sector.

C. Data Sources for Research

i. US Methane Emissions Inventory
ii. CAA
iii. NAICS definitions - 221210 Natural Gas Distribution
iv. Office of Pipeline Safety
v. Pipeline and Gas Journal

[34] EPA. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006*. Available online at http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

Appendix F: Analysis of Definition Options for Natural Gas Production Gathering Pipelines for Emissions Reporting

The purpose of this appendix is to identify issues resulting from defining gathering pipelines as an independent reporting segment for the rule.

A. Issue Identification and Clarification

The initial rule proposal did not require emissions from natural gas production gathering pipelines to be reported. Natural gas production gathering pipelines cannot easily be classified into facilities as they are made up of a network of pipelines. The options for gathering pipelines are to include these facilities in either the Onshore Production sector, the Gas Processing sector, a new segment, or exclude them from reporting.

i. Natural Gas Gathering Pipeline Facility Definition:

From the wellhead, natural gas is transported to processing plants or natural gas transmission pipelines through a network of small-diameter, low-pressure gathering pipelines. A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant to upwards of 100 wells in the area. The Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA) statistics show that there were approximately 12,477 miles of onshore and 7095 miles of offshore gas gathering pipeline in the U. S. in 2007. This is a fraction of the total gathering pipeline mileage because only the mileage closest to human habitation that can pose a safety risk is reported to and regulated by PHMSA. Gathering pipelines may be owned by the producer or the processing plant, or the affiliate of a pipeline company or an independent gathering business. A fee is charged for the service and the fees are negotiated between the producer and the gathering pipeline.

Gathering systems may report to federal land management agencies and state land use agencies primarily for safety and permitting purposes. They must file reports with the PHMSA, Office of Pipeline Safety (OPS). These reports are relative to silting, routing, and safety issues.

The PHMSA collects data from the gathering pipeline sector on pipeline incidents and mileage under CFR Title 49 Section 191.17[1] which requires each operator of a gathering pipeline system to submit an annual report:

> *(a) Except as provided in paragraph (b) of this section, each operator of a transmission or a gathering pipeline system shall submit an annual report for that system on Department of*

[1] Code of Federal Regulations Title 49. "Transportation of Natural and Other Gas By Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports." Available online at http://www.access.gpo.gov/nara/cfr/waisidx_02/49cfr191_02.html

Transportation Form RSPA 7100.2–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

Title 49CFR Part 192.3 defines a gathering pipeline as follows:

Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.

The PHMSA regulations for gas gathering pipelines incorporate an industry standard prepared by the American Petroleum Institute (API RP 80) to better define which portions of the natural gas pipeline network are considered "gathering" pipelines. This includes how a pipeline operator must determine which of its gas gathering pipelines are subject to regulation, i.e., which are "regulated gathering lines." This is done using criteria that determine when a gas gathering pipeline is close enough to a number of homes, or to areas/buildings where people congregate, that an accident on the pipeline could impact them. Offshore gas gathering pipelines and high-pressure onshore lines meeting these criteria must meet all requirements of 49 CFR Part 192 applicable to gas transmission pipelines. Onshore gas gathering pipelines that operate at lower pressures must comply with a subset of these requirements specified in 49 CFR 192.9.

Title 49CFR Part 191.15 for transmission and gathering systems incident reports states:

(a) Except as provided in paragraph (c) of this section, each operator of a transmission or a gathering pipeline system shall submit Department of Transportation Form RSPA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5.

Title 49CFR Part 191.3 defines an incident as follows:

Incident means any of the following events:(1) An event that involves a release of gas from a pipeline or of liquefied natural gas or gas from an LNG facility and (i) A death, or personal injury necessitating in-patient hospitalization; or (ii) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.

Under section 7 of the Natural Gas Act, FERC reviews applications for the construction and operation of natural gas pipelines. In its application review, FERC ensures that the applicant has certified that it will comply with Department of Transportation safety standards. FERC has no jurisdiction over pipeline safety or security, but actively works with other agencies with safety and security responsibilities.

The Clean Air Act (CAA) does not put forth any definition for a facility in the natural gas gathering pipeline sector. This is to be expected as there are few sources of hazardous air pollutants in the natural gas gathering pipeline sector; the primary stationary emissions from this sector are fugitive and vented methane emissions. Only Section 112 (4) (A) mentions natural gas pipeline facilities within the CAA

> *(4) OIL AND GAS WELLS; PIPELINE FACILITIES.—*
> *(A) Notwithstanding the provisions of subsection (a), emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.*

The Climate Registry supports a voluntary GHG emissions reporting system in North America. The Climate Registry proposes that "For purposes of reporting, each pipeline, pipeline system, or electricity T&D system should be treated as a single facility"[35]. This definition indicates that an entire gathering pipeline system operated by a company would report GHG emissions as one entity to The Climate Registry.

These various sources imply that companies are accustomed to reporting data from the gathering pipeline systems that they operate. If GHG emissions from the natural gas gathering pipeline segment were included, it could be most straightforward to have emissions reported at the pipeline company level as this is consistent with the PHMSA reporting.

B. Data Sources Referenced

- **i.** US Methane Emissions Inventory
- **ii.** CAA
- **iii.** Office of Pipeline Safety
- **iv.** Energy Information Administration
- **v.** Gas Research Institute (GRI) Well workover assumptions in the study *Methane Emissions from the Natural Gas Industry*.

[35] The Climate Registry. "General Reporting Protocol". Page 38. Available online at http://www.theclimateregistry.org/downloads/GRP.pdf

Appendix G: Accounting for Inaccessible Emissions Sources

The purpose of this appendix is to evaluate options for ensuring comprehensive fugitive and vented emissions detection and measurement of all potential sources, focusing on accessibility issues of potential sources of fugitive methane emissions. Part 1 identifies and discusses comprehensiveness issues. Part 2 discusses how to evaluate those issues. Part 3 identifies other resources pertaining to the issue, and part 4 provides a summary.

Inaccessible emission sources includes those potentially emitting components which are either unsafe to monitor, or physically out of reach, or visually hidden. Physically out of reach emission sources means those components which are not within arms reach when using a portable VOC detection instrument. Visually hidden emission sources are those that cannot be viewed with a optical imaging instrument due to blockage from other equipment or components. Unsafe-to-monitor emission sources are those described in the regulations discussed below.

A. Review of Current Provisions Pertaining to Inaccessibility

Inaccessible components and comprehensiveness of leak surveys are addressed in current EPA volatile organic compound (VOC) regulations. Method 21 provides general language about adhering to safety practices.

i. 40 CFR 60 Appendices: Method 21

> *5.0 Safety*
> *5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.*

40 CFR 60 Subpart VV covers leak inspections of components and is referenced by subpart KKK for onshore natural gas processing plants. Subpart VV does not discuss equipment as inaccessible but as difficult or unsafe-to-monitor. Unsafe-to-monitor equipment means that the equipment must expose monitoring personnel to immediate danger as a consequence of complying with performance standards. For equipment deemed as such, an explanation is required by the operator and a plan must be developed for future monitoring when the equipment is safe to monitor. Inaccessible equipment includes those that are unsafe-to-monitor; however, the provisions mentioned above only apply to pumps, valves, and connectors.

ii. 40 CFR 63 Subpart UU

(e) Special provisions for connectors —(1) Unsafe-to-monitor connectors. Any connector that is designated, as described in §63.1022(c)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section and the owner or operator shall monitor according to the written plan specified in §63.1022(c)(4).

2) Inaccessible, ceramic, or ceramic-lined connectors. (i) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (e)(2)(i)(A) through (e)(2)(i)(F) of this section, as applicable.

(A) Buried;

(B) Insulated in a manner that prevents access to the connector by a monitor probe;

(C) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(D) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground.

(E) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold;

(F) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(ii) If any inaccessible, ceramic or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

Based on a review of this existing HAP LDAR regulatory language, from 40 CFR Part 63 Subpart UU, many accessibility issues are addressed. Inaccessible connectors are described above as either buried, insulated in a manner that prevents access to the connector by a monitor probe, obstructed by equipment or piping that prevents access to the connector by a monitor probe, or unable to be reached from an permanent support surface. This definition of inaccessible can potentially be applied to all components for leak detection.

The safety conditions outlined in the Clean Air Act and Method 21 may result in a portion of fugitive methane emissions to be excluded from required monitoring, due to safety and physical inaccessibility concerns in measurement. However, these conditions are most common within processing facilities where there are a large number of equipment in close proximity, as well as equipment that deal with hot and cold process streams that may be a safety concern. This is not necessarily the case for the other sectors in the oil and natural gas industry such as onshore production, transmission, and distribution where methane streams are not necessarily a safety concern. The number of emission sources excluded for safety reasons in the other oil and natural gas sectors are most likely less than that from processing because of the relative simplicity of their operations. Since the entire natural gas industry is within the scope of the rule, those leaks or measurements unaccounted for due to safety could be insignificant.

B. Potential methods to account for inaccessible components

i. Remote detection applicability – Distance, field of view, wind speed, and subjectivity of individual instrument technicians are among several factors that affect applicability to inaccessible components. A remote detection instrument is a device that can detect emissions without using a probe at a component's surface.

1) **Distance.** Fugitive methane emissions detection instruments of the remote sensing type can accommodate screening of many components that are inaccessible. Components must first be within the working distance of the remote sensing instrument. One study[36] found that handheld remote sensing instruments can detect fugitive emissions from a 30-foot distance or closer. The study reports that the actual distance will depend, in part, on the specific instrument model: for example, a passive optical imaging instrument will have a maximum stated distance of "hundreds of feet", while an active remote leak detection instrument will indicate a maximum distance of about 100 feet. The effective distance of a remote sensing instrument will vary depending on a number of parameters, many of which will be specific to the individual facility or even the individual component being surveyed. The parameters that affect leak detection performance include minimum detection limit, type of lens, wind speed, field of view, and the ambient and gas temperatures. For example, an instrument may detect a leak of a certain magnitude from a certain vantage point but not detect the same leak from a different vantage point where the view is obstructed or if sustained wind speeds increase.

[36] Implementing Directed Inspection & Maintenance with a Focus on Infrared Remote Screening. Draft document. EPA Natural Gas STAR

The Alternative Work Practice (AWP) to Method 21 monitoring for 40 CFR Parts 60, 61, 63, and 65 in a VOC leak detection and repair program developed regulations to help ensure such standardization. Under the AWP, each monitoring session must begin with a "Daily Instrument Check"–a calibration test by releasing the known hydrocarbon of interest at the calculated mass flow rate and confirming detection is possible at the maximum distance from the component to the instrument that is to be tested during the monitoring session.

> **40 CFR 60 Subpart A [60.18(i)(2)]**
> (*B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey.*
>
> *(v) Repeat the procedures specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.*

This calibration test aims to control the parameters of performance and ensures that an inaccessible component can be screened successfully at a distance—except if the hydrocarbon cannot be detected during the calibration test. The practical effect of this test is that facilities with great distances between the feasible inspection point and the component may be at a disadvantage to those facilities with smaller distances for implementing remote sensing inspections if the greater distance is sufficiently large to prevent leak detection by the instrument. The AWP has provisions that can reduce this potential advantage/disadvantage scenario. The AWP reinforces the idea that monitoring has two components, 1) detection to determine mass flow rates that can be imaged, and 2) survey frequency. More frequent surveys could result in more opportunities to identify new occurrences of fugitives. Less frequent surveys could result in fewer opportunities to identify new occurring fugitives. Therefore, if a remote sensing instrument cannot detect emissions at a certain flow rate because of a large distance, there is the potential to increase the monitoring frequency and then monitor for a smaller size leak more frequently.

2) **Field of View.** Another performance factor for remote sensing instruments that specifically affects monitoring of inaccessible components is the field of view. Either the background behind a component or any obstructions to view in front of the component can prohibit successful monitoring. The background is important for active remote sensing instruments that operate by generating a signal and then detecting emissions based on the reflected signal strength to determine if a hydrocarbon gas is within the signal path. These active instruments therefore require a suitable reflective background for any component being monitored. Facilities with inaccessible components already situated with such backgrounds may have a monitoring advantage with active

instruments over facilities with elevated components and no such backgrounds. For a voluntary effort to detect, measure, and repair methane leaks, one natural gas transmission operator has affixed metal plates behind elevated open-ended lines (a minimal facility modification) to allow inspection from the ground with active remote sensing instruments.

For the passive type of remote sensing instruments, background is a contrast issue to ensure that a gas plume can be detected by the instrument operator. A wall, vessel, or collection of piping often provides the necessary contrast. Inspecting the component against the sky may result in the ability to detect larger leaks. For this reason, the calibration test required by the AWP could be more prescriptive in matching the background requirements to the conditions to be encountered during monitoring to ensure consistent monitoring practices from facility to facility.

Obstructions between the remote sensing instrument and the component will prevent leak inspection. For some components this may be remedied by inspecting the elevated component from a different vantage point, but for other components the obstruction of view may prevent an operator from using remote sensing for that component. Other components such as flanges on top of large vertical vessels may not offer a clear field of view for remote sensing, requiring a lift or other equipment to achieve a suitable viewing location for remote sensing. Applicability of remote sensing for inaccessible component inspection can therefore vary from facility to facility depending on the field of view.

Use of an optical imaging instrument is also a field of view issue, and specific issues to consider are viewing for a sufficient length of time and ambient lighting conditions. Use of a camera by quickly panning through a large number of components is not sufficient to identify leaks or attribute leaks to a specific component. Since optical imaging instruments depend on the ambient IR radiation or IR radiation produced by indoor lighting, monitoring may not be possible during the night or without a light source, and the video image produced by a camera can be blank or difficult to interpret. The Method 21 AWP language appears to cover reasonable use of an IR camera by requiring video recordings and with instruments use specifications.

The AWP requires that video recordings of monitoring be kept and that the video must clearly show the regulated components, which can help determine reasonable camera use.

> **40 CFR 60 Subpart A [60.18(h)(3)]**
> *(vi) Recordkeeping requirements in the applicable subpart. A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping*

requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

The AWP also specifies that the instrument must give the operator a clear view of each component, though the AWP does not otherwise specific a sufficient length of viewing time.

40 CFR 63 Subpart A [60.18(i)]
(1) Instrument Specifications. The optical gas imaging instrument must comply with the requirements specified in paragraphs (e)(1)(i) and (e)(1)(ii) of this section.
(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (e)(2) of this section.

3) **Wind Speed.** Wind speed also affects applicability of remote sensing devices to inspecting inaccessible components. Increased wind speed will disperse a leak plume more quickly and make a leak more difficult to detect. Sustained wind speeds further decrease detection ability since intermittent wind allows leaks to accumulate before being dispersed by wind. Components at ground level or that are otherwise accessible may be shielded from components that are elevated above surrounding buildings or equipment. Remote sensing instruments may still be applicable in cases where components are subject to higher wind speeds, but this applicability may be incorporated into a more prescriptive calibration test for the instrument. Given the inaccessible nature of the elevated components, it may be difficult to ascertain or measure the wind conditions at the component, though measuring wind speed or conducting the calibration test in an open, nearby area may be a reasonable surrogate for wind conditions at the component.

4) **Subjectivity of Individual Instrument Technicians.** Some remote sensing devices display a numerical value or audible alarm upon detection of fugitive emissions, while others display a video representation of the field of view and rely on the instrument technician to make the determination for if a component is leaking. The visual interpretation and judgment of an individual therefore introduces some subjectivity into monitoring elevated components with remote sensing. This subjectivity is an issue at the minimum detection level rather than for large leaks which are obvious due to plume size and motion of the plume. Subjectivity is also minimized with an AWP calibration test ensuring the technician can identify a specified minimum flow rate. A disadvantage of this calibration test is that in the test an individual would be viewing a specific component at a large distance to discern the presence of a leak, however, discerning leaks in the field amongst many components in the same frame of reference could be challenging. As a result, the individual may

be able to discern a very small leak during the calibration test but not discern as small a leak during the actual survey. Though this subjectivity affects comprehensiveness of leak detection for elevated/inaccessible components, this is primarily a performance standard issue. If however, the survey was conducted in the same manner as Method 21 specifies for portable VOC monitoring devices, surveying each component individually, the subjectivity can be minimized.

ii. Non-optical detection applicability – Leak detection instruments that require close proximity or contact with components (such as electronic screening, flame ionization detectors, toxic vapor analyzers, and organic vapor analyzers) are applicable to components that are inaccessible if resources are spent to gain access. Methods to gain access include:
   1) temporary use of a portable ladder,
   2) wearing harnesses or other applicable fall protection equipment to comply with safety regulations,
   3) temporary use of a bucket truck or other lift,
   4) facility modification to either create access to the component or relocate the component to an accessible area
   5) use of a self contained breathing apparatus, and
   6) excavation of buried components.

   A comprehensive leak survey covering all inaccessible components therefore would require additional labor costs and potentially additional capital or lease costs for specialized equipment.

   Hot-wire anemometers may be a niche solution for some inaccessible OELs. These quantification instruments operate by inserting a probe into a hole bored into a vent stack. Using such a device for leak inspections could eliminate the need for lifts to reach the top of some OELs.

iii. Measurement applicability – all measurement instruments appropriate for a leak detection and measurement reporting rule require contact with or close proximity to the leaking component.

   1) High Volume Samplers capture a leak for measurement using a hose, requiring the hose to be in contact with or within several inches of the component. The instrument can typically be mounted on a backpack for use when standing on a ladder or other positions where the technician has limited mobility or requires the use of hands and arms for balance and for directing the leak into the instrument using the hose attachments.

   2) The enclosure method involves constructing a tent around a leaking component, passing a known volume of inert gas through the tent, and collecting the flow out to determine mass emissions. This method is time-consuming, requiring about 30 minutes per enclosure and requiring ample

access to the area surrounding the component to construct the enclosure. Inaccessible components such as elevated OELs are not suitable candidates for the enclosure method given that no other components are typically near the OEL which can support the enclosure. This method is time-consuming on the ground and will encounter construction difficulties when in an elevated, inaccessible position, and for these reasons it is unlikely that the enclosure method is practical for a large-scale monitoring program or applicable to inaccessible elevated components.

3) The calibrated bag method uses a bag of a known volume constructed of anti-static materials plus a stopwatch to measure emissions. This measurement method involved some technique and training so that a technician places the bag over a leak source to capture all of the flow, ensures the bag unfurls correctly, and ensure that full inflation is achieved rather than bursting the bag or under-inflating it. The technique just described means that a technician requires both hands and arms to be free for the measurement rather than in use holding onto a ladder or railing. Calibrated bags are a measurement method applicable to inaccessibly high components, but additional resources such as a lift may be necessary.

4) Correlation equations to estimate mass emissions based on parts per million readings taken from gas detectors are also applicable to an elevated component again but may require extra costs to gain access to that component.

5) Turbine meters and rotameters are applicable to OELs and require access to and direct contact with the end of the stack.

6) Hot wire anemometers operate by inserting a probe into a hole bored into a vent stack. Using such a device for leak inspections could eliminate the need for lifts to reach the top of some OELs but are not suitable for other types of component leaks.

Emission factors or other calculation methods to quantify emissions volumes can limit or overcome the need to access components but sacrifice reporting accuracy.

C. Evaluation Criteria and Approach

Because each industry facility is constructed differently, each facility contains a different number of occurrences of these issues, resulting in different facility cost burdens. The exhibits below are examples of best case, low cost scenarios and a worst case, high cost scenarios as regards cost burdens. A key message for each accessibility issue is that remote sensing instruments require a higher initial capital cost.

i. Elevated Components: Components may be installed out of reach above ground level, above walkways, or beyond fixed platforms for a number of reasons. Pressure relief valves on large separators or other equipment divert the flow from overpressure situations in a safe manner which can warrant high elevations away from the walkways, ladders, and other access points. Similarly, open-ended lines may be elevated for safe venting. Pipe racks in larger facilities that may contain streams with a methane component may also be elevated beyond reach given the clearances needed for heavy maintenance vehicles. Stacks within buildings are typically routed beyond the roof which may be difficult to access since the stacks themselves require little maintenance and therefore do not need to be accessible..

The existing VOC LDAR rule states that pumps, valves, and connectors that cannot be monitored due to safety reasons are to be omitted from the survey work, meaning that a comprehensive report may not include those components. Those components deemed unsafe-to-monitor require an explanation as to why and a plan for future monitoring. Therefore, the inspection of some elevated components using the techniques that require close proximity such as portable VOC detection devices are excluded from the survey.

Exhibit G-1: Survey and measurement of inaccessibly elevated components

Cost Item	Low Cost Scenario ($)		High Cost Scenario ($)	
Survey Instrument	Toxic Vapor Analyzer (TVA)[1]	$ 2,000	Infrared Camera[2]	$ 82,000
			Ultrasonic Leak Detector[3]	$ 250
Survey Accessibility	Cherry Picker 1 hour @ $100/hour	$ 100	Cherry Picker 32 hours @ $100/hour	$ 3,200
Survey Labor	1 hour @ $50/hour[1]	$ 50	32 hours @ $50/hour[1]	$ 1,600
Measurement Instrument	TVA Correlation Equations	$ -	Hi Flow Sampler[4]	$ 18,829
			Hotwire Anemometer[5]	$ 995
			Fall Protection Harness[4]	$ 300
Measurement Accessibility			Cherry Picker 32 hours @ $100/hour	$ 3,200
Measurement Labor	1 hour @ $50/hour[1]	$ 50	32 hours @ $50/hour[1]	$ 1,600
Reporting Labor	2 hours @ $50/hour[6]	$ 100	64 hours @ $50/hour[6]	$ 3,200
Total		$ 2,300		$ 115,174

[1] Data from *Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations* Lessons Learned document epa.gov/gasstar/documents/ll_dimgasproc.pdf

[2] Cost estimate from personal communication with FLIR salesman, Ed Jones

[3] Used to detect leaks. Data from PRO *Inspect Flowlines Annually* epa.gov/gasstar/documents/inspectflowlines.pdf

[4] Fall Protection Harness to be used when climbing elevated component to get an flow reading. Cost data from: media.msanet.com/NA/USA/FallProtection/FullBodyHarnesses/TechnaCurvFullBodyHarness/2301-18TechnaCurvATO.pdf

[5] For very tall vent stacks that cannot be climbed, a hotwire anemometer can be used to obtain a flow rate from a manageable height on a vent stack. Cost data from: topac.com/anemometerTA35.html

[6] Assumed labor cost for Administrative Reporter is equal to labor cost for surveyor.

ii. **Slanted Roofs:** Emission sources may on roofs which are often not physically accessible. Vent stacks in particular are designed for safe venting and typically lead to rooftops away from personnel access points. A vent stack outlet above the roofline requires no routine maintenance, so access may not have been a facility design concern. The type of roof therefore affects accessibility of components on or above the roofline. Accessibility issues include:
   - whether the roof is flat or slanted;
   - whether the roof is accessible by a fixed ladder, by a portable ladder, by fixed stairs, or by portable lifts;

- whether the roof can safely support the weight of a survey/measurement technician; and
- component proximity to the edge of the roof which may require additional fall protection measures.

These factors will vary for each building and for each facility, meaning that slanted roofs and other roof accessibility issues will be more burdensome to some facilities and less burdensome to others.

Exhibit G-2: Survey and measurement of slanted roofs

Cost Item	Low Cost Scenario ($)			High Cost Scenario ($)		
Survey Instrument	Toxic Vapor Analyzer (TVA)[1]	$	2,000	Infrared Camera[2]	$	82,000
				Ultrasonic Leak Detector[3]	$	250
Survey Accessibility	Cherry Picker 1 hour @ $100/hour	$	100	Cherry Picker 32 hours @ $100/hour	$	3,200
Survey Labor	1 hour @ $50/hour[1]	$	50	32 hours @ $50/hour[1]	$	1,600
Measurement Instrument	TVA Correlation Equations	$	-	Hi Flow Sampler[4]	$	18,829
				Fall Protection Harness[5]	$	300
Measurement Accessibility				Cherry Picker 32 hours @ $100/hour	$	3,200
Measurement Labor	1 hour @ $50/hour[1]	$	50	32 hours @ $50/hour[1]	$	1,600
Reporting Labor	2 hours @ $50/hour[6]	$	100	64 hours @ $50/hour[6]	$	3,200
Total		$	2,300		$	114,179

[1] Data from *Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations* Lessons Learned document epa.gov/gasstar/documents/ll_dimgasproc.pdf

[2] Cost estimate from personal communication with FLIR salesman, Ed Jones

[3] Used to detect leaks. Data from PRO *Inspect Flowlines Annually* epa.gov/gasstar/documents/inspectflowlines.pdf

[4] Data from personal communication with Milton Heath of Heath Consultants (1-22-09) Includes cost of Hi Flow Sampler ($17,640) and cost of one calibration kit ($1,189).

[5] Fall Protection Harness to be used when climbing tall vent stack to get an flow reading. Cost data from: media.msanet.com/NA/USA/FallProtection/FullBodyHarnesses/TechnaCurvFullBodyHarness/2301-18TechnaCurvATO.pdf

[6] Assumed labor cost for Administrative Reporter is equal to labor cost for surveyor.

iii. **Confined Spaces:** Confined spaces require added safety measures such as use of a self contained breathing apparatus, so inclusion of components in confined spaces requires additional measures to access them.

Exhibit G-3: Survey and measurement of confined spaces

Cost Item	Low Cost Scenario ($)		High Cost Scenario ($)	
Survey Instrument	Toxic Vapor Analyzer (TVA)[1]	$ 2,000	Infrared Camera[2]	$ 82,000
			Ultrasonic Leak Detector[3]	$ 250
Survey Labor	1 hour @ $50/hour[1]	$ 50	32 hours @ $50/hour[1]	$ 1,600
Measurement Instrument	TVA Correlation Equations	$ -	Hi Flow Sampler[4]	$ 18,829
			SCBA Respriator[5]	$ 224
Measurement Accessibility			Cherry Picker 32 hours @ $100/hour	$ 3,200
Measurement Labor	1 hour @ $50/hour[1]	$ 50	32 hours @ $50/hour[1]	$ 1,600
Reporting Labor	2 hours @ $50/hour[6]	$ 100	64 hours @ $50/hour[6]	$ 3,200
Total		$ 2,200		$ 110,903

[1] Data from *Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations* Lessons Learned document epa.gov/gasstar/documents/ll_dimgasproc.pdf

[2] Cost estimate from personal communication with FLIR salesman, Ed Jones

[3] Used to detect below-ground leaks. Data from PRO *Inspect Flowlines Annually*
epa.gov/gasstar/documents/inspectflowlines.pdf

[4] Data from personal communication with Milton Heath of Heath Consultants (1-22-09)
Includes cost of Hi Flow Sampler ($17,640) and cost of one calibration kit ($1,189).

[5] SCBA (Self-Contained Breathing Apparatus) rental, used for confined spaces, where leak is sufficiently large to preclude breathing. Cost information from personal contact (Joe Hickman) at Dräger (draeger.com). Cost based on 2 hours of breathing time needed to survey leaks. SCBA rental rate is $173/week for unit including one cylinder with 60 minutes of breathing time; extra cylinder rental is $51/week, for a total of $224/week.
http://www.draeger.com/ST/internet/US/en/Industries/Industrial/Appli/Leak/SCBA/AirBossPSS100/pd_ld_airbosspss100_plus.jsp

[6] Assumed labor cost for Administrative Reporter is equal to labor cost for surveyor.

iv. **Buried Components:** The typical buried component is piping, ranging from small diameter flow lines to large diameter transmission lines. Fugitive emissions from such buried components can be detected by various means ranging from spotting dead vegetation above the lines to traversing the lines with various types of methane detection instruments. Quantification is more closely tied to the accessibility issue with buried components. Quantification may be possible without excavating the leaking component, and such quantification would require encasing the surrounding area with a tarp to capture all the methane flux from the ground and also accounting for the soil oxidizing rate. This method does not provide assurance that the entire magnitude is quantified since some of the methane may travel along the buried pipe corridor before moving towards the surface or may otherwise be dispersed over a larger ground area than the surface immediately above the component.

Excavation is another quantification option, and it is labor intensive and has safety issues. Excavation of a line still in service around a leak is a safety issue, especially for high pressure lines. Excavation of the soil supporting the line may also risk a blowout. Quantification of an excavated line that is still in service poses additional safety and measurement issues such as approaching the leak source and routing all emissions into the measurement instrument. Lines can be taken out of service for safe excavation (and replacement), though this complicates the ability to quantify accurately the leak rate.

Exhibit G-4: Survey and measurement of buried components

Cost Item	Low Cost Scenario ($)		High Cost Scenario ($)	
Survey Instrument	Toxic Vapor Analyzer (TVA)[1]	$ 2,000	Infrared Camera[2]	$ 82,000
			Ultrasonic Leak Detector[3]	$ 250
Survey Labor	1 hour @ $50/hour[1]	$ 50	32 hours @ $50/hour[1]	$ 1,600
Measurement Instrument	TVA Correlation Equations	$ -	Hi Flow Sampler[4]	$ 18,829
			Excavation Equipment[5]	$ 3,200
Measurement Accessibility			Cherry Picker 32 hours @ $100/hour	$ 3,200
Measurement Labor	1 hour @ $50/hour[1]	$ 50	32 hours @ $50/hour[1]	$ 1,600
Reporting Labor	2 hours @ $50/hour[6]	$ 100	64 hours @ $50/hour[6]	$ 3,200
Total		$ 2,200		$ 113,879

[1] Data from *Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations* Lessons Learned document epa.gov/gasstar/documents/ll_dimgasproc.pdf

[2] Cost estimate from personal communication with FLIR salesman, Ed Jones

[3] Used to detect leaks. Data from PRO *Inspect Flowlines Annually* epa.gov/gasstar/documents/inspectflowlines.pdf

[4] Data from personal communication with Milton Heath of Heath Consultants (1-22-09) Includes cost of Hi Flow Sampler ($17,640) and cost of one calibration kit ($1,189).

[5] Cost of backhoe used for 32 hours @ $100/hour.

[6] Assumed labor cost for Administrative Reporter is equal to labor cost for surveyor.

v. **Limited Accessibility Because of Safety:** High flow rate fugitives or fugitives with high velocity or high pressure drop can be a safety issue. For example, compressor unit valves, when closed, isolate the compressor from the high pressure main line, and leaks across this valve can be large in magnitude and high in velocity. Another example is compressor or pump seal oil degassing vents that carry methane which has entrained oil mist or other liquids which may not be safe to approach for quantification or measurement without breathing protection.

Exhibit G-5: Survey and measurement of no or limited accessibility due to safety

Cost Item	Low Cost Scenario ($)		High Cost Scenario ($)	
Survey Instrument	Toxic Vapor Analyzer (TVA)[1]	$ 2,000	Infrared Camera[2]	$ 82,000
			Ultrasonic Leak Detector[3]	$ 250
Survey Accessibility	Cherry Picker 1 hour @ $100/hour	$ 100	Cherry Picker 32 hours @ $100/hour	$ 3,200
Survey Labor	1 hour @ $50/hour[1]	$ 50	32 hours @ $50/hour[1]	$ 1,600
Measurement Instrument	TVA Correlation Equations	$ -	Hi Flow Sampler[4]	$ 18,829
			Hotwire Anemometer[5]	$ 995
			SCBA Respriator[7]	$ 224
Measurement Accessibility			Cherry Picker 32 hours @ $100/hour	$ 3,200
Measurement Labor	1 hour @ $50/hour[1]	$ 50	32 hours @ $50/hour[1]	$ 1,600
Reporting Labor	2 hours @ $50/hour[6]	$ 100	64 hours @ $50/hour[6]	$ 3,200
Total		$ 2,300		$ 115,098

[1] Data from *Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations* Lessons Learned document epa.gov/gasstar/documents/ll_dimgasproc.pdf

[2] Cost estimate from personal communication with FLIR salesman, Ed Jones

[3] Used to detect leaks. Data from PRO *Inspect Flowlines Annually* epa.gov/gasstar/documents/inspectflowlines.pdf

[4] Data from personal communication with Milton Heath of Heath Consultants (1-22-09) Includes cost of Hi Flow Sampler ($17,640) and cost of one calibration kit ($1,189).

[5] Cost data from personal communication with Heath Consultants saleswoman on January 16, 2009. Cost data from: heathus.com

[6] Assumed labor cost for Administrative Reporter is equal to labor cost for surveyor.

[7] SCBA (Self-Contained Breathing Apparatus) rental, used for confined spaces, where leak is sufficiently large to preclude breathing. Cost information from personal contact (Joe Hickman) at Dräger (draeger.com). Cost based on 2 hours of breathing time needed to survey leaks. SCBA rental rate is $173/week for unit including one cylinder with 60 minutes of breathing time; extra cylinder rental is $51/week, for a total of $224/week. http://www.draeger.com/ST/internet/US/en/Industries/Industrial/Appli/Leak/SCBA/AirBossPSS100/pd_ld_airbosspss100_plus.jsp

vi. **Scheduling Shutdowns, Startups, or Maintenance to Not Interfere with Measurement:** Fugitive emission can vary depending on operating mode, and the availability of each operating mode for leak inspection and quantification is another accessibility issue. Compressors have a number of operating modes and best illustrate this accessibility issue. Some operators have compressors with high operating factors which limits the leak inspection and quantification of those compressors in the standby or shutdown mode. Conversely, compressors with a standby or peak loading role will have limited availability in the running operating mode for leak inspection and quantification.

vii. **Internal Leaks through Open-Ended Lines:** OELs can be manifolded into a single stack that leads to the atmosphere. A common example of this is valves around a compressor: two unit valves isolate the compressor from the main line, and a blowdown valve allows the volume of the compressor between the unit valves to be depressurized. All three of these valves typically lead to a single stack, and attributing leaks to a specific valve to target for quantification (or repair) can be difficult. In the case of the three compressor valves, a compressor can be cycled through different operating modes to isolate leak rate of the blowdown valve and leak rate of the two unit valves, but attributing leak rates to individual unit valves is difficult. If multiple compressors are connected to the same vent stack then it is difficult to identify the leak with a particular compressor. Hence, though a cumulative emissions reporting is possible in such cases, determining the number of leaking valves may not be possible.

A single fugitive emissions source can also reach the atmosphere through more than one path. An example of this is fugitives from pig trap valve which may reach the atmosphere either through the vent atop a pig trap or through the gasket on the pig trap hatch: both paths to the atmosphere must be measured and totaled to estimate the entire leak rate from the pig trap.

D. Data Sources for Research

Resources related to component accessibility are listed below.

- Clean Air Act
  - 40 CFR 60 Appendices: EPA Method 21
  - 40 CFR 60 Subpart KKK: Standards of Performance of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.
  - AWP in 40 CFR General Provisions
- OSHA Standards
  - The need to carry flammable gas detector (OSHA requires that the employer must provide personal protective equipment (PPE) for employees in a dangerous environment. If it is determined that a flammable gas detector is necessary PPE, then one must be provided and used.) 1910.132 - General requirements.
  - The need to be aware of surroundings and watch where you walking (Requires employer to develop safe work practices and train employees on them) 1910.119 - Process safety management of highly hazardous chemicals.
  - Fall protection 1926.502 - Fall protection systems criteria and practices
  - Confined spaces 1910.146 Confined Spaces - Amended Final Rule (1998)
- Industry published standard operating procedures
  - API Leak Detection Standards API publishes many of these; each costs about $150.

E. Summary

- If the inaccessibility provisions for monitoring under the VOC LDAR regulation also apply to this reporting rule, the reporting rule may be able to require optical leak detection for components that are inaccessible, but may not be able to require direct emission measurement.
- The enclosure method requires that a technician must first gain access to the component and remain in the inaccessible location for a relatively long period of time relative to other quantification methods to perform the measurement.
- For vented methane emissions, significant emissions sources are often routed through OELs which are inaccessible, and exclusion of these OELs in particular would affect

the comprehensiveness of a facility's emissions reporting. Buried components are also potentially large fugitive emissions sources.

- Remote sensing requires a) a capital investment by operators who lack suitable instruments already and b) rule language that ensures consistent and reasonable use of the instrument to detect methane leaks successfully. Method 21 monitoring of inaccessible components requires a capital investment by operators to obtain accessibility equipment such as lifts to gain physical proximity to each inaccessible component. Estimated cost impacts for either type of monitoring have been provided in the exhibits above for various types of inaccessible components.

Appendix H: Review and assessment of potential alternatives to monitoring methods for emissions sources

Pneumatic Pumps

This appendix provides a brief overview of selected key comments (not all) representing initial thoughts to show why changes in the proposed supplemental rule were made. These are not meant to show every comment on an issue, or a response on every issue. First, it summarizes the comment(s) and then it summarizes research on pump curves, in this case, from pump vendors and how it can be used to estimate emissions from pumps.

Comments

A commenter proposes an alternate engineering emissions estimation methodology that employs the ideal gas law, different from direct measurement of emissions or using data from pump manufacturers and emission factors. The data required for this estimation methodology is provided by manufacturers in the form of "pump curves".

The volume of natural gas emissions from a pneumatic pump is a function of the amount of liquid pumped (displacement volume), the liquid outlet pressure from the pump, the gas pressure and temperature used as the pneumatic power gas, and the "mechanical efficiency loss" across the pump. In manufacturers' information, this relationship is typically described using a set of "pump curves." It can be described mathematically as follows: [37]

Gas volume = [{(outlet pressure from the pump psig) + (atmospheric pressure psia)}/14.7 psia] * (atmospheric temperature R/(460 R + gas temperature F) * (volume of liquid pumped in cubic feet) * (1+pump inefficiency)

Volume of liquid:

Measured volume or calculated volume: (gals/stroke of pump/7.48 gal/scf * number of strokes/min)

Pump inefficiency:

Expressed as a fractional decimal (e.g. 0.30) provided by the manufacturer or an assumed default of 30% mechanical efficiency loss

The gas temperature and pressure is assumed to be at atmospheric conditions in the equation above. To estimate the GHG emissions from the above equations:

CO_2 = (Volume of gas above) * (CO_2 content of pneumatic power gas)
CH_4 = (Volume of gas above) * (CH_4 content of pneumatic power gas)

Comments

[37] The use of "fugitive" in quoted text from the initial proposed rule implies both fugitive and vented emissions as defined in this document.

A commenter recommends using emission factors for pneumatic pumps provided in the API Compendium where emissions from pneumatic pumps are considered to be a small contributor to total facility emissions.

Exhibit H-1 provides emission factors from API Compendium 2004

Exhibit H-1: Emission factor for pneumatic pump seals.

Component – Service [a]	Emission Factor original units [b] (lb gas/day/component)	Emission Factor converted to (tonne gas/hr/component)
Pump Seals – gas	0.609	1.15E-05

The engineering estimation method proposed by the first commenter is also supported by the second commenter.

Measurement Methods

A commenter lists the following methods as potential emissions measurement methods:

- Direct measurement of gas consumption rate by pneumatic pump type using gas flow meters, and the measured or estimated CH_4 content of gas.
- Measured gas consumption rates by pneumatic pump type from vendor data, and the measured or estimated CH_4 content of gas.
- Emissions factor by pneumatic pump type (piston, diaphragm or average), and the measured or estimated CH_4 content of gas.
- Vented CH_4 emissions from pneumatic pumps are estimated using the bleed rates of gas from the pumps, and the methane fraction of the vented gas, according to the following equation:

$$E_{CH4} = \frac{1lb-mole/379.3scf * MW_{CH4} * fCH_4 * t_{annual} * Q_{bleed}}{2200}$$

where,

E_{CH4}	=	total pneumatic pump CH_4 venting emissions for a basin or region [tonne/yr]
Q_{bleed}	=	bleed rate of gas from a pneumatic pump [scf/hr]
MW_{CH4}	=	molecular weight of methane (16 lb/lb-mole) [lb/lb-mole]
f_{CH4}	=	molar fraction of methane in the gas
t_{annual}	=	annual usage of the pneumatic devices [hr/yr]

Manufacturer's Pump Curves:

Pneumatic pump manufacturer Kimray was contacted regarding their manufacturer "pump curves". Kimray provides pump curves for all its pneumatic pumps. Pump curves graphically represent the relationship between gas pump speed strokes per minute and gallons per hour of liquid pumped. Manufacturers also provide tables indicating the gas consumption or usage per gallon of liquid pumped at different operating pressures. This information can be used to estimate emissions from pneumatic pumps. Sample Kimray pump curve and gas consumption tables can be found at Kimray's website.[38]

Summary

Measurement of natural gas fugitive emissions either by direct measurement or using data provided by the pump manufacturer, along with appropriate emission factors may be used to estimate total emissions. The application of pump curves provided by manufacturers also seems feasible and a potentially cost-effective method to estimate emissions from pumps. If pump curves are not provided by the manufacturer, then the pump curves for pumps with similar operational capacity and manufacturer can be used for emissions estimation.

Acid Gas Removal (AGR) Vents

This appendix provides a brief overview of selected key comments (not all) representing initial thoughts to show why changes in the proposed supplemental rule were made. These are not meant to show every comment on an issue, or a response on every issue. First, it summarizes the comments, and then it provides quantification methods opted or reported by Natural Gas STAR partners, the API Compendium, and the EPA National GHG Inventory.

Comments

A commenter proposes the use of the following methods to estimate emissions from AGR vents:

- Mass balance
- Emission factor

Comments

Another commenter proposes the use of mass balance methods to estimate emissions from AGR vents. In cases where acid gas flow and composition are measured, this commenter recommends mass balance and in other cases proposes the following equation:

$$E_{ag} = Q_{ag} * (y_{CO2} * \rho_{CO2} + 21 * y_{CH4} * \rho_{CH4})$$

where,

E_{ag}	=	Mass of acid gas removed (tonnes CO_2e)
Q_{ag}	=	Volume of acid gas (1000 m^3)
y_{CO2}	=	Mole fraction of CO_2 in the acid gas
y_{CH4}	=	Mole fraction CH_4 in the acid gas
ρ_{CO2}	=	Density of CO_2 (1.87 kg/m^3)
ρ_{CH4}	=	Density of CH_4 (0.717 kg/m^3)
21	=	Global warming potential for CH_4

[38] Kimray. Available online at: <www.kimray.com.cn/pdf/G_10.17.pdf>

API Compendium Measurement Method

The API compendium lists the following methods to estimate methane emissions from amine units:

- API's AMINECalc is a software that provides a mass emission rate for VOCs that can be converted into methane emission rates based on the methane composition in the gas. Details on this software are available at: engineers.ihs.com/document/abstract/CKFJDBAAAAAAAAAA
- For uncontrolled AGR units, two CH_4 emission factors for AGR vents were developed as part of the 1996 GRI/EPA CH_4 emissions study (Volume 14, page A-13) based on process simulation results for typical unit operations of a diethanol amine (DEA) unit (Myers, 1996). The factors are listed in Exhibit H-2 below[39]:

Exhibit H-2: Process Simulation Results for a Diethanol Amine Unit

Source	Methane Emission Factor original units	Methane Emission Factor converted to tonnes	Uncertainty (+/- %)
AGR vent	965 scf/10^6 scf treated gas	0.0185 tonnes/10^6 scf treated gas 0.654 tonnes/10^6 m^3 treated gas	119
	6,083 scfd/AGR unit	0.1167 tonnes/day-AGR unit	126

EPA National GHG Inventory:

The U.S. GHG Inventory employs a mass balance approach to estimate methane emission from AGRs. The CO_2 content acceptable in natural gas transmission pipelines varies from 1% to 3% depending on the pipeline company. The national average of CO_2 content in pipeline gas is 1%. As a result, natural gas processing companies are most likely aware of their outgoing natural gas CO_2 composition. If the CO_2 composition of the incoming natural gas can be identified, then estimation of emissions from AGR units is feasible using simple and cost effective mass balance approach.

Summary

If processing plants know the composition of their incoming and outgoing gas, the mass balance approach is reasonable for estimating CO_2 emissions. Another approach is using simulation software packages to estimate emissions CO_2 emissions.

The mass balance approach may not be reliable for methane emissions since feed gas and residue gas methane content are two very large numbers while the amount of methane going up the AGR vent is a very small number. For this source, methane losses may not be estimated as they are very small and would be difficult to assess via the mass balance approach.

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[39] API Compendium 2004, Appendix B-Additional Calculation Approaches, Page B-39.

Glycol Dehydrator

This appendix summarizes the input parameters to GTI's GLYCalc™ software and how it is typically used. Below are 1) key GLYCalc™ inputs, 2) precedents for mandated use of GLYCalc™ specifically, and 3) a Summary of a quantification method.

Required GLYCalc™ inputs include:

Volume percent of the following components in the gas at the dehydrator inlet:

CO_2	C2	n-C6	Benzene
H_2S	C3	other C6	Toluene
N_2	C4s	C7s	Xylenes
C1	C5s	2,2,4 Trimethylpentane	C8+.

Other required information:

- Is gas saturated (y/n)
- Lean glycol recirculation ratio
- Type of stripping gas (dry/wet)
- Stripping gas flow rate
- Is gas saturated (y/n)
- Lean glycol recirculation ratio
- Type of stripping gas (dry/wet)
- Stripping gas flow rate
- Dry gas dewpoint
- Lean glycol concentration (%)
- Flash tank temperature and pressure
- Throughput
- Operating hours per year
- Glycol pump type
- What controls are on the reboiler vent and flash gas vent? (i.e. is it vented, routed to fuel gas, etc).

Precedents for GLYCalc™ use

EPA AP-42 is the set of air emissions rate quantification methods for various pollutants (VOC, BTEX, HAPs). AP-42 gives GLYCalc™ as the only option for glycol dehydrators in gas processing[40]. The section on natural gas processing discusses glycol dehydration indicating that glycol dehydrator emissions are important from an air emissions standpoint and recommends using GLYCalc™.

MMS GOADS also uses GLYCalc™ to estimate all air emissions from glycol dehydrators[41].

State guidance documents for permitting show that GLYCalc™ is also specified by name and required for estimating air emissions rates. At least one state has specified an alternative if the operator does not wish to use GLYCALC™[42]. The alternative is a mass balance calculation which requires taking samples of the rich glycol and the lean glycol and

[40] EPA. *AP-42*. Section 5.3. January 1995. <www.epa.gov/ttn/chief/ap42/ch05/index.html>

[41] Mineral Management Service (MMS). *Gulfwide Emission Inventory Study for the Regional Haze and Ozone Modeling Effort.* October 2004. MMS 2004-072. pg. 5-17 <www.gomr.mms.gov/PI/PDFImages/ESPIS/2/3010.pdf >

[42] Oklahoma Department of Environmental Quality. *Fact Sheet: Title V Oil & Gas Facilities.* February 6, 1997. pg. 7 <www.deq.state.ok.us/factsheets/air/o&gfctst.pdf>

calculating the difference for each pollutant species. This method is also applicable for methane and carbon dioxide.

Summary

Given that GLYCalc™ is ubiquitous in industry and in regulatory entities both at the national and the state levels, GLYCalc™ could be used in the mandatory reporting rule: it is an industry standard and is not a cost burden at $140.00 per license[43]. Allowing for alternative estimation methods, either competing models, calculations, or measurement methods, would require additional resources for an EPA validation program since not all alternatives may be as rigorous or correct. Use of the same or similar inputs as GLYCalc™ does not guarantee an accurate emissions rate result as shown by the following two examples.

1. The well-known 1996 EPA-GRI study in volume 14[44] developed glycol dehydrator process simulations using ASPEN/SP® software that had relevant inputs as the basis for its results; however, the results have since been proven to have the unrealistic assumption of holding the glycol circulation rate constant for different runs. As a result, the results were developed assuming that reboiler stack methane emissions rate corresponds to the inlet gas flow rate (stack emissions actually correspond to glycol circulation rate). Though this study is an authority on methane emissions, and ASPEN is an established process simulator, the applied methodology for this particular source has become outdated as understanding of methane emissions has increased. This is an example of how application of different models for dehydrator emissions may cause inconsistent results from reporting entity to reporting entity and one advantage of stipulating a standardized software package.

2. The 1996 EPA-GRI study also uses process simulation to estimate methane emissions from amine units which operate similar to glycol dehydrators in that they have a contactor and regenerator. The study used a process simulator, ASPEN PLUS™, to model methane emissions by using 100 percent water as the solvent as a surrogate for aqueous amine solutions[45]. This may or may not be a valid assumption when using a process simulator for an individual unit, depending on the desired accuracy, and would require further resources to assess how this assumption compares to actual emission rates for specific units. Similar issues would arise for assessing assumptions when allowing other process simulation methods for glycol dehydrator methane emissions.

Thus other glycol dehydrator emission modeling approaches are available but are primarily found in literature before GLYCalc™ became the norm and their use alongside GLYCalc™ may result in non-standard results across reporting entities.

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[43] GTI. *GRI-GLYCalc.* Version 4.0. [CD-ROM]. GRI-00/0102. <www.gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=10abstractpage\12352.xml>

[44] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 14. June 1996. <www.epa.gov/gasstar/documents/emissions_report/14_glycol.pdf>

[45] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 6. June 1996. <www.epa.gov/gasstar/documents/emissions_report/6_vented.pdf>

Appendix I: Flares

This appendix provides results of additional research and general consensus on flare reporting that was conducted to support development of the supplemental proposed rulemaking.

No data source was found that comprehensively reports data on vented and flared emissions from the production and processing sector of the oil and gas industry. The EIA does collect information from states on a voluntary basis. However, this data is not complete and moreover does not distinguish flare data from vent data.

In 2004, the U.S. Government Accountability Office raised concerns on the lack of information on vented and flared data. EIA responded to this, but did not propose any concrete steps to collect accurate information. In summary, EIA proposed to rely on states, the Bureau of Land Management (BLM), and the Mineral Management Services to report, as best as possible, data on vented and flared emissions. In addition, EIA noted that BLM estimated the cost of meter vents and flares to be around $32 million in 2004 dollars.[46]

Flares in general can be categorized into two main types; continuous and intermittent. Continuous flares combust casing head gas, associated gas, well testing gas, and gas from equipment that generate a continuous waste gas stream (such as glycol dehydrators, storage tanks, and pneumatic devices). Intermittent flares combust releases that are not continuous in nature such as streams from equipment/ vessel/ site blowdowns and pressure relief valves.

The emissions from continuous flares can be monitored using predominantly two techniques that are practical for the rule; (1) measurements using either a continuous flow meter or one time measurement meters, and (2) engineering methods. If most of the equipment emissions going to a flare get included in the rule, only associated gas and casing head gas flaring will have to be accounted for in this rule.

Intermittent flare emissions can be measured only using continuous flow meters or engineering estimation methods. The volume of intermittent emissions is lower in magnitude in comparison to continuous emissions. Hence using continuous flow meters could be cost prohibitive for the purposes of the Rule.

Summary
Considering the various options and the magnitude of emissions from each type of flare (continuous and intermittent), the following monitoring options could be adopted for the Rule;

Onshore and Offshore Production

1) Continuous flaring: All major continuous equipment vents are covered in the initial rule proposal as individual sources. The only three major continuous sources not

[46] GAO. *Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions.* July 14, 2004. GAO-04-809. <www.gao.gov/products/GAO-04-809>

covered are casing head gas, associated gas, and well testing gas. Engineering estimation methods can be used for these sources. Companies can easily measure the gas-to-oil ratio for each of the sources and estimate emissions using calculation methods.

2) Intermittent flaring: All equipment sending gas to the flare on an intermittent basis are covered as individual sources in the proposed rule.

Onshore Processing

There are potentially many sources that send their gas to a flare and are not covered in the proposed rule. For example, molecular sieves send gas to the flare intermittently and are not covered in the Rule. In addition, gas plants may send pure hydrocarbon products such as propane and butane to a flare when equipment shuts down (they may prefer to keep the plant running and losing some product as opposed to shutting down the plant). However, the possibility of using continuous meters on flares in processing plants can be cost prohibitive. One option is to provide for calculative methods based on the volume of pure hydrocarbons sent to flares during a disruption.

Appendix J: Development of multipliers to scale emissions or miscellaneous sources connected to storage tanks

This method of quantifying tank emissions assumes that thermodynamically based models such as E&P Tank can accurately predict the effect of flashing emissions from hydrocarbons in fixed roof storage; but are unable to predict or account for emissions from vortexing or dump valves. Either direct measurement or a correction factor is required to represent the total emissions from hydrocarbon storage tanks.

This appendix compares two methods of correcting E&P Tank (GEO-RVP) data to account for non-flashing emission effects on tanks. Actual measurement data from a Texas Commission on Environmental Quality (TCEQ) report[47] were compared to E&P Tank (GEO-RVP) data runs on the same tanks to develop a correction factor which can be applied to E&P Tank (GEO-RVP) results in which additional non-flashing emissions or vortexing are detected.

Selected Data

All data considered were presented in a TCEQ-funded report that compared tank emission predicting equations, charts, and models to actual measured data. Data from the E&P Tank 2.0 GEO-RVP setting were compared against to direct measurement results. The TCEQ study focused on comparing the various methods of predicting VOC portion of emissions; however, for the purposes of this analysis, the total gas-oil ratios were compared.

Where direct measurement results were within ±100% of E&P Tank (GEO-RVP) results, those tanks were assumed to be exhibiting typical flashing emissions only. Direct measurement results greater or less than ±100% of E&P Tank (GEO-RVP) results were used to develop a correction factor for non-flashing effects on tank emissions.

The data were separated into two regimes:

- Hydrocarbon liquids with API gravities less than 45˚API were considered "oil"
- Hydrocarbon liquids with API gravities greater than 45˚API were considered "condensate"

Correction factors were developed for both ranges.

Method 1 – Least Squares Analysis of Emission Difference

The first method sorts qualifying tanks in ascending order of emission rates estimated by the E&P Tank (GEO-RVP) runs. The difference between the measured emission rate and E&P Tank (GEO-RVP) emission rates was plotted against the E&P Tank (GEO-RVP) emission rates and a trend line was fitted to the equation, as shown in Exhibits J-1 and J-2.

Exhibit J-1. Oil Tank Correction Factors

[47] Texas Commission on Environmental Quality (TCEQ). *Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation*. July 16, 2009.

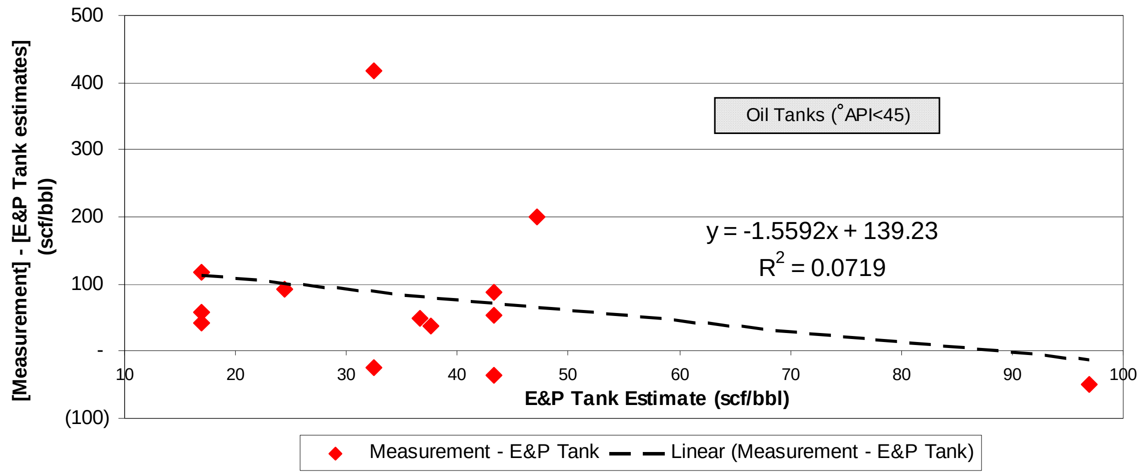
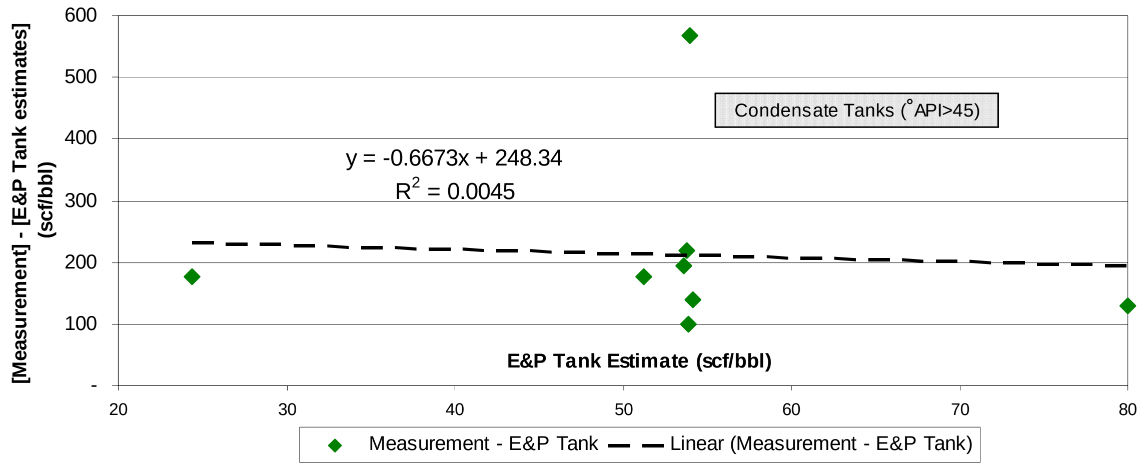


Exhibit J-2. Condensate Tank Correction Factors



The equation for the line of best fit can be used on E&P Tank (GEO-RVP) results where non-flashing emission affects are detected to estimate the true tank emissions. The data used to derive this relationship range from oil gravities from 29.1 to 44.8˚API and separator pressures from 15 to 70 psig; and for condensate gravities from 45.3 to 82.2˚API and separator pressures from 30 to 231 psig.

The E&P Tank (GEO-RVP) emission estimates can be corrected with the following equations:

- For oil: CE = (-0.5592 × EE) + 139.23
- For condensate: CE = (0.3327 × EE) + 248.34

Where "EE" is the E&P Tank (GEO-RVP) emission estimate and "CE" is the corrected emission estimate.

As demonstrated in Exhibits J-1 and J-2, the correlations for the correction factor are very weak, with R^2 values of 0.0719 for oil and 0.0045 for condensate.

Method 2 – Average Emissions Ratio Analysis

This method takes the simple average of the ratio of qualifying measured emission rates to simulated emission rates generated by E&P Tank (GEO-RVP) for the oil and condensate ranges.

Using this method, E&P Tank (GEO-RVP) emission estimates can be corrected with the following equations:

- For oil: $CE = 3.87 \times EE$
- For condensate: $CE = 5.37 \times EE$

Where "EE" is the E&P Tank (GEO-RVP) emission estimate and "CE" is the corrected emission estimate.

Summary

Predicting and evaluating non-flashing effects on emissions (such as dump valves or vortexing) has not yet been thoroughly studied or quantified. The methods above have significant weaknesses as:

1. The sample data set is limited
2. Only weak correlations were observed for the available data.

Method 1 naturally suggests that very low estimates are underestimating the tank emissions and very high estimates (over 89 scf/bbl for oil) are overestimating the emissions. This will tend to "even out" estimates so that none are extremely high or extremely low. It also suggests that if E&P Tank (GEO-RVP) estimates 0 scf/bbl flashing emissions, the emission rates are actually higher than if E&P Tank (GEO-RVP) estimates large (near 89 scf/bbl for oil) emission rates.

Method 2 does not "even out" emission rates, and assumes that in all cases where non-flashing effects are present, each case is uniformly underestimated.

Appendix K: Development of Leaker Emission Factors

Natural Gas Emission Factors for Onshore Production

<u>Leaker Emission Factors – All Components, Light Crude Service</u>

Methodology

Average emission factors by facility type are taken from API's *Emission Factors for Oil and Gas Production Operations*[48]. (A discussion on how this API study was conducted is provided in Appendix P.) Hydrocarbon liquids greater than or equal to 20°API are considered "light crude." The methane content of associated natural gas with onshore light crude is 61.3% is taken from the same API publication, Table ES-4, page ES-3.

Component EF, scf/hour/component = ((Component EF, lb/day THC) * (**A**)) / ((**B**) * (**C**))

Component Name	Component EF, scf/hour/comp	Component EF, lb/day THC
Valve	2.03	3.381
Connector	0.90	1.497
Open-Ended Line	0.96	1.6
Pump	2.35	3.905
Other	2.31	3.846

EF: Emission Factor
THC: Total Hydrocarbons

Conversions:
A: 0.613 – CH_4 content of onshore light crude associated natural gas
B: 0.04246 CH_4 density lb/scf
C: 24 hours/day

<u>Leaker Emission Factors – All Components, Heavy Crude Service</u>

Methodology

Average emission factors by facility type are taken from API's *Emission Factors for Oil and Gas Production Operations*[48]. (A discussion on how this API study was conducted is provided in Appendix P.) Hydrocarbon liquids less than 20°API are considered "heavy crude." The methane content of associated natural gas with onshore heavy crude is 94.2% taken from the same API publication, Table ES-4, page ES-3.

Component EF, scf/hour/component = ((Component EF, lb/day THC) * (**D**)) / ((**B**) * (**C**))

Component Name	Component EF, scf/hour/component	Component EF, lb/day THC
Valve	3.13	3.381
Flange	4.15	4.49

[48] API. *Emission Factors for Oil and Gas Production Operations*. Table 10, page 16. API Publication Number 4615. January 1995.

Connector (other)	1.38	1.497
Open-Ended Line	1.48	1.6
Other	3.56	3.846

EF: Emission Factor
THC: Total Hydrocarbons

Conversions:
B: 0.04246 CH_4 density lb/scf
C: 24 hours/day
D: 0.942 – CH_4 content of onshore heavy crude associated natural gas

Total Hydrocarbon Emission Factors for Processing

Leaker Emissions Factors – Reciprocating Compressor Components, Centrifugal Compressor Components, and Other Components, Gas Service

Methodology
The leaker emissions factors are from Clearstone Engineering's *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*[49] and Clearstone's *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*[50]. (A discussion on how these studies were conducted is provided in Appendix P.) The components were categorized into three groups: reciprocating compressor related, centrifugal compressor related and all other components. Furthermore, the components related to reciprocating and centrifugal compressor were segregated into components before and after the de-methanizer. Once categorized, the sum of the leak rates from components known to be leaking was divided by the sum of number of leaking components.

Component EF, scf/hour/component = (Leak rate**,** Mscf/day/component) * (**E**) / (**C**)

Component Name	Reciprocating Compressor Component, (scf/hour/comp)		Centrifugal Compressor Component, (scf/hour/comp)		Other Components, (scf/hour/comp)
	Before De-Methanizer	After De-Methanizer	Before De-Methanizer	After De-Methanizer	
Valve	15.88	18.09	0.67	2.51	6.42
Connector	4.31	9.10	2.33	3.14	5.71
Open-Ended Line	17.90	10.29	17.90	16.17	11.27
Pressure Relief Valve	2.01	30.46	-	-	2.01
Meter	0.02	48.29	-	-	2.93

[49] EPA. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*. Clearstone Engineering Ltd. June 20, 2002. <www.epa.gov/gasstar/documents/four_plants.pdf>
[50] National Gas Machinery Laboratory, Kansas State University; Clearstone Engineering, Ltd; Innovative Environmental Solutions, Inc. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. For EPA Natural Gas STAR Program. March 2006.

Total Hydrocarbon Emission Factors for Transmission

<u>Leaker Emission Factors – All Components, Gas Service</u>

Methodology

Gas transmission facility emissions are drawn from the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[51] and the *Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*[52].. (A discussion on how these studies were conducted is provided in Appendix P.) All compressor related components were separated from the raw data and categorized into the component types. Once categorized, the sum of the leak rates from components known to be leaking was divided by the sum of number of leaking components.

Component EF, scf/hour/component = (Gas Transmission Facility Emissions, kg/h/src) * (**F**) / (**B**)

Component Name	Component EF, (scf/hour/comp)
Connector	2.7
Block Valve	10.4
Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-Ended Line	21.5

Conversions:

B: 0.04246 CH_4 density lb/scf

F: 2.20462262 lb/kg

[51] Clearstone. *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*. Clearstone Engineering Ltd., Enerco Engineering Ltd, and Radian International. May 25, 1998.

[52] Clearstone. *Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*. Clearstone Engineering Ltd., Canadian Energy Partnership for Environmental Innovation (CEPEI). April 16, 2007.

Methane Emission Factors for LNG Storage

Leaker Emission Factors – LNG Storage Components, LNG Service

Methodology

The light liquid emission factors with leak concentrations greater than or equal to 10,000 ppmv were taken from *Protocol for Equipment Leak Emission Estimates*[53]. The emissions are assumed to be 100% methane.

Component EF, scf/hour/component = (Light Liquid >= 10,000 ppmv Emission Factor) * (**F**) / (**B**)

Component Name	Component EF, scf/hour/comp	† Light Liquid EF, kg/hr THC
Valve	1.19	2.30E-02
Pump Seal	4.00	7.70E-02
Connector	0.34	6.50E-03
Other	1.77	3.40E-02
† Greater or equal to 10,000 ppmv		

Conversions:
B: 0.04246 CH_4 density lb/scf
F: 2.20462262 lb/kg

Methane Emission Factors for LNG Terminals

Leaker Emission Factors – LNG Terminals Components, LNG Service

Methodology

See methodology for Leaker Emission Factors – LNG Storage Components, LNG Service for LNG Storage[53].

Methane Emission Factors for Distribution

Leaker Emission Factors – Above Grade M&R Stations Components, Gas Service

Methodology

Gas distribution meter/regulator station emissions are drawn from: *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[51] and *Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*[52]. (A discussion on how these studies were conducted is provided in Appendix P.)

[53] EPA. *Protocol for Equipment Leak Emission Estimates*. Emission Standards Division. U.S. EPA. SOCMI Table 2-7. November 1995.

Component EF, scf/hour/component = (Gas Distribution Meter/Regulator Station Emissions, kg/h/src) * (**F**) / (**B**)

Component Name	**Component EF, scf/hour/comp**	**Gas Distribution Meter/Regulator Station Emissions, kg/h/src**
Connector	0.67	0.01292
Block Valve	1.49	0.02872
Control Valve	3.94	0.07581
Pressure Relief Valve	5.24	0.1009
Orifice Meter	0.46	0.0088
Other Meter	0.01	0.0002064
Regulator	2.14	0.04129
Open-Ended Line	6.01	0.1158

Conversions:
B: 0.04246 CH_4 density lb/scf
F: 2.20462262 lb/kg

<u>Leaker Emission Factors – Distribution Mains and Services, Gas Service</u>

Methodology

Emission factors for pipeline leaks (mains and services) are drawn from GRI's *Methane Emissions from the Natural Gas Industry*[54].

Component EF, scf/hour/leak = (Pipeline Leak, scf/leak-year) / (**G**)

Component Name	**Component EF (Mains), scf/hour/leak**	**Pipeline Leak EF (Mains), scf/leak-yr**	**Component EF, (Services) scf/hour/leak**	**Pipeline Leak EF (Services), scf/leak-yr**
Unprotected Steel	6.02	52748	2.33	20433
Protected Steel	2.38	20891	1.08	9438
Plastic	11.63	101897	0.35	3026
Copper			0.88	7684

Conversions:
G: 8,760 hours/year

NATURAL GAS EMISSION FACTORS FOR ONSHORE PRODUCTION

Onshore production	Emission Factor (scf/hour/component)
Leaker Emission Factors - All Components, Gas Service	

[54] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 9. Tables 8-9 and 9-4. June 1996. <www.epa.gov/gasstar/documents/emissions_report/9_underground.pdf>

Valve	NA
Connector	NA
Open-ended Line	NA
Pressure Relief Valve	NA
Low-Bleed Pneumatic Device Vents	NA
Gathering Pipelines	NA
CBM Well Water Production	NA
Compressor Starter Gas Vent	NA
Conventional Gas Well Completion	NA
Conventional Gas Well Workover	NA
Leaker Emission Factors - All Components, Light Crude Service[1]	
Valve	2.03
Connector	0.90
Open-ended Line	0.96
Pump	2.35
Other	2.31
Leaker Emission Factors - All Components, Heavy Crude Service[2]	
Valve	3.13
Flange	4.15
Connector (other)	1.38
Open-ended Line	1.48
Other	3.56

[1] Hydrocarbon liquids greater than or equal to 20˚API are considered "light crude"
[2] Hydrocarbon liquids less than 20˚API are considered "heavy crude"

TOTAL HYDROCARBON EMISSION FACTORS FOR PROCESSING

Processing[1]	Before De-Methanizer Emission Factor (scf/hour/component)	After De-Methanizer Emission Factor (scf/hour/component)
Leaker Emission Factors - Reciprocating Compressor Components, Gas Service		
Valve	15.88	18.09
Connector	4.31	9.10
Open-ended Line	17.90	10.29
Pressure Relief Valve	2.01	30.46
Meter	0.02	48.29
Leaker Emission Factors - Centrifugal Compressor Components, Gas Service		
Valve	0.67	2.51
Connector	2.33	3.14
Open-ended Line	17.90	16.17
Leaker Emission Factors - Other Components, Gas Service[2]		
Valve	6.42	
Connector	5.71	
Open-ended Line	11.27	
Pressure Relief Valve	2.01	
Meter	2.93	
Population Emission Factors - Other Components, Gas Service		

Gathering Pipelines[3]	2.81

METHANE EMISSION FACTORS FOR TRANSMISSION

Transmission	Emission Factor (scf/hour/component)
Leaker Emission Factors - All Components, Gas Service	
Connector	2.7
Block Valve	10.4
Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-ended Line	21.5
Leaker Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	NA
Gathering Pipelines[1]	NA

[1] Emission Factor is in units of "scf/hour/mile"

METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE

Underground Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors - Storage Station, Gas Service	
Connector	0.96
Block Valve	2.02
Control Valve	3.94
Compressor Blowdown Valve	66.15
Pressure Relief Valve	19.80
Orifice Meter	0.46
Other Meter	0.01
Regulator	1.03
Open-ended Line	6.01
Leaker Emission Factors - Storage Wellheads, Gas Service	
Connector	NA
Valve	NA
Pressure Relief Valve	NA
Open-ended Line	NA
Leaker Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	NA

METHANE EMISSION FACTORS FOR LNG STORAGE

LNG Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors - LNG Storage Components, LNG Service	

Valve	1.19
Pump Seal	4.00
Connector	0.34
Other	1.77
Leaker Emission Factors - LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	NA

METHANE EMISSION FACTORS FOR LNG TERMINALS

LNG Terminals	Emission Factor (scf/hour/component)
Leaker Emission Factors - LNG Terminals Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other	1.77
Leaker Emission Factors - LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor	NA

METHANE EMISSION FACTORS FOR DISTRIBUTION

Distribution	Emission Factor (scf/hour/component)
Leaker Emission Factors - Above Grade M&R Stations Components, Gas Service	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.270
Orifice Meter	0.212
Regulator	26.131
Open-ended Line	1.69
Leaker Emission Factors - Below Grade M&R Stations Components, Gas Service	
Below Grade M&R Station, Inlet Pressure > 300 psig	NA
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	NA
Below Grade M&R Station, Inlet Pressure < 100 psig	NA
Leaker Emission Factors - Gathering Pipelines, Gas Service	
Gathering Pipelines	NA
Leaker Emission Factors - Distribution Mains, Gas Service[1]	
Unprotected Steel	6.02
Protected Steel	2.38
Plastic	11.63
Cast Iron	NA
Leaker Emission Factors - Distribution Services, Gas Service[1]	
Unprotected Steel	2.33
Protected Steel	1.08
Plastic	0.35
Copper	0.88

[1] Emission Factor is in units of "scf/hour/leak"

Summary

This Appendix provides leaker emissions factors that can be applied to any individual emissions source which meets the leak detection definition in a leak detection survey. These emissions factors provide an estimate of real emissions as opposed to potential emissions since they are applied only to leaking emissions sources. However, it must be noted that these leaker emissions factors assume that any emissions source found leaking has been leaking for the duration of an entire year.

Appendix L: Development of Population emission factors

Natural Gas Emission Factors for Onshore Production

<u>Population Emission Factors – All Components, Gas Service</u>

Methodology

The well counts and emission factors were taken from GRI's *Methane Emissions from the Natural Gas Industry*[55]. The emission factors for each source are calculated using gas production for the Eastern and Western United States. The average methane content of produced natural gas is assumed to be 78.8%.

Component EF, scf/hour/component = (EF All U.S., mscf/yr) / (**A**) * (**B**) / (**C**)

> EF All U.S. Valve, mscf/yr = ((Eastern U.S. Gas Production Count) * (Eastern U.S. Gas Production EF, mscf/yr) + (Western U.S. Gas Production Count) * (Western U.S. Gas Production EF, mscf/yr)) / (Total U.S. Gas Production Count)

Component Name	Component EF, scf/hr/comp	Eastern U.S. Component Count	Eastern U.S. Component EF, Mcf/yr	Western U.S. Component Count	Western U.S. Component EF, Mcf/yr	U.S. Component Count
Valve	0.08	4,200	0.184	6,059	0.835	10,259
Connector	0.01	18,639	0.024	32,513	0.114	51,152
Open-Ended Line	0.04	260	0.42	1,051	0.215	1,311
Pressure Relief Valve	0.17	92	0.279	448	1,332	540

Conversions:

A: 78.8% – production quality of natural gas (% methane) from: "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry,* U.S. EPA, Volume 6, Appendix A, page A-2.

B: 1,000 scf/mscf

C: 8,760 hours/year

"Low-Bleed Pneumatic Device Vents" Methodology

Methane emissions per pneumatic devise are from EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*[56], The average methane content of natural gas is assumed to be 78.8%.

2.75 scf/hour/component EF = (**52** [scfd CH_4/pneumatic devises, low bleed]) / (**A**) / (**D**)

Conversions:

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[55] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 8. Tables 4-3, 4-6 and 4-24. June 1996. <www.epa.gov/gasstar/documents/emissions_report/8_equipmentleaks.pdf>

[56] EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*. Annexes. Tables A-112 – A-125. U.S. EPA. April 2009. <epa.gov/climatechange/emissions/downloads09/Annexes.pdf>

A: 78.8% – production quality of natural gas (% methane) from: "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry,* U.S. EPA, Volume 6, Appendix A, page A-2.
D: 24 hours/day

"Gathering Pipelines" Methodology
Emissions and mileage of underground production pipelines are from GRI's *Methane Emissions from the Natural Gas Industry*[54]. The average methane content of produced natural gas is assumed to be 78.8%.

2.81 scf/hour/mile EF = (**E**) / (**A**) / (**D**)

Conversions:
A: 78.8% – production quality of natural gas (% methane) from: "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry,* U.S. EPA, Volume 6, Appendix A, page A-2.

D: 24 hours/day
E: 53.151651325 scfd/mile EF = (**6.6** Bscf [Total Emissions Estimates from Underground Production Pipelines]) * (**1,000,000,000** cf/bcf) / (**365** days/year) / ((**268,082** miles [Protected Steel Gathering Pipelines]) + (**41,400** miles [Unprotected Steel Gathering Pipelines]) + (**29,862** miles [Plastic Gathering Pipelines]) + (**856** miles [Cast Iron Gathering Pipelines]))

"CBM Well Water Production" Methodology
Gg/gallon of water is from EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*[56]. To calculate Gg/gallon water, 542.9 mg/l is assumed as the concentration of methane in the water, at a well depth of 700ft.

0.11 scf methane/gallon EF = (**51,922,341.5** [CH_4 density, scf/Gg]) * (**2.05216E-09** Gg/gallon water)

> **2.05216E-09** Gg/gallon water EF = (**542.9** mg/l) / (**1,000** mg/g) * (**3.78** l/gallon) * (gallons of water drainage/yr) / (**1,000,000,000** g/Gg)

"Compressor Starter Gas Vent" Methodology
Annual emission factors for compressor starts are from GRI's *Methane Emissions from the Natural Gas Industry*[57]. The average methane content of natural gas is assumed to be 78.8%.

1.22 scf/hour/component EF = (**8,443** [Annual Emission Factor for Compressor Starts]) / (**A**) / (**C**)

Conversions:
A: 78.8% – production quality of natural gas (% methane) from, "Vented and

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[57] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 6. Table 4-2 and Appendix A, page A-2. June 1996. <www.epa.gov/gasstar/documents/emissions_report/6_vented.pdf>

Combustion Source Summary," *Methane Emissions from the Natural Gas Industry,* Volume 6, Appendix A, page A-2.

C: 8,760 hours/year

Flare Methodology

Emissions and flaring efficiency are from GRI's *Methane Emissions from the Natural Gas Industry*[58]. GRI assumed all gas is flared, that the duration is one day per completion, that the gas is 78.8% CH_4, and the flare is 98% efficient. Results are adjusted to assume that no conventional gas well completions are flared.

Conventional Gas Well Completion: 46,510 scf/completion EF **=** (**0.733** scf/completion) / (**0.02** [% Methane not Burned]) * (**B**) / (**A**)

Conventional Gas Well Workover: 3,114 scf/workover EF **=** (**2.454** mscf methane/workover) * (**B**) / (**A**)

Conversions:

A: 78.8% – production quality of natural gas (% methane) from: "Vented and Combustion Source Summary." *Methane Emissions from the Natural Gas Industry*[57]..

B: 1,000 scf/mscf

Population Emission Factors – All Components, Light Crude Service

Methodology

Average emissions factors by facility type were taken from API's *Emission Factors for Oil and Gas Production* Operations.[59] (A discussion on how this study was conducted is provided in Appendix P.) Hydrocarbon liquids greater than or equal to 20°API are considered "light crude." The methane content of associated natural gas with onshore light crude is 61.3% from the same study.

Component EF, scf/hour/component = (Average Emissions Factors by Facility Type, lb/component-day) / (**D**) / (**F**) * (**G**)

Component Name	Component EF, scf/hr/comp	Average EF by Facility Type, lb/component-day
Valve	0.04	7.00E-02
Connector	0.01	8.66E-03
Open-Ended Line	0.04	6.38E-02
Pump	0.01	1.68E-02
Other	0.24	3.97E-01

[58] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 7, page B-9. June 1996. <www.epa.gov/gasstar/documents/emissions_report/7_blowandpurge.pdf>

[59] API. *Emission Factors for Oil and Gas Production Operations*. Table 9, page 10. API Publication Number 4615. January 1995.

Conversions:
D: 24 hours/day
F: 0.04246 CH_4 density lb/scf
G: 0.613 – CH_4 content of onshore light crude associated natural gas

<u>Population Emission Factors – All Components, Heavy Crude Service</u>

Methodology
Average emissions factors by facility type were taken from API's *Emission Factors for Oil and Gas Production Operations*[59]. (A discussion on how this study was conducted is provided in Appendix P.) Hydrocarbon liquids less than 20°API are considered "heavy crude." The methane content of associated natural gas with onshore light crude is 94.2% from the same study.

Component EF, scf/hour/component = (Average Emissions Factors by Facility Type, lb/component-day) / (**D**) / (**F**) * (**H**)

Component Name	Component EF, scf/hr/comp	Average EF by Facility Type, lb/component-day
Valve	0.001	6.86E-04
Flange	0.001	1.16E-03
Connector (Other)	0.0004	4.22E-04
Open-Ended Line	0.01	8.18E-03
Other	0.003	3.70E-03

Conversions:
D: 24 hours/day
F: 0.04246 CH_4 density lb/scf
H: 0.942 – CH_4 content of onshore heavy crude associated natural gas

Methane Emission Factors For Processing

<u>Population Emission Factors – Other Components, Gas Service</u>

"Gathering Pipelines" Methodology
Emissions and mileage of underground production pipelines from GRI's *Methane Emissions from the Natural Gas Industry*[54]. The average methane content of produced natural gas is assumed to be 78.8%.

2.81 scf/hour/mile EF = (**E**) / (**A**) / (**D**)
Conversions:
A: 78.8% – production quality of natural gas (% methane) from: "Vented and Combustion Source Summary." *Methane Emissions from the Natural Gas Industry*[57].
D: 24 hours/day

E: 53.151651325 scfd/mile EF = (**6.6** Bscf [Total Emissions Estimates from Underground Production Pipelines]) * (**1,000,000,000** cf/bcf) / (**365** days/year) / ((**268,082** miles [Protected Steel Gathering Pipelines]) + (**41,400** miles [Unprotected Steel Gathering Pipelines]) + (**29,862** miles [Plastic Gathering Pipelines]) + (**856** miles [Cast Iron Gathering Pipelines]))

Methane Emission Factors for Transmission

Population Emission Factors – All Components, Gas Service

Methodology

Gas transmission facility emission factors were taken from the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[51]. (A discussion on how this study was conducted is provided in Appendix P.) "Connector" includes flanges, threaded connections, and mechanical couplings. "Block Valve" accounts for emissions from the stem packing and the valve body, and it applies to all types of block valves (e.g., butterfly, ball, globe, gate, needle, orbit, and plug valves). Leakage past the valve seat is accounted for the Open-Ended Line emission category. Leakage from the end connections is accounted for by the connector category (i.e., one connector for each end). "Control Valve" accounts for leakage from the stem packing and the valve body. Emissions from the controller and actuator are accounted for by the Instrument Controller and Open-Ended Line categories respectively. This factor applies to all valves with automatic actuators (including fuel gas injection valves on the drivers of reciprocating compressors). "Orifice Meter" accounts for emissions from the orifice changer. Emissions from sources on pressure tap lines etc. are not included in the factor (i.e., these emissions must be calculated separately). "Other Meter" accounts for emissions from other types of gas flow meters (e.g., diaphragm, ultrasonic, roots, turbine, and vortex meters).

Component EF, scf/hour/component = (Gas Transmission Facility Emissions, kg/h/src) * (**I**) / (**F**)

Component Name	Component EF, scf/hour/comp	Gas Transmission Facility Avg. Emissions, kg/hr/src
Connector	0.01	2.732E-04
Block Valve	0.11	2.140E-03
Control Valve	1.02	1.969E-02
Pressure Relief Valve	14.51	2.795E-01
Orifice Meter	0.17	3.333E-03
Other Meter	0.0005	9.060E-06
Regulator	0.17	3.304E-03
Open-Ended Line	4.34	8.355E-02

Conversions:
F: 0.04246 CH_4 density lb/scf
I: 2.20462262 lb/kg

<u>Population Emission Factors – Other Components, Gas Service</u>

"Low-Bleed Pneumatic Device Vents" Methodology
Methane emissions per pneumatic device are from EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*.[56] The average methane content of produced natural gas is assumed to be 78.8%. Pipeline quality natural gas is assumed to be 93.4% methane.

2.57 scf/hour/component EF = (**52** [scfd CH4/pneumatic devises, low bleed]) / (**A**) / (**D**) * (**J**)

Conversions:
A: 78.8% – production quality of natural gas (% methane) from: "Vented and Combustion Source Summary."[57]
D: 24 hours/day
J: 93.4% – pipeline quality of natural gas (% methane) from: "Vented and Combustion Source Summary."[57]

"Gathering Pipelines" Methodology
Emissions and mileage of underground production pipelines from GRI's *Methane Emissions from the Natural Gas Industry*[54]. The average methane content of produced natural gas is assumed to be 78.8%. Pipeline quality natural gas is assumed to be 93.4% methane.

2.62 scf/hour/mile EF = (**E**) / (**A**) / (**D**) * (**J**)

Conversions:
A: 78.8% – production quality of natural gas (% methane) from: "Vented and Combustion Source Summary."[57]
D: 24 hours/day
E: 53.151651325 scfd/mile EF = (**6.6** Bscf [Total Emissions Estimates from Underground Production Pipelines]) * (**1,000,000,000** cf/bcf) / (**365** days/year) / ((**268,082** miles [Protected Steel Gathering Pipelines]) + (**41,400** miles [Unprotected Steel Gathering Pipelines]) + (**29,862** miles [Plastic Gathering Pipelines]) + (**856** miles [Cast Iron Gathering Pipelines]))
J: 93.4% – pipeline quality of natural gas (% methane) from: "Vented and Combustion Source Summary." *Methane Emissions from the Natural Gas Industry*[57].

Methane Emission Factors for Underground Storage

<u>Population Emission Factors – Storage Station, Gas Service</u>

Methodology
See methodology for "Population Emission Factors – All Components, Gas Service" for Transmission.

<u>Population Emission Factors – Storage Wellheads, Gas Service</u>

Methodology
Emission factors for injection/withdrawal wellheads are from GRI's *Methane Emissions from the Natural Gas Industry*[55].

Component EF, scf/hour/component = (Injection/Withdrawal Wellhead) * (**B**) / (**C**)

Component Name	Component EF, scf/hr/comp	Injections/Withdrawal Wellhead, Mcf/yr
Connector	0.01	0.125
Valve	0.10	0.918
Pressure Relief Valve	0.17	1.464
Open-Ended Line	0.03	0.237

Conversions:
B: 1,000 scf/mscf
C: 8,760 hours/year

<u>Population Emission Factors – Other Components, Gas Service</u>

Methodology
See "Low-Bleed Pneumatic Device Vents" Methodology for Population Emission Factors – Other Components, Gas Service for Transmission.

Methane Emission Factors for LNG Storage

<u>Population Emission Factors – LNG Storage Components, LNG Service</u>

Methodology
Component emission factors are from GRI's *Methane Emissions from the Natural Gas Industry*[55]. The emission factors were adjusted by an assumed average methane content of 93.4% by volume.

Component EF, scf/hour/component = (Component EF, Mscf/comp-yr) * (**I**) / (**F**)

Component Name	Component EF, scf/hour/comp	Component EF, Mscf/comp-yr
Valve	0.10	0.867
Open-ended Line	1.28	11.2
Connector	0.02	0.147
PRV	0.71	6.2

Conversions:
F: 0.04246 CH_4 density lb/scf
I: 2.20462262 lb/kg

<u>Population Emission Factors – LNG Storage Compressor, Gas Service</u>

"Vapor Recovery Compressor" Methodology
The methane emissions per compressor are from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*[56]. The methane content of associated natural gas with onshore light crude is 61.3%.[60]

6.81 scf/hour/component EF = (**100** scfd CH_4/compressor) / (**D**) / (**G**)
Conversions:
D: 24 hours/day
G: 0.613 – CH_4 content of onshore light crude associated natural gas

Methane Emission Factors for LNG Terminals

<u>Population Emission Factors – LNG Terminals Components, LNG Service</u>

Methodology
See methodology for Population Emission Factors – LNG Storage Components, LNG Service for LNG Storage.

<u>Population Emission Factors – LNG Terminals Compressor, Gas Service</u>

Methodology
See "Vapor Recovery Compressor" Methodology for Population Emission Factors – LNG Storage Compressor, Gas Service for LNG Storage.

[60]API. *Emission Factors for Oil and Gas Production Operations*. API Publication Number 4615. page ES-3, Table ES-4, January 1995.

Methane Emission Factors for Distribution

Population Emission Factors – Above Grade M&R Stations Components, Gas Service

Methodology

Gas distribution meter/regulator station average emissions from: Gas transmission facility emissions are from the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[51]. (A discussion on how this study was conducted is provided in Appendix P.) "Connector" includes flanges, threaded connections, and mechanical couplings. "Block Valve" accounts for emissions from the stem packing and the valve body, and it applies to all types of block valves (e.g., butterfly, ball, globe, gate, needle, orbit, and plug valves). Leakage past the valve seat is accounted for the Open-Ended Line emission category. Leakage from the end connections is accounted for by the connector category (i.e., one connector for each end). "Control Valve" accounts for leakage from the stem packing and the valve body. Emissions from the controller and actuator are accounted for by the Instrument Controller and Open-Ended Line categories respectively. This factor applies to all valves with automatic actuators (including fuel gas injection valves on the drivers of reciprocating compressors). "Orifice Meter" accounts for emissions from the orifice changer. Emissions from sources on pressure tap lines etc. are not included in the factor (i.e., these emissions must be calculated separately). "Other Meter" accounts for emissions from other types of gas flow meters (e.g., diaphragm, ultrasonic, roots, turbine, and vortex meters).

Component EF, scf/hour/component = (Gas Distribution Meter/Regulator Station Emissions, kg/h/src) * (**I**) / (**F**)

Component Name	Component EF, scf/hour/comp	Gas Distribution Meter/Regulator Station Avg. Emissions, kg/h/src
Connector	5.70E-03	1.098E-04
Block Valve	5.76E-02	1.109E-03
Control Valve	1.02E+00	1.969E-02
Pressure Relief Valve	8.65E-01	1.665E-02
Orifice Meter	1.73E-01	3.333E-03
Other Meter	4.71E-04	9.060E-06
Regulator	9.94E-02	1.915E-03
Open-Ended Line	4.33E+00	8.355E-02

Conversions:
F: 0.04246 CH_4 density lb/scf
I: 2.20462262 lb/kg

Population Emission Factors – Below Grade M&R Stations Components, Gas Service

Methodology

Average emission factors are from GRI's *Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution*[61].

Below Grade M&R Station, Inlet Pressure > 300 psig: 1.30 scf/hour/station EF

Below Grade M&R Station, Inlet Pressure 100 to 300 psig: 0.20 scf/hour/station EF

Below Grade M&R Station, Inlet Pressure < 100 psig: 0.10 scf/hour/station EF

<u>Population Emission Factors – Gathering Pipeline, Gas Service</u>

Methodology
See "Gathering Pipelines" Methodology for Population Emissions Factors – Other Components, Gas Service for Transmission.

<u>Population Emission Factors – Distribution Mains and Services, Gas Service</u>

Methodology
Emission factors for pipeline leaks (mains and service) are from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*[56].

Component EF, scf/hour/service = (Pipeline Leak mscf/mile/year) * (**B**) / (**C**)

Component Name	Component EF (Mains), scf/hr/service	Pipeline Leak EF (Mains), Mscf/mile-yr	Component EF (Services), scf/hr/service	Pipeline Leak EF (Services), Mscf/mile-yr
Unprotected Steel	12.58	110.19	0.19	1.70
Protected Steel	0.35	3.07	0.02	0.18
Plastic	1.13	9.91	0.001	0.01
Cast Iron	27.25	238.7		
Copper			0.03	0.25

Conversions:
B: 1,000 scf/mscf
C: 8,760 hours/year

Nitrous Oxide Emission Factors for Gas Flaring

<u>Population Emission Factors – Gas Flaring</u>

Methodology

[61] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 10. Table 7-1. June 1996. <www.epa.gov/gasstar/documents/emissions_report/10_metering.pdf>.

Emission factors are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*[62].

Gas Production: 5.90E-07 metric tons/MMcf gas production or receipts EF

Sweet Gas Processing: 7.10E-07 metric tons/MMcf gas production or receipts EF

Sour Gas Processing: 1.50E-06 metric tons/MMcf gas production or receipts EF

Conventional Oil Production: 1.00E-04 metric tons/barrel conventional oil production EF

Heavy Oil Production: 7.30E-05 metric tons/barrel heavy oil production EF

NATURAL GAS EMISSION FACTORS FOR ONSHORE PRODUCTION

Onshore production	Emission Factor (scf/hour/component)
Population Emission Factors - All Components, Gas Service	
Valve	0.08
Connector	0.01
Open-ended Line	0.04
Pressure Relief Valve	0.17
Low-Bleed Pneumatic Device Vents	2.75
Gathering Pipelines[1]	2.81
CBM Well Water Production[2]	0.11
Compressor Starter Gas Vent	1.22
Conventional Gas Well Completion[3]	46,510
Conventional Gas Well Workover[4]	3,114
Population Emission Factors - All Components, Light Crude Service[5]	
Valve	0.04
Connector	0.01
Open-ended Line	0.04
Pump	0.01
Other	0.24
Population Emission Factors - All Components, Heavy Crude Service[6]	
Valve	0.001
Flange	0.001
Connector (other)	0.000
Open-ended Line	0.01
Other	0.00

[1] Emission Factor is in units of "scf/hour/mile"
[2] Emission Factor is in units of "scf methane/gallon", in this case the operating factor is "gallons/year". Therefore do not multiply by methane content
[3] Emission Factor is in units of "scf/completion"
[4] Emission Factor is in units of "scf/workover"
[5] Hydrocarbon liquids greater than or equal to 20˚API are considered "light crude"

[62] API. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*. American Petroleum Institute. Table 4-7, page 4-30. February 2004.

[6] Hydrocarbon liquids less than 20˚API are considered "heavy crude"

METHANE EMISSION FACTORS FOR PROCESSING

Processing	Emission Factor (scf/hour/component)
Population Emission Factors - All Equipment Components, Gas Service	
Valve	NA
Connector	NA
Open-ended Line	NA
Pressure Relief Valve	NA
Meter	NA
Population Emission Factors - Centrifugal Compressor Components, Gas Service	
Valve	NA
Connector	NA
Open-ended Line	NA
Dry Seal	NA
Population Emission Factors - Other Components, Gas Service	
Valve	NA
Connector	NA
Open-ended Line	NA
Pressure Relief Valve	NA
Meter	NA
Population Emission Factors - Other Components, Gas Service	
Gathering Pipelines[1]	2.81

[1] Emission Factor is in units of "scf/hour/mile"

METHANE EMISSION FACTORS FOR TRANSMISSION

Transmission	Emission Factor (scf/hour/component)
Population Emission Factors - All Components, Gas Service	
Connector	1.42E-02
Block Valve	1.11E-01
Control Valve	1.02E+00
Compressor Blowdown Valve	NA
Pressure Relief Valve	1.45E+01
Orifice Meter	1.73E-01
Other Meter	4.71E-04
Regulator	1.72E-01
Open-ended Line	4.34E+00
Population Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57
Gathering Pipelines[1]	2.62

[1] Emission Factor is in units of "scf/hour/mile"

METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE

Underground Storage	Emission Factor (scf/hour/component)
Population Emission Factors - Storage Station, Gas Service	
Connector	1.42E-02
Block Valve	1.11E-01
Control Valve	1.02E+00
Compressor Blowdown Valve	NA
Pressure Relief Valve	1.45E+01
Orifice Meter	1.73E-01
Other Meter	4.71E-04
Regulator	1.72E-01
Open-ended Line	4.34E+00
Population Emission Factors - Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.10
Pressure Relief Valve	0.17
Open-ended Line	0.03
Population Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57

METHANE EMISSION FACTORS FOR LNG STORAGE

LNG Storage	Emission Factor (scf/hour/component)
Population Emission Factors - LNG Storage Components, LNG Service	
Valve	0.87
Open-ended Line	11.20
Connector	0.15
PRV	6.20
Population Emission Factors - LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	6.81

METHANE EMISSION FACTORS FOR LNG TERMINALS

LNG Terminals	Emission Factor (scf/hour/component)
Population Emission Factors - LNG Terminals Components, LNG Service	
Valve	0.87
Open-ended Line	11.20
Connector	0.15
PRV	6.20
Population Emission Factors - LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor	6.81

METHANE EMISSION FACTORS FOR DISTRIBUTION

Distribution	Emission Factor (scf/hour/component)
Population Emission Factors - Above Grade M&R Stations Components, Gas Service	
Connector	5.70E-03
Block Valve	5.76E-02
Control Valve	1.02E+00
Pressure Relief Valve	8.65E-01
Orifice Meter	8.65E-01
Other Meter	4.71E-04
Regulator	1.92E-03
Open-ended Line	4.33E+00
Population Emission Factors - Below Grade M&R Stations Components, Gas Service[1]	
Below Grade M&R Station, Inlet Pressure > 300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure < 100 psig	0.10
Population Emission Factors - Gathering Pipelines, Gas Service	
Gathering Pipelines[2]	2.62
Population Emission Factors - Distribution Mains, Gas Service[3]	
Unprotected Steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors - Distribution Services, Gas Service[3]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] Emission Factor is in units of "scf/hour/station"
[2] Emission Factor is in units of "scf/hour/mile"
[3] Emission Factor is in units of "scf/hour/service"

Summary

This Appendix provides population emissions factors for potential emissions sources. These population emissions factors can be used in conjunction with population counts that make it more cost effective in estimating emissions. However, these population emissions factors estimate potential emissions as the percentage of emissions sources leaking may or may not be the same as the assumption made when developing the emissions factors. Also, the population emissions factors assume that a subset of leaking emission sources is leaking continuously throughout the year.

Appendix M: Potential Solutions to Measure Greenhouse Gas Emissions in Various Modes of Equipment Operation

The purpose of this appendix is to analyze the issues involved with and potential solutions to estimating emissions in the different modes of operation for equipment at oil and natural gas facilities. The scope includes fugitive and vented methane and carbon dioxide emissions.

1. Evaluation Criteria and Approach

A. **Assessment on permutations of operating modes: startup, running, pressurized, shut down and depressurized to intermediate pressure shut down and depressurized to atmospheric pressure, shut down for major maintenance:** Equipment will have variable vented and fugitive emissions depending on their modes of operation. The three equipment types discussed are i. compressors, ii. tanks, and iii. other components. The text below discusses how emissions differ and potential approaches for measurement and developing an inventory.

i. Compressors – The table below shows each mode of operation in the rows and each emission type in the columns, forming a matrix of which emission types occur in each mode of operation. Different numbers denote when a different measurement is required, i.e. compressor seals will leak at different rates when pressurized and when depressurized, requiring separate measurements. For example, under normal operations seals on compressor piston rods have been documented to leak at approximately 75 cubic feet (scf)/hour. However, when a compressor is idle and fully pressurized (not blown down), this can increase to 300 scf/hour. On the other hand, blowing a compressor down emits on average approximately 1,500 scf through the open blowdown valve and the upstream unit valve can leak an additional 1,400 scf/hour. However, when the compressor is left idle pressurized, the 1,400 scf/hour is eliminated from the unit valve and instead approximately 450 scf/hour emissions can leak through the closed blowdown valve. This clearly demonstrates how leak rates from different components can change between different operating modes[63].

[63] EPA. *Reducing Emissions when Taking Compressors Off-Line*. EPA430-B-04-001. February 2004.

	Emission Type								
Operating Modes	Starter OEL open	Starter OEL closed	Blowdown OEL open	Blowdown OEL closed	Unit Valves	Seal or Rod Packing Face OEL	Engine Crankcase (where applicable)	Seal Oil Degassing OEL (where applicable)	Engine or Turbine Exhaust (where applicable)
Startup	M1			M5		M8	M12	M14	M18
Running (normal operation)		M2		M5		M8	M12	M14	M19
Shutdown (left pressurized)		M3		M5		M9	M13	M15	
Shutdown (blown down to atmosphere)		M3	M4		M7	M10	M13	M16	
Shutdown (blown down to intermediate pressure)		M3		M6		M11	M13	M17	
Offline (major maintenance)									
Emergency/systems testing			M4				M13	M16	
Emergency venting/shutdown			M4				M13	M16	

In the chart above, the necessary components to monitor are displayed by the letter "M" and a number. The "M" stands for "monitor" to signify it is necessary, and the numbers differentiate measurements. For example, "M3" refers to starter OEL leaks in any of the shutdown operating modes. The leak rates should be the same for measurements sharing the same number; so no duplicate measurement would be necessary. While it is difficult to predict which components will have large leaks, cells highlighted in light blue signify which components are expected to have potentially large leaks for the modes. The table below displays a legend for all the necessary components under different conditions to monitor as derived from the matrix above.

M1	Starter OEL Vents in Startup Mode
M2	Starter OEL Leaks under Normal Operation
M3	Starter OEL Leaks for All Shutdown Modes
M4	OEL Blowdown Venting for All Modes
M5	OEL Blowdown Vent Leaks for All Pressurized Modes
M6	OEL Blowdown during Shutdown at Intermediate Pressure
M7	Unit Valve Leaks during Shutdown Blowdowns to Atmosphere
M8	Wet Seal or Rod Packing Face OEL during Startup and Normal Operation
M9	Wet Seal or Rod Packing Face OEL during Pressurized Shutdown
M10	Wet Seal or Rod Packing Face OEL during Shutdown Blowdown
M11	Wet Seal or Rod Packing Face OEL during Shutdown at Intermediate Pressure
M12	Engine Crankcase (where applicable) during Normal Operations
M13	Engine Crankcase (where applicable) during All Shutdown modes
M14	Wet Seal Oil Degassing OEL during Startup and Normal Operation
M15	Wet Seal Oil Degassing OEL during a Pressurized Shutdown

M16	Wet Seal Oil Degassing OEL during a Blowdown
M17	Wet Seal Oil Degassing OEL during Shutdown at Intermediate Pressure
M18	Engine or Turbine Exhaust during Startup
M19	Engine or Turbine Exhaust during Normal Operation

The 19 measurements, displayed above, are required to potentially cover all the possible compressor operating modes.

ii. Tanks and Vapor Recovery Units (VRUs) – Emissions from storage tanks can potentially be estimated using one of the several options; standard simulation software, one time direct measurement of one cycle of tank operations, or using engineering methods such as Vasquez Beggs Equation. If no control device is present on the tank, then all tank vapors can be assumed to be vented. If control devices are present, then the "efficiency" of the control device will have to be evaluated by logging different operating modes. These events are displayed in the table below, where the owner/operator may have to use its best judgment to determine the recovery "efficiency" (percent of vapors recovered during each mode). By logging these situations, the overall efficiency for the reporting period can be determined. When a vapor recovery unit is operating properly, tank emissions are nearly zero. However, when a tank is able to vent freely, it has been documented to vent as much as 96 million cubic feet per year of gas[64]. The following table summarizes the situations in which a control device may be recovering vapors and when venting may occur. In some cases, both may be going on simultaneously.

	VRU Efficiency Considerations					
	Control functions properly	Valve or hatch pops open	Significant leak in tank structure	Large "slug" of fluids overloads device	Control device malfunctions	Control device down for maintenance
Emitting gas		×	×	×	×	×
Capturing gas	×	×	×	×		

There may be an opportunity to utilize some of the provisions under 40 CFR part 60 regulating petroleum tanks with liquids at a certain vapor pressure, which may require a VRU.

40 CFR part 60, Subpart K

(3) A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

[64] EPA. *Installing Vapor Recovery Units on Crude Oil Storage Tanks*. EPA430-B-03-015. October 2003.

iii. Other components – Most equipment have different operating modes that may affect its magnitude of emissions. Pneumatic actuation instruments will vary depending on whether the instrument is actuating or not. Chemical pumps will emit depending on the current throughput of chemical through the pump. Valves will emit at different rates depending on their configurations (e.g. closed, open, half-open). Wellheads may be producing to a production line or venting after completion or cleanup.

There may be an opportunity to utilize some of the provisions under 40 CFR part 60 regulating natural gas plants, however it may not lead to the "inventory" of emissions that the EPA is seeking.

40 CFR part 60, Subpart KKK Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.

> Equipment included
> *Equipment means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart.*

B. Assessment of potential seasonal differences affecting emissions such as operating pressure or throughput: Seasonal changes typically occur in a changeover to winter operations but can occur based on any periodic yearly cycle. During winter months, throughput to end use may increase while throughput to storage may decrease. Remote wells and their facilities may also be shut in during winter. The result of these changes is that equipment may cycle between very low and very high operating factors through the year and that key operating parameters such as line pressure may vary with each season. Seasonal differences can therefore be tracked with a detailed prescription of operating modes.

C. Assessment on other operating parameters that may vary such as gas composition, temperatures, and flow rates: Calculation of methane emissions depends greatly on gas composition (methane content). While downstream pipelines may require that strict composition specifications are met, upstream gas compositions can vary widely by well production rates and ages or the bringing of new wells/fields online or taking them offline.

D. Discussion on non-continuous or non-steady emissions and how they may vary depending on different equipment modes of operation: Tanks are an example of non-steady and non-continuous emissions. Throughput rates and weather both affect the rate of emissions as well and control activity can affect the continuity. However, all the vapor that evolves from the tank contents will either be vented or collected by the control device and the monitoring methods for these have been discussed in section A. Pneumatic actuation devices and gas-driven pumps may have non-continuous emissions as actuations occur or fluid is pumped more or less heavily.

E. Potential methods to account for various operational modes in emissions monitoring:

i. Compressors – Operators could log time spent in different operating modes. For compressors this may already be automated and recorded, though at remote sites operating hours may have to be determined by alternative means such as fuel consumption. Determining the resulting emissions can be done in several ways:

1) Require that measurements of all operating modes for each reporting period be measured. This may require multiple days of measurement collection for each period if equipment modes are not cycled frequently. Alternatively, this may require scheduling cycling between all modes in a short time span to accommodate data collection.
   - Advantages: This will provide the most accurate and precise emissions inventory data for each reporting period.
   - Disadvantages: This increases the burden on companies to force all modes of operation for a compressor for each reporting period for monitoring purposes.
2) One inspection and measurement survey can be performed per reporting period, but a different operating mode can be surveyed in each reporting period to complete collection of emissions from each operating mode.
   - Advantages: This will decrease the burden of measurement and reporting on companies. For established and steady operations, the accuracy will likely not deteriorate, i.e. compressor blowdown volumes will remain constant.
   - Disadvantages: Initially it may take several reporting periods before the companies have collected enough data to accurately report emissions for compressors when all operating modes are considered. Additionally, by the time emissions data for all modes of operation are collected, the originally measured mode may have changed substantially for facilities with changing process conditions.
3) Only normal operation and the most typical operating modes and parameters can be measured each reporting period, and previously collected measurements for other operating modes can be collected with less frequency.
   - Advantages: EPA receives reliable data for at the most common modes of operation.
   - Disadvantages: Burden on companies still increases.

ii. Tanks – Operators may have to track and log time spent in each mode of operation. The logs of these operating times can be provided to a junior engineer, who can perform the appropriate calculation based on the available data. Determining these emissions can be done in several ways:

1) Use simulation software and require quarterly collection of key parameters such as: liquid hydrocarbon gravity and composition, tank vapor composition, tank conditions (temperature and pressure), hydrocarbon liquid condition immediately upstream of tank (temperature and pressure), average liquid hydrocarbon throughput. Perform the emissions simulation for each quarter using the collected data and apply the appropriately determined control device operating efficiency (if a control device is present) using data logs.
    - Advantages: The most reliable inventory data can be received for every reporting period.
    - Disadvantages: The labor and cost burden of performing this level of monitoring may increase for a company depending on its current internal monitoring practices.
2) Use simulation software and require collection of key parameter data (as described above) once per reporting period.
    - Advantages: The burden of monitoring is diminished on the owner/operator for the reporting period.
    - Disadvantages: Less reliable data will be reported and does not capture changes in the process that may occur within a reporting period due to seasonal or operational changes.

iii. Downstream (Transmission and Storage) Reporting Considerations – As discussed earlier, the increased demand in cooler months affects gas systems such that downstream pipeline throughput increases and operating pressures are increased, and that gas is withdrawn from storage. Alternatively, during warm months the pipeline throughput and pressures decrease while gas is injected into storage. Options for accounting for downstream emissions include:
1) Potentially define warm and cool seasons by fixed months or by average temperature for each month. Entities can then perform monitoring twice annually (once at peak demand, once at low demand for normal operations) to estimate emissions for the warm and cool seasons; then extrapolate the measured/monitored emissions for the entire season and total for the reporting period.
    - Advantages: The most accurate emissions data for the represented reporting period can be obtained.
    - Disadvantages: Economic and labor burden could be significant, as would be required to monitor more than one time per year. Costs would be further impacted by the method required to monitor emissions.
2) Potentially define warm and cool seasons, as discussed in the previous bullet. Companies can then monitor emissions once per period (year), but alternate measurements for peak demand (cold season) every other reporting period, and low demand (warm season) in the remaining seasons. After year 1, it will use the most current

monitoring data for each season to estimate emissions from the reporting period.

- Advantages: Data that represents both seasons can be received.
- Disadvantages: The first reporting will be inaccurate since it will be estimated as if peak demand is reached for the entire period. Subsequent reporting periods will continue to have some level of uncertainty because it requires using data from the previous year.

3) Potentially define an intermediate period between the peak demand and low demand that can be assumed to be representative of the average over the course of the year.
   - Advantages: This can be easier for the companies to track and plan for if the same monitoring time can be used each reporting period. It does not increase the burden of monitoring for reporting entities.
   - Disadvantages: It will be difficult to determine where the representative operating conditions are achieved.

3. Data Sources for Research

- Clean Air Act
  - EPA Method 21
  - EPA Method 21 AWP
- Industry published standard operating procedures
  - API Leak Detection Standards
  - AGA Leak Detection Standards

Appendix N: Identifying gas compositions for emissions estimates

This appendix summarizes the research to identify gas composition sampling needed to quantify CH_4 and CO_2 emissions in estimates of natural gas emissions from direct measurements, engineering calculations, or the use of emissions factors.

Sources that could be affected by gas composition changes

1. The initial proposed rule provided leeway on how gas composition could be estimated. A facility could estimate gas composition from continuous monitoring equipment, or a couple of samples per year. This could lead to GHG under or over reporting if the regulated entity selects samples that are not representative of the emissions source.
2. The composition of produced gas varies widely from well to well, and over time the composition will change for the same well. The initial proposed rule language could be interpreted as a composite gas composition that represents all the wells. Again the issue of how the gas composition estimate is derived is not defined. This will impact GHG reporting for Offshore E&P and for Onshore E&P.
3. The gas composition a processing plant receives will vary over the period of one year for example as wells are taken off-line for maintenance activities; new well volumes are sent to a gas plant; and as the composition and volumes of exiting wells change over time. Gas processing plants are not always owned and operated by the gas producer. This will result in different feed gas compositions as the gas plant starts and ends contracts for taking gas from different producers.
4. For gas plants the initial proposed rule states that only two gas composition estimates are used for the "feed natural gas" upstream of the de-methanizer, and "residue gas" downstream of the de-methanizer. This can be clarified as "downstream of the de-methanizer *overhead*".

Summary

To minimize the cost burden and also achieve a more representative gas composition and therefore more accurate emissions estimation, quarterly samples could be made. In addition the following stream compositions could be used for estimating GHG emissions from natural gas;

1. Gas Processing Facilities: "feed natural gas" can be used for all emissions sources upstream of the de-methanizer
2. Gas Processing Facilities: "residue gas" to transmission pipeline systems can be used for all related emissions sources downstream of the de-methanizer overhead
3. Gas Processing Facilities: gas i) entering and ii) exiting the acid gas removal unit which can be used to calculate the AGR vent emissions and for all emissions of related sources
4. Offshore and Onshore Petroleum and Natural Gas Production: produced natural gas can be used to estimate GHG emissions from all emissions sources in the facility.

Appendix O: Development of performance criteria and monitoring protocol for fugitive measurement techniques

The purpose of this appendix is to outline relevant sources of documentation on fugitive and vented emissions detection and quantification technologies, including available standards of performance, use, and calibration.

1. Issue Identification and Clarification

A. Brief summary of the changes to LDAR under the newly passed AWP

The recently promulgated alternative work practice (AWP) allows owners or operators to detect VOC or HAP leaking equipment using an optical gas imaging instrument if it is capable of imaging compounds in the streams that are regulated by the applicable rule. The imaging instrument must provide the operator with an image of both the leak and the leak source. Before using the instrument, owners and operators are required to determine the mass flow rate that the imaging instrument will be required to image. The mass flow rate can be determined using the method provided in sections *(i)(2)(i)(A)* and *(i)(2)(i)(B)* of the AWP. They are required to conduct a daily instrument check to confirm that the optical gas imaging instrument is able to detect leaks at the emission rate by using the instrument to view the mass flow rate required to be met exiting a gas cylinder.

The AWP specifies that the imaging instrument is to be used as a direct replacement for other acceptable screening equipment; however, no measurement, record keeping, reporting, or other procedures can be replaced because of this. The company still must use the standard Method 21 screening equipment in one screening period per year. In addition to the record keeping practices already prescribed in the current work practice, companies must keep video records of the daily instrument check and leak survey results for at least 5 years. The company must document the equipment, process units, and facilities for which the optical gas imaging instrument will be/is used.

The instrument must be used following the manufacturer's instructions, ensuring that all appropriate settings conform to the instructions and parameters. All leaks that can be viewed with the instrument are regulated by the rule, so that they have to be fixed.

"Optical gas imaging instrument" means an instrument that makes visible emissions that may otherwise be invisible to the naked eye. The AWP defines leaks as "any emissions imaged by the optical gas instrument; indications of liquids dripping; indications by a sensor that a seal or barrier fluid system has failed; or screening results using 40 CFR part 60, Appendix A-7, Method 21 monitor that exceed the leak definition in the applicable subpart to which the equipment is subject."

B. Existing performance criteria and protocols for using fugitive emission *detection* devices

This section reviews existing performance criteria and protocols for using fugitive and emission devices. A discussion of current standards of performance follows.

<u>Method 21</u>
Section 6 defines equipment specifications and performance criteria for VOC monitoring instruments:

> *6.1 The VOC instrument detector shall respond to the compounds being processed. Detector types that may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.*
> *6.2 The instrument shall be capable of measuring the leak definition concentration specified in the regulation.*
> *6.3 The scale of the instrument meter shall be readable to ±2.5 percent of the specified leak definition concentration.*
> *6.4 The instrument shall be equipped with an electrically driven pump to ensure that a sample is provided to the detector at a constant flow rate. The nominal sample flow rate, as measured at the sample probe tip, shall be 0.10 to 3.0 l/min (0.004 to 0.1 ft^3 /min) when the probe is fitted with a glass wool plug or filter that may be used to prevent plugging of the instrument.*
> *6.5 The instrument shall be equipped with a probe or probe extension or sampling not to exceed 6.4 mm (1/4in) in outside diameter, with a single end opening for admission of sample.*
> *6.6 The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the National Electrical Code by the National Fire Prevention Association or other applicable regulatory code for operation in any explosive atmospheres that may be encountered in its use. The instrument shall, at a minimum, be intrinsically safe for Class 1, Division 1 conditions, and/or Class 2, Division 1 conditions, as appropriate, as defined by the example code. The instrument shall not be operated with any safety device, such as an exhaust flame arrestor, removed.*

Section 6.1 is a performance criterion that defines which types of detection devices may be used (all of the devices proposed for use in the initial rule proposal are covered here) and specifies that the instrument must be responsive to the compounds being processed. Section 6.2 indicates that the instrument shall be capable of accurately measuring the specified leak definition and section 6.3 defines the lower limit of instrument detection range or the highest concentration before there are no detectable emissions.

Sections 6.4 and 6.5 would not be applicable to portable monitoring devices that do not have probe extensions for sampling leaks. These specifications could still be applied specifically for portable VOC monitoring devices under the initial rule proposal. Section 6.6 is a reasonable performance criterion to adopt as it specifies that the detection device must conform to safe operating standards for use in explosive atmospheres.

Section 7 of Method 21 covers leak detection device calibration and performance evaluation. It specifies the types of calibration gases that may be used as well as specifications for prepared gases and mixed compound gases that may be used for calibration.

Section 8 details specifications for performance of the leak detection devices. The device must meet requirements for the response factor, calibration precision, and response time. These performance requirements are needed to ensure that the device will respond to the gas of interest, provide reasonably accurate measurements of leak concentration, and take an appropriate leak sample. Section 8 also describes leak detection procedures for individual components. Leak detection procedures are defined for the following sources within Method 21:

i. valves
ii. flanges and other connectors
iii. pumps and compressors
iv. pressure relief devices
v. process drains
vi. open-ended lines or valves
vii. seal system degassing vents and accumulator vents
viii. access door seals

Alternative Work Practice to Detect Leaks from Equipment

Performance criteria for optical gas imaging instruments are disclosed in the AWP document.

> *(1)Instrument Specifications. The optical gas imaging instrument must comply with the requirements in (i)(1)(i) and (i)(1)(ii) of this section.*
> *(i)Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (i)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.*
> *(ii)Provide a date and time stamp for video records of every monitoring event.*
> *(2)Daily Instrument Check. On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (i)(2)(i) of this section in accordance with the procedure specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (i)(2)(v) of this section.*
> *(i)Calculate the mass flow rate to be used in the daily instrument check by following the procedures in paragraphs (i)(2)(i)(A) and (i)(2)(i)(B) of this section.*

(ii) Start the optical gas imaging instrument according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.
(iii) Use any gas chosen by the user that can be viewed by the optical gas imaging instrument and that has a purity of no less than 98 percent.
(iv) Establish a mass flow rate by using the following procedures:
(A) Provide a source of gas where it will be in the field of view of the optical gas imaging instrument.
(B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey. Do not exceed the operating parameters of the flow meter.
(C) Open the valve on the flow meter to set a flow rate that will create a mass emission rate equal to the mass rate specified in paragraph (i)(2)(i) of this section while observing the gas flow through the optical gas imaging instrument viewfinder. When an image of the gas emission is seen through the viewfinder at the required emission rate, make a record of the reading on the flow meter.
(v)Repeat the procedures specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.
(vi)To use an alternative method to demonstrate daily instrument checks, apply to the Administrator for approval of the alternative under § 60.13(i).
(3)Leak Survey Procedure. Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

Additional Sources Investigated

Other sources of data were researched to find additional information on leak detection device performance criteria. The CDM AM0023 methodology for leak detection and repair at natural gas transmission compressor stations and distribution gate stations outlines a procedure for systematic leak detection. This procedure does not provide any detailed performance criteria for the leak detection devices themselves. However AM0023 specifies that portable monitoring instruments such as the OVA and TVA may be used for leak detection but not measurement. For leak measurement, AM0023 specifies that one of five methods be used: rotameters, high volume sampler, flow-through bagging, calibrated bagging and ultrasonic. The American Petroleum Institute and American Gas Association publish leak detection standards that may contain additional performance criteria for leak detection devices that may be applicable to the initial rule proposal.

C. What information is available on existing performance criteria and protocols for using fugitive *measurement* detection devices and how can it be collected and modified for the EPA rule

Method 21 was developed in the 70's and 80's to find and reduce emissions from leaks that were not easily detectable by other means. Although the method was not developed to quantify leak rates, EPA has published the "Protocol for Equipment Leak Emission Estimates."[65] This document covers quantification of leak rates through the use of SOCMI or petroleum industry correlations and Method 21 leak concentration measurements. This document also describes flow-through and vacuum bagging techniques for mass emission sampling. These quantification methods are not included as part of the initial rule proposal however, pieces of the flow-through bagging procedure may be applicable to emissions measurements using calibrated bags. Section 4.3 covers source enclosure of specific leaking components such as valves, pumps and agitators, compressors, connectors, and relief valves.

Method 2C[66] in Appendix A of CFR Title 40 Part 60 defines a procedure for measuring the stack gas velocity and volumetric flow rate. This method can be used for estimating fugitive and vented emissions from flare stacks and compressor wet seal degassing vents as discussed in the initial proposed rule. This method refers back to Method 2 for performance criteria of pitot tubes. This information could be adapted for use in the Fugitive GHG Reporting Rule.

D. Performance criteria and past precedent for existing relevant regulations under the Clean Air Act.

Performance criteria for fugitive detection devices include the following general aspects:

i. The detection device should respond to the compounds being processed. Detector types that may meet this requirement include organic vapor analyzers, toxic vapor analyzers, infrared detection devices (imaging and pointing devices).
   (1) Both Method 21 and its AWP state this performance criterion first (as seen in Method 21 paragraph 6.1 and AWP instrument specifications (e)(1)(i)). This performance criterion ensures that leak detection surveys will be carried out using equipment that is able to detect the presence of the fugitive methane emissions and pinpoint the leak location.

ii. The detection device shall be intrinsically safe for operation in explosive atmospheres.
   (1) Method 21 specifies this in paragraph 6.6. This performance criterion pertains to the safety of the operator performing the leak detection survey. Fugitive methane emissions have the potential to combine with air in a flammable

[65] US EPA. "Protocol for Equipment Leak Emission Estimates". EPA-453/R-95-017

[66] http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=75ed3a088a2e23401559636e29116342&rgn=div9&view=text&node=40:7.0.1.1.1.0.1.1.1&idno=40

mixture. It is necessary that a leak detection survey that is looking for methane releases into the atmosphere does not introduce any possible ignition source.

(2) The AWP, however, does not reference the intrinsic safety issue of optical imaging devices. The onus of the safety of the device is on the reporter and manufacturer of the device.

iii. Two gas mixtures are required for instrument calibration. A zero gas and a methane reference gas should be used to determine that the leak detection device is functioning correctly and will be able to pinpoint leak locations during a survey.

iv. Calibration precision test must be completed prior to placing the detection device into service and at subsequent 3 month intervals or at the next use, whichever is later.

(1) Method 21 and the infrared imaging AWP both prescribe methods for calibration of the instrument. These are potentially applicable to the monitoring rule.

Additional performance criteria should be defined for the various types of detection devices. Performance Criteria specific to OVAs and TVAs has been well defined in Method 21. Information on performance criteria may be derived for infrared imaging devices from the recent AWP for Method 21.

Very little information has been found relating to performance criteria for leak measurement devices. As with leak detection devices it is difficult to define performance criteria that will be applicable to all devices named as appropriate measurement tools in the initial rule proposal. Method 2C provides equipment specifications for pitot tubes.

2. Evaluation Criteria and Approach

A. Review of existing performance criteria in the CAA and if they are applicable to fugitive GHG emissions

i. Method 21 provides performance criteria for portable VOC monitoring devices to detect equipment fugitives. These can be adapted so that references to VOCs are converted to methane and the frequency of confirmation of performance/ calibration is better aligned with the frequency of monitoring associated with this rule.

ii. The AWP provides performance criteria for optical VOC imaging cameras to detect equipment fugitives. These can be adapted so that references to VOCs are converted to methane and the frequency of confirmation of performance/ calibration is better aligned with the frequency of monitoring associated with this rule.

B. CARB Mandatory Greenhouse Gas Emissions Reporting

(1) For reference, the CARB rule for fugitive methane emissions was reviewed. CARB relies on Method 21, screening values and correlations, and VOCs to methane conversion factor.

Equipment fugitive methane emissions methods are based upon your local AQMD/APCD Leak Detection and Repair (LDAR) procedures. You will need to extend your LDAR monitoring to all gas service components. This includes all components carrying natural gas, refinery fuel gas, and low Btu gases. All components should be identified as one [of] *the following six classification types: valve, pump seal, connector, flange, open-ended pipe, and other. For guidance you should consult and use the Component Identification and Counting Methodology found in the following CAPCOA (1999) document:*
California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, CAPCOA and CARB, 1999.
www.arb.ca.gov/fugitive/fugitive.htm

All gas service components should be screened using a monitoring instrument capable of detecting methane. Screenings should be conducted at the frequency interval required by your local air district. Specific screening procedures and instrument calibration requirements can be found in EPA Reference Method 21 published in 40 CFR 60, Appendix A (EPA Method 21), www.epa.gov/ttn/emc/promgate/m-21.pdf.
First identify and screen your gas service components. Component screening values will be used to calculate methane emissions. The CAPCOA document referenced above provides several methods by which VOC emissions may be calculated using component screening values. You will use Method 3: the Correlation Equation Method with modifications as required by the procedures that your local AQMD/APCD has put in place. You will calculate VOC emissions for three categories of components based on the component screening value:
1. Zero components – where the screening value, corrected for background is indistinguishable from zero.
2. Leaking components – components with screening values greater than zero but less than the screening value limit above which the local AQMD/APCD does not allow the use of correlation equations for the calculation of VOC emissions. This upper bound screening value is either 9,999 ppmv or 99,999 ppmv.
3. Pegged components with SVs above the upper SV/correlation equation limit.

After you have calculated VOC emissions for all your zero components, leaking components and pegged components, sum the three to obtain your fugitive equipment VOC emissions. The sum total of VOC emissions is then multiplied by CF, a VOC to CH4 conversion factor and a kg to metric tons conversion factor (0.001) to calculate total methane emissions.

In most cases you should be able to determine a system specific VOC to methane conversion factor (CF) based on determinations of gas composition and methane content from fuel analysis. In cases where fuel analysis data is available, use the mass CH4/mass fuel ratio to calculate a system specific CF. In cases where representative data is not available you should use a default CF value of 0.6.

B. In general, all screening devices do not quantify the mass or volumetric magnitude of leaks

  i. Wind can distort the size of a leak as seen through the camera. Point source suction devices that are screening leaks within touching distance (<1 cm from leak source) do not necessarily encompass an entire leak volume. Currently in the rule §98.234 (d)(4), weather is addressed such that monitoring using infrared imaging devices must be performed under favorable conditions (such as weather).
  ii. Evaluate existing screening protocols such as LDAR/Method21.

<u>Infrared Imaging Protocol, AWP to Method 21, Paragraph (g)(4)(i-vii)</u>

(3) Leak survey procedure. Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

(4) Recordkeeping. Keep the records described in paragraphs (g)(4)(i) through (g)(4)(vii) of this section:

(i) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(ii) The detection sensitivity level selected from Table 3 to subpart A of this part for the optical gas imaging instrument.

(iii) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (g)(2)(i)(A) of this section.

(iv) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (g)(2)(i)(B) of this section.

(v) The daily instrument check. Record the distance, per paragraph (g)(2)(iv)(B) of this section, and the flow meter reading, per paragraph (g)(2)(iv)(C) of this section, at which the leak was imaged. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(vi) Recordkeeping requirements in the applicable subpart. A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(vii) The results of the annual Method 21 screening required in paragraph (f)(7) of this section. Records must be kept for all regulated equipment specified in paragraph (f)(1) of this section. Records must identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in the existing applicable subparts.

Method 21, Section 8.3

8.3 Individual Source Surveys.

8.3.1 Type I - Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained.

Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

8.3.1.1 Valves. The most common source of leaks from valves is the seal between the stem and housing. Place the probe at the interface where the stem exits the packing gland and sample the stem circumference. Also, place the probe at the interface of the packing gland take-up flange seat and sample the periphery. In addition, survey valve housings of multipart assembly at the surface of all interfaces where a leak could occur.

8.3.1.2 Flanges and Other Connections. For welded flanges, place the probe at the outer edge of the flange gasket interface and sample the circumference of the flange. Sample other types of nonpermanent joints (such as threaded connections) with a similar traverse.

8.3.1.3 Pumps and Compressors. Conduct a circumferential traverse at the outer surface of the pump or compressor shaft and seal interface. If the source is a rotating shaft, position the probe inlet within 1 cm of the shaft-seal interface for the survey. If the housing configuration prevents a complete traverse of the shaft periphery, sample all accessible portions. Sample all other joints on the pump or compressor housing where leakage could occur.

8.3.1.4 Pressure Relief Devices. The configuration of most pressure relief devices prevents sampling at the sealing seat interface. For those devices equipped with an enclosed extension, or horn, place the probe inlet at approximately the center of the exhaust area to the atmosphere.

8.3.1.5 Process Drains. For open drains, place the probe inlet at approximately the center of the area open to the atmosphere. For covered drains, place the probe at the surface of the cover interface and conduct a peripheral traverse.

8.3.1.6 Open-ended Lines or Valves. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.7 Seal System Degassing Vents and Accumulator Vents. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.8 Access door seals. Place the probe inlet at the surface of the door seal interface and conduct a peripheral traverse.

8.3.2 Type II - "No Detectable Emission". Determine the local ambient VOC concentration around the source by moving the probe randomly upwind and *downwind at a distance of one to two meters from the source. If an interference exists with this determination due to a nearby emission or leak, the local ambient concentration may be determined at distances closer to the source, but in no case shall the distance be less than 25 centimeters. Then move the probe inlet to the surface of the source and determine the concentration as outlined in Section 8.3.1. The difference between these concentrations determines whether there are no detectable emissions. Record and report the results as specified by the regulation. For those cases where the regulation requires a specific device installation, or that specified vents be ducted or piped to a control device, the existence of these conditions shall be visually confirmed. When the regulation also requires that no detectable emissions exist, visual observations and sampling surveys are required. Examples of this technique are:*

8.3.2.1 Pump or Compressor Seals. If applicable, determine the type of shaft seal. Perform a survey of the local area ambient VOC concentration and determine if detectable emissions exist as described in Section 8.3.2.

8.3.2.2 Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices. If applicable, observe whether or not the applicable ducting or piping exists. Also, determine if any sources exist in the ducting or piping where emissions could occur upstream of the control device. If the required ducting or piping exists and there are no sources where the emissions could be vented to the atmosphere upstream of the control device, then it is presumed that no detectable emissions are present. If there are sources in the ducting or piping where emissions could be vented or sources where leaks could occur, the sampling surveys described in Section 8.3.2 shall be used to determine if detectable emissions exist.

C. Leak measurement instruments to be reviewed; review existing instrument protocol documents

   i. High volume sampler

      Bacharach provides a user manual for the HiFlow® Sampler on its website. The manual has seven chapters, several of which are useful to this rule:

      <u>Chapter 2: Technical Data</u>

      This chapter provides specifications such as measurable leak rates from 0.05 to 8.00 cubic feet per minute (scf/min), sampling flow rate of 10.5 scf/min, accuracy of +/- 10%, as well as natural gas sensor specifications.

      <u>Chapter 3: Operation</u>

      This chapter discusses operation of the instrument; providing useful protocol steps such as:

      a) To ensure gas sensors are properly zeroed, turn the instrument on in clean air.
      b) Calibrate the instrument every 30 days to assure accuracy.
      c) Create a maintenance log to track calibration dates, etc.
      d) Always purge the instrument with clean air after testing.
      e) Instructions on how to ground the instrument for safety.

f) Instructions on how to equip attachments, use them, and when tips for when they are useful.
g) Instructions on how to use various menus programmed into the instrument.
h) Step-by-step instructions on how to measure leaks (section 3.18 pages 31 – 37), including what modes (e.g. automatic 2-stage mode) for measurement.

Chapter 4: Calibration

This chapter provides step-by-step instructions on how to calibrate the instrument, and provides useful specifications such as using 2 calibration gases: 1) 2.5% CH_4 in air, 2) 100% methane.

ii. Rotameters

Rotameters are not complicated instruments. A few key considerations for use of a rotameter are:

a) Using the proper size. Rotameters have ranges of flow rates that they can measure. It is important to select the appropriate size so as not to exceed or fall below this range. For best results, the leak size should fall toward the middle of the acceptable range.
b) Rotameter use a "float bob" in the measurement, and the readings assume the force for gravity pulling down on the float bob. Thus, the rotameter must be upright during measurement.
c) Rotameters require that all of the gas is directed into them, and a tight seal is formed around the edges of the inlet so that gas does not escape out the sides. This would require a flexible hose or tubing with suitable reducers to fit over different size vent pipes.
d) Greenhouse gas emissions are calculated using the following equation:

$$F_i = 3600 \times w_i \times k \times A \times \sqrt{g \times h}$$

where,

F_i	=	the leak flow rate of greenhouse gas "i"
w_i	=	the concentration of greenhouse gas "i" in the natural gas
k	=	constant provided by the rotameter documentation
A	=	annular area between the float and the tube wall
g	=	acceleration due to gravity
h	=	the pressure drop across the float (as shown by height)

iii. Turbine meters

Daniels (subsidiary of Emerson) provides a user manual for its turbine meters. This document provides equipment specifications for each of its models, detailed instructions for installation and use, as well as maintenance instructions. Amongst the key considerations for the use of this instrument are:

a) The meter should be installed in the horizontal position with the arrow pointing in the direction of the flow.
b) To maintain accuracy, the meter should have an upstream meter tube with recommended minimum length of 10 pipe diameters of straight pipe, and a

downstream meter tube with recommended minimum length of 5 pipe diameters of straight pipe.

c) A straightening vane should be installed with a minimum of 5 pipe diameters upstream of the meter (measured from the downstream end of the vane).
d) For accurate measurement, the meter must be installed in the pipe (meter-tube) without offsets at the flanges and without gaskets protruding into the line bore.
e) Wet gas may only require inspection of the internal assembly once per year, while dusty gas may require inspection every 30 days.
f) Depending on the model selected, accuracy can be +/- 0.25% of better. Operational over a temperature range from 0 to 220°F.
g) The majority of this 91-page document is dedicated to the use of the instrument, including the removal and reassembly of internal assembling of the meter for purposes of calibration and measurement.

iv. Hot wire anemometers
Do not have adequate info to elaborate on possible performance criteria for this measurement device.

v. Pitot tube
Accuracy can be more than 1%.
Method 2C provides details on performance criteria in paragraph 6.1, 6.2, and 6.7 of Method 2:

6.1 Standard Pitot Tube (instead of Type S). A standard pitot tube which meets the specifications of Section 6.7 of Method 2. Use a coefficient of O.99 unless it is calibrated against another standard pitot tube with a NIST-traceable coefficient (see Section 10.2 of Method 2).

6.2 Alternative Pitot Tube. A modified hemispherical-nosed pitot tube (see Figure 2C-1), which features a shortened stem and enlarged impact and static pressure holes. Use a coefficient of 0.99 unless it is calibrated as mentioned in Section 6.1 above. This pitot tube is useful in particulate liquid droplet-laden gas streams when a "back purge" is ineffective."

"6.7 Calibration Pitot Tube. When calibration of the Type S pitot tube is necessary (see Section 10.1), a standard pitot tube shall be used for a reference. The standard pitot tube shall, preferably, have a known coefficient, obtained either (1) directly from the National Institute of Standards and Technology (NIST), Gaithersburg MD 20899, (301) 975-2002, or (2) by calibration against another standard pitot tube with an NIST-traceable coefficient. Alternatively, a standard pitot tube designed according to the criteria given in Sections 6.7.1 through 6.7.5 below and illustrated in Figure 2-5 (see also References 7, 8, and 17 in Section 17.0) may be used. Pitot tubes designed according to these specifications will have baseline coefficients of 0.99 ± 0.01.

6.7.1 Standard Pitot Design.

6.7.1.1 Hemispherical (shown in Figure 2-5), ellipsoidal, or conical tip.
6.7.1.2 A minimum of six diameters straight run (based upon D, the external diameter of the tube) between the tip and the static pressure holes.
6.7.1.3 A minimum of eight diameters straight run between the static pressure holes and the centerline of the external tube, following the 90E bend.
6.7.1.4 Static pressure holes of equal size (approximately 0.1 D), equally spaced in a piezometer ring configuration.
6.7.1.5 90E bend, with curved or mitered junction.

Method 2C provides detail on the protocol for use of a pitot tube for flow rate measurement. Below is an excerpt, section 8:

8.1 Follow the general procedures in Section 8.1 of Method 2, except conduct the measurements at the traverse points specified in Method 1A. The static and impact pressure holes of standard pitot tubes are susceptible to plugging in particulate-laden gas streams. Therefore, adequate proof that the openings of the pitot tube have not plugged during the traverse period must be furnished; this can be done by taking the velocity head (Δp) heading at the final traverse point, cleaning out the impact and static holes of the standard pitot tube by "back-purging" with pressurized air, and then taking another (Δp) reading. If the Δp readings made before and after the air purge are the same (within ±5 percent) the traverse is acceptable. Otherwise, reject the run. Note that if the Δp at the final traverse point is unsuitably low, another point may be selected. If "back purging" at regular intervals is part of the procedure, then take comparative Δp readings, as above, for the last two back purges at which suitably high Δp readings are observed.

vi. Calibrated bagging

Calibrated bags are relatively simple instruments to measure flow rates. The key concepts are:

a) Calibrated bagging requires proximity to the leak, requiring user to be cautious of safety considerations (e.g. temperature of emissions and vent pipe).
b) Ensure that the entire emission is captured by the bag.
c) Measure the time required to completely fill the bag. Repeat the process at least 3 times to improve accuracy.
d) The bag must be made of a static material that will not build charge or create sparks under any operating conditions.

2. Data Sources for Research

- CAA – LDAR program, Method 21 guidance documents
- Manufacturers information (Heath, FLIR, etc)
- CDM leak detection methodologies (AM0023)

3. Summary

It is likely that existing performance criteria and protocols may need selective references and exclude selective provisions which do not apply for mandatory reporting for the expressed purpose of finding and measuring methane leaks for the reporting of GHG emissions. Information from Method 21 and the Alternative Work Practice may be adapted into performance criteria for OVAs, TVAs, and infrared imaging cameras. These documents do not contain any standards for performance criteria of leak measurement devices. Manufacturer data may serve as a starting point for developing measurement device performance criteria.

Appendix P: Discussion on Methodologies in Emission References

API's Emission Factors for Oil and Gas Production Operations[48]

Emissions factors were developed using the following approach:

1. The contributions of screening values that are less than 10 ppmv; screening values 10 to 9,999 ppmv; and emitters pegged at 10,000 ppmv were summed for each component type. Emissions from components with these screening values were calculated using the methods below:
   a. Emission rates for screening values: < 10 ppmv
      1) EPA default zero values for connectors and open ended lines; and
      2) Emission rates for non-emitters (at 10 ppmv) were used for flanges, pumps, valves, and other components.
   b. Emission rates for components with screening rates from 10 ppmv to 9,999 ppmv
      1) Correlation equations from the Protocol for Equipment Leaks Emission Estimates (6/1993) were used to calculate emission rates.
   c. Emission rates for components pegged at 10,000 ppmv
      1) EPA 10,000 ppmv pegged emission factors were used to calculate emission rates.
2. The sum of emissions for each component (from step (1)) was then divided by the total number of components of that type to develop average emission factors.
3. The sum of emissions for each component from step (1a) and step (1b) were divided by the total number of components of that type to develop no-leak factors.
4. The sum of emissions for each component from step (1c) was divided by the total number of components of that type to develop leak factors.
5. The emission factors for each type of component were then separated by facility type (i.e. light crude, gas production).

Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants[49]. AND Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites[50].

Emission factors were also developed using the following approach:

1. Equipment components were screened using bubble tests with soap solution, portable hydrocarbon gas detectors and ultrasonic leak detectors.
   a. The majority of the equipment was screened using the bubble test with soap solution method.
   b. Ultrasonic detectors were used to screen equipment in areas with low background noise levels in the ultrasonic range.
   c. Gas detectors were used to screen equipment that could not be screened using the bubble test such as equipment in high-temperature service, certain flanged connections and open-ended lines.

d. The five facilities surveyed in (Clearstone 2006) conducted supplementary leak surveys using a passive midwave infrared camera to qualitatively compare the method with the more traditional portable hydrocarbon analyzer method.
e. Those components found emitting from the bubble test or ultrasonic detectors were rescreened with a portable hydrocarbon vapor analyzer to determine whether they met the leaker definition.
f. 10,000 ppmv or greater was used as the "leaker definition."

2. A HiFlow® Sampler was used to measure components that exceeded 10,000 ppm.
   a. Equipment leaks that were greater than the upper limit of the unit and most open-ended lines and vents were not measured using the HiFlow® Sampler. They were measured using bagging or other "direct measurement techniques."

3. Equipment component counts were conducted.

4. The average emission factors for each type of component were calculated as follows:
   a. The measured emissions were aggregated by component type which also included "non-leaking" components emission rates. The non-leaking emission rates from the EPA's Protocol for Equipment Leak Emission Estimates were used for non-leaking components (screening values < 10,000 ppmv).
   b. The aggregate emissions were divided by the number of components to estimate average emissions factors.

Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems[51], AND
Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry[52]

1. <u>Component Screening Process</u>
   Leak screening was conducted using ultrasonic leak detectors, bubble tests with soap solution and portable hydrocarbon vapor analyzers calibrated to methane. A positive qualitative screening process was followed by a quantitative screening process in which the screening value, 10,000ppmv, was verified. Components that have a screening value equal to or greater than 10,000ppm were categorized as leaking. The leak detection survey was conducted in accordance with Method 21[67] developed by the EPA, and the measurements were conducted in accordance with the Fugitive Emissions Measurement Protocol[68].

2. <u>Leak Rate Measurement</u>
   Emission rates were measured using a variety of techniques that are outlined in Section 4 of the Fugitive Emissions Measurement Protocol. The primary instrument

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[67] U.S. EPA (Environmental Protection Agency). 1997. Method 21 – Determination of Volatile Organic Compound Leaks.
[68] Clearstone Engineering Ltd. 2006. Canadian Energy Partnership for Environmental Innovation (CEPEI) – Fugitive Emissions Measurement Protocol.

used to quantify the emission rate was the HiFlow™ Sampler. However, depending on the source type and emission rate, velocity probes (i.e. hot wire anemometer, thermal dispersion anemometer, vane anemometer and micro-tip anemometer) and flow-through meters (i.e. rotary meter, diaphragm meter and rotameter) were also used. Data was collected and reported in accordance to Section 2 of the Fugitive Emissions Measurement Protocol.

3. Component Count

Clearstone Engineering conducted a thorough count of components in the surveyed facilities in accordance to the Fugitive Emissions Measurement Protocol. These numbers were compared to independent counts provided by facility operators. Significant discrepancies were noticed during the comparison as follows:

- Facility operators used piping and instrumentation drawing that underestimated the number of components. The drawings did not have the detail required to make an accurate component count.
- Facility operators did not use a systematic approach as stipulated by the Fugitive Emissions Measurement Protocol leading to double counting or undercounting.

When developing the average emission factors, the Clearstone component counts were used.

4. Emission Factors

a. *Average Emission Factors*

Average emission factors include emissions rates from leaking and non-leaking components. Emission rates from leaking components were measured using the procedure described earlier. Non-leaking components were assigned emission rates found in EPA's Protocol for Equipment Leak Emission Estimates[69]. Prior to calculating average emission factors, components were grouped into the following source categories: centrifugal compressor seal, reciprocating compressor seal, connector, control valve, controller, blowdown system, open-ended line, orifice meter, other flow meter, pressure regulator, pressure relief valve and valve. Finally, average emission factors were calculated by summing the total organic emission in each source category and dividing by the corresponding component count.

A 95 percent confidence interval limit was created for the average emission factors in each source category. Total organic emissions were calculated for the entire company using average emission factors utilizing the following equation;

$$ER = \sum_i \sum_j EF_{i,j} \cdot N_i \cdot X_j$$

where

i denotes the source category,
j denotes the facility type (i.e. transmission or distribution),
ER is the total emission rate for the target source population (kg/h),
EF is the average emission factor (kg TOC/h/source),

[69] US EPA. 1995. Protocol for Equipment Leak Emission Estimates. Publication No. EPA-453/R-95-017

N is the number of source,
X is the mass fraction of the target pollutant in the process fluid.

b. *Screening Range Approach*
Leaking components were separated from non-leaking components. As described earlier, components found to have a screening value greater than or equal to 10,000ppmv were labeled as leaking. Subsequently, the components were categorized into the source groups. Leaker factors were calculated by summing the emission rates from leaking components in a particular source group and dividing by the number of corresponding component count. Non-leaking components are assigned emission rates found in EPA's Protocol for Equipment Leak Emission Estimates.

Total organic emissions for the entire company was calculated using leaker and non-leaker emission factors using the following equation;

$$E_{TOC} = \sum_i \sum_j \left(F_G \cdot N_G\right)_{i,j} + \left(F_L \cdot N_L\right)_{i,j}$$

where

i denotes the source category,
j denotes the facility type (i.e. transmission or distribution),
E_{TOC} is emission rate for an equipment type (kg/hr),
F_G is applicable emission factor for sources with screening values ≥ 10,000 ppmv (kg/hr/source),
N_G is equipment count (specific equipment type) for sources with screening values ≥ 10,000 ppmv,
F_L is applicable emission factor for sources with screening values < 10,000 ppmv (kg/hr/source),
N_L is equipment count (specific equipment type) for sources with screening values < 10,000 ppmv.

Appendix Q: Glossary

The following definitions are based on common industry terminology for the respective equipment, technologies, and practices.

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Acid Gas means hydrogen sulfide (H_2S) and carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal.

Acid Gas Removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent stack emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e., high non-combustible component content).

Blowdown vent stack emissions mean natural gas released due to maintenance and/or blowdown operations including but not limited to compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to a emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Coal Bed Methane (CBM) means natural gas which is extracted from underground coal deposits or "beds."

Component, for the purposes of subpart W only, means but is not limited to each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

Condensate means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

Conventional wells mean gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas.

Dehydrator means a device in which a liquid absorbent (including but not limited to desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent stack emissions means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream).

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include activated alumina, palletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor.

E&P Tank means the most current version of an exploration and production field tank emissions equilibrium program that estimates flashing, working and standing losses of hydrocarbons, including methane, from produced crude oil and gas condensate. Equal or successors to E&P Tank Version 2.0 for Windows Software. Copyright (C) 1996-1999 by The American Petroleum Institute and The Gas Research Institute.

Engineering estimation means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced Oil Recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Field means standardized field names and codes of all oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

Flare combustion means unburned hydrocarbons including CH_4, CO_2, N_2O emissions resulting from the incomplete combustion of gas in flares.

Fugitive emissions means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Fugitive emissions detection means the process of identifying emissions from equipment, components, and other point sources.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas gathering/booster stations mean centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

High-Bleed Pneumatic Devices are automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

LNG boiloff gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-Bleed Pneumatic Devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Offshore means tidal-affected borders of the U.S. lands, both state and Federal, adjacent to oceans, bays, lakes or other normally standing water.

Onshore petroleum and natural gas production owner or operator means the entity who is the permitee to operate petroleum and natural gas wells on the state drilling permit or a state operating permit where no drilling permit is issued by the state**,** which operates an onshore petroleum and/or natural gas production facility (as described in §98.230(b)(2). Where more than one entity are permitees on the state drilling permit, or operating permit where no drilling permit is issued by the state, the permitted entities for the joint facility must designate one entity to report all emissions from the joint facility.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/o r gases. A reservoir is characterized by a single natural pressure system.

Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Sweet Gas is natural gas with low concentrations of hydrogen sulfide (H_2S) CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Transmission pipeline means high pressure cross country pipeline transporting sellable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Unconventional wells means gas well in producing fields that employ hydraulic fracturing to enhance gas production volumes.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including but not limited to process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

Well Completions means a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics. This process includes high-rate back-flow of injected water and sand used to fracture and prop-open fractures in low permeability gas reservoirs.

Well Workover means the performance of one or more of a variety of remedial operations on producing oil and gas wells to try to increase production. This process also includes high-rate back-flow of injected water and sand used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs.

Wellhead means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/ or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

Wet natural gas means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as ''wet gas''.

Appendix R: References

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