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Innovative Emissions Solutions

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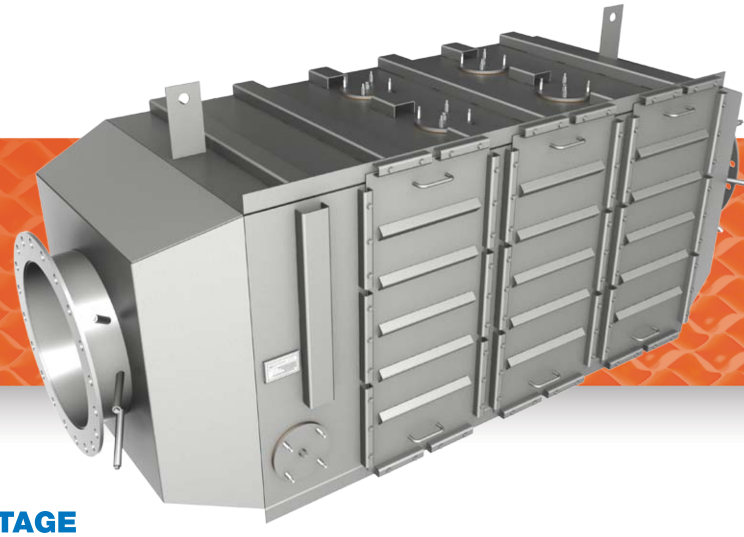
FORMULATIONS

SCR Selective Catalyst Reduction System



WHY THE MIRATECH SCR SYSTEM?

- **NOx Reduction For Tier 4 Compliance**
- **Up to 99% NOx Reduction**
- **Noise Reduction: up to 52 dB(A)**
- **Global Experience**
    - Over 2,000 SCR Systems Installed
- **U.S. Based Service & Support**
    - Fast Response Field Service & Technical Support
    - U.S. Based Engineering & Product Support

APPLICATIONS

- **Stationary Reciprocating Engines**
    - Lean-Burn Natural Gas
    - Diesel and Dual-Fuel
- **Power Generation**
- **Gas Compression**
- **Greenhouse CO_2 Augmentation**

FEATURES & BENEFITS

- **Two-Stage System: SCR & Oxidation**
    - Compliance-Levels For All Emissions: NOx, CO, HAPs, VOCs
    - Three Stage System: DOC/DPF + SCR NOx, CO, VOC, HAPs, PM
- **Efficient Reactant Atomization**
    - Choice Urea or Ammonia Reductant
    - Purge Lines & Air-Assisted Injection Nozzle
- **Designed for Serviceability**
    - Easy Access to Injector for Cleaning & Maintenance
    - Catalyst Access Door
- **Designed for Durability**
    - Carbon or Stainless Steel Housing
    - Aluminum or Galvanized Insulation Sheathing
    - Simple, Quick Bulkhead Connections for Wiring & Plumbing
- **Designed for Easy of Use**
    - Advanced, User-Friendly Controls
    - Safety Shutdown & Alarm Controls
    - Data Storage
    - Data Transfer
    - Network Communications

PRODUCT ADVANTAGE

Where NOx control is a challenge, MIRATECH delivers the best SCR system, service and product support, for both diesel (Tier 4) and natural gas engine applications.

SCR Installation

DESIGN, DELIVER, SUPPORT

Experience

Along with unsurpassed technical expertise, vast real-world experience goes into every MIRATECH SCR project gained in nearly two decades of SCR experience, with more than 2,000 units installed worldwide in power, water pumping and gas compression applications. If there's a problem, or a potential problem—MIRATECH probably has already solved it. If a new issue arises, no one will get to the bottom of it faster.

Bottom-Line Value

When you install MIRATECH's SCR system equipped with advanced injection control, your engine will run efficiently, with low fuel costs, and ongoing compliance assured every step of the way. Your catalyst will work harder, longer, with greater flexibility to handle varying loads, and with less risk of non-compliance fines or operational shutdowns.

World-Class Technology

It starts with the world's best SCR technology. MIRATECH, an acknowledged world leader in the field, provides customers with all the benefits of best available control technology.

- Consistently set the standards for Best Available Control Technology (BACT)
- Simple, user-friendly control and communication technology connects to any building's communication systems
- U.S. based Service & Support
    - Fast-response field service and technical support
    - Replacement components stocked in Tulsa, OK
    - In-house engineering and custom product support

SCR Selective Catalyst Reduction System

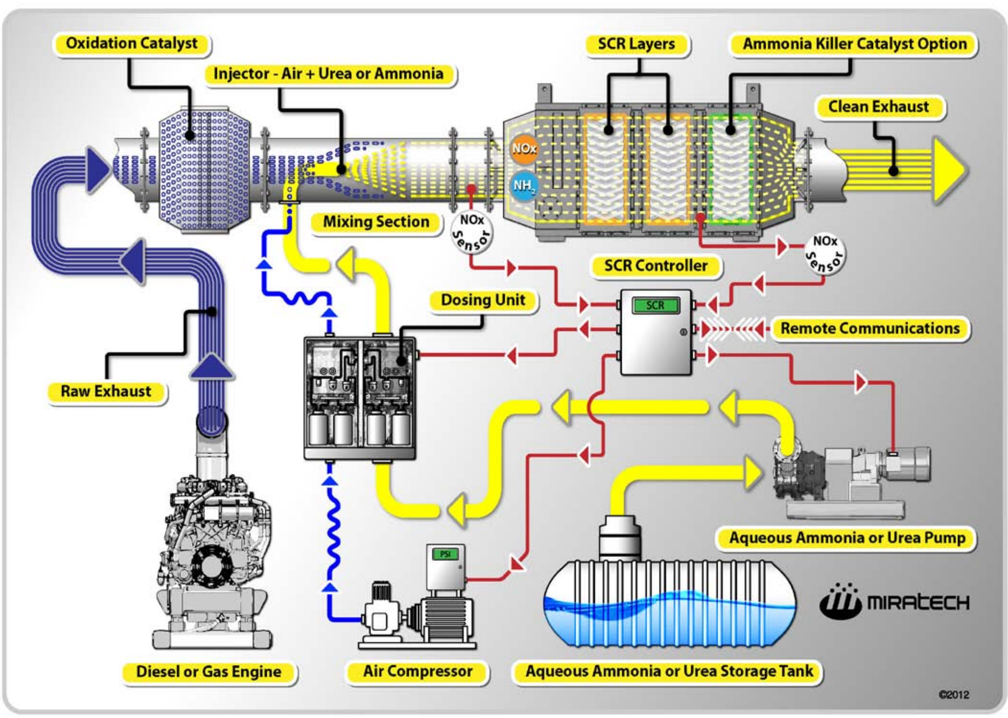
EMISSIONS: CONTROLLED

MIRATECH's SCR catalytic converters reduce regulated exhaust pollutants for stationary reciprocating diesel, dual-fuel and lean-burn natural gas engines. These pollutants include oxides of nitrogen, (NOx), carbon monoxide (CO), and unburned hydrocarbons (HC) comprising Hazardous Air Pollutants (HAPs) and Volatile Organic Compounds (VOCs). The MIRATECH SCR systems work in two efficient stages: the NOx Reduction Stage and the Oxidation Stage for CO and HC reduction. Both stages work together, drastically reducing harmful emissions to satisfy the strictest regulatory requirements. In the mixing section, either ammonia or aqueous urea is injected into the exhaust stream. Urea is often used instead of ammonia; since it's much less toxic than ammonia, it's generally easier to transport and store, and it allows easier permitting. This urea is hydrolyzed and breaks down in the exhaust stream to form ammonia. Ammonia, whether injected directly or formed from urea, reacts with NOx at the SCR catalyst to form harmless water and nitrogen. The Oxidation Stage uses oxidation catalyst elements, with surface coatings impregnated with precious metals, to reduce CO, HAPs, and VOCs—oxidizing these pollutants to form water and carbon dioxide.

COMPLIANCE AND MORE

Most important of all, MIRATECH's SCR solutions give you assured compliance with less cost, less disruption of your operation and full support you can count on over the long haul. With MIRATECH's SCR system, you don't have to deal with complex controls assembly; panels include microprocessor-controlled hardware. MIRATECH's SCR systems give you a choice of reactant, ammonia or urea, for efficient atomization. And MIRATECH's SCR gives you a level of operations control that's simply unique to the industry.

PROCESS DIAGRAM



WHY MIRATECH?

- **Advanced Technology**
- **Product Range: 20 to 20,000+ hp**
- **Innovative, Cost-Effective, Comprehensive Emissions Solutions**
- **RICE NESHAP Compliant**
- **Turnkey Projects**
- **Unsurpassed Experience & Expertise**
- **Fast, Responsive, Customer-Focused Service and Support**
  - Prevent Non-Compliance Fines
  - Improve Engine & Catalyst Performance
  - Cut Maintenance Costs
  - Maximize Catalyst Life
- **Full Service Catalyst Wash & Repair**
  - 'Free Wash for Life' on Next® & Vortex® Substrates
- **Project Management**
- **Onsite Services**
  - Supervision
  - Technical
  - Skilled
- **Product O&M Training**
- **Replacement Parts**

EMISSIONS SOLUTIONS

- **Catalysts**
  - 3-Way
  - Oxidation (Natural Gas & Diesel)
  - HAPs
  - Selective Catalytic Reduction (SCR)
  - Urea Hydrolysis
  - DPF
- **Housings**
  - NX Series
  - IQ
  - CBS
  - CBL
  - Silencer Combinations
    - VX Series
    - RX Series
    - ZX Series
    - Ground Access
- **Controls**
  - SCR
  - Active DPF
  - Air Fuel Ratio (Rich & Lean Burn)
  - Monitors
    - RICE NESHAP
    - DPF

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MIRATECH
420 South 145th East Avenue • Drop Box A
Tulsa, OK 74108 • USA • +1 918 794 0341
info@miratechcorp.com • www.miratechcorp.com

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APPENDIX C TO PART 97—FINAL SECTION 126 RULE: TRADING BUDGET

ST	F126–EGU	F126–NEGU	Total
DC	207	26	233
DE	4,306	232	4,538
IN	7,088	82	7,170
KY	19,654	53	19,707
MD	14,519	1,013	15,532
MI	25,689	2,166	27,855
NC	31,212	2,329	33,541
NJ	9,716	4,838	14,554
NY	16,081	156	16,237
OH	45,432	4,103	49,535
PA	47,224	3,619	50,843
VA	17,091	4,104	21,195
WV	26,859	2,184	29,043
Total	265,078	24,905	289,983

APPENDIX D TO PART 97—FINAL SECTION 126 RULE: STATE COMPLIANCE SUPPLEMENT POOLS FOR THE SECTION 126 FINAL RULE (TONS)

State	Compliance supplement pool
Delaware	168
District of Columbia	0
Indiana	2,454
Kentucky	7,314
Maryland	3,882
Michigan	9,398
New Jersey	1,550
New York	1,379
North Carolina	10,737
Ohio	22,301
Pennsylvania	15,763
Virginia	5,504
West Virginia	16,709
Total	97,159

PART 98—MANDATORY GREENHOUSE GAS REPORTING

Sec.

Subpart A—General Provisions

Subpart B [Reserved]

Subpart C—General Stationary Fuel Combustion Sources

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and outer diameter greater than or equal to 2.375 inch.

Tubing systems means piping equal to or less than one half inch diameter as per nominal pipe size.

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.

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 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).

Vertical well means a well bore that is primarily vertical but has some unintentional deviation or one or more intentional deviations to enter one or more subsurface targets that are offset horizontally from the surface location, intercepting the targets either vertically or at an angle.

Well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80590, Dec. 23, 2011]

TABLE W–1A OF SUBPART W—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION

Onshore petroleum and natural gas production	Emission factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.640
Connector	0.083
Open-ended Line	1.46
Pressure Relief Valve	0.97
Low Continuous Bleed Pneumatic Device Vents [2]	1.39
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	10.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.04
Flange	0.002
Connector	0.005
Open-ended Line	0.04
Pump	0.01
Other [5]	0.23
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0004
Flange	0.0007
Connector (other)	0.0002
Open-ended Line	0.004
Other [5]	0.002
Western U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	2.903
Connector	0.396
Open-ended Line	0.748
Pressure Relief Valve	4.631
Low Continuous Bleed Pneumatic Device Vents [2]	1.77
High Continuous Bleed Pneumatic Device Vents [2]	47.4
Intermittent Bleed Pneumatic Device Vents [2]	17.1
Pneumatic Pumps [3]	10.3

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Onshore petroleum and natural gas production	Emission factor (scf/hour/component)
Population Emission Factors—All Components, Light Crude Service[4]	
Valve	0.04
Flange	0.002
Connector	0.005
Open-ended Line	0.04
Pump	0.01
Other[5]	0.23
Population Emission Factors—All Components, Heavy Crude Service[6]	
Valve	0.0004
Flange	0.0007
Connector (other)	0.0002
Open-ended Line	0.004
Other[5]	0.002

[1] For multi-phase flow that includes gas, use the gas service emissions factors.
[2] Emission Factor is in units of "scf/hour/device."
[3] Emission Factor is in units of "scf/hour/pump."
[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."
[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[6] Hydrocarbon liquids less than 20°API are considered "heavy crude."

[76 FR 80591, Dec. 23, 2011]

TABLE W–1B TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR ONSHORE NATURAL GAS PRODUCTION EQUIPMENT

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Eastern U.S.				
Wellheads	8	38	0.5	0
Separators	1	6	0	0
Meters/piping	12	45	0	0
Compressors	12	57	0	0
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2
Western U.S.				
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

TABLE W–1C TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR CRUDE OIL PRODUCTION EQUIPMENT

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other components
Eastern U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

GREENHOUSE GAS EMISSIONS REPORTING FROM THE PETROLEUM AND NATURAL GAS INDUSTRY

BACKGROUND TECHNICAL SUPPORT DOCUMENT

U.S. ENVIRONMENTAL PROTECTION AGENCY
CLIMATE CHANGE DIVISION
WASHINGTON DC

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.

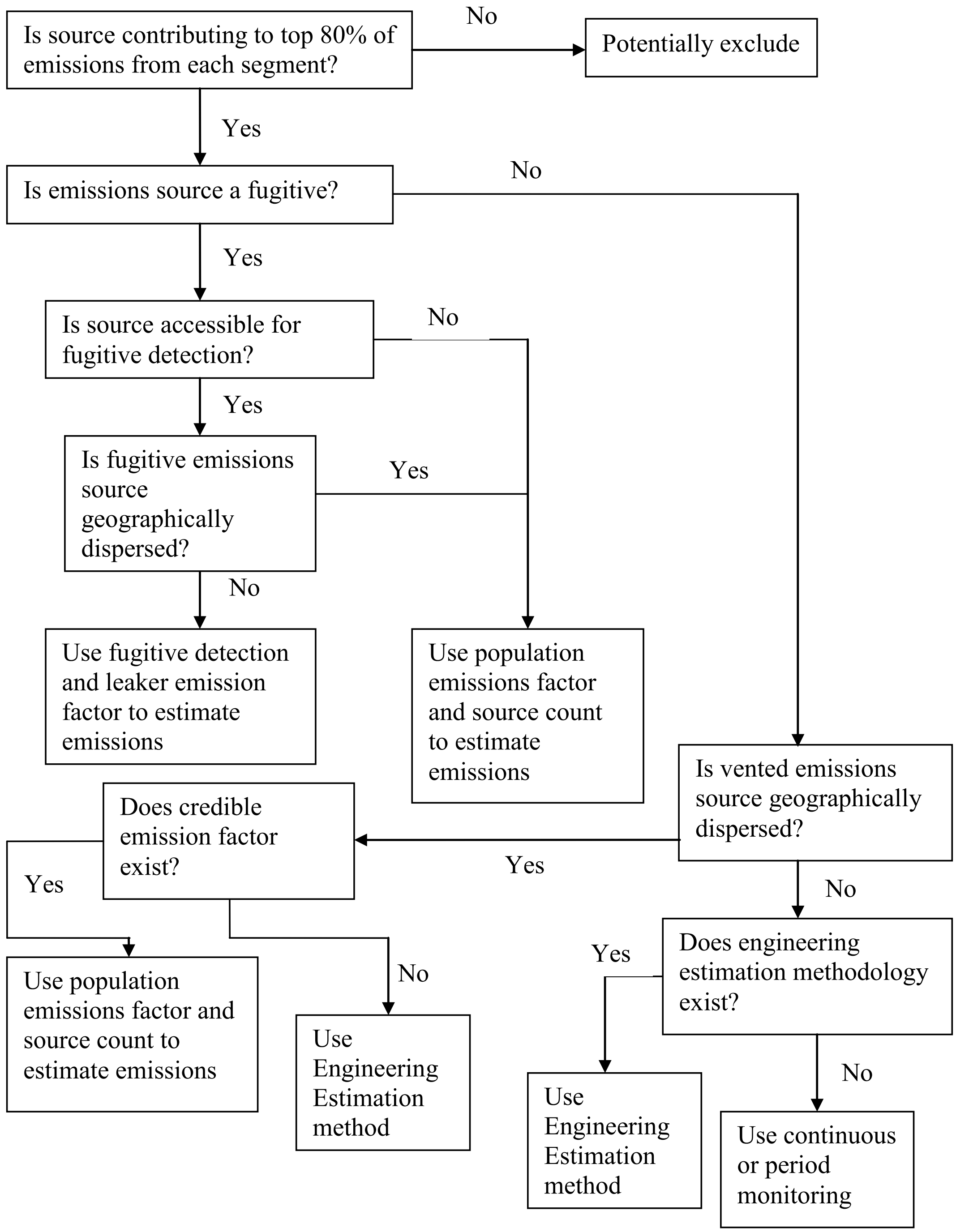

Figure 1: Decision Process for Emissions Source Selection

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 all 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				Facilities Covered	
				Process Emissions ($mtCO_2e$/year)	Combustion CO_2 Emissions (mt/year)	Total Emissions (tons $mtCO_2e$/yr)	Percent	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:

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

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.

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

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

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

where,

$E_{a,i}(un\text{-}combusted)$	=	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:

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

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

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

[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.

- o 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.

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[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: <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.

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*

[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

$$2007 \mathit{ConventionalWorkovers} = 1992 \mathit{ConventionalWorkovers} \times \frac{2007 \mathit{GasWells}}{1992 \mathit{GasWells}}$$

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

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	$9{,}324 \mathit{workovers} \times \frac{431{,}035 \mathit{wells}}{276{,}014 \mathit{wells}} =$	14,569
2007 Unconventional Well Workovers	$10\% \times 41{,}790 \mathit{wells} =$	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
		TOTAL:	**~120 Bcf**

Note: The emission factors and calculated emissions as presented in this table were rounded independently.

[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

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[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_2EOR) 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:

$$\text{Station ``}i\text{'' process emissions} = \frac{StationCapacity_i}{\sum_i StationCapacity} \times TotalInventoryEmissions$$

- 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

  $Emissions_{CO2 \text{ or } N20} = EF_{CO2 \text{ or } N20} \times$ 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
  $\text{Emissions}_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times \text{Compressor energy}_i$ (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.

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[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.

[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.

[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.

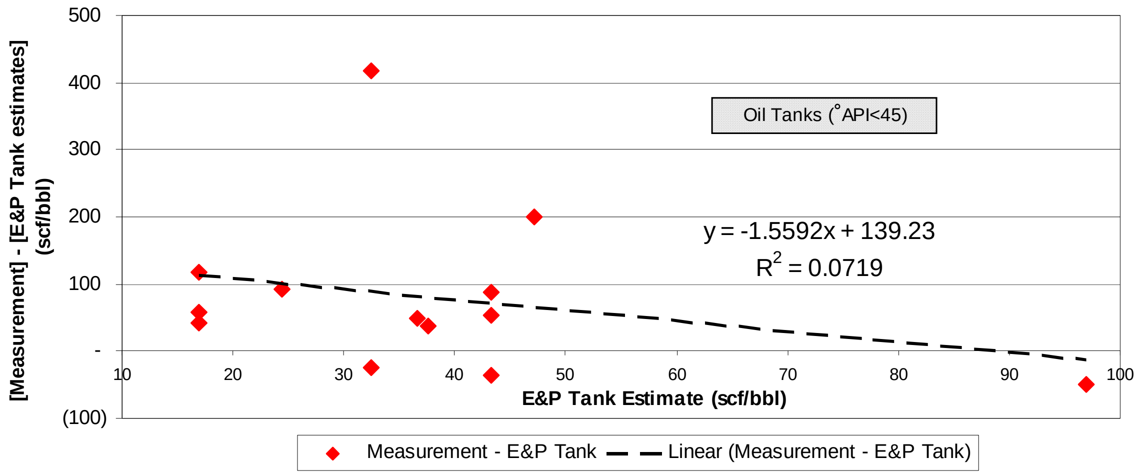
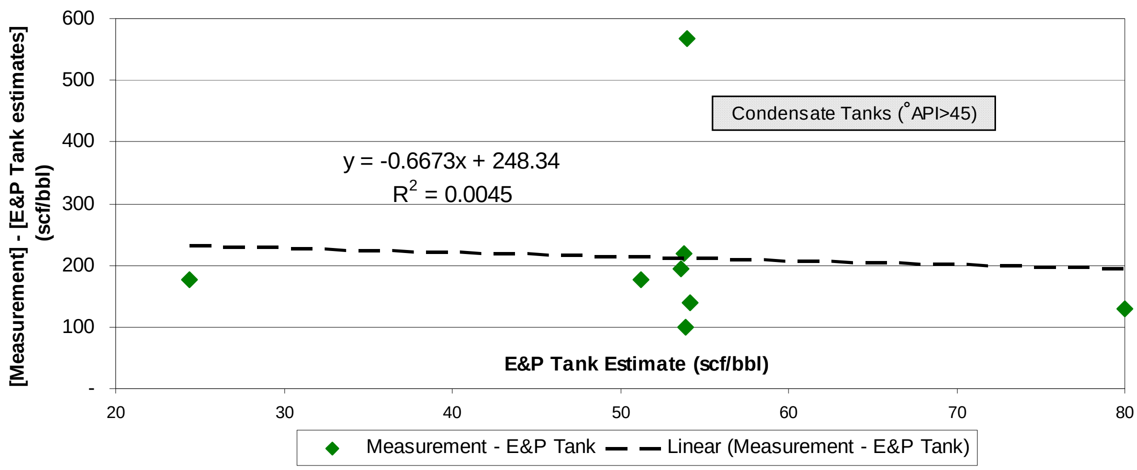


Exhibit J-2. Condensate Tank Correction Factors



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 × EE
- For condensate: CE = 5.37 × 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

Leaker Emission Factors – All Components, Light Crude Service

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

Leaker Emission Factors – All Components, Heavy Crude Service

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

Leaker Emission Factors – All Components, Gas Service

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.)

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[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

Population Emission Factors – All Components, Gas Service

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

[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

Population Emission Factors – Storage Station, Gas Service

Methodology
See methodology for "Population Emission Factors – All Components, Gas Service" for Transmission.

Population Emission Factors – Storage Wellheads, Gas Service

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

Population Emission Factors – Other Components, Gas Service

Methodology
See "Low-Bleed Pneumatic Device Vents" Methodology for Population Emission Factors – Other Components, Gas Service for Transmission.

Methane Emission Factors for LNG Storage

Population Emission Factors – LNG Storage Components, LNG Service

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.

Method 21
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.

<u>Additional Sources Investigated</u>

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.

Infrared Imaging Protocol, AWP to Method 21, Paragraph (g)(4)(i-vii)

(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

[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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NMOGA 12

AMERICAN PETROLEUM INSTITUTE

COMPENDIUM OF GREENHOUSE GAS EMISSIONS METHODOLOGIES FOR THE OIL AND NATURAL GAS INDUSTRY

AUGUST 2009

EXHIBIT 5.21: Sample Calculation for Estimating CH_4 Emissions Using Simplified Transit Emission Factors, continued

CALCULATION METHODOLOGY:
Transit loss emissions are calculated by multiplying the transit loss emission factor given in Table 5-14 for crude oil, by the volume transported and the CH_4 content of the vapors. As a simplifying assumption, the CH_4 content of the vapors is assumed to be 15 wt% (EPA, AP-42 Section 5.2, 2008).

$$E_{CH_4} = \frac{0.57 \text{ tonne TOC}}{\text{week-}10^6 \text{ gal transported}} \times \frac{42 \text{ gal}}{\text{bbl}} \times 500{,}000 \text{ bbl} \times \frac{10 \text{ days}}{\text{trip}} \times \frac{25 \text{ trips}}{\text{yr}} \times \frac{\text{week}}{7 \text{ days}} \times \frac{15 \text{ lb } CH_4}{100 \text{ lb TOC}}$$

$$\underline{E_{CH_4} = 64.1 \text{ tonnes } CH_4/\text{yr}}$$

5.6 Other Venting Sources

5.6.1 Gas-Driven Pneumatic Devices

Natural gas-driven pneumatic devices are a source of CH_4 emissions (and CO_2, if present in the gas). Pneumatic devices may be designed to vent gas continuously (such as when designed with a pilot gas stream) or intermittently (i.e., only when actuated). Low vent and no vent pneumatic devices may also be used. Pneumatic devices may also be operated using compressed air.

If fuel gas is used as the pneumatic gas and is taken downstream of the total fuel gas meter, then the vented gas volume must be subtracted from the total fuel gas volume (used to determine combustion emissions).

Methane emissions from pneumatic devices were evaluated as part of the 1996 GRI/EPA CH_4 emissions study (Shires, 1996). This study observed that most of the pneumatic devices used in the production segment were valve actuators and controllers that used natural gas pressure as the force for the valve movement. Gas from the valve actuator is vented to the atmosphere during the valve stroke, and gas may also be continuously bled from the valve controller pilot in some pneumatic devices.

Emissions from pneumatic devices in the transmission and processing segments were also evaluated during the 1996 GRI/EPA CH_4 study (Shires, 1996). In the transmission segment, compressor and storage stations commonly employed gas-operated isolation valves, as well as a few continuous bleed devices. There were essentially no pneumatic devices associated with the pipeline itself. Compressed air was used to power a majority of the pneumatic devices at gas processing plants, though some devices were operated with natural gas. Many processing plants used gas-driven pneumatic controllers on isolation valves for emergency shut-down conditions or for maintenance work.

Distribution pneumatic devices were evaluated as part of a study of Canadian greenhouse gas emissions (Shires, 2001). Some distribution metering and pressure regulating (M&R) stations use gas-operated pneumatic control loops or isolation valves.

The most rigorous approach for estimating CH_4 emissions (and CO_2 emissions if CO_2 is present in the gas stream) from gas-driven pneumatic devices is to use site-specific device measurements or manufacturers' data.[6] Another rigorous approach to calculate the emissions from a high or continuous bleed pneumatic device is to calculate the volume of gas vented as shown in Equation 5-21 (GPSA, 1987, Equation 3-12).

$$V = 16{,}330 \times \left[1 + \left(\frac{d}{D}\right)^4\right] \times d^2 \times \sqrt{H \times \left[29.32 + \left(0.3 \times H\right)\right]} \times \sqrt{\frac{520}{460 + T_f}} \times \sqrt{\frac{1.0000}{G}} \qquad \text{(Equation 5-21)}$$

where

V = gas flow rate, scf/day

d = orifice diameter, in

D = pipe/tubing inner diameter, in

H = pressure, inches Hg

T_f = gas temperature, °R

G = specific gravity at 60 °F, unitless

After calculating the volume of gas loss, CH_4 and CO_2 emissions can then be calculated using the CH_4 and CO_2 content of the gas, such as described in Section 5.7.1.

Alternatively, simplified CH_4 emission factors are provided in Table 5-15 for each industry sector. Table 5-15 presents the corresponding CH_4 content of the gas used as the basis for the emission

[6] Note, manufacturer emission rates tend to be lower than emissions observed for the same devices in the field due to actual operating conditions and maintenance practices.

factors. The emission factors can be adjusted based on the CH_4 content of the site-specific gas used to drive the devices if the natural gas is significantly different from the default basis. Also, if the pneumatic devices are driven with gas that contains significant quantities of CO_2, the CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

In production, the continuous bleed, intermittent bleed, and average pneumatic device emission factors shown in Table 5-15 are taken from the 1996 GRI/EPA report (Volumes 2 and 12) (Harrison, 1996; Shires, 1996). The pneumatic device emission factors from the GRI/EPA reports were derived using vendor and/or measured data for both intermittent and continuous bleed devices. The instrument controller emission factor (pressure unspecified) is taken from a 2002 CAPP document and is based on data collected in Alberta, Canada (CAPP, 2002). Other pneumatic device emission factors such as transmitters and controllers are taken from a 2003 CAPP report (CAPP, 2003). The emission factors from the 2003 CAPP document are most appropriate for standard (high-bleed) components that were common prior to 1985 and are a function of the device operating pressure (factors are given at 140 kPa or 240 kPa, both gauge pressure).

Table 5-15. Gas-Driven Pneumatic Device CH_4 Emission Factors

Device Type	Emission Factor [a], Original Units		Uncertainty [b] (±%)	Emission Factor [c], Converted to Tonnes Basis	
Production Segment				Based on 78.8 mole% CH_4[a]	
Continuous bleed [a]	654	scfd gas/device	40.3	3.608	tonnes/device-yr
Continuous bleed, low/no-bleed [d]	33.4	scfd gas/device	107	0.184	tonnes/device-yr
Continuous bleed, high-bleed [d]	896	scfd gas/device	33.1	4.941	tonnes/device-yr
Intermittent bleed [a]	323	scfd gas/device	41.2	1.782	tonnes/device-yr
Production average[a] (if device type is unknown)	*345*	*scfd CH_4/device*	*49.5*	*2.415*	*tonnes/device-yr*
Transmitter (140 kPag) [e]	0.12	m^3 gas/hr/device		0.56	tonnes/device-yr
Transmitter (240 kPag) [e]	0.2	m^3 gas/hr/device		0.94	tonnes/device-yr
Controller (140 kPag) [e]	0.6	m^3 gas/hr/device		2.8	tonnes/device-yr
Controller (240 kPag) [e]	0.8	m^3 gas/hr/device		3.7	tonnes/device-yr
Controller (pressure not specified) [f]	0.1996	m^3 gas/hr/device	Uncertainty not specified	0.9333	tonnes/device-yr
I/P Transducer (140 kPag) [e]	0.6	m^3 gas/hr/device		2.8	tonnes/device-yr
I/P Transducer (240 kPag) [e]	0.8	m^3 gas/hr/device		3.7	tonnes/device-yr
P/P Positioner (140 kPag) [e]	0.32	m^3 gas/hr/device		1.5	tonnes/device-yr

Table 5-15. Gas-Driven Pneumatic Device CH_4 Emission Factors, continued

Device Type	Emission Factor [a], Original Units	Uncertainty [b] (±%)	CH_4 Emission Factor [c], Converted to Tonnes Basis
Production Segment, continued			Based on 78.8 mole% CH_4 [a]
P/P Positioner (240 kPag) [e]	0.5 m^3 gas/hr/device		2.3 tonnes/device-yr
I/P Positioner (140 kPag) [e]	0.4 m^3 gas/hr/device		1.9 tonnes/device-yr
I/P Positioner (240 kPag) [e]	0.6 m^3 gas/hr/device		2.8 tonnes/device-yr
Processing			Based on 86.8 mole% CH_4 [a]
Continuous bleed	497,584 scf gas/device-yr	35.5	8.304 tonnes/device-yr
Piston valve operator	48 scf gas/device-yr	60.9	8.010E-04 tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627 scf gas/device-yr	134	0.0939 tonnes/device-yr
Turbine valve operator	67,599 scf gas/device-yr	407	1.128 tonnes/device-yr
Processing average (if device type is unknown)	*164,949 scf CH_4/plant-yr*	*170*	*3.164 tonnes/plant-yr*
	7.431 [g] scf CH_4/MMscf processed		*1.425E-04 tonnes/10^6 scf processed* *5.034E-03 tonnes/10^6 m^3 processed*
Transmission and Storage			Based on 93.4 mole% CH_4 [a]
Continuous bleed	497,584 scf gas/device-yr	35.5	8.915 tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627 scf gas/device-yr	134	0.1008 tonnes/device-yr
Turbine valve operator	67,599 scf gas/device-yr	407	1.211 tonnes/device-yr
Transmission or Storage average (if device type is unknown)	*162,197 scf CH_4/device-yr*	*96.3*	*3.111 tonnes/device-yr*
Distribution			
Pneumatic isolation valves [h] based on 93.4 mole% CH_4	0.366 tonnes CH_4/device-yr	Uncertainty not specified	0.366 tonnes/device-yr
Pneumatic control loops [h] based on 94.4 mole% CH_4	3.465 tonnes CH_4/device-yr		3.465 tonnes/device-yr
Distribution average (if device type is unknown) based on 94.9 mole% CH4 weighted avg.	*2.941 tonnes CH_4/device-yr*		*2.941 tonnes/device-yr*

Footnotes and Sources:

[a] Shires, T.M. and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices*, *Final Report,* GRI-94/0257.29 and EPA-600/R-96-080l, Gas Research Institute and U.S. Environmental Protection Agency, June 1996; and Harrison, M.R., L.M. Campbell, T.M. Shires, and R.M. Cowgill. *Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report, Final Report*, GRI-94/0257.1 and EPA-600/R-96-080b, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The average CH_4 concentration associated with these emission factors is provided in Table E-4.

[b] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[c] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[d] High-bleed devices refer to devices with leak rates greater than 6 scf/hr while low-bleed devices are 6 scf/hr or lower. Developed from data used for Volume 12 of the GRI/EPA natural gas industry CH_4 emissions study (Shires, 1996). Refer to Appendix B for the development of these emission factors.

[e] Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-12, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003. Note that the emission factors provided by this source are for the total gas emitted and were converted to a CH_4 basis using the CH_4 content shown in the table. I/P refers to a device that converts electric current to pneumatic pressure. P/P refers to a device that converts pneumatic pressure to pneumatic pressure.

[f] Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Table 3-4, Canadian Association of Petroleum Producers, Publication Number 2002-0009, May 2002. Factor shown is based on data collected in Alberta, and was converted from a total gas basis to a CH_4 basis using the CH_4 content shown in the table.

[g] Shires, T.M. and C.J. Loughran. *Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation*, *Technical Memorandum*, August 23, 2001.

[h] Derived from estimated processing pneumatic devices vented CH_4 emissions (0.1196 ± 133% Bscf/YR) (Harrison, et al., Vol 2, 1996), and estimated annual gas processed (16,450.855 Bscf/YR (DOE, 1993)).

The production sector continuous bleed device emission factor was further split out according to whether the device is high-bleed or low-bleed, based on the amount of gas vented when the device is not actuating. The EPA Gas STAR program defines a pneumatic device that bleeds more than 6 scfh as a "high-bleed" device, with "low-bleed"/"no-bleed" devices venting less than 6 scfh (EPA Gas STAR, Lessons Learned, July 2003). Therefore, the same data set that was used to develop the production sector continuous bleed device emission factor for the 1996 GRI/EPA study (Volume 12) was also used to develop the high- and low-bleed device emission factors by stratifying the data according to whether the leak rate is greater than or less than 6 scfh. The development of these emission factors is provided in Appendix B.

The processing segment pneumatic device emission factors in Table 5-15 are primarily taken from the 1996 GRI/EPA report (Volumes 2 and 12) (Harrison, 1996; Shires, 1996). The average processing pneumatic device emission factor on a throughput basis is derived from estimated processing devices' vented CH_4 emissions (Harrison, et al., Vol 2, 1996) and estimated annual gas processed (DOE, 1993).

The transmission pneumatic device emission factors are also taken from the 1996 GRI/EPA report (Shires, 1996).

In the distribution segment, the pneumatic isolation valve emission factor is taken from the 1996 GRI/EPA report (Volume 12) (Shires, 1996). The emission factors for pneumatic control loops and average distribution devices are taken from a Canadian GHG inventory for 1995 (Shires, 2001).

An example calculation is provided below in Exhibit 5.22 that demonstrates the use of the pneumatic device emission factors.

EXHIBIT 5.22: Sample Calculation for Gas-Driven Pneumatic Device Emissions

INPUT DATA:
A gas production facility has 80 natural gas-driven pneumatic devices. The average CH_4 content of the gas is 70 mole %. There is also 9 mole % CO_2 in the gas so CO_2 emissions from the pneumatic devices are also estimated. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Emissions are calculated by multiplying the number of pneumatic devices by the emission factor from Table 5-15. The average pneumatic device emission factor for production is used since the type of device is not known.

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United States
Environmental Protection
Agency

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Research and Development

METHANE EMISSIONS FROM THE
NATURAL GAS INDUSTRY
Volume 12: Pneumatic Devices

Prepared for

Energy Information Administration (U. S. DOE)

Prepared by

National Risk Management
Research Laboratory
Research Triangle Park, NC 27711

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16. ABSTRACT The 15-volume report summarizes the results of a comprehensive program to quantify methane (CH4) emissions from the U.S. natural gas industry for the base year. The objective was to determine CH4 emissions from the wellhead and ending downstream at the customer's meter. The accuracy goal was to determine these emissions within +/-0.5% of natural gas production for a 90% confidence interval. For the 1992 base year, total CH4 emissions for the U.S. natural gas industry was 314 +/- 105 Bscf (6.04 +/- 2.01 Tg). This is equivalent to 1.4 +/- 0.5% of gross natural gas production, and reflects neither emissions reductions (per the voluntary American Gas Association/EPA Star Program) nor incremental increases (due to increased gas usage) since 1992. Results from this program were used to compare greenhouse gas emissions from the fuel cycle for natural gas, oil, and coal using the global warming potentials (GWPs) recently published by the Intergovernmental Panel on Climate Change (IPCC). The analysis showed that natural gas contributes less to potential global warming than coal or oil, which supports the fuel switching strategy suggested by the IPCC and others. In addition, study results are being used by the natural gas industry to reduce operating costs while reducing emissions.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Prevention	13B
Emission	Stationary Sources	14G
Greenhouse Effect	Global Warming	04A
Natural Gas		21D
Gas Pipelines		15E
Methane		07C

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FOREWORD

The U.S. Environmental Protection Agency is charged by Congress with protecting the Nation's land, air, and water resources. Under a mandate of national environmental laws, the Agency strives to formulate and implement actions leading to a compatible balance between human activities and the ability of natural systems to support and nurture life. To meet this mandate, EPA's research program is providing data and technical support for solving environmental problems today and building a science knowledge base necessary to manage our ecological resources wisely, understand how pollutants affect our health, and prevent or reduce environmental risks in the future.

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This publication has been produced as part of the Laboratory's strategic long-term research plan. It is published and made available by EPA's Office of Research and Development to assist the user community and to link researchers with their clients.

E. Timothy Oppelt, Director
National Risk Management Research Laboratory

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June 1996

**METHANE EMISSIONS FROM
THE NATURAL GAS INDUSTRY,
VOLUME 12: PNEUMATIC DEVICES**

FINAL REPORT

Prepared by:

Theresa M. Shires
Matthew R. Harrison

Radian International LLC
8501 N. Mopac Blvd.
P.O. Box 201088
Austin, TX 78720-1088

DCN: 95-263-081-09

For

GRI Project Manager: Robert A. Lott
GAS RESEARCH INSTITUTE
Contract No. 5091-251-2171
8600 West Bryn Mawr Ave.
Chicago, IL 60631

and

EPA Project Manager: David A. Kirchgessner
U.S. ENVIRONMENTAL PROTECTION AGENCY
Contract No. 68-D1-0031
National Risk Management Research Laboratory
Research Triangle Park, NC 27711

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RESEARCH SUMMARY

Title	Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices Final Report
Contractor	Radian International LLC GRI Contract Number 5091-251-2171 EPA Contract Number 68-D1-0031
Principal Investigators	Theresa M. Shires Matthew R. Harrison
Report Period	March 1991 - June 1996 Final Report
Objective	This report describes a study to quantify the annual methane emissions from pneumatic devices, which are a significant source of methane emissions within the gas industry.
Technical Perspective	The increased use of natural gas has been suggested as a strategy for reducing the potential for global warming. During combustion, natural gas generates less carbon dioxide (CO_2) per unit of energy produced than either coal or oil. On the basis of the amount of CO_2 emitted, the potential for global warming could be reduced by substituting natural gas for coal or oil. However, since natural gas is primarily methane, a potent greenhouse gas, losses of natural gas during production, processing, transmission, and distribution could reduce the inherent advantage of its lower CO_2 emissions. To investigate this, Gas Research Institute (GRI) and the U.S. Environmental Protection Agency's Office of Research and Development (EPA/ORD) cofunded a major study to quantify methane emissions from U.S. natural gas operations for the 1992 base year. The results of this study can be used to construct global methane budgets and to determine the relative impact on global warming of natural gas versus coal and oil.
Results	The annual national emission rates for pneumatic devices for each industry segment are as follows: production, 31.4± 65% Bscf; gas processing, 0.60 ± 64% Bscf; and transmission, 14.1 ± 60% Bscf. (Distribution emissions are presented in another report.)

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Based on data from the entire program, methane emissions from natural gas operations are estimated to be 314 ± 105 Bscf for the 1992 base year. This is about 1.4 ± 0.5% of gross natural gas production. This study also showed that the percentage of methane emitted for an incremental increase in natural gas sales would be significantly lower than the baseline case.

The program reached its accuracy goal and provides an accurate estimate of methane emissions that can be used to construct U.S. methane inventories and analyze fuel switching strategies.

Technical Approach

Emission rates for pneumatic devices were determined by developing average annual emission factors for devices used in each industry segment and extrapolating these data based on activity factors to develop a national estimate, where the national emission rate is the product of the emission factor and activity factor.

The natural gas industry has two primary types of pneumatic devices that discharge methane: 1) control valves that regulate flow, and 2) gas-actuated block valves. Because each segment of the industry follows its own specific practices regarding "typical" pneumatic device installations, emission factors were developed based on the types of devices observed from site visits.

Emission factor data for the various device types were collected from several sources: measured emissions provided from other studies, manufacturers' data, and data collected from site visits. Data collected during site visits included: the number of each type of pneumatic device, manufacturer and model numbers, operating conditions (e.g., supply gas pressure and supply gas type), and annual device actuation frequency. Equations relating these parameters were developed for the different types of devices to develop an annual emission factor for a generic pneumatic device in each industry segment.

The development of activity factors for each industry segment are presented in a separate report. In general though, the population of pneumatic devices in each industry segment was determined from counts of devices observed during site visits. The national emissions for each industry segment were then based on the product of the emission factor for a generic pneumatic device and the activity factor.

Project Implications

For the 1992 base year, the annual methane emissions estimate for the U.S. natural gas industry is 314 Bscf ± 105 Bscf (± 33%). This is equivalent to 1.4% ± 0.5% of 1992 gross natural gas production. Results from this program were used to compare greenhouse gas emissions from the fuel cycle for natural gas, oil, and coal using the global warming potentials (GWPs) recently published by the Intergovernmental Panel on Climate Change (IPCC). The analysis showed that natural gas contributes less to potential global warming than coal or oil, which supports the fuel switching strategy suggested by IPCC and others.

In addition, results from this study are being used by the natural gas industry to reduce operating costs while reducing emissions. Some companies are also participating in the Natural Gas-Star program, a voluntary program sponsored by EPA's Office of Air and Radiation in cooperation with the American Gas Association to implement cost-effective emission reductions and to report reductions to the EPA. Since this program was begun after the 1992 baseline year, any reductions in methane emissions from this program are not reflected in this study's total emissions.

Robert A. Lott
Senior Project Manager, Environment and Safety

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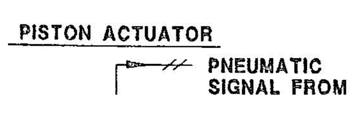
1.0 SUMMARY

This report is one of several volumes that provide background information supporting the Gas Research Institute and U.S. Environmental Protection Agency Office of Research and Development (GRI-EPA/ORD) methane emissions project. The objective of this comprehensive program is to quantify the methane emissions from the gas industry for the 1992 base year to within ±0.5% of natural gas production starting at the wellhead and ending immediately downstream of the customer's meter.

This report describes a study to quantify the annual methane emissions from pneumatic devices, which are a significant source of methane emissions within the gas industry. The gas industry has two primary types of pneumatic devices that discharge natural gas: control valves that regulate flow, and gas-actuated isolation (block) valves. Because each segment of the industry follows its own specific practices regarding "typical" pneumatic device installations, emission factors were developed based on the types of devices observed from site visits. Emission factor data were collected from several sources: measured emissions provided from other studies, manufacturers' data, and data collected from site visits.

The population of pneumatic devices in each industry segment was generally determined from counts of devices observed during site visits. The national emission factor for each industry segment was then based on the product of the emission factor for a generic pneumatic device and activity factor.

The annual emissions for pneumatic devices for each industry segment are as follows: production 31.4 ± 65% Bscf; gas processing, 0.60 ± 64% Bscf; and transmission, 14.1 ± 60% Bscf. (Distribution emissions are included in Volume 10 on metering and pressure regulating stations.[1])



2.0 INTRODUCTION

A pneumatic device is a mechanical device operated by some type of compressed gas. In the oil and gas industry, many devices, especially instruments and valves, are powered by natural gas. Some of these devices discharge the power gas (also called supply gas) to the atmosphere.

This report is concerned with all "pneumatic devices," but focuses on devices that release natural gas to the atmosphere, with the exception of gas-powered pumps and gas-powered compressor starters, which are characterized in other parts of the GRI/EPA study.[2,3,4] Also, it is important to note that some pneumatic devices do not emit gas. For example, gas supply regulators and flow measurement devices such as Barton Chart recorders and strip chart recorders are sealed and do not bleed gas to the atmosphere.

The gas industry has two primary types of pneumatic devices that discharge natural gas: 1) control valves that regulate flow, and 2) gas-actuated block valves. Section 3 describes each type of pneumatic device and the methods of data collection used for each type of device.

Section 4 discusses emission factors developed for each type of pneumatic device. Because each segment of the gas industry follows its own specific practices regarding "typical" pneumatic device installations, this section contains separate discussions for each segment of the gas industry: production, gas processing, and transmission and storage. Emissions from pneumatic devices in the distribution segment are characterized in a separate report on meter and regulation station emissions.[1] Section 5 describes activity factors for each segment of the gas industry, and Section 6 provides annual national emissions calculated for each segment of the gas industry.

3.0 PNEUMATIC DEVICE CHARACTERISTICS

This section describes the characteristics of the various types of pneumatic devices used in the natural gas industry, the data collected, and the methods used to extrapolate the data.

3.1 Overview

Pneumatically operated equipment became the standard in the oil and gas industry since electricity was not readily available at remote production sites. Some pneumatic devices are powered by pressurized air from an instrument air compressor. However, the majority of pneumatic instruments and valves in the gas industry are powered by natural gas.

The pneumatic device can be used to move a valve or make a measurement. Most pneumatic measurement devices in the gas industry are sealed and do not emit natural gas unless they have a defect. However, many of these measurement devices send a signal to a control valve that regulates flow and thus controls process variables such as pressure, temperature, flow rate, and level. The controller for the control valve, if powered by natural gas, will discharge methane to the atmosphere. In gas processing and transmission, isolation valves on large pipelines (also called block valves) can be actuated by natural gas, whereas most of the isolation valves in the production and distribution industry segments are operated manually.

Table 3-1 presents the pneumatic device classifications that will be used for the purpose of this report. The function that a control valve affects, such as level, flow rate, temperature, or pressure, usually dictates the type of control device and therefore the controller bleed rate. Pneumatic controllers linked to valves that control process temperature, flow rate, or level (Figure 3-1) bleed gas. The controller bleed rate may be intermittent – alternating between bleeding gas to the atmosphere and not bleeding gas – or

TABLE 3-1. PNEUMATIC DEVICE CLASSIFICATIONS

Valve Information	Pneumatic Controller Information				Pneumatic Positioner[a] Information
Function/Service	**Type of Control**	**Controller Bleed Frequency**	**Controller Bleed Rate (upon valve actuation)**	**Controller Device Design**	**Bleed Status**
Level, Flow Rate, Temperature, or Pressure Control	Snap-acting	Intermittent Stationary Bleed Rate = 0	High rate, discharges full volume of actuator	On-off (Figure 3-10)	N/A
	Throttling	Continuous Non-zero Stationary Bleed Rate	Small to large volume discharged	Orifice-flapper (Figure 3-6)	Continuous or intermittent
	Throttling	Intermittent Stationary Bleed Rate = 0	Small to large volume discharged	Force-balance piston (Figure 3-3)	Continuous or intermittent
Pressure Control	Throttling	No-bleed (discharges to downstream gas line)	No-bleed (discharges to downstream gas line)	Self-contained spring/diaphragm (Figure 3-2)	N/A
Isolation	N/A	Intermittent Stationary Bleed Rate = 0	High rate, discharges full volume of actuator	Piston, rotary vane, or turbine (Figures 3-4, 3-11, 3-12, and 3-13)	N/A

[a] Positioners are optional devices.

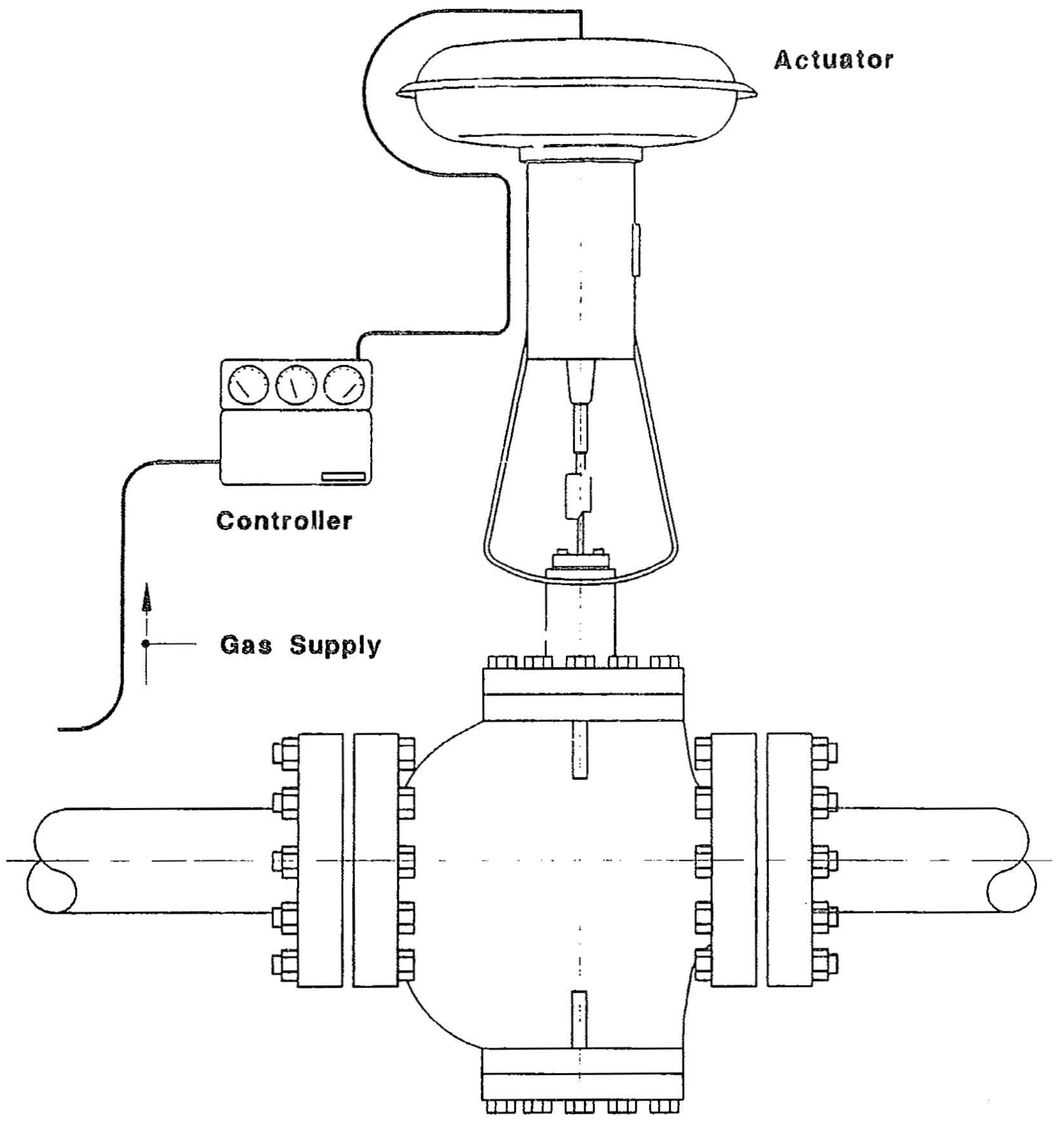


Figure 3-1. Example of a Pneumatic Controller Used for Level, Flow Rate, Temperature, or Pressure Control

the controller may continually bleed gas at various rates (throttling). Pressure controllers may bleed gas to the atmosphere, or may be self-contained (Figure 3-2). Self-contained devices bleed gas from a high-pressure source to a lower pressure source without releasing gas to the atmosphere.

Throttling pneumatic control valves can be equipped with a valve positioner (shown in Figure 3-3), which is a type of mechanical feedback device that senses the actual valve stem position, compares it to the desired position, and adjusts the gas pressure to the valve accordingly. In addition to gas bleeding through the valve controller, the positioner also bleeds gas to the atmosphere.

Isolation valves are used to isolate a segment of pipe or a piece of equipment rather than for process control. An example is shown in Figure 3-4. The valve is either open or closed. Gas is released only when the valve is moved, so the bleed frequency is considered intermittent. This type of operation is fairly infrequent. The bleed rate for these devices varies with the design of the actuator.

Table 3-2 lists the pneumatic devices commonly used in the natural gas industry and whether gas would be emitted in steady-state operation or during the actuation cycle. This table summarizes the bleed modes of the various devices presented in Table 3-1. The pneumatic device bleed modes and classifications are discussed in more detail in the following sections.

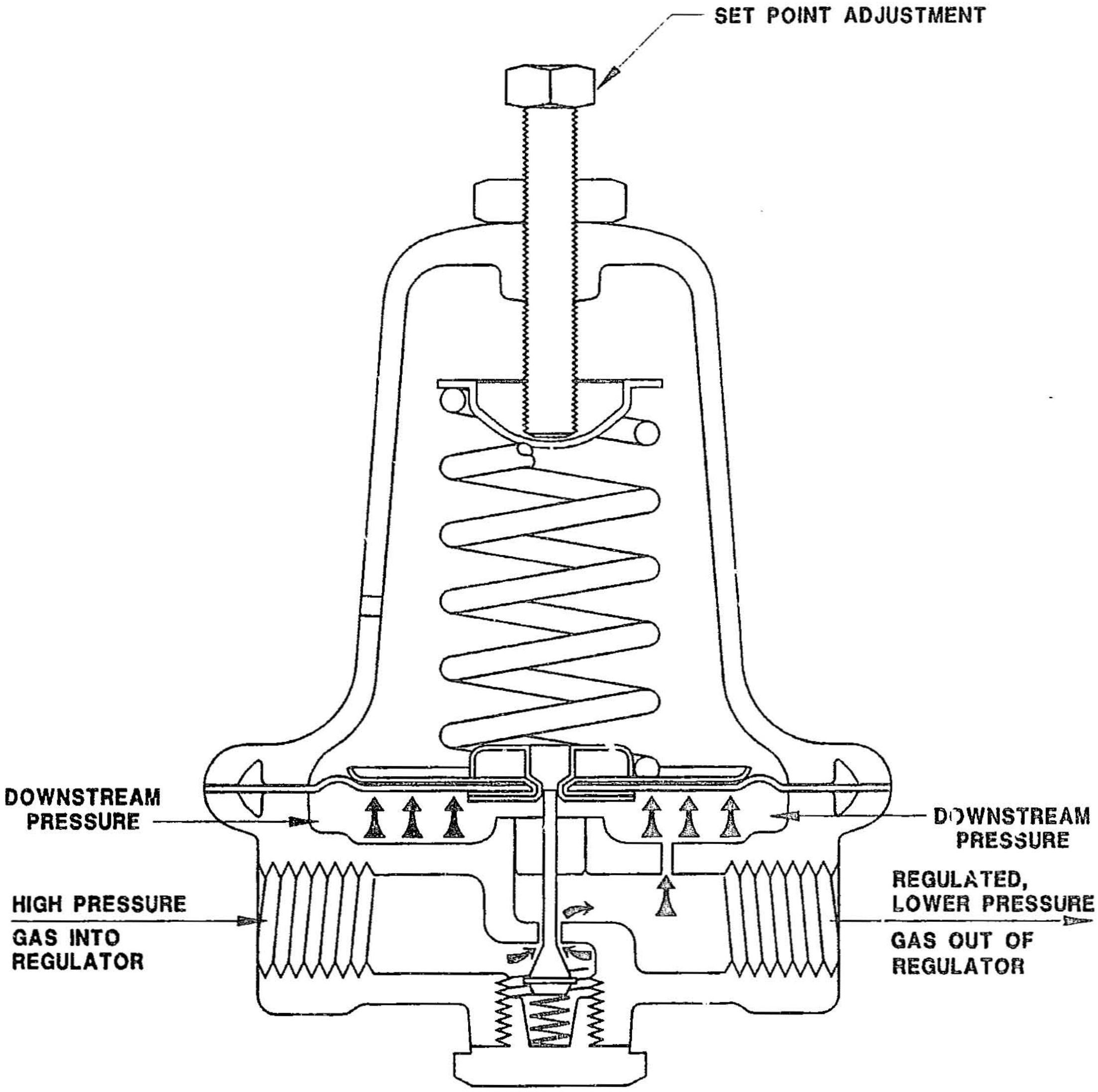


Figure 3-2. Self-Contained, Spring-Loaded Pressure Regulator[5]

ON/OFF SNAP DEVICE

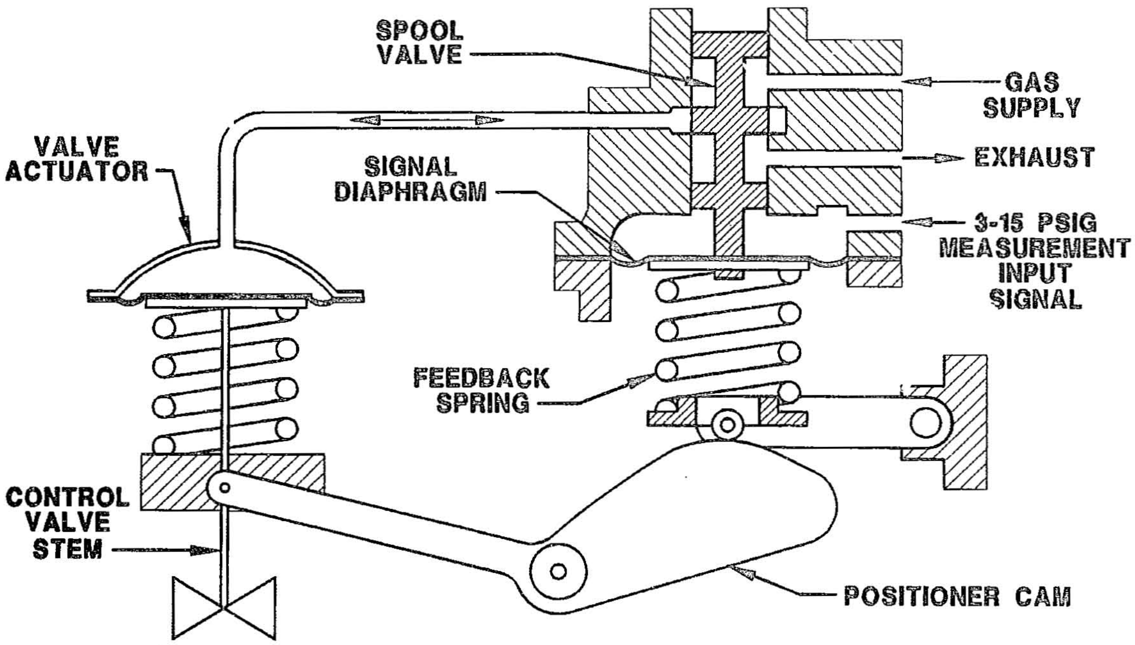


Figure 3-3. Pneumatic Device with Positioner-Force Balance Piston Type[5]

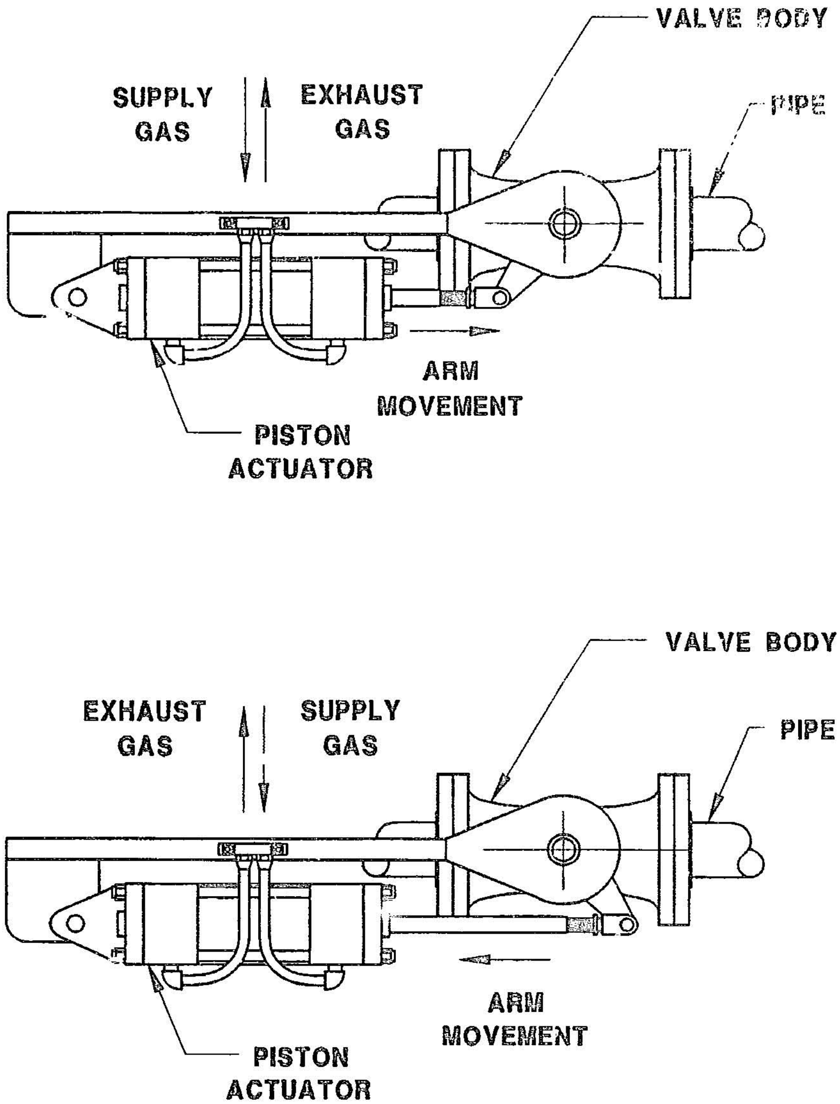


Figure 3-4. Example Isolation Valve - Piston Operator

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TABLE 3-2. TYPICAL PNEUMATIC DEVICE BLEED MODES

Pneumatic Device Type	Does the Device Bleed During: Steady-State Operations?	Actuation Cycle (Valve Stroke)?
Measurement Device		
- Recording	No	No
- Control	No	No
Control Valve (Operator/Actuator)	No	No
Valve Controller		
- Snap-Acting	No	**Yes**
- Throttling		
a. Force Balance	No	**Yes**
b. Orifice/Flapper	**Yes**	**Yes**
Valve Feedback Positioner		
a. Force Balance	No	**Yes**
b. Orifice/Flapper	**Yes**	**Yes**
Self-Contained Pressure Regulators	No	No
Gas-Actuated Isolation Valves	No	**Yes**

3.2 Gas-Actuated Control Valves

3.2.1 Operating Principles

Pneumatic devices (valve controllers) linked to control valves are the largest source of pneumatic emissions in the gas industry. These devices can have two distinct bleed modes: a stationary bleed rate and an actuating bleed rate. The stationary bleed is the rate of gas released when the signal is constant, and the device is not moving. For intermittent bleed pneumatic controllers, the stationary bleed rate is zero. For continuous bleed controllers, the stationary bleed rate is non-zero; it is required to maintain a constant gas supply to the device to provide for a quick response to changes in the controlled process.

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When the pneumatic device is moving the control valve, there is an unsteady and different rate of bleed (actuation bleed rate). If the signal is adding pressure to the actuating chamber, the bleed rate drops from the stationary level. If the signal is to release pressure from the actuating chamber, the bleed rate increases above the stationary rate. Actuating bleed rates must be considered over a long period to determine average emissions. Since the rate varies with the frequency of control, the actuating bleed rate is not available from the device manufacturers.

Various parameters such as pressure, temperature, flow rate, and liquid levels are all controlled by opening or closing a control valve in the process line. The necessary elements for controlling a parameter are a parameter measurement device, a valve, a valve controller, and possibly a feedback positioner. For example, Figure 3-5 illustrates a device to control the volume of liquid in a vessel. A level float in the vessel indicates the volume of liquid based on the level measurement. The measurement device sends a weak signal to the controller. The controller receives the weak pneumatic signal and converts it to a stronger pneumatic signal which is sent to the valve actuator to move the valve stem. The flow rate of liquid from the tank is measured and recorded. Each of the elements – measurement, valve, and valve controller – is described in detail below.

Measurement

Weak signals from a measurement device are translated by sealed transmitters into a stronger signal that can physically change valve position, and thus affect flow control. For example, measurement of level using a level float produces a weak mechanical signal that can be used to move the flapper shown in Figure 3-6a. Other measurement media can also serve as the controlling parameter. For example, process flow is typically measured by a drop in pressure across a restriction. The pressure taps on either side of the restriction in the process flow are tied to a diaphragm that deflects when the pressure changes. The deflection of the diaphragm produces a weak mechanical signal that can be used to move the flapper (baffle) shown in Figure 3-6b.

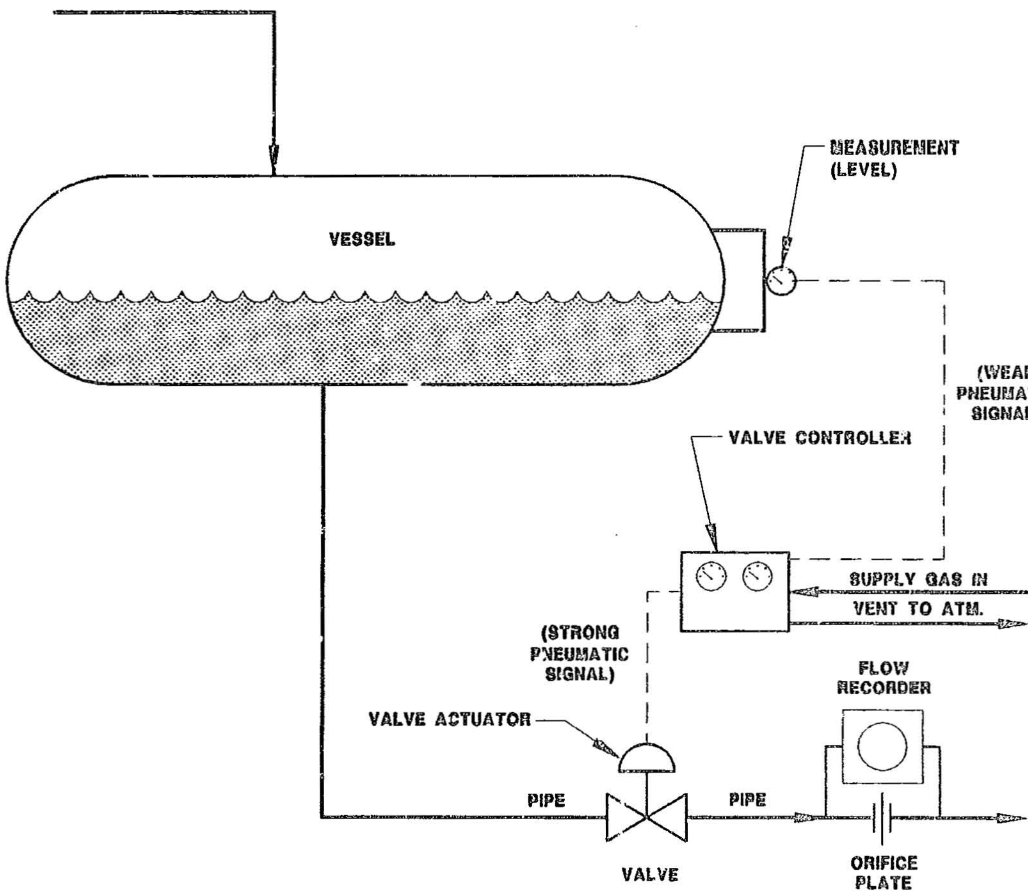

Figure 3-5. Operating Principles

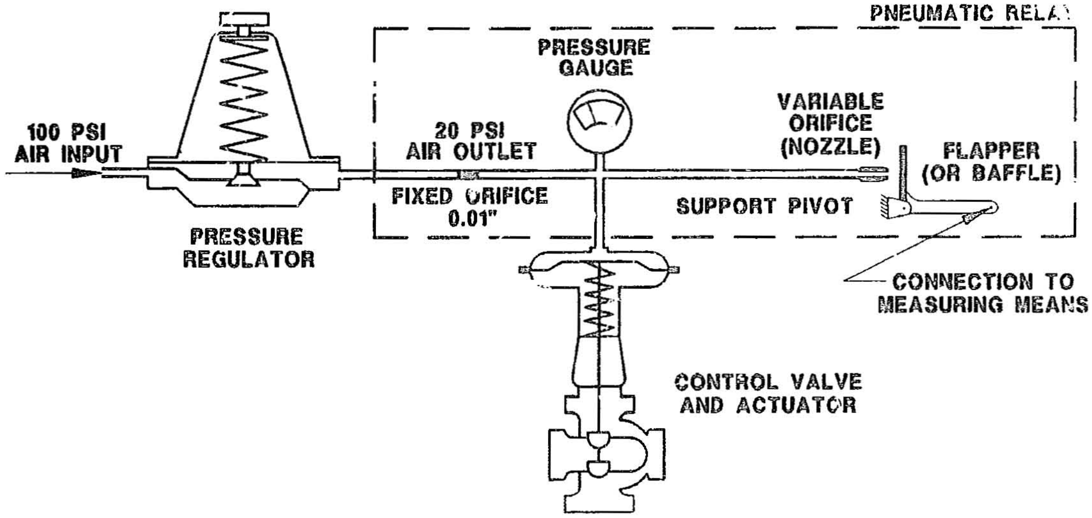

Figure 3-6a. Throttling Continuous Bleed Pneumatic Controller: Orifice Flapper Design[5]

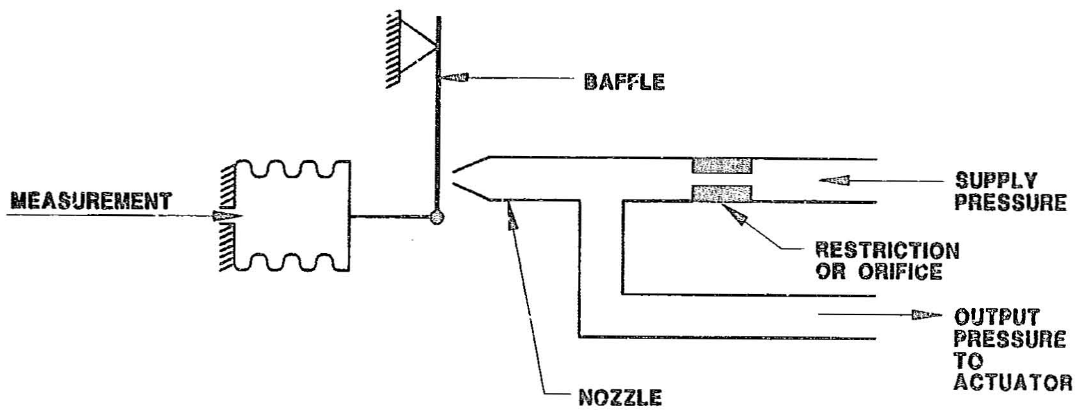

Figure 3-6b. Throttling Continuous Bleed Pneumatic Relay: Orifice Flapper Design[5]

Valve

Flow is regulated by a control valve. The valve operates by moving a valve stem and a valve seat attached to the stem. The movement of the valve seat inside the valve body can then restrict or stop process flow through the valve. The stem can be moved by any force method.

Some valves in the field are moved by small electrical motors; however, a pneumatic device is the most common. In the case of pneumatic actuated valves, the stem is moved by force from the actuator chamber. The actuator chamber is either a diaphragm or a piston device (see Figure 3-7), which deflects or moves because pressure is applied to one side of the chamber. A permanent coiled spring pushes the valve stem in the opposite direction when the pneumatic force is reduced. The valve and valve actuator never bleed directly unless there is a defect. Emissions from such defects are considered fugitive emissions and are considered in the Equipment Leaks[7] report. All actuation gas discharge is emitted back through the valve controller.

Valve Controller

A valve controller is the device that enables a process variable to be changed. The controller device links the valve and the measurement signal to produce a control loop. The controller checks the current measurement of the variable against the desired set point of the variable. If there is a difference, a pneumatic signal is sent to the control valve to open or close the valve. If the measurement matches the set point, equilibrium is maintained and the signal holds a constant level. The controller may bleed at the stationary rate depending on the design.

In the field, the measurement device, valve, and valve controller are often integral. However, the controller is the one element in the measurement/valve/valve-controller loop that discharges gas to the atmosphere. Controllers are highly variable in design. Depending on the design of the controller, the stationary position may or may not

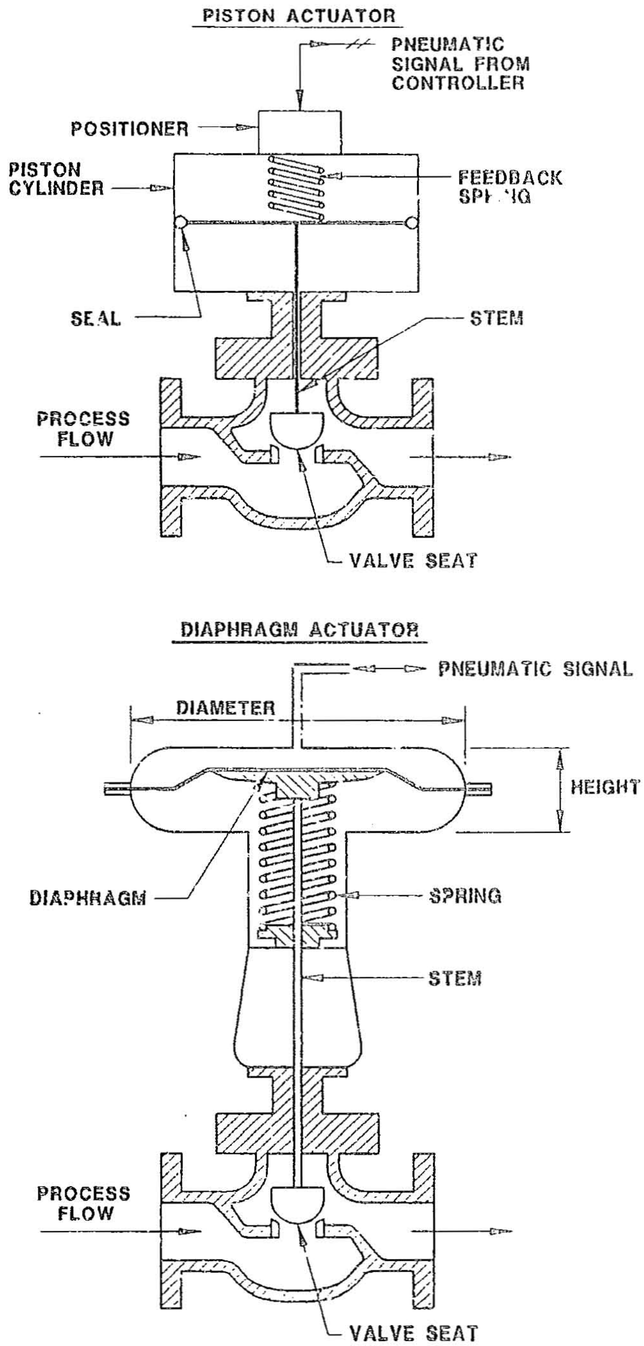

Figure 3-7. Actuator Types[5]

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involve a continuous bleed rate. However, the actuation cycle, which is the actual movement or stroke of the valve stem from open to closed and back, always results in the release of gas. This cycle only occurs when the signal changes and control is needed. The frequency of this occurrence will be different for every application.

Pneumatic Relay

The key component of the controller is the pneumatic relay (also called a booster, transmitter, or amplifier). In the simplest case, a controller is only a supply gas regulator and a pneumatic relay. Since the signal from the measurement device is usually weak, it can not produce enough force to open the valve. A controller device amplifies the signal using a higher-pressure supply gas. The supply gas is often taken directly from the produced gas at the field site.

The pneumatic relay is a kind of mechanical amplifier that produces a stronger pneumatic signal. The mechanical amplifier in the controller uses the small force of the measurement deflection to change the supply gas flow path, which alters the resulting downstream supply gas pressure. The change in pressure is a pneumatic signal that is sent to the valve actuator. Controllers may not bleed at all when there is an increasing signal. An increasing signal sends higher-pressure gas into the actuator, deflecting the diaphragm and compressing the spring. When the signal decreases, the controller reduces the pressure on the actuator by releasing gas to the atmosphere.

There are several types of pneumatic relays which, as the main component of the controller, define the type of controller. The most common are throttling and snap-acting. Throttling implies that the valve can be moved to any position proportional to the signal. These devices are most often used for their quick response to system changes or where more precise control is needed.

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A simplified drawing of a throttling controller's pneumatic relay shows one method that a pneumatic device may use to change a weak mechanical signal into a stronger pneumatic signal (Figure 3-6b). Basically, the pneumatic device uses a small amount of mechanical force to alter the flow and pressure of a supply gas at higher pressure. This higher pressure stream then becomes the amplified control signal. The higher pressure gas stream is "altered" by being partially diverted through a small orifice that bleeds to the atmosphere. The weak mechanical signal moves a "flapper" that alters the flow of gas out of the orifice. If the flapper is fully extended towards the orifice, the device bleeds at a very low rate, and the pneumatic output is at its highest level. If the orifice is fully open, most of the supply stream bleeds to the atmosphere, and the pneumatic output is at its lowest value. This type of throttling device has a continuous bleed rate, even in the stationary position (no movement of the valve or change of signal) because the orifice opening is not completely closed.

Figure 3-6a shows that a small mechanical force can be used to deflect a flapper arm that covers or uncovers an orifice, changing the gas supply into an amplified measurement signal. Other types of pneumatic relays use a chamber instead of an orifice flapper apparatus. The most common chamber relay is called a "force balance piston device." One example was shown in Figure 3-3, and another is shown in Figure 3-8. This type of device only bleeds when it is out of the neutral position; its continuous bleed rate is zero.

In addition to the primary relay amplifier, many throttling controllers have adjustment devices that allow the operator to alter the set point and response (proportional gain, proportional-integral gain, or proportional-integral-derivative gain), and devices that allow the controller to be reset. These additional devices may also bleed gas, but their rates are steady and are included in the manufacturers' reported total gas consumption rate for the controller. Figure 3-9 shows a device with a proportional set point and reset knob.

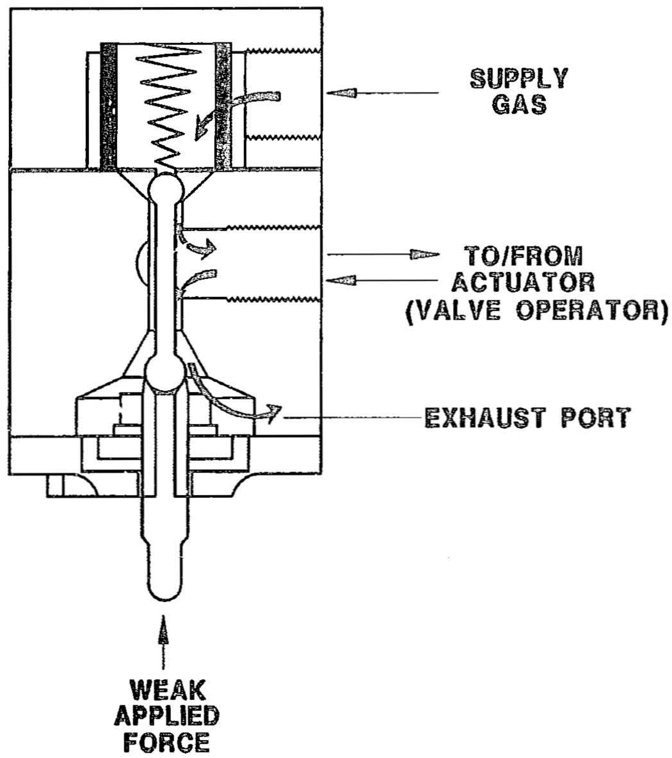

Figure 3-8. Force Balance Piston Device[8]

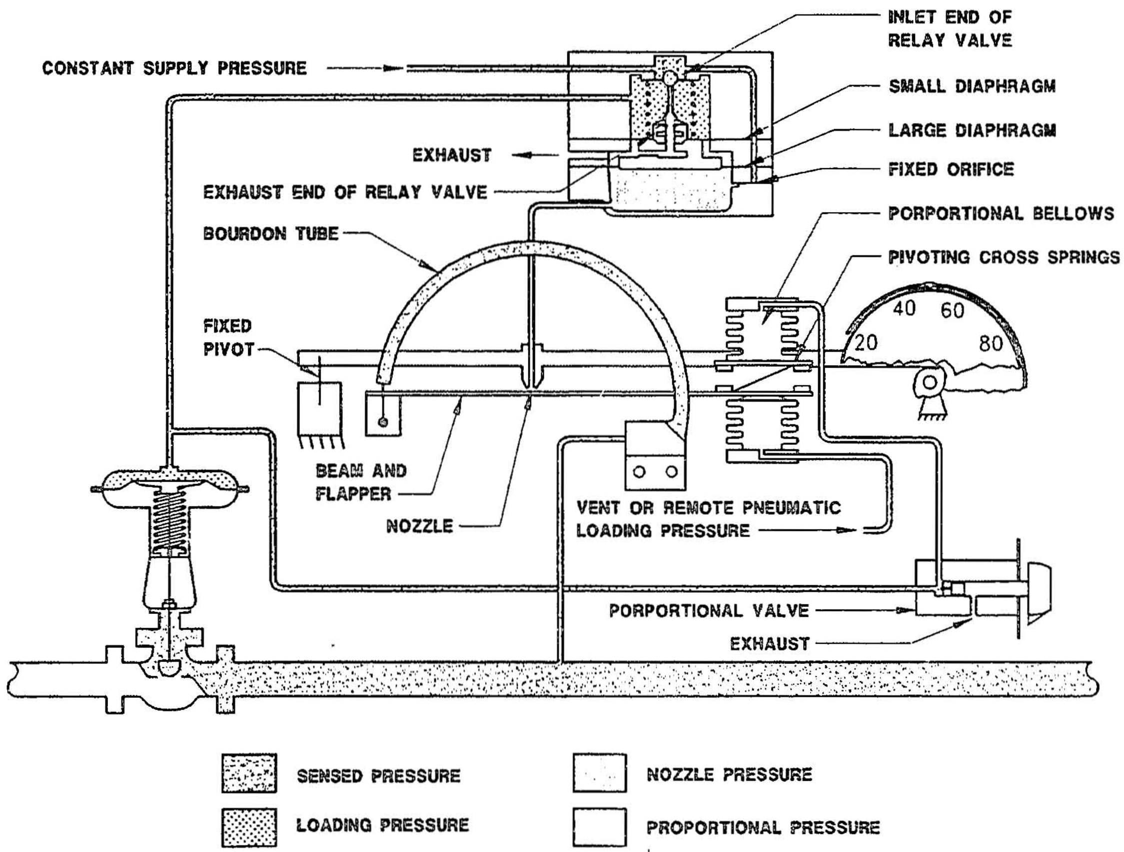

Figure 3-9. Throttling Continuous Bleed Controller with Proportional Adjustment[9]

This knob contains an exhaust port with a continuous bleed line from the actuator diaphragm. These additional bleed locations are typical of proportional controllers.

For throttling controllers, manufacturers can design for any desired bleed rate by sizing the orifice flapper or the force balance piston relay. In general, devices with a lower design bleed rate are slower to respond to signal changes, and have longer response times; therefore, some applications that require fast response also require higher bleed rates.

Snap-acting controllers are another type of device common to the gas industry. A snap-acting or "on/off" device is either fully open or fully closed. A snap-acting controller has no continuous bleed, it only bleeds when the actuator is depressured. Figure 3-10 shows two examples of on/off relay devices. As the diagram shows, when the device is on, the full supply-gas pressure is applied to the control valve actuator, and the vent/exhaust line is blocked off. When the device is off, the actuator is vented to the atmosphere and the supply gas is blocked off.

Some controllers have an additional feedback device: a valve positioner that measures, amplifies, and sends a second signal about the position of the valve stem. These positioner devices introduce a second pneumatic relay device to the existing control loop; therefore, a second bleed rate can also be introduced. Positioners are typically used for "slow systems" such as temperature control, where more precise movement of the valve is needed.

Figure 3-3 illustrates a force balance spool relay and the valve positioner that the relay controls. These devices can be easily identified in the field by the positioner arm attached to the valve stem. Only a small percentage of control valves in the gas industry have positioners since this level of fine tuning is not generally required.

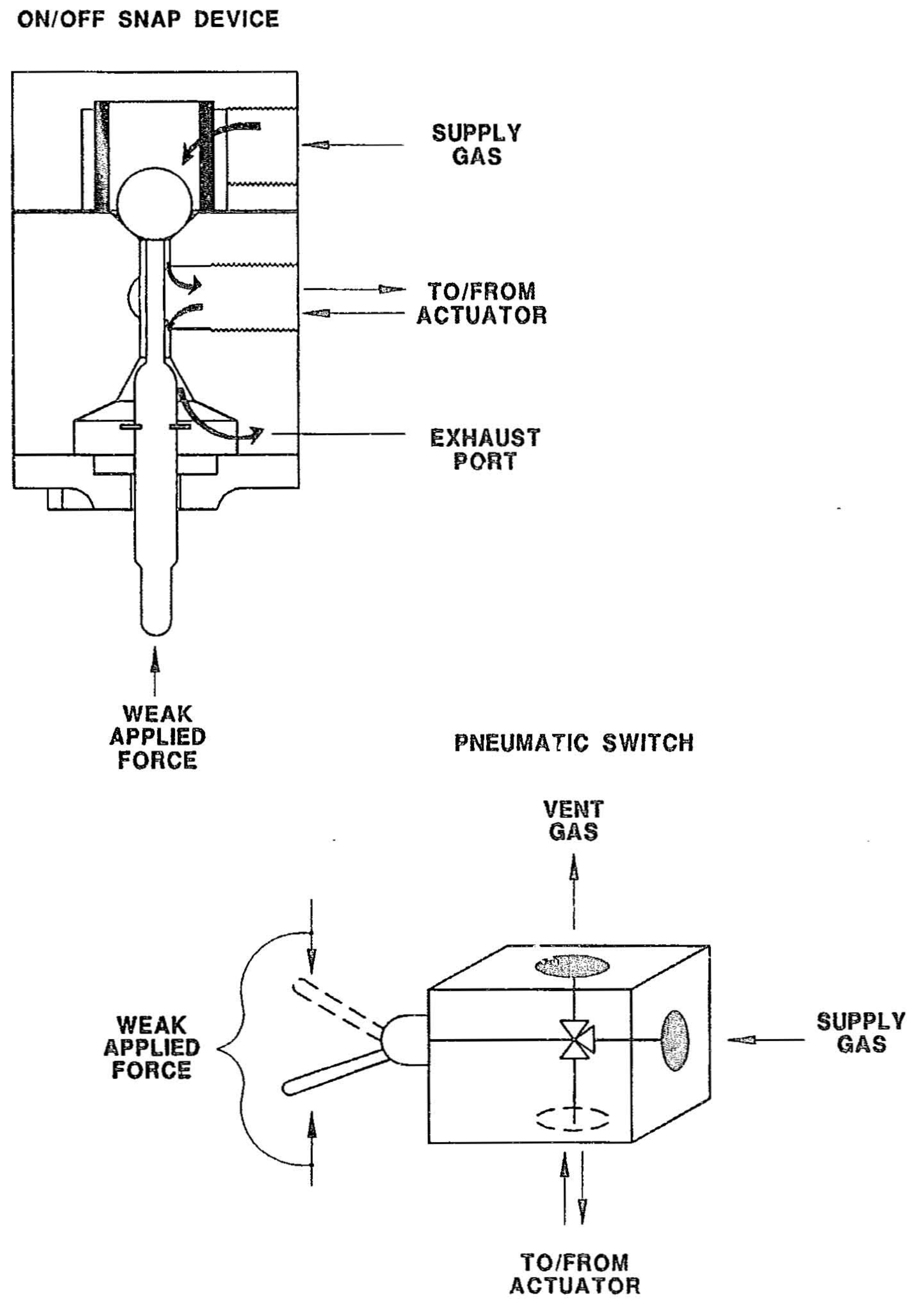

Figure 3-10. On-Off Snap Devices[5]

3.2.2 Data Requirements

As mentioned in the previous section, pneumatic controllers can have two distinct bleed modes, based on the type of relay. There is an actuating bleed rate and a stationary or steady-state bleed rate. The stationary bleed rate occurs when the signal is constant and the valve is not moving; the actuating rate occurs when the valve actuator is depressured. The stationary bleed rate for a device may be zero, depending on its construction. However, every pneumatic controller has a non-zero actuating bleed rate.

The various characteristics that can affect the stationary bleed rate for a production controller are:

1. Basic device type (controller, positioner, self-contained device);
2. Pneumatic relay construction (orifice-flapper versus force balance piston, number of internal control adjustments, such as proportional gain and set point knobs);
3. Device condition (old or worn devices may leak more);
4. Design response time (faster response devices require higher bleed rates); and
5. Supply gas pressure and supply gas type (air produces no methane emissions).

All controller types have an actuation bleed rate. The actuation bleed occurs when the controller moves the valve stem by either releasing pneumatic pressure or applying pneumatic pressure. As the pneumatic pressure is released, the actuator must be vented. The venting occurs through the controller device.

For throttling controllers with continuous bleed rates, the bleed rate will increase above the stationary level so that the actuator can be depressured. For all throttling controllers, actuation bleed rates depend on how far and how often the valve is moved, and must be considered over a long period to determine average emissions.

For snap-acting valves, the actuating bleed depressures the entire actuator to the atmosphere. The actuation bleed rate depends on the size of the device and on how often the valve is moved.

The various parameters that can affect the yearly average actuating bleed rate for a snap-acting or throttling device are:

1. Number of full stroke cycles per year (how often the valve makes a full stroke cycle);
2. Actuating chamber size; and
3. Supply gas pressure.

Based on the characteristics of continuous bleed and intermittent bleed pneumatic devices, the following approach was used to gather pneumatic data from site visits for this report:

1. Basic device type (intermittent versus continuous bleed), the instrument manufacturer, and model number were gathered from several sites by visual inspection;
2. Instrument populations;
3. Supply gas pressure and type; and
4. Field measurements of continuous bleed devices were provided from existing sources.

The bleed rate will vary with the supply gas pressure. The two common signal pressure ranges are: 1) 3 to 15 psig; and 2) 6 to 30 psig.[5] These supply ranges can be easily identified by the gauge dials on the front of the controller box. The 3-15 range will operate at approximately 20 psi gauge; the 6-30 range will operate at about 35 psi gauge.

The site data were combined with manufacturers' data and field measurements (provided from existing sources)[10,11] to produce an annual estimate of emissions for intermittent and continuous bleed actuated controllers.

3.3 Gas-Actuated Isolation Valves

Transmission compressor stations, transmission pipelines, storage stations, and gas plants have large-diameter pipelines, and therefore have large pipeline isolation valves. These valves block the flow to or from a pipeline, and can isolate the facility for maintenance work or in the case of an emergency. The valves are usually actuated remotely by a power source. The valves are so large that manual operation would be extremely slow, and certainly unsuitable in the case of an emergency. The valves are most often actuated pneumatically (by natural gas or compressed air) or by an electric motor.

3.3.1 General Description

Most gas operators on isolation valves discharge gas only when actuated. Once they reach the open or closed position, they do not bleed gas. These valves are actuated infrequently, so their emissions are very intermittent.

The pneumatically actuated isolation valves can generally be divided into two types: 1) displacement operators, and 2) turbine operators. Displacement operators are attached to quarter-turn plug valves or quarter-turn ball valves. These operators use gas pressure (pneumatic force) to move an actuator element in one direction. Sometimes the pneumatic force is applied directly to the actuator element, and sometimes it is applied to oil, so that hydraulic force moves the actuator; in either case, gas is discharged when the valve is actuated. The actuator element is displaced from its original position by the pneumatic or hydraulic force. Displacement operators in the gas industry are of two basic types: 1) rotary vane, and 2) piston.

The rotary vane displacement operator uses natural gas to force a fixed amount of oil from one pressure bottle to another. The oil moves through the vane operator, delivering hydraulic force to the vane, and moving it and the attached valve stem one quarter turn. The oil moving into the bottle forces gas in the top of the receiving pressure bottle to vent to the atmosphere. The most common manufacturer of this type of operator is Shafer Valve Company.[12] Figures 3-11 and 3-12 show a typical pneumatic/ hydraulic rotary vane operator from the Shafer catalogue.

Similarly, Pantex Valve Actuators & Systems, Inc., manufactures a displacement operator that uses natural gas to move a piston.[6] The piston acts on an "arm" or lever that rotates the valve stem. Gas is supplied to one side of the piston and exhausted from the other to move the arm in each direction, either opening or closing the valve. An example of this type of operator is shown in Figure 3-4.

Supply gas for these operators is usually pipeline gas, so pressure varies from site to site. Compressed air can be used if it is available in sufficient volumes. The volume of gas vented depends on the vane or piston displacement size and on the supply gas pressure.

Turbine operators, the second major type of isolation valve operators, are usually attached to gate valves.[13] The turbine operators simply release gas to the atmosphere across a small turbine similar to a gas starter turbine for a reciprocating compressor. The gas spins the turbine blades, and the turbine shaft then turns gears that move the gate valve stem. A turbine operator on a gate valve is illustrated in Figure 3-13.

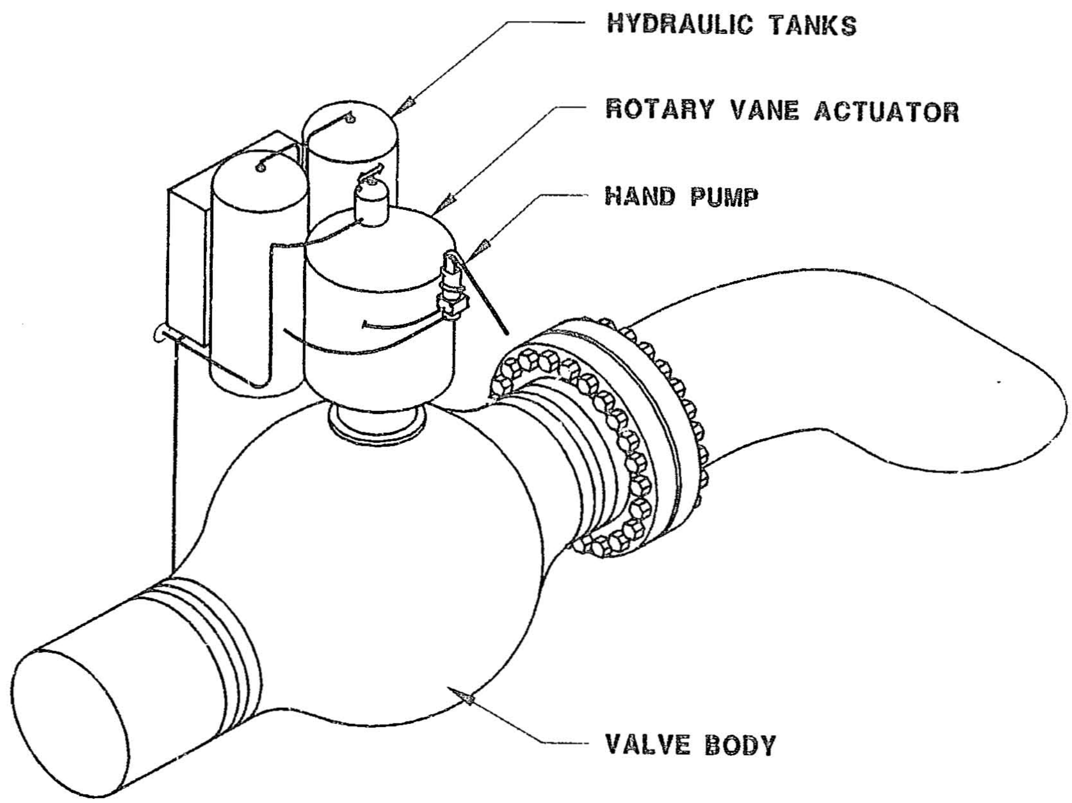

Figure 3-11. Pneumatic/Hydraulic Rotary Vane Operator[12]

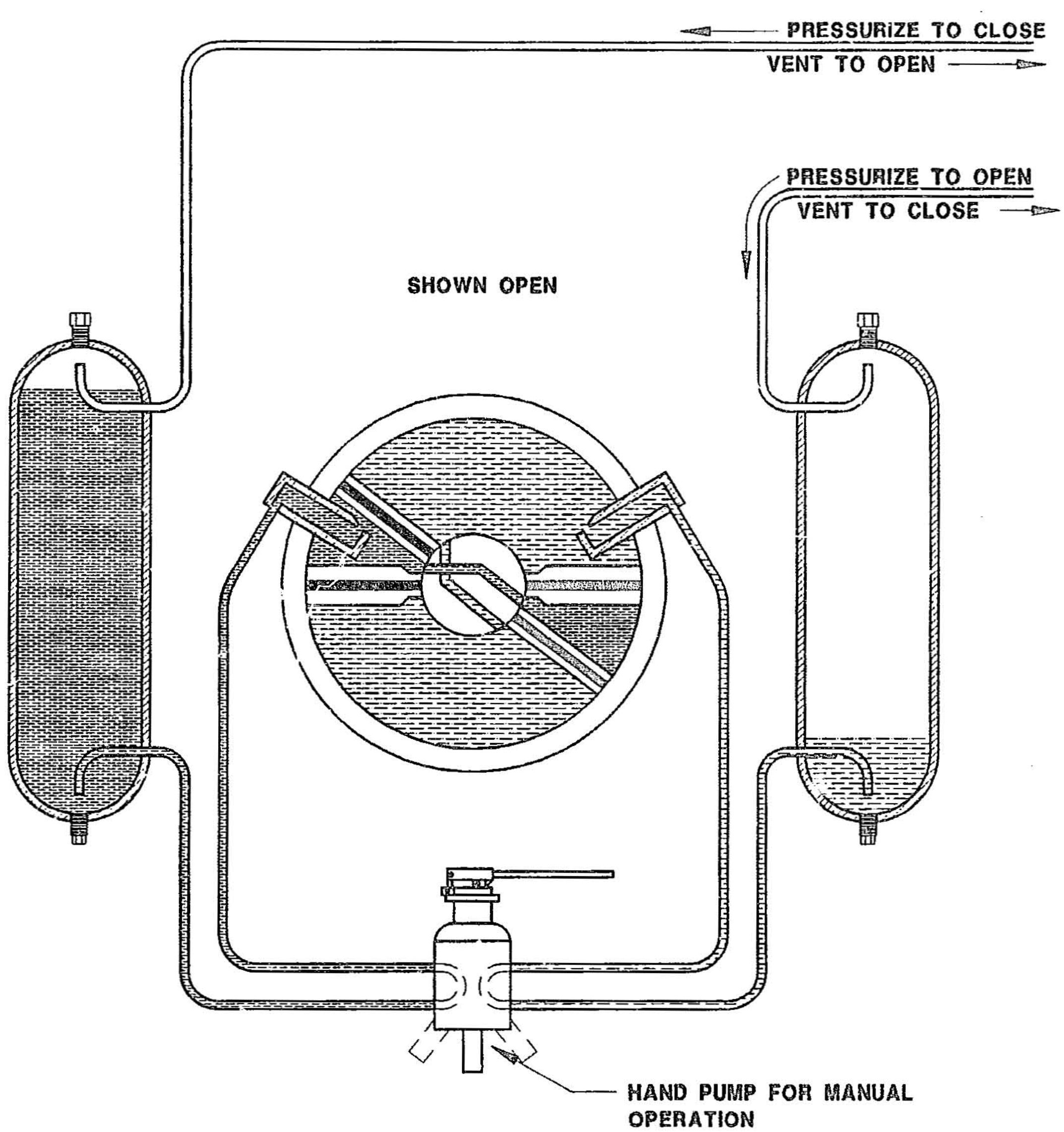

Figure 3-12. Pneumatic/Hydraulic Rotary Vane Operator - Cross Section[12]

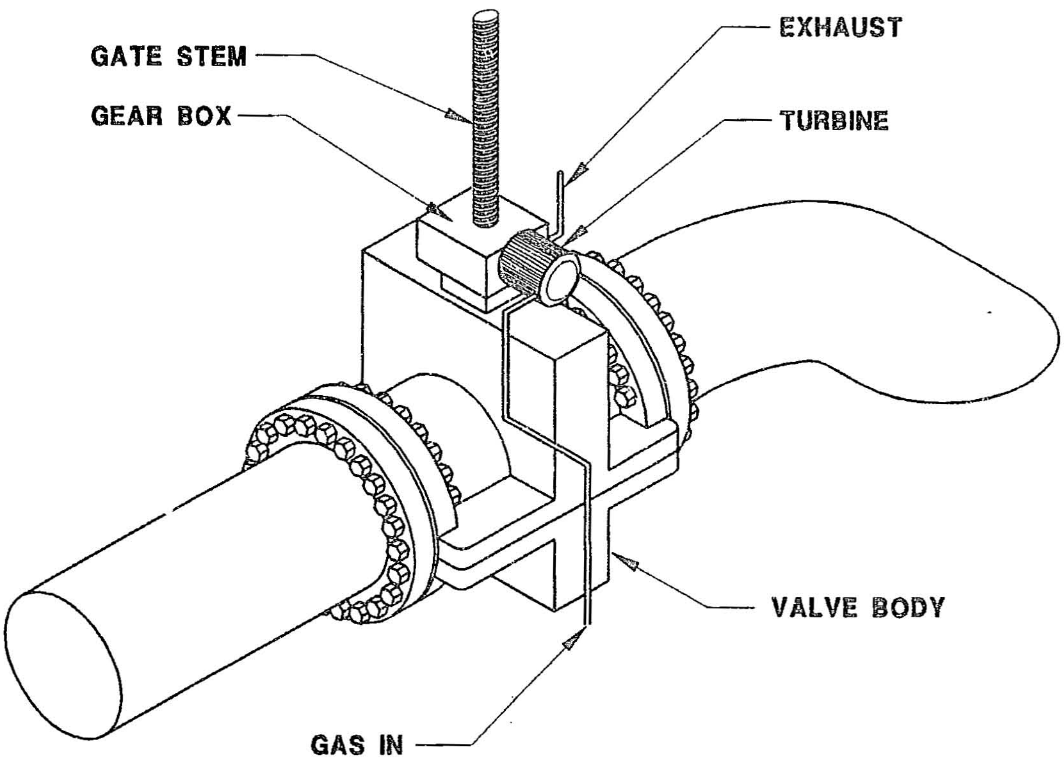

Figure 3-13. Turbine Operator

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Pipeline gas is typically used as the supply gas for the turbine devices, so the pressure varies from site to site. The volumes vented depend on the duration of operation to open or close the valve and on the supply gas pressure.

3.3.2 Data Requirements

Based upon the operating principles discussed above, the various characteristics that affect the bleed rate for isolation valve operators are:

1. Basic device type (turbine or displacement);
2. Manufacturer and model number;
3. Supply gas pressure, supply gas type (air produces no methane emissions); and
4. Number of full stroke cycles per year.

The following approach was used to gather pneumatic data for this report from field site visits:

1. During site visits, instrument populations and the instrument manufacturer and model number were gathered from several sites; and
2. Based on observations and interviews, the frequency of operation cycles per year was estimated.

The site data were combined with manufacturers' data and measured data from other studies to produce an emission factor for a typical device type.

3.4 Other Pneumatic Devices

Numerous other devices in the field can bleed methane but do not neatly fit into the categories listed above. Because these devices are rare, or rarely bleed, they were

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ignored for the purpose of this study. They are listed in this section only for the sake of completeness. Some key examples are:

- Solenoid snap-acting valve controllers;
- Self-contained pressure regulators;
- Pneumatic transmitters; and
- Older flow computers.

The solenoid "snap-acting" controller acts like the pneumatic snap-acting controller, except that its signal is not a weak mechanical signal but an electrical one. The solenoid either opens a valve that puts full supply gas pressure to the top of the valve actuator or closes off that supply and vents the actuator to the atmosphere. Like snap-acting pneumatic relays, it only bleeds when the actuator is depressured. Figure 3-14 shows a diagram of a solenoid relay. These devices are rare since electronic signals are infrequently used in the gas industry.

A common example of a self-contained pressure regulator is the small "gas supply regulator" shown in Figure 3-2. This is a small device that lowers pneumatic gas supply pressure to a desired downstream pressure. These devices are commonly found between pneumatic supply headers and the devices that use the supply gas. Gas supply regulators only bleed if the downstream pressure rises above set-point. Since there are downstream users of the gas, the downstream pressure is almost always lower, so these devices rarely bleed gas. Another common, large, self-contained device is the transmission and distribution pressure letdown regulator (Figure 3-15). These regulators handle the entire gas stream but do not bleed at all. They release actuator pressure to the downstream side and do not bleed to the atmosphere.

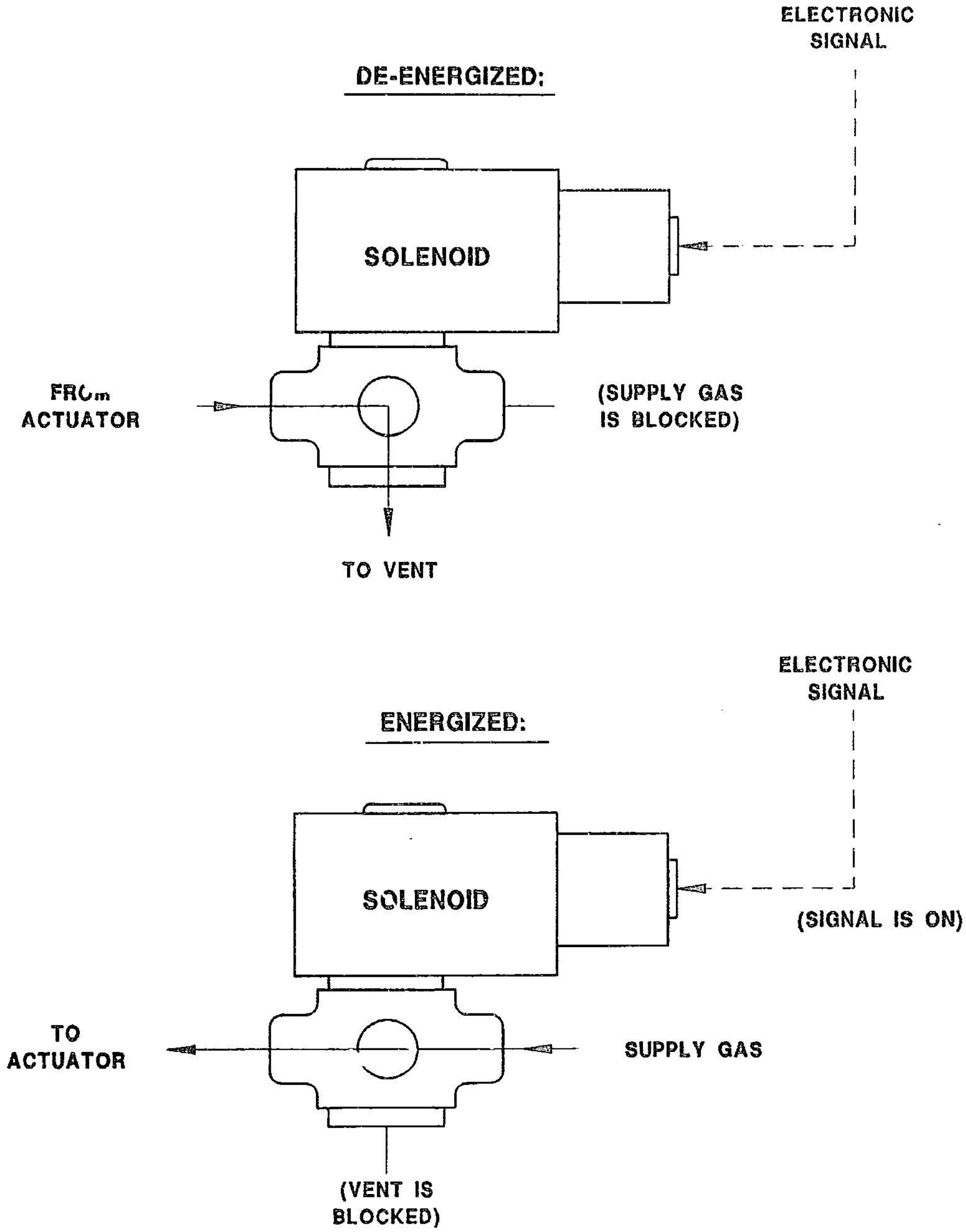

Figure 3-14. Solenoid Relay[5]

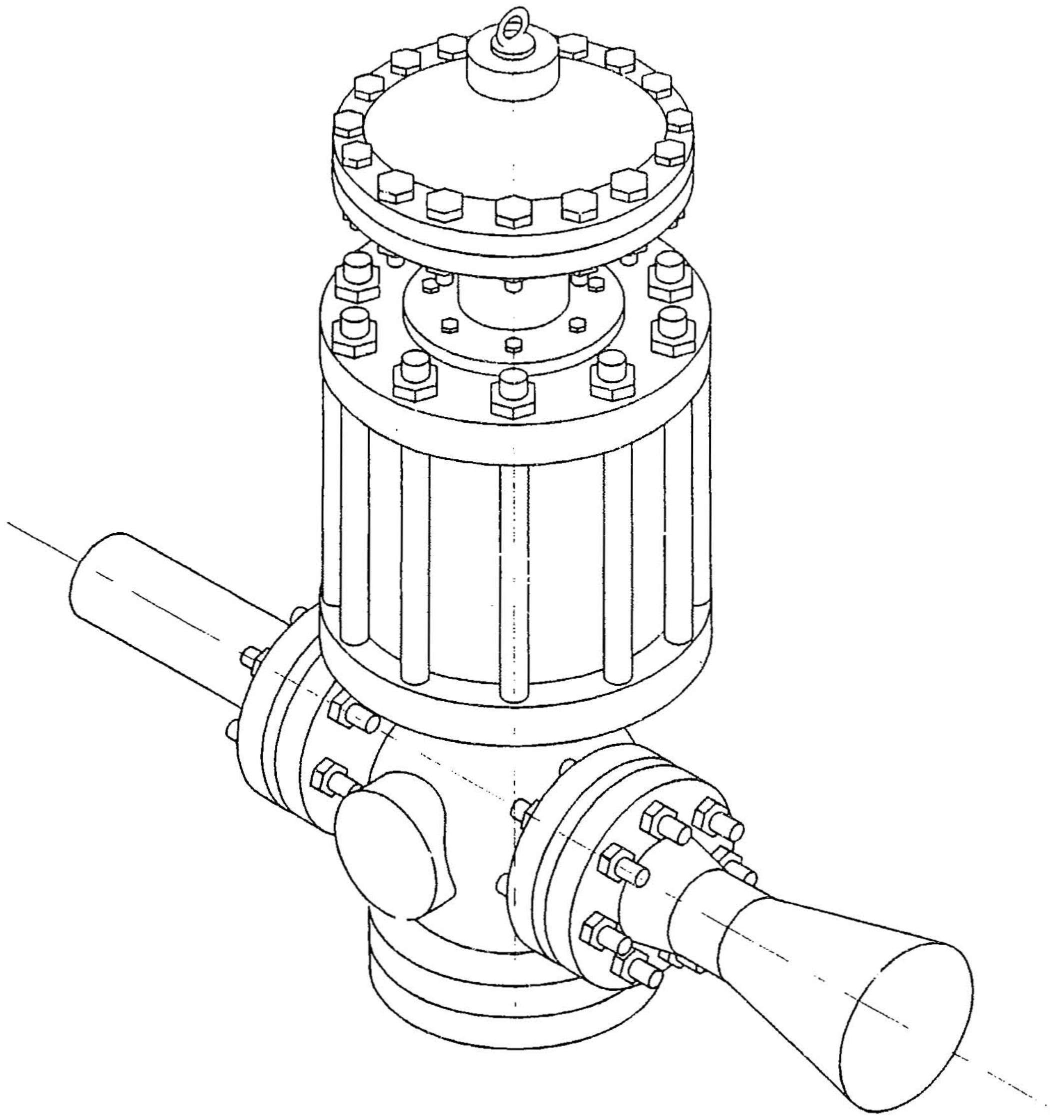

Figure 3-15. Self-Contained Pressure Regulation Valve

The pneumatic transmitters and older flow computers are examples of devices originally installed in older facilities that are out-of-date by today's standards of technology. It is difficult to list, characterize, or group all of the diverse devices in this category. Their total contribution to emissions is considered to be minimal.

4.0 PNEUMATIC DEVICE EMISSION FACTORS

The various segments of the gas industry have different equipment and different standards for using pneumatic devices. Table 4-1 shows the general uses of devices in each segment.

TABLE 4-1. STANDARD USES OF PNEUMATIC DEVICES

	Production	Processing	Transmission	Distribution
Control valves operated by gas?	Yes	Very Few	Yes	Yes
Isolation valves operated by gas?	No	Some	Yes	Some

The following subsections describe the details of pneumatic devices in each segment and the emission factors associated with those devices.

4.1 <u>Production Segment</u>

Valve controllers (pneumatic devices on control valves that regulate flow) are the most common type of pneumatic device in the production segment that discharge gas to the atmosphere. As stated earlier, primary measurement devices, which detect the initial change in the process variable, are sealed and do not directly bleed or exhaust to the atmosphere. In addition, the production pipelines are small, so the isolation valves that exist are manually operated and do not bleed gas.

4.1.1 General Emission Factor Characteristics

Typical production operations include pneumatic valve controllers. Infrequently, production operations may contain valve positioners. There are multiple components (such as set-point adjustment, gain adjustment, and reset knobs) within a controller or positioner that may bleed. These are considered part of the controller device. Certain valves or valve packages may have these emitting elements combined into one field-located box.

The production segment uses both basic types of pneumatic controllers: 1) throttling, and 2) snap-acting. Throttling pneumatic relays of the "force balance piston" type (Figure 3-8) bleed only when they move from the neutral position. They are therefore intermittent emitters and have a stationary bleed rate of zero. Throttling orifice flapper relays (Figure 3-6) bleed continuously, even when the valve is not moving, but their bleed rate varies with the strength of the signal from the process variable. Orifice flapper relays are considered continuous emitters since there is no position where the bleed rate is zero. Snap-acting controllers have a stationary bleed rate of zero and are therefore considered intermittent emitters.

4.1.2 Production Emission Factors

Five sources of information were used to determine the methane emissions from pneumatic devices used in the production segment: the results from a study performed by the Canadian Petroleum Association,[11] manufacturers' data, measured emission rates,[10] data collected from site visits, and literature data for methane composition. Each of these sources is discussed in detail.

Canadian Petroleum Association (CPA) Report

As part of Canada's effort to reduce atmospheric emissions, the Canadian Petroleum Association sponsored a project to quantify methane and VOC emissions in upstream oil and gas operations.[11] Emission measurements from 19 snap-acting pneumatic devices and 16 throttling devices were collected during this study. The results are presented in Table 4-2. The average natural gas emission rate for snap-acting devices was 213 scfd/device $\pm$ 57% (90% confidence interval), and the average emission rate for throttling

TABLE 4-2. RESULTS FROM THE CANADIAN PETROLEUM ASSOCIATION PNEUMATIC EMISSION RATE STUDY

Instrument Type	Facility Type	Equipment Type	Quantity Measured	Minimum Flow, scfd	Maximum Flow, scfd	Average Natural Gas Emission, scfd
Snap-Acting Controller	Oil Battery	Group Treater	1	0.0	690	33
		Test Treater	2	172	172	179
		Group Treater	1			14
		Group Treater	2	0.0	>951	226
		Group Treater	2	0.0	>933	59
		Group Treater	2	0.0	>959	140
		Group Treater	2	0.0	573	81
		Group Treater	1	0.0	>1,911	695
		Group Treater	1			12
		Test Treater	2			210
		Test Separator	2	0.0	430	233
		Group Separator	1	0.0	1397	677
		Average Emission for Snap-Acting Controllers				213 ± 57%
Throttling Controller	Oil Battery	Dehydrator	3	0	10	2
		Line Heater	1	55	55	60
		Line Heater	1	11	11	11
		Line Heater	1	31	31	34
		Group Treater	6	7	7	8
		Test Separator	1	529	529	529
		Test Separator	3	9	240	11
		Average Emission for Throttling Controllers				94 ± 152%

devices was 94 scfd/device ± 152%.[11] The CPA report concluded that there was no statistically significant difference between the bleed rates of the snap-acting and throttling controllers.

It should be noted that the CPA report did not distinguish between throttling controllers with intermittent bleed rates and throttling controllers with continuous bleed rates. In addition, only one of the throttling devices actuated while they were measuring it. The measurements recorded for the other throttling devices only represent the stationary or continuous bleed emissions.[14] Therefore, the Canadian measurements are lower than field measurements of similar devices in the U.S., but do agree with the manufacturer's data for similar devices. The CPA measurements were treated as additional data sources and combined with field measurements provided by another source to generate emission factors for intermittent and continuous bleed devices.[10]

Manufacturers' Data

Manufacturers of pneumatic devices may report a "gas consumption" for specific devices based on laboratory testing of new devices. However, the manufacturers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age, and wear of the device.[15,16,17,18] Examples of circumstances or factors that can contribute to this increase include:

- Nozzle corrosion resulting in more flow through a larger opening;
- Broken or worn diaphragms, bellows, fittings, and nozzles;
- Corrosives in the gas leading to erosion or corrosion of control loop internals;
- Improper installation;
- Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of o-rings and/or seals);

- Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle;
- Foreign material lodged in the pilot seat; and
- Wear in the seal seat.

The manufacturers contacted did not have field measurements of devices in service and did not simulate the aging of devices with laboratory measurements, so they could not provided an indication of the expected increase in emissions due to the factors listed above. Since manufacturers' emission rates are based on new devices, actual emission measurements from pneumatic devices in field service, including worn or defective devices, were used as the basis for developing emission factors.[10,11]

Several pneumatic device manufacturers provided information on the gas consumption rates for their continuous bleed devices.[9,16,18,19,20,21,22,23,24,25] Table 4-3 shows the bleed rates for the model series observed during site visits. The manufacturers' reported gas consumption rates represent the gas usage at the specified supply gas pressure for the controller only (unless otherwise noted). Additional emissions may occur from other components of the control loop (i.e., set point exhaust and valve positioner).

For the types of devices listed, gas consumption rates for the controllers can vary from 0 to 2,150 scfd per device. However, the manufacturers indicated that emissions from these devices in field operation may be higher than the reported "maximum." Some manufacturers provided a maximum gas flow rate or delivery capacity that the controller pilot could withstand (4,320 scfd for the Bristol 624II and 8,880 for the Fisher 4100). This flow rate indicates the maximum amount of gas that can be supplied to the control loop. It is possible that some pneumatic devices could continue to operate up to these flow rates, but not above these rates.

The manufacturers' data serve as a sanity check for the field measurements provided by other sources (discussed in the next section). The data reported in Table 4-3 are

TABLE 4-3. MANUFACTURER BLEED RATES FOR CONTINUOUS BLEED PNEUMATIC DEVICES

Manufacturer/ Model	Gas Consumption Rates, scfd		Comments on Specified Rate
	"Minimum"	"Maximum"	
Norriseal 1000 (A)	Model discontinued in the 1960s		No bleed rate information available.
Norriseal 1001(A)	0-10	2,150	Max. bleed rate is not specified by Norriseal. Estimated for 1001 model based on volume of gas required for one complete actuation @ 30 psig supply (provided by manufacturer) and assuming one actuation/min.
Bristol 624, 624 II	72-144	4,320	Min. based on gas consumption of the controller only. Bristol does not manufacture actuators, so they do not specify a gas consumption for the actuator. Max. bleed rate shown is based on the pilot capacity (maximum amount of gas that the controller pilot can accommodate).
Fisher 2400	Model discontinued in 1957		No bleed rate information available.
Fisher 2500	168	1,008	Bleed rate for 35 psig supply pressure. Min. represents the steady state pilot bleed rate (device not actuating). Max. represents gas consumption when the relay is completely open.
Fisher 2900	Model discontinued in 1991		Gas consumption not listed in device brochure, but Fisher representative provided a laboratory measurement of 555 scfd for 35 psig supply pressure.
Fisher 4100	24	1,200 8,880	Bleed rate for 35 psig supply pressure. Min. represents the steady state pilot bleed rate of the controller. Max. represents maximum gas consumption (1200 scfd) and delivery capacity of the controller (8800 scfd).
Invalco AE 155	Model discontinued ~1975		No bleed rate information available.
Invalco CT series	510	960	Minimum bleed rate specified for supply gas pressure of 20-30 psi. Maximum bleed rate shown here is reported by the manufacturer as a typical bleed rate for this device. A retrofit kit is available for this series of devices to reduce the typical bleed rate from 960 scfd to less than 22 scfd.

consistent with emission measurements in the field, in that the manufacturers confirmed that the devices can emit at rates higher than the manufacturers' reported gas consumption rates. In addition, the delivery capacity reported by the manufacturers for some devices serves as an absolute maximum bleed rate. Any measured emission rate higher than the delivery capacity for a given device would indicate an error in the measurement and would justify discarding the measurement.

Directly Measured Emissions for Continuous Bleed Devices

Field measurements of throttling devices with continuous bleed rates were available from companies participating in a separate contractor's program.[10] For these measurements, a contractor connected a flow meter to the supply gas line between the pressure regulator and the controller to measure the gas consumption of the controller. A cumulative flow rate and the current flow (scfh) were recorded and extrapolated to gas consumption per day. The duration of the test depended on the variability of the gas use. For steady operating conditions, one data point was taken for 15-20 minutes. For variable flow rates, several one-hour measurements were taken.

Although the emission measurements were not performed under the direction of this study, the results are believed to be an accurate representation of pneumatic devices in operation in the U.S. natural gas industry. Through interviews with site personnel and the contractor that performed the measurements,[10] the sampling technique, measurement protocol, and equipment calibration procedures were reviewed. Two measurements were removed from the data set because they did not follow the measurement protocol for a single device (in both cases a single emission measurement was reported for an unknown number of devices). The final data set was deemed acceptable by the industry review panel.

After the QA/QC review, the data set contained a total of 41 measurements from a combination of continuous bleed devices from offshore platforms, onshore production sites, and transmission stations. Table 4-4 summarizes the measurements.

TABLE 4-4. MEASURED EMISSION RATES FOR CONTINUOUS BLEED DEVICES

	Production Onshore	Production Offshore	Total Production	Transmission
Number of Measurements	9	9	18	23
Minimum, scfd/device	380	108	108	152
Maximum, scfd/device	2,334	962	2,334	4,215
Average, scfd/device	1,189 ± 39%	556 ± 33%	872 ± 30%	1,363 ± 29%

The use of pneumatic devices in onshore versus offshore production operations is similar. Both use continuous bleed devices primarily for liquid level control in separators. Comparing the average measurements in Table 4-4, the average emission rate for pneumatic devices in offshore operations is much smaller than the emission rate for these devices in onshore operations. However, the offshore emission measurements shown in Table 4-4 are from one company. Therefore, any difference between onshore and offshore device emissions might also be attributed to a company difference. Because most industry reviewers of this study believe that there is no technical reason to divide the data set between onshore and offshore, and additional data were not available to validate a distinction between onshore and offshore, the measurements for these two categories are combined into one emission factor for continuous bleed devices in the production segment.

Continuous bleed pneumatic devices are used for different functions in production versus transmission operations. As mentioned previously, most continuous bleed pneumatic devices in production are used to control the liquid level in separators. In the transmission segment, the same types of devices are used for liquid level control in filter-separators, but are also used for pressure reduction. In addition, the higher pressures and larger pipeline sizes associated with transmission operations require larger actuators and larger valves than are typically found in production, and therefore pneumatic devices used in transmission operations would be expected to result in higher emission rates. For these reasons, separate emission factors were developed for production and transmission.

Comparing the measured emissions for devices in production versus transmission indicates that there is a difference between the industry segments. The combined onshore and offshore production devices have a lower average emission rate of 872 scfd, while transmission devices have an average emission rate of 1,363 scfd. When the Canadian data are included, the production emission factor is 654 ± 31% scfd/device. The transmission emission factor is unchanged because the Canadian measurements were only from onshore production facilities.

The measured emission rates compare well with the gas consumption ranges provided by the manufacturers, although a direct comparison for all device types can not be made since manufacturer values are not available for all of the models measured. In general, most of the measurements are less than 2,000 scfd (only seven out of the 41 measurements are greater than 2,000 scfd), and all of the measurements are below the reported controller delivery capacities of 4,320 and 8,880 scfd (two devices had emission measurements of 4,215 scfd).

As stated previously, the manufacturers' bleed rates represent laboratory measurements of the gas consumption for new pneumatic devices. In reality, the pneumatic devices in the field have various states of wear and may emit gas at rates higher than the manufacturers' gas consumption data suggest. The measured emissions are in the range of values provided by the manufacturer and are believed to reflect more typical operating conditions for these devices and account for increased emissions due to wear. For the purpose of this report, the measured emissions provided by CPA are combined with the contractor's direct measurements to estimate the emission factor from continuous bleed throttling devices. The resulting natural gas emission factor for the production segment is 654 ± 31% scfd per continuous bleed device.

Measured Emissions for Intermittent Bleed Devices

Field measurements for intermittent bleed devices, using the same technique described for the continuous bleed devices, were also available from companies participating in this study.[10] Based on the criteria described for continuous bleed devices, measurements for the intermittent bleed devices were reviewed and judged to be acceptable. A total of seven measurements were provided from intermittent bleed devices found in onshore production service. No measurements were available for these types of devices in offshore service or the transmission segment. The average emission rate for the seven devices is 511 scfd ± 36%. The measurements ranged from 211 to 950 scfd/device, as compared to the CPA measurements of similar devices which ranged from 12 to 695 scfd/device (average of 211 scfd from Table 4-2). Combining the 19 measurements from both sources (Canadian and U.S. field measurements) results in a natural gas emission factor of 323 ± 34% scfd/device for intermittent bleed devices in production.

Site Data

For this study, data were collected from a total of 22 sites to establish a count of pneumatic devices for production sites and to determine the fraction of intermittent versus continuous bleed devices at each site. The fraction of each device type was used to scale the emission factor to generate one emission factor for a "generic" pneumatic device. Table 4-5 summarizes the data collected at production sites. For each site, the number of snap-acting devices and the number of throttling devices were collected. Where possible, the manufacturer and model number were recorded for each device.

As discussed in Section 3, throttling devices can be either intermittent or continuous bleed, while snap-acting devices are always intermittent bleed. The number of throttling continuous bleed devices at each site was determined based on the manufacturer and model type of the devices observed. Since these two device types have distinctly different emission rates, the fraction of intermittent bleed versus continuous bleed devices is

TABLE 4-5. SUMMARY OF PRODUCTION SITE DATA

Site	Total Count of Devices	Power Media	Number of Snap-Acting Devices	Number of Throttling Devices[a]	Number of Continuous Bleed Devices[b]
1	136	Gas	114	22	22
2	18	Gas	75	95	29
3	405	Gas	405	0	0
4	68	Gas	48	20	20
5	21	Gas	26	83	21
6	13	Gas	94	534	534
7	3	Gas	999	0	0
8	3	Gas	667	0	0
9	6	Gas	3	3	3
10	14	Gas	0	14	0
11	76	Gas	0	76	76
12	600	Gas	0	600	600
13	107	Air	71	36	25
14	69	Gas	42	27	20
15	13	Gas	8	5	0
16	1	Gas	1	0	0
17	3	Gas	3	0	0
18	4	Air	3	1	0
19	46	Air	6	40	40
20	5	Gas	4	1	0
21	11	Gas	5	42	42
22	31	Gas	0	31	31
TOTALS	4,204		2,574	1,630	1,463
FRACTION BY DEVICE TYPE			Non Continuous Bleed 0.65 ± 43%		Continuous Bleed 0.35 ± 43%

[a] Throttling devices can be either continuous or intermittent bleed.
[b] Continuous bleed devices are a sub-category of throttling devices.

required to develop an emission factor. From the site data, the fraction of continuous bleed devices is 0.35 ± 43%. By difference, the fraction of intermittent bleed pneumatic devices is 0.65 ±43%.

Methane Composition

The percentage by volume of methane in produced natural gas was determined to be 78.8% ± 5%. Details about this value are available in the report, *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary.*[26]

Emission Factor Calculation

The weighted emission factor per device was calculated for production facilities as follows:

$$\begin{matrix}\text{Weighted}\\ \text{Emission}\\ \text{Factor}\end{matrix} = \left(\begin{matrix}\text{Fraction of}\\ \text{Intermittent}\\ \text{Bleed}\\ \text{Devices}\end{matrix} \times \begin{matrix}\text{Intermittent}\\ \text{Bleed}\\ \text{Emission}\\ \text{Factor}\end{matrix} + \begin{matrix}\text{Fraction of}\\ \text{Continuous Bleed}\\ \text{Devices}\end{matrix} \times \begin{matrix}\text{Continuous Bleed}\\ \text{Emission}\\ \text{Factor}\end{matrix}\right) \times \begin{matrix}\text{Methane}\\ \text{Composition}\end{matrix} \quad (1)$$

The site data were used to estimate the fraction of intermittent bleed versus continuous bleed devices: 65% ± 43% intermittent bleed and 35% ± 43% continuous bleed (Table 4-5). Table 4-6 summarizes the emission factor terms, where the emission factors for the individual device types (intermittent versus continuous bleed) were based on the field measurements from the United States and Canada discussed previously.

The final result is an average device methane emission factor of 345 scfd/device ± 40% (90% confidence interval), or 126,000 scf/device annually.

TABLE 4-6. PRODUCTION EMISSION FACTOR CALCULATION

Device Type	Fraction of Device Type	Selected Natural Gas Emission Factor, scfd/device
Intermittent Bleed	0.65 ± 43%	323 ± 34%
Continuous Bleed	0.35 ± 43%	654 ± 31%
Methane Emission Factor for Average Device = 345 ± 40% scfd/device		

4.2 Transmission and Storage Segment

The transmission segment is composed of pipelines, compressor stations, and storage stations. Very few pneumatic devices of any type are associated with the pipelines. Within the storage and mainline compressor stations, most of the pneumatic devices are gas-actuated isolation valves and continuous bleed controllers.

4.2.1 General Emission Factor Characteristics

The type of continuous bleed devices in the transmission segment are essentially the same as those in the production segment. The difference is in the use of the devices. In the transmission segment, continuous bleed pneumatic devices are used to regulate pressure on compressors and are sized larger due to the higher pressures in transmission. In production, smaller devices are used primarily to control the liquid level in separators. Since most of the same manufacturers are used, this section will not repeat the discussion from Section 4.1.1.

Isolation valve actuators are predominately found in the transmission segment. Isolation valve actuators emit gas whenever the valve is moved to either the open or closed position. Most compressor stations and storage stations have many valves, since valves are needed to make normal changes in pipeline and equipment flow configurations, as well as to isolate and depressure equipment for maintenance or in case of an emergency. Most sites use natural gas rather than compressed air to actuate these large valves. A large volume of gas is needed to move multiple valves and this requires a large investment in equipment if compressed air is used.

4.2.2 Transmission Emission Factors

Manufacturer and Site Data

The transmission emission factors were determined from information gathered during site visits and from manufacturers' data. The gas-operated devices used in the transmission segment were classified into three categories: continuous bleed devices, isolation valves with turbine operators, and isolation valves with displacement-type pneumatic/hydraulic operators. Devices operating on air were not included in the emission calculation.

The natural gas emission factor for the continuous bleed devices used in transmission is based on measured emissions from these devices at transmission stations (measurement procedure and data quality checks were discussed in Section 4.1.2).[10] As shown in Table 4-4, measured emissions from 23 devices ranged from 152 to 4,215 scfd of natural gas per device, with an average natural gas emission factor of 1,363 $\pm$ 29% scfd/device (497,583 scf/device annually). It should be noted that intermittent bleed devices were not observed at transmission stations.

Data on the following characteristics of isolation valves were gathered at 16 transmission sites:

1. Basic device type (continuous bleed, turbine, or pneumatic/hydraulic);
2. Manufacturer and model number;

3. Supply gas pressure, supply gas type (air produces no methane emissions); and

4. Number of full stroke cycles per year (each cycle consists of two valve movements: open and close).

All of the displacement isolation valves observed at the transmission sites were the pneumatic/hydraulic rotary vane type (Figures 3-11 and 3-12). The number of actuation cycles per year was based on site data. The manufacturer provided the volume of gas used based on the discharge pressure. These values (shown in Table 4-7) were combined to calculate the annual emission factor for each type of displacement-operated isolation valve:

$$EF_{\substack{\text{Displacement-}\\\text{Operated}\\\text{IsolationValve}}} = \underset{\text{(scf/psia)}}{\text{Device Gas Usage}} \times \underset{\text{(psia)}}{\text{Discharge Pressure}} \times \underset{\text{(cycles/year)}}{\text{Frequency}} \times \frac{\text{2 Valve Movements}}{\text{Cycle}} \quad (2)$$

Data provided by Shafer Valve Operating Systems show that the gas usage volumes vary widely, so data on the demographics of various sizes of the rotary-vane-operated valves were gathered from four stations.[27,28] This information is provided in Table 4-7. The total emissions from displacement devices were determined for each site based on the size, actuation frequency, and number of each type of device. An average annual emission factor for this type of device was calculated to be 5,627 ± 112% scf natural gas per device based on the average of the site data.

Due to the diversity of company practices for the few sites which provided data, no direct relationship was established between device count and station size. Therefore, for this emission factor, an average of the four site averages was used, as opposed to an average of all of the individual device measurements. In effect, this weights the measurement by site (transmission station) rather than by device count. Thus, a site with a disproportionately high number of devices is not weighted higher than the other stations.

TABLE 4-7. PNEUMATIC/HYDRAULIC ROTARY VANE ISOLATION VALVE OPERATORS

Site	Supply Gas Pressure, psig	Actuator Size	Gas Usage per Cycle, scf/psi	Number of Devices	Cycles/ Year	Annual Gas Usage, scf/ Device Type
1	935	6.5 x 3.5	0.0042	4	12	383
		6.5 x 3.5	0.0042	1	1	8
		9 x 7	0.0123	1	1	23
		11 x 7	0.022	1	1	42
		14.5 x 14	0.0852	1	1	162
		16.5 x 16	0.1183	3	1	674
		16.5 x 16	0.1183	2	12	5,393
		18 x 8	0.0489	3	1	279
		18 x 8	0.0489	1	12	1,115
		18 x 12	0.0852	1	1	162
		25 x 16	0.318	5	12	36,242
		25 x 16	0.318	1	1	604
		Total Emissions for Site 1 = 45,086 scf Site Weighted Average = 1,879 scf/device ± 54%				
2	935	25 x 16	0.318	4	92	237,496
		25 x 16	0.318	2	64	82,607
		25 x 16	0.318	2	50	64,537
		20 x 16	0.1981	6	5	147,649
		12.5 x 12	0.0482	4	92	1,467
		12 x 12	0.0482	3	5	587
		15 x 8	0.0279	1	6	340
		18 x 8	0.0489	1	6	4,962
		18 x 8	0.0489	1	50	198
		20 x 16	0.1981	1	2	6,031
		20 x 16	0.1981	1	15	14,473
		26 x 36	0.7565	1	36	3,071
		25 x 16	0.318	1	2	19,361
		9 x 7	0.0123	5	5	624
		9 x 7	0.0123	2	2	100
		Total Emissions for Site 2 = 583,803 scf Site Weighted Average = 16,680 scf/device ± 37%				

Continued

TABLE 4-7. (CONTINUED)

Site	Supply Gas Pressure, psig	Actuator Size	Gas Usage per Cycle, scf/psi	Number of Devices	Cycles/ Year	Annual Gas Usage, scf/ Device Type
3	1000	5.5 x 3.5	0.0035	7	15.2	705
		6.5 x 8	0.008	14	15.2	3,224
		9 x 7	0.0123	8	15.2	2,833
		11 x 10	0.0318	1	15.2	915
		12.5 x 10	0.0279	1	15.2	803
		12.5 x 12	0.0482	5	15.2	6,938
		20 x 16	0.1981	3	15.2	17,108
		25 x 16	0.318	12	15.2	109,853
		16.5 x 16	0.1183	9	15.2	30,650
		14.5 x 14	0.0852	1	15.2	2,453
		12.5 x 12	0.0482	1	15.2	1,388
		Total Emissions for Site 3 = 176,870 scf Site Weighted Average = 2,853 scf/device ± 27%				
4	950	12.5 x 12	0.0482	3	12	3,348
		6.5 x 3.5	0.0042	1	12	97
		11 x 10	0.0318	1	12	736
		16 wkm	0.072	2	12	3,507
		Total Emissions for Site 4 = 7,688 scf Site Weighted Average = 1,098 scf/device ± 39%				
AVERAGE DISPLACEMENT DEVICE EMISSION FACTOR = 5,627 ± 112% scf/device						

Discharge volumes for the turbine-operated isolation valves depend on the supply gas pressure, the number of full stroke cycles each year (where each cycle consists of two valve movements), and the duration that the turbine operates to complete a valve movement, as follows:

$$EF_{\substack{\text{Turbine-}\\\text{Operatored}\\\text{Isolation}\\\text{Valve}}} = \frac{\text{Device Gas Usage}}{\text{(scf/min)}} \times \frac{\text{Operating Duration}}{\text{(min/operation)}} \times \frac{\text{Frequency}}{\text{(cycles/year)}} \times \left(\frac{\text{2 Valve Movements}}{\text{Cycle}}\right) \quad \textbf{(3)}$$

Information on the approximate turbine motor gas consumption for a given gas pressure was provided by Limitorque Corporation.[13] The manufacturer also provided a typical value for the time required to open or close a valve. Two sites furnished the supply gas pressure, the number of operations per year, and the length of time required to open or close the valve. This information is shown in Table 4-8. Average or typical values (based on information provided by sites or manufacturers) were used for other sites with turbine operators. As with the rotary vane isolation valve emission factor, the emission factor for turbine operated isolation valves was also based on an average of the site data. The resulting annual emission factor for turbine operators is 67,599 ± 276% scf/device.

Methane Composition

The methane composition for the transmission and storage segment was estimated to be 93.4% ± 1.5%.[26]

Emission Factor Calculation

Site data were used to estimate a relative fraction of each type of device found in the transmission segment. Data on turbine and displacement isolation valves were collected from 16 sites. For continuous bleed devices, data for an additional 38 sites were available from a large transmission company participating in this project. Based on the average number of devices at each site, the total number of devices for a typical transmission station and the

TABLE 4-8. MANUFACTURER DATA FOR TURBINE OPERATED ISOLATION VALVES

Site	Supply Gas Pressure, psig	Gas Consumption, scfm	Time/ Operation, sec	Gas Usage, scf/Operation	Cycles/ Year	Annual Natural Gas Emissions, scf/device
1	900-970	500-520	30 120	255 1020	11 1	3,825
2	800	470	180	1410	75	211,500
3 (Typical Values)	800	470	90	705	29	40,890
4 (Typical Values)	800	470	90	705	29	40,890
5 (Typical Values)	800	470	90	705	29	40,890
AVERAGE ANNUAL TURBINE DEVICE EMISSION FACTOR, scf natural gas/device						67,599 ± 276%

fraction of each type of device were determined. Tables 4-9 and 4-10 summarize the site information for each device type.

The annual transmission segment emission factor (scf/site) was determined from the following equation:

$$EF = \left(EF_{\substack{\text{continuous}\\ \text{bleed}}} \times Fraction_{\substack{\text{continuous}\\ \text{bleed}}} + EF_{\substack{\text{turbine}\\ \text{operators}}} \times Fraction_{\substack{\text{turbine}\\ \text{operators}}} + EF_{\substack{\text{displacement}\\ \text{operators}}} \times Fraction_{\substack{\text{displacement}\\ \text{operators}}} \right) \times \%\ \text{methane} \quad (4)$$

EF = (497,584 scf/device × 0.32 cont. bleed devices/total
+ 67,599 scf/device × 0.16 turbine devices/total
+ 5,627 scf/device × 0.52 displacement devices/total)
× 0.934 mol methane/mol gas

EF = 162,197 ± 44% scf/device

TABLE 4-9. TRANSMISSION DEVICE COUNTS - TURBINE AND DISPLACEMENT DEVICES

Site	Turbine Devices/Site	Rotary Vane Displacement Devices/Site
1	3	26
2	16	62
3	12	34
4	35	0
5	44	0
6	0	11
7	0	17
8	0	35
9	0	69
10	0	6
11	0	18
12	0	4
13	0	50
14	0	2
15	0	0
16	0	0
Average Number of Devices/Site	6.25 ± 94%	20.9 ± 48%
Fraction Device/Site	0.156 ± 94%	0.522 ± 48%
Annual Natural Gas Emission Factor scf/device	67,599 ± 276%	5,627 ± 112%

TABLE 4-10. TRANSMISSION DEVICE COUNTS - CONTINUOUS BLEED

Site	Continuous Bleed Devices/Site	Site	Continuous Bleed Devices/Site
1	39	28	11
2	16	29	11
3	4	30	32
4	3	31	9
5	4	32	12
6	1	33	4
7	1	34	21
8	4	35	12
9	6	36	3
10	2	37	15
11	2	38	3
12	127	39	11
13	18	40	10
14	4	41	44
15	22	42	3
16	3	43	3
17	4	44	9
18	4	45	12
19	4	46	4
20	1	47	26
21	1	48	2
22	1	49	7
23	15	50	11
24	92	51	11
25	3	52	15
26	6	53	6
27	1	54	1

Average Number Devices/Site	12.9 ± 69%
Fraction of Device/Site	0.32 ± 69%
Annual Natural Gas Emission Factor, scf/device	497,583 ± 29%

4.3 Gas Processing Segment

The gas processing segment (gas plants) uses compressed air to power the majority of pneumatic devices within the plant. Of the nine gas plants visited for this study, only one used natural gas-powered, continuous bleed devices in the plant. Approximately one-half of the plants visited had natural gas-driven pneumatic controllers for the isolation valves on the main pipeline emergency shut-down system for the plant or for isolation valves used for maintenance work on specific sections of the plant. All of the other sites used compressed air to power their pneumatic continuous bleed devices and isolation valves.

Unlike the production and transmission industry segments, a mix of pneumatic devices was not observed at each gas processing site. Instead, the gas plants visited generally used only one type of natural gas powered pneumatic device throughout the plant. Stratification by device type could not be determined, so emissions were calculated on a site basis rather than a device type basis.

Manufacturers' and Site Data

The same type of devices used in the transmission segment are also commonly used in the gas processing segment – continuous bleed throttling devices, displacement-operated isolation valves, and turbine-operated isolation valves. For the sites where specific information was provided, emission calculations were based on that information. However, for some sites, the information provided included little more than the type of actuator, supply gas pressure, and an estimate of the number of operations. In these cases, average values from the transmission segment were used to complete the calculations. The site data with the emission estimates are shown in Table 4-11. The technique used to develop emission factors for each site is discussed separately.

TABLE 4-11. GAS PROCESSING SITE EMISSION ESTIMATES FOR NATURAL GAS

Site	Device Type	Number of Devices	Operations/ Year	Displacement/ Device, scf	Annual Natural Gas Emissions scf/Site
1	Continuous Bleed (Fisher)	2	Continuous	497,584	995,168 ± 29%
2	Isolation (Fisher)	3	12	214,675	644,025 ± 29%
3	Air	--	--	--	--
4	Isolation (Turbine)	25	1	780	19,500 ± 112%
5	Isolation Piston Type (Rotary Vane)	7 18	12 1	48	1,206 ± 49%
6	Isolation (Turbine & Pneumatic/ Hydraulic-type Rotary Vane)	1 16	1 12	660 2,716	44,115 ± 68%
7	Air	--	--	--	--
8	Air	--	--	--	--
9	Air	--	--	--	--
	Total				1,704 Mscf ± 21%
	Average (for gas sites)				341 Mscf/gas site ± 103%

Site 1: Continuous bleed devices, such as those used in the transmission segment, were observed at this site. Since the application of these devices is similar to the transmission segment, the annual emission factor of 497,584 scf per device (based on 1,363 scfd/device from Table 4-4) was used.

Site 2: Fisher devices were used to operate isolation valves at this site. Information on the bleed rate for the specific device type was provided by the site.

Site 4: Manufacturer's data from Limitorque were used to estimate emissions for the turbine operators observed at this site.[13] The plant provided the supply gas pressure of 400 psig, and a typical actuation time of 1.5 minutes was used (based on manufacturer data).

Site 5: Piston-type isolation valve operators were found at only one site; information for the specific device types were provided by Pantex, the manufacturer.[6] Table 4-12 lists the manufacturer's data for the model types identified at this site. The weighted average annual emission factor for this type of device was determined to be 48 scf/device ± 49%.
Site 6: For the pneumatic/hydraulic-type rotary vane devices observed at this site, the emission factor was based on the average volume of natural gas released per actuation for the devices presented in Table 4-7. Manufacturer's data from Limitorque, based on a supply gas pressure of 350 psig, were used to estimate the emissions for the turbine operator at this site.

Methane Composition

The percentage of methane in gas used in gas processing plants was determined to be 87.0% ± 5%. Details about this value are available in the GRI/EPA report, *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary.*[26]

TABLE 4-12. GAS USE INFORMATION FOR PANTEX DEVICES (PISTON DISPLACEMENT ISOLATION DEVICES)

No. Devices	Piston Diameter (in.)	Stroke Length (in.)	Gas Usage (acf/stroke)	Annual Gas Consumption[a] (scf/device)
6	8.0	20	0.5818	512
2	3.0	4	0.0164	4.8
1	3.5	4	0.0222	3.3
2	2.0	4	0.0073	2.1
5	8.0	16	0.4654	341
1	2.5	8	0.0227	3.3
1	6.0	16	0.2618	38.4
2	6.0	12	0.1964	57.6
	Annual Site Gas Consumption, scf			965
	Weighted Annual Average per Device, scf			48.1

[a] Gas consumption calculated based on supply pressure of 250 psig, an average of 4.1 operations per year, and two strokes (open and close) per operation.

For the isolation valves with turbine operators, the emission factor depends on the gas usage for a given

Emission Factor Calculation

The gas processing emission factor was calculated according to the following equation:

$$EF = K \times \frac{\sum_{i=1}^{n} \text{Annual Site Emissions, scf Natural Gas}}{n} \times \%\ \text{methane} \qquad (5)$$

where:

K = fraction of sites that use natural gas rather than air (0.556 ± 59%)

n = number of sites operating devices with natural gas

Assuming that the sites surveyed are representative of the United States, the average emission rate for sites using natural gas was adjusted based on the ratio of sites using gas-operated devices to the total number of sites surveyed. The annual gas processing methane emission factor of 165 Mscf/site ± 133% was calculated as shown:

EF = 0.556 ± 59% gas sites/total sites surveyed × 341 ± 103% Mscf/gas site × 0.87 ± 5% mol methane/mol gas

EF = 165 ± 133% Mscf/site

4.4 Distribution Segment

The pneumatic devices in the distribution segment primarily consist of pressure reduction throttling valves at meter and pressure regulation (M&R) stations. The actuators and controllers for these valves are generally gas powered, but may or may not bleed gas to the atmosphere, depending on their design. Emissions from these devices were

2 The number of underground storage facilities is taken directly from A.G.A. *Gas Facts:*

measured as part of the tracer campaign for M&R stations and included in the M&R station emission rates.[1] Distribution pneumatic emissions are therefore excluded from this report.

Isolation valve actuators at distribution M&R stations are usually manually or motor-operated. There were so few pneumatic operators on isolation valves that this emission source is considered negligible.

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5.0 PNEUMATIC DEVICE ACTIVITY FACTORS

Pneumatic device activity factors are discussed in detail in Volume 5 on activity factors.[29] The techniques used to develop pneumatic device activity factors for the various industry segments are summarized in this section. For each industry segment, the activity factor corresponds to the emission factor units presented in Section 4. That is, a count of pneumatic devices is used for the production and transmission segments, while the number of gas plants is used for the gas processing segment.

5.1 Production Segment

The total number of pneumatic devices in the U.S. production segment was determined from regionalized site data. The number of pneumatic devices at each site were weighted based on the number of gas wells and the marketed gas production at each site. The site data were extrapolated by the number of gas wells and the marketed gas production within each region. In production, the resulting count of pneumatic devices nationally is 249,000 ± 48%.

5.2 Gas Processing Segment

The activity factor for gas processing is based on the number of gas processing plants reported annually by the *Oil and Gas Journal*. For the base year 1992, the U.S. activity factor for gas processing is 726 gas plants.[30] A confidence bound of ± 2% was assigned based on engineering judgement.

5.3 Transmission and Storage Segment

The number of natural gas-operated pneumatic devices in the transmission and storage segment was calculated based on the average number of devices per station

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multiplied by the total number of transmission and storage stations nationally using the following equation:

$$AF = \frac{\text{Average Number of Devices}}{\text{Station}} \times \text{Number of Stations} \qquad (6)$$

The average number of pneumatic devices per station is the sum of the average number of turbine devices per site, the average number of rotary vane displacement devices per site, and the average number of continuous bleed devices per site. Using the numbers shown in Tables 4-10 and 4-11, the average number of pneumatic devices per site is 40 ± 37%. Therefore, the pneumatic device activity factor for transmission stations is:

AF = (6.25 ± 94% turbine devices/site
+ 20.9 ± 48% rotary vane devices/site
+ 12.9 ± 69% continuous bleed devices/site)
× 2,175 ± 8% stations
AF = (40 ± 37% devices/station) × (2,175 ± 8% stations)
AF = 87,206 ± 38% pneumatic devices

The activity factor includes only pneumatic devices operated by natural gas. Mechanical, electrical, and air-operated devices were excluded from the site counts and are therefore excluded from the national activity factor.

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6.0 NATIONAL EMISSION RATE

National emission rates from pneumatic devices for each industry segment were calculated by multiplying the emission factor by the activity factor:

$$\text{National Emission Rate} = \text{Emission Factor} \times \text{Activity Factor} \tag{7}$$

Table 6-1 presents the final results of the emission rate calculations for each industry segment.

TABLE 6-1. EMISSION RATE RESULTS

	Methane Emission Factor	Activity Factor	Annual Emission Rate
Production	125,925 ± 40% scf/device	249,111 ± 48% devices	31.4 ± 65% Bscf
Gas Processing	165 ± 133% Mscf/site	726 ± 2% sites	0.12 ± 133% Bscf
Transmission	162,197 ± 44% scf/device	87,206 ± 38% devices	14.1 ± 60% Bscf

Based on these results, pneumatic devices contribute a total of 45.6 ± 48% Bscf of methane for 1992.

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APPENDIX A

Source Sheets

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P-4

PRODUCTION SOURCE SHEET

SOURCES:	Various Equipment (wells, heaters, separators, dehydrators, compressors)
COMPONENTS:	Pneumatic Devices
OPERATING MODE:	Normal Operation
EMISSION TYPE:	Unsteady, Vented
ANNUAL EMISSIONS:	31.4 Bscf $\pm$ 65%

BACKGROUND:

Most of the pneumatic devices in the industry are valve actuators and controllers that use natural gas pressure as the force for valve movement. There is a large population of pneumatic devices throughout the gas industry. Gas from the valve actuator is vented to the atmosphere during every valve stroke, and gas may be continuously bled from the valve controller pilot as well.

EMISSION FACTOR: **125,925 scf per average device $\pm$ 40%**

(This was adjusted for the production methane fraction of natural gas at 78.8 mol%.)

Pneumatic devices (valve controllers) linked to control valves are the largest source of pneumatic emissions in the production segment. There are two types of devices with distinct bleed modes: intermittent and continuous. Intermittent bleed devices emit methane to the atmosphere only when the control valve actuates; when the device is not moving the bleed rate is zero. Continuous bleed devices emit methane both when the valve actuates and when the device is not moving. An emission rate for a generic pneumatic device combines the bleed rates of the two types of devices, weighted by the population of the device types as follows:

$$EF_{\text{avg. pneum. device}} = (\text{Fraction}_{\text{intermittent}} \times EF_{\text{intermittent}} + \text{Fraction}_{\text{continuous}} \times EF_{\text{continuous}}) \times \%\ \text{methane}$$

where:

$$\text{Fraction}_{\text{intermittent}} = 0.65 \pm 43\%$$
$$\text{Fraction}_{\text{continuous}} = 0.35 \pm 43\%$$
$$\%\ \text{Methane} = 78.8\ \text{mol}\ \% \pm 5\%$$

Emissions for intermittent and continuous bleed devices were based on measured data provided by a Canadian study and U.S. field measurements from a separate contractor's program. The average measured emissions for intermittent and continuous bleed devices are 323 $\pm$ 34% and 654 $\pm$ 31% scfd/device, respectively. The fraction of each type of device was determined from site visits.

Therefore the average annual emission factor for a generic pneumatic device is:

$$EF_{\text{avg. pneumatic device}} = 125{,}925 \pm 40\%\ \text{scf/device}$$

EF DATA SOURCES:

1. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices* (1) establishes the important emission-affecting characteristics.

2. Site visit device counts establish the fraction of continuous bleed versus intermittent bleed devices for multiple sites.
3. The Canadian Producers Association (CPA) determined an average emission factor per device based on 19 measurements.
4. An independent contractor provided 18 measurements of pneumatic devices in onshore and offshore production services.

EF PRECISION:

Basis:

EF accuracy is based on error propagation from the spread of site device counts and measured emission rates.

ACTIVITY FACTOR: 249,111 pneumatic controllers $\pm$ 48 %

The average count of devices per equipment type was determined from multiple site visits. The ratios for the number of devices per gas well and the number of devices per marketed gas production were compiled by region. The regional values were summed to give national device counts based on well counts and marketed gas production. These values were averaged to give the final national device count of 249,111.

AF DATA SOURCES:

1. *Methane Emissions from the Natural Gas Industry, Volume 5: Activity Factors* (2) establishes the methodology for extrapolating the site data to a national count.
2. Site visit device counts, well counts, and production rates establish the number of devices per well and the number of devices per gas production.
3. Total regional gas well counts and 1992 marketed gas production rates are from A.G.A. *Gas Facts* (3).
4. The oil wells that market gas were calculated by this report and *World Oil* (4). Total oil wells for 1992 are reported as 602,197 by the *Oil & Gas Journal* (5). The active oil wells that market gas are determined by multiplying the total national active wells by the fraction that market gas. The fraction is determined from a Texas Railroad Commission database (6) on oil leases and gas disposition from those leases; an analysis that shows the percent of oil leases that market the associated gas in Texas is 34.7%.

AF PRECISION:

Basis:

1. The accuracy for the devices per well and devices per gas production rate are calculated from the spread of site data collected for each region (a total of 36 sites).
2. The accuracy for wells that market gas are based on the spread of data from the Texas Railroad Commission database.

ANNUAL METHANE EMISSIONS: 31.4 Bscf $\pm$ 65 %

The national annual emissions were determined by multiplying an emission factor for an average pneumatic device by the population of devices in the production segment.

125,925 scf $\times$ 249,111 devices $=$ 31 Bscf ρ

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T-4
TRANSMISSION AND STORAGE SOURCE SHEET

SOURCES:	Various Equipment (vessels, compressors, piping)
OPERATING MODE:	Normal Operation
EMISSION TYPE:	Unsteady, Vented
COMPONENTS:	Pneumatic Devices
ANNUAL EMISSIONS:	14.1 Bscf ± 60%

BACKGROUND:
The transmission segment is comprised of compressor stations, pipelines, and storage stations. There are essentially no pneumatic devices associated with the pipelines. Within the storage and compressor stations, most of the pneumatics are gas-actuated isolation valves, and there are a few continuous bleed controllers.

Meter-only stations do not have venting pneumatics. Meter and regulation (M&R) stations do have regulating pneumatic controllers (the pressure regulator valves), but all of the M&R station pneumatic emissions are counted in the fugitive calculation for M&R stations and so are not included in this sheet.

The continuous bleed controllers in transmission compressor stations are used for liquid level control in filter-separators and pressure reduction. The higher pressures and large pipe diameters associated with transmission operations require larger actuators and valves than typically found in production, resulting in larger emissions than similar devices in production.

Within the storage and mainline compressor stations, most of the pneumatic devices are gas-actuated isolation valves. These valves block the flow to or from a pipeline and can isolate the facility for maintenance work or in the case of an emergency. Therefore, the isolation valves are actuated infrequently and their emissions are intermittent.

EMISSION FACTOR: **162,197 scf/device ± 44%**

(This was adjusted for the transmission methane fraction of natural gas at 93.4 mol%.)

The average pneumatic device emission factor was determined from a compilation of information from several sites. Counts of devices per site were taken during Radian site visits. The devices were classified into three categories: continuous bleed valves, isolation valves with turbine operators, and isolation valves with displacement operators. The emission factor was determined based on the following equation:

$$EF_{\text{pneumatic devices}} = (EF_{\text{cont. bleed valves}} \times Fraction_{\text{cont. bleed valves}} + EF_{\text{turbine operators}} \times Fraction_{\text{turbine operators}} + EF_{\text{displacement operators}} \times Fraction_{\text{displacement operators}}) \times \%\ \text{methane}$$

Listed below are the average fraction of devices for each of the three valve categories:

$$Fraction_{\text{cont. bleed valves}} = 0.32 \pm 69\%$$
$$Fraction_{\text{turbine operators}} = 0.16 \pm 94\%$$
$$Fraction_{\text{displacement operators}} = 0.52 \pm 48\%$$

Emissions from continuous bleed pneumatics in the transmission segment were measured by an independent contractor. The average emission factor, based on 23 measurements, is 1,363 scfd/device ± 29% (497,584 scf/device).

For the isolation valves with turbine operators, the emission factor depends on the gas usage for a given supply gas pressure, the time required to complete one movement of the valve, and the number of operations per year. The annual emission factor is then:

$$EF_{\text{turbine operators}} = \text{Gas Usage (scf/min)} \times \text{Operating Duration (min/operation)} \times 2 \text{ (operations/cycle)} \times \text{Frequency (cycles/year)}$$

$$EF_{\text{turbine operators}} = 67{,}599 \pm 276\% \text{ scf/device}$$

The equation for isolation valves with displacement operators is similar:

$$EF_{\text{displacement operators}} = \text{Gas Usage (scf/psia)} \times \text{Supply Pressure (psia)} \times 2 \text{ (operations/cycle)} \times \text{Frequency (cycles/year)}$$

$$EF_{\text{displacement operators}} = 5{,}627 \pm 112\% \text{ scf/device}$$

EF DATA SOURCES:

1. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices* (1) establishes the important emission-affecting characteristics of transmission pneumatic devices.
2. Device counts from 16 compressor and storage stations establish the fraction of turbine valve operators, and displacement valve operators. Counts from a total of 54 stations were used to establish the fraction of continuous bleed devices.
3. The emission factor for the continuous bleed valves was based on 23 field measurements.
4. Gas usages for the turbine valve operators were provided by Limitorque. Operating duration and frequency were estimated based on information from two transmission stations.
5. Gas usages for the displacement valve operators were provided by Shafer Valve Operating Systems. Supply pressure and frequency of operation were estimated based on information from four transmission stations.

EF ACCURACY:

Basis:

1. EF accuracy is based on error propagation from the combination of site information and measured data.
2. It was assumed that the manufacturers' data are completely accurate.

ACTIVITY FACTORS: 87,206 pneumatic devices ± 38%

The number of gas operated pneumatic devices in the transmission and storage segment was calculated based on the average number of devices per station and multiplied by the total number of transmission and storage stations nationally. The average number of devices per site was determined to be 40 ± 37%. The total count of transmission compression facilities is 2,175, based on 1,700 compressor stations, 386 UG storage stations, and 89 LNG storage stations.

AF DATA SOURCES:

1. The number of transmission compressor [illegible] was compiled from 1992 Fossil Energy Commission Form No. 2: Annual Report of Major Natural Gas Companies (2).

2. The number of underground storage facilities is taken directly from A.G.A. *Gas Facts*: "Number of Pools, Wells, Compressor Stations, and Horsepower in Underground Storage Fields." Data from base year 1992 were used (3).
3. The number of liquefied natural gas storage facilities was summed from A.G.A. *Gas Facts*, "Liquified Natural Gas Storage Operations in the U.S. as of December 31, 1987 (4)." The table lists 54 complete plants, 32 satellite plants, and 3 import terminals for a total of 89 facilities.
4. The number of devices per site is based on the total number of devices observed during site visits.

AF ACCURACY: 38%

Basis:

1. Extremely tight confidence limits are expected due to the well documented and reviewed numbers published in A.G.A. *Gas Facts* and FERC forms. A 10% confidence bound was assigned to the number of compressor stations and a 5% confidence bound was assigned to the number of storage stations.
2. The confidence bound on the number of devices per station was determined based on the spread of site data.

ANNUAL METHANE EMISSIONS: 14.1 Bscf ± 60 %

The annual emissions were determined by multiplying an emission factor per device (corrected for the methane composition) by the population of pneumatic devices in the transmission segment.

$$162{,}197 \text{ scf/device} \times 87{,}206 \text{ devices} = 14.1 \text{ Bscf}$$

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GP-6
GAS PROCESSING SOURCE SHEET

SOURCES:	Various Equipment (vessels, compressors, piping)
COMPONENTS:	Pneumatic Devices
OPERATING MODE:	Normal Operation
EMISSION TYPE:	Unsteady, Vented
ANNUAL EMISSIONS:	0.1 Bscf ± 133%

BACKGROUND:
The gas processing segment uses compressed air to power the majority of the pneumatic devices within the plant, although some devices may be powered by natural gas. Many plants use gas driven pneumatic controllers on isolation valves for emergency shut-down or maintenance work.

The same type of devices used in the transmission segment are also commonly used in the gas processing segment — continuous bleed throttling/regulating valves, displacement operators, and turbine operators.

EMISSION FACTOR: 165 Mscf per average plant ± 133%

(This was adjusted for the gas processing methane fraction of natural gas at 87 mol%.)

The average device gas emission factor was determined from a combination of vendor information on device emission rates and device counts from several sites. The average emission factor was calculated using the following equation:

$$EF_{avg.pneum.device} = K \times \frac{\sum_{i=1}^{n} (\text{Annual Site Emissions, scf Natural Gas})}{n} \times \%\ \text{Methane}$$

K	=	fraction of sites that use natural gas rather than air (0.56 ± 59%)
n	=	number of sites operating with natural gas

Each term in this equation was determined from site specific information. The summation of the site specific data was then adjusted based on the number of sites with gas operated devices versus the total number of sites surveyed. The site results are shown in the following table.

Site	Device Type	Number of Devices	Operations/ Year	Annual Displacement/ Device, scf	Displacement/ Site, scf
1	Throttling (Fisher)	2	Continuous	497,584	995,168 ± 29%
2	Isolation (Fisher)	3	12	214,675	644,025 ± 29%
3	Air	--	--	--	--
4	Isolation (Turbine)	25	1	780	19,500 ± 112%
5	Isolation (Rotary Vane)	7 18	12 1	48	1,206 ± 49%
6	Isolation (Turbine & Rotary Vane)	1 16	1 12	3,376	44,115 ± 68 %
7	Air	--	--	--	--
8	Air	--	--	--	--
9	Air	--	--	--	--
TOTAL					1,704 Mscf ± 21%
Average (for gas sites)					341 Mscf ± 103%

EF DATA SOURCES:

1. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices* establishes the important emission-affecting characteristics.
2. Site visit device counts establish the number of continuous bleed devices, turbine operators, and displacement operators for each site.
3. The emission factor for continuous bleed devices was estimated using data provided by one site and measurements for transmission pneumatic devices.
4. Gas usages for the displacement operators were provided by Pantex Valve Actuators and Systems and Shafer Valve Operating Systems. The number of devices, supply gas pressure, and operating frequency were based on site information.
5. Gas usages for the turbine operators were provided by Limitorque Corp. Operating duration, frequency, and supply gas pressure were based on site information.

EF ACCURACY:

Basis:
1. EF accuracy is based on error propagation from the spread of data for the nine sites visited.
2. It was assumed that the manufacturers' data are completely accurate.

ACTIVITY FACTOR: 726 gas processing plants ± 2%

The activity factor for the gas processing segment was taken from published information from the year 1992.

AF DATA SOURCES:

1. The number of gas processing plants was taken from the *Oil and Gas Journal* (2).

AF PRECISION:
Basis:
1. AF accuracy is based on engineering judgement.

ANNUAL METHANE EMISSIONS: 0.12 Bscf ± 133%

The annual emissions were determined by multiplying an average site emission factor (adjusted for the methane composition) by the total number of gas processing sites.

$$165 \text{ Mscf/site} \times 726 \text{ sites} = 0.12 \text{ Bscf}$$

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Supplemental Material

Equipment leak detection and quantification at 67 oil and gas sites in the Western United States

Adam P. Pacsi[1,*], Tom Ferrara[2], Kailin Schwan[2], Paul Tupper[3], Miriam Lev-On[4], Reid Smith[5] and Karin Ritter[6]

[1]Chevron Energy Technology Company, Houston, Texas, USA

[2]GHD Services Incorporated, Niagara Falls, New York, USA

[3]Shell Global Solutions (US) Inc., Houston, Texas, USA

[4]The LEVON Group, LLC, Thousand Oaks, CA, USA

[5]Earth Systems Sciences LLC, Houston, Texas, USA

[6]American Petroleum Institute, Washington, District of Columbia, USA

*Corresponding author: Adam Pacsi adam.pacsi@chevron.com

Contents

Section S1. Additional materials and methods information

Basin Selection

For this study, four basins were selected for field sampling: Permian, Anadarko, San Juan, and Gulf Coast basins. As shown in Figure S1, these represent the four basins with the largest reported methane emissions from equipment leaks in 2016 under the US Greenhouse Gas Reporting Program (GHGRP) for the production and gathering and boosting segments. The 2016 comparison year was selected for Figure S1 since it was the first year where emissions, including equipment leak emissions, were reported for the gathering and boosting segment under the GHGRP.

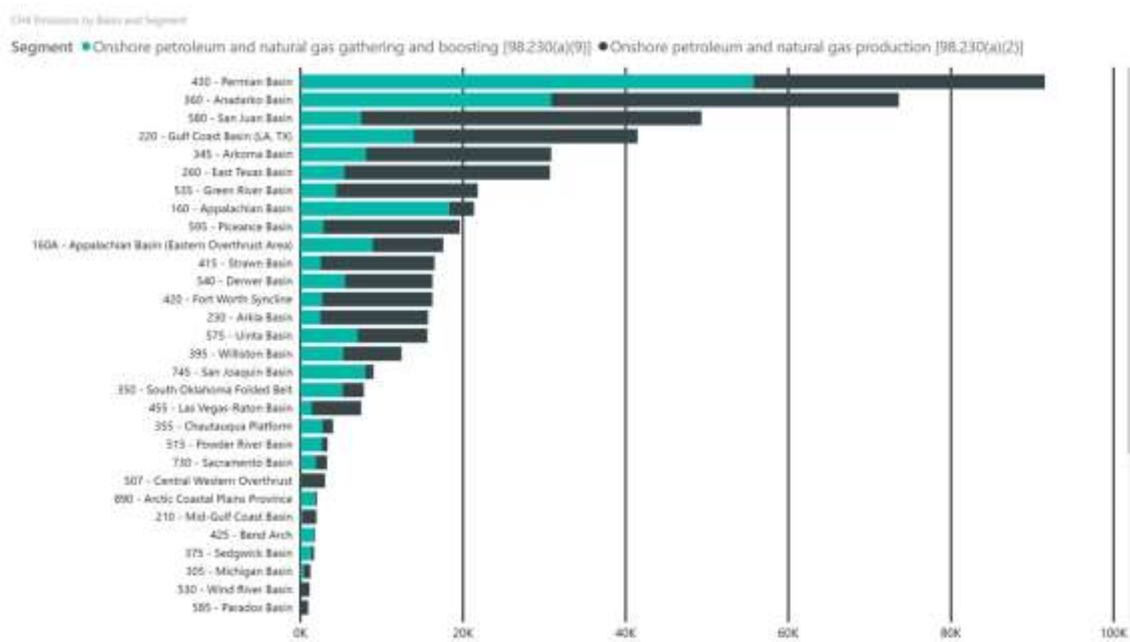

Figure S1. Total reported methane emissions from equipment leaks by basin in 2016. Emissions reported by operators in the production and gathering and boosting segments to the US EPA in 2016 under the GHGRP, grouped by reporting basin. Typically, emissions reported in the production and gathering and boosting segments in the GHGRP are estimated based on a count of major pieces of equipment on the site combined with default component counts per piece of major equipment and default emission factors per component.

Site Selection

Potential sites for the study were provided by eight companies operating in the four target basins. Individual sites selected for the study were representative of the facility and equipment types for the operator in each of the study basins. The site selection process included:

- Classification of the sites into four categories based on the equipment present at each facility (Table S1).
- Random selection of target sites within the assets of each operator in a basin (Table S2).
- Sites were clustered geographically within the basin to minimize drive time.
- Extra sites were chosen for each operator in the event a site was unavailable or additional sites could be visited.

Table S1. Site classification for facilities in this study. Classification of the 67 sites in this study based on the type of major equipment present. The use of an X indicates that the type of equipment was present for that category of site.

	Facility Category for This Study			
Major Equipment Type	**Well Site**	**Well Production**	**Central Production**	**Gathering and Boosting**
Wellhead	X	X	X	
Separator	X	X	X	X
Heater Treater	X	X	X	
Compression	X	X	X	X
Dehydration		X	X	X
Treatment			X	X
Other				X

Table S2. Details on basin and classification of sites in the study. Table includes count of sites by oil/gas, basin, and study classification.

Site Classification	Count of Gas Sites				Count of Oil Sites			
	San Juan	Gulf Coast	Anadarko	Permian	San Juan	Gulf Coast	Anadarko	Permian
Well Production	2	3	12	0	0	0	1	3
Central Production	1	4	0	0	2	0	0	2
Well Site	4	3	5	0	2	2	3	8
Boosting and Gathering	1	2	5	0	0	2	0	0
Total	**8**	**12**	**22**	**0**	**4**	**4**	**4**	**13**

The 67 sites included in this study included 20 back-up sites selected. Of these 20 sites, 12 sites were opportunistically selected nearby sites that were measured after the leak detection and quantification were completed at the original 5 sites for each operator. Eight sites were unavailable to the study team due to issues such as shut in wells, compressor maintenance, and sites where all piping was overhead and would have required an aerial lift for screening and measuring leaks.

Major Equipment Inventory

An inventory of the major equipment was completed at each facility. The types of equipment were used to classify the site into each of the four site categories. The major equipment lists provided in tables W-1B and W-1C of 40 CFR 98 Subpart W (Subpart W) were used wherever possible for describing equipment at each facility (Table S3).

Subpart W does not include a clear definition of separators. As a result, this study assumes that separators are process equipment that remove the bulk of the liquids from the well stream prior to further processing. Minor separators are defined in this study as smaller separators that handle minor amounts of liquids, such as fuel scrubbers, instrument gas separators, and compressor inlet and mid stage scrubbers. Minor separators are not used in site equipment counts for purposes of emission estimation and comparison to EPA methods since they would be unlikely to be counted for Subpart W reporting but components associated with minor separators are included in the development of site-level component counts (i.e. number of valves, etc.).

Table S3. List of major equipment types used throughout this study.

Natural Gas Sites	Crude Oil Sites
Wellhead	Wellhead
Separator	Separator
Meters/Piping	Heater Treater
Compressor	Header
Inline Heater	
Dehydrator	

Component Counts

The number of components at each site was determined by counting all the process components in liquid or gaseous service associated with each piece of major equipment. Components were classified as valves, connectors, pump seals, etc. in alignment with Subpart W categories outline in 40 CFR 98 Subpart W Table W-1B.

Leak Screening

Leak screening of all components at each facility handling hydrocarbon gas was completed by two GHD crew members, one conducting Reference Method 21 (RM-21) screening using a Thermo TVA-1000B flame ionization detector (FID) and one conducting optical gas imaging (OGI) screening using a FLIR GF-320 infrared camera, working independently. By working independently, sampling bias between the two techniques was limited. Operationally, the OGI screener started screening while the RM-21 screener was calibrating the instrumentation.

Optical Gas Imaging

OGI devices, such as the FLIR GF-320, are capable of detecting hydrocarbon emissions by imaging gases that absorb in the 3.2-3.4 µm Mid-Wave Infrared (MWIR) range. The OGI technique has been recognized by the US EPA as a method for identifying fugitive emissions from process components as an alternative to Method 21 for New Source Performance Standards (NSPS) Leak Detection and Repair (LDAR) regulations (40 CFR §60.18(h)(7)).

The FLIR GF-320 IR camera does not require a daily calibration adjustment. This instrument is equipped with an internal ‘power on’ self-test calibration that occurs as the instrument is energized and warmed-up. Prior to each use, the OGI device was checked for proper operation, and the instrument’s sensitivity to methane gas was confirmed.

After daily operational checks and orientation at the site, the OGI operator systematically traced each pipe run and component at the facility scanning for leaks. Once a leak was identified, it was given a unique identification number, but not tagged until completion of the RM-21 survey in that area of the facility.

An evaluation of the sensitivity demonstration consists of a controlled release of 100 % methane at two mass rates: 6 and 60 grams methane per hour, with a video recording made of each result. The distance from which the OGI device operator was able to see the test plume of the controlled release (i.e., the sighting distance) was recorded for each mass flow rate together with ambient temperature, wind speed, relative humidity, barometric pressure, cloud cover, and ambient lighting conditions.

RM-21 Methods and Procedures

Reference Method 21 (RM-21) - Determination of Volatile Organic Compound Leaks, is a leak detection method that is described in 40 CFR 60 Appendix A for determining leaks from process equipment. The GHD field team used a Thermo TVA-1000B (TVA) flame ionization detector (FID) calibrated with methane. During RM-21 screening the operator placed the TVA probe along the areas of a component where leaks were possible. The probe was slowly moved along the sealing surfaces while the operator watched the instrument concentration display. If the reading was greater than 500 ppm, the component was tagged by the operator for subsequent emission rate measurement. The date, time, operator name and screening concentration were recorded for each leak. Screening concentrations greater than 50,000 ppmv generally caused the TVA to 'flame-out', and for these instances, the screening value was recorded as 50,000 ppmv in the study data set.

The TVA was performance-tested (response time, precision, flow rate) at the start of the measurement program and was calibrated daily prior to field use at three concentration levels using ambient air, 500 ppmv methane-in-air , and 10,000 ppmv methane-in-air. The calibration gases had a certified accuracy of ± 2%. Drift checks were performed using the 500 ppmv and 10,000 ppmv standards at mid-day and at end of the day with a 10% acceptance criteria for recalibration.

Emission rate measurements

Natural gas emission rates were determined using a technique known as high-volume sampling that was first described in Indaco Air Quality Services, Inc., 1995 and referred to by the USEPA as the "high volume sampler" in 40 CFR 98.233 (k). This technique uses an instrument that consists of a vacuum pump operating at a sample flow rate of between six and ten SCFM, a flow rate sensor, and a dual range combustible gas sensor. The combustible gas sensor is comprised of a catalytic oxidation detector for gas concentrations between 0 and 5% gas and a thermal conductivity detector for gas concentrations from 5 to 100% gas. The method involves using the vacuum sampler to collect the gas emitted from a release point and ambient air surrounding the leak into the sampler. The leak rate is calculated from the sample flow rate and the concentration of combustible gas in the sample using the following calculation:

$$Q_{Raw} = F_{Sample} \times (C_{Sample} - C_{Background})$$

Where:

Q_{Raw}	= uncorrected emission rate of combustible gas from the leak (SCFM)
F_{Sample}	= sample flow rate (SCFM)
C_{Sample}	= concentration of combustible gas in the sample (% gas)
$C_{Background}$	= concentration of combustible gas in the background (% gas)

The background gas concentration is subtracted from the sample concentration to account for other sources near the source being measured.
For this study, a Hi Flow® Sampler manufactured by Bacharach Inc. was used to as the primary equipment to quantify emissions from component leaks. An additional high volume sampler, the Indaco sampler, was used as a backup to the Bacharach high-volume sampler in cases where the Bacharach could not be used due to maintenance or time-constraints. The sampler used for each component measurement are shown in the supporting database for the study. The sensors used by the high-volume samplers respond to CH_4 and have a range of responses to C_2 through C_4 compounds. The sensors of the Bacharach Hi Flow ® sampler have higher responses for the heavier hydrocarbons and non-hydrocarbons that may be present in field natural gas. Thus, the raw high volume sampler responses need to be adjusted to reflect the composition of the gas being measured to report the results as a whole gas emission rate.

A series of response factors (RF), based on mole-percent, were developed for the high-volume samplers (Bacharach and Indaco) and secondary detectors used in this fieldwork by metering known volumes of gas to the detection equipment as shown in Figure S2 and S3. An Alicat Mass Flow Controller (Alicat Scientific, Inc.) Model MCR-50SLPM-D was used to meter a range of volumetric flow rates of methane, ethane, propane, and butane to each detection instrument used in this study. Alicat Flow Controllers provide gas flows corrected to standard temperature and pressure (20°C and 1 atm.) and are equipped with an internal gas program that allows the operator to adjust the flow controller for the gas being metered. The Alicat MCR serial number 177760 was calibrated in the range of 0-40 SLPM by Alicat Scientific on May 30, 2018. Prior to response testing, gas detection equipment was calibrated according to the manufacturer's specifications. The specific hydrocarbon was selected on the Alicat Flow Controller for each metered gas prior to testing. The connection line from the flow controller to the detection equipment was purged between each test set. The response factor is the ratio of the instrument response to a controlled release of a pure gas to the true value of the metered gas.

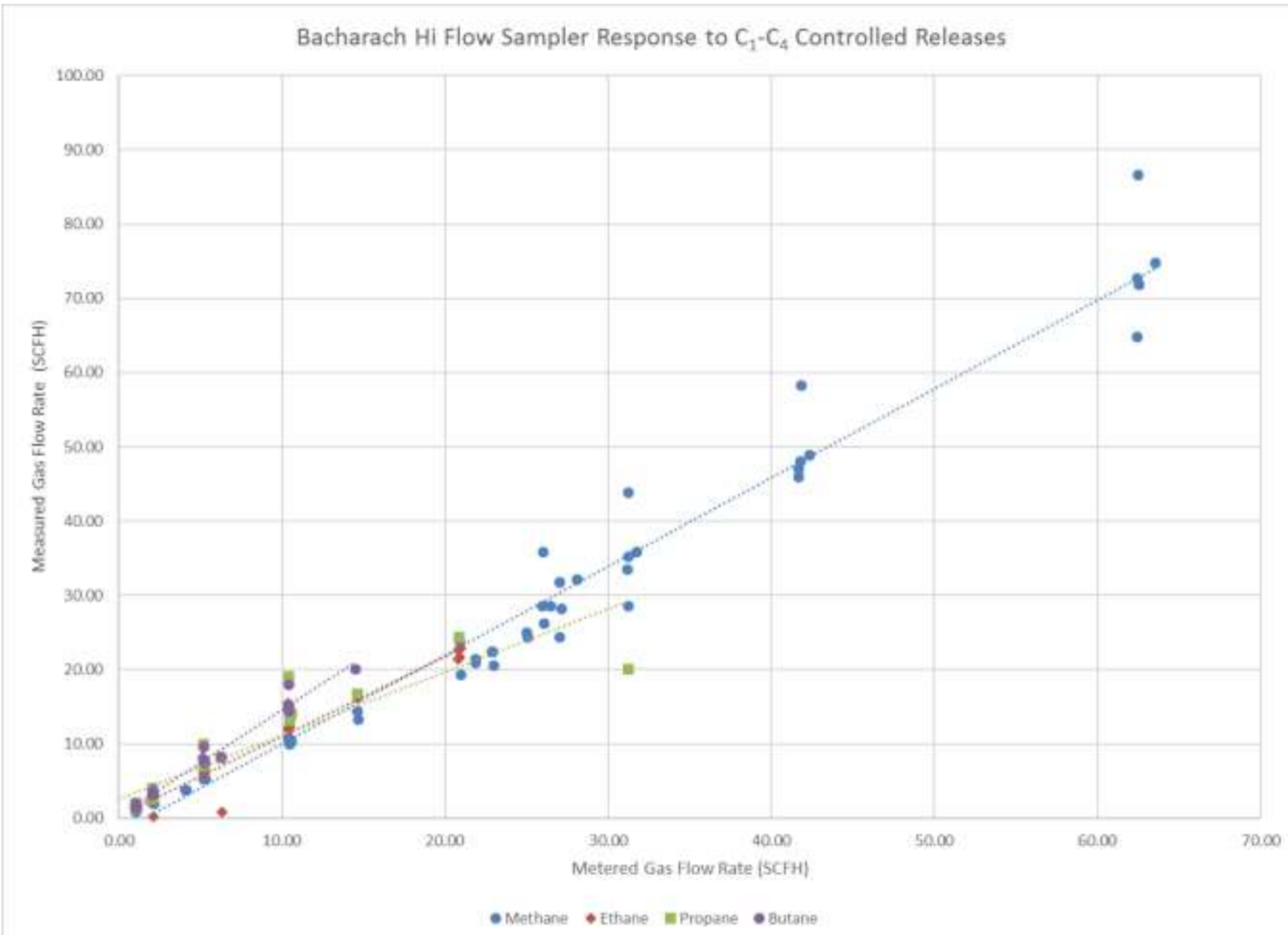

Figure S2. C1-C4 Instrument Responses for the Bacharach High Volume Sampler. Instrument responses were determined for each of the primary constituents found in natural gas, for each sampler used in this study.

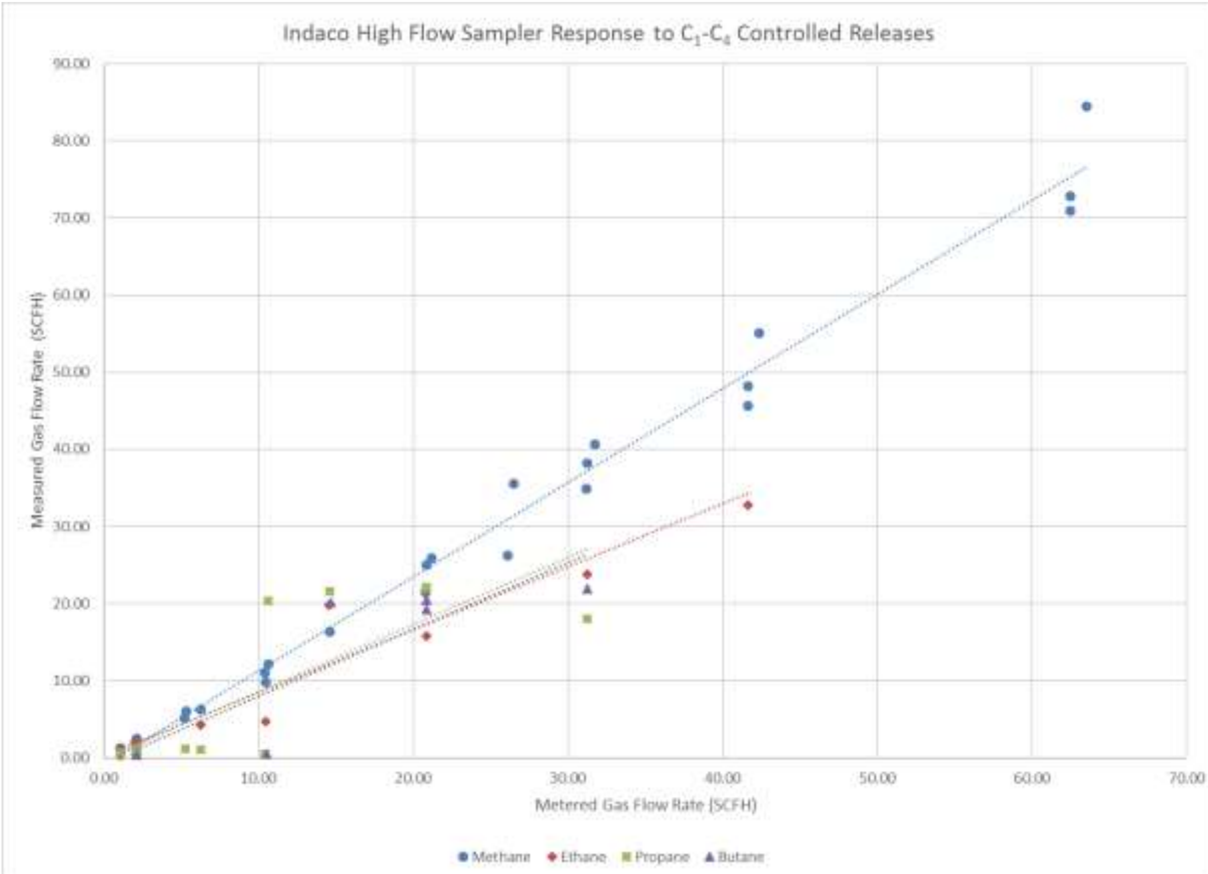

Figure S3. C1-C4 Instrument Responses for the Indaco High Volume Sampler. Instrument responses were determined for each of the primary constituents found in natural gas, for each sampler used in this study.

An instrument response model was developed for each sampler based on each site's gas composition and laboratory testing for the RF factors (as shown in Table S5), as follows:

$$RF_{Site} = \left(\%CH_4 \times RF_{CH_4}\right) + \left(\%C_2H_6 \times RF_{C_2H_4}\right) + \left(\%C_3H_8 \times RF_{C_3H_8}\right) + \left(\%C_4H_{10} \times RF_{C_4H_{10}}\right)$$

The whole gas emission rates were calculated by adjusting the measured emission rate by the site-specific response factor as follows:

$$Q_{Whole\ Gas} = \frac{Q_{Raw}}{RF_{Site}}$$

Gas composition data for 57 out of the 67 sites surveyed was provided by the host companies. For the ten sites where data was not available the average gas composition from similar sites within the same basin were substituted.

Augmented high-volume sampler quality assurance procedure

There have been documented instances when the Bacharach Hi Flow® Sampler quantification results were biased low (Brantley, et al., 2015, Howard et al., 2014 and Modrak et al., 2012) due to failure of the device to transition between detector ranges. Brantley reported that significant negative bias occurred when the sample stream had greater than 10% non-methane hydrocarbons (<90% CH_4 in the site gas composition). For this reason, the Hi Flow® Sampler used on this project was equipped with a backup hydrocarbon sensor at the Hi Flow® sampler exhaust to provide real time quality assurance of the gas concentration measurement. These past studies have shown that the Hi Flow® Sampler can experience issues in the transition region (~5% gas) and displays an unstable reading fluctuating between 2% and 4% gas.

In those instances where the Hi Flow® high-volume sampler and the secondary detector did not agree, and the Hi Flow® Sampler concentration was within 2% to 4% hydrocarbon measurement range, the higher measurement from the secondary detector was used in the emission calculation that is shown as Q_{Raw} in the previous section. There were six instances in this field program where the Hi Flow® Sampler failed to transition between the low range (0-5% gas) and the high range (> 5% gas). In these six cases, the concentration data taken from the backup detector, which in these cases was the DPIR, was used to calculate the component leak rates.

In addition to using the backup detectors for providing data during transition failures, the backup instruments had lower detection limits than the Hi Flow® Sampler. The Bascom-Turner Gas Rover was one of the instruments used as a secondary detector and has a minimum gas detection limit below that of the Hi Flow® Sampler. In those instances when the Hi Flow® Sampler reading was non-detect (ND), the gas concentration reading from the Gas Rover was used in the emission rate calculation. This situation occurred for leaks at the lower end of the leak distribution. The DPIR was not used for replacing Hi Flow® Sampler ND reading due to the elevated response for the DPIR to hydrocarbons above C1 in laboratory testing. In these cases, the Hi Flow® Sampler detection limit value was reported. Table S4 provides a total for how often each sampler/detector combination was used throughout the study.

Table S4.: Summary of detection equipment used in final emissions calculations. Row with X indicates the number of times that a backup instrument was used in final emission rate quantification for a leak in this study.

High Volume Sampler	Gas Detection Instrument Used for Concentration Reading	Backup Gas Instrument	No. of Leaks in Study where used for concentration reading
Bacharach	Bacharach Cat Ox/TCD		213
Bacharach	Heath DPIR IR	X	6
Bacharach	Bascom-Turner Gas Rover Cat Ox/TCD	X	73
Bacharach	Bascom-Turner Gas Sentry Cat Ox/TCD	X	0
Indaco HF	Bascom-Turner Gas Rover Cat Ox/TCD		39

The high-volume sampler was calibrated daily, or more frequently, if a single point mid-day check of the previous calibration was outside the ±10% acceptability range. The high-volume sampler was calibrated using the vendor-supplied calibration kit and demand regulators to ensure consistent flow rates. Gas standards for the calibration included zero-air (rather than background air), a 2.5% methane standard for the low threshold sensor, and a 100% methane standard for the high threshold sensor. The full calibration procedure followed the guidance provided in Section 3.0 of the Bacharach Hi Flow® Sampler Operations & Maintenance Manual (Bacharach, 2015). Flow sensors were verified weekly using a calibrated rotameter connected to the sample line. All periodic flow calibration checks were within ± 8 % of the accepted value and averaged 4%, which includes the uncertainty in the rotameter calibration.

Additional quality assurance measures

The high-volume samplers have combustible gas detectors that utilize both catalytic oxidation (Cat Ox) and thermal conductivity (TCD) sensors. The catalytic oxidation sensor is used in the range of 0% to 5% gas and the TCD in the range >5% to 100%. The Hi Flow® Sampler uses differential pressure across an orifice plate to measure flow rate. The Indaco high-volume sampler uses a TSI® hot-wire hotwire anemometer to measure sample gas flow rate.

The high-volume instrument's hydrocarbon sensors were calibrated at 2.5% and 100% methane. These points represent the span of the TCD sensor (Gas concentrations > 5 %) and the midpoint of the catalytic oxidation sensor (Gas concentrations between 0 and 5 %). Before conducting field measurements, the high-volume samplers were challenged with a range of methane volumetric flow rates to verify the linearity of the instrument. The linearity of each sensor was documented and is shown in Figures S2 and S3.

Separate response factors and linearity checks (Figure S3 for the Indaco high flow sampler) were developed for each of the backup instruments as shown in Table S5 and used in the emission rate calculations in this work.

Table S5. Response factors determined for each instrument used in the study. Due to the large uncertainty of the Heath DPIR's response in previous testing to higher hydrocarbons, a Heath DPIR response factor was developed based on the gas compositions of the leaks where the Heath DPIR was used. Artificial mixtures of gases representing the composition of the field gas where the DPIR was prepared in a Tedlar bag. Dilutions of this gas were supplied to the Heath DPIR and a response factor was developed and applied to the six measurements where the DPIR was used.

	Observed Response Factor			
Equipment	C_1	C_2	C_3	C_4
Bacharach HF				
(0.5%≥ x ≤5%)	1.02	1.24	1.40	1.53
(x ≥5%)	1.09	1.24	1.40	1.53
Indaco HF	1.13	0.79	0.60	0.70
BT Gas Rover	1.04	1.11	0.46	1.38
BT Gas Sentry	1.01	0.86	1.02	2.95
Heath DPIR	4.48			

Section S2. Details on Emissions from Glycol Pump

When arriving at one of the field sites, the GHD technicians and company representatives on-site immediately heard a hissing sound that is associated with the release of high pressure gas. Upon investigating the sound, the personal lower explosion limit (LEL) detectors for the GHD field team alarmed, and the field team also noted a strong hydrocarbon odor.

The operations personnel from the host company conducted an audio, visual, olfactory (AVO) survey of the site and located the source, which was a cracked fitting on a glycol pump discharge for a dehydration system on the wet (rich) side of the unit. The problem was apparent to the operator through visible signs (i.e. the ice in Figure S4). A maintenance crew was called and when they arrived, the pump was immediately removed from service by re-routing flow to the on-site spare pump. A root cause analysis was undertaken on the site and through follow-up discussions through Kimray, which is the vendor of the equipment.

Due to safety reasons, the equipment near this dehydrator was not surveyed.

The vendor (Kimray) indicated that this type of crack would cause the emissions to be primarily hydrocarbon in gas content versus the typical mixture (1/3 site natural gas, 2/3 glycol) that would be in the wet-side discharge from the pump. The emissions from the pump also had a clear temporal pattern that corresponded to the stroking of the pump. This allowed for maximum emissions to be estimated based on the system volumes and the frequency of pumping strokes. However, it is not known what percentage of this maximum gas volume escaped since quantification measurements would have been unsafe and likely unable to accurately characterize the release volume.

Figure S4. Photograph of the wet glycol discharge piping where the emission source was identified. The equipment was determined to be a Kimray 21020 PV model glycol pump. The maximum emission rate from the event was determined through interaction with the pump manufacturer and parameters recorded on-site.

The upper bound of emissions from this glycol pump was calculated based on the manufacturer specification sheet for the equipment (Kimray, 2013) and data collected while the GHD field team was on-site. This included a cellular phone video of the pump strokes that allowed for a counting of the number of strokes per minute for the pump in operations. The upper bound emission calculation presented below assumes that the entire internal volume of the wet side of the pump is emitted (30 cubic inches) during each of the 32 strokes per minute for the pump that were counted from the video, and results in an emission estimate of 2,074 scfh.

$$System\,Volume\,(scf) = \frac{(30\,in^3)\left(\frac{900+14.69\,psi}{14.69\,psi}\right)}{1728\ in^3/ft^3} = 1.08\,scf$$

$$Upper\ bound\ emission\ rate\ (scfh) = \left(\frac{1.08\,scf}{stroke}\right)\left(\frac{32\ strokes}{minute}\right)\left(\frac{60\ minute}{hour}\right) = 2074\,scfh$$

Given the uncertainty around the composition of the gas release, it is not feasible to adequately characterize the methane emissions or hydrocarbon content of the gas leak. Since the emission source could not be safely screening with an FID or infrared camera and since the site observations (personal LEL alarms, hydrocarbon odor, and human-eye visible emissions) immediately drew the attention of the GHD field team and company operations representatives, this emission is not included in the development of equipment leak emission factors for this study. In the opinion of the GHD field team, any trained operator that arrived on site would have immediately identified the emission source and mitigated the emissions, so it would not have required an instrumented LDAR survey for identification.

Section S3. Additional results and discussions

Table S6. Count and emission of leaking components identified in leak detection surveys in this study. Leaking components were identified by optical gas imaging (OGI) and/or flame ionization detectors (FID) surveys at 67 oil and gas sites in the US.

Component Type	Count of Leaking Components	Percent of Leaking Components	Emissions from Leaking Components (scfh)	Percent of Emissions from Leaking Components (scfh)
Connectors	187	57%	500.9	35%
OELs	16	5%	135.7	9%
Valves	54	16%	317.0	22%
Flange	17	5%	233.0	16%
Instrument	10	3%	42.7	3%
Regulator	24	7%	107.6	8%
Vent	2	1%	42.3	3%
Other	16	5%	42.1	3%
Piping	1	0%	15.5	1%
PRVs	3	1%	3.4	0.2%
Pump	1	0%	0.2	0.02%
Total	331	100%	1440.7	100%

Table S7. Summary statistics for leaking components identified in oil, gas, and both services. Leaking components were identified by optical gas imaging (OGI) and/or flame ionization detectors (FID). Counts are shown for all 67 sites in the study and for the 65 sites in the study with a component count.

	Oil and Gas Service	Gas Service	Oil Service
Count at 67 Sites	331	307	24
Count at 65 Sites with a component count	326	302	24
Minimum (scfh)	0.006	0.006	0.026
Maximum (scfh)	83.7	83.7	27.4
Average (scfh)	4.35	4.42	3.50
Median (scfh)	0.34	0.34	0.30

Table S8. Summary Statistics for leaking components identified by OGI and FID-based survey methods. Leaking components were identified by optical gas imaging (OGI) and/or flame ionization detectors (FID) surveys at oil and gas sites in the US. At two sites, an OGI survey was undertaken but an FID-based survey was not undertaken. Thus, OGI results are presented both including and excluding those two sites.

	Detected with OGI	Detected with FID	Detected with OGI, FID survey also occurred
Count at 67 Sites	113	293	106
Count at 65 Sites with a component count	111	290	104
Minimum (scfh)	0.011	0.006	0.011
Maximum (scfh)	83.7	75.9	83.7
Average (scfh)	10.33	3.68	10.36
Median (scfh)	2.80	0.31	2.73

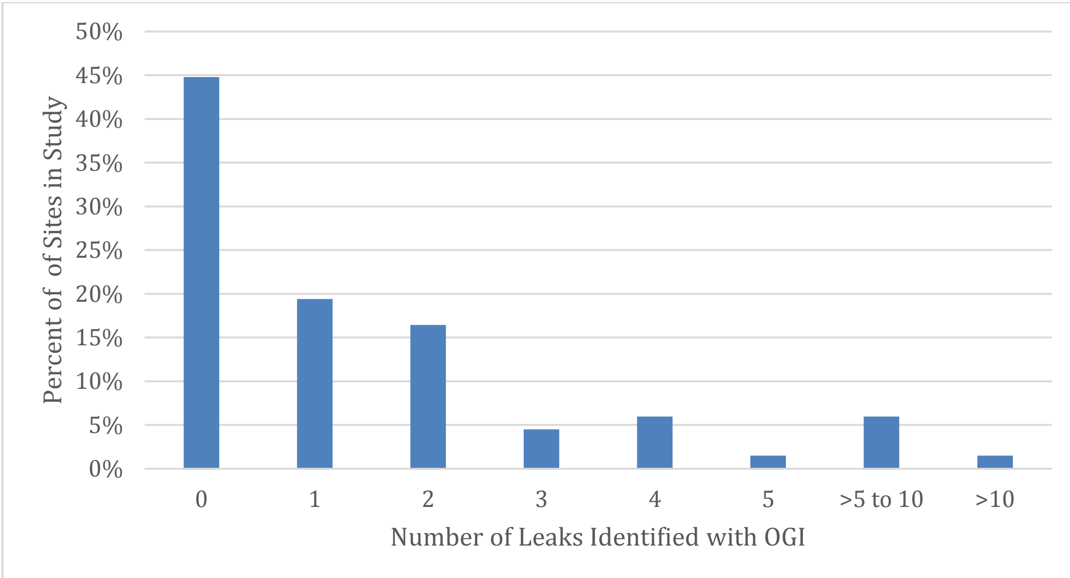

Figure S5. Distribution of number of leaks identified by OGI per site. Figure displays the count of sites in the study binned by the number of leaks detected at that site by OGI.

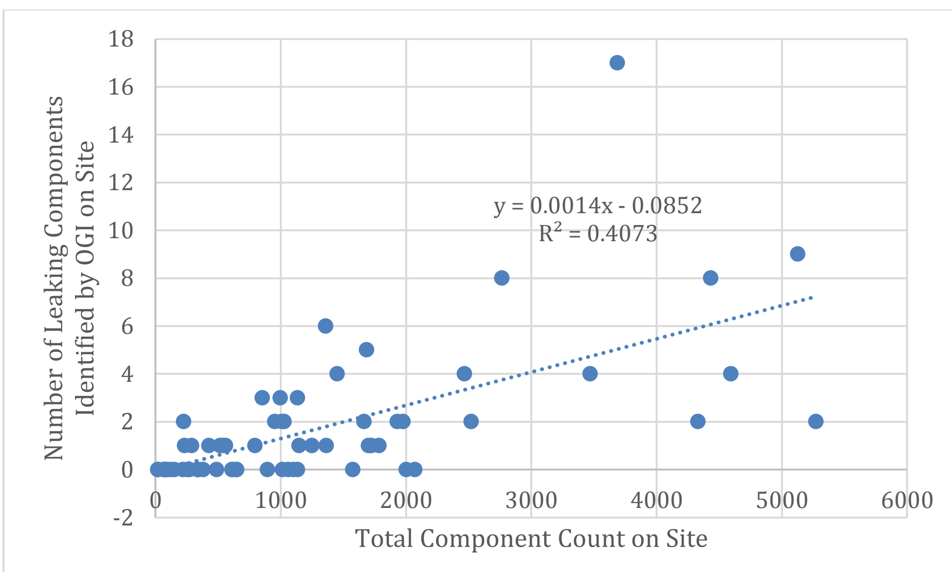

Figure S6. Relationship between site component count and the number of leaks detected by OGI. Graphic shows a weak linear correlation between the number of leaks detected on a site by a given leak detection method and the number of components that were counted at the site by the field team.

Description of Methodology for Comparison to Current EPA Emission Factors

Data from this study was analyzed so that direct comparisons could be made to current EPA emission factors used for reporting greenhouse gas emissions as part of the US Greenhouse Gas Reporting Program (GHGRP) for equipment leaks in the production and gathering and boosting segments for gas and light oil service. The current method that is used mostly frequently (US EPA, 2017a) includes a count of major pieces of equipment located on a site, default factors to estimate component counts based on major equipment counts, and a default population-level emission factor per component type (US EPA, 2017b). In general, comparisons are made between the field determined service (gas versus oil) of each piece of equipment or leaking component and the analogous emission factors from GHGRP methods. Since the API gravity of the oil produced at sites was not recorded as part of the metadata for this study, the assumption is made that all oil service in the study was light oil service rather than heavy oil service. All comparisons in this section are also made to emission factors and component counts in the western United States as all four basins where sampling occurred in this study were in that geographic region, as defined in Table W1-D in 40 CFR 98 Subpart W.

Comparisons between estimated site-level emissions from the current EPA major equipment-based approach and measured emissions from leaking components in this study are made in Table S9. Site-level measured equipment leaks were determined by summing the measured emissions from all leaking components that were identified by OGI or FID-based methods at the 65 sites with both a component count and a leak detection survey. Calculated equipment leaks were estimated by developing a count of major equipment per site and applying default component counts (Table W1-B and C) and default population-level emissions per component (Table W1-A) that are outlined in 40 CFR 98 Subpart W. For major equipment, such as wellheads or separators, that could be in oil or gas service, depending on the application, the classification of the site (oil vs. gas) by the field team was used in deciding which type of wellhead or separator population-level emission factors would be used.

For individual sites, measured emissions from equipment leaks were both higher and lower than suggested by major equipment count-based approaches; however, for most sites and the study overall emissions were overestimated by the major equipment count-based method in 40 CFR 98 Subpart W.

Table S9. Comparison of measured equipment leak emissions from the field campaign to default EPA emission estimation method from major equipment counts. Table compares the 65 sites for which both a component count and LDAR survey were available in this study to the emissions that would have been estimated using methods outlined in 40 CFR 98. Measured emissions represent results of direct measurements of all leaking components identified by OGI or FID.

Site Data				Site Equipment Count							
Site ID	Site Type	Measured Emissions from Leaking Components (scfh)	Calculated Emissions Using Major Equipment Count (scfh)	Wellhead	Separator	Meters/Piping	Compressor	Inline Heater	Dehydrator	Heater Treater	Header
GHD0001	Gas	8.89	8.46	1	1	0	0	0	0	0	0
GHD0002	Gas	0.35	26.09	1	1	0	1	0	1	0	0
GHD0003	Oil	49.99	25.43	2	2	3	1	0	0	4	0
GHD0004	Oil	48.78	26.04	3	2	3	1	0	0	4	0
GHD0005	Gas	46.72	64.78	1	5	0	2	0	1	0	0
GHD0006	Gas	11.00	33.26	1	2	2	1	0	0	0	0
GHD0007	Gas	4.43	43.45	1	4	1	1	0	0	0	0
GHD0008	Gas	0.00	54.22	0	4	1	2	0	0	0	0
GHD0009	Gas	3.19	23.99	1	1	1	1	0	0	0	0
GHD0011	Oil	68.00	88.37	2	4	3	3	12	0	4	0
GHD0013	Gas	6.58	54.12	3	7	1	0	0	0	0	0
GHD0014	Gas	0.95	44.64	1	4	6	0	0	0	0	0
GHD0015	Oil	2.24	6.44	2	6	1	0	0	0	0	0
GHD0016	Gas	65.68	89.45	2	6	3	3	0	0	0	0
GHD0017	Gas	2.43	73.24	0	10	3	0	0	0	0	0
GHD0018	Gas	27.98	76.02	0	10	4	0	0	0	0	0
GHD0019	Oil	79.67	78.85	2	12	7	4	0	0	4	0
GHD0020	Oil	1.90	14.22	0	4	4	0	0	0	2	1
GHD0021	Oil	104.97	110.52	0	20	7	6	0	0	8	6
GHD0022	Gas	0.00	17.50	1	0	1	1	0	0	0	0
GHD0023	Gas	0.00	17.50	1	0	1	1	0	0	0	0
GHD0024	Gas	15.53	27.46	1	0	0	2	0	0	0	0
GHD0025	Gas	0.10	17.50	1	0	1	1	0	0	0	0
GHD0026	Gas	0.00	47.73	0	3	1	2	0	0	0	0
GHD0027	Gas	66.08	90.61	0	2	5	5	0	0	0	0
GHD0028	Oil	9.16	5.02	1	4	1	0	0	0	0	0
GHD0029	Gas	27.43	41.96	2	5	2	0	0	0	0	0
GHD0030	Gas	0.08	17.74	1	2	1	0	0	0	0	0
GHD0031	Gas	45.41	49.94	1	5	1	1	0	0	0	0
GHD0032	Gas	14.78	40.90	1	3	2	1	0	0	2	0
GHD0033	Oil	11.42	6.17	1	4	1	0	0	0	2	0

GHD0034	Oil	1.01	6.17	1	4	1	0	0	0	2	0
GHD0035	Gas	4.54	30.71	1	4	1	0	0	0	0	0
GHD0036	Gas	77.04	69.17	1	6	1	2	0	0	0	0
GHD0037	Oil	1.17	6.17	1	4	1	0	0	0	2	0
GHD0038	Gas	1.13	43.69	1	6	1	0	0	0	0	0
GHD0039	Gas	90.83	46.81	0	2	3	2	0	0	0	0
GHD0040	Gas	0.00	4.76	1	0	1	0	0	0	0	0
GHD0041	Gas	0.00	4.76	1	0	1	0	0	0	0	0
GHD0042	Gas	0.00	4.76	1	0	1	0	0	0	0	0
GHD0043	Gas	266.47	92.49	0	6	2	3	0	2	0	0
GHD0044	Gas	81.13	18.31	0	0	2	1	0	0	0	0
GHD0045	Gas	0.00	1.97	1	0	0	0	0	0	0	0
GHD0046	Gas	0.00	4.76	1	0	1	0	0	0	0	0
GHD0047	Gas	0.00	1.97	1	0	0	0	0	0	0	0
GHD0048	Gas	84.38	135.95	8	8	21	0	0	2	0	0
GHD0049	Gas	18.71	99.92	1	6	13	1	0	2	0	1
GHD0050	Gas	15.53	77.64	1	6	5	1	0	2	0	1
GHD0051	Gas	0.08	17.74	1	2	1	0	0	0	0	0
GHD0052	Gas	1.31	65.83	0	8	5	0	0	0	0	0
GHD0053	Gas	0.09	1.97	1	0	0	0	0	0	0	0
GHD0054	Gas	0.00	1.97	1	0	0	0	0	0	0	0
GHD0055	Oil	0.14	4.21	1	2	1	0	0	0	0	0
GHD0056	Oil	35.81	64.75	0	21	5	3	0	0	6	2
GHD0057	Oil	1.40	1.42	1	2	0	0	0	0	0	0
GHD0058	Oil	5.19	4.21	1	2	1	0	0	0	0	0
GHD0059	Oil	19.37	40.97	0	18	2	2	0	0	4	1
GHD0060	Oil	0.31	1.42	1	2	0	0	0	0	0	0
GHD0061	Oil	3.05	34.44	1	4	2	2	0	0	2	0
GHD0067	Oil	0.00	6.38	0	2	2	0	0	0	0	0
GHD0068	Oil	0.00	0.61	1	0	0	0	0	0	0	0
GHD0069	Oil	0.00	17.86	2	2	1	1	0	0	0	1
GHD0070	Oil	0.36	4.72	0	4	1	0	0	0	0	1
GHD0071	Oil	0.03	0.61	1	0	0	0	0	0	0	0
GHD0072	Oil	0.00	0.61	1	0	0	0	0	0	0	0

Comparisons were also made between the average emissions per component in the field study to default emission factors per component in 40 CFR 98 Subpart W in Table W1-A for gas and light liquid services. The emission factors for this study were developed summing the measured emissions (scfh) for leaking components with an analogous counterpart in Table W1-A (i.e. a valve in gas service) and dividing by the total number of components of that type counted by the field team in that service across the 65 sites in this study with both a component count and leak detection survey. An implicit assumption of this approach is that all components that were not identified as leaking by either OGI or FID-based surveys are assumed to have negligible emissions, which is similar to EPA approaches for reporting equipment leaks from sites with qualifying LDAR surveys. No measurements were made on these non-leaking components as part of the field campaign to validate this approach. As noted in the paper, the impact of this assumption is expected to be minor, with an estimated addition of 3.4% to measured site emissions from leaking components. Except for open-ended lines (OELs) in gas service, the trend in this study was that average emission factors per component from this study were lower than factors in 40 CFR 98 Subpart W Table W1-A.

Table S10. Comparison of average component emission factors from study to current US EPA factors. Table compares emissions from equipment leaks detected at the 65 sites that also included a site component count. Note that some equipment leak emissions that were attributed to component types not listed in this table, such as a leak on a regulator, are not attributed to component-specific emission factors developed in this table. These emissions are included in other analyses in the paper that consider all equipment leak emissions from site surveys.

	Western U.S. Gas Service					Western U.S. Light Liquid Service			
	Component Count in Study	Emissions from Leaking Components (scfh)	Study Average Emission Factor (scfh/component)	Current EPA Average Emission Factor (scfh/component)	Percent Difference	Component Count in Study	Emissions from Leaking Components (scfh)	Study Average Emission Factor (scfh/component)	Current EP Average Emission Fa (scfh/compo
Valve	8789	286.8	0.033	0.121	-73%	3009	29.6	0.010	0.05
Connector	44491	477.5	0.011	0.017	-37%	14015	16.2	0.001	0.007
OEL	603	135.7	0.225	0.031	627%	128	0.0	0.000	0.05
PRV	512	3.4	0.007	0.193	-97%	77	0.0	0.000	-
Flange	8580	233.0	0.027	-	-	3756	0.0	0.000	0.003

Table S11 shows a comparison between the total components in oil and gas service that were counted by the GHD field team and the estimated component counts that would have been generated from current EPA default component counts in 40 CFR 98 Table W-1B for gas service and Table W-1C for oil service using an EPA online tool for Subpart W reporting for 2017 (EPA, 2018). In general, component counts from the GHD field team were higher than those that would have been estimated from the EPA default component count factors, especially in oil service.

Similar trends were observed based on component count for oil sites and gas sites as with oil service and gas service.

Table S11. Comparison of field component counts to predictions from current EPA estimation methods. Table compares component counts from 65 sites in this study to current EPA default component count estimation methods from the study site major equipment counts.

	Oil and Gas Service			Oil Service		
	Study Field Count	Estimated Count from EPA Methods	Percent Difference	Study Field Count	Estimated Count from EPA Methods	Perc
Valves	11798	12816	-8%	3009	1313	
Connectors	58506	36903	59%	14015	2326	
OELs	731	1178	-38%	128	0	
PRVs	589	665	-11%	77	0	
Flanges	12336	2442	405%	3756	2442	
Total	83960	54004	55%	20985	6081	

For the most common equipment leak reporting method in the GHGRP, the US EPA provides default component counts per piece of major equipment (i.e. number of valves per compressor) that are used in emission reporting. Table S12 provides a comparison between the factors developed based on data collected in this study and current EPA factors for the Western United States for gas (40 CFR 98 Table W-1B) and oil (40 CFR 98 Table W-1C) sites for the comparable region in this work. Component counts per piece of equipment are generally higher in this work than the current EPA factors, which is consistent with the overall component counts presented in Table S11.

It should be noted that some of the major equipment listed in the study database does not have an exact match to the types of equipment in current EPA factors. For sites with these types of equipment, such as minor separators like fuel gas scrubbers, the component counts from the unmatched equipment were proportionally allocated to the listed major equipment on site such that the total component counts used in the development of Table S12 were equal to the total component counts reported by the GHD field team and inventoried in the study data.

Care should be taken in making a few comparisons between data collected in this field campaign and current EPA GHGRP factors. First, there is no current factor in the GHGRP for flanges on gas sites, but such components were inventoried in this field campaign. The EPA approach in Subpart W includes flanges under the more general heading of connectors, while this study is presenting results for flanges and other connectors separately. Thus, a direct comparison to the current EPA factors for gas sites would include the count of both connectors and flanges from this study. Second, the current EPA factors for oil sites includes a factor for “Other components”, which is broader than the pressure relief valves (PRVs) in Table S12. A direct comparison to “Other components” cannot be made since the study only inventoried valves, flanges, connectors, open-ended lines (OELs), and PRVs as part of the component counts. It should be noted that leaks identified on-site from other types of non-inventoried components were quantified and included in study emission results presented in this work.

Table S12. Comparison of component counts per major equipment to current EPA component count factors for the Western United States. Table compares component counts per major equipment from 65 sites in this study to current EPA default factors used in GHGRP reporting. Note that the current EPA factors for gas sites do not include flanges, which are rolled-up into connectors in the current reporting program. In addition, oil sites do not have pressure relief valves (PRVs) and have a category labeled “Other components”, which includes components beyond PRVs, which were not tracked in this study.

	Components/Major Equipment in Study (Gas)					Current Subpart W Component Factors (Gas)				
	Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Wellhead	16	11	59	2	1	11	-	36	1	0
Separator	19	10	100	1	1	34	-	106	6	2
Meters/Piping	21	20	51	1	0	14	-	51	1	1
Compressor	24	34	259	3	3	73	-	179	3	4
Inline Heater	4	0	24	0	1	14	-	65	2	1
Dehydrator	26	4	165	0	1	24	-	90	2	2
	Components/Major Equipment in Study (Oil)					**Current Subpart W Component Factors (Oil)**				
	Valves	**Flanges**	**Connectors**	**OELs**	**PRVs**	**Valves**	**Flanges**	**Connectors**	**OELs**	**PRVs**
Wellhead	23	13	134	2	0	5	10	4	0	1
Separator	17	28	87	1	1	6	12	10	0	0
Heater Treater	18	24	91	1	1	8	12	20	0	0
Header	30	51	37	0	0	5	10	4	0	0

For 2017 emission reporting into the GHGRP, a new methodology for reporting equipment leaks was introduced as an option for oil and gas production and gathering and boosting sites. This methodology is based on counts of leaking components that are identified through a qualifying field leak detection survey, such as with OGI and FID-based methods, and a leaker emission factor from 40 CFR 98 Subpart W Table W1-E. The number of leaks and leaker emission factor is used to estimate site equipment leak emissions for each component type. Emissions from other components on site are assumed to be negligible. Leaker emission factors were developed for leaking components identified in this study and compared to the equivalent leaker emission factors from Table W1-E.

Comparison of the leaker emission factors developed in this study to those in Table W1-E indicate the average emissions per leaking component in gas service (Table S13) were larger in this study than in the datasets used to develop the current EPA emission factors. Comparisons for emissions from leaking components identified in oil service (Table S14) were more varied than for gas service. Further comparisons are made to EPA-derived leaker emission factors (EPA, 2016) based on a 2013 study (Allen et al. 2013) and the Fort Worth Air Quality Study (City of Fort Worth, 2011) for components in gas service. In general, the resulting leaker emission factors from measurements in this study were lower than the factors developed from either of those study datasets.

Table S13. Comparison of study and EPA leaker emission factors for natural gas service. Table compares the emissions per leaking component measured in this study to data from other publicly-available sources.

Component Type	Number of Leaking Components	Emissions from Leaking Components (scfh)	Leaker Emission Factors in Gas Service (scfh/leaking component)			
			Study Factor	Current EPA Factor	EPA Analysis of Allen (2013) Study	EPA Analysis of Fort Worth Air Quality Study
Valve	48	287.4	6.0	4.9	7.6	12.2
Flange	17	233.0	13.7	4.1	9.6	14.4
Connector	173	484.8	2.8	1.3	3.3	5.4
OEL	16	135.7	8.5	2.8	21.8	10.6
PRV	3	3.4	1.1	4.5	9.8	-
Pump Seal	0	-	-	3.7	-	-
Other	50	212.4	4.2	4.5	3.8	9.5

Table S14. Comparison of study and EPA leaker emission factors for oil service. Table compares the emissions per leaking component measured in this study to data from other publicly-available sources.

Component Type	Number of Leaking	Emissions from	Leaker Emission Factors in Oil Service (scfh/leaking component)

	Components	Leaking Components (scfh)	Study Factor	Current EPA Factor
Valve	6	29.6	4.9	3.2
Flange	0	-	-	2.7
Connector	14	16.2	1.1	1
OEL	0	-	-	1.6
Pump	1	0.23	0.23	3.7
Other	3	38.0	12.7	3.1

Comparisons of Percent of Components Identified as Leaking

Some equipment leak studies (e.g. Allen et al., 2013) have simply noted the types and emission quantity for identified leaking devices. Other studies (e.g. Kuo et al., 2015) have also conducted overall component counts to aid in the development of component-specific population emission factors and to understand the frequency of leaking components from the general population of components.

As part of contextualizing the study results related to the percent of components counted in the survey that were identified as leaking, the origin of the current factors used in EPA Subpart W GHGRP reporting was examined. For gas service, the population emission factors were adopted from a 1996 Gas Research Institute (GRI) and EPA study (Hummel et al., 1996) that utilized population component counts, leaking component counts, and FID screening values from a 1995 API study (API, 1995). Emissions from leaking components in gas service were estimated from correlation equations developed from an EPA emission estimation protocol (EPA, 1995). For light and heavy crude services, population emission factors for Subpart W emission reporting were developed directly from emission and population data in the 1995 API study (API, 1995).

Table S15 compares the fraction of components that were identified as leaking in prior research studies as a point of comparison for the results in this work. It is important to point out that the underlying studies referenced may have included different definitions of leak thresholds (100 ppm or 10,000 ppm) versus the assumption used in this work (500 ppm). Table S15 includes analysis of the underlying source data such that comparisons are made on the same leak definition for sites with a component count and FID-based survey. The rate of FID-determined leaking components at 500 ppm and 10,000 ppm thresholds were much lower (0.4% to 0.3% of components surveyed) than previous API study results (2.8% to 1.1% of components surveyed).

Table S15. Comparison of the fraction of leaking components identified in previous equipment leak estimation studies. Note that the analysis presented required a re-analysis of some of the source information for referenced sources since the leak threshold definition was not always consistent between studies. Leaking and overall component counts are based on the subset of sites with both an FID survey and a full site component count.

Reference	Source Description	Component Count in Population	Leaking Component Count		Leaking Component Frequency in Population	
			>500 ppm	>10,000 ppm	>500 ppm	>10,000 ppm
API 1995	Onshore Gas Production	40,178	1,138	648	2.83%	1.61%
API 1995	Onshore Oil Production	62,408	673	419	1.08%	0.67%
API 1995	Onshore Oil and Gas Production	102,586	1,811	1,067	1.77%	1.04%
This Study	Onshore Gas Production	46,140	173	82	0.37%	0.18%
This Study	Onshore Oil Production	36,134	117	56	0.32%	0.15%
This Study	Onshore Oil and Gas Production	82,274	290	138	0.35%	0.17%

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Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers

David T. Allen,*[,†] Adam P. Pacsi,[†] David W. Sullivan,[†] Daniel Zavala-Araiza,[†,∇] Matthew Harrison,[‡] Kindal Keen,[‡] Matthew P. Fraser,[§] A. Daniel Hill,[∥] Robert F. Sawyer,[⊥] and John H. Seinfeld[#]

[†]Center for Energy and Environmental Resources, University of Texas at Austin, 10100 Burnet Road, Building 133, M.S. R7100, Austin, Texas 78758, United States

[‡]URS Corporation, 9400 Amberglen Boulevard, Austin, Texas 78729, United States

[§]School of Sustainable Engineering and the Built Environment, Arizona State University PO Box 875306, Tempe, Arizona 85287, United States

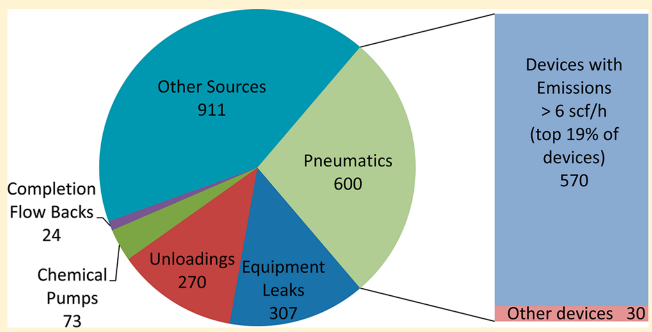
[∥]Department of Petroleum Engineering, Texas A&M University, 3116 TAMU, College Station, Texas 77843-3116, United States

[⊥]Department of Mechanical Engineering, Mail Code 1740, University of California, Berkeley, California 94720-1740, United States

[#]Department of Chemical Engineering, California Institute of Technology, M/C 210-41, Pasadena, California 91125, United States

Supporting Information

ABSTRACT: Emissions from 377 gas actuated (pneumatic) controllers were measured at natural gas production sites and a small number of oil production sites, throughout the United States. A small subset of the devices (19%), with whole gas emission rates in excess of 6 standard cubic feet per hour (scf/h), accounted for 95% of emissions. More than half of the controllers recorded emissions of 0.001 scf/h or less during 15 min of measurement. Pneumatic controllers in level control applications on separators and in compressor applications had higher emission rates than controllers in other types of applications. Regional differences in emissions were observed, with the lowest emissions measured in the Rocky Mountains and the highest emissions in the Gulf Coast. Average methane emissions per controller reported in this work are 17% higher than the average emissions per controller in the 2012 EPA greenhouse gas national emission inventory (2012 GHG NEI, released in 2014); the average of 2.7 controllers per well observed in this work is higher than the 1.0 controllers per well reported in the 2012 GHG NEI.



INTRODUCTION

Natural gas production in the United States is increasing; the U.S. Energy Information Administration projects that by 2040, total natural gas production in the United States will increase by 40%.[1] With increased production, natural gas is displacing other fuels,[2] and this fuel switching has implications for greenhouse gas emissions.

Natural gas may have a lower greenhouse gas footprint than other, more carbon intensive, fossil fuels (coal and petroleum), since the carbon dioxide emissions associated with natural gas combustion are less than those associated with the combustion of coal and petroleum. For example, for identical heat releases on combustion, natural gas generates less than half of the carbon dioxide emissions of a typical coal.[3] The greenhouse gas benefits of natural gas relative to other fossil fuels may be eroded, however, by natural gas leaks in the supply chain. Methane, the principal component of natural gas, is a potent, but short-lived greenhouse gas. Because one kg of methane emissions is equivalent to between 28 and 120 kg of CO_2 emissions, depending on the time scale over which impacts are assessed (100-year to immediate time horizons),[4,5] methane emissions in the natural gas supply chain amounting to more than a few percent of natural gas use can change the greenhouse gas footprint of natural gas, relative to other fossil fuels.[5−9] Thus, to characterize the greenhouse gas footprint of natural gas, it is important to determine the magnitude of methane emissions in the natural gas supply chain.[10]

Methane emissions in the natural gas supply chain have been estimated using two basic approaches, commonly referred to as top-down and bottom-up approaches. Top-down approaches for estimating methane emissions from the natural gas supply chain involve measuring ambient concentrations of methane near emission sources. These concentrations can be measured using fixed ground monitors,[11,12] mobile and vehicle mounted ground monitors,[13,14] aircraft based instruments[15−17] or

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Table 1. Sample Population, Categorized by Controller Application and Region (AP= Appalachian; GC = Gulf Coast; MC = Mid-Continent; RM = Rocky Mountain)

		number of controllers sampled, categorized by application							
region	separator	process heater	compressor	wellhead	.plunger lift	dehydration system	flare	sales	total
AP	14	13	0	24	1	0	0	0	52
GC	73	0	13	11	7	17	1	1	123
MC	48	11	7	0	11	0	0	0	77
RM	51	21	0	32	11	8	2	0	125
total	186	45	20	67	30	25	3	1	377

satellite instruments.[18] Brandt et al.[19] and Miller et al.[20] have summarized recent top-down estimates of methane emissions and conclude that top-down emission estimates are generally higher than current bottom-up inventories of methane emissions, and some of this difference may be due to methane emissions from the natural gas supply chain. However, these analyses do not reveal which of the many potential sources of methane emissions along the natural gas supply chain might be incorrectly estimated.

Complementing top-down measurements, bottom-up measurements of methane emissions are made directly at the emission sources. In this approach, emission measurements are made at a representative sample of sources; the measurements from the sample population are then extrapolated to larger regional or national populations. The advantage of "bottom-up" approaches is that they can gather much more detail about the emission sources, and therefore can identify which source categories, among many, are responsible for emissions. For example, Allen, et al.[21] concluded that emissions from well completion flowbacks are overestimated, while emissions from pneumatic controllers may be underestimated, in current inventories of emissions. Both top-down and bottom-up approaches can contribute to an improved understanding of methane emissions from the natural gas supply chain. The work reported here uses bottom-up measurements to improve understanding of emissions from pneumatic controllers on natural gas production sites.

Pneumatic controllers use gas pressure to control the operation of mechanical devices, such as valves. The valves, in turn, control process conditions such as levels, temperatures, and pressures. When a pneumatic controller identifies the need to change liquid level, pressure, temperature or flow, it will open or close a control valve in order to return to a desired set point. The opening and closing of the valve can occur either through discrete (on/off) changes, or through changes that are proportional in magnitude to the deviation from the set point (throttling). Controllers can deliver this type of service (on/off and throttling) through either continuously venting or intermittent venting of gas. Thus, controllers can be grouped into four categories, depending on the type of service (on/off or throttling) and the type of venting (continuous or intermittent). In estimating emissions, the U.S. EPA uses the categories of low continuous bleed (<6 scf/h of gas vented), high continuous bleed (>6 standard cubic feet per hour (scf/h) of gas vented) and intermittent controllers.[22] Finally, controllers can also be categorized based on equipment manufacturer, model number, and the type of application (e.g., separator level control) in which they are used. In this work, the primary categorization of controllers will be as either continuous vent or intermittent vent based on the pattern observed during measurement; data on applications, service types, and EPA categorization for the controllers sampled in this work are provided in Supporting Information (SI).

The U.S. EPA[22] reports 477 606 pneumatic controllers are in use at natural gas production sites in the United States. These controllers are estimated to emit 334 Gg/yr of methane (17.4 billion cubic feet (bcf) methane), for an average of 0.7 Mg device^{-1} yr^{-1} or 4.2 scf/h methane device^{-1}. These estimated emissions from pneumatic controllers have been based on relatively limited measurements;[23] recent field measurements have suggested that these emissions may be understated.

Allen et al.[21] made measurements of emissions from 305 pneumatic controllers on well sites in the United States where the wells had been hydraulically fractured. Average emissions were 10.5 scf/h of methane, approximately double the average emission rate per device in the current EPA national emission inventory. Measurements of emissions from 581 pneumatic controllers, made in British Columbia and Alberta, averaged 9.2 scf/h of whole gas,[24] an emission rate similar to that reported by Allen et al.[21] In both of these studies, emissions from controllers exhibited wide ranges. In both sets of measurements, a small subset of controllers accounted for most of the emissions.

While the measurements at hydraulically fractured gas wells in the United States[21] and the measurements in British Columbia and Alberta[24] recorded emissions higher than the average emissions per device in the EPA national emission inventory, the sampled populations for these two sets of measurements were not necessarily broadly representative of U.S. national populations of pneumatic controllers. The measurements reported by Allen et al.[21] were made exclusively in shale gas production regions, and at sites where the wells had been hydraulically fractured. Many of the sites were recently completed wells, which initially tend to have higher liquid production rates, and therefore may have more frequent actuation of certain types of pneumatic devices than the average for the entire population of gas wells in the United States, leading to potentially higher emissions. The Canadian measurements[24] were made exclusively in one production region and on devices with manufacturer specified emission rates in excess of 4.2 scf/h.

The goals of the work presented here were (i) to measure emissions from pneumatic controllers at a wider population of wells, geographically distributed across the United States, including conventional gas wells, shale gas wells and a limited number of oil wells, and (ii) to characterize the features of the controllers with high emissions, which previous work[21,24] has found to be the major contributor to emissions.

MATERIALS AND METHODS

Sampled Population. A total of 377 pneumatic controllers were sampled at 65 sites (some with multiple wells) throughout the United States (an average of 5.8 pneumatic controllers per

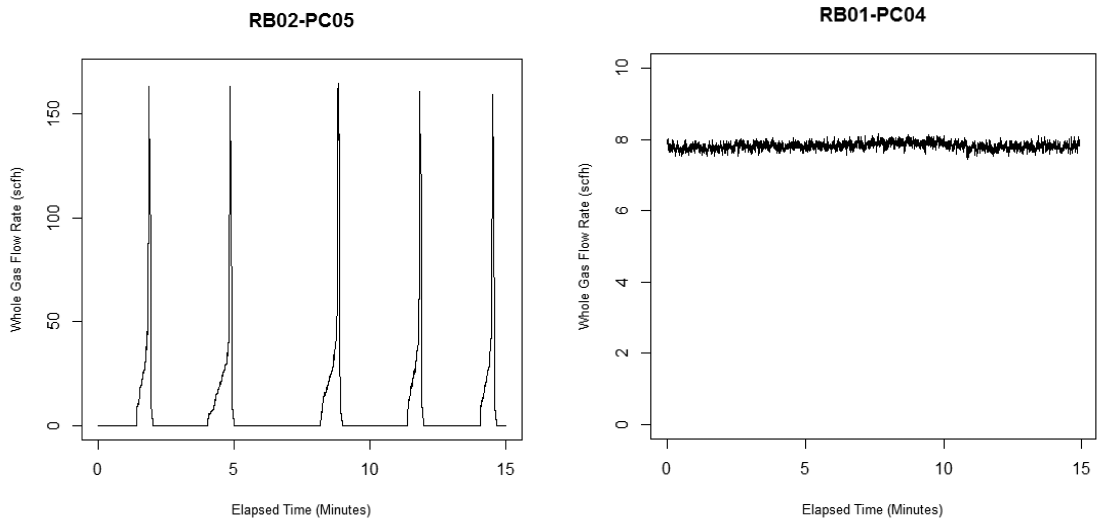

Figure 1. Representative time series for supply gas measurements for intermittent vent (left) and continuous vent (right) controllers; the intermittent vent controller (RB02-PC05) had a total of five actuations during the sampling period and an average emission rate, over the 15 min period of 7.9 scf/h; the continuous vent controller (RB01-PC04) had nearly constant emissions of 8.0 scf/h.

site, 2.7 controllers per well). Measurements were made primarily at natural gas production sites (351 of 377 controllers), and at a limited number of oil sites (26 controllers). Because the definitions of oil and gas wells vary, largely depending on gas to oil production ratios, the data will be treated as a single set. Sampling sites were selected from well sites owned by companies participating in the study using a process designed to yield a random sampling of participant sites (see SI, Section S1). For each well site that was visited, all controllers on the site were sampled using supply gas meters, unless operating conditions, safety issues or other factors prevented sampling. A total of 333 controllers had measurements made using the supply gas meters; 97 controllers could not be measured using the supply gas meter; of the 97 that were not sampled with the supply gas meter, 44 were sampled using exhaust gas measurements, leading to a total of 377 controllers in the sampled population. The applications that the controllers were used in (e.g., separator level control, compressor pressure control) are shown in Table 1. Details of the regions, device types, associated well types, operating methods and other characteristics of each of the 377 controllers sampled in this work are provided in SI, Section S4.

Emission Measurement Methods. Emissions from pneumatic controllers can be determined either by measuring the supply of gas entering the controller or by measuring the gas discharged from the controller. Both approaches were used in this work, and since there is no accumulation of gas in the controller, both measurement approaches should lead to equivalent measurements, if there are no leaks in the equipment downstream of the controller.

Measurements of the gas entering the controller were made by one of three Fox flow meters (model #FT2A); flow meters were inserted into the supply gas line for the controller. This supply gas measurement was the primary measurement method used in this work, and was used to measure emission rates on 333 of the 377 controllers in the sample population (the remainder were sampled by measuring gas emitted by the controller using a HiFlow Sampler described later in this section, see SI for comparisons between the supply gas and exhaust gas measurements). The flow meters reported flows at a sampling frequency of 10 Hz. Two of the Fox model #FT2A instruments (labeled A and C in this study) had a range of operation of 0−300 scf/h, with a precision of ±1% of flow, and the third Fox model #FT2A (labeled B in this study) had a range of operation of 0−1200 scf/h, with a precision of ±1% of flow. The Fox model #FT2A instruments A and C were used whenever possible because of their greater absolute precision, however, if any instantaneous reading on the A or C Fox model #FT2A was greater than 300 scf/h, the measurement on the pneumatic device was repeated with the B meter to ensure that high leak rates were measured accurately. This happened only once during the measurement campaign, and for this single controller, the flow exceeded 300 scf/h only during a few seconds when the flow from an actuation was peaking (average whole gas flow rate over 15 min of sampling was 3.06 scf/h, a value lower than the average emissions per controller in the sampled population). A repeat test with the B instrument did not detect any actuations.

For each controller measurement using the supply gas flow meter, a site operator depressurized and disconnected the controller supply gas line; the flow meter was inserted and the system was reconnected, repressurized, and allowed to stabilize for several minutes before measurements began. Once the system had stabilized, measurements were made for approximately 15 min. Longer sampling times may have allowed a more complete measurement of emission rates from devices with relatively fewer controller actuations, but would have limited the number of controllers that could be sampled. Figure 1 shows representative 15 min emission time series for pneumatic controllers measured using the supply gas measurement.

All three Fox flow meters were calibrated by the instrument manufacturer and in laboratory testing, using methane. The instruments measure flow based on a thermal conductivity measurement. In this work, since gas composition information was available for each site where measurements were made, site specific correction factors were employed to estimate methane and whole gas emission rates. The method is described in SI Section S2. Results in this work are reported as both methane and whole gas emission rates, based on site specific gas composition data.

For some pneumatic controllers, it was not possible or safe to disrupt the supply gas to insert the supply gas flow meter, so exhaust gas measurements were used as the primary measurement on that subset of devices. Exhaust gas flow rate was measured using a Hi Flow instrument similar to that described by Allen et al.[21] Briefly, the Hi Flow Sampler is a portable, intrinsically safe, battery-powered instrument that has been used for several decades in measuring emissions of methane in the natural gas supply chain.[25−27] An emission source is enclosed, using attachments that come with the instrument; leak rate is measured by drawing air from the enclosure, through the sampler, at a high flow rate (up to 8−10 cfm) to capture all the gas emitted by the component, along with a certain amount of entrained surrounding air. By accurately measuring the flow rate of the sampled stream and the background corrected natural gas concentration within the sampled stream, the gas leak rate is calculated. Methane is measured, at concentrations less than approximately 5%, by a catalytic oxidizer unit coupled with a thermal conductivity detector. At methane concentrations greater than approximately 5%, concentrations are measured directly using a thermal conductivity detector. The instrument was calibrated using pure methane and a mixture containing 2.5% methane. The instrument reading based on the methane calibration was corrected for gas composition using site specific gas composition data and laboratory data, as described in SI Section S2. The commercial Hi Flow instrument is designed primarily to measure methane leaks that have a relatively steady flow and flow rates are not normally automatically recorded at high frequency. For this work, the instrument software was modified by the manufacturer to output data every 2−3 s. A 0.3−0.5 Hz reporting frequency was selected based on residence times expected in the leak enclosures at the maximum flow rate of the Hi Flow device (at a 10 cubic feet per minute sample flow, gas in a 1 ft^3 sample enclosure has a residence time of 6 s). As with the in-line supply gas measurement, Hi Flow data were collected for approximately 15 min for each controller. A time series from the Hi Flow device, along with a parallel measurement made using a supply gas meter, is shown in Figure 2. The Hi Flow device, because it entrains ambient air in a long sample loop, dampens some of the peak rate. Therefore, the Hi Flow is not able to resolve high frequency actuations as well as the in-line supply measurement. For 24 controller measurements, both supply gas and Hi Flow measurements were made to compare the two measurement methods (for these controllers, the supply gas flow was treated as the primary measurement). The detailed results are provided in SI Section S3. To summarize, 11 of the 24 simultaneous measurements had emissions of less than 0.005 scfh (46%), as recorded by the in-line supply gas meter (the primary measurement device). For five devices which had an average emission rate greater than 6 scfh (measured by the supply gas meter) the supply gas meter to Hi Flow measurement ratio was between 0.7 and 1.1.

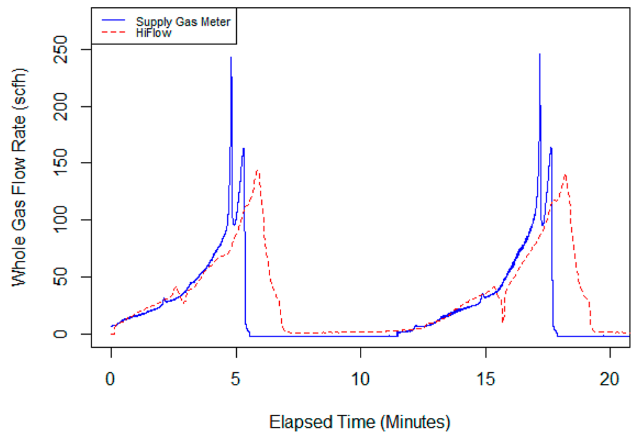

Figure 2. Comparison of supply gas meter (blue line) and Hi Flow measurements (red line) for device LB07-PC04, which was a water level control on a separator. The average emission rate measured by the supply gas meter was 27.0 scf/h as compared to 33.9 scf/h measured by the Hi Flow. Note that the time lag, longer period of emission detection, and the reduced maximum flow rate associated with the Hi Flow measurement is expected because of the dilution that occurs with ambient air in the exhaust enclosure and the flow through the instrument.

RESULTS AND DISCUSSION

Methane emissions from 377 controllers were measured in this work and details of each of the individual measurements are available in SI Section S4. A relatively small subset of devices accounts for a majority of the emissions. At the high end of the emission rate distribution, 20 percent of devices accounted for 96% of whole gas and methane emissions. The 19% of devices that had emissions in excess of 6 standard cubic feet whole gas per hour (scf/h) accounted for 95% of all whole gas and methane emissions. At the low emission rate end of the distribution, more than half (51%) of the controllers had an emissions rate less than 0.001 scf/h over the 15 min sampling period; 62% had an emissions rate less than 0.01 scf/h over the 15 min sampling period.

The average emission rate for the 377 devices is 5.5 scf/h of whole gas (4.9 scf/h of methane), however, this average emission may be influenced by the estimated emission rates for devices that had no emissions over the 15 min sampling period. If the devices with no emissions detected over 15 min are assigned the lowest emission rate detected (0.001−0.01 scf/h), there is no change in the average emission rate. However, using this minimum detection limit approach may underestimate potential emissions for devices that had little to no detectable emissions over 15 min. Some of these devices may have relatively infrequent actuations that were not sampled. In principle, any device actuating less than four times per hour may not have been detected over a 15 min sampling period. To estimate the emissions from devices with no emissions detected over a 15 min sampling period, the average emission per actuation was calculated for controllers in each application. The average emissions per actuation were multiplied by an estimated frequency of actuation. For example, for separator level controllers, the average volume per actuation was estimated by averaging observed volumes per actuation for separator level controllers; the average frequency of actuation for devices, for which no actuations were observed, was estimated by extrapolating observed actuation frequency data for controllers in separator level control service. A variety of assumptions can be made in extrapolating actuation frequencies. Details of a variety of approaches are available in SI Section S5. Using a variety of approaches, the estimated average emissions associated with devices with no emissions recorded over a 15 min sampling increases the population average emissions by 2−11%. Because this increase is relatively small, for clarity, all of the data reported in this work are based on

Table 2. Whole Gas Emissions from Controllers (scf/h), Categorized by Region and Application[a]

		average whole gas emission rates from controllers (scf/h), categorized by the application								
region	all devices	separator	process heater	compressor	wellhead	plunger lift	dehydration system	flare	sales	avg. w/o compressors
AP	1.7	0.3	1.3		2.8	0.0				1.7
GC	11.9	16.3		10.6	0.0	7.3	4.3	0.0	0.0	12.0
MC	5.8	4.9	0.0	20.2		6.5				4.4
RM	0.8	1.5	0.2		0.4	0.1	0.0	0.0		0.8
average	5.5	8.1	0.5	14.0	1.2	4.1	3.0	0.0	0.0	5.0

[a]Numbers of devices sampled in each category are reported in Table 1.

actual measurements, not including additions to the emissions for devices with low (0.001−0.01 scf/h) observed emissions.

To estimate an uncertainty bound on the overall average, a bootstrapping process was used.[28] In the bootstrapping procedure, the original data set of 377 devices was recreated by making 377 random device selections, with replacement, from the data set. A total of 1000 of these resampled data sets were created and the mean value of the emissions for each resampled data set was determined. The 95% confidence interval for the average whole gas emission estimate of 5.5 scf/h is 4.0−7.2 scf/h, where the bounds represent the 2.5% and 97.5% percentiles of the means in the 1000 resampled data sets. Similarly, the 95% confidence interval for the average methane emissions estimate of 4.9 scf/h is 3.6−6.5 scf/h.

The measurements showed significant variations among regions, the controller application, and whether the device was continuous vent or intermittent vent. Table 2 summarizes the distribution of emission rates among controllers in various applications, and shows the regional distribution of controller emissions. Measurements made on pneumatics in service on compressors had average emission rates of 14.0 scf/h (12.4 scf/h methane), compared to an average whole gas emission rate of 5.5 scf/h (4.9 scf/h methane) for all devices. Devices in use for level control on separators averaged 8.1 scf whole gas/h (7.1 scf methane/h). Overall, 76% of devices measured with whole gas emission rates greater than 6 scf/h were in service on compressors or as level controllers on separators. Emission rates for continuous vent controllers (57 devices, average emissions of 24.1 scf/h whole gas, 21.8 scf/h methane) were higher than for intermittent vent devices (2.2 scf/h whole gas, 1.9 scf/h methane).

In addition to varying by application and controller type (continuous vent or intermittent vent), emissions also varied by region. Emissions were highest in the Gulf Coast and Mid-Continent regions and were lowest in the Rocky Mountain and Appalachian regions (see SI, Section S4, for geographical boundaries of regions). Controllers on compressors, with high average emissions, were only observed on sampling sites in the Gulf Coast and Mid-Continent regions, so some of the regional differences can be attributed to the presence of compressors. As shown in Table 2, however, if average emissions by region are recalculated without including controllers associated with compressors, the Gulf Coast and Mid-Continent regions still had average emissions greater than those observed in the Rocky Mountain and Appalachian regions.

Another factor that may account for regional differences in emission rates is frequency of actuation. For example, controllers on separators in the Gulf Coast could actuate more frequently due to higher liquid production rates, which could explain higher emission rates in that region. However, the frequencies of actuation for the devices in Gulf Coast were similar to those in most other regions, indicating a larger emission per actuation for the devices in the Gulf Coast, rather than more frequent actuation. In contrast, the Appalachians showed a considerably higher frequency of actuations and a smaller emission rate, indicating a smaller emission per actuation for those devices (Table 3). Thus, regional differences in pneumatic controller emission rates cannot be completely explained by frequency of actuation of controllers, or by controllers associated with compressors and separator level control (Table 2); much of the difference may be due to differences in controller type (continuous vent vs intermittent vent) among regions. Continuous vent devices, with average whole gas emissions of 24.1 scf/h, were 21% of the controllers in the Gulf Coast and Mid-Continent regions, but only 9% in the Appalachian and Rocky Mountain regions.

Table 3. Frequency of Actuations and Emissions from Intermittent Vent Controllers Where Actuations Were Observed, Categorized by Region

region	count of devices	frequency of actuations (#/min)	avg. emission rate (scf/h)
AP	8	2.42	4.85
GC	30	0.37	20.5
MC	17	0.93	5.05
RM	25	0.43	1.72
total	80	average: 0.73	average: 9.76

This data set of emissions from pneumatic devices has elements that are similar to and different from the previous data sets reported for the United States,[21] and for British Columbia and Alberta.[24] The primary similarity is that all three data sets indicate that a small population of devices dominates total emissions. In this work, 19% of devices with emissions greater than 6 scf/h of whole gas account for 95% of the whole gas and methane emissions. In the previous measurements reported by Allen et al.,[21] 20% of devices account for 80% of the whole gas emissions and 41% of devices with emissions greater than 6 scf/h of whole gas, account for 90% of the whole gas emissions (88% of the methane emissions). In the measurements for British Columbia and Alberta[24] (referred to here as the British Columbia data), which were restricted to pneumatic devices with manufacturer reported bleed rates greater than 4.2 scf/h, 44% of devices with emissions greater than 6 scf/h accounted for 91% of emissions. Both the British Columbia data and the measurements reported in this work had large numbers of devices for which no emissions were detected during the sampling period. For the British Columbia data (again, focused on devices with manufacturer reported bleed rates in excess of 4.2 cfh), 31% of measurements had no detectable emissions over a 30 min sampling period; in this work 62% of devices had emissions less than 0.01 scf/h over the 15 min sampling period.

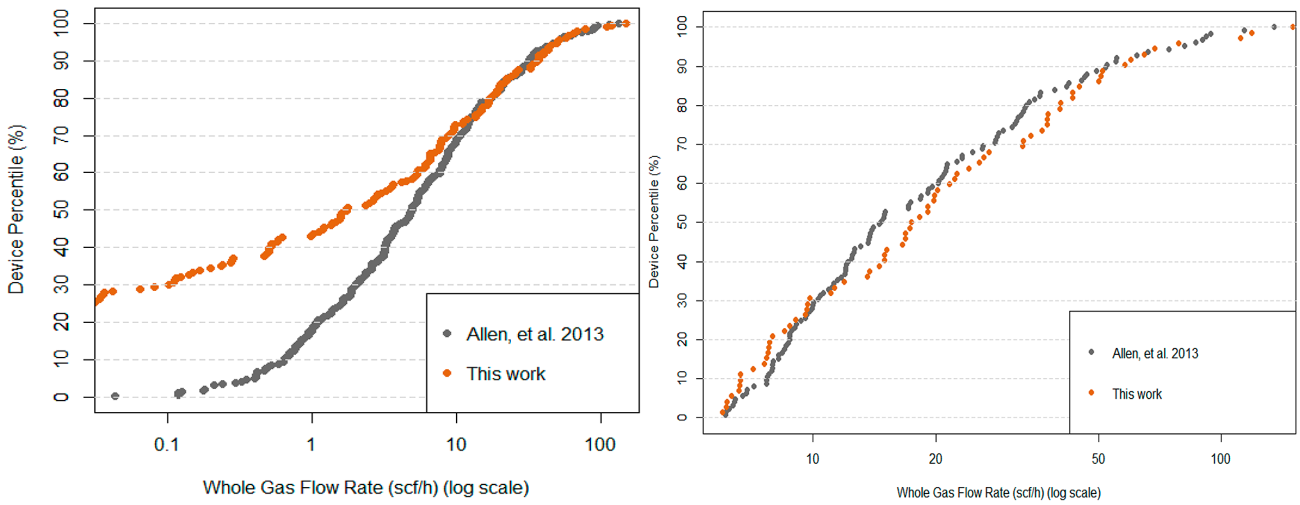

Figure 3. Distributions of emissions for subsets of controllers (38% of devices measured in this work) venting greater than 0.01 scf/h (left) and subsets of controllers venting greater than 6 scf/h of whole gas (right) as reported in this work (the 19% of devices that account for 95% of emissions) and Allen et al.[21]

The overall average emission rates reported in this work are lower than the previous data sets reported by Allen et al.[21] for the United States, and for British Columbia and Alberta.[24] For the British Columbia data this can be attributed to the sampling design for that data set, which selected devices with manufacturer reported bleed rates in excess of 4.2 scf/h. These controller types tend to be found in particular applications. When the emissions from the British Columbia data set are compared to the emissions reported in this work, for devices in similar applications, the results are in reasonable agreement. For example, for the separator controllers that were the most frequent application observed in this work, the British Columbia data report an average emissions rate of approximately 7.8 scf/h (level control) while the average for this work was 8.1 scf/h (separator application).

The lower average emission rates reported in this work, compared to those reported by Allen et al.[21] is primarily due to the number of controllers with no emissions detected over the sampling period. Figure 3 compares emission rates for controllers sampled in this work, with emissions rates reported by Allen et al.[21] The results show reasonable agreement between the two studies for controllers with emissions above 6 scf/h. These controllers accounted for 95% of the emissions in this work and 90% of the emissions in the sample reported by Allen et al. (2013).

The primary reason for the differences in the average emission rates reported in this work and in Allen et al.[21] is the higher percentage of low emission devices (<0.01 scf/h) observed in this work. This could be due to multiple factors. In this work, all controllers on-site were sampled, regardless of whether they would be reported through emission inventories. For example, emergency shut-down (ESD) controllers represented 12% of the sampled population in this work. These controllers do not have planned actuations, so they would not have been sampled in the work of Allen et al.,[21] and they may or may not be included in controller counts in national emission inventories. In addition, in the work of Allen et al.[21] about 40% of the inventoried controllers on sites were sampled; while these were intended to be selected randomly from inventoried controllers, there may have been an unintentional bias toward devices that were observed, with an infrared camera, to have emissions.

Implications for National Emission Estimates. As shown in Table 4, if regional average emission rates determined in this work are multiplied by regional controller counts reported in the 2012 EPA national greenhouse gas emission inventory (2012 GHG NEI, released in 2014), the national methane emission estimate for pneumatic controllers in natural gas service is 313 Gg/yr (within 10% of the 2012 GHG NEI estimate of 334 Gg). If the national average of the emission rates measured in this work (5.5 scf/h of whole gas, or 4.9 scf/h of methane) is multiplied by the total national equipment count in the 2012 GHG NEI (477 606 controllers) the national methane emission estimate is 394 Gg/yr, 17% higher than the 2012 GHG NEI estimate of 334 Gg. Adding an additional 2–11% to the estimated emission totals to account for potential emissions from controllers that had less than 0.01 scf/h of emissions over 15 min, would only slightly change these comparisons with the 2012 GHG NEI. This estimate may represent a lower bound on national emissions, however, since the average emissions per controller observed in this work includes some low- or nonemitting devices, such as ESD controllers, that may not be included in the count of national controllers. If the average emissions per controller from this

Table 4. National Emission Estimates, Based on Regional Device Counts for Pneumatic Controllers and Regional Average Emissions Measured in This Work

region	count of devices	avg. emission rate whole gas(scfh)	avg. emission rate methane (scfh)	regional emissions (Gg/yr)
AP	77 261	1.70	1.65	21.5
GC	53 436	11.80	10.61	95.4
MC[a]	222 684	5.80	4.87	182.5
RM[b]	124 225	0.75	0.67	14.0
total	477 606			313.4

[a]MC totals include equipment counts for Mid-Continent and Southwest regions reported in the 2012 EPA GHG NEI. [b]RM totals include equipment counts for Rocky Mountain and West Coast regions reported in the 2012 EPA GHG NEI.

work were recalculated with ESD controllers excluded, the average emissions would increase by approximately 15% (see SI, Section S7).

The inclusion or exclusion of ESD controllers in national pneumatic controller counts is just one part of the uncertainty associated with the total count of controllers. The average number of controllers per well observed in this work (2.7 controllers per well) was higher than the average number of controllers per well (1.0 controllers per well) reported in the 2012 GHG NEI, potentially indicating an under-count of controllers in the GHG NEI. Some of the difference between the controllers per well observed in this work and the average pneumatic controllers per well in the GHG NEI is due to wells that use mechanical or other nonpneumatic controllers; as an example of how an alternative controller count could influence national emission estimates, if 75% of wells in the United States have an average of 2.7 pneumatic controllers per well (the remainder having nonpneumatic controllers), and if 75% of the controllers on well sites are inventoried as having emissions, the total count of pneumatic controllers would double the level in the current inventory, roughly doubling emissions to 600 Gg (see SI). It was beyond the scope of this work to develop new national pneumatic controller counts, but the data reported here indicate that this is a topic that merits attention.

Characteristics of High Emitting Devices. Because average emissions are strongly influenced by the highest emitting devices, the characteristics of the 40 controllers with highest emissions rates were examined in detail by experts in pneumatic device operation. These characterizations included the service type, region of use, device type, the numbers of actuations and other temporal features of the emission time series. Based on these analyses, many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design. For example, some devices not designed to bleed continuously had continuous emissions. This could be the result of a defect in the system, such as a crack or hole in the end-device's (control valve's) diaphragm actuator, or a defect in the controller itself, such as fouling or wear. No additional troubleshooting analysis was performed on these high emitters, so the actual root causes are not known with certainty. The results, however, do indicate that some of the high emissions were caused by repairable issues. Details are provided in the SI (Section S8).

ASSOCIATED CONTENT

Supporting Information

Additional material as described in the text. This material is available free of charge via the Internet at http://pubs.acs.org/.

AUTHOR INFORMATION

Corresponding Author

*Phone: 512-475-7842; e-mail: allen@che.utexas.edu.

Present Address

[∇]Environmental Defense Fund, 301 Congress Avenue, Suite 1300 Austin, Texas 78701

Notes

The authors declare the following competing financial interest(s): Lead author David Allen serves as chair of the Environmental Protection Agencys Science Advisory Board, and in this role is a paid Special Governmental Employee. He is also a journal editor for the American Chemical Society and has served as a consultant for multiple companies, including Eastern Research Group, ExxonMobil, and Research Triangle Institute. He has worked on other research projects funded by a variety of governmental, nonprofit and private sector sources including the National Science Foundation, the Environmental Protection Agency, the Texas Commission on Environmental Quality, the American Petroleum Institute and an air monitoring and surveillance project that was ordered by the U.S. District Court for the Southern District of Texas. Adam Pacsi and Daniel Zavala-Araiza, who were graduate students at the University of Texas at the time the work in this paper was done, have accepted positions at Chevron Energy Technology Company and Environmental Defense Fund, respectively. John Seinfeld served as a consultant for Shell in 2012. A. Daniel Hill owns ExxonMobil, BP, and ConocoPhillips stock, serves on the Advisory Board for Sanchez Oil and Gas, for which he is compensated, and has been a consultant for Schlumberger and numerous oil and gas operating companies..

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Assessment of Uinta Basin Oil and Natural Gas Well Pad Pneumatic Controller Emissions

Eben D. Thoma[1*], Parikshit Deshmukh[2], Russell Logan[2], Michael Stovern[3], Chris Dresser[3], Halley L. Brantley[4]

[1]Office of Research and Development, National Risk Management Research Laboratory, U.S. EPA, Durham, NC, USA
[2]Jacobs Technology Inc., Durham, NC, USA
[3]Region 8, U.S. EPA, Denver, CO, USA
[4]ORISE Participant, U.S. EPA Office of Research and Development, National Risk Management Research Laboratory, Durham, NC, USA
Email: *thoma.eben@epa.gov

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Abstract

In the fall of 2016, a field study was conducted in the Uinta Basin Utah to improve information on oil and natural gas well pad pneumatic controllers (PCs) and emission measurement methods. A total of 80 PC systems at five oil sites (supporting six wells) and three gas sites (supporting 12 wells) were surveyed, and emissions data were produced using a combination of measurements and engineering emission estimates. Ninety-six percent of the PCs surveyed were low actuation frequency intermittent vent type. The overall whole gas emission rate for the study was estimated at 0.36 scf/h with the majority of emissions occurring from three continuous vent PCs (1.1 scf/h average) and eleven (14%) malfunctioning intermittent vent PC systems (1.6 scf/h average). Oil sites employed, on average 10.3 PC systems per well compared to 1.5 for gas sites. Oil and gas sites had group average PC emission rates of 0.28 scf/h and 0.67 scf/h, respectively. This difference was due in part to differing site selection procedures used for oil and gas sites. The PC system types encountered, the engineering emissions estimate approach, and comparisons to measurements are described. Survey methods included identification of malfunctioning PC systems and emission measurements with augmented high volume sampling and installed mass flow meters, each providing a somewhat different representation of emissions that are elucidated through example cases.

Keywords

Pneumatic Controller Emissions, Oil and Natural Gas Production, Uinta Basin, Methane, Volatile Organic Compounds

1. Introduction

Oil and natural gas (ONG) well pad operations employ natural gas (NG)-driven pneumatic controllers (PCs) for production process control and safety functions [1]. As part of regular operations, typical well pad PCs are designed to emit a small quantity of NG to the atmosphere. Because of the large numbers of PCs in use, methane (CH_4) emissions associated with this source category contribute significantly to total greenhouse gas (GHG) emissions for the ONG sector. Currently, pneumatic devices, including PCs, account for well over 30 percent of methane emissions, making them among the largest source categories in ONG production field operations [2]. Since the emitted field NG contains a small percentage of higher chain hydrocarbons, PCs also contribute to volatile organic compound (VOC) emissions for the sector. To support environmentally responsible development of these U.S. energy assets, it is of ongoing importance to continually improve information on the number, type, operational conditions, and emissions of well pad PCs, as well as methods to characterize these emissions.

In the fall of 2016, an on-site study of 80 PC systems on eight Utah ONG well pads was conducted in cooperation with three Uinta Basin operators. The goals of the limited-scope effort were to build on existing PC emission research performed in other ONG basins [3] [4] [5] [6], help advance PC emissions survey and measurement methods, and inform Uinta emissions inventories to the extent possible. The procedures used in this project were adapted from the Oklahoma Independent Petroleum Association (OIPA) study [3], that cataloged 680 PCs on 162 Oklahoma sites using on-site surveys and engineering emission estimates (EEEs), and Allen *et al.* [5], who sampled 125 PCs in the Rocky Mountain (RM) region, and many more in other ONG basins, using measurement methods similar to methods employed here. Following an introduction to PC types, emission survey and measurement methods are described, and field results are discussed and compared to other studies. A supplemental data file (SF1), with supporting quality assurance (QA) archive files (AFs), is contained on the United States Environmental Protection Agency (U.S. EPA), Environmental Dataset Gateway [7]. A list of acronyms and abbreviations used in this paper is contained in the final section.

Well pad PCs convert a sensed process variable (e.g. mechanical float level, temperature, gas flow, pressure) to a pneumatic valve actuation to control a process or execute a safety function. The expected air emission profile of an NG-driven PC system depends on its design and physical dimensions, the process application and the characteristics of the well pad and product, and on the maintenance state of the PC system. Some NG-driven PCs are designed not to emit to the atmosphere, and a growing number of well pad safety and control value actuation systems are electronically sensed and electrically controlled, producing no NG emissions. These categories of control devices are not considered in this project, nor are other pneumatic devices such as chemical injection pumps, tank pressure relief devices, or non-venting pressure regulators. The potential secondary emissions effects of malfunctioning PC systems are not considered. General fugitive or vented emissions from well pad systems are not part of this study, but when found during field measurements were noted to the operator so corrective action could be pursued if necessary.

In a simplified form, there are four major categories of NG-emitting PCs with definitions based on the combination of the system depressurization method and service type [1]. The depressurization method of a PC relates to its primary venting mode and can be either continuous (CPC) or intermittent (IPC) in time. As part of normal operation, a CPC emits at a relatively constant rate that is modulated or temporarily spiked during the actuation event, (e.g. to open or close a valve in response to a process signal). An IPC has a physical barrier between the NG supply and the atmosphere and emits primarily in short bursts, typically a few seconds in duration as part of each actuation event.

For each depressurization method, there are two primary PC service types that relate to the degree of valve actuation, and hence the amount of NG released. Some well pad processes require valves to be actuated in a fully "on/off" fashion, whereas other processes require a "throttling" action where the valve set point varies in response to the control loop signal. The amount of NG released during the actuation event of an on/off controller is approximated by the entire volume space of the PC system (including the PC, the valve actuator bonnet, and the connecting tubing), whereas a throttling controller represents a fraction of this volume. Within these four major categories, there are several possible PC subtypes, hybrid combinations, add-on relays, and retrofit packages (designed to reduce emissions from high-bleed CPCs), but these variations were not a factor in the current study so are not discussed. Representative examples of PCs encountered in this study are shown in **Figure 1**.

From an emissions assessment standpoint, CPC and IPC systems can be viewed as possessing both a constant and a periodic emissions component, with the latter associated with the actuation event. For CPCs, the relatively constant component of emissions is determined by the engineered orifice size and is called the "bleed rate". The constant component of emissions for an IPC is called the "seepage rate" and is present because it is not possible to make metal to metal seals completely tight under real world conditions [1]. The seepage rate for properly maintained IPC systems should be very low, on the order of 0.05 standard cubic feet per hour (scf/h), as specified by one manufacturer [3]. For both CPCs and IPCs, it also necessary to know the emissions associated with the periodic, short duration actuation events as well as the frequency of occurrence of these events.

Superimposed on the designed emissions are emissions associated with the maintenance state of the PC system. If a PC is not well-maintained or malfunctioning, the emissions from the system can increase significantly. For example, the designed seepage rate of an IPC system may be very low, but the pilot seal quality may degrade overtime due to routine use or debris that prevent proper sealing, causing continuous emissions through the PC exhaust port (or weep

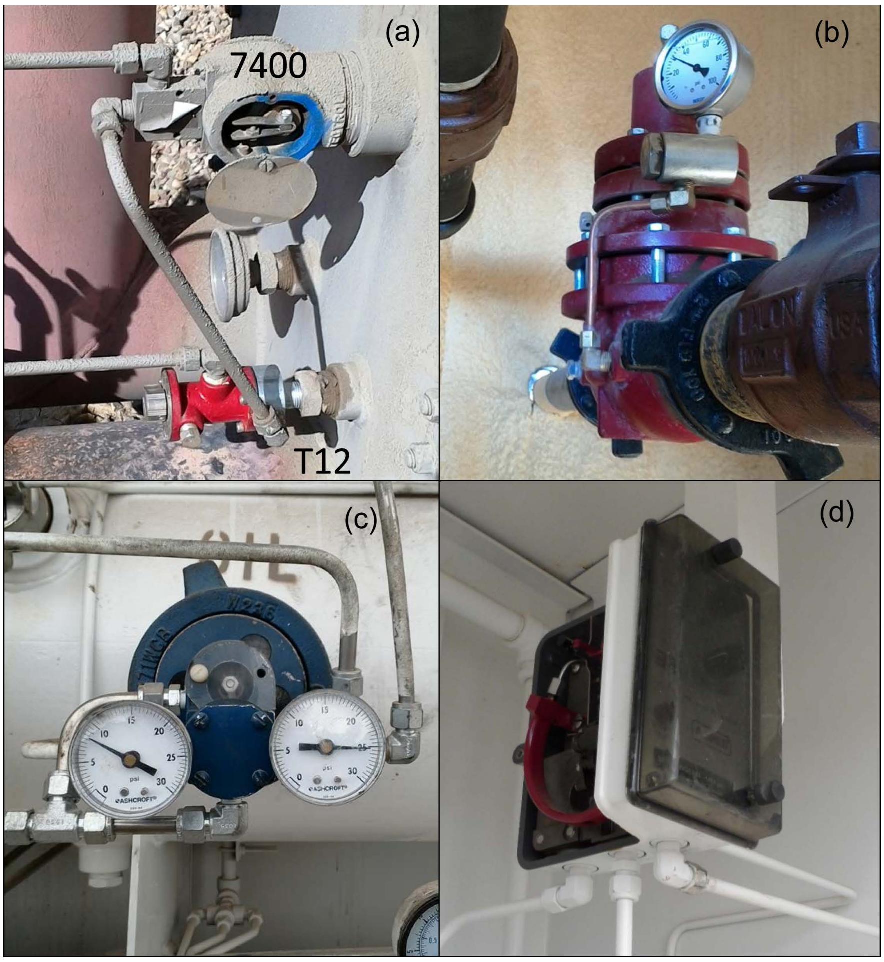

Figure 1. Example PCs encountered in this study: (a) WellMark 7400 IPC level and Kimray T12 temperature IPC; (b) Kimray back pressure regulator IPC; (C) WellMark 6900 level controller IPC; and (d) Fisher™ 4660 high-low pressure pilot CPC with side cover removed.

hole) that can be are orders of magnitude higher than the designed rate. Malfunctions can also manifest as emissions from failures in seals or diaphragms in other parts of the PC body or actuator or could be caused by issues with the process the PC is designed to control.

For any analysis of PC emissions, it is critical to define the components that make up the system. The part of the PC system that controls action is called here the "pilot", and the subsystem that executes action is called the "actuator" and includes the valve creating the process change. If the pilot and actuator are contained in the same housing, the PC system is called "integral". If the pilot and actuator are physically separated it is referred to here as a "pilot-actuator PC". For this analysis, emissions from any subsystem, including the tubing connecting the pilot and actuator, are considered PC system emissions. This inclusive definition is necessary to elucidate differences in measurement methods and is informative for other reasons, but may not comport with regulatory definitions that could ascribe some of these emissions to general fugitives or equipment leaks.

Regarding emission factors for PC systems, a large range exists with the U.S. EPA's GHG Inventory using whole gas device emission rates of 37.3 scf/h and 1.39 scf/h for high and low bleed CPCs, respectively, and 13.5 scf/h for IPCs [8]. For applicable well pads and other ONG facilities, the U.S. EPA defines a maximum emission rate limit for CPCs of 6 scf/h under 40 CFR Part 60 Subpart OOOO and OOOOa Standards [9]. Considering studies in basins near Utah, OIPA [3] calculated average emission rates of 21.54 scf/h and 0.40 scf/h for CPCs and IPCs, respectively, with an overall average of 1.05 scf/h for Oklahoma sites. With flow meter measurements in the RM region, Allen *et al.* [5] found 7.23 scf/h and 0.31 scf/h for CPCs and IPCs respectively with an overall average of 0.8 scf/h. These RM region values were significantly lower than Allen's measurements in other U.S regions with differing production profiles, and also lower than the Prasino Group's study in British Columbia [6]. Driven by basin-specific product extraction and processing demands, well pad engineering differences clearly play a major role in determining regional PC emission factors.

The Uinta basin has both NG and waxy crude oil production well pads with process engineering and PC populations potentially dissimilar to each other and to other basins. In this study, a multistep on-site survey approach was used to gather information on PC populations, assess maintenance states, and execute emissions measurements. In addition to gaining insight on Uinta Basin PC emission profiles, the effort provided some perspective on assessment of PC systems with less invasive tools readily available to operators and inspectors. Use of installed flow meter measurements in both supply line and exhaust port configurations provided additional information on PC system emissions and data for comparisons to EEEs and to other studies. The variety of measurement approaches utilized allowed the strengths and weaknesses of the methods and definitional aspects of PC systems emissions to be explored.

2. Methods

2.1. Site Description

The cooperating Uinta Basin ONG operators selected the sites that were surveyed and provided site access and on-site technical support for the project. A total of five waxy crude oil well pads, supporting six oil wells in total, and three NG gas well pads, supporting 12 gas wells in total, were surveyed over six field days. Each company used their own site selection criteria with most sites considered to be relatively well-maintained and subject to regular company inspections, as defined by each company's policy, with inspection frequencies ranging from weeks to months. One of the eight well pads (Gas Site 3) was intentionally chosen to be an older site, without benefit of recent company inspection. The selection process did not systematically consider the regulatory or permit status of the sites. **Table 1** provides information on the well pads that were surveyed including the number of wells, date of first production for the first and last wells on site and the cumulative production of oil, produced water, and NG in thou

Table 1. Site information and cumulative well pad production for the surveyed sites.

Site	No. of Wells	Prod. Start	Oil	Water	Gas
	(N)	(MM/YY)	(Mbbls)	(Mbbls)	(Mscf)
Oil 1	1	11/2012	70.9	100.8	22.4
Oil 2	2	07/2006, 07/2014	96.5	106.1	8.4
Oil 3	1	03/2015	32.3	28.4	7.6
Oil 4	1	04/2015	26.2	33.5	12.0
Oil 5	1	01/2015	88.4	186.2	40.1
Gas 1	4	06/2000, 8/2000	6.3	16.8	2818.9
Gas 2	3	04/1982, 12/1999	9.4	12.0	3300.8
Gas 3	5	08/1983, 12/1998	9.1	17.4	4594.0

sands of barrels (Mbbls) and standard cubic feet (Mscf).

Each of the oil well pad sites sent their produced field gas, (referred to as "sales gas"), for off-site drying, then returned the majority of this processed gas (now called "fuel gas") to the well pads to operate the PCs and other process functions, such as heaters. Some PCs associated with the separators or (heater treaters) on the oil sites emitted sales gas directly. The gas well pad sites utilized sales gas tapped off the driest part of the process (e.g., highest point of liquids separator) to directly operate PCs and other functions.

2.2. PC System Assessment Methods

This study employed QA-augmented versions of methods used in previous studies in other ONG basins [3] [4] [5]. The on-site PC assessment procedures consisted of: (1) information gathering, (2) emissions screening with optical gas imaging (OGI) and hand-held probe (HHP) emissions detection, (3) emissions measurement with augmented high volume sampling (HVS) and (4) installed mass flow meters (MFMs), and (5) calculation of EEEs for the PC systems that were encountered. All instrumentation was calibrated to and/or checked with certified high purity CH_4 (various manufacturers). Whole gas emission rates were measured for a subset of the PC systems with instrument response corrected for gas composition differences and other factors and reported for standard conditions of 20.0˚C and 1013.25 hPa (SF1) [7]. Additional information on auxiliary equipment and procedures can be found in AF [7]. The equipment used in this study was not uniformly certified as intrinsically safe for use in hazardous environments. Extreme caution, pre-operation emission safety checks, personal safety monitors, and operator oversight were used to ensure safe operations.

(1) Information Gathering: Details of PC systems and their functions were gathered through on-site survey and discussion with the ONG operators. Photos of the PC systems and process information such as supply pressures (where possible) were acquired. The PC systems were identified as pilot-actuator or integral type and the manufacturer, model, depressurization me-

thod (CPC or IPC), and service type (on/off or throttle) of the PC system was determined. The physical dimensions of the PC system components and connecting tubing were measured for calculation of EEEs (SF1, Data1) [7].

(2) Emissions Screening: Both standard and high sensitivity mode OGI observation of each PC system was conducted using a FLIR GF320 (FLIR Inc., North Billerica, MA, USA). General information on OGI is discussed elsewhere [10]. HHP leak detection of each PC system was performed, primarily using a PPM Gas Surveyor 500 (Gas Measurements Instruments, Ltd., Renfrew, Scotland), with a TVA-1000B (Thermo Scientific, Waltham, MA, USA), and other HHPs [7] additionally used in some cases. With close in (short distance) inspection, under low effective wind speeds (inside equipment cabinets and sheds), OGI is believed to have routinely detected PC emissions at 1.0 scf/h and above for this project. On-component inspection with parts per million (ppm) sensitivity HHPs routinely detected emissions <0.1 scf/h. These direct HHP observations did not represent an emissions measurement and cannot be compared to leak detection limits used in other regulatory and compliance programs as direct coupling of an HHP to the exhaust port of the PC can yield an extremely sensitive emission detection, potentially of designed seepage rates.

(3) HVS Emissions Measurements: For PC systems that exhibited continuous emissions in Step (2), an augmented HVS emissions measurement was performed using a Bacharach Hi Flow® Sampler (Bacharach, Inc., New Kensington, PA, USA). This instrument was the only commercially available HVS for NG measurements and is described elsewhere [4] [5] [11] [12] [13]. The augmented QA protocol was necessitated by previous observations of potential HVS malfunction [11] [13] when measuring mixed hydrocarbon (HC) emission streams. The protocol included a pre-deployment instrument update and check-out by the manufacturer, standard HVS sensor calibrations (typically daily with 2.5% and 100% CH_4), multiple in-field mass flow controller-based simulated emission tests to confirm overall HVS operation, and 100% HVS exhaust stream checks with the HHP to confirm each measurement. Figure 2(a) illustrates an HVS measurement of a CPC with the HHP exhaust stream QA check. With a maximum of 1.9% and an average of 0.3% HVS exhaust stream HC concentration, all field HVS measurements were well below the previously observed sensor transition failure level of approximately 5% HC concentration, thus eliminating a major source of HVS uncertainty for this particular data set. Simultaneous OGI was used to help ensure plume capture in most cases. The minimum quantification limit (MQL) of the augmented HVS approach was determined to be ≈ 0.2 scf/h, using the HHP probe for readings < 0.4 scf/h in some cases (SF1, Figure S1) [7]. The uncertainty of the HVS approach was estimated at ±30% with combined correction factors for mixed HC streams and instrument flow rates ranging from +10% to +22% (SF1, Data2) [7]. Due to relatively low sampling rates (~ 0.3 Hz) and multi-second stabilization times, the HVS was limited to measure-

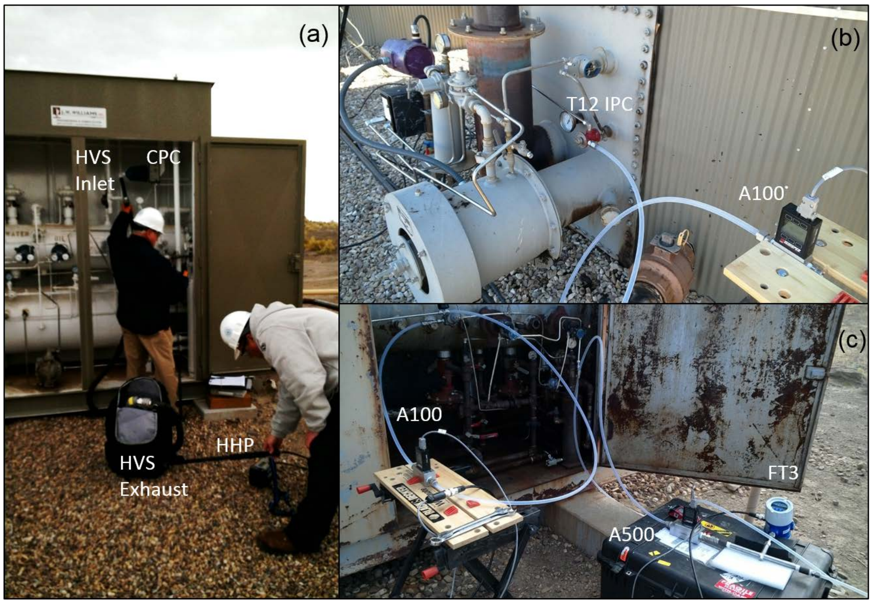

Figure 2. Examples of HVS and installed MFM measurements (a) HVS of Fisher™ 4660 CPC with HHP exhaust check; (b) Alicat MFM installed on exhaust port of Kimray T12 IPC; (c) supply line measurement of two WellMark 6900 IPCs with Alicat and Fox MFMs in series (right), and a Fisher™ 4660 CPC with an Alicat MFM (left).

ment of relatively continuous emissions and was not used to assess the rapid (few second) manual PC actuation trials in this study. For instrument response correction purposes, representative evacuated canister grab samples (1.4L Silonite® 29-MC1400SQT, Entech Instruments, Simi Valley, CA, USA), were acquired at the exhaust port of the HVS and analyzed for speciated non-CH_4 organic compounds using U.S. EPA Method TO-1A [14] and CH_4 by U.S. EPA Method 18 [15], (SF1, Data2; AF [7]).

(4) MFM Emissions Measurements: Following Steps (1), (2), and (3), emissions from a subset of PC systems were measured using one or more installed MFMs [MW500SLPM, MW100SLPM, MW10SLPM (Alicat Scientific, Inc., Tucson, AZ, USA), FT3 (Fox Thermal Instruments, Marina CA, USA)], subsequently referred to as A500, A100, A10, and FT3, respectively. Data were recorded using a custom data acquisition system operating at 1 Hz (Techstar Inc. Deer Park, TX, USA). The system allowed simultaneous recording of all four MFMs and was fitted with 30 m cables so multiple areas of the well pad could be monitored. The Alicat MFMs were fast response (<100 ms), low pressure-drop laminar flow meters while the FT3 was a thermal MFM with 1-3 seconds response times with a similar model used by Allen *et al.* [5]. The FT3 was factory calibrated to CH_4 in two operational ranges, zero to 100 scf/h and zero to 500 scf/h, but only the former range was used. The MQLs of the MFMs were determined to be ≈ 0.5 scf/h, ≈ 0.2 scf/h, <0.1 scf/h, and ≈ 2.0 scf/h for the A500, A100, A10, and FT3, respectively, with an uncertainty estimate of ±10% with low bias increasing as MQL was approached for the A500 and FT3 (SF1, Figure S1) [7]. Instrument correction factors for mixed HC streams ranged from +2% to +7% for the A500, A100, and A10 and +3%

to +10% for the FT3 (SF1, Data2) [7]. The MFMs and HVS were checked with calibrated flow controllers before, after, and multiple times during the study with simulated emissions ranging from 0.1 scf/h to 160 scf/h and primary check points of 5.0 scf/h and 50.0 scf/h.

The MFMs were installed on either the exhaust port of the PC pilot [**Figure 2(b)**] or on the supply lines of one or more PCs systems [**Figure 2(c)**]. Exhaust port monitoring, which was not possible in all cases due to PC design, provided a focused view of the PC pilot emissions and was the only practical choice for MFM measurements of integral PC systems [e.g., **Figure 1(b)**]. Supply line measurements provided a more comprehensive view of the PC system, including emissions from connecting tubing and actuators, and potentially unrelated well pad systems present on the common supply. Following previous method critiques [11] [13] the HVS measurement was used prior to installation of the MFMs to avoid inadvertent PC malfunction reset during installation. The installed MFM tubing connections were leak-checked with OGI, HHP, and/or a soap liquid bubble test, and care was taken by the operator to set the supply pressure to 'as found' conditions. The MFM emissions measurements were typically performed for a time period of more than one hour in an attempt to observe the natural actuation rate of intermittent PCs. In many cases, manual actuation experiments were conducted at the end of the measurement cycle to produce data for comparison to EEEs. Unless otherwise specified, all MFM values reported here are from the Alicat models.

(5) Engineering Emission Estimates: Similar to the procedures used by OIPA [3], EEEs were developed for the PC systems that were encountered (SF1 Data1) [7]. A simplified emissions estimate equation (E) for each PC system was utilized:

$$E = Ce + Ae * Ar \tag{1}$$

where:

Ce = Continuous emission rate from PC system in scf/h

Ae = Emissions associated with a PC system actuation event in scf

Ar = Number of PC system actuation events occurring in one hour

As previously discussed, for CPCs, Ce is the orifice size-determined bleed rate with actuations appearing as a discrete or near-continuous modulation of this rate. For IPCs, Ce is the designed seepage rate for well-maintained systems and is conservatively assumed here to be 0.1 scf/h. This level is 50% of the HVS MQL and is easily detected by HHP. Continuous emissions from malfunctions of the PC system are also part of Ce, appearing primarily as an additive term to the designed Ce, but may also affect Ae. Using the physical dimensions of the measured connecting tubing, actuator model measurements and information, and process data, the physical volume of the actuators and the emissions per actuation event for the PC system were determined using a simplified ideal gas law approach developed by Kimray (AF [7]). Whereas OIPA [3] assumed four actuations per hour for infrequently actuating IPCs, this analysis employs five potential discrete actuation frequency bins for the PC systems; 1/month, 1/day, 1/h, 4/h, or 20/h. Consistent and rapidly actuating CPCs are assumed to appear as a modulated continuous emission with average emission rate values determined by measurement and safely ascribed to the *Ce.* In each case, a more frequent actuation bin is used for the EEE. For example, a tank temperature controller may actuate once per day in the summer or several times per day in the winter but a once per hour (1/h) bin is assumed in the EEE. Some information on natural PC actuation rates was available from aural observations (e.g. audible flow, burners firing, etc.), the MFM measurements of Step (4), and through limited trial application of simple diaphragm mechanical counters (SERN-5, Control Equipment Inc. Wichita Falls, TX, USA).

3. Results and Discussion

3.1. PC Types Encountered

A total of 80 in-service NG-emitting PC systems were found on the eight well pad sites and those PC systems were subjected to the survey procedures described in Section 2. Table 2 summarizes the total number of PCs, the number classified as IPCs, the average number of PCs per well, and the three most frequently encountered PCs on each site. Only three PC systems (4%) were classified as CPCs. Eighty-eight percent (88%) of the PC systems were identified as snap-action on/off controllers with the remainder the throttling variety. Fifty-eight percent (58%) of the PCs were used for process control with the reminder serving a safety or process protection function. Fifty percent (50%) of the PCs were associated with separators or heater treaters, 38% with tanks, 6% with enclosed combustors, and 6% with well control. Forty-five percent (45%) of the PC systems controlled or monitored liquid levels, 35% temperature, and 20% pressure.

The three CPCs were Fisher™ model 4660 high-low pressure pilots (Emerson Electric Co., St. Louis, MO, USA) that actuated safety shut-in valves on each of the gas sites [Figure 1(d)]. Kimray model T12 temperature controllers (Kimray

Table 2. PC type summary by site with intermittent vent (IPCs) accounting for 96% of the total.

Site	PCs	IPCs	PCs per Well	Three Most Common PC Types by Site
	(N)	(N)	(N)	Manufacturer, Model Family, (N)
Oil 1	15	15	15	WellMark 7400 (7), Kimray T12 (4), Kimray BP (3)
Oil 2	14	14	7	Kimray T12 (5), Wellmark 7400 (4), Kimray BP (2)
Oil 3	10	10	10	WellMark 7400 (5), Kimray T12 (4), Kimray BP (1)
Oil 4	12	12	12	WellMark 7400 (6), Kimray T12 (5), Kimray BP (1)
Oil 5	11	11	11	WellMark 7400 (6), Kimray T12 (3), Kimray BP (1)
Gas 1	6	5	1.3	WellMark 6900 (3), Kimray T12 (2), Fisher 4460 (1)
Gas 2	7	6	2.3	Kimray T12 (3), WellMark 6900 (2), Fisher 4460 (1)
Gas 3	5	4	1.0	WellMark 6900 (2), Kimray T12 (2), Fisher 4460 (1)

Inc., Oklahoma City, OK, USA) accounted for 35% of PCs encountered and were used for separator and tank burner control and temperature-related process protection functions [**Figure 1(a)**]. The WellMark 7400 Snaptrol level controller (WellMark LLC, Oklahoma City OK, USA) also accounted for 35% of the PCs surveyed and were frequently found in series with the Kimray T12 PCs, usually providing a tank or vessel liquid level burner shutoff protection in these cases [**Figure 1(a)**].

The WellMark 6900 snap-action level controller was prevalent at the gas sites accounting for 41% of the PCs on those well pads and 9% of the overall total. The four aforementioned PC types were of the pilot-actuator variety, which accounted for 89% of the PC systems surveyed. The last commonly encountered PC was the Kimray back pressure (BP) controller (10% of occurrences), which is an integral PC. Five of the remaining six PC systems were of the pilot-actuator type including three electronically controlled oil well shut-in safety devices, a "direct to sales" gas metering system, and an unidentified level controller. The last PC was an integral type Kimray venting pressure regulator.

The high percentage of IPC systems observed was similar to the percentage reported in the OIPA study [3] that found 97% of the 680 PCs surveyed were of the intermittent vent variety. In the RM region, Allen *et al.* [5] sampled 125 PCs, primarily from NG and condensate-producing sites (likely not including waxy crude oil sites), finding 91% IPCs. Allen *et al.* employed a measurement-based type assignment for CPCs that could include constantly emitting IPCs that are classified as malfunctions in this analysis. The most notable difference in the OIPA PC populations was that BP controllers were the dominant PC type (40%), a much higher percentage than we observed in the current study. This difference is believed to be primarily due to site production and engineering design factors, such as generally less need for gas pressure management, and the requirement to maintain a minimum crude temperature for waxy crude at the Uinta Basin oil sites.

Assuming the population of PCs measured in this study is representative of the basin, the difference between oil and gas site engineering is reflected in the large differences in the average number of PCs per well, 10.3 for oil sites, compared to 1.5 for gas sites. The latter may be depressed for the specific sites surveyed in comparison to the basin-average for gas sites as no plunger lift controllers were found and the front end well pressure control was accomplished with electrically actuated devices. The OIPA study found an even lower number of 0.85 PCs per well on average while Allen *et al.* found 2.7 PCs per well for all regions (includes non-pneumatic PCs), making the high number of PCs per well at the Uinta oil sites noteworthy.

3.2. Continuous Emissions and Malfunctions

For this analysis, a PC system is defined as all control loop components necessary to execute the process or safety function. Any significant (non-designed) emission, such as a leaking PC body, tubing connector, or actuator diaphragm, is considered a PC system maintenance issue or a malfunction (terms used interchangeably). Screening detects were expected and observed on the three CPCs (Fisher™ 4460). Since the 77 IPCs had low expected actuation periods (>15 minutes), sustained emissions observed with OGI and HHP and verified with HVS and/or MFM to exceed 0.2 scf/h, were defined as malfunctioning PC systems. Table 3 summarizes the emissions assessment surveys with focus on those identified as malfunctioning. Here the three continuous Fisher™ 4460 PCs at Gas Sites 1-3 are included in the HHP and OGI detection counts, but the HVS-measured emission rates (0.9 scf/h, 2.2 scf/h, and 0.3 scf/h, respectively) are assumed to be designed CPC venting and are therefore not included in malfunctioning PC emission rate column.

As expected, the HHP screen yielded a higher number of potential malfunction detects (28%) compared to OGI (16%), as even small emissions can be found with ppm-sensitivity HHP probes. Out of the 20 HHP detects on IPCs, 11 exhibited continuous emissions above the defined 0.2 scf/h malfunction level, as measured by HVS, with all of these detected by OGI. Malfunctioning IPCs exhibited emission rates ranging from 0.3 scf/h to 4.5 scf/h, with an average of 1.6 scf/h. The rate of PC malfunctions was 14.3 % for this study, 8.2 % for oil sites and 28% for gas sites; however, this difference is in part due to site selection factors. The malfunction rate varied widely over the sites from 0% to 60%. Three of the eight sites appeared to be very well maintained with a higher percentage of newer looking PCs and no observed malfunctioning PCs systems. Gas Site 3, an intentionally selected older, less frequently inspected site, had the highest percentage of malfunctioning PCs and possessed an older WellMark 6900 water dump valve controller (Figure 3) that exhibited the highest observed study emissions at 4.5 scf/h. This PC was found to be non-operational (would not actuate a dump) in manual actuation trials.

Table 3. Summary PC emission assessment surveys with focus on malfunctions.

Site	HHP Detects	OGI Detects	Malf. PCs	Malf. PCs	Malf. PC[1] Emission rate(s)
	(N, %)	(N, %)	(N, %)	Identity	(scf/h)
Oil 1	0, 0	0, 0	0, 0	N/A	N/A
Oil 2	4, 28	1, 7	1, 7	WellMark 7400 (actuator)	0.7
Oil 3	2, 20	2, 20	2, 20	Kimray T12 (2)	1.4, 3.4
Oil 4	1, 8	0, 0	0, 0	N/A	N/A
Oil 5	6, 55	3, 27	3, 27	Kimray T12, WellMark 7400, WellMark 7400 (actuator)	3.1*^, 0.3, 1.2
Gas 1	1, 17	1, 17	0, 0	N/A	N/A
Gas 2	4, 57	4, 57	2, 29	Kimray T12, WellMark 6900	0.4, 1.6*
Gas 3	5, 100	3, 60	3, 60	Kimray T12, WellMark 6900 (2)	0.3, 4.5*, 0.6

[1]Defined as malfunctioning (malf.) if continuous emissions >0.2 scf/h for IPCs or >6 scf/hr for CPCs [assumes a low bleed category for CPCs (9)]. All measurements were HVS, except (*) by Alicat MFMs. Emission rates are whole gas at standard conditions with gas stream composition correction factors applied. (^) Multiple PC systems with hidden tubing, location of emission not identified, 3.1 scf/h arbitrarily assigned to Kimray T12.

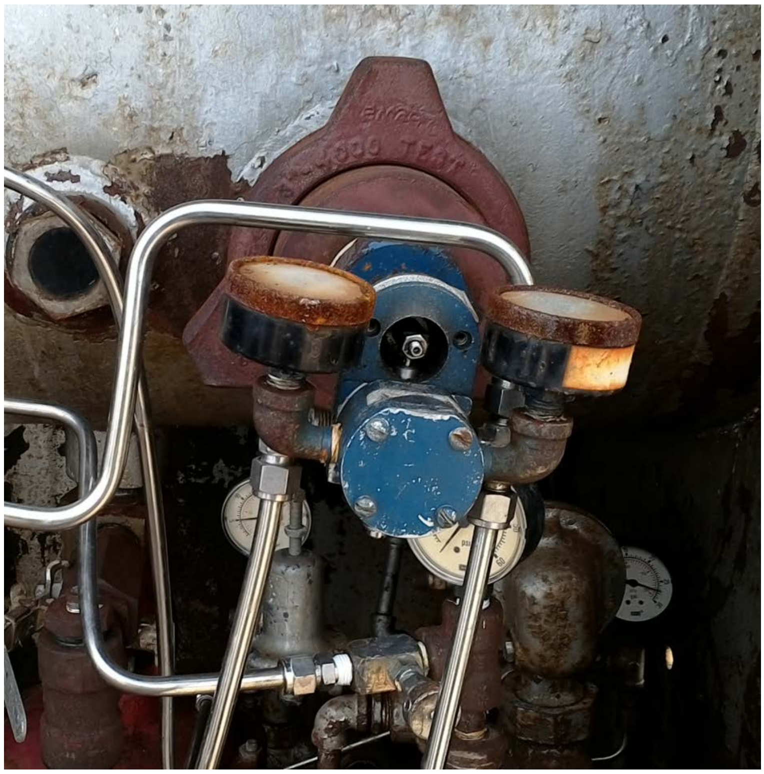

Figure 3. An older WellMark 6900 IPC found to be malfunctioning.

An important factor in the on-site survey assessment of the maintenance states of PCs and identification of the origin of emissions is related to the ability to observe and access the entire PC system. The 'entire PC System' refers to all normally external components, such as the pilot, actuator, and connecting tubing. In theory, part of the PC system, for temperature or level controls for example, extends inside the tank or vessel and may provide a path for emissions, but this route is not considered here. Starting with easily understood cases, some of the complexities of the PC system assessment and the advantages and disadvantages of particular measurement approaches are discussed.

Two straightforward examples of **Table 3** were the WellMark 7400 (actuator) cases (Oil Sites 2 and 5), which had emissions originating from the valve stem travel indicator of the Kimray 212 SMA PO actuator. In these cases, the entire PC system was fully observable and the emissions were easily identified by OGI and HHP, and measured by HVS. These malfunctions were repaired by the operator in a very rapid fashion by tightening the travel indicator, and the actuator was then confirmed to be emission free. Under other definitions, these emissions could be considered equipment leaks and not part of the PC system.

For the oil sites, Kimray T12 and WellMark 7400 PC systems [**Figure 1(a)**] commonly supported storage tank heating functions, accounting for 38% of all PCs and were easily observable and accessible. On Oil Site 3, two Kimray T12 tank burner controllers were emitting from the exhaust port and potentially the body of the controllers with HVS measurements of 1.4 scf/h and 3.4 scf/h for these units. Exhaust port MFM measurements of the same units were 1.0 scf/h and 1.7 scf/h, respectively, indicating that only a portion of the emissions were exiting the exhaust port and could be assessed with this MFM approach.

On Oil Site 5, the Kimray T12 horizontal separator temperature controller and an in-series WellMark 7400 fluid level safety shut-off PC were part of a complex system that once utilized a secondary burner control package (now by-passed) and had extended lengths of tubing, much of which was hidden inside the separator vessel insulation. MFM supply line measurements showed that this combined system had a continuous emission rate of 3.4 scf/h but HVS measurements could detect only 0.3 scf/h emissions from the body of the WellMark 7400 and were below detection limit on the Kimray T12. This complex system shared supply lines with several PCs, also with partially hidden lengths of tubing. An unidentified emission point was present but could not be located so the majority of MFM-determined emissions were arbitrarily assigned to the Kimray T12 (3.1 scf/h, Table 3). An HVS-only or exhaust port MFM measurement would underestimate PC system emissions in this case.

In a similar case, all PC system components of the malfunctioning Gas Site 3 WellMark 6900 dump valve (Figure 3) could not be assessed fully because the actuators were confined in the back of the cabinet. Even though this PC would not actuate (operational malfunction), and produced the highest emission rate as determined by MFM supply line measurements (4.5 scf/h), the initial HVS measurement indicated a 0.2 scf/h emission from the pilot, which changed as the operator attempted adjustments to regain functionality (subsequent to the initial MFM measurement). The operator could affect (and reduce to low levels) the supply line flow registered by the MFM pair [Figure 2(c), right] by adjusting the pilot all the way out but was unsuccessful in restoring functionality, and a later rebuild was required. The original point of emissions was uncertain, and it is possible the origin point was internal to the vessel.

In addition to PC component access, temporal variability in the PC system malfunction states must also be considered. As an example, at site Gas 2, a WellMark 6900 was found initially to be malfunctioning at a rate of 1.6 scf/h, but after several trial actuations, this rate was reduced without other adjustment to below 0.2 scf/h. Variable emissions were subsequently measured (0.3 to 1.3 scf/h) and we observed that even a small motion of the connecting tubing for this controller could change the continuous emission level of this PC. In another case, an experiment was performed on an infrequently actuated over-pressure protection PC. This PC was not emitting prior to the experiment but after a trial actuation, the PC pilot did not seal properly, likely due to long accumulated debris. An additional actuation cleared the issue and emission ceased. Similar behavior was observed in other cases, and it was evident that for these sites, manual actuation of some types of PCs was routinely performed by the operators to induce resets of potentially malfunctioning states or to check PC functionally.

Regarding the continuous emission (*Ce*) term of Eq. 1, out of the 80 PC systems, 14 exhibited measureable continuous emissions ranging from 0.3 scf/h to 4.5 scf/ h, with an average of 1.5 scf/h (includes three CPCs). The remaining 66

IPC systems passed the HHP, OGI and emissions measurement screen and were assigned a *Ce* of 0.1 scf/h for this analysis (Section 2.2(5)). Allen *et al.* [5], produced 15-minute duration HVS and MFM measurements of all 125 PCs in the RM region with 22% of these PCs exhibiting whole gas emission rates > 0.1 scf/h as compared to 18% for the current study. The average whole gas emission rate measured by Allen was 0.8 scf/h with 13% of readings exceeding 1.0 scf/h with highest three readings of 11.3, 13.8, and 19.8 scf/h. The largest PC emissions levels observed by Allen *et al.* were significantly higher than the levels observed in this study and this difference may be due to a combination of the site types (oil vs. gas), engineering utilized (e.g., lack of high-bleed continuous controllers), gas production levels, and operator inspection and maintenance practices for sites surveyed.

3.3. Actuation Event Emissions

In addition to *Ce* of Equation (1), the emissions per actuation event *Ae* and event occurrence rate *Ar* must be understood. For the latter, from operator input and aural observations, it was apparent that the expected actuation frequency of a large portion of the encountered PC population was very low. In an attempt to observe naturally occurring actuation rates, the installed MFM measurements were conducted for an extended observation period of one hour, longer than the 15-minute observation period used in previous studies [3] [5], with no natural actuation events registered. Five representative Kimray T12 PC systems were monitored with SERN-5 pneumatic counters for approximately one month with data further supporting low (multi-hour) actuation rates. For the current data, only three of the five actuation frequency bins for IPCs described in Section 3.2 (Step 5) were required. Approximately 50% of the PC systems were conservatively assumed to actuate once per hour. Evidence suggested 16% of the PC systems actuated daily to several times per month (e.g. secondary separator or liquid knockouts, low tank level PCs), assumed here to be once per day. The remainder of the PC systems were safety or process protection devices with extremely infrequent actuations, assumed here to be once per month.

A total of 18 IPCs and one CPC were measured with installed MFMs, and manual actuation experiments were conducted successfully in 14 cases. Six Kimray T12 tank burner controllers [**Figure 2(b)**], two Kimray T12 separator or bath burner controllers, and 3 Kimray BP controllers were measured using exhaust port MFM sampling. MFMs were installed on the supply lines of four Wellmark 6900 dump valves (two sets of two in series) [**Figure 2(c)**], a T12 separator burner controller in series with a Wellmark 7400, a WellMark level controller, and a Fisher™ safety shut-in controller [**Figure 2(c)**]. In some cases, multiple MFMs were installed in series for comparison purposes.

Figure 4 shows several examples of repeat actuation experiments with emissions for individual actuations determined by the trapezoidal rule integration method with baseline line removed using code written in "R" [16]. These actuation experiments were conducted by the operator triggering a manual dump in

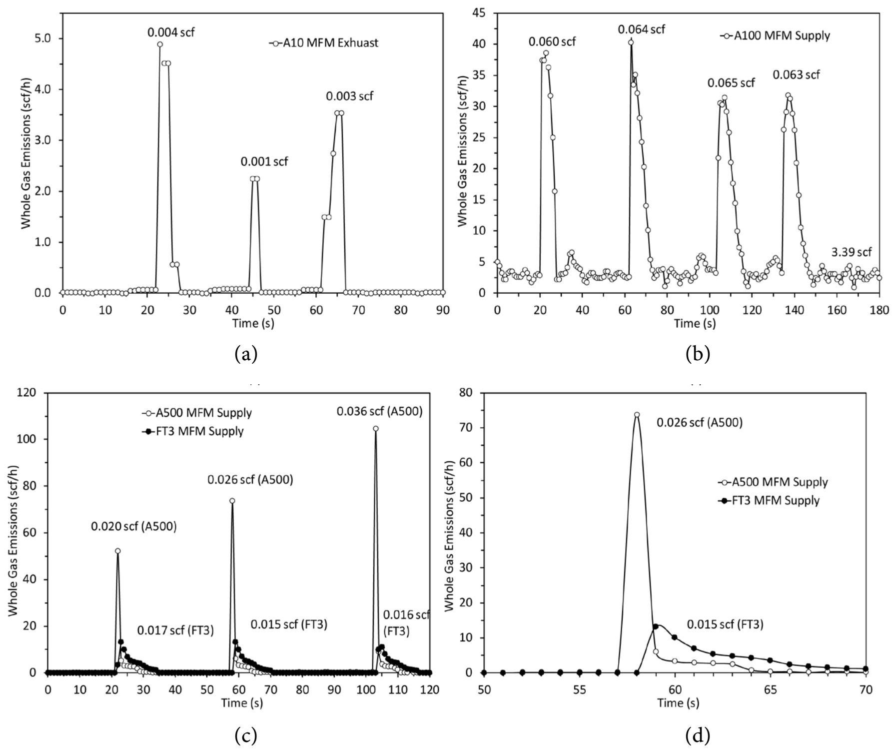

Figure 4. Manual actuation experiment of (a) Kimray T12 tank burner IPC; (b) complex Kimray T12 Separator IPC with malfunction; (c) Wellmark 6900 dump valve with both Alicat and Fox MFMs; and (d) Expanded view of (c).

the case of a Well Mark 6900 dump valve PC, or turning the temperature set point up and down for a Kimray T12 temperature controller. The very fast (3 s to 5 s) and low emission response (<0.01 scf) of the T12 in Figure 4(a), is typical of many PC systems encountered in this study. The low emissions of Figure 4(a) are due to the small actuation volume of the Kimray 112 SMT DAB motor valve (~ 1.1 in^3) and limited tubing lengths, a very common scenario with 60% of all PC systems surveyed using this actuator. Figure 4(b) shows actuation events for the previously discussed Oil Site 5 malfunction case (Kimray T12, WellMark 7400). With tubing lengths approaching 600 inches, higher than normal supply pressures (50 psi), these actuations were among the highest measured in the study and the baseline (between actuations) exhibited significant variability. Figure 4(c) and Figure 4(d) show supply line-measured actuation experiments of a Wellmark 6900 dump with both Alicat and Fox MFMs. Here the temporal response differences of the meters are evident and could play a factor in the observed differences. In general, the 1 Hz sampling rate of the data acquisition system could be increased to take advantage of the high response rate of the Alicat MFMs and to better characterize the temporal profiles. As a thermal meter, the Fox FT3 would benefit less from higher data acquisition rates.

Using field conditions at the time of measurement, EEE values for emissions per actuation event (*Ae*) were calculated, and compared to measured actuation events for the 14 available manual actuation trials (Figure 5). Rough magnitude agreement of the calculated (*EAe*) and measured (*MAe*) data is evident. The somewhat higher *EAe* values were likely due in part to the simplified model employed that does not account for gas compressibility or potential entrained liquids. The slow time response of the current MFM data acquisition system [Figure 4(d)] may contribute to the *MAe* low bias. Some of larger outlier values were associated with malfunctioning PCs or installations on complex shared supply lines. The abscissa error bars of Figure 5 illustrate the sensitivity of *EAe* to the 20% level (combined) input parameter changes, with the relatively well-bounded nature of the low actuation volume evident in these PC systems.

3.4. Composite Study Results and Comparisons to Other Basins

In a manner similar to OIPA [3], EEEs were produced for each of the PC systems using Equation 1 with *Ce* equal to the measured value in 14 cases (11 malfunctioning IPCs and three CPCs) and set to 0.1 scf/h in the remainder of cases. For *Ae*, the calculated EEEs with annual average conditions were used. For *Ar*, conservative bin estimates for actuation frequencies were used with the following assignments [0% (20/h), 0% (4/h), 49% (1/h), 16% (1/day), and 35% (1/month)]. In two cases (Kimray 312 FGT BP vessel pressure relief safety PCs on Oil Sites 1 and 2), a 12 hr process upset vent of 27.7 scf/h, once per month was assumed, with the level based on an actuation trial that simulated a process upset condition (SF1 Data1) [7].

Using the combined measurement and EEE analysis approach, the study mean whole gas PC system emission rate was estimated at 0.36 scf/h (0.33 scf/h methane), with a median of 0.11 scf/h, and a standard deviation of 0.77 scf/h. The IPC (N = 77) and CPC (N = 3) group average emission rates where 0.32 scf/h and 1.1 scf/h, respectively. Overall, seven measured values (9%) exceeded 1.0 scf/h with a maximum of 4.58 scf/h. Six of these values were ascribed to

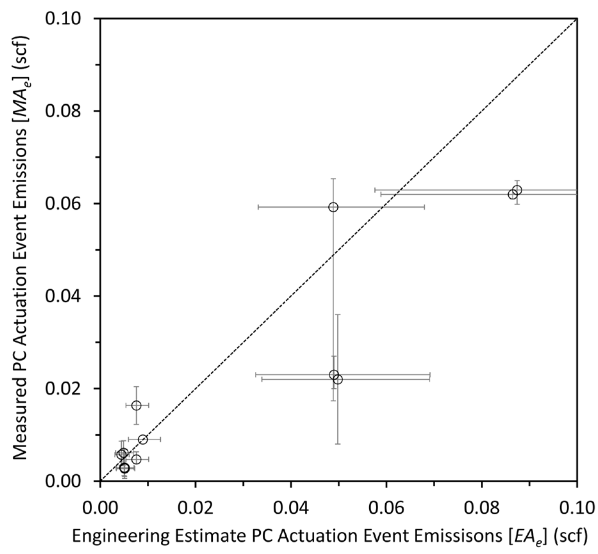

Figure 5. Comparison of EEE (*EAe*) and measured actuation events (*MAe*). Error bars for *EAe* (high/low) represent ±20% actuation volume, ±20% pressure, and −/+20% temperature based on conditions at the time of the survey. Error bars for *MAe* are minimum and maximum measured values.

malfunctioning IPC systems and one to a properly operating CPC (2.2 scf/h). The study mean and median values reflect the assignment of 0.1 scf/h for *Ce* for IPCs with no detectable emissions, as this assumption defines the low end of the distribution. Due to the low actuation volumes and rates found for a large portion of the population, the *Ae*Ar* component of Equation 1 played a small role in the estimate of emissions for the study. As a percentage of emissions for each device, the actuation event portion of the PC system emissions accounted for less than 15% of the emissions in 94% of the cases. To investigate the sensitivity to default *Ar* bins, the mean emission rate was calculated assuming higher actuation frequencies. Use of the conservative values in OIPA [3], four actuations per hour, increased the study mean emission rate to from 0.36 scf/h to 0.54 scf/h. Setting the *Ar* term to 10 actuations per hour produced a study mean of only 0.81 scf/h, further illustrating the potential relative impact of malfunctioning PCs with *Ce* rates exceeding 1.0 scf/h.

With the distribution dominated by IPCs, the current study mean (0.36 scf/h), was comparable to the IPC values from the OIPA study (0.40 scf/h) [3] and the RM region of the Allen *et al.* (0.31 scf/h) [5]. Including both IPCs and CPCs, the overall average for Allen *et al.*'s RM region was 0.8 scf/h with the continuous group (9% of PC systems) exhibiting an average of 7.23 scf/h, seven times higher than the CPC average of the current study (1.1 scf/h). Allen *et al.* measured wellhead, plunger lift, and dehydration PCs that were not found in this study, potentially explaining some of the difference. In other regions of the U.S., Allen *et al.* found much higher PC emissions compared to the RM region with an overall study average of 5.5 scf/h with group average emissions of 21.8 scf/h and 2.2 scf/h for CPCs and IPCs, respectively. The Prasino study [6], with focus on higher bleed CPCs, also differs greatly from the current result. The complete lack of high emitting CPCs or malfunctioning IPCs > 6 scf/h in the current study is an obvious difference but trends similarly with the RM region of Allen *et al.*, compared to other study regions (relatively higher liquids production levels in the RM are assumed, as in the Uinta). Overall, Allen noted that 76% of devices with emission rates greater than 6 scf/h were in service on compressors (not part of this study) or as level controllers on separators, with the latter also observed here as a high emitting group.

With a very small sample size (N = 3), the average CPC emission rate for this study (1.1 scf/h) compared favorably with the U.S. EPA estimate for low bleed CPCs (1.39 scf/h). The IPC emission rate for the study (N =77) was 0.32 scf/h, significantly less than the U.S. EPA IPC emission factor of 13.5 scf/h. The low average IPC emission rate observed is a consequence of high percentage small actuation volume, infrequently actuating IPCs encountered. Much of the PC population in use on waxy crude sites for tank product heating and level limit safety functions falls into this category. As discussed in comparison to other studies, this PC population likely differs markedly to that encountered in other areas of the country on well pads with different engineering requirements.

Breaking down the current study, the overall average whole gas emission rate for the oil sites was 0.28 scf/h compared to 0.67 scf/h for the gas sites, with a much higher relative percentage of PCs emitting greater than 1 scf/h for the latter. From evacuated canister measurements (SF1 Data 1) [7], the approximate average molar percentage [weight percentage] of CH_4 emissions was 88.2% [75.3%], and 93.7% [85.6%] for oil sites and gas site respectively. Combining the whole gas emission rates and gas profiles, oil site PC systems on average emit 60% less methane than gas site PCs, for this limited scope study. Since malfunctioning PC systems help drive this difference, the observation of lower PC system emissions on oil sites should take into account the relative gas well pad site age (**Table 1**) and site selection (intentional choice of Gas Site 3, not recently inspected) used in this study. This information coupled with the observation of, on average, 10.3 PCs per well for oil sites, compared to 1.5 PCs per well for gas sites, shows that intra-basin engineering differences on the two types of production sites likely reflect two distinct populations.

4. Conclusions

This observational study produced information on 80 PC systems on eight Uinta Basin ONG sites using a combination emission survey and EEE approach. The study was performed in cooperation with three ONG operators who selected the sites. With limited scope and nonrandomized sampling, the degree to which study results are representative of the basin is not known. However, several general conclusions can be drawn. Based on the study population, waxy crude oil and NG sites in the Uinta Basin have very different PC population profiles, with the former utilizing a larger number of PCs for heating functions. Overall, the percentage of IPCs in the basin is likely very high and may approach 100% for oil sites. For oil sites in particular, a significant percentage of IPC systems have low actuation volumes and actuation rates with typical designed emissions profiles representing a small fraction of a scf/h. The average IPC emission rate estimate of 0.32 scf/h was significantly lower than the GHG Inventory IPC emission factor of 13.5 scf/h per device. This result is driven by the PC types surveyed in this study and is not indicative of other ONG basins that have different engineering needs and production profiles.

A significant difference in PC emission levels from oil and NG sites was noted and was likely due in part to company differences in site selection and average age of the sites. A key finding was that the emissions were dominated by malfunctioning PC systems, which were defined here to include actuators and connecting tubing. The emission assessment survey procedures used here centered on identifying IPCs with continuous emissions above 0.2 scf/h, and therefore defined as malfunctioning. Along with CPCs, measurement of continuous emissions from malfunctioning IPCs are critical for understanding the population, with non-malfunctioning IPCs emissions more efficiently determined by EEEs.

The HVS and installed MFM exhaust port and supply line measurements each provide value, assessing PC emissions in different ways with varying levels of completeness and implementation burden. For many fully accessible PC systems encountered in the Uinta Basin (e.g., tank heaters), emissions can be effectively determined using an augmented HVS protocol and EEEs. For PC systems with a higher potential to emit or with inaccessible features, installed MFM supply line measurements can provide additional emission measurement information. High time-resolved MFM exhaust port measurements are relatively easy to implement and can be used to study short duration actuation event emissions for EEE comparisons and measure some forms of IPC seepage.

Due to the high percentage of IPCs and their generally low actuation volumes and rates, the overall emission profile of PC systems in the Uinta Basin was determined in large part by the frequency of occurrence of malfunctioning PC systems. For the definitions employed here, this malfunction rate was found to be 14% with these PC systems emitting at levels four times the study average. With sites access provided by the cooperators, it is difficult to determine if the observed malfunction rate or associated emissions is representative of the basin. Underestimates of malfunction rate and/or the average level of emissions from malfunctioning PC systems could increase the basin average PC emission rate significantly from the levels observed in this study. Future work in the Uinta Basin should focus on randomized sampling in an attempt to more accurately characterize malfunction rates and levels of emissions.

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Declare

The authors declare no competing financial interest.

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Acronyms and Abbreviations

A*e* PC emissions resulting from an actuation event (scf)

A*r* PC actuation rate (number of events/h)

AF archive file

C*e* continuous PC emissions rate (scf/h)

CH_4 methane

CPC continuous pneumatic controller

EA*e* engineering emissions estimate of A*e*

EEE engineering emissions estimate

U.S. EPA United States Environmental Protection Agency

FT3 Fox Thermal Flow meter

GHG greenhouse gas

PC pneumatic controller

HC hydrocarbon

HHP hand-held probe

HVS high volume sampler

IPC intermittent pneumatic controller

M100 Alicat 100 slpm mass flow meter (also M10, M500)

MA*e* measured A*e*

Mbbls thousands of barrels

MFM mass flow meter

MQL minimum quantification limit

Mscf thousands of standard cubic feet

NG natural gas

OGI optical gas imaging

OIPA Oklahoma Independent Petroleum Association

ONG oil and natural gas

QA quality assurance

RM Rocky Mountain region

SF supplemental file

VOC volatile organic compound

UDAQ response to EPA Comments on Changing the Intermittent Pneumatic Controller Emission Factor for the Utah Air Agencies 2014 Emissions Inventory

July 27, 2017

On July 10 staff from UDAQ, EPA R8, and the Ute Tribe convened a conference call to discuss changing the emission factor for intermittent pneumatic controls in the 2014 Air Agencies emissions inventory. On the call two technical memos were discussed: The UDAQ memo sent to EPA R8 and the Ute Tribe on 6/7/2017 which provided the rationale for updating the emission factor, and EPA's response dated 7/6/2017.

During the call UDAQ suggested that an EPA paper published in April 2015[i] supported the contention that the default emission factor of 13.5 scf/hr used in the Air Agencies inventory is not appropriate. Since EPA staff had not had time to review the document it was decided that staff from UDAQ and EPA would review other literature on the subject and then reconvene later in the month to find a mutually agreeable and scientifically defensible emission factor to be used for the 2014 inventory. After review of the EPA paper, as well as the Gas Research Institute Report (GRI/EPA 1996)[ii] [iii] which is the technical basis for the 13.5 scf/hr emission factor, UDAQ feels strongly that the default emission factor should be discarded completely based upon data collected by Thoma, et al[iv] and Allen, et al[v].

Study and reference	Year	Random/representative	Sites/measurements
EPA 2015; i,ii,iii	1996/1992	No/no	22/44 includes intermittent & continuous
EPA Uinta; iv	2017	No/somewhat	8/77 intermittent only
Dave Allen; v	2014	Somewhat/somewhat	~3/25 intermittent only

Table 1. Studies referenced in this paper. Random/representative refers to the sampling method and whether the samples representative of the Uinta Basin. Sites/measurements are the number of well sites visited while measurements refer to the total number of samples used to create the emission factor for each study.

The three documents, collectively referred to as "*EPA 2015*", provide the basis for UDAQ's contention that the intermittent pneumatic controller emission factor used as a default in Utah Air Agencies 2014 emissions inventory should be changed.

- Data from *EPA 2015* is 25 years old. "… the project reached its accuracy goal and provides an accurate estimate of methane emissions for 1992 gas industry practices". (pg 10 ii).
- The number of measurements is extremely low considering that it represents the entire country. "Data were collected from 22 sites to determine the fraction of continuous bleed devices versus intermittent bleed devices. A total of 44 measurements of various device types in field operation were used to estimate the emission factor" (Section 4.3.1, pg 53, iii).
- The field sampling campaigns on which the subpart W emission factors are based were not random. The following statements are made in regard to sample selection: "… These factors made selection of representative samples for measurement or observation difficult, and

traditional random sampling methods, such as random or stratified random sampling were not directly applicable in most cases." "… companies contacted were not required to participate and a complete list of all sources in the United States was generally not available; therefore, site selection was not truly random." (Section 5.4.1, pg 84, iii).

Recent subpart W greenhouse gas inventories have adjusted the default 13.5 scf/hr factor to account for changes in technology since the original study was done. However, UDAQ does not feel that such an approach is advisable for the Uinta Basin because it does not change the underlying emission factor that is used. Also, current, region-specific measurements are available with arguably less bias than the emission factors based on EPA 2015.

UDAQ Proposes to Use the Emission Factor from Dave Allen Rather than EPA Uinta

UDAQ agrees that the whole gas intermittent pneumatic controller emission factor of 0.32 scf/hr from *EPA Uinta* potentially underestimates VOC from pneumatic controllers for the reasons given in EPA Region 8's response to UDAQ's original memo. For that reason we provide the following rationale for using the *Dave Allen* Rocky Mountain Region Intermittent controller whole gas emission factor of 1.72 scf/hr as the most appropriate alternative.

- Measurements were taken from 25 intermittent vent controllers specifically in the Rocky Mountain region. This is almost as many measured devices as the *EPA 2015* study measured for all pneumatic device types across the entire country in 1992.
- In the initial development of the Air Agencies emissions inventory it was decided not to use the *Dave Allen* pneumatic controller emission factors based on concern about the proposed high and low bleed factors. In the *Dave Allen* study the emission factor for intermittent controllers, unlike the ones for high and low bleed continuous controllers was not skewed low by the inclusion of controllers with zero observed actuations (during the 15 minute measurement period) and 0 scf/h assumed bleed rate.
- Hi Flow sampler measurements, like those used in the *Dave Allen* study, have recently come under fire for underreporting emissions. However, the *EPA Uinta* study used multiple measurement methods in conjunction with Hi Flow measurements and did not note any significant differences in measurements taken via the Hi Flow versus other methods.
- Sampling in the *Dave Allen* study was more representative than in other studies. As noted in the study, sites visited were limited to only two or three participating companies. However, the companies provided descriptions, or lists of well pad sites, or central facilities in the area to be sampled. The study team, rather than the company, then selected all of the sites to visit either randomly or based on the relative proximity to the starting location. The goal was to sample a cross section of typical facilities. If a company had a mix of old and new facilities, or acquired and company built facilities, the study team selected pad types in proportion to the population of sites in the area[VI].

Based on the points above, an emission factor based on the *Dave Allen* study provides an intermediate emission factor. Use of a new factor acknowledges that the EPA 2015 factor is indeed an over estimate and not specific enough to the Uinta Basin or Rocky Mountain region, and provides an alternative to the insufficiently supported *EPA Uinta* factor.

Conclusion

UDAQ expects the Utah Air Agencies emissions inventory will go through a wide range of improvements as data is collected and understanding of processes and equipment increases with time. It is important to UDAQ that all three agencies involved in the inventory continue to use a consensus-based approach to decision making as these changes and adjustments are made. UDAQ also believes that adhering to an objective, evidence-based approach to inventory improvements will pay dividends in the long term stakeholder process. Finally, it is important that the regulated community, researchers, and other agency staff recognize the value of keeping high standards in the development and maintenance of the oil and gas emissions inventory.

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[ii] Methane Emissions from the Natural Gas Industry, Volume 1: Executive Summary, https://www.epa.gov/sites/production/files/2016-08/documents/1_executiveummary.pdf

[iii] Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report, https://www.epa.gov/sites/production/files/2016-08/documents/2_technicalreport.pdf

[iv] Thoma, E., et al. (2017), *Assessment of Uinta Basin Oil and Natural Gas Well Pad Pneumatic Controller Emissions*. Journal of Environmental Protection.

[v] Allen, D., et al. (2014), *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers.* Environmental Science & Technology.

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The Colorado Sun

ENERGY

First-in-the-nation rule to slash methane emissions from Colorado oil and gas operations relied on compromise

Industry and environmental groups worked out a way to reduce emissions from new wells and old ones that contribute to Colorado's ozone problem.

Mark Jaffe 4:05 AM MST on Feb 19, 2021

Pneumatic controllers are used to manage manage temperatures, pressure and liquid levels at oil and gas facilities and drill pads of all sizes. Colorado now requires non-emitting or no-bleed controllers on all new oil and gas pr... and at existing sites being upgraded. (Dana Coffield, The Colorado Sun)

NMOGA 18

Credibility: Original Reporting Sources Cited Subject Specialist

The Colorado Sun

Colorado Sun Daily Sun-Up: Colorado's ener

00:00 / 10:40

A rule clamping down on air pollution from key devices used by the oil and gas industry – which drew support from environmental groups and industry – was unanimously adopted by Colorado air quality regulators Thursday.

The first-in-the-nation rule requires the installation of non-emitting controllers on all new oil and gas operations and the retrofitting of existing controllers – a major source of emissions in the industry.

The environment groups and the industry worked out a compromise proposal that they jointly submitted to the Air Quality Control Commission. A wide range of local governments, including Weld County, the state's top oil-producing county, also supported or did not oppose the proposal.

"There's not a whole lot to talk about," Commissioner Elise Jones said. "This is such an unusual situation with everybody agreeing."

The state Air Pollution Control Division had initially proposed a rule to the AQCC that would have required non-emitting controllers only at new facilities, but over the past few months negotiations among industry representatives, environmental groups and local governments broadened the rule to encompass existing operations.

Recommended

Colorado regulators target tiny oil field device that's a big contributor to greenhouse gas, ozone pollution

The regulation will lead to "a large portion of controllers in the state being non-emitting by May 1, 2023," according to the Environmental Defense Fund, one of the groups involved in the compromise.

Controllers manage temperatures, pressure and liquid levels at oil and gas facilities and drill pads. Most controllers run on natural gas from the well itself and every time they open and close a valve or other mechanism, they release a little bit of gas.

The methane released is a powerful greenhouse gas that contributes to Front Range ozone pollution.

While the amount of gas released is small — an average 2.8 standard cubic feet of methane an hour, according to one study — there were an estimated 100,000 controllers operating in Colorado in 2019.

Nationally, controllers account for 29% of the oil industry air emissions, according to David McCabe, a senior scientist with the Boston-based Clean Air Task Force, a public health and environmental advocacy group.

The new rule requires non-emitting controllers at all wells and production facilities constructed after May 1, 2021, or at existing facilities when new wells are drilled or wells are refracked to boost production.

The regulation also applies to new natural gas compressor stations and existing compressor stations that swap out equipment to increase their horsepower.

NMOGA 18

Operators are also obliged to systematically replace emitting controllers at existing facilities and they were given the flexibility to develop companywide plans to do it.

The size of the required emissions cuts is also on a sliding scale – between 15% and 40% – with companies already using non-emitting controllers needing to make smaller reductions.

"With the flexibility offered by the companywide plans, each operator would be able to make the retrofits that are most cost-effective," according to EDF.

The regulation also provides limited exemptions from the requirements for temporary or portable equipment, distant or offsite wells, as well as safety and production issues. The exemption would have to be approved by the state's APCD.

Older and smaller wells – known as stripper wells – that produce the equivalent of 15 barrels of oil or less per day would also be exempt, although their status is set to be reviewed in future negotiations.

The compromise rule was supported by groups ranging from the Colorado Oil and Gas Association, an industry trade group, to Conservation Colorado. More than 60 local governments also backed the rule.

"The stakeholder discussions surrounding pneumatic controllers have proven intensive and deeply substantive, but the collaborative and good-faith work across parties has led to a clear path forward for further emissions reduct in the state," Lynn Granger, executive director of the trade group API-Colorado, said in a statement.

The APCD also backed the compromise. "It's unique rulemaking," said Jeramy Murray, a division environmental specialist. "Compromise and collaboration are the Colorado way."

Commissioner Curtis Rueter said, "as a commission it is really nice for something to come forward with no outstanding issues."

Mark Jaffe
Special to The Colorado Sun

Read More: Air Pollution Control Division American Petroleum Institute Colorado Air Quality Control Commission Colorado Oil and Gas Conservation Commis

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Oil and Natural Gas Sector Pneumatic Devices

Report for Oil and Natural Gas Sector Pneumatic Devices

Review Panel

April 2014

Prepared by

U.S. EPA Office of Air Quality Planning and Standards (OAQPS)

Table of Contents

PREFACE

On March 28, 2014 the Obama Administration released a key element called for in the President's Climate Action Plan: a Strategy to Reduce Methane Emissions. The strategy summarizes the sources of methane emissions, commits to new steps to cut emissions of this potent greenhouse gas, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut methane emissions from several sectors, including the oil and natural gas sector.

This technical white paper is one of those steps. The paper, along with four others, focuses on potentially significant sources of methane and volatile organic compounds (VOCs) in the oil and gas sector, covering emissions and mitigation techniques for both pollutants. The Agency is seeking input from independent experts, along with data and technical information from the public. The EPA will use these technical documents to solidify our understanding of these potentially significant sources, which will allow us to fully evaluate the range of options for cost-effectively cutting VOC and methane waste and emissions.

The white papers are available at:

www.epa.gov/airquality/oilandgas/whitepapers.html

1.0 INTRODUCTION

The oil and natural gas exploration and production industry in the U.S. is highly dynamic and growing rapidly. Consequently, the number of wells in service and the potential for greater emissions from oil and natural gas sources is also growing. There were an estimated 504,000 producing gas wells in the U.S. in 2011 (U.S. EIA, 2012a), and an estimated 536,000 producing oil wells in the U.S. in 2011 (U.S. EIA, 2012b). It is anticipated that the number of gas and oil wells will continue to increase substantially in the future because of the continued and expanding use of horizontal drilling combined with hydraulic fracturing (referred to here as simply hydraulic fracturing).

Due to the growth of this sector and the potential for increased air emissions, it is important that the U.S. Environmental Protection Agency (EPA) obtain a clear and accurate understanding of emerging data on emissions and available mitigation techniques. This paper presents the Agency's understanding of emissions and available emissions mitigation techniques from a potentially significant source of emissions in the oil and natural gas sector.

1.1 Definition of the Source

The focus of this white paper is natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps. Such pneumatic controllers and pumps are widespread in the oil and natural gas industry and emit natural gas, which contains methane and VOCs. In some applications, pneumatic controllers and pumps used in this industry may be driven by gases other than natural gas and, therefore, do not emit methane or VOCs.

1.1.1 Pneumatic Controllers

For the purposes of this white paper, a *pneumatic controller* means an automated instrument used for maintaining a process condition such as liquid level, pressure, pressure difference and temperature. Based on the source of power, two types of pneumatic controllers are defined for this paper:

- *Natural gas-driven pneumatic controller* means a pneumatic controller powered by pressurized natural gas.
- *Non-natural gas-driven pneumatic controller* means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses. For the purposes of this white paper, they are characterized primarily by their emissions characteristics:

- *Continuous bleed pneumatic controllers* are those with a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator. For the purposes of this paper, continuous bleed controllers are further subdivided into two types based on their bleed rate:
    - *Low bleed*, having a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh).
    - *High bleed*, having a bleed rate of greater than 6 scfh.
- *Intermittent pneumatic controller* means a pneumatic controller that vents non-continuously. These natural gas-driven pneumatic controllers do not have a continuous bleed, but are actuated using pressurized natural gas.
- *Zero bleed pneumatic controller* means a pneumatic controller that does not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

1.1.2 Pneumatic Pumps

Pneumatic pumps are devices that use gas pressure to drive a fluid by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or set of rotating impellers. Pneumatic pumps are generally used at oil and natural gas production sites where electricity is not readily available (GRI/EPA, 1996d). The supply gas for these pumps can be compressed air, but most often these pumps use natural gas from the production stream (GRI/EPA, 1996e).

1.2 Background

1.2.1 Pneumatic Controllers

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations, across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these natural gas-driven pneumatic controllers, natural gas is released with every actuation of the valve, i.e., valve movement. In some designs, natural gas is also released continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs of natural gas-driven pneumatic controllers: (1) continuous bleed controllers are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) intermittent controllers release gas only when they open or close a valve or as they throttle the gas flow; and (3) zero bleed controllers, which are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere (EPA, 2011a).

As noted above, intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. Thus, the actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Continuous bleed controllers also vent an additional volume of gas during actuation, in addition to the device's continuous bleed stream. Thus, actual emissions from a continuous bleed device also depend, in part, on the frequency of activation and the amount of gas vented during activation. As the name implies, zero bleed controllers are considered to emit no natural gas to the atmosphere (EPA, 2011a).

In general, intermittent controllers serve functionally different purposes than bleed controllers and, therefore, cannot replace bleed controllers in most (but not all) applications. Furthermore, zero bleed controllers are "closed loop" systems that can be used only in applications with very low pressure and therefore may not be suitable to replace continuous bleed pneumatic controllers in many applications.

Non-natural gas-driven pneumatic controllers can be used in some applications. These controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Instrument air systems are feasible only at oil and natural gas locations that have electrical service sufficient to power an air compressor. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic controllers can be used. Non-natural gas-driven controllers do not directly release methane or VOCs, but may have secondary impacts related to generation of required electrical power (EPA, 2011a).

1.2.2 Pneumatic Pumps

There are two types of pneumatic pumps that are commonly used in the oil and natural gas sector: piston and diaphragm (GRI/EPA, 1996d). These pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas (GRI/EPA, 1996d).

The majority of pneumatic pumps used in oil and natural gas production are used for chemical injection or glycol circulation (GRI/EPA, 1996d). Pneumatic pumps used for chemical injection are needed in oil and natural gas production to inject small amounts of chemicals to limit processing problems and protect equipment. Typical chemicals that are injected into the process include: biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers and hydrogen sulfide scavengers (GRI/EPA, 1996d). These chemicals are normally injected using pneumatic pumps at the wellhead, and into gathering lines or at production separation facilities (GRI/EPA, 1996d). Pneumatic pumps, commonly referred to as "Kimray" pumps, used for glycol circulation recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber (GRI/EPA, 1996e).

1.3 Purpose of the White Paper

This white paper provides a summary of the EPA's understanding of the emissions from natural gas-driven pneumatic controllers and pumps in the oil and natural gas sector, the mitigation techniques available to reduce these emissions, the efficacy of these techniques and the prevalence of these techniques in the field. Section 2 of this document provides the EPA's understanding of emissions from pneumatic controllers and pumps, and Section 3 provides our understanding of available mitigation techniques. Section 4 summarizes the EPA's understanding based on the information presented in Sections 2 and 3, and Section 5 presents a list of charge questions for reviewers to assist the EPA with obtaining a more comprehensive understanding of pneumatic controller and pump VOC and methane emissions and emission mitigation techniques.

2.0 AVAILABLE EMISSIONS DATA AND ESTIMATES

There are a number of studies that have been published that have estimated VOC and methane emissions from pneumatic controllers and pneumatic pumps in the oil and natural gas sector. These studies have used different methodologies to estimate these emissions including the use of equipment counts and emission factors and direct measurement of emissions. Section 2.1 discusses the studies relevant to pneumatic controllers, and Section 2.2 discusses the studies relevant to pneumatic pumps. These studies are listed in Table 2-1, along with an indication of the type of information contained in the study.

Table 2-1. Summary of Major Sources of Pneumatic Controller and Pump Information

Report Name	Affiliation	Year of Report	Activity Factor	Pneumatic Controllers	Pneumatic Pumps
Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c)	Gas Research Institute / EPA	1996	Nationwide	X	X
Estimates of Methane Emissions from the U.S. Oil Industry (ICF Consulting, 1999)	EPA	1999	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)	EPA	2014	Nationwide/ Regional	X	X
Greenhouse Gas Reporting Program (U.S. EPA, 2013)	EPA	2013	Basin	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the United States (Allen et al., 2013)	Multiple Affiliations, Academic and Private	2013	Nationwide	X	
Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino, 2013)	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas (Roy et al., 2014)	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)	ICF International	2014	Nationwide	X	X

2.1 Discussion of Data Sources for Pneumatic Controllers

This section presents and discusses pertinent studies and data sources that estimate emissions from pneumatic controllers.

2.1.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c)

This report's main objective was to quantify annual methane emissions from pneumatic controllers from the natural gas production, processing, transmission, and distribution sectors. The methane emissions were determined by developing average annual emissions factors for the various types of pneumatic controllers used in each of the natural gas segments. The annual emission factors were then extrapolated to a national estimate using activity factors for each of the natural gas segments.

Production

The data used to develop emission factors for pneumatic controllers in the natural gas production sector were obtained from a study performed by the Canadian Petroleum Association (CPA)[1], manufacturers' data, measured emission rates[2], data collected from site visits, and literature data for methane composition.

The CPA study consisted of methane and VOC emission measurements from pneumatic controllers in two types of service: 19 in on/off service and 16 in throttling service.[3] The CPA study determined the average natural gas emission rate for on/off controllers was 213 standard cubic feet per day per device (scfd/device), and the average natural gas emission rate for throttling controllers was 94 scfd/device. For throttling controllers, the CPA study did not distinguish between the throttling controllers with intermittent bleed rates and throttling controllers with continuous bleed rates. In addition, only one throttling controller actuated during the emission measurement. Therefore, these measurements are lower in comparison to field measurements of similar devices in the U.S. (GRI/EPA, 1996c).

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[1] Picard, D.J., B.D. Ross, and D.W.H. Koon, *A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta*. Canadian Petroleum Association, Calgary, Alberta, 1992.

[2] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.

[3] Controllers in on/off service wait until a specific set point is reached before actuating (e.g., a high or low liquid level). Controllers in throttling service maintain a desired set point (e.g., pressure).

The manufacturers' data were obtained from four manufacturers of pneumatic controllers and were based on laboratory testing of new controllers. The manufacturers' noted that emissions in the field can be higher due to operating condition, age, and wear of the device. The gas consumption rates for the manufacturers' pneumatic controllers ranged from 0 to 2,150 scfd. The manufacturers noted that the emissions from these controllers in the field may be higher than the reported maximum value (GRI/EPA, 1996c).

The measured emissions data[4] were collected by connecting a flow meter to the supply line between the pressure regulator and the controller to measure the gas consumption of the controller. The duration of the test depended on the operating conditions. For steady operating conditions, one data point was measured for 15-20 minutes. For variable operating conditions, several one-hour measurements were taken. The data set contained a total of 41 measurements from a combination of continuous bleed controllers from offshore and onshore production sites and transmission stations. The average gas emissions rates for continuous bleed controllers were determined to be 872 scfd/device for onshore and offshore production sites and 1,363 scfd/device for transmission stations.

The measured emission data[5] also provided data for intermittent bleed controllers that were measured using the same techniques that were used for the continuous bleed pneumatic controllers. A total of seven measurements were performed on intermittent bleed controllers located at onshore natural gas production sites. No measurements were available for intermittent bleed controllers in the offshore or transmission segments. The average natural gas emission rate for the intermittent pneumatic controllers was determined to be 511 scfd/device.

Site visit data were collected from a total of 22 sites to determine the number of pneumatic controllers located at natural gas production sites, and to determine the fraction of these controllers that were intermittent or continuous bleed. The study determined that 65% of

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[4] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.
[5] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.

the pneumatic controllers were intermittent bleed and 35% of the pneumatic controllers were continuous bleed.

The measured emission data, the CPA study emissions data, and the pneumatic controller counts were used to develop a single emission factor for a "generic" pneumatic device. For the production segment, the "generic" pneumatic controller emission factor was calculated using:

- 323 scfd/device for intermittent bleed controllers,
- 654 scfd/device for continuous bleed controllers,
- a methane content of 78.8%, and
- the ratio of intermittent bleed to continuous bleed controllers at natural gas production sites.

The "generic" emission factor was determined to be 345 scfd/device of methane for a pneumatic controller at natural gas production sites.

Transmission

The transmission "generic" emission factor was calculated using data from three types of gas-operated pneumatic controllers: continuous bleed controllers and two types of intermittent bleed controllers used to operate isolation valves[6] (isolation valves with turbine operators and isolation valves with displacement-type pneumatic/hydraulic operators). The continuous bleed emission factor was obtained from the transmission station measured emission data, which was determined to be 1,363 scfd/device. The isolation valve with displacement-type pneumatic/hydraulic operators emission factor was determined using data provided by Shafer Valve Operating Systems[7,8] and the count of the isolation valves at four sites. Using these data,

[6] Isolation valves at transmission stations are very large and are most often actuated either pneumatically or by electric motor. Isolation valve pneumatic controllers only discharge gas when they are actuated and are considered to be intermittent.

[7] Shafer Valve Operating Systems. Gas Consumption Calculation Method for Rotary Vane, Gas/Hydraulic Actuators. Technical Bulletin Data, Bulletin GC-00693. June 1993.

the average annual emission factor was determined to be 5,627 standard cubic feet per year per device (scfy/device). For turbine-operated isolation valves, the natural gas emissions were estimated using information provided by Limitorque Corporation[9] and information from two transmission sites. This information was used to calculate an emission factor of 67,599 scfy/device. The above emission factors, a methane content of 93.4% and proportions of each of these controllers at transmission sites was used to calculate a "generic" emission factor of 162,197 scfy/device of methane for pneumatic controllers at transmission stations.

Processing

The site visit information from nine natural gas processing plants found that plants used compressed air to operate the majority of pneumatic controllers at the plants. Only one of the plants used natural gas-powered continuous bleed controllers, and five had natural gas-driven pneumatic controllers for the isolation valves on the main pipeline emergency shutdown system or isolation valves used for maintenance. The same type of pneumatic controllers used in the transmission sector are used at natural gas processing sites; therefore, the same emission factors were used to calculate a facility pneumatic emission factor. Using the survey data and the transmission sector pneumatic controller emission factors, the annual methane emissions were determined to be 165 thousand standard cubic feet per facility (Mscfy/facility).

Summary

A summary of the pneumatic controller emission factors, activity factors, and annual methane emission rates estimated by this report are provided in Table 2-2 for the natural gas production, processing and transmission segments. The total methane emissions from pneumatic controllers was estimated to be 45,634 million standard cubic feet per year (MMscfy) or 861,704 metric tons (MT).

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[8] Shafer Valve Operating Systems. Gas Consumption Calculation Method for Rotary Vane, Gas/Hydraulic Actuators. Technical Bulletin Data, Bulletin GC-2-00394. March 1994.

[9] Personal correspondence with Belva Short of Limitorque Corporation, Lynchburg, VA, April 5, 1994.

Table 2-2 GRI Nationwide Pneumatic Controller Methane Emissions in the United States (1992 Base Year)

Natural gas Segment	Methane Emission Factor	Activity Factor	Annual Methane Emission Rate (MMscf/yr)	Annual Methane Emission Rate (MT)
Production	125,925 scfy/device	249,111 controllers	31,369	592,349
Processing	165,000 scfy/facility	726 facilities	120	2,262
Transmission	162,197 scfy/device	87,206 controllers	14,145	267,093
Total			45,634	861,704

2.1.2 Estimates of Methane Emissions from the U.S. Oil Industry (ICF Consulting, 1999)

ICF Consulting (ICF Consulting, 1999) prepared a report for the EPA that estimated methane emissions from crude oil production, transportation and refining, identified potential methane mitigation techniques and provided an analysis of the economics of reducing methane emissions. The report estimated that 97% of the annual methane emissions occur during crude oil production (59.1 billion cubic feet, Bcf or 1,116,000 MT) in 1995. The transportation and refining sectors generate 0.3 Bcf (5,700 MT) and 1.3 Bcf (24,500 MT) of the annual methane emissions, respectively. The annual methane emissions were estimated using methane emission factors and activity factors to calculate the annual methane emissions from the oil industry.

In the production segment, annual vented methane emissions from 13 sources account for 91% (53.8 Bcf or 1,016,000 MT) of the total 1995 methane emissions from crude oil production. Two of these sources: high bleed pneumatic controllers and low bleed pneumatic controllers account for 37% (19.9 Bcf or 376,000 MT) and 7% (3.7 Bcf or 69,900 MT) of the annual vented methane emissions, respectively.

The high bleed pneumatic controller methane emissions were calculated using an emission factor of 345 scfd (GRI/EPA, 1996c). The activity factor for high bleed pneumatic controllers was determined to be 157,581 and assumes that tank batteries with heater treaters have four pneumatic controllers (three level controllers and one pressure controller). Tank batteries without heater treaters were assumed to have three pneumatic controllers. In addition, it was assumed that 35% of the total pneumatic controllers were high bleed, which is based on the percentage of continuous bleed pneumatic controllers determined in the GRI/EPA study (GRI/EPA, 1996c).

The low bleed pneumatic controller methane emission factor was estimated to be 10% of the high bleed methane emission factor or 35 scfd.[10] The activity factor for low bleed controllers was calculated to be 292,650 controllers and was determined using the assumption that 65% of the total pneumatic controllers are intermittent bleed (GRI/EPA, 1996c), which this report assumed to be low bleed pneumatic devices.

No methane emissions from pneumatic controllers were estimated in this report for the transportation and refining segments of the oil industry.

2.1.3 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

The EPA leads the development of the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory). This report tracks total U.S. greenhouse gas (GHG) emissions and removals by source and by economic sector over a time series, beginning with 1990.

The U.S. submits the GHG Inventory to the United Nations Framework Convention on Climate Change (UNFCCC) as an annual reporting requirement. The GHG Inventory includes estimates of methane and carbon dioxide for natural gas systems (production through distribution) and petroleum systems (production through refining).

[10] EPA Natural Gas STAR default value for low bleed pneumatic controllers.

Table 2-3 summarizes the 2014 GHG Inventory's (published in 2014; containing emissions data for 1990-2012) estimates of 2012 national methane emissions from pneumatic controllers in the natural gas production, processing, transmission and storage segments and the petroleum production segment. Where presented in the GHG Inventory, the table includes potential emissions (i.e., emissions that would be released in the absence of controls), emission reductions and net emissions. For pneumatic controllers, the emission reductions reported to the Natural Gas STAR program are deducted from potential emission to calculate net emissions. In future years, the GHG Inventory will also account for regulatory reductions impacting emissions from pneumatic controllers that result from subpart OOOO.

Table 2-3. Summary of GHG Inventory 2012 Nationwide Emissions from Pneumatic Controllers

Industry Segment	Potential CH_4 Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Natural gas and petroleum production[a]	1,642,622	873,100	769,522
Natural gas processing	1,923	[b]	[b]
Natural gas transmission and storage	263,561	14,078	249,483

[a] In the GHG Inventory, all Natural Gas STAR reductions for pneumatic devices are removed from the natural gas systems estimate. As some of these reductions likely occur in petroleum systems, a combined number for production segment pneumatic devices in natural gas and petroleum systems is presented here.

[b] The GHG Inventory does not include a specific emission reduction for pneumatic controllers in the natural gas processing sector resulting from the Natural Gas STAR program although it is likely non-zero.

The GHG Inventory data estimates that pneumatic controller emissions are 13% of overall methane emissions from the oil and natural gas sectors. The following sections provide greater detail on the estimates given in Table 2-3.

2.1.3.1 Natural gas and petroleum production industry segment

Table 2-4 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas and petroleum production industry segment. The table presents the population of pneumatic controllers, methane emission factors, potential methane emissions, and the estimated national total of pneumatic controllers and potential methane emissions. The natural gas production data are broken down by the Energy Information Agency's (EIA's) National Energy Modeling System (NEMS) regions. The table also presents the national total of methane emission reductions compiled from Natural Gas STAR reports and the resulting estimated national net methane emissions from pneumatic controllers.

Table 2-4. Estimated 2012 National and Regional Methane Emissions from Pneumatic Controllers in the Natural Gas and Petroleum Production Segment

NEMS Region	Population of Pneumatic Controllers[a]	CH_4 Potential Emission Factor (scfd/device)[a]	CH_4 Emissions (MT)
Potential Emissions-Natural Gas Systems			
North East	77,261	373	202,696
Midcontinent	167,589	362	426,133
Rocky Mountain	122,127	339	291,166
South West	55,095	353	136,534
West Coast	2,098	402	5,933
Gulf Coast	53,436	386	145,057
Total	477,606		1,207,519
Potential Emissions-Petroleum Systems			
High Bleed	145,179	330	336,692
Low Bleed	269,618	52	98,411
Total	414,797		435,103
Combined Natural Gas and Petroleum Systems			
Total	892,403		1,642,622
Voluntary Emission Reductions-Natural Gas and Petroleum			873,100
Net Emissions-Natural Gas and Petroleum[b]			769,522

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.
[b] In the GHG Inventory, all Natural Gas STAR reductions for pneumatic devices are removed from the natural gas systems estimate. As some of these reductions likely occur in petroleum systems, a combined number for production segment pneumatic devices in natural gas and petroleum systems is presented here.

Recent national activity data on pneumatic controllers are not available. To calculate national emissions for these sources for the GHG Inventory, a set of industry activity data drivers was developed and used to update activity data. For the natural gas production segment, pneumatic controllers were estimated each year by applying a regional factor for the number of pneumatic controllers per well to annual regional data on gas well population. These factors ranged from 0.5 to 1.6 pneumatic controllers per well. For the petroleum production segment, pneumatic controllers were estimated each year by applying a factor for the number of pneumatic controllers per heater/treater (4), and pneumatic controller per battery without a heater/treater (3).

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas and petroleum production industry segment is the 1996 GRI/EPA report. The factor for natural gas systems represents a mix of the average emissions from continuous bleed and intermittent natural gas-driven pneumatic controllers in the 1996 GRI/EPA report. The region-specific factors are developed using the GRI/EPA factor and regional gas composition data. For petroleum systems, it was then assumed that 65% of pneumatic controllers in the petroleum production segment are low bleed pneumatic controllers, and 35% of controllers are high bleed. The GRI/EPA factors for low and high bleed controllers are applied to these populations

According to the GHG Inventory, the 1996 GRI/EPA report "still represents the best available [emissions] data in many cases, [but] using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. For this reason, 'potential emissions' are calculated using the [1996 GRI/EPA report] data, and then current data on voluntary and regulatory emission reduction activities are deducted to calculate actual emissions."

In the case of pneumatic controllers in the natural gas production industry segment, the GHG Inventory reduces the calculated potential emissions using voluntary emission reductions reported by industry partners to the Natural Gas STAR Program. The reductions undergo quality assurance and quality control checks to identify errors, inconsistencies, or irregular data before being incorporated into the GHG Inventory. Future inventories are expected to reflect the subpart OOOO requirements for pneumatic controllers as they are implemented.

2.1.3.2 Natural gas processing industry segment

Table 2-5 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas processing industry segment.

Table 2-5. Estimated 2012 National Methane Emissions from Pneumatic Controllers in the Natural Gas Processing Segment

Activity Factor	CH_4 Potential Emission Factor (scfy/plant)[b]	CH_4 Potential Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
606 gas plants[a]	164,721	1,923	[c]	[c]

[a] *Oil and Gas Journal*, with available 2012 activity data.
[b] 1996 GRI/EPA report.
[c] Although voluntary Natural Gas STAR emission reductions are reported for this industry segment in the aggregate, no value is given specifically for pneumatic controllers.

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas processing segment is the 1996 GRI/EPA report. This potential emission factor is expressed in terms of standard cubic feet per year per processing plant (scfy/plant). The associated activity factor is the number of U.S. gas plants, which comes from the *Oil and Gas Journal*.

The GHG Inventory does not report emissions reductions specific to pneumatic controllers in this industry segment and, thus, there is no reported net emissions figure.

2.1.3.3 Natural gas transmission and storage segment

Table 2-6 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas transmission and storage industry segment.

Table 2-6. Estimated 2012 National Methane Emissions from Pneumatic Controllers in the Natural Gas Transmission and Storage Segment

Subsegment	Activity Factor (# of controllers)	CH_4 Potential Emission Factor (scfy/device)	CH_4 Potential Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Transmission	70,827	162,197[a]	221,257		
Storage	13,542	162,197[a]	42,304		
Total	84,369		263,561	-14,078[b]	249,483

[a] 1996 GRI/EPA report.
[b] Voluntary Natural Gas STAR emission reductions are reported for all pneumatic controllers in this industry segment, not split out by transmission and storage.

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas transmission and storage segment is the 1996 GRI/EPA report. In this case, the potential emission factor is expressed in terms of scfy/device. The associated activity factor is the number of pneumatic controllers. For transmission, the number of pneumatic controllers is calculated based on transmission pipeline length. For storage, the number of pneumatic controllers is calculated based on number of compressor stations in the storage segment.

The 2014 GHG Inventory includes voluntary emission reductions reported by industry partners to the Natural Gas STAR Program for pneumatic controllers in the natural gas transmission and storage industry segment.

2.1.4 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

In October 2013, the EPA released 2012 GHG data for Petroleum and Natural Gas Systems collected under the Greenhouse Gas Reporting Program (GHGRP). The GHGRP, which was required by Congress in the FY2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain GHGs and products that would emit GHGs if released or combusted.

When reviewing this data and comparing it to other data sets or published literature, it is important to understand the GHGRP reporting requirements and the impacts of these requirements on the reported data. The GHGRP covers a subset of national emissions from Petroleum and Natural Gas Systems; a facility in the Petroleum and Natural Gas Systems source category is required to submit annual reports if total emissions are 25,000 MT of CO_2 equivalent (MT CO_2e) or more. Facilities use uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors derived from direct measurement. In some cases, facilities have a choice of calculation methods for an emission source.

The GHGRP addresses petroleum and natural gas systems with implementing regulations at 40 CFR part 98, subpart W. The rules define three segments of the oil and natural gas industry sector that are required to report GHG emissions from pneumatic controllers: (1) onshore petroleum and natural gas production, (2) onshore natural gas transmission compression, and (3) underground natural gas storage. Facilities calculate emissions from pneumatic controllers by determining the number of each type of controller at the facility and applying emission factors. In the petroleum and natural gas production segment, facilities must apply facility-specific gas composition factors for methane and CO_2. In the natural gas transmission and storage segments, default gas composition factors are used. Subpart W emission factors for pneumatic controllers are located at 40 CFR Part 98, subpart W, Table W-1A (Onshore Petroleum and Natural Gas Production), Table W-3 (Onshore Natural Gas Transmission Compression), and Table W-4 (Underground Natural Gas Storage). These emission factors are based on the 2009 document *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* published by the American Petroleum Institute (API), which in turn is based on the 1996 GRI/EPA report.

Table 2-7 shows the number of reporting facilities[11] in each of the three industry segments, along with reported pneumatic controller methane emissions.

Table 2-7. Facilities and Reported Emissions from Pneumatic Controllers, 2012

Segment	Number of Reporting Facilities	Reported Methane Emissions (MT)[a]
Petroleum and NG Production	417	861,224
Transmission	330	7,582
Storage	38	4,493

[a] The reported methane MT CO2e emissions were converted to methane emissions in MT by dividing by a global warming potential (GWP) of methane (21).

2.1.5 Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)

A study completed by multiple academic institutions and consulting firms was conducted to gather methane emissions data at onshore natural gas sites in the U.S. and compare those emission estimates to the 2011 estimates reported in the 2013 GHG Inventory. The sources or operations tested included 305 pneumatic controllers located at 150 distinct natural gas production sites in four production regions (Appalachian, Gulf Coast, Midcontinent, and Rocky Mountain).

Testing was carried out using a Hi-Flow Sampler, which is a portable, battery-powered instrument designed to determine the rate of gas leakage around various pipe fittings, valve packings and compressor seals found in natural gas production, transmission, storage and processing facilities. To allow the quantity of methane to be separated out from other chemical

[11] In general, a “facility” for purposes of the GHGRP means all co-located emission sources that are commonly owned or operated. However, the GHGRP has developed a specialized facility definition for onshore production. For onshore production, the “facility” includes all emissions associated with wells owned or operated by a single company in a specific hydrocarbon-producing basin (as defined by the geologic provinces published by the American Association of Petroleum Geologists).

species, gas composition data were collected for each natural gas production site, typically provided by the site owner. The 305 sampled pneumatic controllers represented an estimated 41% of all the controllers associated with the wells that were sampled. The sampling time for each controller was not specified in the study. Table 2-8 shows the emission rates determined by the testing.

Table 2-8. Pneumatic Controller Methane Emission Rates Reported in the Allen Study

	Methane Emissions per Pneumatic Controller				
	Appalachian	Gulf Coast	Midcontinent	Rocky Mtn.	Total
Number sampled[a]	133	106	51	15	305
Emissions rate (scf methane/min/device)[b]	0.126 ± 0.043	0.268 ± 0.068	0.157 ± 0.083	0.015 ± 0.016	0.175 ± 0.034
Emissions rate (scf whole gas/min/device, based on site-specific gas composition)[b]	0.130 ± 0.044	0.289 ± 0.071	0.172 ± 0.086	0.021 ± 0.022	0.187 ± 0.036

[a] Intermittent and low bleed controllers are included in the total; no high bleed controllers were reported by companies providing controller type information
[b] Uncertainty characterizes the variability in the mean of the data set, rather than an instrumental uncertainty in a single measurement

The Allen study reports that the average whole gas emission rate was 11.2 scfh per pneumatic controller for the tested population, which consisted of a mix of intermittent and low bleed controllers. No high bleed controllers were reported by the companies that provided controller type information. The study also reports whole gas emission factors of 5.1 scfh for low bleed controllers and 17.4 scfh for intermittent controllers. These emission factors are based on measured emissions at the 24 sites where the site operators reported only low bleed controllers and the 55 sites reporting only intermittent controllers, where potential misidentification of controller type is less likely to be a confounding factor.

The study notes that there is significant geographical variability in the emissions rate from pneumatic controllers between production regions. Emissions per controller from the Gulf Coast are highest and are statistically different than emissions from controllers in the Rocky Mountain and Appalachian regions. The difference in average values is more than a factor of 10 between Rocky Mountain and Gulf Coast regions. The study provided the following discussion of these differences:

> Some of the regional differences in emissions may be explained by differences in practices for utilizing low bleed and intermittent controllers. For example, new controllers installed after February 1, 2009 in regions in Colorado that do not meet ozone standards, where most of the Rocky Mountain controllers were sampled, are required to be low bleed (or equivalent) where technically feasible (Colorado Air Regulation XVIII.C.1; XVIII.C.2; technical feasibility criterion under review as this is being written). However, observed differences in emission rates between intermittent and low bleed devices (roughly a factor of 3) are not sufficient to explain all of the regional differences. A number of additional hypotheses were examined to attempt to explain the differences in emissions. For datasets consisting entirely of intermittent or entirely of low-bleed devices, the volume of oil produced was not a good predictor of emissions. Wellhead and separator pressure were also not good predictors of emissions. The definition of low-bleed controllers may be [an] issue, however. All low bleed devices are required to have emissions below 6 scf/hr (0.1 scf/m), but there is not currently a clear definition of which specific controller designs should be classified as low bleed and reporting practices among companies can vary. Other possibilities for explaining the low-bleed emission rates observed in this work, that have not yet been investigated, but that may be pursued in follow-up work, include operating practices for the use of the controllers.

The study estimated 2011 national methane emissions from pneumatic controllers in the natural gas production industry segment at 570,000 MT (with a range of 510,000 – 812,000 MT based on the 95% confidence bounds of the emission factor) using the same number of controllers (447,379) used in the 2013 GHG Inventory for 2011. This estimate was computed using a regionally weighted emission factor of 67,400 scfy methane/device.

2.1.6 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013)

A study completed by the Prasino Group was conducted to determine the average bleed rate of pneumatic controllers when operating under field conditions in British Columbia (BC). Bleed rates were sampled from pneumatic controllers using a positive displacement bellows meter at upstream oil and gas facilities across a variety of producing fields in the Fort St. John, BC and surrounding areas. For this study, bleed rate was defined as "the amount of fuel gas released to the atmosphere per hour," including both continuous bleed (where applicable) and emissions during activation. The study centered on high bleed controllers, including both continuous bleed and intermittent controllers with emissions greater than 0.17 cubic meters per hour ($m^{3/}hr$) (e.g, > 6 scfh).[12] The study aimed to identify the most common high bleed pneumatic controllers in the field and test emissions from at least 30 units of each model. In identifying controllers to test, the study used a manufacturer-supplied emission rate of 0.119 m^3/hr as a cutoff to explore whether some models identified by manufacturers as low bleed perform at that level in the field.

Field measurements were carried out with a Calscan Hawk 9000 Vent Gas Meter, which uses a positive displacement diaphragm meter that detects flow rates down to zero, and can also effectively measure any type of vent gas (methane, air, or propane). (A few sampled devices ran on air at large sites using compressed air, or propane at sour sites using compressed propane; such samples were corrected using a density ratio to equivalent natural gas emissions rates.) This device uses "a precision pressure sensor, an external temperature probe, and industry standard gas flow measurement algorithms to accurately measure the gas rates and correct for pressure and temperature differences." The report notes that metering a device can affect the operation of the device when hooked up due to back pressure, adding that it is possible that certain controllers did not produce enough pressure when hooked up to overcome the back pressure, resulting in a

[12] This definition of "high bleed" is slightly different than the definition presented in Section 1.1.1 of this paper, because "intermittent bleed controllers" are included as "high bleed controllers" if their emissions are above the specified threshold. The definition presented in Section 1.1.1 places "intermittent bleed controllers" in their own category.

zero reading. The sample time for each controller was 30 minutes, so there was variability in the number of actuation events captured for each controller depending on operating conditions.

In addition to emission factors for individual models of pneumatic controllers, the study generated emission factors for "generic high bleed controllers" and "generic high bleed intermittent controllers." The study also included a regression analysis of the relationship between bleed rate and the pressure of the supply gas routed to the controller. Based on the analysis, the study found that the positive relationship between these parameters was strong enough to recommend use of a supply pressure coefficient to calculate the bleed rate for several controller models and for generic controllers. The generic emission factors and supply pressure coefficients are shown in Table 2-9.

Table 2-9. Generic Natural Gas Emission Factors and Supply Pressure Coefficients for High Bleed Pneumatic Controllers

Type of Pneumatic Controller	Average Bleed Rate (m^3/hr)[a]	Average Bleed Rate (scfh)[b]	Coefficient Related to Supply Pressure[c]
Generic High Bleed Controller	0.2605	9.199	0.0012
Generic High Bleed Intermittent Controller	0.2476	8.744	0.0012

[a] "Bleed rate" defined to include actuation emissions as well as continuous bleed.
[b] Calculated.
[c] Supply pressure apparently in kPa, although not clearly stated in the report.

Based on what it termed a "positive correlation," the Prasino study recommended the use of the supply pressure coefficients above for calculating emission rates for generic high bleed controllers and generic high bleed intermittent controllers. It should be noted that the coefficients of determination (R^2 values) for these supply pressure coefficients are 0.41 and 0.35 for high bleed and high bleed intermittent controllers, respectively.

2.1.7 Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas (Roy et al., 2014)

A study by the Center for Atmospheric Particle Studies at Carnegie Mellon University was conducted to develop an emission inventory for the development, production, and processing of natural gas in the Marcellus Shale region for 2009 and 2020. (Note: The focus of this white paper is current emissions, therefore, the 2020 projections are not discussed further.) The inventory includes estimates for emissions of nitrogen oxides, VOC, and particulate matter less than 2.5 micrometers in diameter from major activities, including VOC emissions from pneumatic controllers associated with "wet" and "dry" gas wells. The study estimated VOC emissions from pneumatic controllers associated with Marcellus Shale natural gas wells to be on the order of 10 tons/day in 2009.

This study developed these emissions estimates by estimating the number of wet and dry wells in the region and establishing per-well emission factors for 2009. The per-well emission factors are shown in Table 2-10.

Table 2-10. Per-Well VOC Emissions from Pneumatic Controllers in 2009 (95% confidence interval)

Type of Well	VOC Emissions, 2009 (tons/producing well)
Dry Gas	0.5 (0.08 – 0.8)
Wet Gas	3.5 (2.4 – 4.4)

The per-well emission factors were based on assumptions regarding the type, number, and emission factors for pneumatic controllers associated with each natural gas well, which were drawn primarily from a 2008 ENVIRON report.[13] Table 2-11 shows these assumptions.

[13] Bar-Ilan, Amnon et al., ENVIRON International Corporation. *Recommendations for Improvement to the CENRAP States' Oil and Gas Emissions Inventories*. Prepared for the Central States Regional Air Partnership. November 13, 2008. This report also includes emission factors for positioners (15.2 scfh) and transducers

Table 2-11. Assumed Type, Number, and Emission Factors for Pneumatic Controllers Associated with Each Natural Gas Well

Type of Device	Number of Controllers	Emission Factor (scfh)[a]
Liquid Level Controller	2	31 (2009)
Pressure Controller	1	17 (2009)

[a] 2009 emission factors are from the 2008 ENVIRON report.

The emission factors from this study and the ENVIRON report are not comparable to the emission factors discussed above because they are provided for different classifications of pneumatic controllers. In addition, these emission factors differ from those discussed previously in that they are based on bleed rates provided by manufacturers rather than measured emissions.

2.1.8 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)

The Environmental Defense Fund (EDF) commissioned ICF International (ICF) to conduct an economic analysis of methane emission reduction opportunities from the oil and natural gas industry to identify the most cost-effective approach to reduce methane emissions from the industry. The study projects the estimated growth of methane emissions through 2018 and focuses its analysis on 22 methane emission sources in the oil and natural gas industry (referred to as the targeted emission sources). These targeted emission sources represent 80% of their projected 2018 methane emissions from onshore oil and gas industry sources. Pneumatic devices are several of the 22 emission sources that are included in the study and include: high bleed pneumatic controllers, intermittent bleed pneumatic controllers, Kimray pumps, intermittent bleed pneumatic controllers – dump valves, and chemical injection pumps. The

(13.6 scfh). The emission factors in the report "were obtained from data gathered as part of the EPA's Natural Gas STAR program." Examination of Natural Gas STAR program materials clearly shows that these emission factors were derived from the manufacturer-supplied natural gas bleed rates for high bleed pneumatic controllers listed in Appendix A to *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. The ENVIRON report also includes the number of controllers of each type associated with each gas well, said to be drawn from survey data in the CENRAP states. The numbers for liquid level controllers and pressure controllers are reflected in Table 2-15; the report found zero positioners and transducers per well.

methodology that was used for this analysis is based on the 2013 GHG Inventory and uses data from the GHGRP and the University of Texas/EDF gas production measurement study (Allen et al., 2013).

The study relied on the 2013 GHG Inventory for 1990-2011 for methane emissions data for the oil and natural gas sector. These emissions data were revised to include updated information from the GHG Inventory and the *Measurements of Methane Emissions at Natural Gas Production Sites in the United States* study (Allen et al., 2013). The revised 2011 baseline methane emissions estimate was used as the basis for projecting onshore methane emissions to 2018. (Note: The focus of this white paper is current emissions, therefore, the 2018 projections are not discussed further.)

The study used the 2013 GHG Inventory estimates for 2011 to develop new activity and emission factors for pneumatic controllers. The count of pneumatic controllers was calculated using the well counts and assuming 0.94 pneumatic controllers per well. The study did find that there are an additional 8.6 pneumatic controllers per gathering/boosting station that were not accounted for in the 2013 GHG Inventory. The study also used emission factors from subpart W, which reported pneumatic controllers in three categories: low bleed, intermittent bleed and high bleed controllers. To break out the number of pneumatic controllers in each of these categories, the emission data from subpart W were analyzed, and the study determined that the percentage of pneumatic controllers were 10% high bleed, 50% intermittent bleed and 40% low bleed. These percentages were applied to the pneumatic controller counts and the respective emission factor was used to calculate the emissions from these controllers. Intermittent pneumatic controllers were further segregated into two categories: dump valves and non-dump valve intermittent controllers. The dump valves represent intermittent controllers that do not continuously bleed and only emit during actuation. The study estimated that 75% of the total intermittent pneumatic controllers were dump valves. Based on the subpart W data and the assumptions above, the study used the following emission factors for each of the controllers: 320 Mcf/yr/device for high bleed, 120 Mcf/yr/device for non-dump intermittent, 20 Mcf/yr/device for dump intermittent and 11 Mcf/yr/device for low bleed pneumatic controllers. Using these factors, the study estimated an increase of 41% (26 Bcf or 491,000 MT) in methane emissions in comparison to the 2013 GHG Inventory.

Further information included in this study on the replacement of high bleed and intermittent bleed pneumatic controllers with low bleed pneumatic controllers, and the replacement of pneumatic pumps with electric pumps as mitigation or emission reduction techniques, methane control costs, and their estimates for the potential for VOC emissions co-control benefits from the replacement of these pneumatic controllers are presented in Section 3 of this document.

2.2 Discussion of Data Sources for Pneumatic Pumps

Many of the data sources for pneumatic pumps are the same as those for pneumatic controllers, therefore, the overall descriptions of these data sources are not repeated in this section and only the information relevant to pneumatic pumps is discussed.

2.2.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c) (GRI/EPA, 1996e)

The methane emission estimates for pneumatic pumps are separated into two categories for the GRI/EPA reports; chemical injection pumps (GRI/EPA, 1996d) and gas-assisted glycol pumps (GRI/EPA, 1996f). A summary of each of these reports and the methane calculation methodologies are provided in the following sections.

2.2.1.1 Methane Emissions from the Natural Gas Industry – Chemical Injection Pumps (GRI/EPA, 1996c)

This report estimates emissions from two types of pumps that the oil and natural gas industry uses for chemical injection into process streams: piston pumps and diaphragm pumps. Four sources of information were used to develop an emission factor for chemical injection pumps: a study by the CPA[14], data collected from site visits, literature data for methane composition, and data from pump manufacturers.

The CPA study provided natural gas emissions from five diaphragm chemical injection pumps using the "bagging" method. This method involves enclosing the pump and measuring the flow rate and concentration of the natural gas emissions from the pump. The measurements from this study reported natural gas emissions ranging from 254 to 499 standard cubic feet per day per pump (scfd/pump) with an average of 334 scfd/pump.

Data from site visits included: the total number of chemical injection pumps for a particular site, number of chemical injection pumps used in natural gas production, the energy source for the pump (e.g., natural gas, instrument air, electricity), frequency of operation (e.g., pumping rate in strokes per minute), number of pumps that are active or idle, pump operation schedule, size of the unit (e.g., volume displacement of the motive chamber), manufacturer and model number of the pump, and supply gas pressure. Table 2-12 provides a summary of the site visit data. The methane emission factor in Table 2-12 was calculated using a methane composition of 78.8% (GRI/EPA, 1996d).

Table 2-12. Summary of Chemical Injection Pump Site Visit Data

Chemical Injection Pump Data	All Data		Natural Gas Industry Data	
	Piston Pumps	Diaphragm Pumps	Piston Pumps	Diaphragm Pumps
Percent of Total Pumps	49.8 ± 38%	50.2 ± 38%	4.5 ± 678%	95.5 ± 32%
Pump Actuation Rate (strokes/min)	26.32 ± 29%	13.64 ± 49%	3.57 ± 42%	14.75 ± 61%
Number of Pump Actuation Measurements	32	8	15	5
Number of Sites with	7	5	2	4

[14] Canadian Petroleum Association. A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta, March 1992.

Chemical Injection Pump Data	All Data		Natural Gas Industry Data	
	Piston Pumps	Diaphragm Pumps	Piston Pumps	Diaphragm Pumps
Pump Actuation Measurements				
Percent of Pumps Operating	44.6 ± 62%	40.0 ± 52%	77.5 ± 148%	58.0 ± 39%
Number of Sites with Pumps Operating	7	10	4	6
Methane Emissions Factor (scfd/pump)	248 ± 83%		668 ± 88%	

Manufacturers' data and the CPA data were used to determine the volume of gas released per pump stroke. This was done by using the natural gas usage data (amount of natural gas required to pump one gallon of liquid), stroke length, and stoke diameter to calculate volume of natural gas per pump stoke. For diaphragm pumps, the average natural gas usage was calculated to be 0.0719 standard cubic feet per stroke (scf/stroke). The piston pump average natural gas usage was calculated to be 0.0037 scf/stroke. These averages were then used to determine the emission factor for each of the pump types by multiplying the average frequency (strokes per day) by the operating time percentage. Note that the report uses the "all data" frequency and operating percentage to calculate the emission factor for each type of pump. The emission factor for diaphragm pumps was calculated to be 446 scfd/pump and the emission factor for piston pumps was calculated to be 48.9 scfd/pump.

The percentage of piston and diaphragm pumps and their respective emission factors were then used to calculate an average emission factor for chemical injection pumps. The average emission factor was determined to be 248 scfd/pump. The 1992 national emissions were then calculated using the average chemical injection pump emission factor (248 scfd/pump) and the activity factor for chemical injection pumps of 16,971 (GRI/EPA, 1996a). The resulting 1992 national emissions from chemical injection pumps for the natural gas production segment was calculated to be 1,536 MMscf/yr (29,008 MT).

2.2.1.2 Methane Emissions from the Natural Gas Industry – Gas-Assisted Glycol Pumps (GRI/EPA, 1996e)

For many glycol dehydrators in the natural gas industry, small gas-assisted pumps are used to circulate the glycol. These pumps use energy from the high-pressure rich glycol/gas mixture leaving the absorber to pump the low-pressure lean glycol back to the absorber. Natural gas is entrained in the rich glycol stream feeding the pump and is discharged from the pump at a lower pressure to the regenerator. If the glycol unit has a flash tank, most of the natural gas in the low-pressure stream can be recovered and used as a fuel or stripping gas. If the natural gas from the pump is used as a stripping gas, or if there is no flash tank, all of the pump exhaust gas will be vented through the regenerator's atmospheric vent stack (GRI/EPA, 1996e).

Methane emissions from these gas-assisted pumps were calculated using technical information from Kimray, a manufacturer of gas-assisted pumps. No direct measurements of pump gas usage were used in the calculations. Kimray reported that the natural gas usage ranges from 0.081 actual cubic feet per gallon of glycol pumped (acf/gal) for high-pressure pumps (>400 psig) to 0.130 acf/gal for low-pressure pumps (< 400 psig). These values convert to 3.73 standard cubic feet per gallon (scf/gal) at an operating pressure of 800 psig and 83 mole percent methane for high-pressure pumps and 2.31 scf/gal at an operating pressure of 300 psig and 83 mole percent methane for low-pressure pumps.

The gas usage rates were then converted to an amount of natural gas treated by assuming a typical high-pressure dehydrator would remove 53 pounds of water per million cubic feet of gas (lbs/MMscf), and a typical low-pressure dehydrator would remove 127 lbs/MMscf. The design glycol-to-gas ratio was assumed to be three gallons of glycol per pound of water removed and an overcirculation ratio of 2.1 was used to determine the emission factors for the pumps for the natural gas production segment. Using these factors and the fraction of dehydrators without flash tanks (0.735) and the fraction of dehydrators without combustion vent controls (0.988), the emission factor for the gas-assisted pumps in the natural gas production segment were calculated to be 904.5 standard cubic feet of methane per million standard cubic feet of natural gas treated (scf/MMscf) for high-pressure pumps, and 1342.2 scf/MMscf for low-pressure pumps. The final emission factor for methane from an average gas-assisted glycol pump was determined assuming that 80% of these pumps are high-pressure and 20% are low-pressure. The average emission factor was calculated to be 992.0 scf/MMscf and was used to estimate methane emissions from the natural gas production segment.

For natural gas processing, the study assumed that only high-pressure gas-assisted glycol pumps are used. The emission factor was calculated using the high-pressure pump gas usage (3.73 scf/gal), the design glycol-to-gas ratio (3 gal glycol/lb water), the water removal rate for a high-pressure system (53 lbs/MMcsf), an overcirculation ratio of 1.0, the fraction of dehydrators without flash tanks (0.333) and the fraction of dehydrators without combustion vent controls (0.900). These values were used to calculate a methane emission factor of 177.8 scf/MMscf for gas-assisted pumps for the natural gas processing segment. The natural gas transmission and storage segments do not use gas-assisted glycol pumps.

The 1992 national methane emissions were calculated using data from site surveys to determine the natural gas throughput of dehydrators with gas-assisted pumps. The natural gas throughput of dehydrators with gas-assisted pumps was estimated to be 11.1 trillion standard cubic feet per year (Tscf/yr) for the natural gas production segment and 0.958 Tscf/yr for the natural gas processing segment. The 1992 national methane emissions from gas-assisted pumps were calculated to be 10,962 MMscf/yr (206,989 MT) for the natural gas production segment and 170 MMscf/yr (3,215 MT) for the natural gas processing segment.

2.2.2 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

Table 2-13 summarizes the 2014 GHG Inventory estimates of 2012 national methane emissions from pneumatic pumps in the natural gas production and processing segments. (Note: The GHG inventory does not include estimates of emissions from pneumatic pumps in the natural gas transmission and storage segments.) The pneumatic pumps described in the GHG Inventory include: chemical injection pumps and Kimray pumps. The table includes potential emissions, emission reductions and net emissions. For pneumatic pumps, the emission reductions in this report are voluntary reductions through the Natural Gas STAR program. In future years, the GHG Inventory will also account for regulatory reductions that result from subpart OOOO.

Table 2-13. Summary of GHG Inventory 2012 Nationwide Emissions from Pneumatic Pumps

Industry Segment	Potential CH_4 Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Natural gas production	455,719	2,771	452,948
Petroleum Production	49,973	N/A	
Natural gas processing	5,011	N/A	

The 2014 GHG Inventory data estimates that pneumatic pump emissions are around 16% of overall methane emissions from the natural gas production and processing sectors.

Tables 2-14 and 2-15 show the 2014 GHG Inventory's estimates of 2012 methane emissions from chemical injection pumps and gas-assisted pumps (Kimray pumps) in the natural gas and petroleum production and processing industry segments. The tables present population of chemical injection and Kimray pumps, methane emission factors and potential methane emissions from these devices in each of the EIA's NEMS regions, and the estimated national total of chemical injection pumps, Kimray pumps and potential methane emissions. The activity factors for chemical injection pumps are based on the estimated count of chemical injection pumps in operation. For the production sector, a regional factor for pumps per well (ranging from 0.01 to 0.68) is applied to annual regional well counts to calculate chemical injection pumps each year for natural gas, and for petroleum systems it is estimated that around 20% of wells have pumps (based on 1996 GRI/EPA) and that 25% of pumps use gas. For the production sector, the activity factors for Kimray pumps are based on the total throughput of natural gas multiplied by the fraction of dehydrators using gas-driven pumps (0.9 for the production segment). For the processing segment, the activity factor for Kimray pumps is based the total processing plant throughput multiplied by the fraction of natural gas treated by dehydrators at gas plants (0.5) and then multiplied by the fraction of dehydrators that use a gas-driven pump (0.1 for the processing segment).

Table 2-14. Estimated 2012 National and Regional Methane Emissions from Chemical Injection Pumps in the Natural Gas Production Segment

NEMS Region	Population of Chemical Injection Pumps[a]	CH_4 Potential Emission Factor (scfd/device)[a]	CH_4 Emissions (MT)
Natural Gas Production			
North East	795	268	1,499
Midcontinent	15,343	260	28,045
Rocky Mountain	14,849	244	25,448
South West	2,531	253	4,508
West Coast	1,422	289	2,890
Gulf Coast	2,537	278	4,951
Total Natural Gas	37,477		67,341
Voluntary Emission Reductions			-2,771
Net Emissions-Natural Gas			64,570
Petroleum Production	28,702	248	49,973

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.

Table 2-15. Estimated 2012 National and Regional Methane Emissions from Kimray Pumps in the Natural Gas Production and Processing Segments

NEMS Region	Total Natural Gas using Kimray Pumps[a]	CH_4 Potential Emission Factor (scfd/MMscf)[a]	CH_4 Emissions (MT)
Natural Gas Production			
North East	6,487,241	1,073	134,073
Midcontinent	4,409,271	1,040	88,322
Rocky Mountain	3,404,114	975	63,934
South West	1,692,957	1,014	33,050
West Coast	85,450	1,157	1,904
Gulf Coast	3,137,482	1,110	67,095
Production Total	19,216,515		388,378
Natural Gas Processing			

All Regions	1,463,675	178	5,011
Total Potential Emissions			393,389

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.
Note: The GHG Inventory did not list any Kimray pumps in the natural gas transmission or distribution sectors.

The basis for the GHG Inventory's potential methane emission factors for pneumatic pumps in the natural gas production and processing segments is the 1996 GRI/EPA report.

The region-specific factors used in the production segment are developed using the GRI/EPA factor and regional gas composition data.

2.2.3 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

The GHGRP addresses petroleum and natural gas systems with implementing regulations at 40 CFR part 98, subpart W. The rule requires facilities in the onshore petroleum and natural gas production segment to report GHG emissions from pneumatic pumps. Facilities calculate emissions from pneumatic pumps by determining the number of pneumatic pumps at the facility and applying an emission factor of 13.3 scf/hour/pump. Facilities also apply a facility-specific gas composition factor for calculating emissions. For 2012, 343 facilities in the onshore petroleum and natural gas production industry segment reported emissions from pneumatic pumps, with total methane emissions of 135,227 metric tons.

2.2.4 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013)

The study used data from the Canadian Association of Petroleum Producers (2008), Pacific Carbon Trust (2011), Cap-Op Energy's Distributed Energy Efficiency Project Platform (DEEPP) database to compile a list of pneumatic pumps. The study notes that the total number of pneumatic pumps is unknown and the list only comprises a subset of the total population. In total, 184 samples were taken from chemical injection pumps. From the data collected, the study determined the average bleed rate for a piston-type pneumatic pumps to be 0.5917 m^3/hr (approximately 20.9 scfh). For diaphragm-type pneumatic pumps, the bleed rate was calculated to be 1.0542 m^3/hr (approximately 37.2 scfh).

2.2.5 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)

The analysis developed by ICF includes an inventory of methane emissions for 2011 using data from the 2013 GHG Inventory and the GHGRP (U.S. EPA, 2013), in addition to data from the EIA and GRI.

For pneumatic chemical injection pumps in the natural gas production segment, the 2011 ICF inventory updated the count of chemical injection pumps to reflect changes made to the well counts and applied the Natural Gas STAR estimated reductions associated with pneumatic pumps. These changes resulted in a 2011 methane estimate of 3 Bcf (56,600 MT) from chemical injection pumps in the natural production segment. Kimray pumps (gas-assisted glycol pumps) were estimated to be 17 Bcf (321,000 MT).

3.0 AVAILABLE PNEUMATIC DEVICE EMISSIONS MITIGATION TECHNIQUES

The following sections describe the different available emissions mitigations techniques that the EPA is aware of for pneumatic controllers and pneumatic pumps. The primary sources of information for mitigations techniques was the EPA's Natural Gas STAR Lessons Learned documents and the ICF economic analysis (ICF, 2014).

3.1 Available Pneumatic Controller Emissions Mitigation Techniques

Several techniques to reduce emissions from pneumatic controllers have been developed over the years. Table 3-1 provides a summary of these techniques for reducing emissions from pneumatic controllers including replacing high bleed controllers with low bleed or zero bleed models, driving controllers with instrument air rather than natural gas, using non-gas-driven controllers, and enhanced maintenance.

Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Install Zero Bleed Controller in Place of Continuous Bleed Controller (U.S. EPA, 2011a, GE Energy Services, 2012)	Zero bleed controllers are self-contained natural gas-driven devices that vent to the downstream pipeline, not the atmosphere. Provide the same functional control as continuous bleed controllers, where applicable (U.S. EPA, 2011a, GE Energy Services, 2012).	Applicable only for relatively low-pressure control valves, e.g., in gathering, metering and regulation stations, power plant and industrial feed, and city gate stations/distribution applications (U.S. EPA, 2011a).	The EPA does not have cost information on this technology.	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field, however, it is the EPA's understanding that applicability is limited.
Install Low Bleed Controller in Place of High Bleed Controller (U.S. EPA, 2006b)	Low bleed controllers provide the same functional control as a high bleed devices, while emitting less continuous bleed emissions (U.S. EPA, 2006b).	Applicability depends on the function of instrumentation for an individual device and whether the device is a level, pressure, or temperature controller. Not recommended for control of very large valves that require fast and/or precise response to process changes. These are found most frequently on large compressor discharge and bypass pressure controllers (U.S. EPA, 2006b).	Based on information from Natural Gas STAR (U.S. EPA, 2006b) and supplemental research conducted for subpart OOOO, low bleed devices cost, on average, around $165 more than high bleed versions. ICF report assumed a cost of $3,000 per replacement based on industry comments (ICF, 2014).	Estimated average reductions (U.S. EPA, 2011a): *Production segment:* 6.6 tpy methane *Transmission:* 3.7 tpy methane The EPA does not have information on the prevalence of this technology in the field.

Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Convert to Instrument Air (U.S. EPA, 2006c)	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel (U.S. EPA, 2006c).	Most applicable at facilities where there are a high concentration of pneumatic control valves and an operator present. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic device (U.S. EPA, 2006c).	System costs are dependent on size of compressor, power supply needs, labor and other equipment (U.S. EPA, 2006c). A cost analysis is provided in Section 3.1.3 below.	100% emission reduction, where applicable. There are secondary emissions associated with electrical power generation. The EPA does not have information on the prevalence of this technology in the field.
Mechanical and Solar-Powered Systems in Place of Bleed Controller (U.S. EPA, 2006a, U.S. EPA, 2006b)	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar-powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability (U.S. EPA, 2006a).	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric-powered valves are only reliable with a constant supply of electricity (U.S. EPA, 2006a).	Depending on supply of power, costs can range from below \$1,000 to \$10,000 for entire systems (U.S. EPA, 2006a).	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field.

Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Enhanced Maintenance (U.S. EPA, 2006a)	Instrumentation in poor condition typically bleeds 5 to 10 scfh more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear; or loose control tube fittings. This may not impact operations but does increase emissions. Proper methods of maintaining a device are highly variable (U.S. EPA, 2006a).	Enhanced maintenance to repair and maintain pneumatic controllers periodically can reduce emissions at many controllers (U.S. EPA, 2006a).	Variable based on labor, time, and fuel required to travel to many remote locations.	Natural gas emission reductions of 5 to 10 scfh (U.S. EPA, 2006a). The EPA does not have information on the prevalence of this practice in the field.

The mitigation techniques summarized in Table 3-1 are discussed in more detail in the following sections.

3.1.1 Zero Bleed Pneumatic Controllers

Zero bleed pneumatic controllers are self-contained, “closed loop” natural gas-driven controllers that vent to the downstream pipeline rather than to the atmosphere (U.S. EPA, 2011a). These closed loop devices are considered to emit no natural gas to the atmosphere. However, they can be used only in applications with very low pressure and, therefore, may not be suitable to replace continuous bleed pneumatic controllers in many applications. Some applications where they may suitable include gathering, metering and regulation stations, power plant and industrial feed, and city gate stations/distribution (U.S. EPA, 2011a). To date, the EPA has not obtained any information on the cost of zero bleed controllers or their prevalence in the field.

3.1.2 Low Bleed Pneumatic Controllers

Description

Low bleed controllers provide similar functional control as high bleed controllers, but have lower continuous bleed emissions. It has been estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low bleed device in place of a high bleed device (U.S. EPA, 2011a). In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively (U.S. EPA, 2011a). As defined in this white paper, a low bleed controller can emit up to 6 scfh, but this is higher than the expected emissions from the typical low bleed controllers available on the current market.

Applicability

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved.

Replacing high bleed pneumatic with low bleed controllers is infeasible in situations where a process condition may require a fast or precise control response so that it does not stray too far from the desired set point (U.S. EPA, 2011a). A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic controllers monitor the suction and discharge pressure and actuate a recycle when one or the other is out of the specified target range. Another scenario where fast and precise control is necessary includes transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably (U.S. EPA, 2011a). In this case, a responsive high bleed device may be required to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes may be appropriate for control from a low bleed device, which is slower acting and less precise.

Safety concerns can limit the appropriateness of low bleed controllers in specific situations where any amount of bleeding is unacceptable. Emergency valves are often not controlled with bleeding controllers (e.g., neither low bleed nor high bleed), because it may not be acceptable to have any amount of bleeding in emergency situations (U.S. EPA, 2011a). Pneumatic controllers are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,[15] the equipment in place for such an event is spring-loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic

[15] ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.

gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

Costs

The costs described in this section are based on vendor research and information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic controllers (U.S. EPA, 2006a). As Table 3-2 indicates, the average cost for a low bleed pneumatic is $2,553, while the average cost for a high bleed is $2,338.[16] Thus, the incremental cost of installing a low bleed device instead of a high bleed device is on the order of $165 per device. (Note: The ICF report assumed a cost of $3,000 to replace an existing high bleed pneumatic controller with a low bleed pneumatic controller based on industry comments (ICF, 2014).)

Table 3-2. Cost Projections for the Representative Pneumatic Controllers[a]

Device	Minimum cost ($)	Maximum cost ($)	Average cost ($)	Low Bleed Incremental Cost ($)
High bleed controller	366	7,000	2,388	$165
Low bleed controller	524	8,852	2,553	

[a] Major pneumatic controllers vendors were surveyed for costs, emission rates and any other pertinent information that would give an accurate picture of the present industry.

Monetary savings associated with additional gas captured to the sales line were estimated based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).[17] The representative low bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high bleed device per year. Assuming production quality gas is 82.8% methane by volume, this equals 385.5 Mcf natural gas recovered

[16] Costs are estimated in 2008 U.S. Dollars.
[17] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the value, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

per year (EC/R, 2011). Therefore, the value of recovered natural gas from one pneumatic controller in the production segment equates to approximately $1,500. While the owner of the transmission system is generally not the owner of the natural gas, the potentially lost gas still has value. The total value of the recovered gas from one pneumatic controller in the transmission segment is $1,375 assuming a natural gas value of $4.00 per Mscf and transmission natural gas is 92.8% methane by volume (EC/R, 2011).

3.1.3 Instrument Air Systems

Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document (U.S. EPA, 2006c), *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air:*

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.
- A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of

electric power can be difficult to ensure. In some instances, solar-powered battery-operated air compressors can be effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. A diagram of a natural gas pneumatic controller is presented in Figure 3-1. A diagram of a compressed instrument air system is presented in Figure 3-2.

<u>Applicability</u>

The use of instrument air eliminates natural gas emissions from the natural gas-driven pneumatic controllers; however, these systems may only be used in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning (U.S. EPA, 2006c).

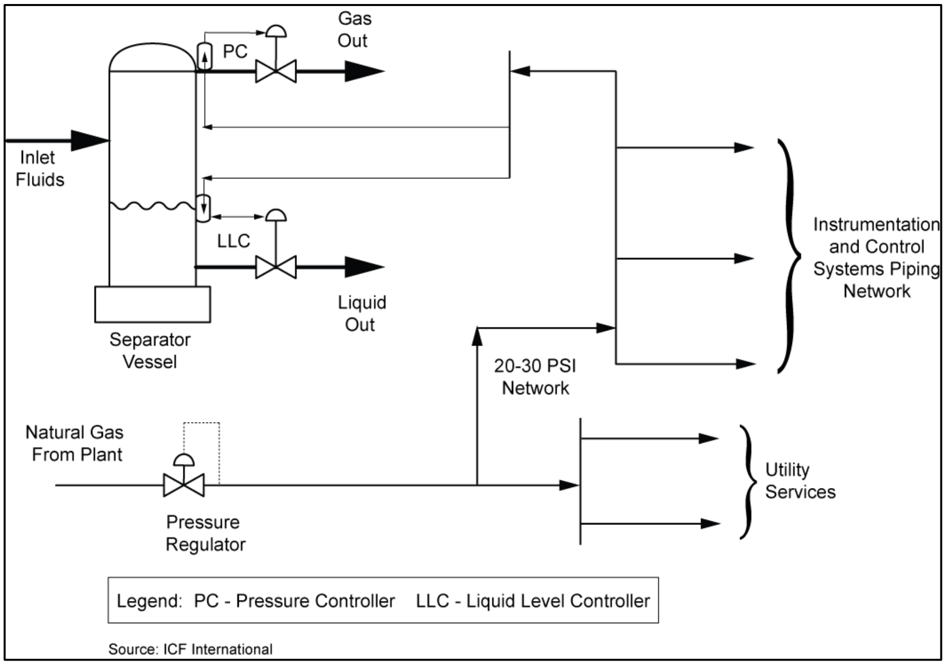

Figure 3-1 Natural Gas Pneumatic Control System

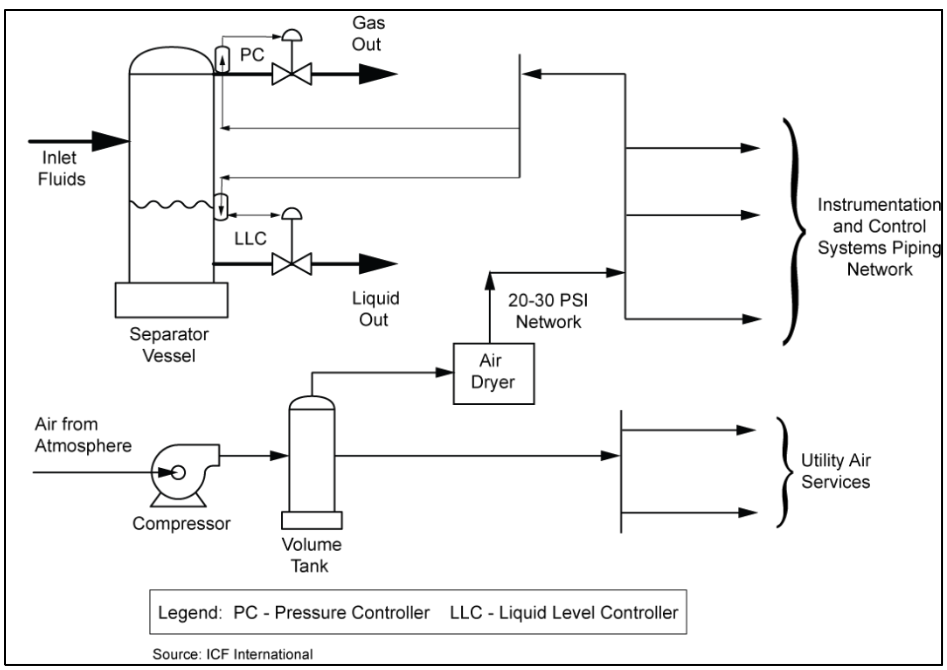

Figure 3-2. Compressed Instrument Air System

Costs

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation—adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is 1 cubic foot per minute (cfm) of instrument air for each control loop. As the system is powered by electric compressors, the system requires a constant source of electrical power or a backup pneumatic device. Table 3-3 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

Table 3-3. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate	Control Loops
Size of Unit	Hp	kW	(cfm)	Loops/Compressor
Small	10	13.3	30	15
Medium	30	40	125	63
Large	75	100	350	175

[a] Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air.*

[b] Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50% of the year).

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors based on assumptions found in the Natural Gas STAR document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air” are summarized in Table 3-4.

3.1.4 Mechanical and Solar-Powered Systems in Place of Bleed Controller

Description

Mechanical controls have been widely used in the natural gas and petroleum industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical control device being a liquid-level float to the drain valve position with mechanical linkages (U.S. EPA, 2006a). Another device that is increasing in use is electronic control instrumentation. Electricity or small electrical motors (including solar-powered) have been used to operate valves and therefore do not bleed natural gas into the atmosphere (U.S. EPA, 2006a). Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability.

Applicability

Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations (U.S. EPA, 2006c). Electric-powered valves are only reliable with a constant supply of electricity. These controllers can achieve 100% reduction in emissions where applicable.

Costs

Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems (U.S. EPA, 2006a).

Table 3-4 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital[a]	Annualized Capital[b]	Labor Cost	Total Annual Costs[c]	Annualized Cost of Instrument Air System
Small	$3,772	$754	$2,262	$16,972	$2,416	$1,334	$8,674	$11,090
Medium	$18,855	$2,262	$6,787	$73,531	$10,469	$4,333	$26,408	$36,877
Large	$33,183	$4,525	$15,083	$135,750	$19,328	$5,999	$61,187	$80,515

[a] Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.

[b] The annualized cost was estimated using a 7% interest rate and 10-year equipment life.

[c] Annual Costs include the cost of electrical power as listed in Table 3-3 and labor.

3.1.5 Maintenance of Natural Gas-Driven Pneumatic Controllers

Manufacturers of pneumatic controllers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age, and wear of the device (U.S. EPA, 2006a). Examples of circumstances or factors that can contribute to this increase include:

- Nozzle corrosion resulting in more flow through a larger opening.
- Broken or worn diaphragms, bellows, fittings, and nozzles.
- Corrosives in the gas leading to erosion or corrosion of control loop internals.
- Improper installation.
- Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of O-rings and/or seals).
- Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle.
- Foreign material lodged in the pilot seat.
- Wear in the seal seat.

Maintenance of pneumatics can correct many of these problems and can be an effective method for reducing emissions. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device (U.S. EPA, 2006a).

However, proper methods of maintaining a device are highly variable, thus, costs are variable based on labor, time, and fuel required to travel to many remote locations.

3.2 Available Pneumatic Pump Emissions Mitigation Techniques

There are several techniques that are currently being used to reduce emissions from pneumatic pumps. Table 3-5 provides a summary of these techniques for reducing emissions from pneumatic pumps, which include chemical injection pumps and natural gas-assisted recirculation pumps.

3.2.1 Instrument Air Pump

Description

Circulation pumps in glycol dehydration processes and chemical injection pumps are often powered by pressurized natural gas at remote locations. As a result, these pumps vent natural gas to the atmosphere as part of their normal operation. To mitigate VOC and methane emissions, some companies are using instrument air to power these pumps. These companies have found that the use of instrument air increased operational efficiency, decreased maintenance and decreased costs, while eliminating emissions of methane and VOC (U.S. EPA, 2011b).

Applicability

Converting chemical injection pumps and glycol dehydration circulation pumps to instrument air can be applied to natural gas hydration operations across all gas industry sectors with excess capacity of its instrument air system. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic device (U.S. EPA, 2011b).

Costs

The total cost to convert a natural gas pneumatic circulation pump to instrument air includes the installation of piping and an appropriate control system between the existing instrument air system and the glycol pump if the driver is independent of the circulation pump. If the driver is separated from the pump by O-rings, then the pump would need to also be replaced. The implementation capital costs are estimated to be $1,000 to $10,000, and the incremental operating costs are estimated to be $100 to $1,000 (U.S. EPA, 2011b). The potential annual

Table 3-5. Summary of Alternative Mitigation Techniques for Pneumatic Pumps

Option	Description	Applicability	Costs	Efficacy and Prevalence
Replace natural gas-assisted pump with instrument air pump (U.S. EPA, 2011b)	Circulation pumps in glycol dehydration units and chemical injection pumps are retrofitted with instrument air to drive the pumps (U.S. EPA, 2011b).	Facilities with excess capacity of instrument air or facilities that can install an air compressor system. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic pump (U.S. EPA, 2011b).	The installation of the piping from the air compressor system to the pump accounts for the bulk of the capital cost and typically ranges from $100 to $1,000 (U.S. EPA, 2011b).	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 2,500 Mcf for glycol circulation pumps and 183 Mcf for chemical injection pumps (U.S. EPA, 2011b). The EPA does not have information on the prevalence of this technology in the field.
Replacement of natural gas-assisted pump with solar-charged direct current pump (U.S. EPA, 2011b)	In field settings, low volume natural gas pneumatic pumps can be replaced with solar-charged DC pumps (U.S. EPA, 2011b).	Low volume solar-charged pneumatic pumps are limited to approximately 5 gallons per day discharge at 1,000 psig. Large volume solar pumps are available with maximum output of 38 to 100 gallons per day at maximum injection pressures of 1,200 to 3,000 psig (U.S. EPA, 2011b).	The reporting partners for Natural Gas STAR stated a replacement cost of $2,000 per pump, including the solar panels, storage batteries and pump (U.S. EPA, 2011b).	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 182.5 Mcf per chemical injection pump conversion (U.S. EPA, 2011b). The EPA does not have information on the prevalence of this technology in the field.

Option	Description	Applicability	Costs	Efficacy and Prevalence
Replacement of natural gas-assisted pump with electric pump (ICF, 2014)	In settings where a constant supply of electricity is available, natural gas pneumatic pumps can be replaced with electric pumps (ICF, 2014).	These pumps require a constant source of electricity, thus, they are typically installed at processing plants or large dehydration facilities, which are normally equipped with electricity (U.S. EPA, 2011b).	Electrical pumps are estimated to cost roughly $10,000 per pump and the annual electrical usage cost was estimated to be $2,000 per year. (ICF, 2014)	100% emission reduction, where applicable. The annual methane reduction from replacing pneumatic pumps with electrical pumps is estimated to be 5,000 Mcf (ICF, 2014). The EPA does not have information on the prevalence of this technology in the field.

natural gas savings are estimated to be 2,500 Mcf (U.S. EPA, 2011b) or $10,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010). For chemical injection pumps, the implementation costs are the same, but the potential annual natural gas savings are estimated to be 183 Mcf per pump conversion (U.S. EPA, 2011b) or $732 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

3.2.2 Solar Power Pump

Description

Solar power can be used to operate pumps located at remote sites where electricity is not available. These solar-powered pumps use electric power captured by solar panels to operate a DC-charged pump. Solar injection pumps can handle a range of throughputs and injection pressures. Low volume solar-charged DC pumps are limited to approximately 5 gallons per day discharge at 1,000 psig (U.S. EPA, 2011b). Large volume solar pumps are available with maximum output of 38 to 100 gallons per day at maximum injection pressures of 1,200 to 3,000 psig (U.S. EPA, 2011b). These pumps eliminate the methane and VOC emissions that would have resulted from the use of a pneumatic pump.

Applicability

These solar-powered pumps are generally used to replace low volume natural gas pneumatic pumps if sufficient sunlight is available to power the pumps and backup power is not required. These low volume pumps are typically used to inject methanol or corrosion inhibiters into producing wells and other field equipment. These chemical injection pumps are typically sized for 6 to 8 gallons of methanol injection per day. The large volume pumps can be used to replace gas-assisted circulation pumps for glycol dehydrators.

Costs

The Natural Gas STAR program reported the cost of replacing pneumatic pumps with solar-charged electric pumps to be approximately $2,000 per pump (U.S. EPA, 2011b). The solar panels and storage batteries are nearly maintenance free, and the solar panels have a life span of up to 15 years and the electric motors last approximately 5 years in continuous use (U.S. EPA, 2011b). The potential annual natural gas savings are estimated to be 2,500 Mcf or $10,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010) for recirculation pumps (U.S. EPA, 2011b). For chemical injection pumps, the implementation costs are the same, but the potential annual natural gas savings are estimated to be 183 Mcf (U.S. EPA, 2011b) or $732 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010). The ICF report estimates the cost of replacing chemical injection pneumatic pumps with solar-powered pumps to be $5,000 per pump with a natural gas savings of 180 Mcf per year (ICF, 2014) or $720 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

3.2.3 Electric Power Pumps

Description

Electric power pumps are used to replace natural gas-assisted pneumatic used to recirculate glycol in gas dehydrators. These pumps eliminate the methane and VOC emissions that would have resulted from the use of a pneumatic pump.

Applicability

These pumps require a constant source of electricity, thus, they are typically installed at processing plants or large dehydration facilities, which are normally equipped with electricity.

Costs

Electrical pumps are estimated to cost roughly $10,000 per pump and the annual electrical usage cost was estimated to be $2,000 per year (ICF, 2014). The annual methane reduction from replacing pneumatic pumps with electrical pumps is estimated to be 5,000 Mcf (ICF, 2014) or $20,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

4.0 SUMMARY

The EPA has used the data sources, analyses and studies discussed in this paper to form the Agency's understanding of emissions from pneumatic controllers and pumps and the emissions mitigation techniques. The following are characteristics the Agency believes are important to understanding these sources of VOC and methane emissions.

4.1 Pneumatic Controllers

- The majority of recent emissions estimates for pneumatic controllers have focused on methane emissions and not VOC emissions.
- The GHG Inventory data estimates that pneumatic controller emissions are 13% of overall methane emissions from the oil and natural gas sectors.
- Recent emission measurement studies have resulted in a wide range of methane emission factors for natural gas-driven pneumatic controllers. The studies all show that emissions can vary depending on sector (e.g., production, transmission, or storage) and the type of gas-driven pneumatic controller.
- Natural gas-driven pneumatic controllers are particularly useful in segments of the oil and natural gas industry that involve remote locations where electrical power is not available or reliable.
- Low bleed gas-driven controllers can replace high bleed gas-driven controllers in many, but not all, applications.
- Where a reliable source of electrical power is available, instrument air systems can replace natural gas-driven pneumatic controllers, and result in no methane or VOC emissions.
- Zero bleed, mechanical, and solar-powered controllers can replace continuous bleed controllers in certain applications, but are not broadly applicable to all segments of the oil and natural gas industry.

4.2 Pneumatic Pumps

- Pneumatic pumps in the oil and natural gas industry are used as chemical injection pumps and circulation pumps for glycol dehydrators. Pressure from the natural gas line is used to power these pumps and the natural gas is vented to the atmosphere.
- There are several mitigation techniques that can be used to reduce or eliminate emissions from pneumatic pumps and they include: instrument air pumps and electric pumps (both AC and DC powered).
- The 2014 GHG Inventory data estimates that pneumatic pump emissions are 16% of overall methane emissions from the natural gas production and processing sectors. The 2014 GHG Inventory estimated methane emissions from these sources to be 64,570 MT of methane for chemical injection pumps and 393,389 MT of methane for natural gas-assisted Kimray pumps. Chemical injection pumps at petroleum systems emitted 49,973 MT of methane, or around 3% of emissions from petroleum production.
- Natural gas-driven pneumatic pumps are particularly useful in segments of the oil and natural gas industry that involve remote locations where electrical power is not available or reliable.
- Where a reliable source of electrical power is available, instrument air systems are an effective replacement for natural gas-driven pneumatic pumps.

5.0 CHARGE QUESTIONS FOR REVIEWERS

1. Did this paper appropriately characterize the different studies and data sources that quantify emissions from pneumatic controllers and pneumatic pumps in the oil and gas sector?
2. Please discuss explanations for the wide range of emission rates that have been observed in direct measurement studies of pneumatic controller emissions (e.g., Allen et al., 2013 and Prasino 2013). Are these differences driven purely by the design of the monitored controllers or are there operational characteristics, such as supply pressure, that play a crucial role in determining emissions?

3. Did this paper capture the full range of technologies available to reduce emissions from pneumatic controllers and pneumatic pumps oil and gas facilities?
4. Please comment on the pros and cons of the different emission reduction technologies. Please discuss efficacy, cost and feasibility for both new and existing pneumatics.
5. Please comment on the prevalence of the different emission control technologies and the different types of pneumatics in the field. What particular activities require high bleed pneumatic controllers and how prevalent are they in the field?
6. What are the barriers to installing instrument air systems for converting natural gas-driven pneumatic pumps and pneumatic controllers to air-driven pumps and controllers?
7. Are there situations where it may be infeasible to use air driven pumps and controllers in place of natural gas-driven pumps and controllers even where it is feasible to install an instrument air system?
8. Did this paper correctly characterize the limitations of electric-powered pneumatic controllers and pneumatic pumps? Are these electric devices applicable to a broader range of the oil and gas sector than this paper suggests?
9. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from pneumatic controllers and pneumatic pumps and available techniques for increased product recovery and emissions reductions?

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NMOGA 20

Convert Gas Pneumatic Controls To Instrument Air

Executive Summary

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. The constant bleed of natural gas from these controllers is collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 51 billion cubic feet (Bcf) per year in the production sector, 14 Bcf per year in the transmission sector, and <1 Bcf from processing.

Companies can achieve significant cost savings and methane emission reductions by converting natural gas-powered pneumatic control systems to compressed instrument air systems. Instrument air systems substitute compressed air for the pressurized natural gas, eliminating methane emissions and providing additional safety benefits. Cost effective applications, however, are limited to those field sites with available electrical power, either from a utility or self-generated.

Natural Gas STAR Partners have reported savings of up to 70,000 thousand cubic feet (Mcf) per year per facility by replacing natural gas-powered pneumatic systems with instrument air systems, representing annual savings of up to $490,000 per facility. Partners have found that most investments to convert pneumatic systems pay for themselves in just over one year. Individual savings will vary depending on the design, condition and specific operating conditions of the controllers.

Technology Background

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. In the vast majority of applications, the natural gas industry uses pneumatic devices, which make use of readily available high-pressure natural gas to provide the required energy and control signals. Pneumatic instrument systems powered by high-pressure natural gas are used throughout the natural gas industry. In the production sector, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. Most processing plants already use instrument air, but some use gas pneumatics, and including the gathering/booster stations that feed these processing plants, there are about 13,000 gas pneumatic devices in this sector. In the transmission sector, an estimated 85,000 pneumatic devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Non-bleed pneumatic devices are also found on meter runs at distribution company gate stations and distribution grids where they regulate flow and pressure.

Exhibit 1 depicts a pneumatic control system powered by natural gas. The pneumatic control system consists of the process control instruments and valves that are operated by natural gas regulated at approximately 20-30 pounds

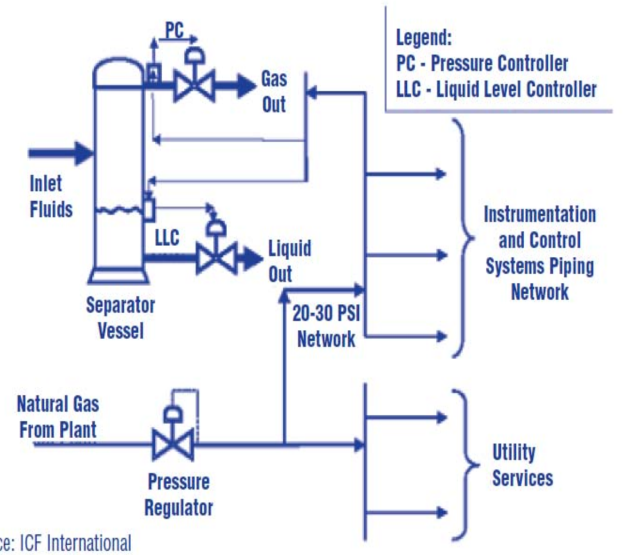
Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf/ year)	Value of Natural Gas Savings ($/ year)			Implementation Cost ($)[a]	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Replace Gas with Air in Pneumatic Systems (per facility)	20,000	$60,000	$100,000	$140,000	$60,000	12	8	6

General Assumptions:
[a] Cost of installing compressor, dryer and other accessories, and annual electricity requirements.

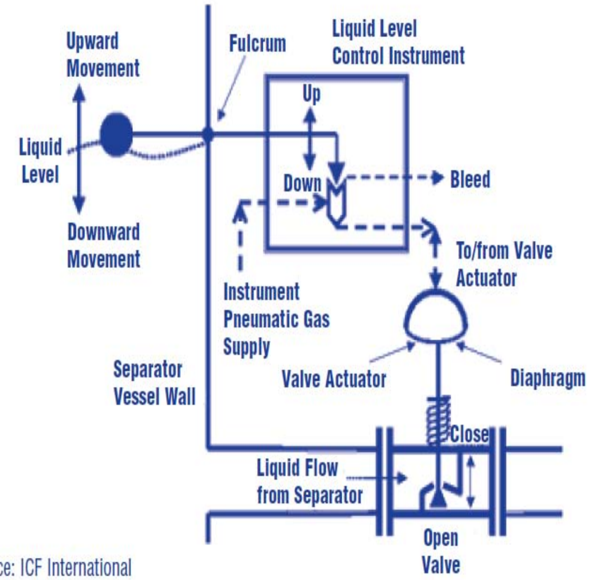
Convert Gas Pneumatic Controls To Instrument Air
(Cont'd)

Exhibit 1: Natural Gas Pneumatic Control System



Source: ICF International

Exhibit 2: Signal and Actuation Schematics



Source: ICF International

per square inch (psi), and a network of distribution tubing to supply all of the control instruments. Natural gas is also used for a few "utility services," such as small pneumatic pumps, compressor motor starters, and isolation shutoff valves. Exhibit 2 shows a simplified diagram of a pneumatic control loop. A process condition, such as liquid level in a separator vessel, is monitored by a float that is mechanically linked to the liquid level controller outside the vessel. A rise or fall in liquid level moves the float upward or downward, which is translated to small needle valves inside the controller. Pneumatic supply gas is either directed to the valve actuator by the needle valve pinching off an orifice, or gas pressure is bled off the valve actuator. Increasing gas pressure on the valve actuator pushes down a diaphragm connected by a rod to the valve plug, causing the plug to open and increasing the flow of liquid draining out of the separator vessel. Gas pressure relieved from the valve actuator allows a spring to push the valve plug closed.

As part of normal operation, natural gas powered pneumatic devices release or bleed gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network. The actual bleed rate or emissions level largely depends on the design of the device. In general, controllers of similar design have similar steady-state bleed rates regardless of brand name. The methane emission rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment.

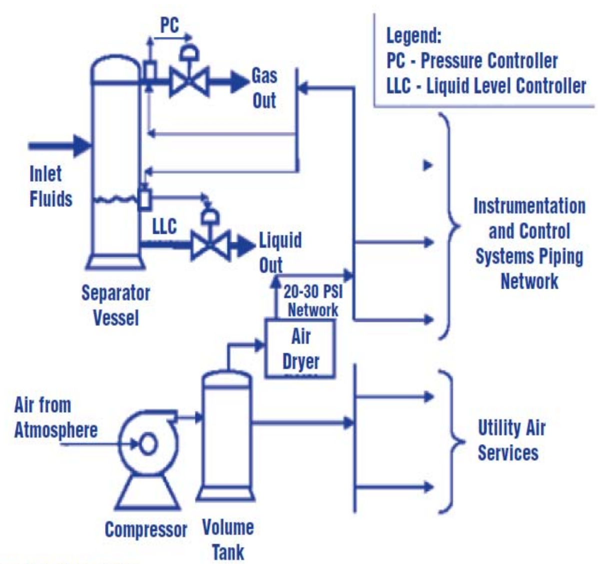
Many Partners have found that it is economic to substitute compressed air for natural gas in pneumatic systems. The use of instrument air eliminates methane emissions and leads to increased gas sales. In addition, by eliminating the use of a flammable substance, operational safety is significantly increased. The primary costs associated with conversion to instrument air systems are initial capital expenditures for installing compressors and related equipment and operating costs for electrical energy to power the compressor motor. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.

A compressed instrument air system is shown in Exhibit 3. In these systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. Air used for utility services (e.g. small pneumatic pumps, gas compressor motor starters, pneumatic tools, sand blasting) does not need to be dried. All other parts of a gas pneumatic system will work the same way with air as they do with gas.

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following are descriptions of each of

Convert Gas Pneumatic Controls To Instrument Air
(Cont'd)

Exhibit 3: Compressed Instrument Air System



Source: ICF International

these components along with important installation considerations.

- ★ **Compressor.** Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.

- ★ **Power Source.** A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduces both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- ★ **Dehydrators.** Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices. For smaller systems, membrane dryers have become economic. These are molecular filters that allow oxygen and nitrogen molecules to pass through the membrane, and hold back water molecules. They are very reliable, with no moving parts, and the filter element can be easily replaced. For larger applications, desiccant (alumina) dryers are more cost effective.

- ★ **Volume Tank.** The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Economic and Environmental Benefits

Reducing methane emissions from pneumatic devices by converting to instrument air control and instrumentation systems can yield significant economic and environmental benefits for natural gas companies including:

- ★ **Financial Return From Reducing Gas Emission Losses.** Assuming a natural gas price of $7.00 per Mcf, savings from reduced emissions can be estimated at $840 per year per device or $490,000 or more per year per facility. In many cases, the cost of converting to instrument air can be recovered in less than a year.

- ★ **Increased Life of Control Devices and Improved Operational Efficiency.** Natural gas used in pneumatic control devices and instruments often contains corrosive gases (such as carbon dioxide and hydrogen sulfide) that can reduce the effective operating life of these devices. In addition, natural

Convert Gas Pneumatic Controls To Instrument Air
(Cont'd)

gas often produces by-products of iron oxidation, which can plug small orifices in the equipment resulting in operational inefficiencies or hazards. When instrument air is used, and properly filtered and dried, system degradation is reduced and operating life is extended.

★ **Avoided Use Of Flammable Natural Gas.** Using compressed air as an alternative to natural gas eliminates the use of a flammable substance, significantly increasing the safety of natural gas processing plants and transmission and distribution systems. This can be particularly important at offshore installations, where risks associated with hazardous and flammable materials are greater.

★ **Lower Methane Emissions.** Reductions in methane emissions have been reported as high as 70,000 Mcf per facility annually, depending on the device(s) and the type of control application.

Decision Process

The conversion of natural gas pneumatics to instrument air system is applicable to all natural gas facilities and plants. To determine the most cost-effective applications, however, requires a technical and economic feasibility study. The six steps outlined below, and the practical example with cost tables, equations, and factors, can help companies to evaluate their opportunities.

Step 1: Identify Possible Locations For Instrument Air System Installations.

Most natural gas-operated pneumatic control systems can be replaced with instrument air. Instrument air systems will require new investments for the compressor, dehydrator, and other related equipment, as well as a supply of electricity. As a result, a first step in a successful instrument air conversion project is screening existing facilities to identify locations that are most suitable for cost effective projects. In general, three main factors should be considered during this process.

Decision Process for Converting Gas Pneumatic Devices to Instrument Air:

1. Identify possible locations for system installations.
2. Determine optimal system capacity.
3. Estimate the project costs.
4. Estimate gas savings.
5. Evaluate the economics.
6. Develop an implementation plan.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

★ **Facility Layout.** The layout of a natural gas facility can significantly affect equipment and installation costs for an instrument air system. For example, conversion to instrument air might not be cost effective at decentralized facilities where tank batteries are remote or widely scattered. Instrument air is most appropriate when used at offshore platforms and onshore facilities where pneumatics are consolidated within a relatively small area.

★ **Number Of Pneumatics.** The more pneumatic controllers converted to instrument air, the greater the potential for reduced emissions and increased company savings. Conversion to instrument air is most profitable when a company is planning a facility-wide change.

★ **Available Power Supply.** Since most instrument air systems rely on electric power for operating the compressor, a cost-effective, uninterrupted electrical energy source is essential. While major facilities often have an existing power supply or their own power generation system, many smaller and remote facilities do not. For these facilities, the cost of power generation generally makes the use of instrument air unprofitable. In addition, facilities with dedicated generators need to assess whether the generators have enough available capacity to support an air compression system, as the cost of a generator upgrade can be prohibitive. Remote facilities should examine alternatives for power generation, which range from microturbines to solar power.

Step 2: Determine Optimal System Capacity.

Once project sites have been identified, it is important to determine the appropriate capacity of the new instrument air system. The capacity needed is a direct function of the amount of compressed air needed to both operate the pneumatic instrumentation and meet any utility air requirements.

Convert Gas Pneumatic Controls To Instrument Air
(Cont'd)

- ★ **Instrument Air Requirements.** The compressed air needs for the pneumatic system are equivalent to the volume of gas being used to run the existing instrumentation—adjusted for air losses during the drying process. The current volume of gas usage can be determined by a direct meter reading (if a meter has been installed). In nonmetered systems, a conservative rule-of-thumb for sizing air systems is one cubic foot per minute (cfm) of instrument air for each control loop (consisting of a pneumatic controller and a control valve).

Rule-of-Thumb

1 cfm air/control loop

The initial estimate of instrument air needs should then be adjusted to account for air losses during the drying process. Typically, the membrane filters in the air dryer consume about 17 percent of the air input. As a result, the estimated volume of instrument air usage is 83 percent of the total compressed air supply: i.e., divide estimated air usage by 83 percent. Desiccant dryers do not consume air and therefore require no adjustment.

Rule-of-Thumb

17 percent of air input is consumed by the membrane dryer

- ★ **Utility Air Requirements.** It is common to use compressed air for utility purposes, such as engine starters, pneumatic driven pumps, pneumatic tools (e.g., impact wrenches), and sand blasting. Unlike instrument air, utility air does not have to be dried. The frequency and volumes of such utility air uses are additive. Companies will need to evaluate these other compressed air services on a site-specific basis, allowing for the possibility of expansion at the site. A general rule-of-thumb is to assume that the maximum rate of compressed air needed periodically for utility purposes will be double the steady rate used for instrument air.

Rule-of-Thumb

Pneumatic air uses: 1/3 for instrument air; 2/3 for utility air

Exhibit 4 illustrates how the instrument air compressor size can be estimated. Using the rule-of-thumb of 1 cfm/control loop, the current gas usage would translate to approximately 35 cfm of dry instrument air. Adjusting for the dryer's air consumption (17 percent of air input), the total instrument air supply requirement will be 42 cfm. Factoring in utility air needs of about 70 cfm, the project would require a total of 112 cfm of compressed air.

Exhibit 4: Calculate Compressor Size for Converting Gas Pneumatics to Instrument Air

Given:	For an average size production site with pneumatics, glycol dehydration, compression, 35 control loops, and an average of 10 cfm utility gas usage for pneumatic pumps and compressor engine starting.
A IAu IAs UAs L	= Total Compressed Air = Instrument air use = Instrument air supply = Utility air supply = Control loops
	Rule-of-thumb: 1 cfm per control loop for estimating instrument air systems. Rule-of-thumb: 17% of air is bypassed in membrane dryers. Rule-of-thumb: 1/3 of total air used for instruments, 2/3 of total air used for utility services.
	Calculate: A = Air compressor capacity required.
A IAu IAs UAs A	= IAs + UAs = L * (1 cfm/loop) = IAu/(100% - % air bypassed in dryer) = IAu * (fraction of utility air use) / (fraction of instrument air use) = (35*1) / (100% - 17%) + (35*1) * (2/3) / (1/3) = 112 cfm

Step 3: Estimate the Project Costs.

The major costs associated with installing and operating an instrument air system are the installation costs for compressors, dryers, and volume tanks, and energy costs. The actual installation costs will be a function of the size, location, and other location specific factors. A typical conversion of a natural gas pneumatic control system to compressed instrument air costs approximately $45,000 to $75,000.

To estimate the cost for a given project, all expenses associated with the compressor, dryer, volume tank, and power supply must be calculated. Most vendors are willing to provide estimates of the equipment costs and installation requirements (including compressor size, motor horsepower, electrical power requirements, and storage capacity). Alternatively, operators can use the following information on the major system components to estimate the total installed cost of the instrument air system.

- ★ **Compressor Costs.** It is common to install two compressors at a facility (one operating and one stand-by spare) to ensure reliability and allow for maintenance and overhauls without service interruptions. The capacity for each of the compressors must be sufficient to handle the total expected compressed air volume for the project (i.e., both instrument and utility air). Exhibit 5 presents

Convert Gas Pneumatic Controls To Instrument Air
(Cont'd)

cost estimates for purchasing and servicing small, medium, and large compressors. For screw-type compressors, operators should expect to overhaul the unit every 5 to 6 years. This normally involves exchanging the compressor core for a rebuilt compressor at a cost of approximately $3,929, with an additional $720 in labor expense and a $650 core exchange credit.

Exhibit 5: Air Compressor Costs

Service Size	Air Volume (cfm)	Comp-ressor Type	Horse-power	Equip-ment Costs ($)	Annual Service ($/yr)	Service Life (yrs)
Small	30	Recipro-cating	10	3,275[a]	434	1
Medium	125	Screw	30	16,371	868	5-6[b]
Large	350	Screw	75	28,812	868	5-6[b]

[a] Cost included package compressor with a volume tank.
[b] Rebuilt compressor costs $3,929 plus $500 labor minus $500 core exchange credit.

★ **Volume Tank.** Compressed air supply systems include a volume tank, which maintains a steady pressure with the on-off operation of the air compressor. The rule-of-thumb in determining the size of the volume tank is 1-gallon capacity for each cfm of compressed air. Exhibit 6 presents equipment costs for small, medium, and large volume tanks. Volume tanks have essentially no operating and maintenance costs.

Rule-of-Thumb

1 gallon tank capacity/1 cfm air

★ **Air Dryer Costs.** Because instrument air must be very dry to avoid plugging and corrosion, the compressed air is commonly put through a dryer. The most common dryer used in small to medium applications is a permeable membrane dryer. Larger air systems can use multiple membrane dryers, or, more cost effectively, alumina bed desiccant dryers. Membrane dryers filter out oil mist and particulate solids and have no moving parts. As a result, annual operating costs are kept low. Exhibit 7 presents equipment and service cost data for different size dryers. The appropriate sized dryer would need to accommodate the expected volume of gas needed for the instrument air system.

Exhibit 6: Volume Tank Costs

Service Size	Air Volume (gallons)	Equipment Cost ($)
Small[a]	80	655
Medium	400	1,964
Large	1,000	3,929

[a] Small reciprocating air compressors, 10 horsepower and less, are commonly supplied with a surge tank.

Exhibit 7: Air Dryer Costs

Service Size	Air Volume (cfm)	Dryer Type	Equipment Cost ($)	Annual Service ($/yr)
Small	30	membrane	1,964	724
Medium	60[a]	membrane	5,893	2,894
Large	350	alumina	13,096	4,341

[a] Largest membrane size; use multiple units, larger volumes.

Using the equipment information described above, the total installed cost for a project can be calculated. Exhibit 8 illustrates this using the earlier example of a medium-sized production facility with an instrument air requirement of 42 cfm and a maximum utility air requirement of 70 cfm (for a total of 112 cfm of compressed air). To estimate the installed cost of equipment, it is a common practice in industry to assume that installation labor is equivalent to equipment purchase cost (i.e. double equipment purchase cost to estimate the installed cost). This would be suitable for large, desiccant dried instrument air systems, but for small, skid-mounted instrument air systems a factor of 1.5 is used to estimate the total installed cost (installation labor is half the cost of equipment).

In addition to the facility costs, it is also necessary to estimate the energy costs associated with operating the system. The most significant operating cost of an air compressor is electricity, unless the site has excess self-generation capacity. To continue the example from above, assuming that electricity is purchased at 7.5 cents per kilowatt-hour (kWh) and that one compressor is in standby while the other compressor runs at full capacity half the time (a 50 percent operating factor), the electrical power

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(Cont'd)

Exhibit 8: Calculate Total Installation Costs

Given:	
Compressors (2) Volume Tanks (2-small) Membrane Dryer Installed Cost Factor	= $32,742 (Exhibit 5) = $1,310 (Exhibit 6) = $5,893 (Exhibit 7) = 1.5
Calculate Total Installed Cost:	
Equipment Cost	= Compressor Cost + Tank Cost + Dryer Cost = $32,742 + $1,310 + $5,893 = $39,945
Total Cost	= Equipment Cost * Installation Cost Factor = $39,945 * 1.5 = $59,917

cost amounts to $13,140 per year. This calculation is shown in Exhibit 9.

Step 4: Estimate Gas Savings.

To estimate the gas savings that result from the installation of an instrument air system, it is important to determine the normal bleed rates (continuous leak from piping networks, control devices, etc.), as well as the peak bleed rates (associated with movements in the control devices). One approach is to list all the control devices, assess their normal and peak bleed rates, frequency of actuation, and estimates of leakage from the piping networks. Manufacturers of the control devices usually publish the emission rates for each type of device, and for each type of operation. Rates should be increased by 25 percent for devices that have been in service without overhaul for five to 10 years, and by about 50 percent for devices that have not been overhauled for more than 10 years to account for increased leakage associated with wear and tear. Alternatively, installing a meter can be more accurate, provided monitoring occurs over a long enough period of time to take account of all the utility uses of gas (i.e., pumps, motor starters, activation of isolation valves).

Exhibit 9: Calculate Electricity Cost

Given:	
Engine Power Operating Factor (OF) Electricity Cost	= 30 HP = 50 percent = $0.075/kwh
Calculate Required Power:	
Electrical Power	= Engine Power * OF * Electricity Cost = [30 HP * 8,760 hrs/yr * 0.5 * $0.075/kwh] / 0.75 HP/kw = $13,140/yr

EPA's *Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, provides brand name, model, and gas consumption information for a wide variety of currently used pneumatic devices. Manufacturer information and actual field measurement data, wherever available, are provided as well (see Appendix of that report). To simplify the calculation of gas savings for the purpose of this lesson learned analysis, we can use the earlier rules-of-thumb to estimate the gas savings. The gas savings for the medium-sized production facility example in Exhibit 4 include the conservatively estimated 35 cfm used in the 35 gas pneumatic controllers plus the gas used occasionally for compressor motor starters and small pneumatic chemical and transfer pumps. (Note that replacing these gas usages will result in direct savings of gas emissions.) Natural gas is not used for pneumatic tools or sand blasting, so additional compressed air provided for these services does not reduce methane emissions. Assuming an annual average of 10 cfm gas use for natural gas powered non-instrument services, the gas savings would be 45 cfm. As shown in Exhibit 10, this is equivalent to 23,652 Mcf per year and annual savings of $165,600.

Step 5: Evaluate the Economics.

The cost effectiveness of replacing the natural gas pneumatic control systems with instrument air systems

Exhibit 10: Calculate Gas Savings

Given:	
Pneumatic instrument gas usage Other non-instrument gas usage	= 35 cfm = 10 cfm
Calculate Value of Gas Saved:	
Volume of Natural Gas Saved	= Instrument Usage + Other Usage = 35 cfm + 10 cfm = 45 cfm
Annual Volume of Gas Saved	= 45 cfm * 525,600 min/yr / 1000 = 23,652 Mcf/yr
Annual Value of Gas Saved	= volume * $7.00/Mcf = 23,652 Mcf/yr * $7.00/Mcf = $165,600/year

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can be evaluated using straightforward cost-benefit economic analyses.

Exhibit 11 illustrates a cost-benefit analysis for the medium-sized production facility example. The cash flow over a five-year period is analyzed by showing the magnitude and timing of costs from Exhibits 8 and 9 (shown in parentheses) and benefits from Exhibit 10. The annual maintenance costs associated with the compressors and air dryer, from Exhibits 5 and 7, are accounted for, as well as a five-year major overhaul of a compressor per Exhibit 5. The net present value (NPV) is equal to the benefits minus the costs accrued over five years and discounted by 10 percent each year. The Internal Rate of Return (IRR) reflects the discount rate at which the NPV generated by the investment equals zero.

Step 6: Develop an Implementation Plan.

After determining the feasibility and economics of converting to an instrument air system, develop a systematic plan for implementing the required changes. This can include installing a gas measuring meter in the gas supply line, making an estimate of the number of control loops, ensuring an uninterrupted supply of electric energy for operating the compressors, and replacing old, obsolete and high-bleed controllers. It is recommended that all necessary changes be made at one time to minimize labor costs and disruption of operations. This might include a parallel strategy to install low-bleed devices in conjunction with the switch to instrument air systems. There are similar economic savings for conserving instrument air use as for conserving methane emissions with low bleed pneumatic devices. Whenever specific pneumatic devices are being replaced, such as in the case of alternative mechanical and/or electronic

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Exhibit 11: Economic Analysis of Instrument Air System Conversion

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Implementation Cost ($)	(59,917)					
O&M Cost ($)		(13,140)[a] (4,630)[b]	(13,140) (4,630)	(13,140) (4,630)	(13,140) (4,630)	(13,140) (4,630)
Overhaul Cost ($)	0	0	0	0	0	(6,286)[c]
Total Cost ($)	(59,917)	(17,770)	(17,770)	(17,770)	(17,770)	(24,057)
Gas Savings ($)	0	165,600[d]	165,600	165,600	165,600	165,600
Annual Cash Flow ($)	(59,917)	147,830	147,830	147,830	147,830	141,543
Cumulative Cash Flow ($)	(59,917)	87,912	235,742	383,571	531,401	672,944
					Payback Period (months)	5
					IRR	246%
					NPV[e]	$496,570

[a] Electrical power at 7.5 cents per kilowatt-hour.
[b] Maintenance costs include $1,736 compressor service and $2,894 air dryer membrane replacement.
[c] Compressor overhaul cost of $3,929, inflated at 10% per year.
[d] Value of gas = $7.00/Mcf.
[e] Net Present Value (NPV) based on 10% discount rate for 5 years.

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systems, the existing pneumatic devices should be replaced on a similar economic basis as discussed in the companion document *Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*.

When assessing options for converting gas pneumatic controls to instrument air, natural gas price may influence the decision making process. Exhibit 12 shows an economic analysis installing two 30 hp compressors, two medium sized volume tanks, and a medium sized membrane dryer at different natural gas prices.

Exhibit 12: Gas Price Impact on Economic Analysis

	$3/Mcf	$5/Mcf	$7/Mcf	$8/Mcf	$10/Mcf
Value of Gas Saved	$70,971	$118,286	$165,600	$189,257	$236,571
Payback Period (months)	14	8	5	5	4
Internal Rate of Return (IRR)	84%	166%	246%	286%	365%
Net Present Value (*i*=10%)	$137,853	$317,211	$496,570	$586,249	$765,607

Partner Experiences

Several EPA Natural Gas Star Partners have reported the conversion of natural gas pneumatic control systems to compressed instrument air systems as the single most significant source of methane emission reduction and a source of substantial cost savings. Exhibit 13 below highlights the accomplishments that several Natural Gas STAR Partners have reported.

Other Technologies

The majority of Partners' experiences in substituting natural gas-powered pneumatic devices and control instrumentation with alternative controllers have involved

Exhibit 13: Partner Reported Experience

Gas STAR Partner	Description of Project	Project Cost ($)	Annual Emissions Reductions (Mcf/yr)	Annual Savings ($/yr)[a]	Payback (months)[b]
Unocal[c] (now Chevron)	Installed an air compression system in its Fresh Water Bayou facility in southern Vermillion Parish, Louisiana	$79,000	69,350	$485,450	2
Texaco[c] (now Chevron)	Installed compressed air system to drive pneumatic devices in 10 South Louisiana facilities	$52,000	23,000	$161,000	4
Chevron[c]	Converted pneumatic controllers to compressed air, including new installations	$227,000 over 2 years	31,700	$221,900	7
ExxonMobil[d]	Installed instrument air systems at 3 production satellites and 1 central tank battery at Postle CO_2 unit	$72,000	19,163	$134,141	7
Shell	Used instrument air operated devices on over 4,300 valves at off-shore platforms	Not available	532,800	$3,729,600	Not available
Marathon	Installed 15 instrument air systems in New Mexico facilities	Not available	120 - 38,000 per facility	$840 - 226,000	Not available

[a] Value of gas = $7.00/Mcf.
[b] Calculated based on Partner-reported costs and gas savings updated to 2006 costs.
[c] Data for this report were collected prior to the Chevron-Texaco and Chevron-Unocal mergers.
[d] Data for this report were collected prior to the Exxon/Mobil merger in 1999.

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the installation of compressed instrument air systems. Some additional alternatives to gas pneumatics implemented by Partners are described below:

- **Liquid Nitrogen.** In a system using liquid nitrogen, the volume tank, air compressor, and dryer are replaced with a cylinder containing cryogenic liquid nitrogen. A pressure regulator allows expansion of the nitrogen gas into the instrument and control-piping network at the desired pressure. Liquid nitrogen bottles are replaced periodically. Liquid nitrogen-operated devices require handling of cryogenic liquids, which can be expensive as well as a potential safety hazard. Large volume demands on a liquid nitrogen system require a vaporizer.

- **Mechanical Controls and Instrumentation System.** Mechanical instrument and control devices have a long history of use in the natural gas and petroleum industry. They are usually distinguished by the absence of pneumatic and electric components, are simple in design, and require no power source. Such equipment operates using springs, levers, baffles, flow channels, and hand wheels. They have several disadvantages, such as limited application, the need for continuous calibration, lack of sensitivity, inability to handle large variations, and potential for sticking parts.

- **Electric and Electro-Pneumatic Devices.** As a result of advanced technology and increasing sophistication, the use of electronic instrument and control devices is increasing. The advantage of these devices is that they require no compression devices to supply energy to operate the equipment; a simple 120-volt electric supply is used for power. Another advantage is that the use of electronic instrument and control devices is far less dangerous than using combustible natural gas or cryogenic liquid nitrogen cylinders. The disadvantage of these devices is their reliance on an uninterrupted source of electric supply, and significantly higher costs.

Although these options have advantages, systems using air instead of natural gas are the most widely employed alternative in replacing natural gas-operated pneumatic control devices. It is important to note that maintaining a constant, reliable supply of dry, compressed air in a plant environment is a significant cost, albeit more economic than natural gas. Therefore, a parallel strategy to install low-bleed devices in conjunction with the switch to instrument air systems (refer to *Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*), and to design a maintenance schedule to keep the instruments and control devices in tune, is often economic. Such actions can significantly reduce the consumption of instrument air in the overall system and, therefore, minimize both the size of the compression system and the electricity consumption over the life of the plant.

Lessons Learned

The lessons learned from Natural Gas STAR Partners are:

- Installing instrument air systems has the potential to increase revenues and substantially reduce methane emissions.

- Instrument air systems can extend the life cycle of system equipment, which can accumulate trace amounts of sulfur and various acid gases when controlled by natural gas, thus adding to the potential savings and increasing operational efficiencies.

- Remote locations and facilities without a reliable source of electric supply often need to evaluate alternate power generation sources. When feasible, solar-powered air compressors provide an economical and ecologically beneficial alternative to expensive electricity in remote production areas. On site generation using microturbines running on natural gas is another alternative.

- A parallel strategy of installing low-bleed devices in conjunction with the switch to instrument air systems is often economic.

- Existing infrastructure can be used; therefore, no pipe replacement is needed. However, existing piping and tubing should be flushed clear of accumulated debris.

- Rotary air compressors are normally lubricated with oil, which must be filtered to maintain the life and proper performance of membrane dryers.

- Use of instrument air will eliminate safety hazards associated with flammable natural gas usage in pneumatic devices.

- Nitrogen-drive systems may be an alternative to instrument air in special cases, but tends to be

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expensive and handling of cryogenic gas is a safety concern.

★ Report reductions in methane emissions from converting gas pneumatic controls to instrument air in your Natural Gas STAR Annual Report.

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United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

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