Oil and Natural Gas Sector Technical White Papers

Briefing for the Independent Petroleum Producers of New Mexico

June 3, 2014

Obama Administration's Climate Action Plan: Strategy to Reduce Methane Emissions

- Strategy released March 2014
- Summarizes the sources of methane emissions, commits to new steps to cut emissions, and outlines the Administration's efforts to improve the measurement of these emissions.
- Focuses on four key sources
  - Landfills
  - Coal Mines
  - Agriculture
  - Oil and Gas
- For oil and gas, strategy focuses taking new steps to encourage cost-effective reductions.
  - Technical white papers on potentially significant sources of methane are a key step.

White Paper Overview

- Purpose
  - Obtain a common understanding of emerging data on emissions and mitigation techniques for certain potentially significant sources of VOCs and methane
  - Focus on technical issues
  - Part of Administration's *Climate Action Plan: Strategy to Reduce Methane Emissions*
- Topics
  - Compressors
  - Completions and ongoing production of hydraulically fractured oil wells
  - Leaks
  - Liquids unloading
  - Pneumatic devices
- Status
  - Released April 15, 2014 for external peer review
  - Peer review to be completed by June 16, 2014
  - Also seeking technical information and data from the public until June 16, 2014

White Paper Structure

- Problem statement
  - Define the source(s)
  - Define the context
- Available emissions data and estimates
  - Summarize and compare the various data sources and estimates
  - Characterize quantity, geographic dispersion, distribution across sources
- Available mitigation techniques
  - Cost, efficacy, and prevalence of technologies
- Charge questions for reviewers
  - Technical questions of particular interest to EPA

White Paper Charge Questions: Compressors

- Appropriate characterization of the different studies and data sources
- Ongoing or planned studies on this source of emissions
- Full range of technologies available to reduce vented compressor emissions
- Technical limitations to replacement of wet seals with dry seals
- Technical reasons for using a wet seal compressor without a gas recovery system
- Technical limitations to installation of gas capture systems at reciprocating compressors
- Specific applications that require wet seal compressors

White Paper Charge Questions: Completions and Ongoing Production of Hydraulically Fractured Oil Wells

- Appropriate characterization of the different studies and data sources
- Ongoing or planned studies on this source of emissions
- Full range of technologies available to reduce emissions
- Hydraulically fractured oil well completions
  - Methodologies for estimating completion emissions and rate of recompletions
  - Feasibility/cost of “green completions” at oil wells
  - Feasibility/cost of completion combustion devices at oil wells
- Ongoing production from hydraulically fractured oil wells
  - Methodologies for estimating associated gas emissions
  - Availability of pipeline infrastructure in tight oil formations

White Paper Charge Questions: Leaks

- Appropriate characterization of the different studies and data sources
- Ongoing or planned studies on this source of emissions
- Types of facilities more prone to leaks
- Full range of technologies available to detect leak emissions
- Applicability of detection and repair techniques to both oil and gas wells
- Comparison of the cost of detecting vs. cost of repairing a leak
- Necessity of leak detection technologies to quantify emissions
- State of innovation in leak detection technologies

White Paper Charge Questions: Liquids Unloading

- Appropriate characterization of the different studies and data sources
- Ongoing or planned studies on this source of emissions
- Full range of technologies available to reduce emissions
- Types of wells most likely to require liquids unloading
- Ability of plunger lift systems to perform liquids unloading without any air emissions
- Pros and cons of installing a “smart” automation system as part of a plunger lift system
- Feasibility of the use of flares during liquids unloading operations
- Rationale of performing blowdowns instead of using more effective liquid removal technologies

White Paper Charge Questions: Pneumatic Devices

- Appropriate characterization of the different studies and data sources
- Ongoing or planned studies on this source of emissions
- Full range of technologies available to reduce emissions
- Explanation for wide range of emission rates from pneumatic controllers
- Barriers to installing instrument air systems
- Barriers to using instrument air-driven controllers and pumps
- Limitations of electric-powered pneumatic controllers and pneumatic pumps

White Paper Next Steps

- June 16, 2014
  - Peer review deadline
  - Deadline for technical information and data from the public
- Summer 2014
  - Submitted information and reviews will be made available
  - Review submitted information
- Fall 2014
  - Determine how best to pursue further methane reductions
- End of 2016
  - If EPA decides to develop additional regulations, complete those regulations

Also of Interest

- Indian Country Minor New Source Review Program - Advance Notice of Proposed Rulemaking
  - Issued May 22, 2014
  - Seeking broad feedback on options for implementing the Indian Country Minor NSR program for oil and gas production in Indian country
  - Requests feedback on options for streamlining permitting to minimize delays, while ensuring air quality in Indian country is protected.
- Extension of minor NSR permitting deadline
  - Final action May 22, 2014
  - Extends minor NSR deadline from Sept. 2, 2014 to March 2, 2016 for true minor sources in the oil and gas industry located, or planning to locate, in Indian country.
  - Additional time allows EPA to determine the best option for permitting sources in this sector.

For Additional Information

- For more information on the white papers and the ANPR for minor NSR permitting in Indian country, visit:
  - http://www.epa.gov/airquality/oilandgas/whitepapers.html
- For additional information on the white papers, contact:

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EPA White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector

June 6, 2014

TRC Company Profile

A pioneer in groundbreaking scientific and engineering developments since 1954, we are a national engineering, consulting and construction management firm that provides integrated services to three primary markets:

Energy, Environmental and Infrastructure

90 Offices Nationally

We have a long history as **expert** problem solvers.

We excel in constructing **creative** options to find the optimal solution for clients.

We are **dedicated** to helping our clients reach their ultimate goals.

TRC Air Quality Consulting Services

- Experience in Oil and Gas Permitting
  - Albuquerque, NM Office
  - Denver, CO Office
  - Greenville, SC Office
  - Houston, TX Office
  - Harrisburg, PA Office
  - Lyndhurst, NJ Office
- PSD/NSR permitting services around the country
- Meteorological and ambient air monitoring services
- Emissions testing services
- Control equipment process engineering
- Litigation support
- Albuquerque and Denver offices specialize in Air Permitting & Compliance

Overview of the Climate Action Plan

- White House Strategy to Reduce Methane Emissions
- Comprehensive, Interagency Strategy (EPA, BLM)
- Goal to improve measurement of methane emissions
- Highlight technologies and industry best practice already in place to reduce methane emissions
- Reduce emissions by 17% below 2005 levels by 2020

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Strategy to Implement Climate Action Plan

- April 15, 2014 – EPA releases for "external peer review" 5 white papers on oil & gas sector whose purpose is to:
  - Summarize EPA's understanding of emissions sources
  - Evaluate available mitigation techniques and associated costs
- White Papers include information already presented previously by EPA under the 2012 NSPS Subpart OOOO
- White papers claim some data and mitigation techniques are new and not covered under NSPS OOOO
- EPA peer review/comment deadline is June 16, 2014

White Paper Topics

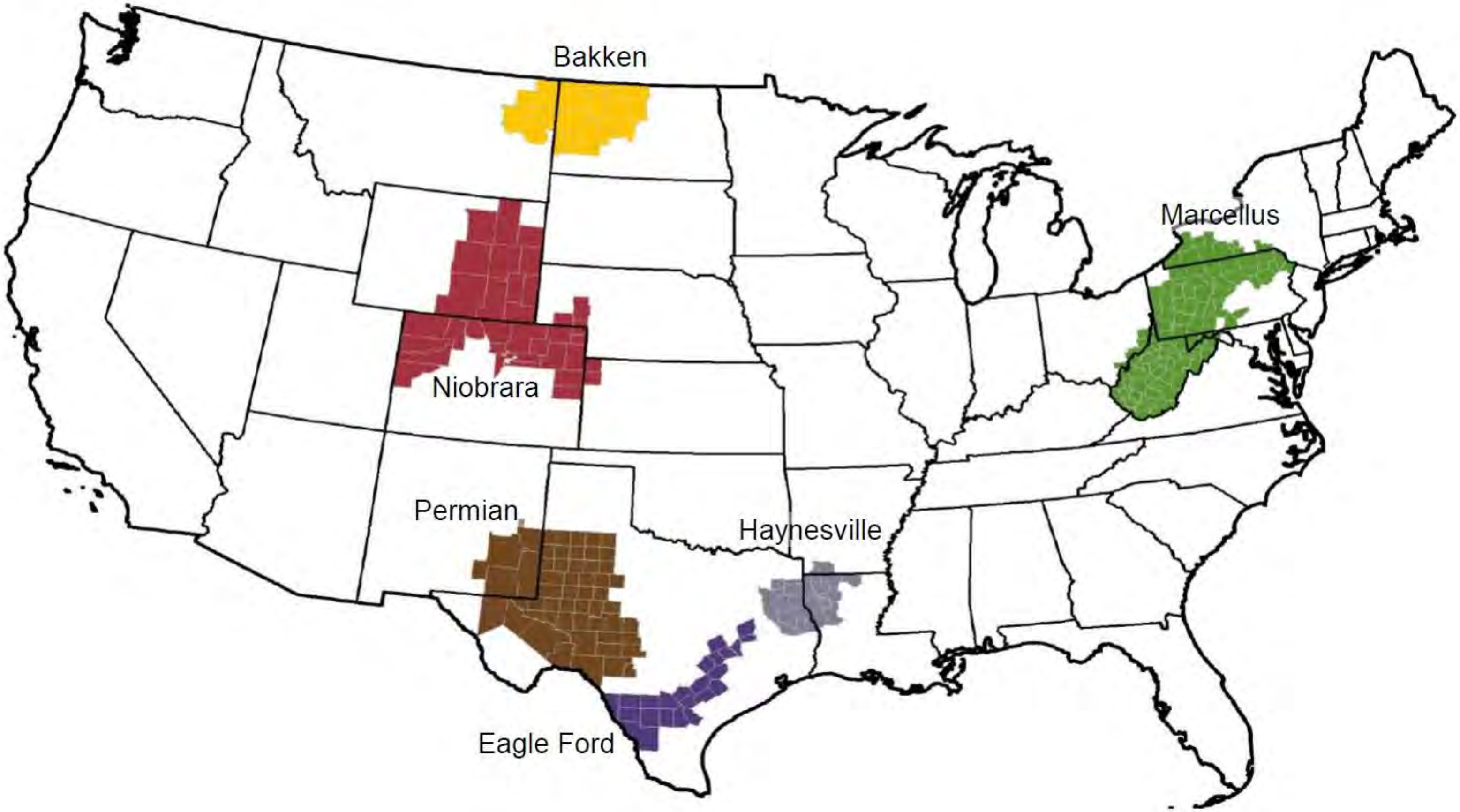
- White papers present data and mitigation techniques not covered under NSPS Subpart OOOO for:
  - Compressors
  - Pneumatic Devices
  - Well Completions and Hydraulically Fractured Wells
  - Leaks
- Other issues already covered under NSPS OOOO
- “Liquids unloading” is the only topic not covered by NSPS

Oil & Gas Production Statistics

- 504,000 Producing Gas Wells in 2011 (EIA, 2012 a)
- 536,000 Producing Oil Wells in 2011 (EIA, 2012b)
- 44% projected gas production increase thru' 2040 (EIA 2013)
- 25% projected oil production increases thru' 2019 (EIA 2013)
- More than 50% of new oil wells coproduce gas (EIA 2013)

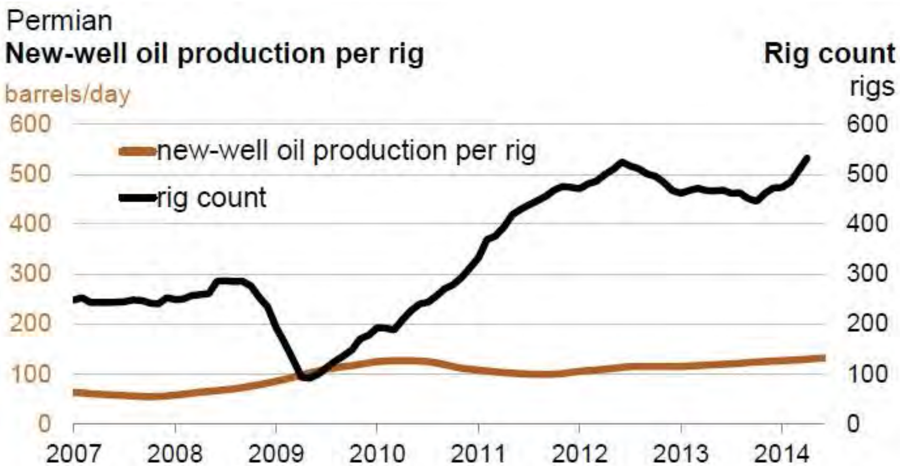
Shale Gas Regions

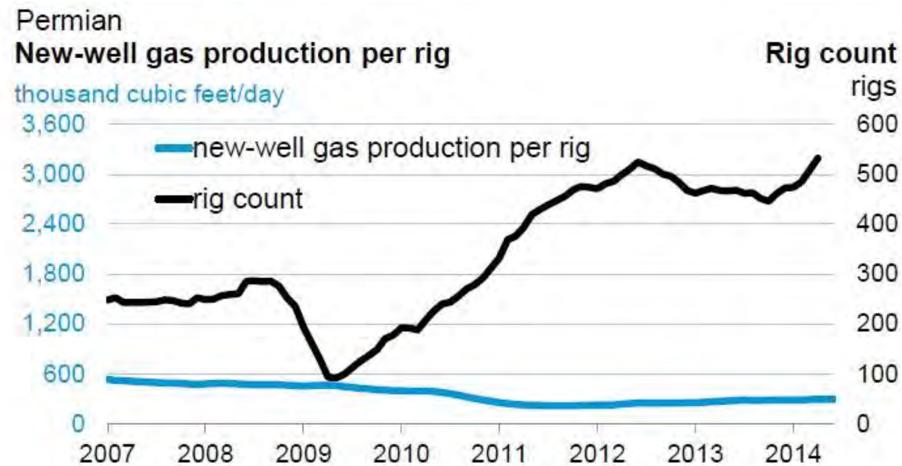
Key tight oil and shale regions



Source: U.S. Energy Information Administration

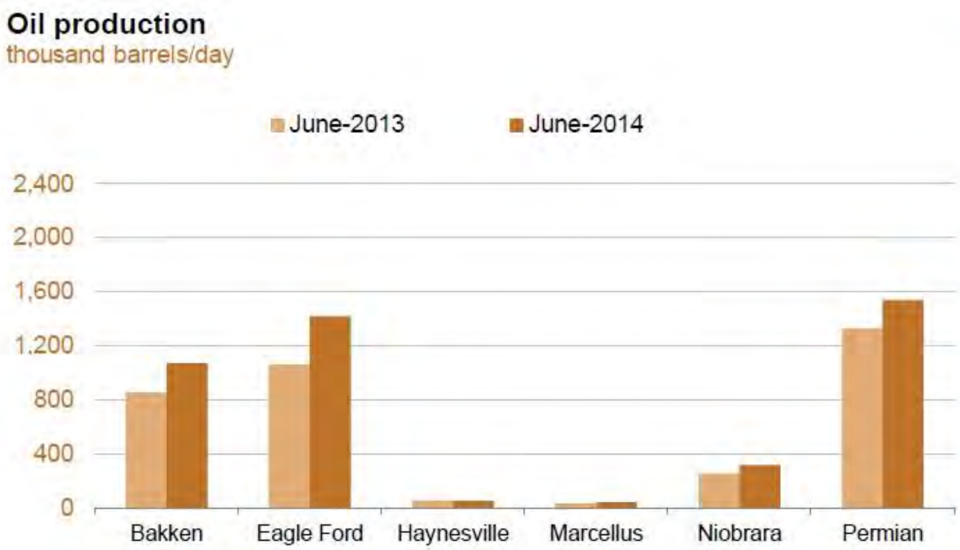
Permian Rig Count

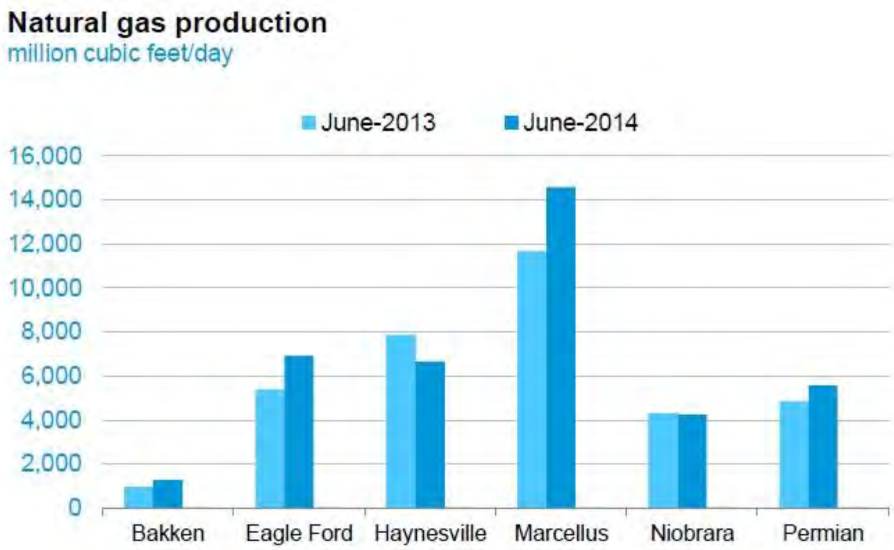




Source: U.S. Energy Information Administration, Drilling Productivity Report, May 2014

Permian- Oil & Gas Production





Source: U.S. Energy Information Administration, Drilling Productivity Report, May 2014

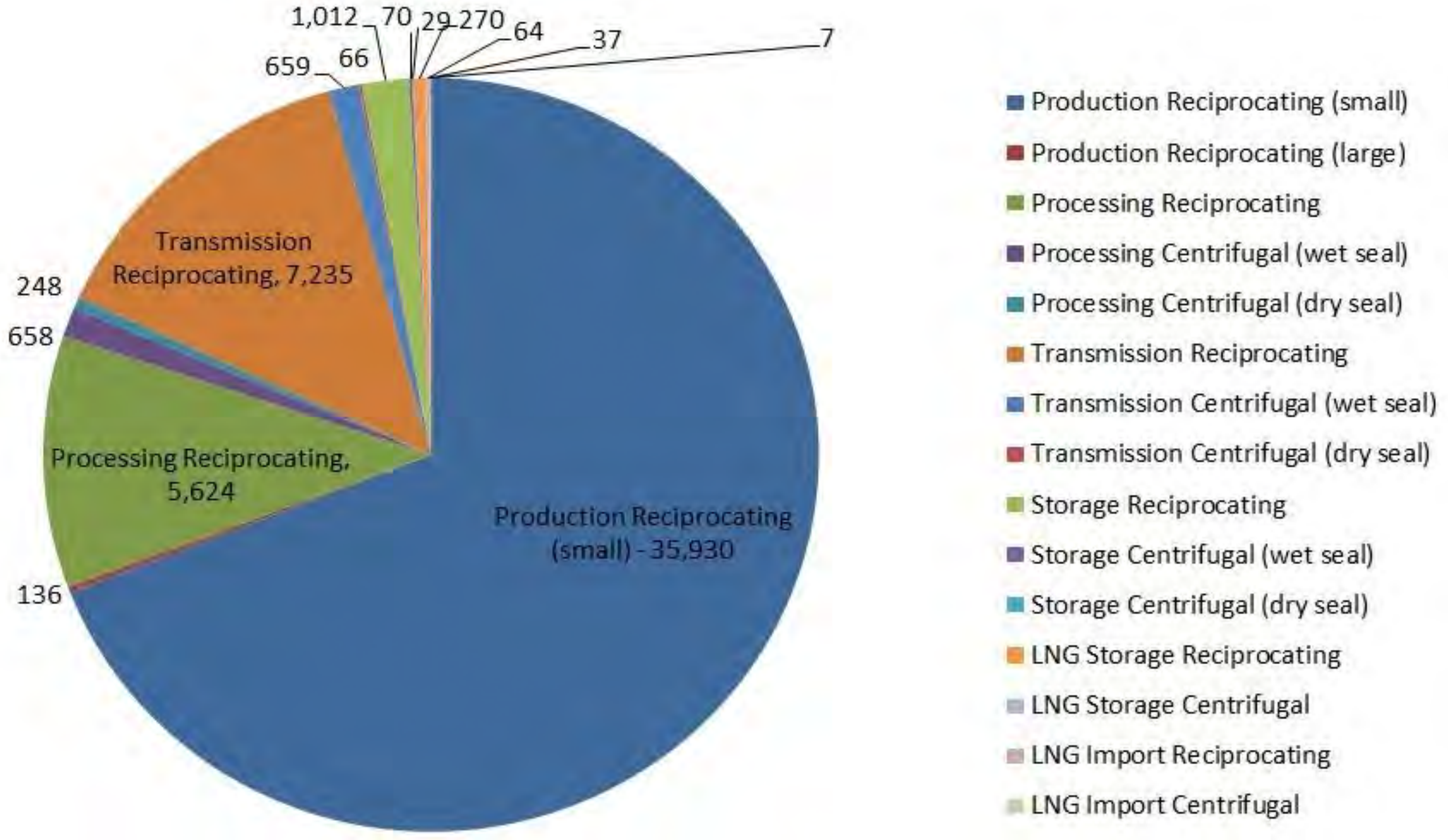
EPA White Paper No. 1

Oil and Natural Gas Sector Compressors

Compressor Types

- Reciprocating (Gathering & Boosting Segment)
  - Compression by a piston rod driven by crankshaft
  - Rod Packing: Seal of flex-rings in machined cups around piston rod
    - Leak occurs in rod packing: Nose gasket, packing case, around rings
    - Assumes 4 cylinders per compressor
- Centrifugal: (Processing & Transmission Segment)
  - Rotating vanes or impellers to increase gas velocity
  - Wet seal: Oil barrier around rotating shaft to prevent gas leak
    - Leak occurs during degassing or off-gassing of absorbed gas
  - Dry seal: Grooves & springs provide the seal
    - Leak occurs through inboard labyrinth between seal housing
  - Assumes 1.5 seals per compressor

Compressors- Number of units by type



Source: USEPA OAQPS Report for Oil and Natural Gas Sector Compressors, April 2014

Definitions and Assumptions in White Paper

- Small Compressor < 1,600 hp; Large ≥ 1,600 hp

- Small Gathering Compressor (GRI/EPA 1996) is:
  - "Compressors on overhead lines from gas well separators"

- Large Gathering Compressor (GRI/EPA 1996):
  - "compressors [located] at large gathering compressor stations (stations with 8 compressors or more)"

- 1 BCF = 20,815 short tons of methane (approx.)
  = 18,923 MT of methane (approx.)
  = 473,068 MT of CO2e (Multiply by a GWP of 25)

- 41.63 lbs of methane/MSCF; 1 ton = 48.125 MSCF

Source of Emissions Data (1)

- 1996 GRI/EPA Study on Methane Emissions
  - Data from12 oil & gas sites in Western US
  - 40 Reciprocating engines;
  - Assumes no Centrifugals at Production and Gathering Sites
  - 2.71 SCF/hr-cylinder reciprocating engines for Production Sites
  - 9.48 SCF/hr (assumes 4 cylinders) for Production Sites
  - Assumes operating & pressurized 79% of time at Gathering Sites
  - For Production, assumes operating & pressurized 100% of time

- 2011 URS/UT Methane Emission Factor Improvement Study
  - Data collected at 11 sites in TX & NM
  - 66 Reciprocating engines, 18 at Gathering & Boosting sites
  - 241 MSCF/year average from Reciprocating engines

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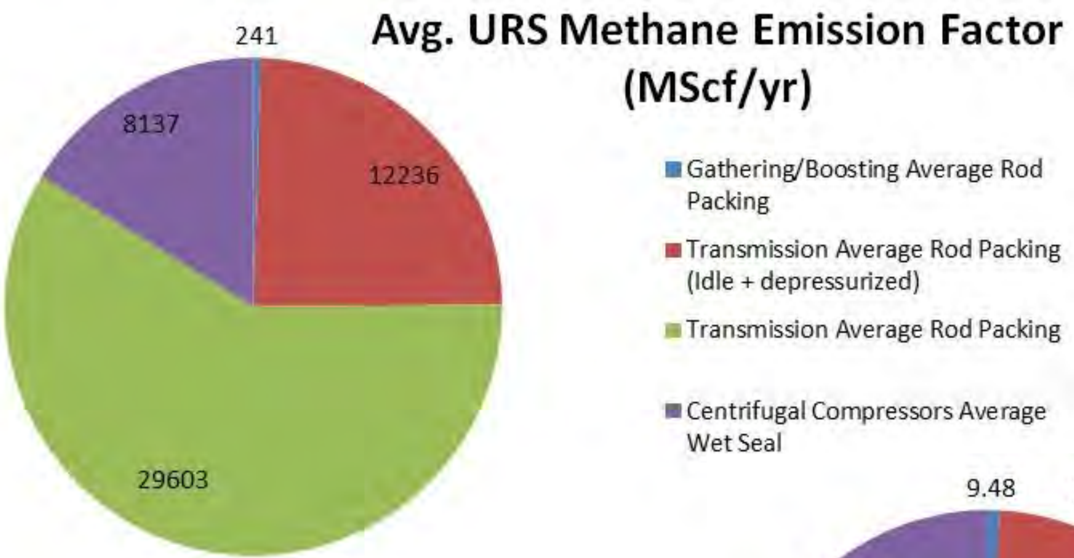
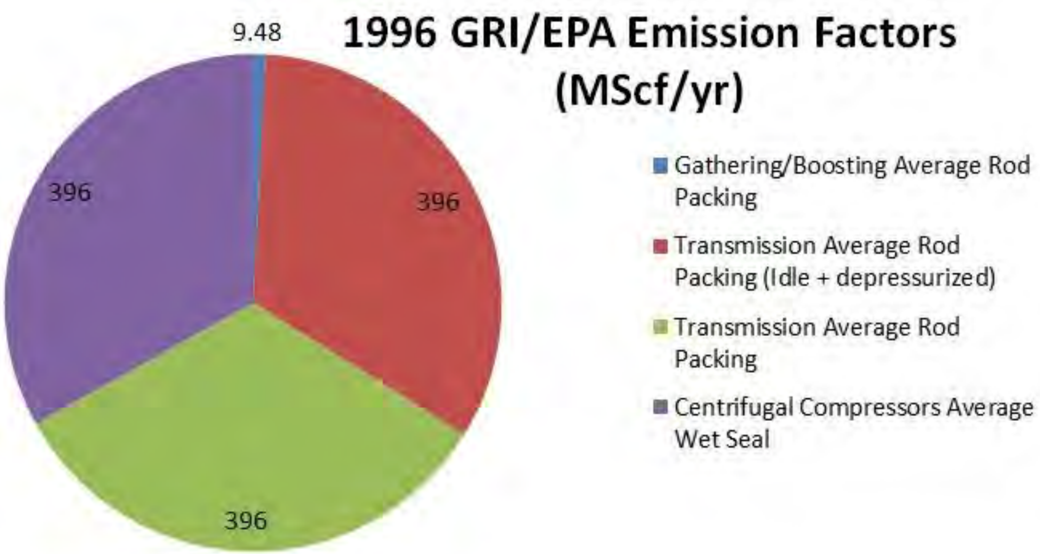
Source of Emissions Data (2)

- NSPS OOOO
  - Uses Emissions Factors from 1996 GRI/EPA study
  - Except for Gathering & Boosting where Clearstone Engineering data was used (developed from study of 5 sites)
  - Assumes 0.278 lb VOC per lb Methane (about 29%)

- EDF/ICF Int'l Study 2014
  - 22 oil & gas sites in the US
  - Raises Gathering & Boosting compressor emissions to 1,980 scf/day or 82.5 scf/hr (more than 9 times GRI/EPA study)
  - Emission Factor may be applied to Production Sites

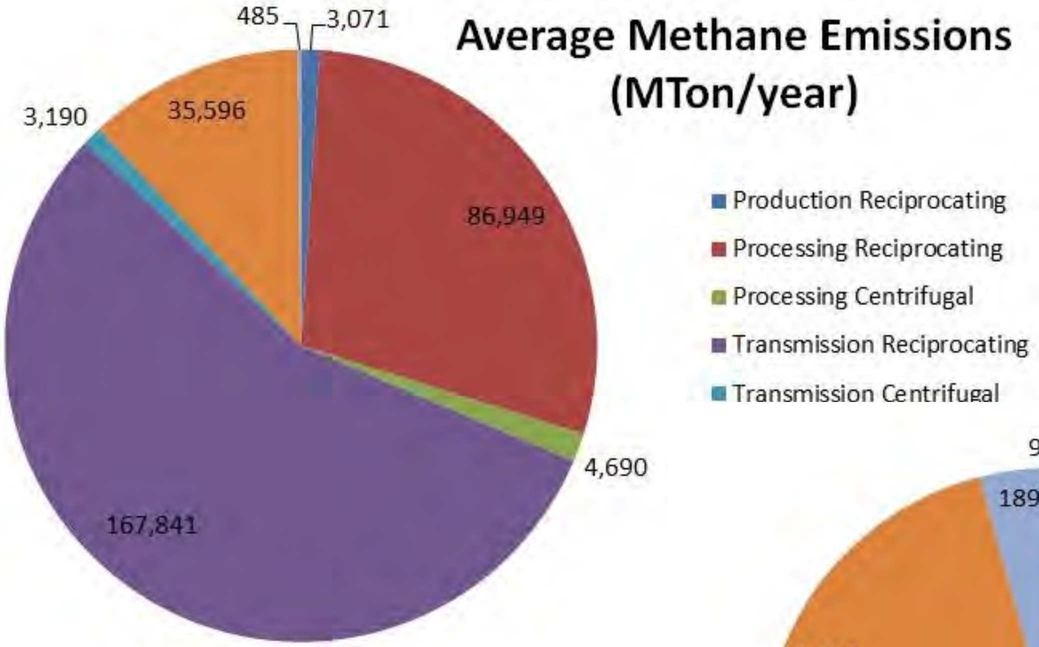
Comparison of Emission Factors

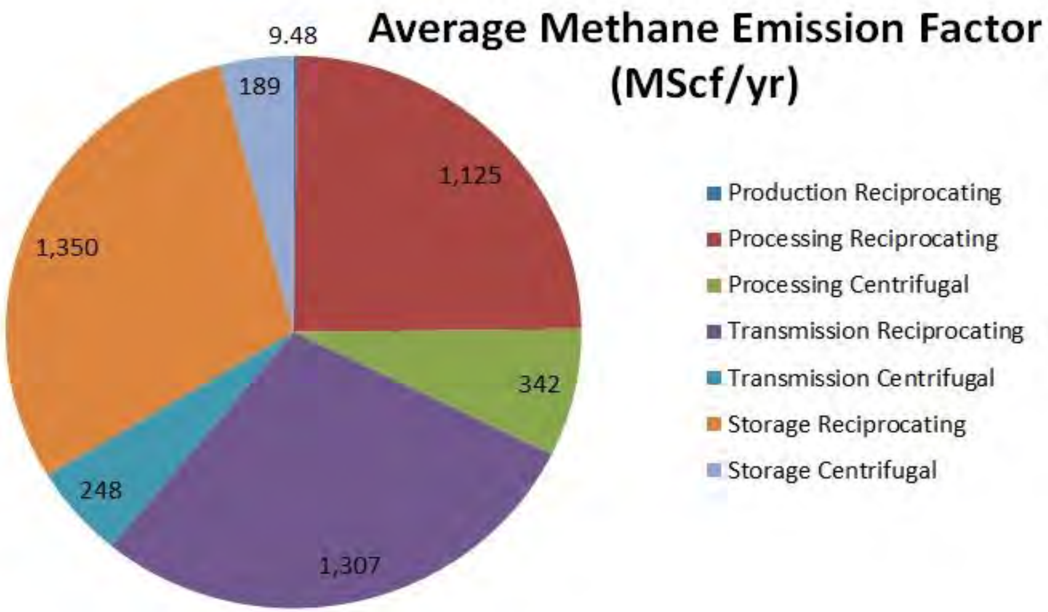




Source: USEPA OAQPS Report for Oil and Natural Gas Sector Compressors, April 2014

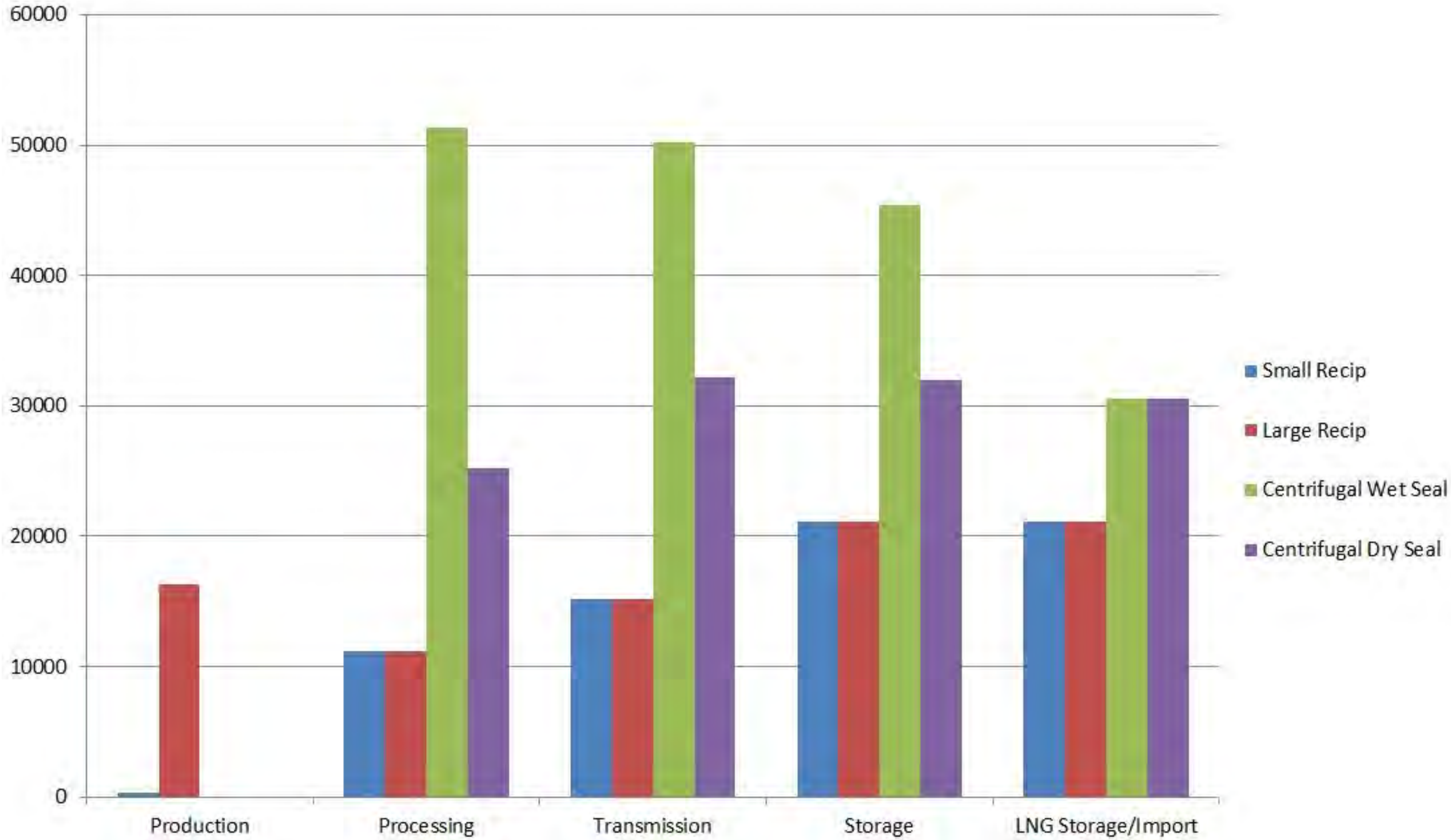
Methane Emissions





Source: USEPA OAQPS Report for Oil and Natural Gas Sector Compressors, April 2014

Emission Factor Comparison



Source: USEPA OAQPS Report for Oil and Natural Gas Sector Compressors, April 2014

Mitigation techniques (slide 1)

- Rod packing replacement
- Piston rod replacement
- Refitting or realignment of the piston rod
- Ring replacement
- Coating piston rods with chrome or tungsten carbide
- Capture emissions and route to flare or a "useful process"
- New rod packing leak rate- 11.5 SCF/hr/cylinder (EPA 2006a)
- Economical threshold for replacement: 30 SCF/hr
  - No explanation or basis for this number in white paper
- Cost to replace rod packing is $1,620/cyl.(EPA 2006a)
- Assuming 4 cylinders, cost is $6,480 per compressor
- Replace rod packing every 3 years or if leak rate ≥ 30 scf/hr

Mitigation techniques (slide 2)

- Gas Recovery of rod packing leaks to a VRU
- REM Technology -- 99% VOC and Methane capture
- Gas recovery of 78 MCF/day per compressor engine
- 95% reduction possible with a Flare
- EPA's questions for reviewers:
  - Is there a "Low emissions" rod packing? Other technologies?
  - Is it technically infeasible or impractical to install gas capture systems on the rod packing systems at Reciprocating engines?
  - Are emissions estimates in the paper appropriate?
  - Are emissions technologies and their cost estimates accurate?
  - Are other emissions studies available or being conducted?

EPA White Paper No. 2

Hydraulically Fractured Oil Well Completions and Associated Gas During Ongoing Production

Definitions (1)

- Well Completion

  "The process allows for the flowback of petroleum or natural gas or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank."

- Hydraulic Fracturing:

  "The process of directing pressurized fluids containing any combination of water, proppant (generally sand), and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completion."

- Backflow:

  "Phenomena created by pressure differences between zones in the borehole. If wellbore pressure rises above the average pressure in any zone, backflow will occur (i.e., fluids will move back to the borehole)."

Definitions (2)

- Oil Well: EPA chooses <u>NOT</u> to define an oil well
- Flowback:

  "refers to the process of allowing fluids to flow from the well following treatment, either in preparation for a subsequent phase of treatment of in preparation for cleanup and returning the well to production."

- Associated Gas Emissions:

  "Associated gas emissions from the production phase (i.e., excluding completion events and emissions from normal equipment operations) that could be captured and sold rather than being flared or vented to the atmosphere if the necessary pipeline and other infrastructure were available to take gas to the market."

- REC's- Reduced emission completions (green completions)

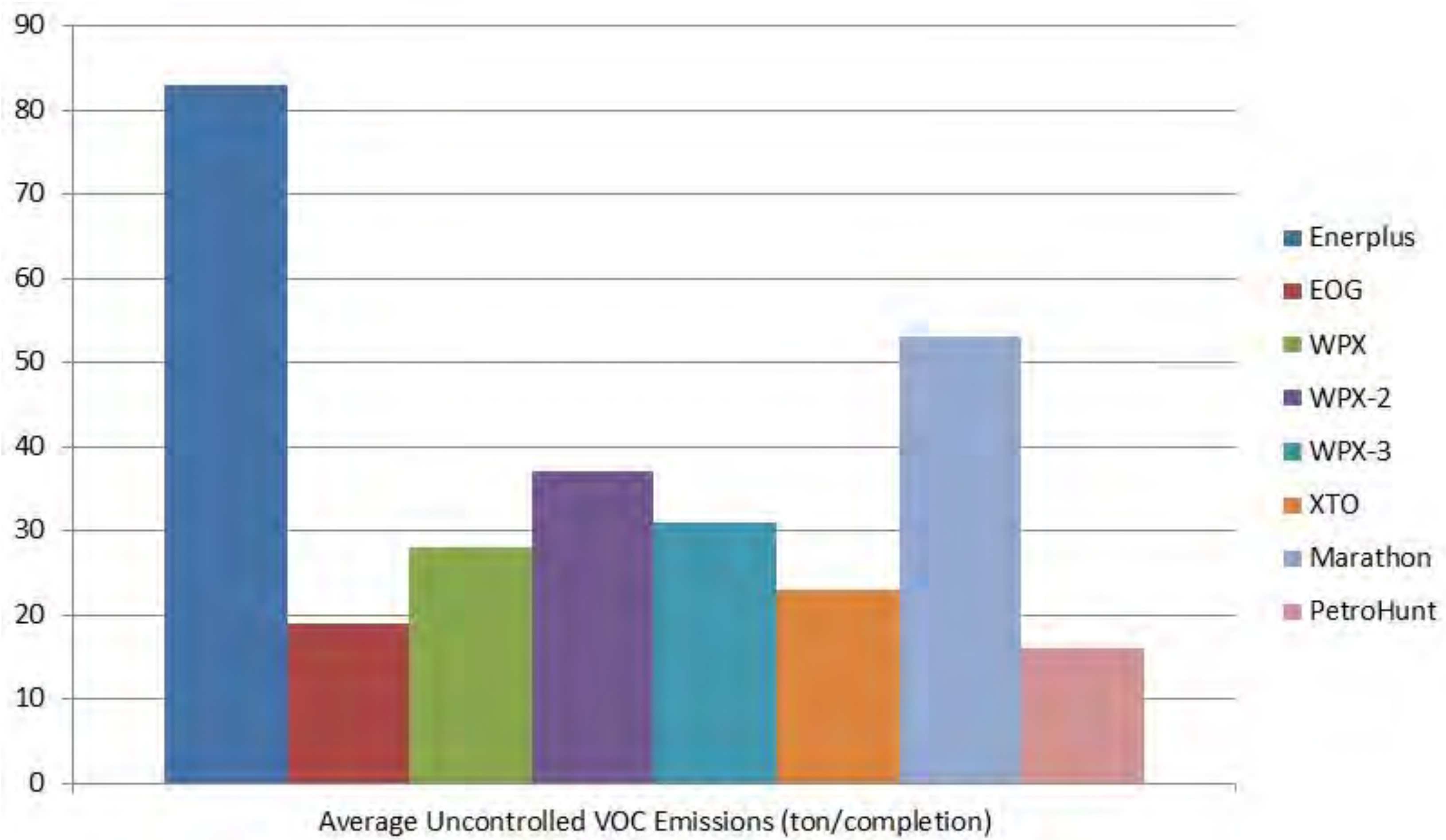
Emissions estimation methodology

- To estimate emissions from a well determine:
- Estimate of Gas produced during completion
  - Use flow rate, casing diameter and casing pressure
- Estimate or measure Gas produced annually/daily.
- Gas Analysis from a lab
- Duration of well completion
- Control technology- flares, green completions, etc.,

Bakken: Fort Berthold Indian Reservation Study

- FBIR Study in the Bakken conducted by EPA
- 533 production wells from five major companies
- Average uncontrolled emissions of VOC
- Gas composition data for each well
- Oil production data
- Calculated with average daily flow and 7-day flowback period
- Average uncontrolled VOC emission 37 tons per completion
- Bakken contains high amounts of lighter end components which result in higher VOC emissions than typical US well

VOC Emissions from Wells in FBIR Bakken



Source: USEPA OAQPS Report for Oil and Natural Gas Sector Hydraulically Fractured Well Completions, April 2014

ERG/ECR Analysis of HPDI Data for the US

- HPDI maintains a national database of drilling permits and well production data
- ERG/ECR analyzed well completions in 2011
- ERG/ECR define oil wells with GOR below 12,500 scf/bbl
- Calculates emissions with average daily flow for 7-day flowback period and 3-day flowback period
- Calculates using oil well values of:
  - 46.732% by volume methane
  - 0.8374 lb VOC/lb methane
- Total of 5,754 well completions in 2011 nationally
- Average daily gas production 262 MCF nationwide
- ERG/ECR: 2011 NM average of 337 wells was 114.89 MCF

Summary of ERG/ECR 2011 HPDI Data

Data	7-day event	3-day event
Total no. of hydraulically fractured wells in 2011	5,754	5,754
Natural gas production per well, weighted average (MCF)	262	262
VOC emissions per well (tons)	20.2	6.4
Methane emissions per well (tons)	24	7.7
VOC emissions nationwide (tons)	116,230	36,825
Methane emissions nationwide (tons)	138,096	44,306

Source: USEPA OAQPS Report Oil and Natural Gas Sector Hydraulically Fractured Well Completions, April 2014

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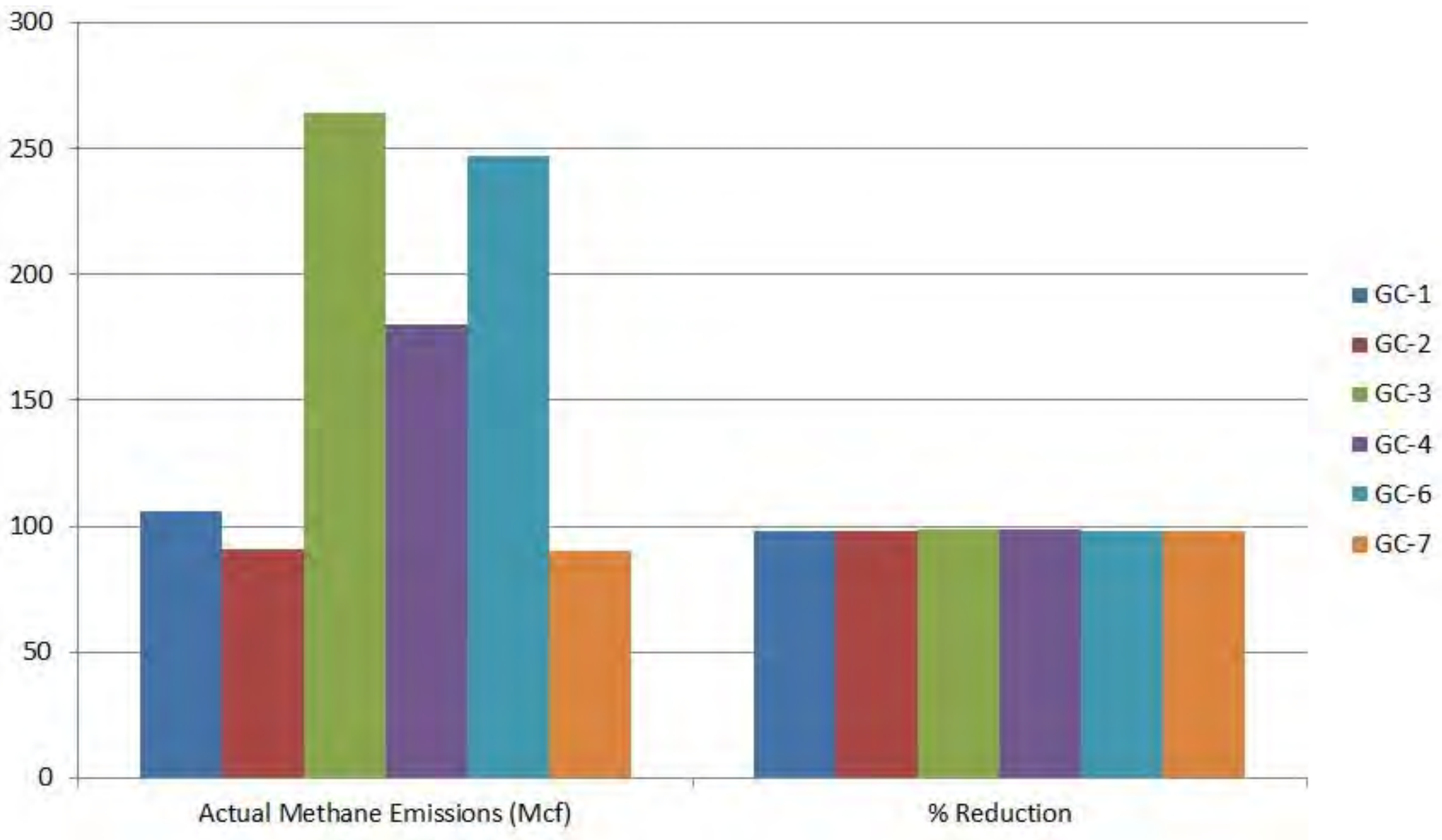
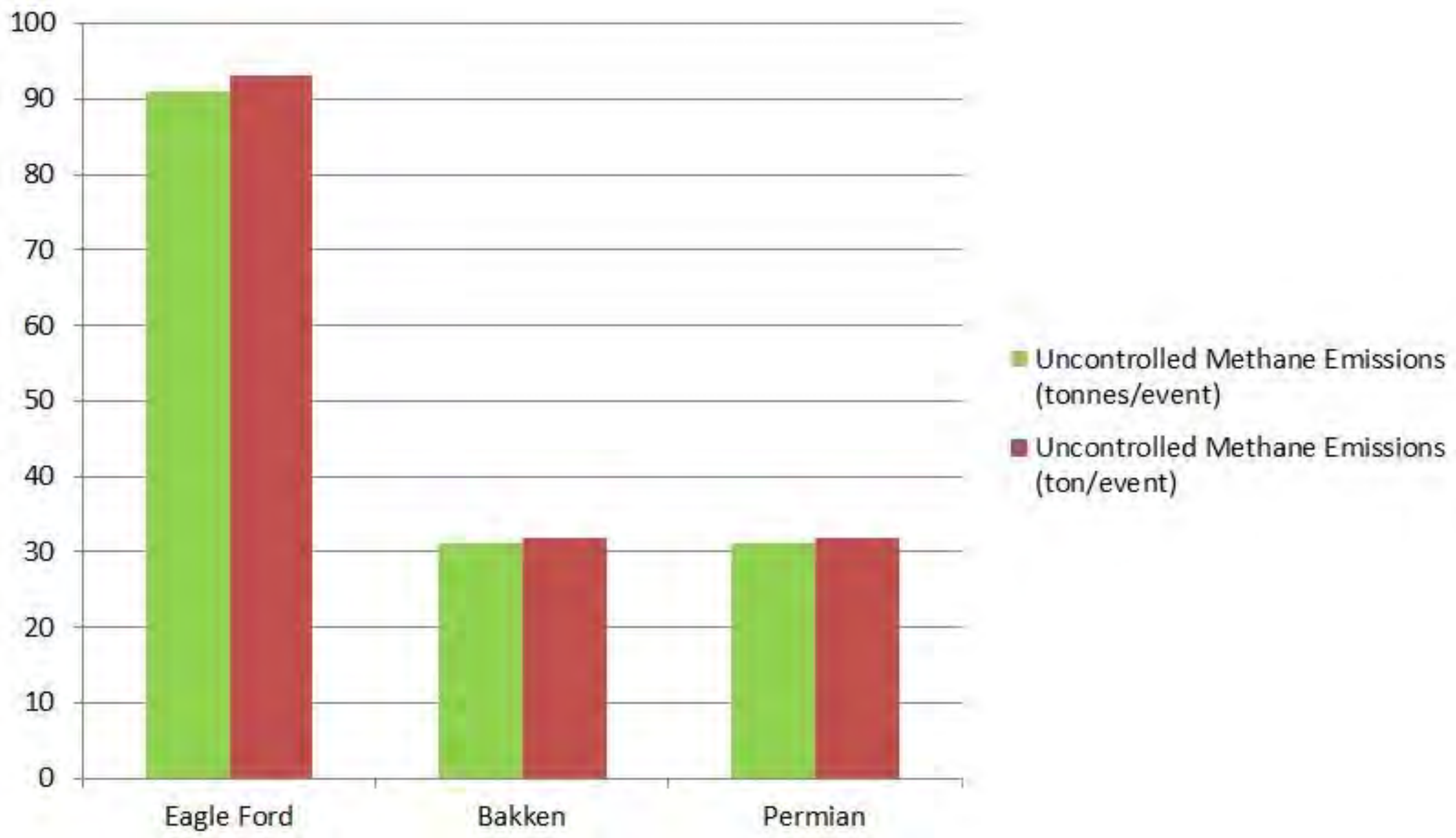
UT Study Measurement of 150 well sites



Source: USEPA OAQPS Report for Oil and Natural Gas Sector Hydraulically Fractured Well Completions, April 2014

Novim Study of 2,969 wells in HDPI database: Uncontrolled Methane Emissions



Source: USEPA OAQPS Report for Oil and Natural Gas Sector Hydraulically Fractured Well Completions, April 2014

Flaring Study in the Bakken

- Conducted between 2007 and 2013
- NDIC defines associated gas as anything not defined as oil
- Casinghead gas
- 55% of wells are flaring associated gas
- 266,000 Mcf per day is flared
- 30% of the total gas produced is flared
- Reasons for flaring:
  - Lack of pipeline infrastructure
  - Lack of capacity
  - Lack of compression infrastructure

Mitigation techniques (Slide 1)

- Reduced emissions completion (REC)
  - "Green completion"
  - Where gas flowback is:
    - Captured, cleaned and routed to flow line or collection system
    - Reinjected into the well or another well
    - Used as an onsite fuel source or another useful purpose with no release
- 90% control efficiency estimated for REC's (USEPA 2011)
- Limitations of REC's
    - Lack of Proximity to pipelines
    - Pressure of flowback gas may not be sufficient
    - Nitrogen or CO_2 concentration may be excessive
- Cost of REC's between $700 and $6,500 per day
- 7-day flowback REC Cost $29,022 (includes 3 phase separator, dehydrator, gas-liquid-sand separator traps)

Mitigation techniques (Slide 2)

- Completion Combustion Device
  - Enclosed combustor 95% control efficiency
  - Average cost $18,902
- NGL Recovery
  - Turbo expander with demethanizer
  - Low pressure separation membranes
  - Adsorption using carbon or molecular sieve
  - Twister Supersonic Gas Low Temperature Separation
- Natural Gas Reinjection EOR or IOR
  - Boost depleted pressure with multiple wells placed in the field
- Electricity generation for onsite use
  - Removal of NGL followed by use in microturbine or recip. Engine
  - $3.2 million CC: 250 kW from recips and 200 kW from microturbines

EPA's Charge Questions for Reviewers

- If VOC and Methane emissions estimates in paper are accurate? Any other sources of information?
- Is the use of 3-day and 7-day flowback period appropriate?
- Effectiveness of REC's? Other technologies?
- Are emissions technologies and their cost estimates accurate?
- Other studies on controls that may be available?

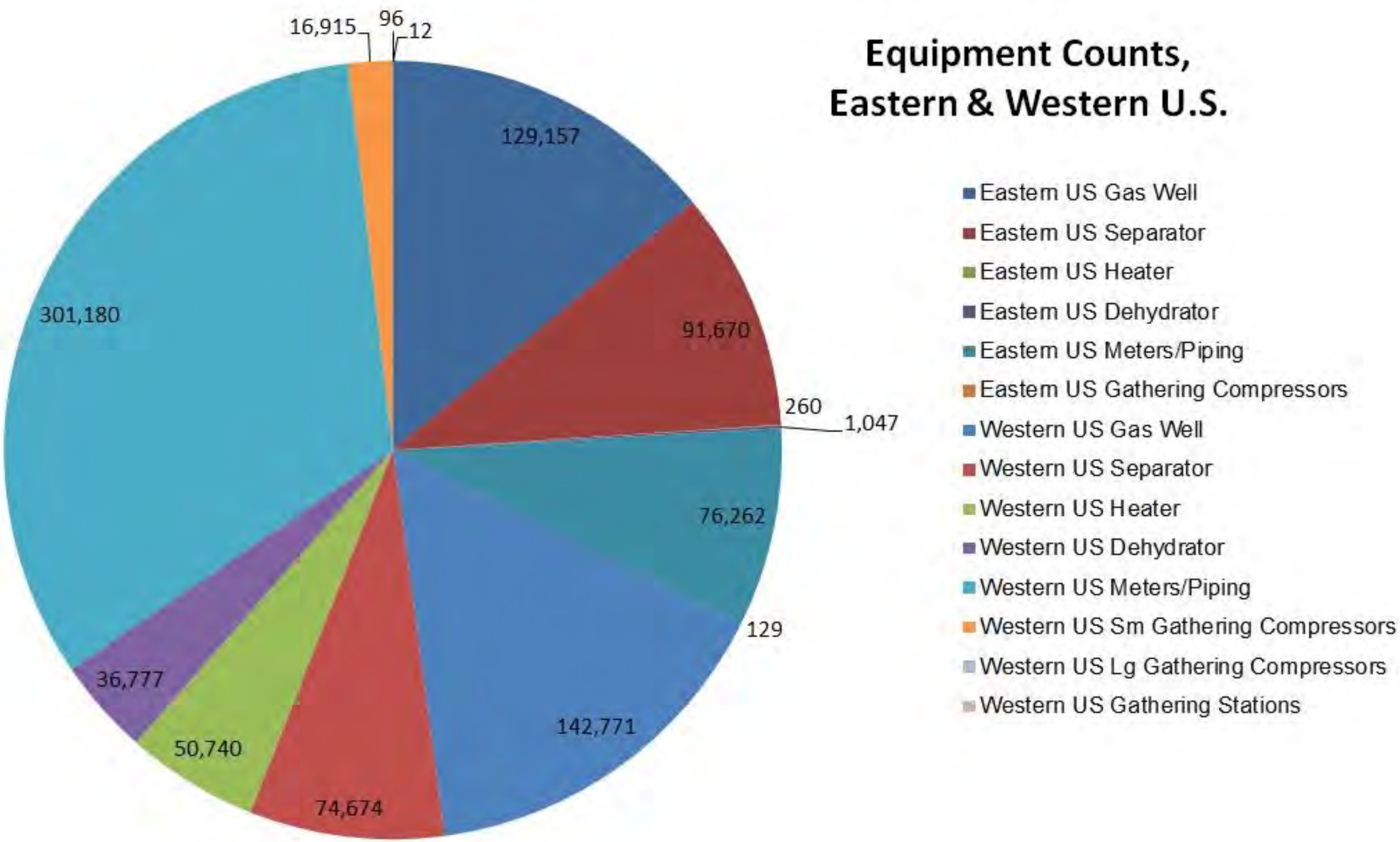
EPA White Paper No. 3

Oil and Natural Gas Sector Leaks

Leak Emissions and Component Categories

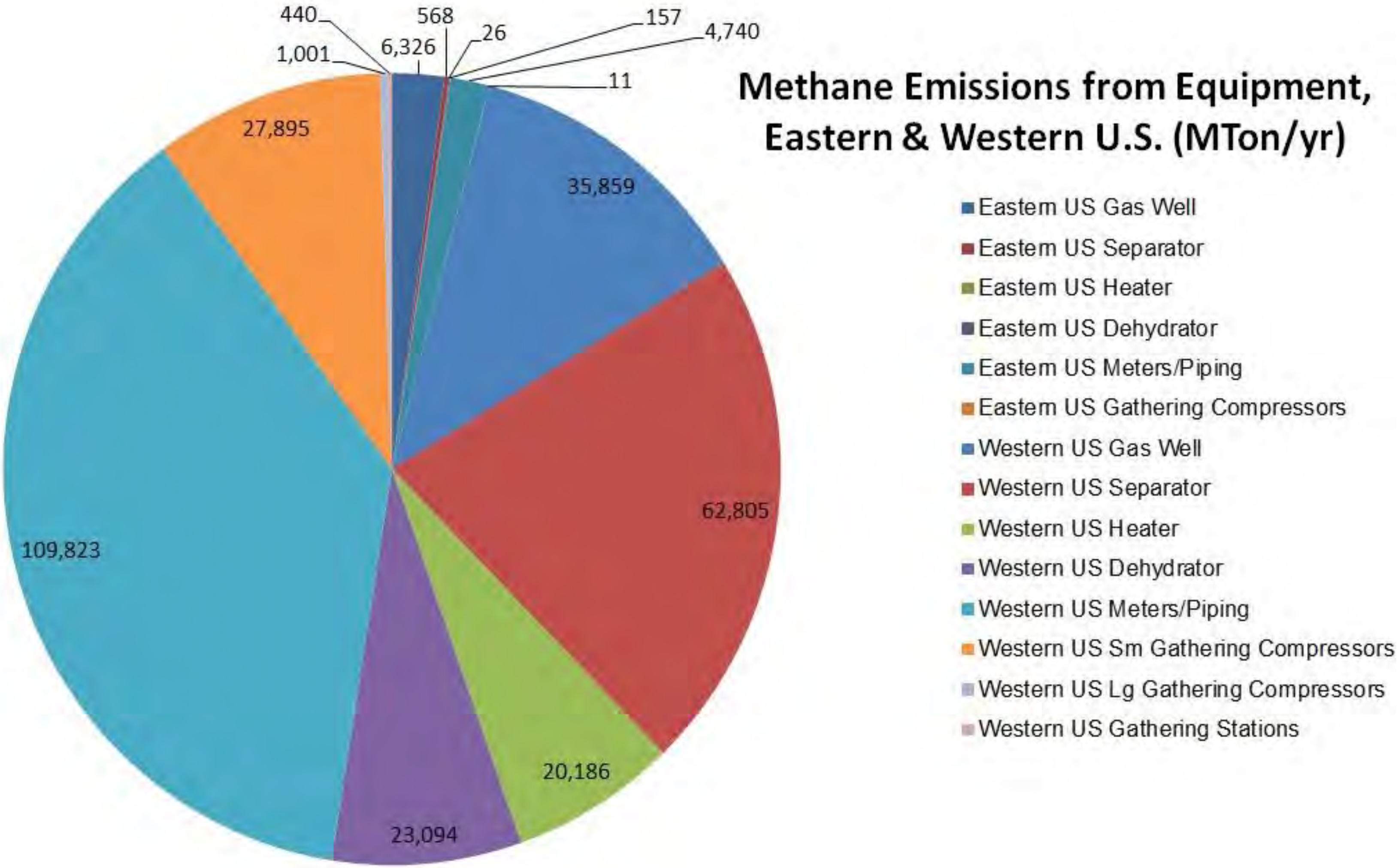
- Leak emissions include VOC and methane from:
  - Natural gas Well Pads
  - Co-producing oil wells
  - Gathering and boosting stations
  - Gas processing plants
  - Transmission and Storage
- Components are divided into the following categories:
  - Valves (manual and automatic actuation Valves)
  - Connectors (flanges, threaded unions, tees, plugs, caps)
  - Pump seals
  - Pressure relief valves
  - Open ended lines
  - Sampling connections, meters regulators, gauges and vents

Onshore Gas Production: Equipment Count



Source: USEPA OAQPS Report for Oil and Natural Gas Sector Leaks, April 2014

Methane emissions by Equipment Type & Region

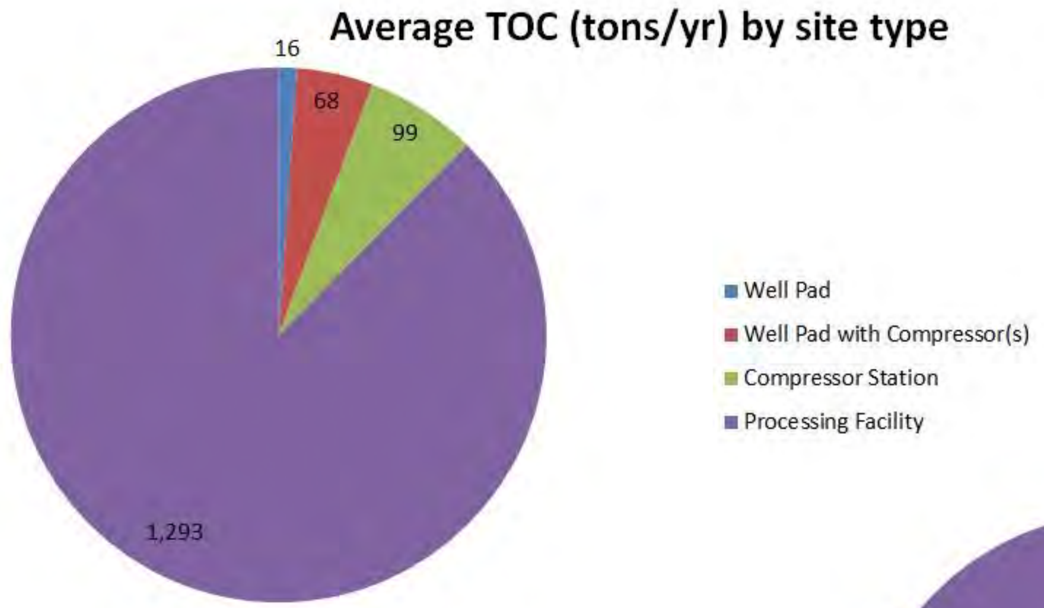


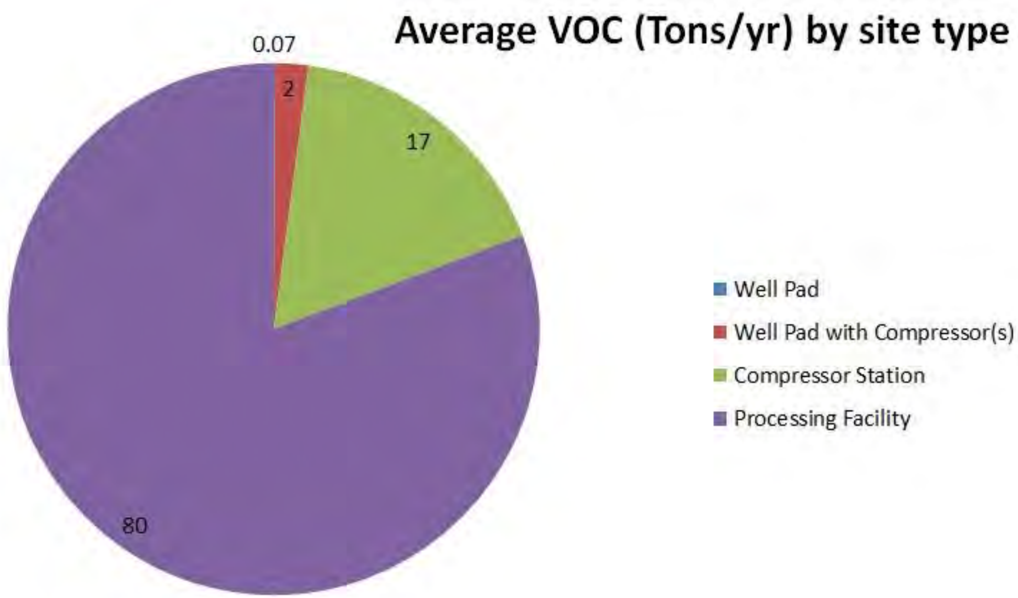
Source: USEPA OAQPS Report for Oil and Natural Gas Sector Leaks, April 2014

City of Forth Worth Study (ERG, 2011)

- Findings of study conducted by ERG:
- 375 well pads and 8 compressor stations studied
- OGI cameras to detect leak; GRI Hi-Vol. sampler used to measure
- TVA used if leak was over 500 ppmv
- 20,818 tpy of TOC leaks- Well pads account for 75% of total
- 283 out of 375 Well Pads had at least 1 leak
- Average of 3.2 leaks per Well Pad
- 275 out of 375 Well pads had at least 1 leak over 500 ppmv
- Average component at each well site:
  - 212 valves, 1596 connectors, 3 tanks, 0.5 compressor
  - 1 out of 3 well sites has a compressor onsite
- Breakdown of leak type:
  - 15% Connectors; 7% Valves; 23% tanks; 58% Other (pneumatic controllers, instrumentation, regulators, gauges, vents)

Ft. Worth Study: VOC Emissions by Site Type

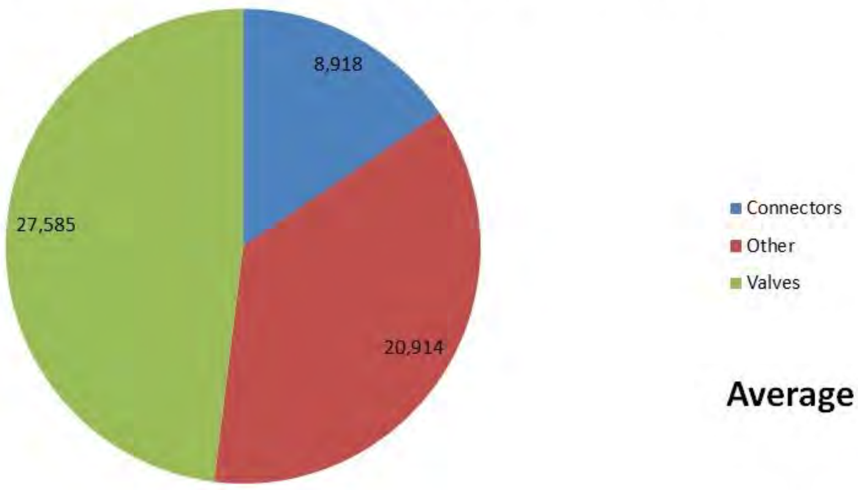




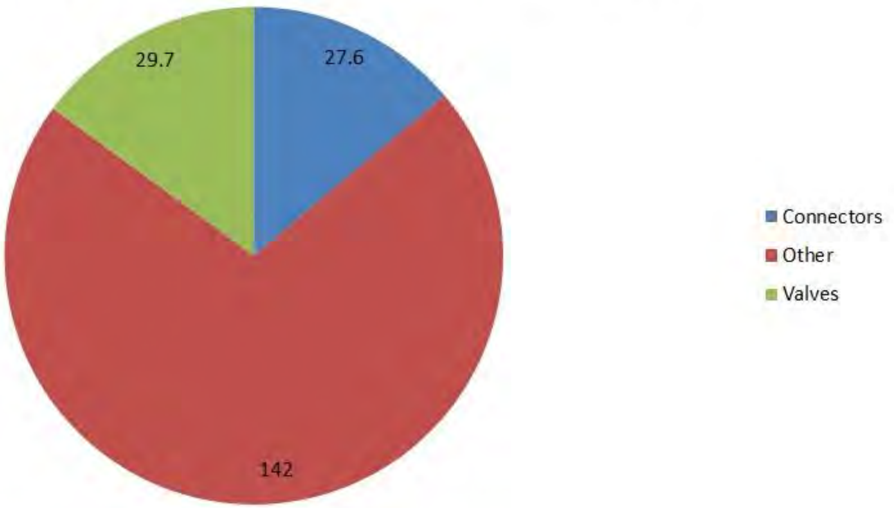
Source: USEPA OAQPS Report for Oil and Natural Gas Sector Leaks, April 2014

Ft. Worth- Methane Emissions by Equipment Type

Average Methane Emissions (lb/yr) of Equipment Types



Average VOC Emissions (lb/yr) of Equipment Types



Source: USEPA OAQPS Report for Oil and Natural Gas Sector Leaks, April 2014

Methane emissions from Leaks; Mitigation Techniques

- 2012 Total for oil & gas industry 480,691 million MT
- Leaks are 8% of overall emissions for oil & gas industry
- 2012 Methane Leaks from Production: 332,662 MT
- 2012 Methane Leaks from Processing: 33,681 MT
- 2012 Methane Leaks from Transmission: 114,348 MT
- Mitigation with Leak Detection Instruments:
  - Portable Analyzers (OVA or TVA) (costs $10,000) measures leaks
  - Optical Gas Imaging (OGI) Camera (cost $85,000) detects leaks
  - OGI contractors survey for about $2,300 per well site
  - Acoustic leak detectors
  - Ambient/Mobile measurement instrumentation $20,000-100,000

EPA White Paper No. 4

Oil and Natural Gas Sector Pneumatic Devices

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Definitions/Types of Pneumatic Devices

- Continuous bleed pneumatic controller
  - Continuous supply of gas to the control (e.g., level, temp., pressure)
    - Low bleed (bleed rate < 6 scfh);
    - High bleed (bleed rate ≥ 6 scfh)
- Intermittent pneumatic controller
  - Not continuous but actuated using pressurized natural gas
- Zero bleed pneumatic controller
  - Self-contained devices releasing gas to a downstream pipeline
- Pneumatic pumps
  - Chemical injection into wellhead, gathering lines or separators (biocide, clarifier, demulsifier, corrosion inhibitor, scale inhibitor, surfactants, paraffin dewaxer)
  - Glycol recirculation into absorber (Kimray pumps)

Methane emissions estimates for controllers

- GRI/EPA 1996 and CPA Study for Production Segment
  - Continuous 654 scfd/device; Intermittent 323 scfd/device
  - 65% intermittent and 35% continuous (high bleed)
- 345 scfd/device estimated for continuous controllers
- 35 scfd/device estimated for low bleed controllers
- Production- methane emissions of 861,224 MT in 2012
- GRI/EPA 1996 Study on Pumps
  - Emission factor of 248 scfd/CI pump for Production Segment
  - 1992 emissions of 29,008 MT from CI pumps in Production Segment
  - Emission factor of 992 scf/MMSCF for Glycol Pumps in Production
  - At 11.1 TSCF/yr throughput, 1992 annual emissions 206,889 MT from Glycol Pumps in the Production Segment

Mitigation techniques for Controllers & Pumps

- Replace High bleed with Low Bleed ($3,000 per controller)
- Replace Continuous Controllers with Zero Bleed
- Replace Gas-Assist Glycol Pumps with Instrument Air
- Replace Gas-Assist Glycol Pumps with Solar-charged pumps
- Solar pumps eliminate VOCs in addition to reducing methane
- Replace Gas-Assist Glycol Pumps with electric pumps ($10,000 replacement cost and annual electric cost $2,000)

EPA White Paper No. 5

Oil and Natural Gas Sector Liquids Unloading Processes

Liquids Unloading

- Liquids accumulate when bottom well pressure approaches reservoir shut-in pressure
- Accumulation impedes gas production
- Removal of liquids is required to improve gas flow
- Liquid unloading events are significant source of VOC & methane emissions
- Common practices to improve gas flow
  - Shutting in well to allow bottom hole pressure to increase, then venting well to atmosphere ("Well blowdown")
  - Swabbing well to remove fluids
  - Installing a plunger lift
  - Installing velocity tubing
  - Installing an artificial lift system

Methane emissions and mitigation techniques

- ICF study to improve EPA 2013 GHGRP data
  - 44,286 venting wells with plunger lifts
  - 31,113 venting wells without plunger lifts
  - Emission factor 277,000 scf/venting well for wells with plunger lift
  - Emission factor 163,000 scf/venting well for wells without plunger lift
  - Total Production methane emission estimate of 321,012 MT (17 Bcf)
- API/ANGA 2012 survey data 319,664 MT of methane/year
- Mitigation techniques recommended:
  - Optimized plunger lift system with "smart well automation" – can reduce need for venting due to overloading ($20,000)
  - Scanned coil velocity tubing with or without foaming agents (cost to install soap launchers and tubing is $64,000)
  - Foaming agents (annual cost $6000)
  - Artificial lift system (Capital cost $41,000-62,000)

EPA's Questions for Reviewers

- Are the emissions estimates in the paper appropriate?
- Are the emissions technologies and their cost estimates accurate? Any regional variability to report?
- Are other emissions studies available or being conducted?
- Anecdotal evidence suggest well blowdown removes 15% of liquid, while a plunger lift removes up to100%? Discuss the efficacy of plunger lifts and any conditions that limit its use?
- Please comment on the feasibility of using flares to control emissions during well blowdown events?

TRC

Useful links and information

To download the white papers:

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

Submit comments on the technical white papers to:

Oilandgas.whitepapers@epa.gov

Please reference the White Paper you are commenting on. Deadline for submitting comments: **June 16, 2014**

To submit comments containing confidential business information, mark as "CBI" and submit CD's to:

Roberto Morales,

US EPA Office of Air Quality Planning and Standards

Mail Code: C404-02

109 T.W. Alexander Dr.

Research Triangle Park, NC 27711

Questions or Comments on the Presentation

Questions?

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The information and material in this presentation is for informational purposes only and is not intended to be construed or used as any general technical advice. Please contact the author if you have questions regarding this information and material. Unless otherwise referenced, the information and material in this presentation is compiled from the April 2014 Report for the Oil and Natural Gas Sector Review Panel (White Papers) prepared by the U.S. EPA Office of Air Quality Planning and Standards (OAQPS). This presentation is a compilation of the five White Papers. Charts and graphs are created using the information in the tables in the White Paper(s). The author has made a good faith effort to present the material accurately. However, no one should rely on the information or material presented here, and each reader or recipient of this presentation should seek the advice of a professional engineer.

White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector

On April 15, 2014, EPA released for external peer review five technical white papers on potentially significant sources of emissions in the oil and gas sector. The white papers focus on technical issues covering emissions and mitigation techniques that target methane and volatile organic compounds (VOCs). As noted in the Obama Administration's Strategy to Reduce Methane Emissions, EPA will use the papers, along with the input we receive from the peer reviewers and the public, to determine how to best pursue additional reductions from these sources.

The five white papers cover:

- ***Compressors:*** Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported along a pipeline. Vented emissions of methane and VOCs from compressors occur from seal degassing for wet seal centrifugal compressors or packing surrounding the mechanical compression components of reciprocating compressors. These emissions typically increase over time as the compressor components begin to degrade. This paper presents data and mitigation techniques for emissions from these compressors, some of which are not covered under EPA's 2012 New Source Performance Standards (NSPS) for VOCs.
- ***Emissions from completions and ongoing production of hydraulically fractured oil wells***: Completion is the process of preparing a well for production. Completions of hydraulically fractured or refractured oil wells can be a source of methane and VOC emissions. Hydraulically fractured oil wells also may produce natural gas along with the oil; this gas is often vented during production. This paper presents data and mitigation techniques for emissions from completions and associated gas from ongoing production at hydraulically fractured oil wells, which are not covered under the 2012 NSPS.
- ***Leaks***: As oil and gas production from unconventional formations such as shale deposits continues to grow, so does the amount of related equipment that has the potential to leak. This paper presents data and mitigation techniques for onshore natural gas leak emissions that occur from natural gas production, processing, transmission and storage.
- ***Liquids unloading:*** Liquids unloading refers to a number of processes used to remove accumulated liquids that can impede the flow of gas from a well to the surface. This paper presents data and mitigation techniques for the methane and VOC emissions that can occur during these processes. Liquids unloading is not covered under EPA's 2012 NSPS for VOCs.
- ***Pneumatic devices*****:** Controllers and pumps powered by high-pressure natural gas are widespread in the oil and natural gas industry. These pneumatic devices may release gas – including methane and VOCs – with every valve movement, or continuously in many

cases. This paper presents data and mitigation techniques for emissions from pneumatic controllers and pumps, some of which are not covered under EPA’s 2012 NSPS for VOCs.

Submitting information:

EPA welcomes technical information and data from the public on the papers. Please provide input by June 16, 2014, following the instructions available at http://www.epa.gov/airquality/oilandgas/whitepapers.html

Oil and Natural Gas Sector
Liquids Unloading Processes

Report for Oil and Natural Gas Sector

Liquids Unloading Processes

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 air 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 air 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.

In new gas wells, there is generally sufficient reservoir pressure to facilitate the flow of water and hydrocarbon liquids to the surface along with produced gas. In mature gas wells, the accumulation of liquids in the well can occur when the bottom well pressure approaches reservoir shut-in pressure. This accumulation of liquids can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production (i.e., liquids loading), removal of fluids (i.e., liquids unloading) is required in order to maintain production. Emissions to the atmosphere during liquids unloading events are a potentially significant source of VOC and methane emissions.

Most gas wells will have liquid loading occur at some point during the productive life of the well. When this occurs, common courses of action to improve gas flow include (U.S. EPA, 2011):

- Shutting in the well to allow bottom hole pressure to increase, then venting the well to the atmosphere (well blowdown, or "blowing down the well"),

- Swabbing the well to remove accumulated fluids,
- Installing a plunger lift,
- Installing velocity tubing, and
- Installing an artificial lift system.

Blowing down the well involves the intentional manual venting of the well to the atmosphere to improve gas flow, whereas the use of a plunger lift system uses the well's own energy (gas/pressure) to lift liquids from the tubing by pushing the liquids to the surface by the movement of a free-traveling plunger ascending from the bottom of the well to the surface. The plunger essentially acts as a piston between liquid and gas. Use of a plunger lift often minimizes and sometimes eliminates the need for blowing down the well.

Because of the potential for substantial VOC and methane emissions occurring during liquids unloading at natural gas wells, there are an increasing number of studies on emissions from natural gas well liquids unloading events. These studies of liquids unloading practices attempt to quantify emissions on a well specific, regional and national level and often take into account the use of available mitigation techniques, such as plunger lifts. This document provides a summary of the EPA's understanding of VOC and methane emissions from natural gas production liquids unloading events, available liquids unloading and emission mitigation techniques, the relative magnitude of emissions associated with the respective techniques and the efficacy and prevalence of those techniques in the field. Section 2 of this document provides our understanding of emissions from liquids unloading events, and Section 3 provides our understanding of available liquids unloading and emissions 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 us with obtaining a more comprehensive understanding of liquids unloading VOC and methane emissions and emission mitigation techniques for the liquids unloading process.

2.0 OIL AND NATURAL GAS SECTOR LIQUIDS UNLOADING AVAILABLE EMISSIONS DATA AND EMISSIONS ESTIMATES

Given the potential for significant emissions from liquids unloading, there have been several information collection efforts and studies conducted to estimate emissions and available emission mitigation techniques. Some of these studies are listed in Table 2-1, along with an indication of the type of information contained in the study (i.e., activity level, emissions data, mitigation techniques).

Table 2-1. Summary of Major Sources of Liquids Unloading Information

Name	Affiliation	Year of Report	Activity Data	Emissions Data	Mitigation Techniques
Greenhouse Gas Reporting Program (U.S. EPA, 2013)	U.S. Environmental Protection Agency	2013	Sub-basin	X	X
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012 (2014 GHG Inventory) (U.S. EPA, 2014)	U.S. Environmental Protection Agency	2013	Regional	X	X
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses (API and ANGA, 2012)	American Petroleum Institute (API)/America's Natural Gas Alliance (ANGA)	2012	Regional	X	X
Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)	Multiple Affiliations, Academic and Private	2013	9 Liquids Unloading Events	X	X
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014)	ICF International (Prepared for the Environmental Defense Fund)	2014	Regional	X	X

A more-detailed description of the data sources listed in Table 2-1 is presented in the following sections, including how the data may be used to estimate national VOC and methane emissions from liquids unloading events.

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

In October 2013, the EPA released 2012 greenhouse gas (GHG) data for Petroleum and Natural Gas Systems[1] 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 datasets 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[2] in the Petroleum and Natural Gas Systems source category is required to submit annual reports if total emissions are 25,000 metric tons carbon dioxide equivalent (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 liquids unloading source emissions reported under the GHGRP include emissions from facilities that have wells that are venting, including those wells that vent during plunger lift operation. Liquids unloading techniques that do not involve venting are not reported. The total reported methane emissions in 2012 for liquids unloading were approximately 276,378 metric tons (MT). Facilities were given the option among three methods for calculating emissions from liquids unloading. The first calculation method involved using a representative well sample to calculate emissions for both wells with and without plunger lifts. The second and third

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[1] The implementing regulations of the Petroleum and Natural Gas Systems source category of the GHGRP are located at 40 CFR Part 98 Subpart W.

[2] 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).

calculation methods provided engineering equations for wells with plunger lifts and without plunger lifts.

Of the 251 facilities that reported emissions for well venting for liquids unloading, 120 facilities reported using Best Available Monitoring Methods (BAMM) for unique or unusual circumstances. Where a facility used BAMM, it was required to follow emission calculations specified by the EPA, but was allowed to use alternative methods for determining inputs to calculate emissions. These inputs are the values used by facilities to calculate equation outputs or results. Table 2-2 shows the activity count and reported emissions for the different calculation methods.

Table 2-2. Greenhouse Gas Reporting Program 2012 Reported Emissions from Liquids Unloading (U.S. EPA, 2013)

Calculation Method	Number of Facilities Reporting[a]	Number of Wells Venting During Liquids Unloading	Number of Wells Venting that are Equipped With Plunger Lifts	Reported CH_4 Emissions (MT)[b]
Method 1: Direct Measurement of Representative Well Sample	42	10,024	7,149	112,496
Method 2: Engineering Calculation for Wells without Plunger Lifts	188	23,536	0	71,593
Method 3: Engineering Calculation for Wells with Plunger Lifts	132	25,103	25,103	92,289
Total	**251**	**58,663**	**32,252**	**276,378**

[a] Total number of facilities is smaller than the sum of facilities from each method because some facilities reported under both Method 2 and Method 3.
[b] The reported CH_4 MT CO_2e emissions were converted to CH_4 emissions in MT by dividing by a global warming potential (GWP) of methane (21).

2.2 API/ANGA 2012 Survey Data (API and ANGA, 2012)

The API/ANGA 2012 Survey Data includes a dataset from over 20 companies covering over 90,000 gas wells, including approximately 59,000 wells that conducted liquids unloading operations. This study sample population includes representation from most of the geographic regions of the country as well as most of the geologic formations currently developed by the industry. The study provides estimated methane emissions from liquids unloading for 5,327 wells that were calculated based on well characteristics such as well bore volume, well pressure, venting time, and gas production rate and using 40 CFR part 98, subpart W engineering equations. These emissions estimates and the activity data used to calculate the estimates are presented in Table 2-3.

Table 2-3. API/ANGA Study Liquids Unloading Emissions Estimates (API and ANGA, 2012; pg. 14)

Mid-Level Survey Data	
Total number of wells with plunger lift (42,681 in sample)	11,518
Total number of wells without plunger lift (42,681 in sample)	31,163
Number of plunger equipped wells that vent (42,681 in sample)	2,426 (21.1%)
Number of non-plunger equipped wells that vent (i.e., wells performing blowdowns)(42,681 in sample)	2,901 (9.3%)
Total annual volume gas vented for venting wells	1,719,843,596 standard cubic feet (scf) gas/year
Calculated volume vented gas per venting well	322,854 scfy gas/well
Calculated methane volume vented per venting well	254,409 scfy CH_4/well
Calculated National Well Data	
Calculated national number of wells with plunger lift that vent for unloading	36,806
Calculated national number of wells without plunger lift that vent for unloading (i.e., wells performing blowdowns)	28,863
National Emission Calculations	
Total gas venting for liquids unloading volume (scaled for national wells)	21,201,410,618 scf gas/yr
Total methane venting for liquids unloading (scaled for national wells)	16,706,711,567 scf CH_4/yr
Total liquid unloading vented methane (scaled for national wells)	319,664 MT CH_4/yr

The authors of the study made the following conclusions:

- The 2012 GHG Inventory emissions estimates for liquids unloading were overestimated by orders of magnitude. The API/ANGA Survey data indicated a lower percentage of gas wells that vent for liquids unloading and a shorter vent duration.
- The emissions from liquids unloading are not specific to only conventional wells, but can be for any well depending on several technical and geological aspects of the well.
- Although most wells do not require liquids unloading until later in the well's productive lifetime, the timeframe for initiating liquids unloading operations varies significantly and can be early in the well's productive life span.
- Most of the emissions from liquids unloading operations are produced by less than 10% of the venting well population.

The study does not discuss the characteristics that cause certain wells to have significantly higher emissions than other venting wells. The study showed that the majority of emissions came from a small percentage of venting wells, and both conventional and hydraulically fractured wells can vent during liquids unloading. Additionally, while a large percentage of wells equipped with plunger lifts do not vent during liquids unloading events, many wells with plunger lifts produce emissions during liquids unloading events. This suggests that plunger lifts are capable of unloading liquids from a well without venting, but in many cases they are operated in a manner that results in venting. It is not clear to the EPA what the conditions are that cause these wells with plunger lifts to be operated in a manner that results in significant venting during liquids unloading.

2.3 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. 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). The 2014 GHG Inventory data (published in 2014; containing emissions data for 1990-2012) was evaluated for information on liquids unloading emissions.

The 2014 GHG Inventory applied calculated National Energy Modeling System (NEMS) (U.S. EPA, 2014) region- and unloading technology-specific emission factors to the percentage of wells requiring liquids unloading by using the percentages of wells venting for liquids unloading with plunger lifts, and wells without plunger lifts in each region based on API/ANGA Survey data (*see* Section 2.1.1.3 for a discussion on this data).

The 2014 GHG Inventory activity data (number of wells), emissions factors (standard cubic feet per year [scfy]/well) and the calculated emissions for liquids unloading are presented by NEMS region in Table 2-4.

Table 2-4. Data and Calculated CH_4 Emissions [MT] for the Natural Gas Production Sector by NEMS Region (U.S. EPA, 2014, ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories)

NEMS Region	Activity	Activity Data[a,b] (number of wells)	Emission Factor (scfy)/well[b]	Calculated Emissions (MT)
North East	Liquids Unloading (with plunger lifts)	6,924	268,185	35,764
	Liquids Unloading (without plunger lifts; blowdowns)	17,906	141,646	48,849
Midcontinent	Liquids Unloading (with plunger lifts)	2,516	1,140,052	55,245
	Liquids Unloading (without plunger lifts; blowdowns)	4,469	190,179	16,369
Rocky Mountain	Liquids Unloading (with plunger lifts)	10,741	119,523	24,726
	Liquids Unloading (without plunger lifts; blowdowns)	1,267	1,998,082	48,758

NEMS Region	Activity	Activity Data[a,b] (number of wells)	Emission Factor (scfy)/well[b]	Calculated Emissions (MT)
South West	Liquids Unloading (with plunger lifts)	1,379	2,856	76
	Liquids Unloading (without plunger lifts; blowdowns)	8,078	77,899	12,120
West Coast	Liquids Unloading (with plunger lifts)	159	317,292	972
	Liquids Unloading (without plunger lifts; blowdowns)	142	279,351	764
Gulf Coast	Liquids Unloading (with plunger lifts)	1,784	61,758	2,122
	Liquids Unloading (without plunger lifts; blowdowns)	5,445	265,120	27,803
Total		60,810		273,568

[a]DI Desktop, 2014.
[b]API/ANGA 2012 Survey Data, Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production – Summary and Analysis of API and ANGA Survey Responses (API and ANGA, 2012).

The 2014 GHG Inventory data estimates that liquids unloading emissions in 2012 were 14% of overall methane emissions from the natural gas production segment.

2.4 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 EPA's 2013 GHG Inventory. The sources or operations tested included liquids unloading. Under this study, sampling was performed for liquids unloading in which an operator manually bypassed the well's separator. These manual unloading events could be scheduled, which allowed time to install measurement equipment.

Analysis included nine well unloading events, ranging from 15 minutes to two hours, including both continuous flow and intermittent flow events. Some of the wells sampled only unloaded liquids once over the current life of the well, where others were unloaded monthly. The average emissions per unloading event were 1.1 MT of methane (95% confidence limits of 0.32-2.0 MT). The study reports that the average emissions per well per year (based on the emissions per event for each well multiplied by the frequency of the events per year reported by the well operator) was 5.8 MT. The study acknowledges that the sampled population characteristics reflected a wide range of emission rates and that when emissions are averaged per event, emissions from four of the nine events contribute more than 95% of the total emissions. This result is consistent with the API/ANGA 2012 Survey Data and 2012 data reported to the GHGRP; all suggest that certain wells produce significantly more emissions during liquids unloading events than others. The study also suggests that the length of the liquids unloading event and the number of events are crucial factors in a well's annual emissions from liquids unloading.

The authors report that their study supports their belief that the application of the API/ANGA 2012 Survey data method used when calculating the 2013 GHG Inventory overestimates GHG emissions. Although the authors believe that their study provides valuable information, they caution that the sampling in their study was insufficient to characterize emissions from liquids unloading for all well sites in all basins and recommend that additional measurement of unloading events be conducted in order to improve national emissions estimates. Because characteristics of the unloading events sampled in the study were highly variable, and because the number of events sampled was small, the authors caution the use of the data to extrapolate to larger populations.

2.5 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 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. Liquids unloading is one of the 22 emission sources that is included in the study.

The study relied on the EPA's 2013 GHG Inventory for methane emissions data for the oil and natural gas sector. This emissions data was revised to include updated information from the GHGRP (EPA) 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. The projected emissions are not discussed further here, because projected emissions are not a topic covered by this white paper.

The study used the GHGRP data for 2011 and 2012 to develop new activity and emission factors for wells with liquids unloading. It was assumed that the respondents represented 85% of the industry, therefore, the EPA's 2013 GHG Inventory estimate of the number of venting wells with plunger lifts was increased to 44,286 from 37,643, and the estimate of the number of venting wells without plunger lifts was increased to 31,113 from 26,451.[3] The emission factors were updated by dividing the total emissions for each venting well type (those equipped with plunger lifts and those that were not equipped with a plunger lift) by the total number of reporting wells. The calculated emission factors were 277,000 scf/venting well for wells with plunger lifts and 163,000 scf/venting well for wells without plunger lifts. Using these updated emission factors, ICF estimated a net increase of methane emissions from liquids unloading (as compared to the EPA's 2013 GHG Inventory) by approximately 30% to 17 billion cubic feet (Bcf)(approximately 321,012 MT). This represented the study's baseline methane emissions for 2011 for liquids unloading.

[3] The EPA is unaware of how the study authors determined the GHGRP data represented 85% of the industry.

Further information included in this study on the use of a plunger lift as a mitigation or emission reduction option, methane control costs, and their estimates for the potential for VOC emissions co-control benefits from the use of a plunger lift are presented in Section 3.1 of this document.

3.0 AVAILABLE LIQUIDS UNLOADING EMISSIONS MITIGATION TECHNIQUES

As noted previously, many natural gas wells have sufficient reservoir pressure to flow formation fluids (water and hydrocarbon liquids) to the surface along with the produced gas. As the bottom well pressure approaches reservoir shut-in pressure, gas flow slows and liquids accumulate at the bottom of the tubing. A common approach to temporarily restoring flow is to vent the well to the atmosphere (well "blowdown") which removes liquids but also produces emissions.

Several techniques are available that could produce less (compared to blowdown) or no emissions from liquids unloading. The following section describes techniques that remove liquids from the well by other means than a blowdown and in the process can reduce the amount of vented gas and, thus, reduce the VOC and methane emissions. These technologies can reduce the need for liquids unloading operations or result in the capture of gas from liquids unloading operations.

3.1 Liquid Removal Technologies

Numerous liquid removal technologies have been evaluated for their emission levels and their potential for eliminating or minimizing emissions from liquids unloading. The Natural Gas STAR program reports the potential for significant emissions reductions and economic benefits from implementing one or more lift options to remove this liquid instead of blowing down the well to the atmosphere (U.S. EPA, 2006b and 2011).

As noted in Section 1 of this document, the Natural Gas STAR program reports that when liquids loading occurs during the productive life of the well, one or more of the following actions are generally taken (U.S. EPA, 2011):

- Shutting in the well to allow the bottom hole pressure to increase, and then venting the well to the atmosphere (well blowdown),
- Swabbing the well to remove accumulated fluids,

- Installing velocity tubing,
- Installing a plunger lift system, and
- Installing an artificial lift system.

In the sections below, the technologies have been divided into “primary” and “remedial” technologies. It is the EPA’s understanding that the “primary” technologies are used as more permanent solutions to liquids loading problems, while the “remedial” technologies may mitigate the problem but do not provide a long term permanent solution. These technologies are summarized in Table 3-1.

Table 3-1. Liquid Removal Techniques for Liquid Unloading of Natural Gas Wells

Mitigation Techniques	Description	Applicability	Costs	Efficacy and Prevalence
Primary Techniques				
Plunger Lift Systems	Plunger lifts use the well's own energy (gas/pressure) to drive a piston or plunger that travels the length of the tubing in order to push accumulated liquids in the tubing to the surface (U.S. EPA, 2006b).	Plunger systems have been known to reduce emissions from venting and increase well production. Specific criteria regarding well pressure and liquid to gas ratio can affect applicability. Candidate wells for plunger lift systems generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system (U.S. EPA, 2006b).	The following information is from the EPA's Natural Gas STAR Program technical documents, however, additional cost data may be available such as from equipment or service providers (U.S. EPA, 2006b and 2011): • Capital, installation and startup cost estimates: $1,900-$7,800 (Note: Commenters on the ICF study cited a cost of $15,000. The study escalated the cost to $20,000 (ICF International, 2014)) • Smart automation system: $4,700/well - $18,000/well depending on the complexity of the system. • Additional startup costs (*e.g.*, well depth survey, miscellaneous well clean out operations): $700-$2,600.	API/ANGA Survey data show plunger lifts can result in zero emissions or significant emissions depending on how they are operated. The EPA has learned plunger lift systems rely on manual, onsite adjustments. When a lift becomes overloaded, the well must be manually vented to the atmosphere to restart the plunger. Optimized plunger lift systems (e.g., with smart well automation) can decrease the amount of gas vented by up to 90+% and reduce the need for venting due to overloading (U.S. EPA, 2006b).

Mitigation Techniques	Description	Applicability	Costs	Efficacy and Prevalence
			• Annual operating and maintenance costs (e.g., inspection and replacement of lubricator and plunger): $700-$1,300 • Annual cost savings from avoided emissions from use of an automated system: $2,400-$10,241.	
Artificial lifts (e.g., rod pumps, beam lift pumps, pumpjacks and downhole separator pumps)	Artificial lifts require an external power source to operate a pump that removes the liquid buildup from the well tubing (U.S. EPA, 2011).	The devices are typically used during the eventual decline in the gas reservoir shut-in pressure, when there is inadequate pressure to use a plunger lift. At this point, the only means of liquids unloading to keep gas flowing is downhole pump technology (U.S. EPA, 2011).	The following information is from the EPA's Natural Gas STAR Program technical documents, however, additional cost data may be available such as from equipment or service providers (U.S. EPA, 2011): • Capital and installation costs (includes location preparation, well clean out, artificial lift equipment and pumping unit): $41,000-$62,000/well • Average cost of pumping unit: $17,000-$27,000.	Artificial lifts can be operated in a manner that produces no emissions (U.S. EPA, 2011). The EPA does not have information on the prevalence of this technology in the field.

Remedial Techniques				
Velocity tubing	Velocity tubing is smaller diameter production tubing and reduces the cross-sectional area of flow, increasing the flow velocity and achieving liquid removal without blowing emissions to the atmosphere. Generally, a gas flow velocity of 1,000 feet per minute (fpm) is necessary to remove wellbore liquids (U.S. EPA, 2011).	• Velocity tubing strings are appropriate for low volume natural gas wells upon initial completion or near the end of their productive lives with relatively small liquid production and higher reservoir pressure. Candidate wells include marginal gas wells producing less than 60 Mcfd (U.S. EPA, 2011). • Coil tubing can also be used in wells with lower velocity gas production (U.S. EPA, 2011).	The following information is from the EPA's Natural Gas STAR Program technical documents, however, additional cost data may be available such as from equipment or service providers (U.S. EPA, 2011): • Installation requires a well workover rig to remove the existing production tubing and place the smaller diameter tubing string in the well. • Capital and installation costs provided from industry include the following: \$7,000-\$64,000/well	Considered to be a "no emissions" solution. Low maintenance, effective for low volumes lifted. Often deployed in combination with foaming agents. Seamed coiled tubing may provide better lift due to elimination of turbulence in the flow stream (U.S. EPA, 2011). The EPA does not have information on the prevalence of this technology in the field.
Foaming agents	A foaming agent (soap, surfactants) is injected in the casing/tubing annulus by a chemical pump on a timer basis. The gas bubbling through the soap-water solution creates gas-water foam which is more easily lifted to the surface for water removal (U.S. EPA, 2011).	A means of power will be required to run the surface injection pump. The soap supply will also need to be monitored. If the well is still unable to unload fluid, additional, smaller tubing may be needed to help lift the fluids. Foaming agents work best if the fluid in the well is at least 50% water. Surfactants are not effective for natural gas liquids or liquid hydrocarbons. Foaming agents and velocity tubing may be more effective when used in combination (U.S. EPA, 2011).	The following information is from the EPA's Natural Gas STAR Program technical documents, however, additional cost data may be available such as from equipment or service providers (U.S. EPA, 2011): Foaming agents are low cost. No equipment is required in shallow wells. In deep wells, a surfactant	Considered to be a "no emissions" solution. Low volume method applied early in production decline when bottom hole pressure still generates sufficient velocity to lift liquid droplets (U.S. EPA, 2011). The EPA does not have information on the prevalence of this technology in the field.

			injection system requires the installation of surface equipment and regular monitoring. Pump can be powered by solar or AC power or actuated by movement of another piece of equipment. • Capital and startup costs to install soap launchers: $500-$3,880 • Capital and startup costs to install soap launchers and velocity tubing: $7,500-$67,880 • Monthly cost of foaming agent: $500/well or $6,000/yr	

3.1.1 Primary Techniques

Plunger Lifts

Based on our assessment of the data, a plunger lift system for liquids unloading is capable of performing liquids unloading with little or no emissions. The level of emissions depends on how the plunger lift system is operated, specifically, whether gas is directed to the sales line or vented to the atmosphere. There may be potential for improved production and emissions reduction when paired with a smart well automation that optimizes production and reduces product losses to the atmosphere. A schematic diagram of a plunger lift is shown in Figure 3-1.

Basic installation costs for plunger lifts were estimated as ranging from \$1,900 - \$7,800 based on information gathered from the EPA's Natural Gas STAR program (*see* Table 3-1). Plunger lift installation costs include installing the piping, valves, controller and power supply on the wellhead and setting the downhole plunger bumper assembly, assuming the well tubing is open and clear. Lower costs (*e.g.*, \$1,900) would result where no other activities are required for installation. Higher costs (*e.g.*, \$7,800) would be incurred in situations where running a wire-line, which is necessary to check for internal blockages within the tubing, and a test run of the plunger is conducted from top to bottom (a process also known as broaching) to ensure that the plunger will move freely up and down the tubing string (U.S. EPA, 2006b).

Other startup costs in addition to the installation costs can include a well depth survey, swabbing to remove well bore fluids, removing mineral scale and cleaning out perforations, fishing out debris in the well, and other miscellaneous well clean out operations. Additional startup costs were estimated to be \$700 - \$2,600 (U.S. EPA, 2006b). However, commenters on the ICF study cited startup costs of \$15,000. The commenters also stated that well treatments and clean outs are often required before plunger lifts can be installed. The study escalated the cost to \$20,000 per well (ICF International, 2014).

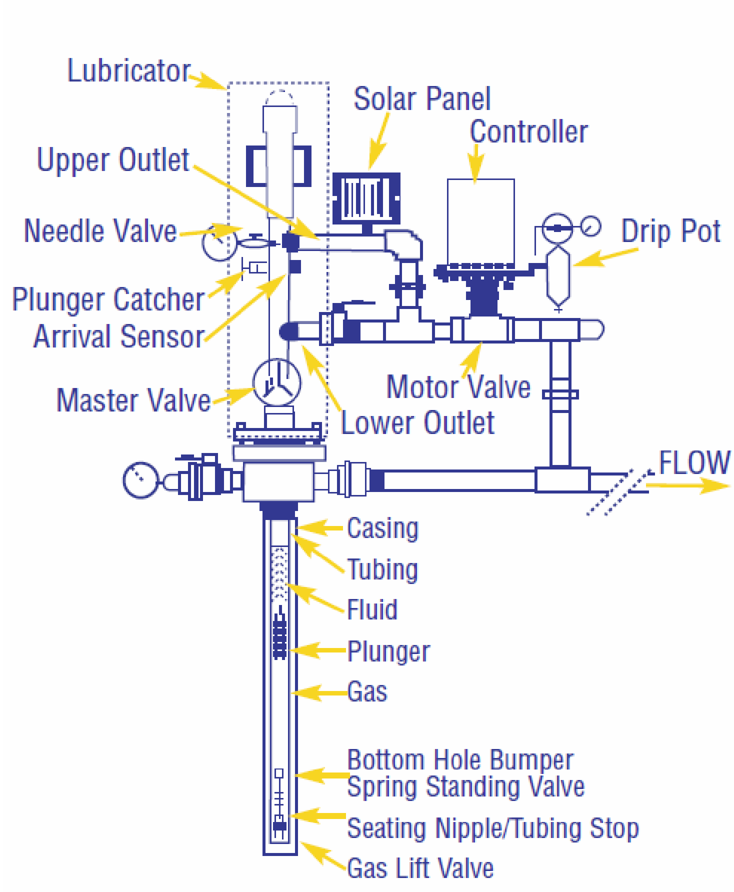

Figure 3-1. Example Plunger Lift (U.S. EPA, 2006b)

The activities to install the smart automation plunger lift include installing the controller, power supply, and host system, in addition to the activities required for the plunger itself. The typical cost of automating a plunger lift system is approximately $5,700 - $18,000, depending on the complexity of the well. This cost would be in addition to the startup costs of a plunger-only system (U.S. EPA, 2011). Installing telemetry units can help to optimize production; however, automated controllers are not necessarily required for reducing emissions.

Natural Gas STAR Partners have reported methane emissions reductions and economic benefits from implementing plunger lifts as compared to conducting blowdowns, especially those equipped with smart automation systems. The reported economic benefits from natural gas savings and improved well production range from $2,400 - $4,389 per well per year[4] (U.S. EPA, 2011). The EPA is not aware of any adverse secondary environmental impacts that would result from the installation and operation of plunger lifts in a liquid producing natural gas well, and the use of a smart automated plunger lift system has the potential to optimize production and minimize emissions over the use of a non-automated plunger lift system.

The ICF study (ICF International, 2014) calculated emission control cost curves ($/Mcf of methane reduced) using their 2018 projected methane emission estimates. The primary sources used for projecting onshore methane emissions for liquids unloading for 2018 included natural gas forecast information from the U.S. EIA's Annual Energy Outlook (AEO) and 2014 Early Release (*Lower 48 Natural Gas Production and Supply Prices by Supply Region*) and API's Quarterly Well Completions Report. The EIA information was used to project methane emissions by using regional gas production information projected in EIA's 2014 AEO for 2018. The API's report was used to update well counts by EIA AEO regions whereby a ratio of the number of wells in 2018 to wells in 2011 was used to drive the activity for most of the emission sources involved in gas production. The study assumed the application of a plunger lift (assuming 95% control of methane emissions) on 30% of the estimated venting wells without plunger lifts. ICF estimated a methane reduction of 1.6 Bcf (or approximately 30,212 MT) at a cost of $0.74/Mcf methane reduced with the application of a plunger lift on these uncontrolled wells. ICF also estimated that VOC emissions would be reduced by 9.3 kilotons (or approximately 9,300 MT) at a cost of $125/ton. According to the report, liquids unloading can increase production by anywhere from 3 to 300 thousand cubic feet per day (Mcf/day) and, without taking credit for the productivity increase, the report estimates that the cost-effectiveness breakeven point is about 1,200 Mcf/yr of venting (estimated as a reduction cost of $0.05/Mcf reduced). Their analysis assumed capital costs of $20,000 and annual operating costs of $2,400.

Artificial Lift Systems

Artificial lift systems (e.g., rod pumps and pumping units) require an external power source to operate, such as electric motors or natural gas fueled engines. However, these systems can be

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[4] Assumes a gas price of $3 per Mcf.

installed and effectively remove liquids from the well even after the well pressure has declined to the point where a plunger lift system can no longer be operated, thus they are capable of prolonging the life of a well. They typically require the use of a well workover rig to install a downhole rod pump, rods, and tubing in the well.

Based on results reported by Natural Gas STAR Partners, the cost of implementing artificial lift systems range from $41,000 - $62,000. The reported economic benefits from natural gas savings range from $2,919 - $6,120 per well per year[5] (U.S. EPA, 2011).

Secondary environmental impacts occur due to the emissions from the natural-gas fueled engine used to power the lift system, however, these impacts can be reduced by using an electric motor instead.

3.1.2 Remedial Techniques

Velocity Tubing

As was described previously, liquids build up in the well tubing as well pressure declines and the gas flow velocity is not sufficient to push the liquids out of the well tubing. Velocity tubing (smaller diameter production tubing) decreases the cross-sectional area of the conduit through which the gas flows and thus increases the velocity of the flow. The Natural Gas STAR Program uses 1,000 fpm as a general rule of thumb for the velocity necessary to remove liquids from the well (Note: This is a rule of thumb and the actual required velocity will differ based on well characteristics). When velocity tubing is installed, it must be a small enough diameter to increase the gas flow velocity to 1,000 fpm or to the necessary velocity to remove the liquids from the particular well. A well workover rig is required to remove the existing production tubing and replace it with the velocity tubing. The EPA experience through the Natural Gas STAR Program suggests the wells that are the best candidates for this technology are marginal wells that produce less than 60 Mcfd. However, as well pressure continues to decline as the well ages, the installed velocity tubing may no longer be sufficient to increase the gas flow velocity to the level necessary to remove liquids from the well. At this point, velocity tubing of a smaller diameter or other liquids

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[5] Estimate does not include value of improved well production. Assumes a gas price of $3 per Mcf.

removal technologies may be required to remove liquids from the well tubing.

Based on results reported by Natural Gas STAR Partners, the cost of implementing velocity tubing ranges from $7,000 - $64,000. The reported economic benefits from natural gas savings and improved well production range from $27,855 - $82,830 per well per year[6] (U.S. EPA, 2011). The EPA is not aware of any adverse secondary environmental impacts that would result from the installation and operation of velocity tubing.

Foaming Agents

Foaming agents can help to remove liquids from wells that are accumulating liquids at low rates. The foam produced from surfactants can reduce the density of the liquid in the well tubing and can also reduce the surface tension of the fluid column, which reduces the gas flow velocity necessary for pushing the liquid out of the well tubing. This technology can be used in conjunction with velocity tubing. However, foaming agents work best when the majority of the liquid built up in the well tubing is water, because they are not effective on natural gas liquids or liquid hydrocarbons (U.S. EPA, 2011).

The foaming agent can be delivered into the well as a soap stick or it can be injected into the casing-tubing annulus or a capillary tubing string. If the well is deep, then an injection system is required that includes foaming agent reservoir, an injection pump, a motor valve with a timer and a power source for the pump (e.g., AC power for electric power or gas for pneumatic pumps) (U.S. EPA, 2011).

Based on results reported by Natural Gas STAR Partners, the costs of foaming agents range from $500 - $9,880. The reported economic benefits from natural gas savings and improved well production range from $1,500 - $28,080 per well per year[7] (U.S. EPA, 2011).

[6] Assumes a gas price of $3 per Mcf.
[7] Assumes a gas price of $3 per Mcf.

For deep wells that require an injection system, secondary environmental impacts occur due to the emissions from the power source for the pump. Pneumatic pumps can result in vented gas emissions and electric pumps emissions depending on the source of the electric power.

4.0 SUMMARY

The EPA has used the data sources, analyses and studies discussed in this paper to form the Agency's understanding of VOC and methane emissions from liquids unloading and the emissions mitigation techniques. The following are characteristics the Agency believes are important to understanding this source of VOC and methane emissions:

- A majority of gas wells (conventional and unconventional) must perform liquids unloading at some point during the well's lifetime. As gas wells age and well pressure declines, the need for liquids unloading to enhance well performance becomes more likely.
- The 2014 GHG Inventory estimates the 2012 liquids unloading emissions to be 14% of natural gas production sector emissions.
- The majority of emissions from liquids unloading events come from a small percentage of wells. Some of the characteristics that affect the magnitude of liquids unloading annual emissions from a well are the length of time of each event and the frequency of events.
- A wide range of emission rates from blowdowns have been reported from the limited available well-level data. In the Allen et. al. study, when emissions are averaged per event, emissions from four of the nine events included in the study contribute more than 95% of the total emissions. This result is consistent with the API/ANGA 2012 Survey data and 2012 data reported to the GHGRP; all suggest that certain wells produce more emissions during blowdowns than others. Some suggested causes of this variation are the length of the blowdown and the number of blowdowns per year, which are affected by underlying geologic factors.
- Industry has developed several technologies that effectively remove liquids from wells and can result in fewer emissions than blowdowns. Plunger lifts are the most common of those technologies.

- The emissions reduction efficiency plunger lifts can achieve varies greatly depending on how the system is operated. It is not clear to the EPA what the conditions are that lead to wells with plunger lifts to be vented during plunger lift operation.
- The two liquids unloading techniques that result in vented emissions that the EPA is aware of are plunger lifts when vented to the atmosphere and blowdowns.

5.0 CHARGE QUESTIONS FOR REVIEWERS

1. Please comment on the national estimates of methane emissions and methane emission factors for liquids unloading presented in this paper. Please comment on regional variability and the factors that influence regional differences in VOC and methane emissions from liquids unloading. What factors influence frequency and duration of liquids unloading (e.g., regional geology)?
2. Is there further information available on VOC or methane emissions from the various liquids unloading practices and technologies described in this paper?
3. Please comment on the types of wells that have the highest tendency to develop liquids loading. It is the EPA's understanding that liquids loading becomes more likely as wells age and well pressure declines. Is this only a problem for wells further down their decline curve or can wells develop liquids loading problems relatively quickly under certain situations? Are certain wells (or wells in certain basins) more prone to developing liquids loading problems, such as hydraulically fractured wells versus conventional wells or horizontal wells versus vertical wells?
4. Did this paper capture the full range of feasible liquids unloading technologies and their associated emissions? Please comment on the costs of these technologies. Please comment on the emission reductions achieved by these technologies. How does the well's life cycle affect the applicability of these technologies?
5. Please provide any data or information you are aware of regarding the prevalence of these technologies in the field.
6. In general, please comment on the ability of plunger lift systems to perform liquids unloading

without any air emissions. Are there situations where plunger lifts have to vent to the atmosphere? Are these instances only due to operator error and malfunction or are there operational situations where it is necessary in order for the plunger lift to effectively remove the liquid buildup from the well tubing?

7. Based on anecdotal experience provided by industry and vendors, the blowdown of a well removes about 15% of the liquid, while a plunger lift removes up to 100% (BP, 2006). Please discuss the efficacy of plunger lifts at removing liquids from wells and the conditions that may limit the efficacy.

8. Please comment on the pros and cons of installing a plunger lift system during initial well construction versus later in the well's life. Are there cost savings associated with installing the plunger lift system during initial well construction?

9. Please comment on the pros and cons of installing a "smart" automation system as part of a plunger lift system. Do these technologies, in combination with customized control software, improve performance and reduce emissions?

10. Please comment on the feasibility of the use of artificial lift systems during liquids unloading operations. Please be specific to the types of wells where artificial lift systems are feasible, as well as what situations or well characteristics discourage the use of artificial lift systems. Are there standard criteria that apply?

11. The EPA is aware that in areas where the produced gas has a high H_2S concentration combustion devices/flares are used during liquids unloading operations to control vented emissions as a safety precaution. However, the EPA is not aware of any instances where combustion devices/flares are used during liquids unloading operations to reduce VOC or methane emissions. Please comment on the feasibility of the use of combustion devices/flares during liquids unloading operations. Please be specific to the types of wells where combustion devices/flares are feasible. Are there operational or technical situations where combustion devices/flares could not be used?

12. Given that liquids unloading may only be required intermittently at many wells, is the use of a mobile combustion device/flare feasible and potentially less costly than a permanent combustion device/flare?

13. Given that there are multiple technologies, including plunger lifts, downhole pumps and velocity tubing that are more effective at removing liquids from the well tubing than blowdowns, why do owners and operators of wells choose to perform blowdowns instead of employing one of these technologies? Are there technical reasons other than cost that preclude the use of these technologies at certain wells?

14. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from liquids unloading events and available options for increased product recovery and emissions reductions? The EPA is aware of an additional stage of the Allen et al. study to be completed in partnership with the EDF and other partners that will directly meter the emissions from liquids unloading events. However, the EPA is not aware of any other ongoing or planned studies addressing this source of emissions.

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Oil and Natural Gas Sector Compressors

Report for Oil and Natural Gas Sector Compressors

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 air 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 air emissions and available mitigation options. This paper presents the Agency's understanding of emissions and available control technologies from a potentially significant source of emissions in the oil and natural gas sector.

Oil and gas production from unconventional formations such as shale deposits or plays has grown rapidly over the last decade. Oil and natural gas production is projected to steadily increase over the next two decades. Specifically, natural gas development is expected to increase by 44% from 2011 through 2040 and crude oil and natural gas liquids are projected to increase by approximately 25% through 2019 (U.S. EIA, 2013). The projected growth is primarily led by the increased development of shale gas, tight gas, and coalbed methane resources utilizing new production technology and techniques such as horizontal drilling and hydraulic fracturing. According to the U.S. Energy Information Administration (EIA), over half of new oil wells drilled co-produce natural gas (U.S. EIA, 2013). Based on this increased oil and gas development and the fact that half of these new oil wells co-produce natural gas, the potential exists for increased emissions from production through distribution of natural gas from these operations.

Compressors have been identified as an emission source that has the potential to produce emissions to the atmosphere during oil and gas production (gathering and boosting), processing, transmission and storage. Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. Vented emissions from compressors occur from seals (wet seal compressors) or packing surrounding the mechanical compression components (reciprocating compressors) of the compressor. These emissions typically increase over time as the compressor components begin to degrade. Leak emissions from various compressor components can also occur, but those emissions are not covered in this paper because the causes and mitigation techniques are different than the vented emissions.

The purpose of this paper is to summarize the EPA's understanding of vented VOC and methane emissions from compressors, and the EPA's understanding of available mitigation techniques (practices and equipment) to reduce vented emissions from compressors. Included in the mitigation techniques discussion is our understanding of the efficacy and cost of these technologies and the prevalence of use of the technologies in the industry.

In the oil and natural gas sector, the most prevalent types of compressors used are reciprocating and centrifugal compressors. For the purposes of this paper, a reciprocating compressor is defined as:

> A piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

For the purposes of this paper, a centrifugal compressor is defined as:

> Any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers.

Compressors are used in all aspects of natural gas development. In the production segment, compressors are used at the wellhead to compress gas for fluids removal and pressure equalization with gathering equipment systems. However, the primary use of compressors is in the natural gas processing, transmission and storage (particularly underground storage) segments of the industry.

Section 2 of this document provides background and context for discussions of vented emissions from compressors, Section 3 presents our understanding of vented VOC and methane emissions from compressors, and Section 4 provides our understanding of available emissions mitigation techniques. Section 5 summarizes the EPA's understanding based on the information presented in Sections 3 and 4, and Section 6 presents a list of charge questions for reviewers to assist us with obtaining a more comprehensive understanding of vented VOC and methane emissions from compressors and emission mitigation techniques.

2.0 PROCESS DESCRIPTIONS

2.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. For the purposes of this paper, reciprocating compressor rod packing is defined to mean:

> 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.

Over the operating life of the compressor, the rings become worn and the packing system will begin to wear resulting in higher leak rates. Emissions from packing systems originate from mainly four components; the nose gasket, between the packing cups, around the rings and between the rings and the shaft. See Figure 2-1 for a depiction of a typical compressor rod packing system configuration. Typically, gases leaked from the packing system are vented.

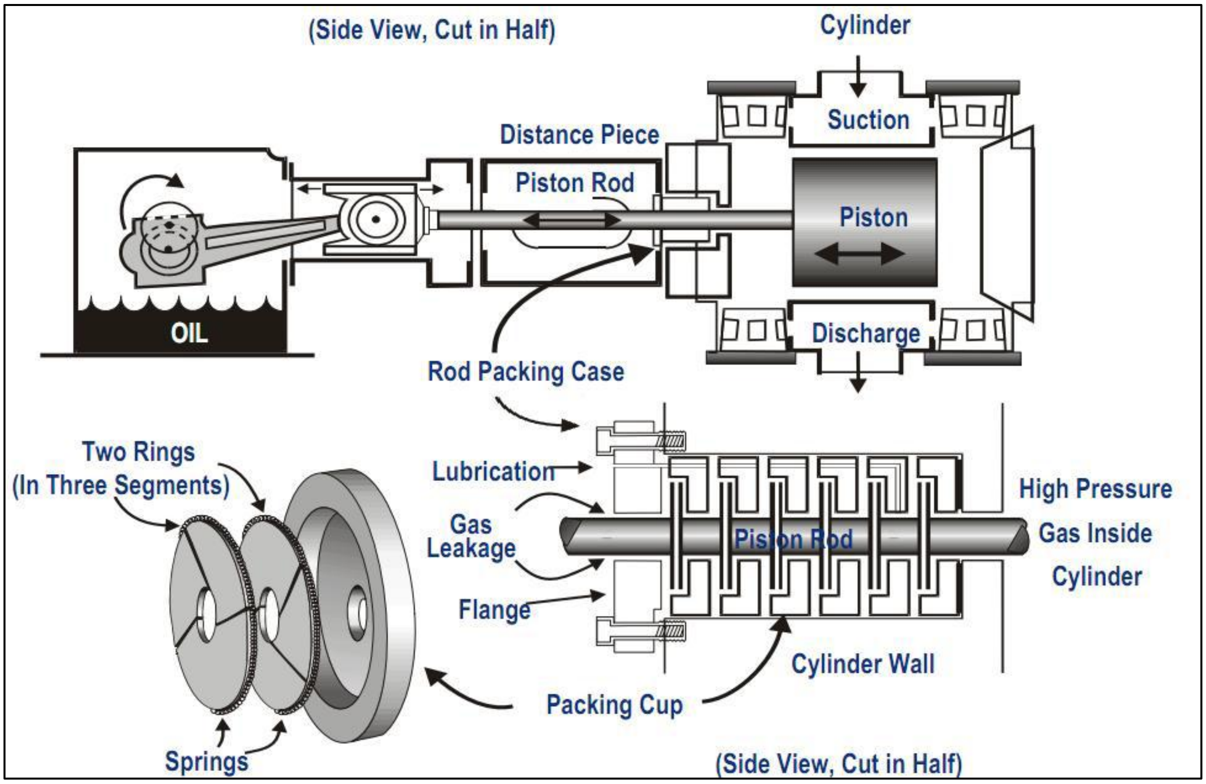

Figure 2-1. Typical Reciprocating Compressor Rod Packing System (U.S. EPA, 2006a)

2.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas and are widely used in the processing and transmission industry segments. Centrifugal compressors are equipped with either a wet or dry seal configuration. Wet seals use oil around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The oil is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process (degassing or off-gassing). Figure 2-2 illustrates the wet seal compressor configuration.

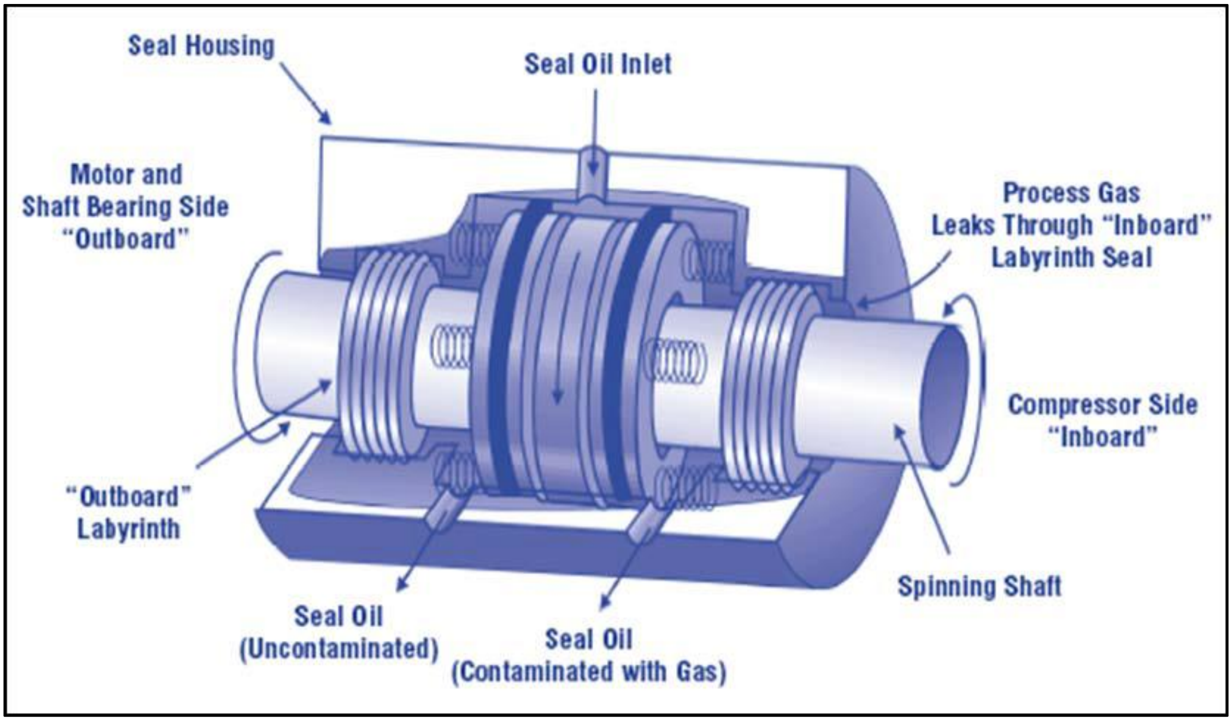

Figure 2-2. Typical Centrifugal Compressor Wet Seal (U.S. EPA, 2006b)

Alternatively, dry seal compressors use the opposing force created by hydrodynamic grooves and springs to provide a seal. The opposing forces create a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. The combination of two or more of the dry seals in series is called "tandem dry seals" and is effective in reducing gas leakage. Figure 2-3 illustrates the tandem dry seal compressor configuration.

Gas emissions from wet seal centrifugal compressors have been found to be higher than dry seals compressors primarily due to the off-gassing of the entrained gas from the oil. This gas is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process. In addition to lower gas leakage (and therefore lower emissions), dry seals have been found to have lower operation and maintenance costs than wet seal compressors because they are a mechanically simpler design, require less power to operate, are more reliable and require less maintenance. Dry seal compressors will be discussed in more detail in Section 4.

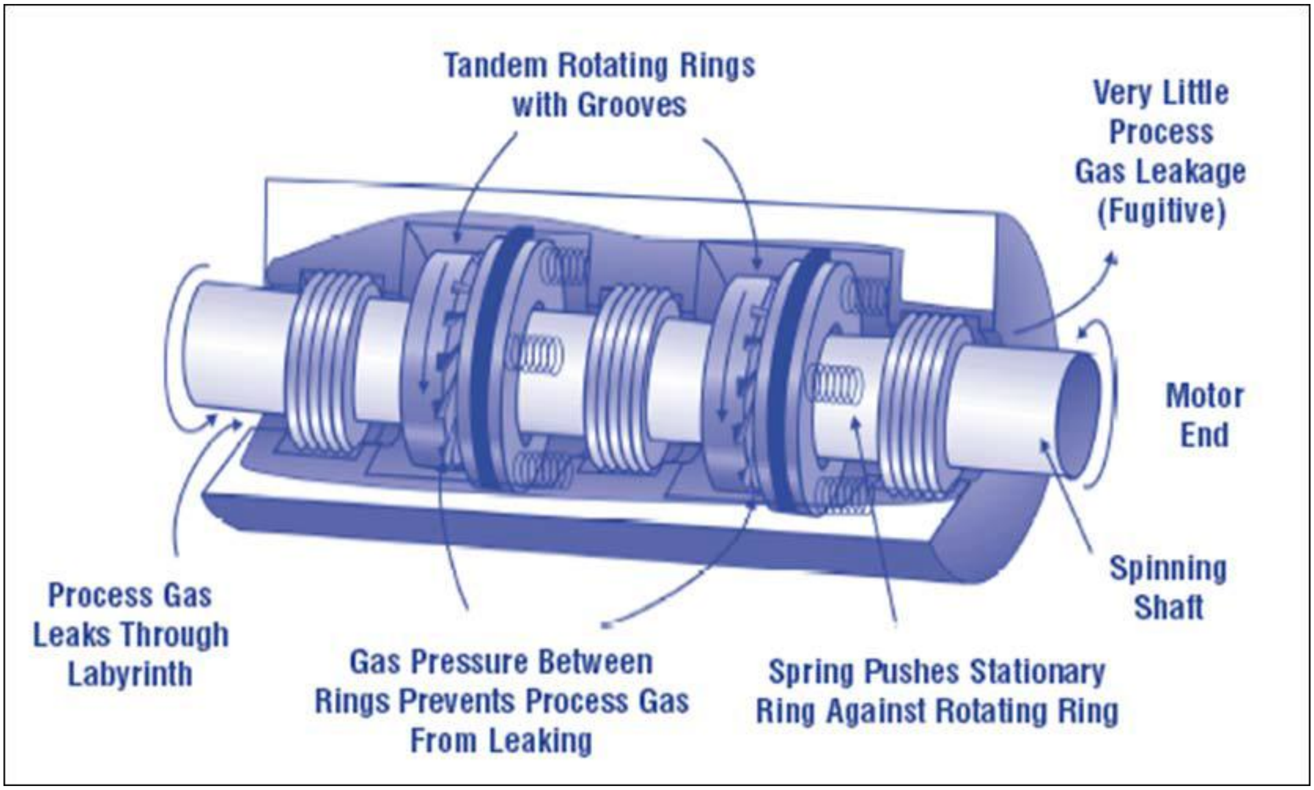

Figure 2-3. Typical Centrifugal Compressor Tandem Dry Seal (U.S. EPA, 2006b)

3.0 EMISSIONS DATA AND EMISSIONS ESTIMATES

There are several sources of emissions factors, activity data, and direct measurement data that have been used to estimate emissions from compressors in the oil and natural gas sector. Some of these studies are listed in Table 3-1, along with an indication of the type of information contained in the study (i.e., activity level and emissions data).

Table 3-1. Summary of Major Sources of Information and Data on Compressors

Name	Affiliation	Year of Report	Activity Factor	Emissions Data
Methane Emissions from the Natural Gas Industry: Equipment Leaks (GRI/U.S. EPA, 1996)	Gas Research Institute (GRI)/ U.S. Environmental Protection Industry	1996	Nationwide	X
Natural Gas Industry Methane Emission Factor Improvement Study ((URS/UT, 2011)	URS Corporation, UT Austin, and U.S. Environmental Protection Agency	2011	None	EF Only
Greenhouse Gas Reporting Program (U.S. EPA, 2013)	U.S. Environmental Protection Agency	2013	Facility Level	X
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012 (2014 GHG Inventory)	U.S. Environmental Protection Agency	2014	Nationwide	X
Analysis under subpart OOOO (U.S. EPA, 2012a)	U.S. Environmental Protection Agency	2012	Nationwide	X
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses (API/ANGA Survey)	American Petroleum Institute (API)/America's Natural Gas Alliance (ANGA)	2012	Regional	X[a]
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF/EDF Study)	ICF International (Prepared for the Environmental Defense Fund)	2014	Regional	X

a. The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emissions information was included.

The following sections describe emissions data, emission factors, the origin of the emission factors, and the methodologies used in the emission estimation process including the identification of national populations for several sources of information.

3.1 GRI/EPA Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks (GRI/EPA, 1996a)

This report provides an estimate of annual methane emissions from reciprocating and centrifugal compressor seals from the natural gas production, processing, transmission and storage sector using the component method. The component method uses average emission factors for reciprocating and centrifugal compressor seals and the average number of reciprocating and centrifugal compressors per facility to estimate the average facility emissions. The average facility emissions were then extrapolated to a national estimate using the number of facilities in each of the sectors.

The emissions data for natural gas production sites were based on screening and bagging data collected at 12 oil and gas production sites in the Western U.S. Screening involves using a handheld organic vapor analyzer (OVA) or toxic vapor analyzer (TVA) to measure the concentration (e.g., parts per million volume, ppmv) of the vented vapors. The method of bagging involves enclosing the component to collect venting vapors and measuring the flow rate. The measured flow rates from bagged equipment coupled with screening values are used to determine the unit-specific mass emission rate. A total of 40 reciprocating compressor seals were screened and bagged and an emission factor of 2.37 thousand standard cubic feet per cylinder per year (Mscf/cyl-yr) was calculated. No centrifugal compressors were located at any of the production sites that were screened.

The reciprocating and centrifugal compressor seal emissions data for the natural gas processing, natural gas transmission and natural gas storage sectors were obtained using a GRI Hi-Flow™ (trademark of the Gas Research Institute) sampler to quantify emissions and to develop emissions factors (GRI/EPA, 1996b). The sampler has a high flow rate and generates a flow field around the component that captures the entire leak. As the sample stream passes through the instrument, both the flow rate and the total hydrocarbon (THC) concentration are measured. The mass emission rate was then determined using these measurements. Different emission rates were calculated for the different operating modes of the compressor (GRI/EPA, 1996b), and were as follows;

- Operating and pressurized;
- Idle and fully pressurized;
- Idle and partially pressurized using a fuel saver system (reciprocating compressors only);
- Idle and depressurized.

The pressurized compressor seal emission rates (operating and idle) were calculated as the average of all reciprocating and centrifugal compressor seals combined. The compressor seal emission rates were determined to be 599 thousand standard cubic feet per seal per year (Mscf/seal-yr) in the operating and pressurized mode, 531 Mscf/seal-yr in the idle and pressurized mode, and 116 Mscf/seal-yr in the idle and partially pressurized mode (e.g., fuel saver) (GRI/EPA, 1996b). The compressor seal emission rate was assumed to be negligible in the idle and depressurized mode.

Using the percentage of the time pressurized and the compressor seal emission rates for the operating modes (e.g., operating and pressurized, idle and pressurized, idle and partially pressurized, idle and depressurized), emission factors were calculated for the natural gas processing, transmission, and storage segments. A summary of the emissions factors for each of these segments and the natural gas production segment are provided in Table 3-2. The number of seals was determined by averaging the compressor seal counts from the data in each of the segments. The number of centrifugal compressor seals depends on the type of compressor: centrifugal compressors with overhung rotors have one seal and beam type compressors have two seals. Information from three compressor vendors and one compressor seal vendor showed an even split between the two type of centrifugal compressors; therefore, the number of seals per centrifugal compressor was averaged to be 1.5.

Table 3-2. Summary of Reciprocating and Centrifugal Compressor Seal Methane Emission Factors

Type of Compressor	Percentage of Time the Compressor is Pressurized (%)	Compressor Seal Methane Emission Factor (Mscf/seal-yr)	Assumed Number of Seals per Compressor	Average Compressor Methane Emission Factor from Seals (Mscf/yr)
Natural Gas Production				
Reciprocating	N/A	2.37	4	9.48
Natural Gas Processing				
Reciprocating	89.7	450	2.5	1,125
Centrifugal	43.6	228	1.5	342
Natural Gas Transmission				
Reciprocating	79.1	396	3.3	1,307
Centrifugal	24.2	165	1.5	248
Natural Gas Storage				
Reciprocating	67.5	300	4.5	1,350
Centrifugal	22.4	126	1.5	189

The GRI/EPA study presented the emissions for reciprocating and centrifugal compressors as a sum of the emission components from compressors. These components included methane emissions from compressor seals, blowdown open-ended line, pressure relief valves, starter open-ended line, and miscellaneous, which includes valves and connectors. For the purposes of this paper, only the methane emissions from reciprocating and centrifugal compressor seals were calculated using the equipment counts of reciprocating and centrifugal compressors and applying the methane emission factor for each of the sectors. A summary of these emissions are presented in Table 3-3 for each of the sectors reported in the GRI/EPA study.

Table 3-3. Summary of GRI/EPA Methane Emissions from Reciprocating and Centrifugal Compressor Seals

Type of Compressor	Average Methane Emission Factor (Mscf/yr)	Activity Factor, Compressor Count	Annual Methane Emissions (Mscf/yr)	Average Methane Emissions (MT/yr)
Natural Gas Production				
Reciprocating	9.48	17,152	162,601	3,071
Natural Gas Processing				
Reciprocating	1,125	4,092	4,603,500	86,949
Centrifugal	342	726	248,292	4,690
Natural Gas Transmission				
Reciprocating	1,307	6,799	8,886,293	167,841
Centrifugal	248	681	168,888	3,190
Natural Gas Storage				
Reciprocating	1,350	1,396	1,884,600	35,596
Centrifugal	189	136	25,704	485
Total			15,978,655	301,799

The GRI/EPA study reported methane emissions of 568,670 Mscf/yr (10,741 MT) from reciprocating compressors from both Eastern and Western U.S. natural gas production. These totals, as stated earlier, include emissions from compressor blowdowns, starter gas, and miscellaneous equipment associated with the compressor. Methane emissions from reciprocating compressor seals represent approximately 29% of the total emissions from reciprocating compressors. Note that the Eastern U.S. natural gas production did not include methane emissions from compressor seals in the reciprocating compressor emission factor, only emissions from the associated equipment (e.g., valves, connectors, and open-ended lines). Table 3-3 does include the estimated 129 gathering reciprocating compressors from the Eastern U.S. in the activity factor for natural gas production and estimates compressor seal methane emissions using the listed reciprocating compressor seal emission factor.

For natural gas processing, the total methane emissions from reciprocating and centrifugal compressors and associated equipment and operations were reported as 16,736,280 Mscf/yr (316,108 MT) and 5,626,500 Mscf/yr (106,271 MT), respectively. The methane emissions from reciprocating and centrifugal compressor seals represent 28% and 4.4%, respectively, of the total methane emissions from reciprocating and centrifugal compressors in the natural gas processing sector. In the natural gas transmission sector, the total methane emissions from reciprocating and centrifugal compressors were estimated to be 37,734,450 Mscf/yr (712,714 MT) and 7,559,100 Mscf/yr (142,773 MT), respectively. The methane emissions from reciprocating and centrifugal compressor seals represent 24% and 2.2%, respectively, of the total methane emissions from reciprocating and centrifugal compressors in the natural gas processing sector. The total methane emissions from reciprocating and centrifugal compressors and their associated equipment were estimated to be 10,763,160 Mscf/yr (203,290 MT) and 1,517,760 Mscf/yr (28,667 MT), respectively, for the natural gas storage sector. The methane emissions from reciprocating and centrifugal compressor seals represents 18% and 1.7%, respectively, of the total methane emissions from reciprocating and centrifugal compressors in the natural gas storage sector.

3.2 Natural Gas Industry Methane Emission Factor Improvement Study, Final Report (URS/UT, 2011)

The report describes the effort to update default methane emission factors for selected processes and equipment in the natural gas industry. These processes and equipment are believed to contribute the greatest uncertainty in the U.S. natural gas industry methane emissions inventory and concentrated on high emission rate leaks (fugitive leaks) from transmission, gathering/boosting, and gas processing reciprocating and centrifugal compressor components, including emissions from compressor vents (i.e., blowdown lines and compressor seals).

The emissions data were collected at 11 sites in Texas and New Mexico and included data from gathering and boosting stations, natural gas processing plants, and transmission stations. The sites were all constructed between the 1950s and 2000s. The total number of compressors that were measured included 66 reciprocating compressors and 18 centrifugal compressors, with 48 of the reciprocating compressors located at transmission compressor stations. For compressor seals, the measurements were conducted using the following steps:

- Where the reciprocating compressor rod packing vent lines were piped together (multiple cylinders joined into a single vent line for each compressor), the enclosed rotary vane anemometer was used to make the measurements at the top of the rod packing vent line;
- Where the reciprocating rod packing vent lines were individually vented to the atmosphere, each vent line was measured with a handheld hot wire anemometer; and
- For centrifugal compressors equipped with wet seals, measurements were made at the wet seal degassing fill port to the seal oil pump using plastic bags of known internal volume and measuring the required flow to fill the bag.

The study noted several technical issues with measuring emissions from a wet seal system including location of the flash emissions and configuration of the seal oil degassing system (which may include blowers or a flash drum/pot). The study noted that the wet seal measurements from this study should be used as a benchmark and requires further analysis before the measurements could be used to develop emission factors.

A summary of the testing results from the study are provided in Table 3-4. The study grouped the test results for centrifugal compressors located at natural gas gathering and boosting, processing and transmission together. The test data for reciprocating compressors were separated into units located at gathering and boosting stations and units located at transmission stations. The study found that the largest emission sources at a compressor stations are the compressor blowdown vent lines and the compressor seal vents (URS/UT, 2011).

Table 3-4. Sampling Results for Reciprocating and Centrifugal Compressor Seals

Compressor Vent Measured	Sample Size	Average Methane Emission Factor (Mscf/yr)	1996 GRI/EPA Emission Factor[a] (Mscf/yr)
Natural Gas Gathering/Boosting Reciprocating Compressors			
Average Rod Packing	15	241	9.48[b]
Natural Gas Transmission Reciprocating Compressors			
Average Rod Packing (Idle + depressurized)	5	12,236	396[c]
Average Rod Packing	2	29,603	
Natural Gas Gathering/Boosting, Processing and Transmission Centrifugal Compressors			
Average Wet Seal	9	8,137	396[d]

[a] (GRI/EPA, 1996b)
[b] Appendix B-4, assumes 4 seals per compressor.
[c] Table 4-15, adjusted for 79.1% time the compressor is pressurized.
[d] Table 4-15, adjusted for 24.2% time the compressor is pressurized.

The study authors concluded that the centrifugal compressor wet seal degassing vent emissions were much higher in comparison to the GRI/EPA emission factors. The study authors also determined that the average reciprocating compressor rod packing vent emissions that they calculated were significantly higher than the GRI/EPA study (GRI/EPA, 1996b).

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

In October 2013, the EPA released 2012 greenhouse gas (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 metric tons carbon dioxide equivalent (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. Because some of the methods required direct measurement of emissions or parameters, for an interim period, the EPA made available the optional use of Best Available Monitoring Methods (BAMM) for unique or unusual circumstances. Where a facility used BAMM, it was required to follow emission calculations specified by the EPA, but was allowed to use alternative methods for determining inputs to calculate emissions.

Emissions for both reciprocating and centrifugal compressors are reported under the processing, transmission, underground gas storage, and liquid natural gas (LNG) import/export and storage segments. The calculation method varied by industry segment. Emissions from compressors in onshore production were calculated by using population counts multiplied by an emission factor. Emissions from compressors in the other industry segments were calculated by the use of direct measurement.

Table 3-4 shows activity data and emissions for reciprocating compressors for the natural gas processing, natural gas transmission, and underground natural gas storage industry segments. The EPA received data for 4,466 reciprocating compressors, including 2,149 reciprocating compressors in natural gas processing, 2,008 reciprocating compressors in natural gas transmission, and 309 reciprocating compressors in underground natural gas storage. Of the reciprocating compressors, BAMM was used to calculate emissions for 1,847 compressors, including 993 in natural gas processing, 790 in natural gas transmission, and 64 in underground natural gas storage.

Table 3-5. 2012 Direct Measurement Reported Process Emissions from Reciprocating Compressors from Natural Gas Processing, Natural Gas Transmission and Underground Natural Gas Storage

Industry Segment	Total Number of Reciprocating Compressors	Number of Reciprocating Compressors that used BAMM	Reported CH_4 Emissions ($MT\ CO_2e$)	Reported CH_4 Emissions[a] (MT)
Natural Gas Processing	2,149	993	1,009,045	48,050
Natural Gas Transmission	2,008	790	1,591,990	75,809
Underground Natural Gas Storage	309	64	160,809	7,658
Total	4,466	1,847	2,761,844	131,516

a. Conversion factors MT CO_2e to tons: 21 MT CH_4/MT CO_2e

Table 3-6 shows activity data and emissions for centrifugal compressors for the natural gas processing, natural gas transmission, and underground natural gas storage industry segments. For centrifugal compressors the number of compressors with wet seals is also shown. Overall emissions from centrifugal compressors were lower than those for reciprocating compressors, but the total number of reported compressors was lower as well. The EPA received data for 1,191 centrifugal compressors, including 428 centrifugal compressors in natural gas processing, 724 centrifugal compressors in natural gas transmission, and 39 centrifugal compressors in underground natural gas storage. Of these centrifugal compressors, BAMM was used to calculate emissions for 538 compressors, including 234 in natural gas processing, 292 in natural gas transmission, and 12 in underground natural gas storage.

Table 3-6. 2012 Direct Measurement Reported Process Emissions from Centrifugal Compressors from Natural Gas Processing, Natural Gas Transmission and Underground Natural Gas Storage

Industry Segment	Total Number of Centrifugal Compressors	Number of Centrifugal Compressors that used BAMM	Number of Centrifugal Compressors with Wet Seals	Reported CH_4 Emissions (MT CO_2e)	Reported CH_4 Emissions[a] (MT)
Natural Gas Processing	428	234	274	752,054	35,812
Natural Gas Transmission	724	292	291	439,714	20,939
Underground Natural Gas Storage	39	12	23	118,500	5,643
Total	1,191	538	588	1,310,268	62,394

a. Conversion factors: 21 MT CH_4/MT CO_2e

3.4 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. 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).

The 2014 GHG Inventory (published in 2014; containing emissions data for 1990-2012) calculates net methane emissions for reciprocating compressors using emission factors based on the GRI/EPA study (GRI/U.S. EPA, 1996a). The factors are used to develop potential emissions. The total potential emissions are reduced by known controls or practices that reduce emissions to calculate net emissions. For centrifugal compressors, the EPA has developed emission factors for both wet seal and dry seal compressors that are used to directly calculate net emissions (i.e., after control).

For the natural gas production stage, emission factors for gathering compressors are regional and cover small and large reciprocating compressors (no centrifugal compressors).

For natural gas processing, and transmission and storage, the emission factors are for reciprocating compressors and the two types of centrifugal compressors (wet and dry seal). For LNG storage and import/export, there are factors for reciprocating and centrifugal compressors. The emission factors used to calculate methane emission for compressors for the 2014 GHG Inventory are summarized in Table 3-8.

Table 3-9 summarizes the activity data and 2012 calculated potential methane emissions for compressors by industry segment and compressor type.

Table 3-8. Natural Gas Sector Methane Emission Factors for Compressors

	Emission Factor (scf/day/compressor)			
	Reciprocating		Centrifugal	
Industry Activity	Small[1]	Large	Wet Seal	Dry Seal
Production	263-312	14,947-17,728	-	
Processing	11,196		51,370	25,189
Transmission	15,205		50,222	32,208
Storage	21,116		45,441	31,989
LNG Storage/Import	21,116		30,573	

[1] The GRI/EPA study defines small gathering compressors as compressors on the overhead lines from gas well separators and associated gas well separators. Large gathering compressors are compressors at large gathering compressor stations (stations with 8 compressors or more).

Table 3-9. Summary of Natural Gas Sector Compressor Activity and Calculated Potential Methane Emissions

Industry Segment	Activity (Compressor Units)	Calculated Potential Methane Emissions (MT)
Production		
Reciprocating (small)	35,930	70,859
Reciprocating (large)	136	15,400
Processing		
Reciprocating	5,624	442,634
Centrifugal (wet seal)	658	237,724
Centrifugal (dry seal)	248	43,937
Transmission		
Reciprocating	7,235	773,294
Centrifugal (wet seal)	659	232,826
Centrifugal (dry seal)	66	14,972
Storage		
Reciprocating	1,012	150,225
Centrifugal (wet seal)	70	22,347
Centrifugal (dry seal)	29	6,532
LNG Storage		
Reciprocating	270	40,147
Centrifugal	64	13,766
LNG Import Terminal		
Reciprocating	37	5,552
Centrifugal	7	1,419

The GHG Inventory emissions calculations used regional values by industry segment for the methane content in natural gas. The average national value for general sources was 83.3% methane for 2012.

The net 2012 methane emissions reported for compressors for the 2014 GHG Inventory were 86,259 MT for the natural gas production segment, 724,295 MT for the natural gas processing segment, and 1,261,080 MT for the natural gas transmission and storage segment, for a total of 2,071,633 MT of methane.

3.5 Development of the New Source Performance Standard (NSPS) For Oil and Natural Gas Production (U.S. EPA, 2011b and U.S. EPA, 2012a)[2]

VOC emission factors were developed for reciprocating and centrifugal compressors in order to support the development of subpart OOOO. In order to develop these factors the EPA used information from the GHGRP[3], the GHG Inventory, the EPA's Natural Gas STAR Program, and a study by the GRI/EPA study. Updates to the GHGRP and the GHG Inventory have occurred since this analysis, however, it is presented here for completeness.

The methodology for estimating emissions from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study (GRI/EPA, 1996a) and use the methane-to-pollutant ratios developed in the gas composition memorandum developed for subpart OOOO. (EC/R, 2011) The emission factors in the EPA/GRI study were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinders per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density.

The centrifugal compressor emission factors for wet seals and dry seals were based on emission factors from the 2012 GHG Inventory (published in 2012; containing emissions data for 1990-2010). The wet seal methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the Natural Gas STAR Program. The methane emissions were converted to VOC emissions using the same gas composition ratios that were used for reciprocating engines. (EC/R, 2011) A summary of the methane emission factors is presented in Table 3-10.

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[2] Unless otherwise indicated, the following sections are excerpts from either Section 6 of the technical support document for the proposed subpart OOOO (U.S. EPA, 2011b) or Section 6.0 of the technical support document for the final subpart OOOO rule (U.S. EPA, 2012a).

[3] http://www.epa.gov/ghgreporting/

Table 3-10. Methane Emission Factors for Reciprocating and Centrifugal Compressors

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scf/hr-cylinder)	Average Number of Cylinders per Compressor	Pressurized Factor (% of hour/year Compressor Pressurized)	Wet Seal Methane Emission Factor (scf/minute)	Dry Seals Methane Emission Factor (scf/minute)
Production (Well Pads)	0.271[a]	4	100%	N/A[f]	N/A[f]
Gathering & Boosting	25.9[b]	3.3	79.1%	N/A[f]	N/A[f]
Processing	57[c]	2.5	89.7%	47.7[g]	6[g]
Transmission	57[d]	3.3	79.1%	47.7[g]	6[g]
Storage	51[e]	4.5	67.5%	47.7[g]	6[g]

[a] (GRI/EPA, 1996a), Table 4-8.
[b] Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*.: 2006.
[c] (GRI/EPA, 1996a), Table 4-14.
[d] (GRI/EPA, 1996a) Table 4-17.
[e] (GRI/EPA, 1996a) Table 4-24.
[f] The 1996 EPA/GRI Study Volume 11[4], does not report any centrifugal compressors in the production or gathering/boosting sectors; therefore, no emission factor data were published for those two sectors.
[g] (U.S. EPA, 2011a), Annex 3. Page A-153.
Source: Derived from (U.S. EPA, 2011b), Table 6-2 and (U.S. EPA, 2012a), Table 6-1

Once the methane emission rates for compressors were calculated using the emission factors, ratios were applied to the methane emissions to estimate VOC emissions. The specific ratios that were used for this analysis were 0.278 pounds VOC per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane for the transmission and storage segments. A summary of the baseline individual compressor emission rates are shown in Table 3-11 for each of the oil and gas industry segments.

4 EPA/GRI (1996) Methane Emission from the Natural Gas Industry, Vol. 11, .Pages 11 – 15. Available at: http://epa.gov/gasstar/documents/emissions_report/11_compressor.pdf

Table 3-11. Baseline Emission Rates for Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	Baseline Emission Estimates (tons/compressor/year)	
	Methane	VOC
Reciprocating Compressors		
Production (Well Pads)	0.198	0.0549
Gathering & Boosting	12.3	3.42
Processing	23.3	6.48
Transmission	27.1	0.751
Storage	28.2	0.782
Centrifugal Compressors (Wet seals)		
Processing	228	20.5
Transmission	126	3.50
Storage	126	3.50
Centrifugal Compressors (Dry seals)		
Processing	28.6	2.58
Transmission	15.9	0.440
Storage	15.9	0.440

Source: Derived from (U.S. EPA, 2011b), Table 6-2 and (U.S. EPA, 2012a), Table 6-1

The analysis performed in the technical support document (TSD) to proposed subpart OOOO (U.S. EPA, 2011b) was designed to provide information about new compressors for the purposes of establishing new source performance standards; accordingly, the analysis did not estimate nationwide emissions for all compressors.

3.6 Characterizing Pivotal Methane Emissions from the Oil and Natural Gas Sector, (API /ANGA, 2012)

The API/ANGA study (API/ANGA, 2012) is an analysis of industry survey data that includes data from over 20 companies covering over 90,000 gas wells. This study sample population includes representation from most of the geographic regions of the country as well as most of the geologic formations currently developed by the industry.

With respect to compressors, the API/ANGA study collected information related to the activity count for centrifugal compressors, specifically to supplement the EPA's data on the prevalence of wet seal and dry seal compressors in the industry. According to the survey results, the data collected represented approximately 5% of the national centrifugal compressor count for gas processing operations (38 centrifugal compressors from the survey, compared to 811 from 2012 GHG Inventory). Of the gas processing centrifugal compressors reported through the survey, 79% were dry seal compressors and 21% were wet seal units. If the results of the survey were considered to be representative, the authors assert that the EPA's current ratio of 80% wet seal and 20% dry seals severely overestimates the emissions from the wet seal compressors. Based on the emission factors from Table A-123 of Annex 3 of the 2012 GHG Inventory, the methane emissions from centrifugal compressors would be 190,573 tons (172,887 MT) compared to 288,068 tons (261,334 MT) from the 2012 GHG Inventory. This would equate to an approximate 34% reduction in the emissions from this source. The authors recommended using the GHGRP data to further refine these activity numbers.

With respect to production and gathering facilities that use centrifugal compressors, the API/ANGA survey responses reported only 550 centrifugal compressors associated with production and gathering at 21 participating companies. The authors noted that the 2012 GHG Inventory did not include centrifugal compressors in production/gathering operations. The study reported that, on a well basis, the survey response equates to 0.07 centrifugal compressor per gas well with 81% of those being dry seal and the remaining being wet seal. The authors recommended that the EPA continue to refine these numbers using data from the GHGRP.

3.7 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 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 economic 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 the study's projected 2018 methane emissions from onshore oil and gas industry sources. Centrifugal compressor and reciprocating compressor emission sources were included in their list of targeted emission sources.

The study relied on the 2013 GHG Inventory for methane emissions data for the oil and natural gas sector. These emissions data for compressors were revised to include updated information from the GHGRP, data from the 1996 GRI/EPA study of methane emissions, information on the Federal Energy Regulatory Commission (FERC) website, data obtained from the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration and information from various state energy and environmental departments. The revised ICF 2011 baseline methane emissions estimates were then used as the basis for projecting onshore methane emissions to 2018. A summary of the most significant revisions made to the 2013 GHG Inventory activity and emission factors to develop the revised ICF 2011 baseline by industry segment are presented in Section 3.8.1. The methodology used to project onshore methane emissions from the revised 2013 GHG Inventory (referred to as the ICF 2011 baseline) to 2018 for compressors is presented in Section 3.8.2.

3.7.1 ICF 2011 Baseline

The ICF study breaks out emissions by natural gas segment (gas production, gathering and boosting, gas processing, gas transmission, gas storage, LNG and gas distribution) and petroleum segment (oil production, oil transportation and oil refining). The most significant revisions made to the 2013 GHG Inventory to develop the ICF 2011 baseline for compressors are summarized by industry segment in the following paragraphs. Note that no emission factor or activity changes related to compressors were made for the gas production, oil production, oil transportation, and oil refining segments.

3.7.1.1 Gathering and Boosting Segment

Reciprocating Compressors

- Updated the 1996 EPA/GRI study emissions factors used in the 2013 GHG Inventory using information obtained from five state energy agencies (Texas, Colorado, Wyoming, Oklahoma and Pennsylvania) on permitted engines for production and gathering compressors in the petroleum and natural gas industry. These data were split into large and small compressors using the 1,600 horsepower (hp) threshold from the 1996 EPA/GRI study. The state data showed a larger percentage of large compressors than assumed in the 2013 GHG Inventory. A new weighted average factor was calculated using the 1996 EPA/GRI study emission factors. The new methane emission factor for all gathering compressors was calculated at 1,980 scf/day/compressor.
- The reciprocating compressor emission factor used in the 2013 GHG Inventory was updated to distinguish compressor seal emissions versus compressor fugitives (which are combined in the GHG Inventory) using the 1996 EPA/GRI study emission factors, whereby compressors seals were then separated into two categories: reciprocating compressors – non-seals (75%) and reciprocating compressors – seals (25%).
- Developed new activity factors for reciprocating compressors using information obtained from the five state energy agencies (discussed above) by using the 2013 GHG Inventory ratio of compressors in these five states to the national count of compressors to obtain a new national reciprocating compressor count of 15,687.

Based on these revisions, ICF estimated the net change in methane emissions from reciprocating compressors (as compared with the 2013 GHG Inventory) to be 166% or an increase to 11 Bcf (228,965 tons).

Centrifugal Compressors

- Created a new emission category for wet seal centrifugal compressors based on information obtained from the GHGRP that included 162 wet seal centrifugal compressors used in the upstream sector. ICF assumed that the respondents under the GHGRP represented 85% of the industry. Therefore, ICF adjusted the number of wet seal centrifugal compressors to be 191. ICF used an emission factor of 12,000,000 scf/year/compressor (from subpart W) and their estimated number of wet seal centrifugal compressors to estimate methane emissions for the 2011 baseline (over 2 Bcf [41,630 tons] methane).

3.7.1.2 Gas Processing

- Reciprocating compressors emission factor updated to breakout emissions from compressor seals versus "other" compressor fugitives as discussed in Section 3.8.1.1.

3.7.1.3 Gas Transmission

- Number of compressor stations revised from 1,808 to 1,768 (based on a change in pipeline miles included in the 2013 GHG Inventory using data obtained from the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration indicating a lower value for transmission pipeline miles), resulting in an emissions decrease of just over 2%.
- Number of reciprocating compressors changed from 7,270 to 7,111 (based on changes to the pipeline miles included in the 2013 GHG Inventory – see above), resulting in an emissions decrease of over 2%.
- Number of centrifugal compressors revised from 654 to 648 (based on changes to the pipeline miles included in the 2013 GHG Inventory – see above), resulting in an emissions decrease of over 2%.

3.7.1.4 Gas Storage

- Reciprocating compressors emission factor updated to breakout emissions from compressor seals versus "other" compressor fugitives as discussed in Section 3.8.1.1.

3.7.2 ICF Projections to 2018

Emissions projections are not the subject of this paper; therefore, the estimates of 2018 emissions produced in the ICF study are not presented here. However, the ICF study uses the projections to evaluate emissions mitigation techniques for compressors, which are addressed in this paper. Those mitigation techniques are discussed in detail in Section 4 of this paper. The methodology the ICF study used to project emissions to 2018 is described here in order to provide context for the later discussion of mitigation techniques.

The primary sources used for projecting onshore methane emissions for centrifugal and reciprocating compressors for 2018 included the INGAA Foundation *North American Midstream Infrastructure Through 2035-A Secure Energy Future* report (ICF, 2011), an analysis of past projected infrastructure change, FERC and ICF information on emission reductions anticipated as a result of regulation (40 CFR Part 60, subpart OOOO).

The INGAA report provided yearly forecast information of incremental gathering pipeline miles, gas processing plants and processing compressor counts that were used with existing activity data from the 2013 GHG Inventory to estimate a regional activity factor for use to make projections out to 2018. For the gathering and boosting segment, the activity factors were estimated based on a ratio of pipeline miles in 2018 to pipeline miles in the ICF 2011 baseline to obtain 2018 activity levels. For the gas processing segment, the activity factors were estimated based on a ratio between the compressor count in 2018 and the compressor count in the ICF 2011 baseline. For the gas transmission segment, projections out to 2018 were based on an analysis of past pipeline infrastructure changes, where the change in the length of transmission pipeline from 1990 to 2011 was used to establish an incremental value based on trends that were then used to project the pipeline miles for 2018.

The new 2018 forecast of emissions for centrifugal and reciprocating compressors (for all but production and transmission segments) were adjusted to account for emission reductions that are expected as a result of the EPA's NSPS, subpart OOOO.

Further information included in this study on mitigation or emission reduction options, methane control costs, and their estimates for the potential for VOC emissions co-control benefits from their use is presented in Section 4 of this document.

4.0 AVAILABLE COMPRESSOR EMISSIONS MITIGATION TECHNIQUES

Emissions mitigation options for reciprocating compressors involve techniques that limit the leaking of natural gas past the piston rod packing, including replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod. The EPA is also aware of new technologies that enable the emissions to be captured and either routed to a combustion device or a useful process. Emission mitigation options for centrifugal compressors limit the leaking of natural gas across the rotating shaft using a mechanical dry seal, or capture the gas and route it to a useful process or to a combustion device. A discussion of these techniques and their costs is presented in the following sections.

4.1 Reciprocating Compressor - Rod Packing Replacement

4.1.1 Description

The potential emission reduction options for reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the "nose gasket" around the packing case, between the packing cups, and between the rings and shaft (see Figure 2-1). Mitigation options for these emissions include replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod (U.S. EPA, 2006a).

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas past the piston rod. Over time, the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces VOC and methane emissions.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Rods can wear "out-of-round" or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod (U.S. EPA, 2006a).

4.1.2 Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The emission reductions are related to the rate of deterioration and the frequency of replacement.

Subpart OOOO Technical Support Document (U.S. EPA, 2011b)

In the TSD for the subpart OOOO rulemaking, the expected emission reductions from a rod packing replacement were calculated by comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing (U.S. EPA, 2011b). For gathering and boosting compressors, the analysis calculated the potential methane emission reductions by multiplying the number of new reciprocating compressors by the difference between the average rod packing emission factor in Table 3-10 by the average emission factor from a newly installed rod packing. The average rod packing emission factor used for gathering and boosting compressors was developed from the Clearstone II study (Clearstone, 2006) using rod packing measurement data (which was adjusted for the percent of time transmission compressors are operating) (GRI/U.S. EPA, 1996). For wellhead reciprocating compressors, the analysis calculated a percentage reduction using the transmission emission factor from the 1996 EPA/GRI report and the minimum emissions rate from a newly installed rod packing to determine methane emission reductions. The emission reductions for the processing, transmission, and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment and the difference between the average rod packing emission factors in Table 3-10 (GRI/U.S. EPA, 1996) and the average emission factor from newly installed rod packing. Newly installed packing average methane emissions were assumed to be 11.5 cubic feet per hour per cylinder (U.S. EPA, 2006a).

A summary of the estimated emission reductions for reciprocating rod packing replacement for each of the oil and gas segments from the subpart OOOO TSD is shown in Table 4-1. The emissions of VOC were calculated using the methane emission reductions calculated above and the gas composition (EC/R, 2011) for each of the segments.

Table 4-1. Estimated Annual Individual and Nationwide Emission Reductions from Replacing Rod Packing in Reciprocating Compressors

	Individual Compressor Emission Reductions (tons/compressor-year)	
Oil & Gas Segment	**Methane**	**VOC**
Production (Well Pads)	0.158	0.0439
Gathering & Boosting	6.84	1.90
Processing	18.6	5.18
Transmission	21.7	0.600
Storage	21.8	0.604

Economic Rod Packing Replacement

The Natural Gas STAR Lessons Learned document titled "Reducing Methane Emissions from Compressor Rod Packing Systems" (U.S. EPA, 2006a) states that a new, properly installed rod packing system should leak approximately 11 to 12 standard cubic feet per hour (scfh) of gas. The effectiveness of the system on minimizing leaks is reliant on the fit of, and wear to the rod packing components (such as the rod packing material, the cups that hold it, and the piston rod). As the rod packing system ages, the leak rates will increase. Eventually, the leak rate will reach a point where the amount of gas saved by replacing the rod packing will justify the cost of performing the replacement. In some cases, the economic threshold for replacement can be as low as 30 scfh of gas leakage. However, if the rod packing systems are not well maintained, the leakage rates can far exceed that value. In one instance, a Natural Gas STAR partner reported emissions from an aging rod packing system to be as high as 900 scfh.

Updated rod packing components made from newer materials can also help improve the life and performance of the rod packing system. Another potential option is replacing the bronze metallic rod packing rings with longer lasting carbon-impregnated Teflon rings. Compressor rods can also be coated with chrome or tungsten carbide to reduce wear and extend the life of the piston rod (U.S. EPA, 2006a).

4.1.3 Cost of Controls

The Natural Gas STAR Lessons Learned document estimates the cost to replace the packing rings on reciprocating compressors to be $1,620 per cylinder. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. (U.S. EPA, 2006a)

The TSD for the subpart OOOO rulemaking used the above costs from the Natural Gas STAR Lessons Learned document and operating factors from the GRI/EPA study to determine the costs and gas savings from rod packing replacement (U.S. EPA, 2011b). The weighted hours, on average, per year the reciprocating compressor is pressurized was calculated to be 98.9%

using the operating factors presented in Table 3-2 of this paper (GRI/EPA, 1996a). The calculated years were assumed to be the equipment life of the compressor rod packing. Table 3-2 was used to estimate the average number of cylinders per compressor for each industry segment. Information reviewed did not identify any annual or periodic maintenance costs for the rod packing systems. Because replacement of rod packing systems reduces gas emissions, a monetary savings can be realized that is associated with the amount of gas saved with reciprocating compressor rod packing replacement. The savings were estimated using a natural gas price of $4.00 per Mcf (U.S. EIA, 2010). This gas price was used to calculate the annual savings using the methane emission reductions in Table 4-1. The savings over the useful equipment life of the rod packing system was then calculated based on equipment life discussed above. A summary of the estimated capital costs and estimated gas savings for each of the oil and gas segments is shown in Table 4-2.

Table 4-2. Capital Cost and Gas Savings for Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost per compressor ($2008)	Gas Savings for Equipment Life per Compressor
Production	$6,480	$2,493
Gathering & Boosting	$5,346	$1,669
Processing	$4,050	$1,413
Transmission	$5,346	$1,669
Storage	$7,290	$2,276

The ICF International study (ICF, 2014) evaluated the effectiveness of replacing rod packing systems in reciprocating compressors for existing sources to reduce methane emissions assuming 98% control with timely replacement to minimize emissions. Their analysis assumed capital costs of $2,000 every 3 years for replacement of the packing system, and revenue benefits from reduction of methane emission losses of $3,500 (at $4.00/Mcf gas). The estimated payback period for this control option was estimated to be seven months. National emission reductions were estimated to be 3.6 Bcf (74,934 tons) methane/yr. ICF estimated national annualized costs of replacing rod packing systems to be $22.3 million/yr and total initial capital costs to be an estimated $182.3 million. ICF also estimated that VOC emissions would be reduced by 8 kilotons (or approximately 8,816 tons) at a cost of $2,784/ton of VOC reduced. ICF concluded that replacing rod packing systems in reciprocating compressors can significantly reduce methane emissions and increase savings.

4.2 Reciprocating Compressor – Gas Recovery

4.2.1 Description

The potential emission reduction options for reciprocating compressors include control techniques that recover natural gas leaking past the piston rod packing. The EPA is aware of one company, REM Technology, Inc., that has developed a system that captures the gas that would otherwise be vented and routes it back to the compressor engine to be used as fuel (REM, 2012). The vent gases are passed through a valve train that includes a demister and then are injected into the engine intake air after the air filter. The EPA is aware that this technology has been deployed commercially, but does not have any information on the extent it is used in the field.

Another method for capturing emissions from reciprocating compressor rod packing vents is to manifold the vent line to a vapor recovery unit (VRU) system. A VRU is a simple system designed to capture vented gas streams, usually from tanks, that would otherwise go to the atmosphere. The main components of the system include a compressor and scrubber. If a VRU system is already in place at a facility with reciprocating compressors, it is often possible to route the vent streams to tanks, allowing the vented rod packing gas to be picked up by the VRU. The recovered gas can then be sold or routed for fuel or other meaningful use onsite. If the gas cannot be used productively, it can also be sent to a flare system. While flaring may have a higher cost than venting to the atmosphere, this practice can reduce methane and VOC emissions.

4.2.2 Effectiveness

REM Technology estimates that the gas recovery system can result in the elimination of over 99% of VOC and methane emissions that would otherwise occur from the venting of the emissions from the compressor rod packing (REM, 2013). The emissions that would have been vented are combusted in the compressor engine to generate power. This technique is discussed further in the Natural Gas STAR PRO Fact Sheet titled “Install Automated Air/Fuel Ratio Controls” (U.S. EPA, 2011c). This document reported an average fuel gas savings of 78 thousand cubic feet per day (Mcfd) per engine with the gas recovery system installed.

If the facility is able to route rod packing vents to a VRU system, it is possible to recover approximately 95-100% of emissions. If the gas is routed the gas to a flare, approximately 95% of the methane and VOCs are reduced.

4.2.3 Cost of Controls

The EPA has not been able to obtain cost data on the REM technology. Some costs would be mitigated by fuel gas savings, as using the captured gas to displace some of the purchased fuel would require less fuel to be purchased in order to run the compressor engine.

For a VRU, assuming the proper equipment is already available at the facility, capturing the rod packing gas would require minimal costs. The investment would only need to include the cost of piping and installation. While the EPA has not obtained a cost estimate specifically for routing rod packing vents to a VRU, this process has been studied for dehydrators and would be similar for rod packing systems. According to the Natural Gas STAR PRO Fact Sheet titled “Pipe Glycol Dehydrator to Vapor Recovery Unit” (U.S. EPA, 2011d), the cost for planning and installing additional piping is approximately $2,000. Routing to a VRU also provides additional incentive as there is a value associated with recovered gas. However, the installation of a VRU to only capture rod packing emissions may not be economically viable if an additional compressor system is required. If the VRU is already present at the facility, the incremental cost to capture the rod packing vent gas can be recovered from the value of the additional captured gas.

4.3 Centrifugal Compressor - Dry Seals

4.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak (see Figure 2-3). While the compressor is operating, the rings are not in contact with each other; therefore, they do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals reduce emissions and, at the same time, they reduce operating costs and enhance compressor efficiency. Economic and environmental benefits of dry seals include:

- Gas Leak Rates. Wet seals generate vented emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is recirculated is usually vented to the atmosphere, bringing the total leakage rate for tandem wet seals to 47.7 scfm natural gas per compressor (U.S. EPA/ICR, 2009) (U.S. EPA, 2011a, Annex 3, page A-153).
- Mechanically Simpler. Dry seal systems do not require additional oil circulation components and treatment facilities.
- Reduced Power Consumption. Because dry seals have no accessory oil circulation pumps and systems, they avoid “parasitic” equipment power losses. Wet seal systems require 50 to 100 kW per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability. The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.

- Lower Maintenance. Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- Elimination of Oil Leakage from Wet Seals. Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

4.3.2 Effectiveness

The emissions reduction effectiveness of the dry seals was calculated in the TSD for the proposed subpart OOOO (U.S. EPA, 2011b) by subtracting the dry seal emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 3-2 were used in combination with an operating factor of 43.6% for processing centrifugal compressors and 24.2% for transmission centrifugal compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors for the processing and transmission sectors are based on data in the EPA/GRI study (GRI/EPA, 1996a). The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program (U.S. EPA, 2006b). A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 4-3.

Table 4-3. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals

Oil & Gas Segment	Individual Compressor Emission Reductions (ton/compressor-year)	
	Methane	VOC
Processing	199	18.0
Transmission/Storage	110	3.06

4.3.3 Cost of Controls

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is small relative to the cost for the entire compressor. The analysis in the TSD for proposed subpart OOOO assumed the additional capital cost for a dry seal compressor to be $75,000, with an equipment life of 10 years (U.S. EPA, 2011b).

The Natural Gas STAR Program estimated that the operation and maintenance savings from the installation of dry seals is $88,300 annually in comparison to wet seals (U.S. EPA, 2006b). Monetary savings associated with the amount of gas saved with the replacement of wet seals with dry seals for centrifugal compressors was estimated using a natural gas price of $4.00 per Mcf (U.S. EIA, 2010). This cost was used to calculate the annual gas savings using the methane emission reductions in Table 4-2. There is no gas savings cost benefits for transmission and storage facilities, because it is assumed the owners of the compressor station do not own the natural gas that is compressed at the station. A summary of the capital cost, annual operation and maintenance cost and the natural gas savings for replacing wet seals with dry seals is presented in Table 4-4. As shown in the table, there is a net savings after one year of operation without considering any potential natural gas savings.

Table 4-4. Costs for Replacing Centrifugal Compressor Wet Seals with Dry Seals

Oil and Gas Segment	Capital Cost per compressor ($2008)	Annual Operation and Maintenance Savings ($/compressor)	Annual Natural Gas Savings ($/compressor)
Processing	$75,000	$88,300	$46,109
Transmission/Storage	$75,000	$88,300	0

The ICF International study (ICF, 2014) evaluated replacing a wet seal with a dry seal for centrifugal compressors (assuming 97% control of methane emissions) as a control option using their 2018 projected methane emission estimates (discussed in Section 3.8.2 of this document). Their analysis assumed retrofit capital and annual operating costs of $400,000 and $17,500, respectively, and annual product revenue benefits of \$180,500 (assuming \$4/Mcf of gas) due to the reduction of product loss to the atmosphere. The report states that a dry seal retrofit is not common due to the high up-front costs and the downtime that would be required, and estimates that the payback period would be 29 months. The report also states that information from vendors indicates that 90% of new centrifugal compressors are already equipped with dry seals.

4.4 Centrifugal Compressor - Wet Seal with a Flare

4.4.1 Description

Another emission reduction option for centrifugal compressors equipped with wet seals is to route the emissions to a combustion device or capture the emissions and route them to a fuel system. A wet seal system uses oil that is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either combusted, released to the atmosphere, or captured and routed to a process. The emission reduction technique investigated in this section is the use of wet seals with the removed gas sent to an enclosed flare.

4.4.2 Effectiveness

Flares have been used in the oil and gas industry to combust gas streams that have VOC and methane constituents. A flare typically achieves 95% reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that 100% of the entrained gas from the seal oil that is removed in the degassing process would be directed to a flare that achieves 95% reduction of organic compounds. The wet seal emissions in Table 3-2 were used along with the control efficiency of the flare to calculate the emissions reductions from this option. A summary of the emission reductions is presented in Table 4-5.

Table 4-5. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Flare

Oil & Gas Segment	Individual Compressor Emission Reductions (tons/compressor-year)	
	Methane	VOC
Processing	216	19.5
Transmission/Storage	120	3.32

4.4.3 Cost of Controls

The capital and annual costs of the enclosed flare were calculated using the methodology in the EPA Control Cost Manual. (U.S. EPA, Cost) The heat content of the gas stream was calculated using information from an the EPA study to estimate the composition of natural gas previously developed for the analysis of subpart OOOO. (EC/R, 2011) A summary of the capital and annual operation and maintenance costs for wet seals routed to a flare is presented in Table 4-6. There is no cost saving estimated for this option because the recovered gas is combusted.

Table 4-6. Costs for Centrifugal Compressor Wet Seals Routed to a Flare

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor
Processing	$67,918	$98, 329
Transmission/Storage	$67,918	$98,329

4.5 Centrifugal Compressor - Wet Seals with Gas Recovery for Use

4.5.1 Description

The final option for emissions reduction for wet seal centrifugal compressors is to capture and reroute the emissions back into the process. Based on comments received during development of subpart OOOO, in some cases gas may be routed back to the compressor suction or fuel system.

4.5.2 Effectiveness

The emissions reductions for wet seal centrifugal compressors in the processing sector and transmission and storage sectors are summarized in Table 4-7 using 95% control efficiency for the capture system.

Table 4-7. Wet Seal Centrifugal Compressor Emission Reductions at 95% Capture and Control

Source	VOC (tpy)	Methane (tpy)
Emissions Reductions Per Wet Seal Centrifugal Compressor – Natural Gas Processing	19.5	216
Emissions Reductions Per Wet Seal Centrifugal Compressor – Transmission/Storage	3.32	120

4.5.3 Cost of Controls

Natural Gas STAR estimated the cost of a system of this type in which the seal oil degassing vents are routed to fuel gas or compressor suction to be $22,000 (U.S. EPA, 2009). The estimated cost includes the installation of an intermediate pressure degassing drum, new piping, gas demister/filter, and a pressure regulator for the fuel line. The capital and installation costs were estimated using Guthrie's modular method of equipment cost estimation (U.S. EPA, 2009). The annual operating and maintenance cost of the systems was assumed to be minimal (U.S. EPA, 2009).

Because this option results in natural gas capture, savings can be realized from the use of the gas for beneficial purposes (e.g., the gas captured can replace other fuel that would have to be purchased). The per unit annual savings from natural gas is calculated by taking the value of the gas that is not emitted and routed to a useful purpose as a result of the capture control. This assumes that all gas that is not emitted is being routed for a useful purpose, which is reasonable given the available information on the destination of recovered seal oil degassing streams. Using the methane reductions provided in Table 4-7, the value of the natural gas saved is estimated to be $44,729 per year for centrifugal compressors equipped with one wet seal in the natural gas processing sector and $24,849 per year for centrifugal compressors equipped with one wet seal in the transmission/storage sector. These cost savings assume the value of the natural gas saved is $4/Mscf and the natural gas has a methane content of 92.8%.

Natural Gas STAR estimated the potential cost benefit of installing a seal oil capture system that uses the captured gas to fuel onsite boilers and heaters (U.S. EPA, 2009). The report estimates the potential gas savings from reduced site fuel gas consumption to be 63,000 Mscf/yr (U.S. EPA, 2009). At $4/Mscf, the potential cost savings from reduced fuel consumption would be $252,000 per year, not including the capital cost of the seal oil gas capture system.

The ICF International study (ICF, 2014) calculated emission control cost curves ($/Mcf of methane reduced) using their 2018 projected methane emission estimates (discussed in Section 3.8.2 of this document). The report evaluated the cost of preventing emissions from the use of centrifugal compressors with wet seals by capturing the seal oil degassing stream from a small disengagement vessel and recycling it back into the compressor suction (or for us as high pressure turbine fuel or low pressure fuel gas to heaters) (assuming up to 99% control of methane emissions) using their 2018 projected methane emission estimates. Their analysis assumed capital costs of $33,700 (for seal oil gas separator, seal oil gas demister for low quality gas, and seal oil gas demister for high quality gas), minimal annual operating costs, and annual product revenue benefits per centrifugal compressor of $120,000 (assuming $4/Mcf of gas) due to the reduction of product loss to the atmosphere. The estimated payback period for this control option was estimated to be three months. In total, the study estimated that methane emissions would be reduced by 19.1 Bcf (397,567 tons) methane/yr nationally. The study also estimated that VOC emissions would be reduced by 72,800 MT (or approximately 80,226 tons) nationally at a cost of $806/ton of VOC reduced.

5.0 SUMMARY

The EPA has used the data sources, analyses and studies discussed in this paper to form the Agency's understanding of vented VOC and methane emissions from centrifugal and reciprocating compressors and the applicable emissions mitigation techniques. The following are characteristics the Agency believes are important to understanding this source of VOC and methane emissions:

- Reciprocating compressors may be found throughout the oil and natural gas sector. Centrifugal compressors are predominantly used in the processing and transmission segments.

- The net 2012 methane emissions reported for compressors for the 2014 GHG Inventory were 86,259 MT for the natural gas production segment, 724,295 MT for the natural gas processing segment, and 1,261,080 MT for the natural gas transmission and storage segment, for a total of 2,071,633 MT of methane.

- Reciprocating compressor emissions may be controlled by periodic replacement of rod packing systems. Additionally, new technologies are being used that capture these emissions and route them back to the process, both reducing emissions and providing an economic benefit.
- Centrifugal compressor emissions may be controlled by using dry seals in place of wet seals. Dry seal centrifugal compressors have lower emissions, require less maintenance, and are more energy efficient that wet seal centrifugal compressors and the cost of the two technologies is similar.
- When wet seal centrifugal compressors are used, it may be feasible to capture emissions from the seal oil and route the recovered gas back to the compressor or another process, or combust the gas. Routing the gas back to a process reduces the loss to the atmosphere and reduces the destruction of natural gas.

6.0 CHARGE QUESTIONS FOR REVIEWERS

1. Please comment on the national estimates of methane emissions and methane emission factors for vented compressor emissions presented in this paper. Please comment on the activity data and the methodologies used for calculating emission factors presented in this paper.

2. Did this paper appropriately characterize the different studies and data sources that quantify vented emissions from compressors in the oil and gas sector?
3. Did this paper capture the full range of technologies available to reduce vented emissions from reciprocating compressors and wet seal centrifugal compressors at oil and gas facilities? In particular, are there other options for reducing emissions at existing reciprocating or centrifugal compressors? For example, the EPA is aware of "low emissions packing" for reciprocating compressors but has no detailed information on this technology.
4. Did this paper appropriately characterize the emissions reductions achievable from the emissions mitigation technologies discussed for reciprocating compressors and wet seal centrifugal compressors?
5. Did this paper appropriately characterize the capital and operating costs for the technologies discussed for reduction of vented emissions from reciprocating compressors and wet seal centrifugal compressors?
6. If there are emissions mitigation options for reciprocating and centrifugal compressors that were not discussed in this paper, please comment on the pros and cons of those options. Please discuss the efficacy, cost and feasibly for both new and existing compressors.
7. Are there technical limitations that make the replacement of wet seals with dry seals impractical at certain existing centrifugal compressors?
8. Are there technical reasons why an operator would use a wet seal centrifugal compressor without a gas recovery system?
9. Are there technical limitations that make the installation of gas capture systems at certain reciprocating compressors impractical?
10. Please comment on the prevalence of the different emission mitigation options in the field.
11. Given the substantial benefits of dry seal systems (e.g., lower emissions, less maintenance, and higher efficiency), are you aware of situations where new wet seal centrifugal compressors are being installed in the field? If so, are there specific applications that require wet seal compressors?
12. Are there ongoing or planned studies that will substantially improve the current understanding of vented VOC and methane emissions from reciprocating and centrifugal compressors and available techniques for increased product recovery and emissions reductions?

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Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production

Report for Oil and Natural Gas Sector
Oil Well Completions and Associated Gas during Ongoing Production
Review Panel

April 2014

Prepared by

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

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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 air 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) which allows for drilling in formerly inaccessible formations.

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 air emissions and available mitigation options. This paper presents the Agency's understanding of air emissions and available control technologies from a potentially significant source of emissions in the oil and natural gas sector.

Oil and gas production from unconventional formations such as shale deposits or plays has grown rapidly over the last decade. Oil and natural gas production is projected to steadily increase over the next two decades. Specifically, natural gas development is expected to increase by 44% from 2011 through 2040 (U.S. EIA, 2013b) and crude oil and natural gas liquids (NGL) are projected to increase by approximately 25% through 2019 (U.S. EIA, 2013b). The projected growth of natural gas production is primarily led by the increased development of shale gas, tight gas, and coalbed methane resources utilizing new production technology and techniques such as horizontal drilling and hydraulic fracturing. According to the U.S. Energy Information Administration (EIA), over half of new oil wells drilled co-produce natural gas (U.S. EIA, 2013a). Based on this increased oil and gas development, and the fact that half of new oil wells co-produce natural gas, the potential exists for increased air emissions from these operations.

One of the activities identified as a potential source of emissions to the atmosphere during oil development is hydraulically fractured oil well completions. Completion operations are conducted to either bring a new oil well into the production phase, or to maintain or increase the well's production capability. Although the term "recompletion" is sometimes used to refer to completions associated with refracturing of existing wells, this paper will use the term "completion" for both newly fractured wells and refractured wells. In addition, hydraulically fractured coproducing oil wells can generate emissions of associated gas during the production phase. These processes and emissions are described in detail in Section 2.

The purpose of this paper is to summarize the EPA's understanding of VOC and methane emissions from hydraulically fractured oil well completions and associated gas during ongoing production. It also presents the EPA's understanding of mitigation techniques (practices and equipment) available to reduce these emissions, including the efficacy and cost of the technologies and the prevalence of use in the industry.

2.0 DEFINITION OF THE SOURCE

2.1 Oil Well Completions

For the purposes of this paper, a well completion is defined to mean:

> The process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Completion operations with hydraulic fracturing are conducted to either bring a new oil well into the production phase or to maintain or increase the well's production capability (sometimes referred to as a recompletion). Well completions with hydraulic fracturing include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and are installed as necessary for production to begin.

For the purposes of this paper, hydraulic fracturing is defined to mean:

> The process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic fracturing is one technique for improving oil and gas production where the reservoir rock is fractured with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that "props open" the fractures after fluid pressure is reduced.

Oil well completions with hydraulic fracturing can result in VOC and methane emissions, which occur when gas is vented to the atmosphere during flowback. The emissions are a result of the backflow[1] of the fracture fluids and reservoir gas at high volume and velocity necessary to lift excess proppant and fluids to the surface. This comingled fluid stream (containing produced oil, natural gas and water) flows from each drilled well to a respective vertical separator and heater/treater processing unit. Fluid may be heated to aid in separation of the oil and natural gas and produced water. Phase separation is the process of removing impurities from the hydrocarbon liquids and gas to meet sales delivery specifications for the oil and natural gas. Oil may go directly to a pipeline or be stored onsite for future transfer to a refinery. If infrastructure is present, produced gas can be metered to a sales pipeline. If infrastructure is not available, the produced gas is frequently sent to combustion devices for destruction (e.g., flares) or is vented to the atmosphere.

Recompletions are conducted to minimize the decline in production, to maintain production, or in some cases to increase production. When oil well recompletions using hydraulic fracturing are performed, the practice and sources of emissions are essentially the same as for new well completions involving hydraulic fracturing, except that surface gas collection

[1] Backflow is the phenomena created by pressure differences between zones in the borehole. If the wellbore pressure rises above the average pressure in any zone, backflow will occur (i.e., fluids will move back towards the borehole). In contrast, "flowback" is the term used in the industry to refer to the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.(http://www.glossary.oilfield.slb.com/)

equipment may already be present at the wellhead after the initial fracture. However, the backflow velocity during refracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

2.2 Associated Gas

Associated gas is the term typically used for natural gas produced as a by-product of the production of crude oil. Industry publications typically refer to associated gas as gas that is co-produced with crude oil while the well is in the production phase and is vented directly to the atmosphere or is flared. One published definition for associated gas is "gaseous hydrocarbons occurring as a free-gas phase under original oil-reservoir conditions of temperature and pressure (also known as gas-cap gas)."[2] Therefore, associated gas can include gas that is produced during flowback associated with completion activities and gas that is emitted from equipment as part of normal operations, such as natural gas driven pneumatic controllers and storage vessels. However, in this paper, the term "associated gas emissions" refers to:

> Associated gas emissions from the production phase (i.e., excluding completion events and emissions from normal equipment operations) that could be captured and sold rather than being flared or vented to the atmosphere if the necessary pipeline and other infrastructure were available to take the gas to market.

3.0 EMISSIONS DATA AND EMISSIONS ESTIMATES – HYDRAULICALLY FRACTURED OIL WELL COMPLETIONS

For consistency in the review of the various data sources and studies and to better understand the data discussions presented below, this section presents an overview of the types of the emissions estimation processes and the data that have been used in a number of studies to estimate VOC and methane emissions from hydraulically fractured oil well completions and recompletions.

[2] McGraw-Hill Dictionary of Scientific & Technical Terms, 6E, Copyright © 2003 by the McGraw-Hill Companies, Inc.

1) For estimating source emissions:
   - Gas produced during completions of oil wells. Estimated. This type of data would provide natural gas or methane production volumes for a completion. The data may be estimated using well characteristics (e.g., flow rate, casing diameter, and casing pressure) and established emission factors.
   - Gas produced by the oil well annually/daily/monthly. Direct measure or estimated. This type of data would be similar to the gas produced during completions but would be related to ongoing production of associated gas from the well.
   - Gas composition. This data is typically composition results from laboratory analysis of the raw gas stream to determine methane and other hydrocarbon volume or weight percent for use in converting natural gas or methane emissions estimates to VOC.
   - Duration of completion cycle. Length of the completion process in days.
   - Use of control technology. Flares, reduced emissions completions (RECs), other control technology or none. This information indicates whether a control device or practice is used and, if possible, the amount of produced gas captured and controlled.
2) For estimating nationwide emissions:
   - Number of oil well completions conducted annually. This information requires identification of the number of oil wells conducting completions/recompletions annually.
   - Number of oil wells co-producing natural gas. This involves identifying the population of oil wells using a definition of oil well based on some production criteria.
   - Number of oil wells completions with emissions controls such as RECs or flaring.

There are several available data sources for the data elements described above. Because most of the available data were not collected specifically for the purpose of estimating emissions, each source has to be qualified to ensure that the data are being used appropriately. In characterizing the nationwide emissions, we analyzed several sources of data and qualify each source with respect to the different aspects of the emission estimation process. Therefore, in addition to describing the data source and any relevant results of analysis, this paper discusses the implications of the data and/or results of analysis of the data with respect to the quantity of data, quantity of emissions, scope of emissions estimates, geographic dispersion, and variability in data.

Lastly, methodologies used in the emission estimation process are described, such as a discussion of the methodology for deriving emission factors or for identifying national populations.

There is variation in the industry as to how oil wells and gas wells are defined. Some publications do not differentiate at all between them, while others use the amount of oil produced or a gas-to-oil ratio (GOR) threshold as a dividing line between a gas well and an oil well. This paper does not attempt to choose a specific definition of "oil well," but instead describes the definitions used in each study or data source. The intent of this section of the paper is to present the EPA's understanding of the available data and its usefulness in estimating VOC and methane emissions from this source.

3.1 Summary of Major Studies and Sources of Emissions Data

Given the potential for emissions from hydraulically fractured oil well completions, there have been several information collection efforts and studies conducted to estimate emissions and available emission control options. Studies have focused on completion emission estimates. Some of these studies are listed in Table 3-1, along with an indication of the type of information contained in the study (i.e., activity level, emissions data, and control options).

Table 3-1. Summary of Major Sources of Information and Data on Oil Well Completions

Name	Affiliation	Year of Report	Activity Factor	Uncontrolled/Controlled Emissions Data	Control Options Identified
Fort Berthold Federal Implementation Plan (U.S. EPA, 2012a)	U.S. Environmental Protection Agency	2012	Regional	Uncontrolled	X
ERG/ECR Contractor Analysis of HPDI® Data	U.S. Environmental Protection Agency	2013	Nationwide	Uncontrolled	X
Environmental Defense Fund Analysis of HPDI® Data (EDF, 2014)	Environmental Defense Fund	2014	Nationwide	Uncontrolled	-

Name	Affiliation	Year of Report	Activity Factor	Uncontrolle d/Controlled Emissions Data	Control Options Identified
Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)	Multiple Affiliations, Academic and Private	2013	26 Completion Events	Both	-
Methane Leaks from North American Natural Gas Systems (Brandt et. al, 2014a and 2014b)	Multiple Affiliations	2013	Regional	Uncontrolled	-

Data for Petroleum and Natural Gas Systems collected under the EPA's Greenhouse Gas Reporting Program (GHGRP) or the EPA's Inventory of U.S. Greenhouse Emissions and Sinks (GHG Inventory), are not discussed in detail in this section. The GHGRP does not require reporting of vented emissions from hydraulically fractured oil well completions. The GHG Inventory estimates emissions from oil well completions, but does not distinguish between completions/recompletions of conventional wells and completions/recompletions of hydraulically fractured wells.

A more-detailed description of the data sources listed in Table 3-1 is presented in the following sections, including how the data may be used to estimate national VOC and methane emissions from oil well completion events.

3.2 Fort Berthold Federal Implementation Plan (FIP) – Analysis by EC/R (U.S. EPA) 2012a)

On March 22, 2013, the EPA published (78 FR 17836) the FIP for existing, new and modified oil and natural gas production facilities on the Fort Berthold Indian Reservation (FBIR). In support of that effort, the EPA conducted an analysis of 154 applications for synthetic minor New Source Review (NSR) permits that indicated VOC emissions were the most prevalent of the pollutants emitted from the oil and natural gas production sources operating on the FBIR, which contain equipment that handles natural gas produced during well completions, phase separation during production, and temporary storage of crude oil (U.S. EPA, 2012).

The EPA FIP established federally enforceable requirements to control VOC emissions from oil and natural gas production activities that were previously unregulated or regulated less strictly. The FIP requires a 90%-98% reduction of VOC emissions from gas not sent to a sales line using pit flares, utility flares and enclosed combustors, all technologies which were found to be standard industry practice on the FBIR. The analysis included a large dataset of combustion control equipment cost information based on three well/control configuration scenarios.

The FBIR dataset includes:

- 533 production wells from five major operators
- Average controlled and uncontrolled VOC emissions from oil wells for wellhead gas, heater/treaters, and storage tanks
- Oil production data
- Number of sources; storage tanks, combustors, flares, and if a pipeline is present
- Current capital and annualized cost estimates for combustion and REC control options
- Gas composition data (for each permit application)
- Projected 2,000 new wells or 1,000 well pads per year between 2010 and 2029.

The data provided for the FBIR, although useful, has certain qualifying limitations. For instance, the FBIR data is primarily for wells producing from the Bakken and Three Forks formations, which limits it to a regional dataset. Also, the FBIR data showed high variability in oil well production rates and in product composition. This variability may not be representative of other formations. Also, according to the North Dakota Department of Health, the Bakken formation typically contains a high amount of lighter end VOC components which have the potential to produce increased volumes of flash emissions compared to typical oil production wells (U.S. EPA, 2012a). This may be somewhat unique to the Bakken formation and not be representative nationally.

Table 3-2 summarizes an analysis performed by EC/R of the FBIR data with respect to oil well completion emissions. The analysis estimated completion emissions by multiplying the average gas volume per day for each well by a 7 day flowback period. The analysis indicated that the average uncontrolled emissions from a well completion event are 37 tons of VOC per completion event.

Table 3-2. Summary of FBIR FIP Oil Well Completion Uncontrolled[3] Casing Gas and VOC Emissions

	Data from FBIR FIP											
Data Element	**Enerplus**	**EOG**	**QEP[c]**	**WPX[b]**	**WPX-2[b]**	**WPX-3[b]**	**XTO[d]**	**Marathon**	**PetroHunt**	**Average**	**Min**	**Max**
VOC Molecular weight	27.0	27.7	NA	28.1	29.6	31.7	24.5	28.5	25.8	27.8	24.5	31.7
Natural Gas Molecular weight	37.8	40.5	NA	43.7	45.9	51.0	32.9	41.4	34.3	41.0	32.9	51.0
Gas Constant (ft^3/lbmol)[a]	379	379	NA	379	379	379	379	379	379	379	379.0	379
Average Oil Production (bpd) - per well	1,181	255	NA	347	420	303	305	2,094	214	639.7	214	2,094
Average Gas Volume (Mcf/day) - per well	885	182	NA	250	292	210	305	491	197	351.5	182	885
Average Gas Volume (Mcf/completion)	6,197	1,272	NA	1,748	2,042	1,473	2,133	3,439	1,378	2,460	1,272	6,197
Average Uncontrolled VOC Emissions (ton/completion)	83	19	NA	28	37	31	23	53	16	37	16	83

NA = Not Reported, FBIR FIP = Fort Berthold Indian Reservation Federal Implementation Plan, EOG = EOG Resources, QEP = QEP Energy Co., WPX = WPX Energy, XTO = XTO Energy Inc.
a-Value used by North Dakota facilities represents 60°F and 1 atm. For subpart OOOO, this value is based on 68°F and 1 atm.
b-NOTE for WPX:
i. They used three different molecular weights and percent. Therefore, each of these are represented in this table.
ii. They only reported 10% of the VOC emissions because they flare 90% of their casinghead gas emissions. This table represents 100%.
c-The QEP molecular weight and VOC content data for casinghead gas were claimed as copyrighted and were not in the online docket.
d-XTO reported oil production and associated gas production as the same value. Therefore, did not include this gas to oil production ratio in the average.

[3] Uncontrolled emissions are the emissions that would occur if no emissions mitigation practices or technologies were used (*e.g.*, completion combustion devices or RECs).

3.3 ERG Inc. and EC/R Analyses of HPDI Data

ERG Inc. and EC/R (ERG/ECR) conducted an analysis of Calendar Year (CY) 2011 HPDI[4] data to estimate uncontrolled emissions from hydraulically fractured oil well completions for the EPA. For this analysis the following methodology was used:

ERG extracted HDPI oil well data for hydraulically fractured, unconventional oil wells completed in CY 2011. Because the HPDI database does not differentiate between gas and oil wells, the following criteria were used to identify the population of hydraulically fractured oil well completions:

- Identified wells completed in 2011 using HPDI data covering U.S. oil and natural gas wells. Summary of the data and the logic for dates used is included in the memo "Hydraulically Fractured Oil Well Completions" (ERG, 2013)
- Identified wells completed in 2011 that were hydraulically fractured using the Department of Energy EIA formation type crosswalk supplemented with state data for horizontal wells (ERG, 2013)
- Determined which wells were oil wells based on their average gas-to-liquids ratio (less than 12,500 scf/barrel were considered to be oil wells)
- Estimated the average daily gas flow from the cumulative natural gas production for each well during its first 12 months of production
- The resulting dataset provided 192 data points representing county level average daily natural gas production at a total of 5,754 oil well completions for CY 2011.

Emissions in the ERG/ECR analysis were calculated using both a 3-day and a 7-day flowback period. The volume of natural gas emissions (in Mcf) per completion event was calculated using the average daily flow multiplied by both a 7-day flowback period and a 3-day flowback period. The gas volume was converted to mass of VOC using the same VOC

[4] HPDI, LLC is a private organization specializing in oil and gas data and statistical analysis. The HPDI database is focused on historical oil and gas production data and drilling permit data. For certain states and regions, this data was supplemented by state drilling information. The 2011 data was the most current data available when the analysis was performed.

composition and conversion methodology used for gas wells in the subpart OOOO well completion evaluation. The composition values used were 46.732% by volume of methane in natural gas and 0.8374 pound VOC per pound of methane for oil wells (EC/R, 2011a).

The analysis of the 2011 HPDI data for oil well completions provided an average gas production of 262 Mcf per well per day. Based on this gas production, the average uncontrolled VOC emissions were 20 tons per completion event based on a 7-day flowback period and 6.4 tons of VOC per completion event based on a 3-day flowback period. The average uncontrolled methane emissions were 24 tons per completion event based on a 7-day flowback period and 7.7 tons of methane per completion event based on a 3-day flowback period. It was assumed that the emissions for an oil well recompletion event are the same as an oil well completion event.

To estimate nationwide uncontrolled emissions for hydraulically fractured oil well completions, the average methane and VOC emissions per event were multiplied by the total number of estimated oil well completions. For 2011, which was the most recent data available in HPDI, the estimated nationwide uncontrolled hydraulically fractured oil well completion VOC emissions are 116,230 tons per year (i.e., VOC emissions/completion of 20.2 tons/event times the total oil well completion events per year of 5,274) based on a 7-day flowback period and 36,825 tons per year (i.e., VOC emissions/completion of 6.4 tons/event times the total oil well completion events per year of 5,274) based on a 3-day flowback period. The estimated nationwide uncontrolled hydraulically fractured oil well completion methane emissions are 138,096 tons per year (i.e., methane emissions/completion of 24 tons/event times the total oil well completion events per year of 5,274) based on a 7-day flowback period and 44,306 tons per year (i.e., VOC emissions/completion of 7.7 tons/event times the total oil well completion events per year of 5,274) based on a 3-day flowback period. Table 3-3 presents the results of the emission estimate analysis for both the 7-day and 3-day completion duration periods.

Table 3-3. Summary of Oil Well Completion Uncontrolled Emissions from 2011 HPDI Data

	7-day event	**3-day event**
Total number of hydraulically fractured oil well completions in 2011	5,754	5,754
Number of county well production averages (data points)	195	195
Natural Gas production per well, per day, weighted average (Mcf)	262	262
Methane emissions per completion/recompletion event, weighted average (tons)	24	7.7
VOC emissions per completion/recompletion event, weighted average (tons)	20.2	6.4
Uncontrolled Nationwide methane emissions, oil well completions (tpy)	138,096	44,306
Uncontrolled Nationwide VOC emissions, oil well completions (tpy)	116,230	36,825

Note: This estimate does not include recompletion emissions.

As stated earlier, these estimates are for uncontrolled emissions, thus estimates assume no control technology applied. National-level data on the prevalence of the use of RECs or combustors for reduction of emissions from oil well completion or recompletion operations were unavailable for this analysis.

State level information for Colorado, Texas and Wyoming on oil well recompletion counts was used to determine a percentage of producing wells for which recompletions were reported. The state level data were obtained for Colorado, Texas and Wyoming for recent years (COGCC, 2012, Booz, 2008 and RRCTX, 2013). Based on the state level data, it was determined that the average percentage of producing well undergoing recompletion was 0.5%. This includes both conventional and hydraulically fractured oil wells (the data did not allow the different types of wells to be distinguished from each other). Table 3.4 presents a summary of this analysis.

Table 3-4. Analysis of Texas, Wyoming and Colorado Recompletions Counts

State Data Source	Year	Total Number of Producing Wells	Total Number of Recompletions	Percent Recompletions to Total Producing Wells
Railroad Commission of Texas	2012	168,864	685	0.4
Wyoming Heritage Foundation	2007	37,350	304	0.8
State of Colorado Oil & Gas Conservation Commission	2012	50,500	152	0.3
Average Percent				**0.5**

While the state level recompletion data are recent, the percentage of producing oil wells that undergo recompletion in future years may increase due to more prevalent use of hydraulic fracturing on oil wells. However, no data have been obtained to quantify any potential increase in the oil well recompletion rate. This percentage was not used to estimate the number of recompletions of hydraulically fractured oil wells, because the data did not distinguish between conventional wells and hydraulically fractured wells.

3.4 Environmental Defense Fund and Stratus Consulting Analysis of Oil Well Completions[5] (EDF, 2014)

The Environmental Defense Fund (EDF) and Stratus Consulting (EDF/Stratus) conducted an analysis of HPDI data for oil wells to determine the cost effectiveness of the use of RECs and flares for control of oil well completion emissions within three major unconventional oil play formations, Bakken, Eagle Ford and Wattenberg. The oil well completion population was extracted using the DI Desktop for all oil wells with initial production in 2011 and 2012. Different filters were applied in each formation in order to identify the hydraulically fractured oil wells:

[5] This analysis is described in the EDF white paper "Co-Producing Wells as a Major Source of Methane Emissions: A Review of Recent Analyses" (http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf). It is referred to in that paper as the "EDF/Stratus Analysis." The supplemental materials, including the data that was used in the analysis are available at https://www.dropbox.com/s/osrom4w6ewow4ua/EDF-Initial-Production-Cost-Effectiveness-Analysis.xlsx.

- Eagle Ford
    - Well Production Type: Oil
- Bakken
    - Well Production Type: Oil and Oil & Gas
- Wattenberg
    - Well Production Type: Oil

The resulting dataset included 3,694 oil wells for the Bakken formation, 1,797 oil wells for the Eagle Ford formation, and 3,967 oil wells for the Wattenberg formation. The assumptions EDF/Stratus made while conducting this analysis were:

- Well completions lasted an average of 7 to 10 days and the total gas production over that period was equal to 3 days of "Initial Gas Production" as reported in DI Desktop (i.e., 3 days of "Initial Gas Production" was equal to the uncontrolled natural gas emissions from the oil well completion).
- The natural gas content was 78.8% methane.

Table 3-5 summarizes the results of this analysis.

Table 3-5. EDF Estimated Uncontrolled Methane Emissions from Oil Well Completions Based on Analysis of HPDI® Oil Well Production Data

Formation	Wells (#)	Uncontrolled Completion Emissions (gas Mcf/event)	Uncontrolled Completion Emissions (MT CH_4/event)	Uncontrolled Completion Emissions (tons CH_4/event)
Wattenberg[a]	3,967	624	9.5	10.5
Bakken[b]	3,694	1,183	18.0	19.8
Eagle Ford[c]	1,797	1,628	24.7	27.2

All results represent mean values.
a - Production data was downloaded for all oil wells in the Colorado Wattenberg formation with a first production date between 1/1/2010 and 3/1/2013.
b - Production data was downloaded for wells in the North Dakota Bakken formation with a completion date from 1/1/2010-12/31/2012. North Dakota does not distinguish between oil and gas wells. All wells with the type O&G were assumed to be oil wells.
c - Production data was downloaded for all oil wells in the Texas Eagle Ford formation with a completion date between 1/1/2010 and 2/23/2013.

The EDF/Stratus Analysis also provided an estimate of uncontrolled methane emissions from oil well completions of 247,000 MT (272,000 tons), however, the materials describing the analysis do not explain how this estimate was calculated.

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

The UT Study was primarily authored by University of Texas at Austin and was sponsored by the EDF and several companies in the oil and gas production industry. The study was conducted to gather methane emissions data at onshore natural gas well sites in the U.S. and compare the data to the EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory). The sources and operations that were tested included well completion flowbacks, well liquids unloading, pneumatic pumps and controllers and equipment leaks. The full study analysis included 190 onshore natural gas sites, which included 150 production sites, 26 well completion events, 9 well unloading and 4 well recompletions or workovers.

Six of the completion events in the UT Study were at co-producing wells (at least some oil was produced). The study reported the total oil produced, the total associated gas produced, the potential and actual methane emission, the completion duration, the type of emission control used, and the percent reduction from the control that was observed (Note: for two of the completion events, data was not gathered for the initial flow to the open tank). The data for these wells are summarized in Table 3-6.

Table 3-6. Summary of Completion Emissions from Co-Producing Wells

Site ID	Oil Produced (bbl)	Gas Produced (Mcf)	GOR (scf/bbl)	Potential Methane Emissions[a] (Mcf)	Actual Methane Emissions[b] (Mcf)	% Reductio n	Data Analyzed	Duration (hrs)	REC or Flare
GC-1	1,594	6,449.9	4,046.36	5,005	106	97.9	Yes	75	Flare
GC-2	1,323	5,645	4,266.82	4,205	91	97.8	Yes	76	Flare
GC-3	2,395	26,363	11,007.52	21,500	264	98.8	Yes	28	REC
GC-4	1,682	24,353	14,478.60	13,000	180	98.6	Yes	28	REC
GC-6	448	13,755	30,703.13	12,150	247	98	No[d]	164	Flare
GC-7	1,543	5,413	3,508.10	4,320	90	97.9	No[d]	108	Flare

a – Measured emissions before flare or REC.
b - Measured emissions after flare or REC.
c - Calculated from measured before and after control.
d -Data not used in developing average emissions factor in the UT Study because, in these flowbacks, the study team was unable to collect completion emissions data for the initial flow to the open tank.

Using the threshold of a GOR of 12,500 scf/barrel to distinguish oil wells from gas wells, wells GC-1, GC-2, GC-3, and GC-7 would be considered oil wells. The average uncontrolled methane emissions from those wells were 213 tons (10,237 Mcf) and the average controlled (actual) emissions were 3.2 tons (154 Mcf).[6] The average duration of the completion for these wells was 72 hours (3 days). It is also worth noting that well GC-3 was controlled using a REC and 98.8% of the potential methane emissions were mitigated, demonstrating that RECs can be used effectively to control emissions from hydraulically fractured oil wells.

3.6 Methane Leaks from North American Natural Gas Systems (Brandt et. al, 2014a and 2014b)

Novim, a non-profit group at the University of California, sponsored a meta-analysis of the existing studies on emissions from the production and distribution of natural gas. As part of this analysis, Novim estimated emissions from hydraulically fractured oil well completions based on data from HPDI®. Novim included wells that were drilled in 2010 or 2011 in the Eagle Ford,

[6] These averages do not include well GC-7, because, as noted above, data from this well was not used in the UT Study due to the inability to collect all the emissions data.

Bakken, and Permian formations (Brandt et. al., 2014a). Different filters were applied in each formation in order to identify the hydraulically fractured oil wells:

- Eagle Ford
  - Well Production Type: Oil
  - Drill Type: Horizontal
- Bakken
  - Well Production Type: Oil and Oil & Gas
  - Drill Type: Horizontal
- Permian
  - Well Production Type: Oil
  - Drill Type: All

Using this method of qualifying the well population, Novim concluded 2,969 hydraulically fractured oil wells were completed in 2011 in the three formations (Brandt et. al., 2014a). In order to estimate completion emissions, Novim used the O'Sullivan method[7] in which peak gas production (normally the production during the first month) is converted to a daily rate of production. The O'Sullivan method assumes that during flowback emissions increase linearly over the first nine days until the peak rate is reached. Table 3-7 summarizes the estimated uncontrolled methane emissions per completion calculated by the Novim study.

Table 3-7. Summary of Uncontrolled Completion Emissions from Co-Producing Wells

Formation	Uncontrolled Methane Emissions (tonnes/event)[a]	Uncontrolled Methane Emissions (ton/event)[b]
Eagle Ford	90.9	93
Bakken	31.1	31.9
Permian	31.2	31.9

a – 1 Mg = 1 metric tonne of methane
b – Converted to U.S. short tons. 1 tonne = 1.02311 tons (short/U.S.) of methane

[7] O'Sullivan, Francis and Sergey Paltsev, "Shale gas production: potential versus actual greenhouse gas emissions", Environmental Research Letters, United Kingdom. November 26, 2012.

The Novim Study assumes methane emissions from these formations are representative of total national methane emissions from hydraulically fractured oil well completions and estimates those emissions to be 0.12 Tg (120,000 tonnes or 122,773 tons) per year for 2011.

It should be noted that the methodology in this study, like the ERG/ECR Analysis and the EDF/Stratus Analysis, uses gas production from HPDI® to estimate completion emissions. However, Novim uses the O'Sullivan method in which the emissions increase linearly through the flowback period until a peak is reached, while the ERG/ECR Analysis and the EDF/Stratus Analysis assume emissions are constant through the flowback period.

4.0 EMISSIONS DATA AND EMISSIONS ESTIMATES – ASSOCIATED GAS FROM HYDRAULICALLY FRACTURED OIL WELLS

Given the potential for emissions of associated gas from oil production, available information sources have been reviewed as to their potential use for characterizing the VOC and methane emission from associated gas production at oil well sites. As was stated previously, the term "associated gas emissions" in this paper refers to emissions from gas that is vented during the production phase that could otherwise be captured and sold if the necessary pipeline infrastructure was available to take the gas to market.

One methodology for estimating emissions would be to use the GOR of the well, which is a common piece of well data in the industry. An emission factor based on average GOR could be developed, and then the emission factor could be used to estimate uncontrolled associated gas emissions by applying it to known oil production (assuming all gas produced at an oil well is included in uncontrolled associated gas emissions). However, research indicates that associated gas production from oil wells declines over the life of the well, similar to oil production, but the decline is typically at a different rate than the oil production (EERC, 2013). This phenomenon introduces another variable into the analysis.

A second approach would be to use gas production reported for the well for economic and regulatory reasons. Conceivably, gas production could be used to estimate uncontrolled associated gas emissions. However, the EPA is not aware of a methodology that would allow the Agency to calculate the percentage of produced gas that could be captured if pipeline infrastructure were available. Some gas is emitted from equipment as part of normal operations, such as bleeding from pneumatic controllers. These emissions would not qualify as associated gas emissions as they have been defined in this paper.

The GHGRP does require reporting of "associated gas venting and flaring emissions." Additionally, the Ceres report contains data potentially useful for basic evaluation of VOC and methane associated gas emissions, but does not provide national estimates or per well estimates of emissions (Ceres, 2013). Both these sources are discussed in detail in the sections below.

The GHG Inventory does not include a category that specifically covers all associated gas emissions. Instead, these emissions are estimated in several categories in Petroleum Systems, and in Natural Gas Systems (emissions downstream of the gas-oil separator, and flaring).

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

In October 2013, the EPA released 2012 greenhouse gas (GHG) data for Petroleum and Natural Gas Systems[8] collected under the 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 datasets 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[9] in the Petroleum and Natural Gas Systems source

[8] The implementing regulations of the Petroleum and Natural Gas Systems source category of the GHGRP are located at 40 CFR Part 98 Subpart W.

[9] 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).

category is required to submit annual reports if total emissions are 25,000 metric tons carbon dioxide equivalent (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.

Under the GHGRP, facilities report associated gas vented and flared emissions. Vented emissions are calculated based on GOR and the volume of oil produced and flared emissions using a continuous flow measurement device or engineering calculation. For 2012, 171 facilities reported associated gas vented and flared emissions to the GHGRP. Total reported methane emissions were 89,535 MT.

4.2 FLARING UP: North Dakota Natural Gas Flaring More Than Doubles in Two Years (Flaring Up) (CERES, 2013)

The Flaring Up report discusses the increase in North Dakota's oil and gas production from the Bakken formation between 2007 and mid-2013, the increased flaring of associated gas, and the potential value of NGL lost as a result of flaring. The report presents some associated gas production and flaring data that the authors derive from the gas production and flaring data reported by the North Dakota Industrial Commission (NDIC), Department of Mineral Resources. The Commission defines associated gas to be all natural gas and all other fluid hydrocarbons not defined as oil. Oil is defined by the Commission to be all crude petroleum oil and other hydrocarbons, regardless of gravity which are produced at the wellhead in liquid form and the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas, other than gas produced in association with oil and commonly known as casinghead gas[10].

This Flaring Up report indicates that of the wells that are flaring the associated gas, approximately 55% are wells are not connected to a gas gathering system, while 45% are wells that are already connected. In addition, the report states that in May of 2013, 266,000 Mcf per day was flared, which represents nearly 30% of the gas produced (CERES, 2013). Percent flaring is currently reported by the NDIC while the connection data is tracked by the North Dakota

[10] North Dakota Century Code, Section I, Chapter 38-08 Control of Gas & Oil Resources, Section 38-08-02.

Pipeline Authority. The report concludes that the reason for the flaring of the associated gas is lack of pipeline infrastructure, lack of capacity and lack of compression infrastructure.

The data and information in this report is useful for discussion on the relative percentages of gas emissions being flared. The data, however, are specific to the Bakken, a formation that possesses unique characteristics both with regard to reservoir and formation characteristics, gas composition and the lack of infrastructure due to rapid development of the industry in the area.

5.0 AVAILABLE EMISSION MITIGATION TECHNIQUES

Two mitigation techniques were considered that have been proven in practice and in studies to reduce emissions from well completions and recompletions: REC and completion combustion. One of these techniques, REC, is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would otherwise be vented. The second technique, completion combustion, destroys the organic compounds. Both of these techniques are discussed in the following sections, along with estimates of the efficacy at reducing emissions and costs for their application for a representative well. Combustion control for control of associated gas emissions (e.g., flaring) has been demonstrated as effective in the industry. However, flaring results in the destruction of a valuable resource and, as such, alternate uses for uncaptured/sold associated gas have been the subject of several studies with respect to new emerging technologies.

5.1 Reduced Emission Completions (REC)

5.1.1 Description

Reduced emissions completions are defined for the purposes of this paper as:

> A well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other

useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced emission completions, also referred to as "green" completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. It is the EPA's understanding that the additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps and a gas dehydrator. In many cases, portable equipment used for RECs operates in tandem with the permanent equipment that will remain after well drilling is completed (EC/R, 2010b). In other instances, permanent equipment is designed (e.g., oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs because technical barriers vary from well to well. Three main limitations include the following:

- Proximity of pipelines. For certain wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields.

- Pressure of produced gas. Based on experience using RECs at gas wells, the EPA understands that during each stage of the completion process, the pressure of flowback fluids may not be sufficient to overcome the sales line backpressure. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line.

- Inert gas concentration. Based on experience using RECs at gas wells, if the concentration of inert gas, such as nitrogen or carbon dioxide, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

5.1.2 Effectiveness

Based on data available on RECs use at gas wells, the emission reductions from RECs can vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on the results reported by four different Natural Gas STAR Partners who performed RECs primarily at natural gas wells, a representative control efficiency of 90% for RECs was estimated. The companies provided both recovered and total produced gas, allowing for the calculation of the percentage of the total gas which was recovered. This estimate was based on data for more than 12,000 well completions (ICF, 2011). Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95% reduction in emissions. Additionally, both wells that co-produced oil and gas and were controlled with a REC in the UT Austin study achieved greater than 98% reduction in methane emissions.

5.1.3 Cost

The discussion of cost in this section is based on the EPA's experience with RECs at gas wells. It is the EPA's understanding that the same equipment is used for RECs at gas wells and co-producing oil wells. All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs.

The average cost of RECs was obtained from data shown in the Natural Gas STAR Lessons Learned document titled "Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells" (U.S. EPA, 2011a). The impacts calculations use the cost per day for gas capture and the duration of gas capture along with a setup/takedown/transport cost and a flare cost to represent the total cost. The cost is then annualized across the time horizon under study.

Costs of performing a REC are projected to be between $700 and $6,500 per day (U.S. EPA, 2011a). This cost range is the incremental cost of performing a REC over a completion without a REC, where typically the gas is vented or combusted because there is an absence of REC equipment. These cost estimates are based on the state of the industry in 2006 (adjusted to 2008 U.S. dollars). [11] Cost data used in this analysis are qualified below:

- $700 per day (equivalent to $806 per day in 2008 dollars) represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three-phase separator, are already found onsite and are of suitable design and capacity for use during flowback.
- $6,500 per day (equivalent to $7,486 in 2008 dollars) represents situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought onsite and then relocated after the completion.

The average of the above data results in an average incremental cost for a REC of $4,146 per day (2008 dollars).[12] The total cost of the REC depends on the length of the flowback period, and thus the length of the completion process. For example, if the completion takes 7 days then the total cost would be $29,022, and if the completion takes 3 days then the total cost would be $12,438 versus an uncontrolled completion. These costs would be mitigated by the value of the captured gas. The extent of this cost mitigation would depend on the price of the gas and the quantity that was captured during the REC.

[11] The Chemical Engineering Cost Index was used to convert dollar years. For REC, the 2008 value equals 575.4 and the 2006 value equals 499.6.
[12] The average incremental cost for a REC was calculated by averaging $806 per day and $7,486 per day (2008 dollars). While the average estimated cost per day is presented here, it is likely that the cost that is paid by a well operator will be the low incremental cost if key pieces of equipment are already present onsite or the high incremental cost if this equipment is not present onsite, and not the average of these two estimates.

5.1.4 Prevalence of Use at Oil Wells

The UT Austin study found that some co-producing oil wells are conducting RECs. It is the EPA's understanding that in some cases RECs are currently used on co-producing oil wells if pipeline infrastructure is available.

5.2 Completion Combustion Devices

5.2.1 Description

Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in gas streams (U.S. EPA, 1991). Completion combustion devices are used to control VOC in many industrial settings, since the completion combustion devices can normally handle fluctuations in concentration, flow rate, heating value, and inert species content (U.S. EPA, Flares). These devices can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Completion combustion devices provide a means of minimizing vented gas during a well completion and are generally preferable to venting, due to reduced air emissions.

5.2.2 Effectiveness

Completion combustion devices can be expected to achieve 95% emission reduction efficiency, on average, over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it may be more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. If a completion combustion device has a continuous ignition source with an independent external fuel supply, then it is assumed to achieve an average of 95% control over the entire flowback period (U.S. EPA, 2012b).

5.2.3 Cost

An analysis of costs provided by industry for enclosed combustors was conducted by the EPA for the FBIR FIP. In addition, the State of Colorado recently completed an analysis of industry provided combustor cost data and updated their cost estimates for enclosed combustors (CDPE, 2013). Table 5-1 summarizes the data provided from each of the sources with the average cost for an enclosed combustor across these sources being $18,092. It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimations. Also noted in the table is the most recent combustor cost used for reconsideration of control options for storage vessels under subpart OOOO.

As with RECs, because completion combustion devices are purchased for these one-time events, annual costs were assumed to be equal to the capital costs. However, multiple completions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. Costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. This approach may overestimate the true cost of combustion devices per well completion or recompletion.

5.2.4 Prevalence of Use at Oil Wells

The UT Austin study found that some co-producing oil wells are using completion combustion devices to reduce emissions. It is the EPA's understanding that the most common approach to reducing emissions from hydraulically fractured oil well completions is the use of a completion combustion device.

Table 5-1. Analysis of Industry Provided Enclosed Combustor Cost

Cost Parameter	Industry Provided Data						EPA Estimate in Subpart OOOO	
	FBIR				CDPHE			CDHPE
	EOG	**XTO**	**Enerplus**	**QEP**		**Average of quotes**	**Original Data Used**	**Adjusted Data Used**[a]
Annualized Capital Cost	$5,268	$6,727	$6,116	$6,763	$3,569	$6,281	$3,546	$4,746
Other Annual Costs								
Pilot Fuel	NR	NR	NR	NR	$636		$2,078	$2,144
Operating Labor (includes management)	NR	NR	NR	NR	$10,670		$10,670	$11,012
Maintenance	NR	NR	NR	NR	$2,206		$2,190	$2,260
Data Management	NR	NR	NR	NR	$1,000		$1,095	$1,130
Total Other Annual Costs (combustor)[c]	$1,500	$23,250	$6,289	$8,500	$14,512	$10,810	$16,033	$16,546
Other Annual Costs (continuous pilot)[c]	$1,000	NR	NR	NR	included in combustor costs[b]	$1,000	included in combustor costs[b]	included in combustor costs[c]
Total Annual Costs	**$7,768**	**$29,977**	**$12,405**	**$15,263**	**$18,081**	**$18,092**	**$19,580**	**$21,292**

NR = Not reported, FBIR = Fort Berthold Indian Reservation, CDPHE = Colorado Department of Public Health and Environment, EOG = EOG Resources, XTO = XTO Energy Inc. , QEP = QEP Energy Co
Cost data in 2012 dollars
a - Cost data for 40 CFR part 60, subpart OOOO updated to reflect more current cost year and equipment life (industry comments indicated a 10-year equipment life as opposed to 15 years)
b - Data used for subpart OOOO included a cost for an auto ignition system, surveillance system, VRU system, and freight and installation
c - Quotes received for FBIR FIP did not specify what was included in other annual costs.

5.3 Emerging Control Technologies for Control of Associated Gas

Several types of alternative use technologies are being investigated both by industry and regulators for use of associated gas.

The most prominent alternative technologies being investigated to address associated gas are liquefaction of natural gas, NGL recovery, gas reinjection, and electricity generation.

According to the Schlumberger Oilfield Glossary, "liquefied natural gas refers to natural gas, mainly methane and ethane, which has been liquefied at cryogenic temperatures. This process occurs at an extremely low temperature and a pressure near the atmospheric pressure. When a gas pipeline is not available to transport gas to a marketplace, such as in a jungle or certain remote regions offshore, the gas may be chilled and converted to liquefied natural gas (a liquid) to transport and sell it. The term is commonly abbreviated as LNG." Research is being conducted on the economic and technical feasibility of liquefaction of natural gas as a means to realize the full potential of the U.S. natural gas resources, particularly with respect to the potential of U.S. exports of LNG. However, available information indicates that this technology is typically implemented on a macro scale, requiring installation of large facilities and transportation infrastructure. Because the EPA is unaware of existing studies or further information on liquefaction of gas at the wellhead, liquefaction of natural gas is not discussed further in this paper.

Cost information is summarized to the extent that this information is readily available. In many cases, available literature does not provide cost information as the economics of the technology are still being researched.

5.3.1 Natural Gas Liquids (NGL) Recovery

Natural gas liquids are defined as "components of natural gas that are liquid at surface in field facilities or in gas-processing plants. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapor pressure. Natural gas liquids include propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied. The term is commonly abbreviated as NGL."[13]

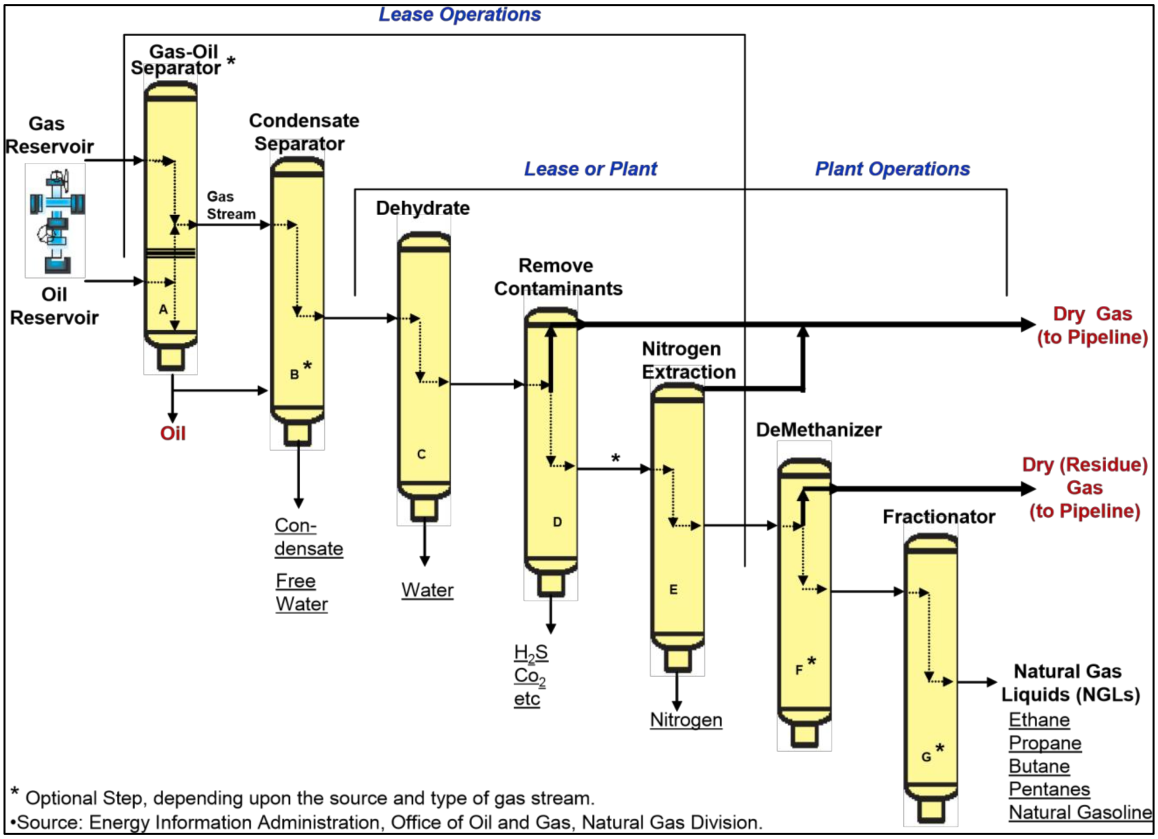
Associated gas from the Bakken formation has been termed "rich" gas, which is defined as naturally containing heavier hydrocarbons than a "lean" gas. Its liquid content adds important economic value to developments containing this type of fluid. Therefore, the value of the NGLs in the associated gas from the Bakken formation has been the subject of several studies, particularly with the concerns raised based by the rapid development of Bakken and increased flaring of associated gas. As would be expected, most of the recent studies related to NGL recovery are based on the Bakken formation.

One of these studies is the "End-Use Technology Study – An Assessment of Alternative Uses for Associated Gas" conducted by the Energy & Environmental Research Center (EERC) of the University of North Dakota (EERC, 2013). The study was conducted based on associated gas production in December 2011 and was published in 2012. This study provides an evaluation of alternative technologies and their associated costs and benefits. In particular, the study looks at NGL recovery, as a standalone operation for both recovery of salable NGLs and as a pretreatment of the associated gas for use in other local operations such as power generation.

To understand NGL recovery, the typical natural gas processing that occurs at or near the wellhead will be reviewed. Liquids and condensates (water and oil) are separated from the "wet" gas. The condensates are transported via truck or pipeline for further processing at a refinery or gas processing plant. The minimally processed wellhead natural gas is then transported to a gas-processing plant via pipeline. There, the gas is processed to remove more water, separate out NGL, and remove sulfur and carbon dioxide in preparation for release to the sales distribution system. Figure 5-1 summarizes generalized natural gas processing.

[13] From Schlumberger Oilfield Glossary available at http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=natural+gas++liquids

Figure 5-1. Generalized Natural Gas Processing Schematic



Source: U.S. EIA, 2006.

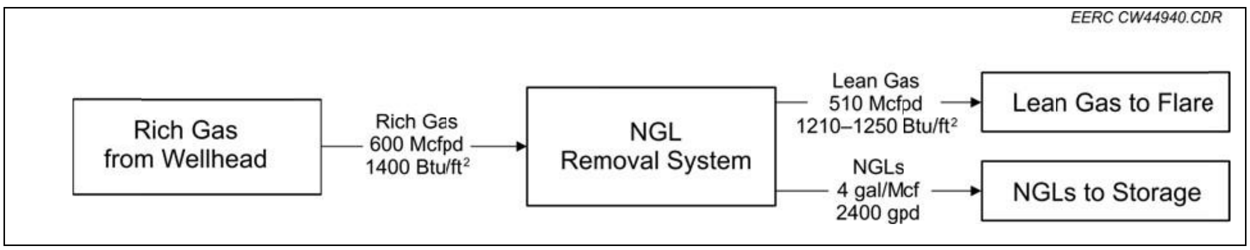
Because of the relatively high value of NGL products produced, recovery technologies have been developed both for large and small scale gas-processing applications. There are generally three approaches used in these technologies:

- Control of temperature and pressure to achieve condensation of NGLs
- Separation of heavier NGLs from lighter gas with pressurized membrane separation systems
- Physical/chemical adsorption/absorption

The typical NGL recovery technologies used are turboexpander with demethanizer, Joule-Thomson (JT) low pressure separation membranes, absorption (Refrigerated Lean Oil Separation, RLOS), adsorption using active carbon or molecular sieve, and Twister Supersonic Gas Low Temperature Separation Dew Pointing Process. For the purposes of this paper, the specifics of these technologies are not discussed; rather, the focus will be on the overall outcome and potential costs for small scale implementation at the well head for addressing associated gas.

The EERC study included a case study for a small scale NGL Recovery process at a well head. The case study evaluated the potential for deploying small scale NGL recovery systems as an interim practice to flaring associated gas while gathering lines and infrastructure were being installed or upgraded. These systems would allow the most valuable hydrocarbon portion of the gas to be captured and marketed. The leaner gas resulting could be used onsite for power generation or transported as a compressed gas. Alternatively, the leaner gas could continue to be flared. Figure 5-2 depicts the NGL Removal system flow diagram.

Figure 5-2. Natural Gas Liquids (NGL) Removal System Flow Diagram



Source: Figure 22, EERC, 2013

According to the EERC study, 10 to 12 gallons of NGL/Mcf of associated gas is present in many producing Bakken wells. At an estimated NGL removal rate of 4 gallons/Mcf (from 1000 Mcf/day of rich gas), the daily production of NGLs would be approximately 4,000 gallons of NGLs per day (EERC, 2013). The study also states that at least at the current natural gas price, the NGLs make up a majority of the economic value of the rich gas. An evaluation of a simplified model on small-scale NGL recovery was developed based on a JT-based technology. The NGL removal system evaluation assumes the parameters shown in Table 5-2.

Table 5-2. Assumptions for NGL Recovery Case (Table 9, EERC, 2013)

Parameter	Assumed Value
Rich Gas Flow Rate from the Wellhead, average	300 Mcf/day
Rich Gas Flow Rate Processed, economic cutoff	600 Mcf/day
Rich Gas Flow Rate, design flow	1000 Mcf/day
Rich Gas Heat Content	1400 Btu/ft^3
Rich Gas Price (cost) at the Wellhead	$0.00/Mcf
Volume of NGLs Existing in Rich Gas	10–12 gallons/Mcf
NGL Price, value	$1.00/gallon
Lean Gas Flow Rate from NGL Removal System	85% of rich gas flow rate
Lean Gas Heat Content	1210–1250 Btu/ft^3
Lean Gas Price, value	$2.00/Mcf

The EERC study estimated capital and annual costs for the NGL removal system. Operating and maintenance (O&M) costs were assumed to be 10% of the total capital cost. Revenue calculations were based on NGL sales only at $1/gallon and a recovery rate of 4 gallons/Mcf. In this scenario, it has been assumed that residue gas is flared (EERC, 2013). Table 5-3, derived from Table 10 of the study, summaries the cost for the small sale NGL recovery system.

Table 5-3. Summary of NGL Removal System Costs (Table 10, EERC)

Description	Capital Cost	Annual O&M Cost
NGL Removal System, 300 Mcfd rich gas	$2,500,000	$250,000
NGL Removal System, 600 Mcfd rich gas	$2,500,000	$250,000
NGL Removal System, 1000 Mcfd rich gas	$2,500,000	$250,000

Mcfd = One thousand standard cubic feet per day.

The EERC study concluded that the technical aspects of NGL recovery are fairly straight forward; however, the business aspects are much more complicated, particularly with respect to NGL product supply chain and contractual considerations. Further, the study concluded that NGL recovery would be most economical at wells flaring larger quantities of gas immediately after production begins. Other attributes that would be important for the economic feasibility of the NGL recovery system would be that the systems are mobile and easily mobilized, and that infrastructure with respect to truing of NGL production is available.

5.3.2 Natural Gas Reinjection

Schlumberger's Oilfield Glossary defines gas injection as "a reservoir maintenance or secondary recovery method that uses injected gas to supplement the pressure in an oil reservoir or field. In most cases, a field will incorporate a planned distribution of gas-injection wells to maintain reservoir pressure and effect an efficient sweep of recoverable liquids."[14]

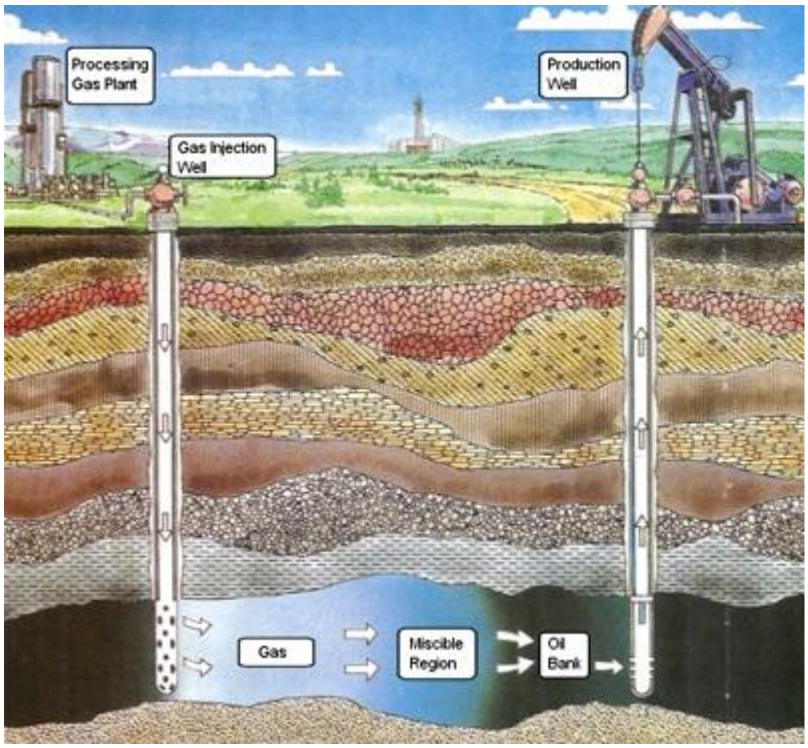
The industry has employed production methods to increase production, which are termed enhanced oil recovery (EOR) or improved oil recovery (IOR) (Rigzone, 2014). These methods are generally considered to be tertiary methods employed after waterflooding or pressure maintenance. The practice involves injecting gas into the gas cap of the formation and boosting the depleted pressure in the formation with systematically placed injection wells throughout the field. The pressure maintenance methods maybe employed at the start of production or introduced after the production has started to lessen. The reinjection of natural gas is the use of associated gas at the same oilfield to accomplish the goals of gas injection as defined above. The increase in the pressure within the reservoir helps to induce the flow of crude oil. After the crude has been pumped out, the natural gas is once again recovered.

Natural gas injection is also referred to as cycling. Cycling is used to prevent condensate from separating from the dry gas in the reservoir due to a drop in reservoir pressure. The condensate liquids block the pores within the reservoir, making extraction practically impossible. The NGL are stripped from the gas on the surface after it has been produced, and the dry gas is

[14] Schlumberger Oilfield Glossary, available at http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=gas+injection

then re-injected into the reservoirs through injection wells. Again, this helps to maintain pressure in the reservoir while also preventing the separation within the hydrocarbon (Rigzone, 2014). Figure 5-3 illustrates the relationship between the gas injection well and the production well.

Figure 5-3. Gas Injection and Production Well

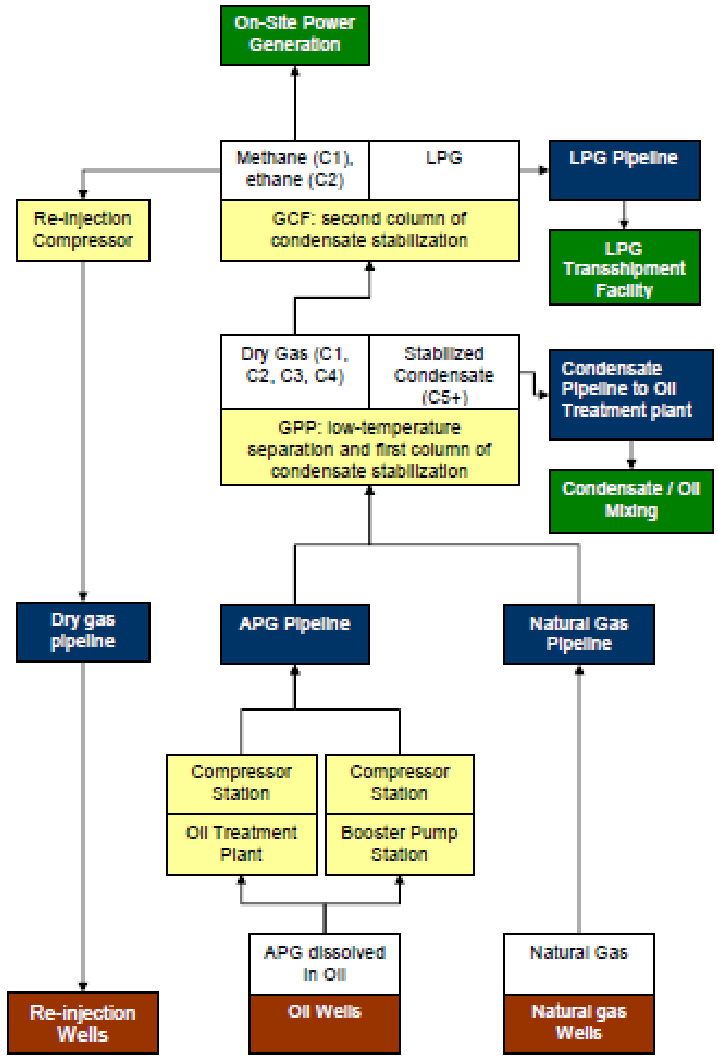


Source: Rigzone, 2014

In the scenarios that were found in available literature, the dry gas is also used as fuel onsite for the generators that power the reinjection pumps. Therefore, the costs associated with the process are mainly initial capital costs. No published information was obtained on the capital and annual costs for these operations.

Figure 5-4 presents a fully implemented gas injection project scheme. In this scheme, associated gas from an oil well (or natural gas from a gas well) is processed through a gas cycling facility (GCF) where recoverable NGLs are separated from methane and the resulting methane is either used for onsite power generation or re-injected in to the formation.

Figure 5-4. Gas Cycling Facility Project Flow



The literature that was reviewed evaluated gas reinjection projects only from the perspective of an enhanced oil recovery opportunity and did not specifically discuss the quantity or percentage of associated gas emissions that were eliminated through the process. The EPA is not aware of literature that discusses the efficacy of mitigating associated gas emissions using the natural gas reinjection process. The efficacy would be highly dependent on many factors, which include the composition value of the gas and the availability of transmission infrastructure. Further, because the use of this process to reduce associated gas emissions in conjunction with oil recovery is an emerging technology, the prevalence of use in the industry and estimated cost to implement the process is unknown to the EPA.

5.5.3 Electricity Generation for Use Onsite

As discussed above, associated gas can be used for generation of electrical power to be used onsite. The EERC study stated that power generation technologies would need to be designed to match the variable wellhead gas flow rates and gas quality, and would need to be constructed for mobility. The EERC study discussed previously also looked at options for use of associated gas for power generation. The EERC study included an evaluation of several technologies fired by natural gas both for grid support (i.e., power generation for direct delivery onto the electric grid) and local power (i.e., power generation for local use with excess generation, if any, sent to the electrical grid). This study provides one of the most comprehensive and recent evaluations of the economics of use of associated gas for electric generation. Therefore, the case study results of this study are used to discuss the cost of this technology for this paper.

Although grid support is potentially a viable use for this gas, it is not considered to be an emissions reduction technology for the purposes of this paper. Grid support requires an infrastructure similar in scope as that needed to bring gas to market. The focus of this section of the paper is on the venting or flaring of associated gas due to the lack of infrastructure to bring it to market. It is unlikely that a well site that is lacking pipeline infrastructure would have access to the necessary infrastructure to provide grid support. Therefore, the focus here is on the use of the gas at the local level, either directly at the wellpad or in an immediate oilfield region to support local activities. The benefits of using associated gas to provide electricity for these activities are both reducing the quantity of gas vented and reducing the quantity of other types of fuel used (e.g., diesel).

The EERC study considered a local power project to be wellhead gas (with limited cleanup) being piped to an electrical generator that produces electricity which is first used to power local consumption (e.g., well pad, group of wells, or an oilfield) with any excess electricity put on the electrical grid for distribution by the local utility to its customers. These projects can range widely in scale, depending on the goal of the project (i.e., satisfy only local load, satisfy local load with minimal excess generation, or satisfy local load with significant excess generation). The study evaluated two power generation scenarios: reciprocating engine and a microturbine.

The first step in using associated gas for electric generation is removal of NGLs from the rich gas. Removal of the NGLs significantly increases the performance of the genset and reduces the loss of resource (when flaring is necessary). According to the EERC study, removal of NGLs such as butane and some propane could be accomplished using a low temperature separation process. The study found that small, modular configurations of these types of systems are not widely available. The estimated capital cost for the NGL removal and storage system is $2,500,000. This capital cost includes the necessary compression to take the rich gas from the heater/treater at 35 psi up to 200 - 1000 psi delivered to the NGL removal system as well as the cost for four 400-bbl NGL storage tanks (EERC, 2013). The study authors considered NGL recovery a valuable first step; however, they also stated that it was not necessary in all circumstances.

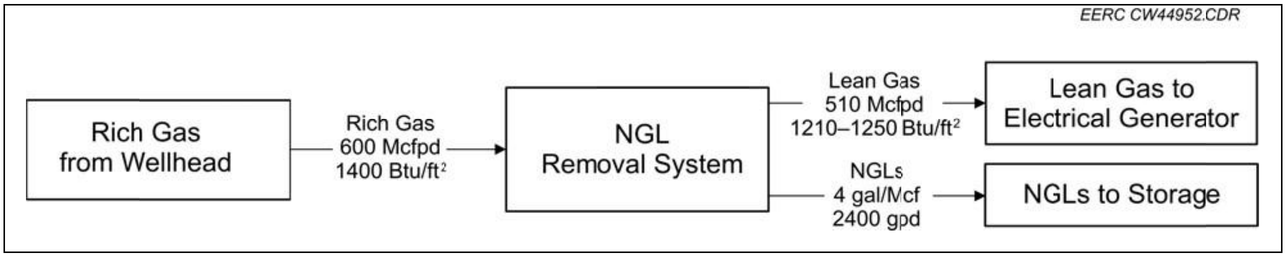
The study made certain assumptions about the flow of associated gas from the wellhead and fuel consumption of the respective electrical generator for the case study. Table 5-4 summarizes the assumed wellhead gas flow for the case study. Figure 5-5 shows a block flow diagram of an example NGL removal system.

Table 5-4. Summary of Wellhead Gas Flow and Product Volume Assumptions

Scenario	Rich Gas Flow, Mcf/day	NGLs Produced, gallons/day	Lean Gas Produced, Mcf/day
Reciprocating Engine	600	2,400	510
Microturbine	600	2,400	510

Source Table 33, EERC 2013

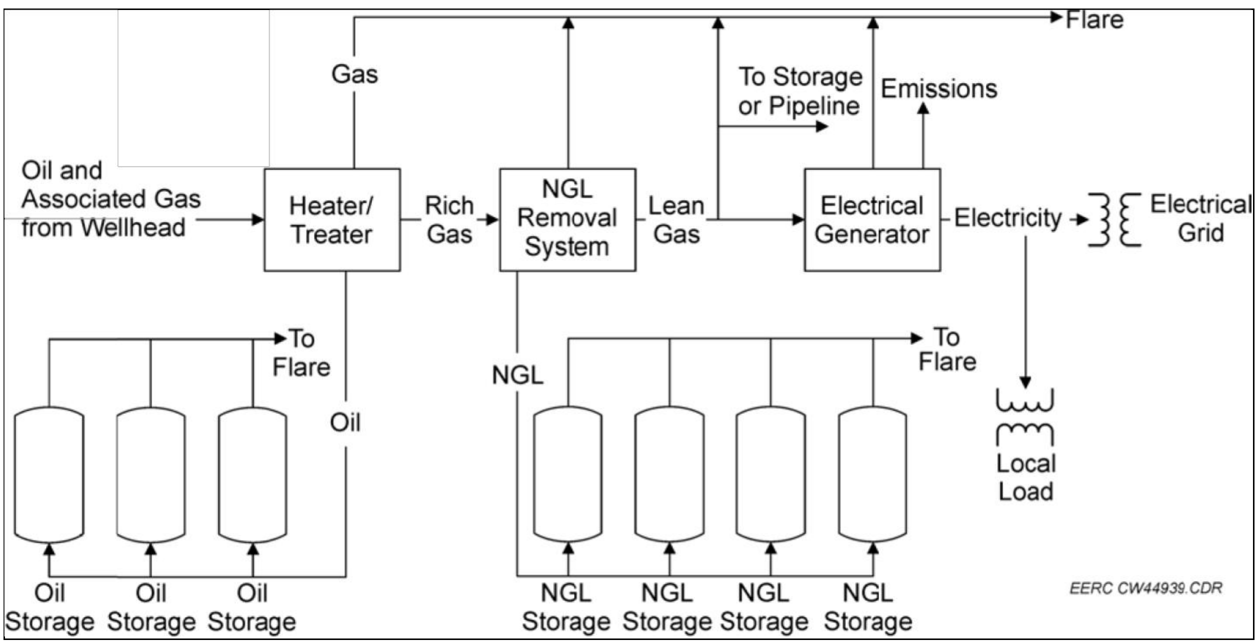
Figure 5-5. NGL Removal System Block Flow Diagram



Source Figure 32, EERC 2013

For the case study, the authors targeted a power production scenario of 1 MW for the reciprocating engine and 200 kW for the microturbine. Both scenarios used the same NGL removal system prior to introduction of the rich gas to the generator. Figure 5-6 depicts the process flow diagram for the local power generation scenario.

Figure 5-6. Process Flow Diagram, Local Power Generation Scenario



Source: Figure 33, EERC, 2013

For the reciprocating engine scenario, vendor provided costs for a 250-kW natural gas fired reciprocating engine genset was $200,000. The study estimated the annual O&M cost was assumed to be 10% of the capital cost. The costs for this scenario are summarized in Table 5-5.

Table 5-5. Total Cost Summary - Reciprocating Engine Scenario

	Capital Cost	Annual Cost
NGL Removal and Storage System	$2,500,000	$250,000
Electrical Generator System	$200,000	$20,000
All Other Infrastructure	$500,000	
Total Capital Cost	**$3,200,000**	**$270,000**

Source Table 38, EERC 2013

For the microturbine scenario, the authors chose to analyze a four, 65 kW microturbine package rated to provide approximately 195 kW of power. This scenario also involved the removal of NGLs prior to delivery of gas to the microturbine and the use of generated electricity to satisfy local electrical demand, with the excess electricity delivered to the grid. The authors noted that the volume of gas generated from the wellhead(s) will determine the size of the system needed and that a range of generation scales should be considered for optimum performance. The process flow for this scenario is the same as shown above in Figure 5-6.

The NGL removal system is likely to be much larger in processing capacity than the electrical generation system. Generally, the NGL removal system will be most economical only at the higher-gas-producing wells. The microturbine package evaluated consumed less than 100 Mcf/day, which meant that excess gas would either need to be flared or the project must be designed to store the excess gas for sale to the pipeline. In the scenarios described here, the authors assumed that the excess lean gas is sold.

For the microturbine system analyzed, the vendors offered a factory protection plan (FPP) that covers all scheduled and unscheduled maintenance of the system as well as parts, including an overhaul or turbine replacement at 40,000 hours of operation. The FPP “locks in” the annual O&M cost of the system and, in both scenarios presented below, it is assumed that the FPP is purchased (EERC, 2013). Table 5-6 summarizes the capital and annual O&M costs for the microturbine system, as well as the NGL recovery system discussed above.

Table 5-6. Total Cost Summary - Microturbine Scenario (Four 65-kW)

	Capital Cost	Annual Cost
NGL Removal and Storage System	$2,500,000	$250,000
Electrical Generator System	$383,200	$33,640
All Other Infrastructure	$500,000	
Total Capital Cost	**$3,382,200**	**$283,640**

Source: Table 41, EERC, 2013.

The study authors also evaluated revenue potential for electricity sent to the grid as an offset to the costs summarized above. Their analysis indicated that based on cost (discussed above) and their revenue assumptions, both scenarios provided a simple payback of 3 years or less. However, given the substantial upfront capital costs of these options, these options may not be preferable to building the necessary pipeline infrastructure to take the gas to market.

In addition to the electric generation potential for associated gas, the study also discussed the use of wellhead gas as a fuel for drilling operations. The authors indicated that the EERC is working with Continental Resources, ECO-AFS, Altronics, and Butler Caterpillar to conduct a detailed study and field demonstration of the GTI Bi-Fuel System. Within that task, the EERC conducted a series of tests at the EERC using a simulated Bakken gas designed to test the operational limits of fuel quality and diesel fuel replacement while monitoring engine performance and emissions. The authors indicated that the Bi-Fuel System is an aftermarket addition to the system allowing natural gas to the air intake, and the engine performance is unaltered from the diesel operation. This system, as the name implies, could be used on either fuel without requiring any alterations.

According to the study report, total installed capital cost for the Bi-Fuel System ranges from $200,000 to $300,000 (EERC, 2013). Other costs that would be incurred would be those for piping wellhead gas to the engine building. The study did not include those costs because they can be highly variable depending on the distance to the nearest gas source and gas lease terms.

The study reports that ECO-AFS had recently installed several Bi-Fuel Systems on rigs in the Williston Basin and that early data suggest that diesel fuel savings of approximately $1 to $1.5 million can be achieved annually. Under typical conditions, operators can expect to achieve diesel replacement of 40% - 60% at optimal engine loads of 40% - 50% (EERC, 2013).

The EERC study noted that there are a number of other potential natural gas uses related to oil production and operations that could take advantage of rich gas on a well site. Those would include:

- Heating of drilling fluids during winter months (replacing the diesel or propane fuel used currently)
- Providing power for hydraulic fracturing operations decreasing reliance on diesel fuel (i.e., by using Bi-fuel systems)
- Providing fuel for workover rigs (if the rig is equipped with a separate generator)

6.0 SUMMARY

As discussed in the previous sections, the EPA used the body of knowledge presented in this paper to summarize its understanding of emissions characterization and potential emissions mitigation techniques for oil well completions and associated gas. From that body of knowledge, the following statements summarize the EPA's understanding of the state of the industry with respect to these sources of emissions:

- Available estimates of uncontrolled emissions from hydraulically fractured oil well completions are presented below:

Study	Average Uncontrolled VOC Emissions (Tons/Completion)	Average Uncontrolled Methane Emissions (Tons/Completion)
Fort Berthold Federal Implementation Plan	37	N/A
ERG/ECR Analysis of HPDI® Data (7 day flowback period)	20.2	24
ERG/ECR Analysis of HPDI® Data (3 day flowback period)	6.4	7.7
EDF/Stratus Analysis of HPDI® Data (Eagle Ford)	N/A	27.2
EDF/Stratus Analysis of HPDI® Data (Wattenberg)	N/A	10.5
EDF/Stratus Analysis of HPDI® Data (Bakken)	N/A	19.8
Measurements of Methane Emissions at Natural Gas Production Sites in the United States	N/A	213
Methane Leaks from North American Natural Gas Systems (Eagle Ford)	N/A	90.9
Methane Leaks from North American Natural Gas Systems (Bakken)	N/A	31.1
Methane Leaks from North American Natural Gas Systems (Permian)	N/A	31.2

- Limited information is available on uncontrolled emissions from hydraulically fractured oil well recompletions, and controlled emission factors for hydraulically fractured oil well completions and recompletions.
- National level estimates of uncontrolled methane emissions from hydraulically fractured oil well completions range from 44,306 tons per year (ERG/ECR) to 247,000 tons per year (EDF/Stratus analysis).
- One study (ERG/ECR) estimated nationwide uncontrolled VOC emissions from hydraulically fractured oil well completion to be 116,230 tons per year assuming a 7-day flowback period and 36,825 tons per year assuming a 3-day flowback period.
- There is some data that shows (Allen et. al.) that RECs, in certain situations, can be an effective emissions control technique for oil well completions when gas is co-produced.

However, there may be a combination of well pressure and gas content below which RECs are not technically feasible at co-producing oil wells.

- Some oil well completions are controlled using RECs; however, national data on the number of completions that are controlled using a REC are not available. It is the EPA's understanding that most oil well completion emissions are controlled with combustion; however, data on an average percentage are not available. Likewise, data are not available on the percentage of oil wells nation-wide that vent completion emissions to the atmosphere.
- Other gas conserving technologies are being investigated for use in completions and for control of associated gas emissions. These include gas reinjection, NGL recovery and use of the gas for power generation for local use. Some studies have evaluated the economics of some of these technologies and determined, in some cases, they can result in net savings to the operator depending on the value of the recovered gas or liquids or the value of the power generated. However, some barriers exist with respect to technology availability and application of the technology to varying scales of oil well gas production. In addition, costs vary for implementing some of these technologies.

7.0 CHARGE QUESTIONS FOR REVIEWERS

1. Please comment on the national estimates and per well estimates of methane and VOC emissions from hydraulically fractured oil well completions presented in this paper. Are there factors that influence emissions from hydraulically fractured oil well completions that were not discussed in this paper?

2. Most available information on national and per well estimates of emissions is on uncontrolled emissions. What information is available for emissions, or what methods can be used to estimate net emissions from uncontrolled emissions data, at a national and/or at a per well level?

3. Are further sources of information available on VOC or methane emissions from hydraulically fractured oil well completions beyond those described in this paper?

4. Please comment on the various approaches to estimating completion emissions from hydraulically fractured oil wells in this paper.
    - Is it appropriate to estimate average uncontrolled oil well completion emissions by using the annual average daily gas production during the first year and multiplying that value by the duration of the average flowback period?
    - Is it appropriate to estimate average uncontrolled oil well completion emissions using "Initial Gas Production," as reported in DI Desktop, and multiplying by the flowback period?
    - Is it appropriate to estimate average uncontrolled oil well completion emissions by increasing emissions linearly over the first nine days until the peak rate is reached (normally estimated using the production during the first month converted to a daily rate of production)?
    - Is the use of a 3-day or 7-day flowback period for hydraulically fractured oil wells appropriate?
5. Please discuss other methodologies or data sources that you believe would be appropriate for estimating hydraulically fractured oil well completion emissions.

6. Please comment on the methodologies and data sources that you believe would be appropriate to estimate the rate of recompletions of hydraulically fractured oil wells. Can data on recompletions be used that does not differentiate between conventional oil wells and hydraulically fractured oil wells be reasonably used to estimate this rate? For example, in the GHG Inventory, a workover rate of 6.5% is applied to all oil wells to estimate the number of workovers in a given year, and in the ERG/ECR analysis above a rate of 0.5% is developed based on both wells with and without hydraulic fracturing. Would these rates apply to hydraulically fractured oil wells? For hydraulically fractured gas wells, the GHG Inventory uses a refracture rate of 1%. Would this rate be appropriate for hydraulically fractured oil wells?

7. Please comment on the feasibility of the use of RECs or completion combustion devices during hydraulically fractured oil well completion operations. Please be specific to the types of wells where these technologies or processes are feasible. Some characteristics that should be considered in your comments are well pressure, gas content of flowback, gas to oil ratio

(GOR) of the well, and access to infrastructure. If there are additional factors, please discuss those. For example, the Colorado Oil and Gas Conservation Commission requires RECs only on "oil and gas wells where reservoir pressure, formation productivity and wellbore conditions are likely to enable the well to be capable of naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD to the surface against an induced surface backpressure of five hundred (500) psig or sales line pressure, whichever is greater."[15]

8. Please comment on the costs for the use of RECs or completion combustion devices to control emissions from hydraulically fractured oil well completions.

9. Please comment on the emission reductions that RECs and completion combustion devices achieve when used to control emissions from hydraulically fractured oil well completions.

10. Please comment on the prevalence of the use of RECs or completion combustion devices during hydraulically fractured oil well completion and recompletion operations. Are you aware of any data sources that would enable estimating the prevalence of these technologies nationally?

11. Did the EPA correctly identify all the available technologies for reducing gas emissions from hydraulically fractured oil well completions or are there others?

12. Please comment on estimates of associated gas emissions in this paper, and on other available information that would enable estimation of associated gas emissions from hydraulically fractured oil wells at the national- and the well-level.

13. Please comment on availability of pipeline infrastructure in hydraulically fractured oil formations. Do all tight oil plays (e.g., the Permian Basin and the Denver-Julesberg Basin) have a similar lack of infrastructure that results in the flaring or venting of associated gas?

14. Did the EPA correctly identify all the available technologies for reducing associated gas emissions from hydraulically fractured oil wells or are there others? Please comment on the

[15] Colorado Department of Natural Resources: Oil and Gas Conservation Commission Rule 805.b(3)A. (http://cogcc.state.co.us/)

costs of these technologies when used for controlling associated gas emissions from hydraulically fractured oil wells. Please comment on the emissions reductions achieved when these technologies are used for controlling associated gas emissions from hydraulically fractured oil wells.

15. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from hydraulically fractured oil well completions and associated gas and available options for increased product recovery and emission reductions?

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Appendix A

(ERG, 2013)

<u>Memorandum (Draft)</u>:

Environmental Research Group, Inc.

Hydraulically Fractured Oil Well Completions.

October 24, 2013

DRAFT MEMORANDUM

TO: David Hendricks, EC/R Incorporated

FROM: Mike Pring, Eastern Research Group, Inc. (ERG)

Regi Oommen, ERG

DATE: October 24, 2013

SUBJECT: Hydraulically Fractured Oil Well Completions

Eastern Research Group, Inc. (ERG) is currently under contract with EC/R Incorporated to provide technical support under EC/R Work Assignment #1-11 with U.S. EPA. This memorandum describes ERG's findings relative to Task 2 of the support effort. Specifically, under this task ERG:

- Identified wells which were hydraulically fractured in 2011;
- Determined which of the hydraulically fractured wells completed in 2011 were oil wells;
- Estimated daily associated gas production from the hydraulically fractured oil wells; and
- Provided a summary of this information at the national and county level (in Excel spreadsheet format).

Wells Hydraulically Fractured in 2011

Starting with the most recent analysis and files delivered by ERG to the U.S. EPA Office of Compliance, ERG queried DI Desktop, a production database maintained by DrillingInfo, Inc.

covering U.S. oil and natural gas wells, to identify hydraulically fractured oil and gas well completions performed in 2011. This was accomplished using a two-step process:

- Identification of wells completed in 2011;
- Identification of wells completed using hydraulic fracturing.

Wells completed in 2011 were identified as those wells meeting one of the following criteria:

- The DI Desktop data for the well indicated it was completed in 2011; or
- The DI Desktop data for the well indicated the well 1st produced in 2011.

While the DI Desktop database is fairly comprehensive in its geographic and temporal coverage of production data, completion date information can lag behind by a year or more afterwards and is not universally available for all areas of the country. Therefore, the list of wells with explicit well completion dates of 2011 was supplemented with those wells having a date (month) of 1st production of either gas or oil in 2011. This methodology is consistent with the methodology used to estimate well completions in the "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2011 (April 12, 2013)".

Using this approach, 39,262 conventional and unconventional well completions were identified for 2011.

Once the population of wells completed in 2011 was identified, hydraulically fractured wells were identified as those wells meeting either of the following:

- Wells completed in a coalbed methane, tight, or shale formation as determined using the DOE EIA formation type crosswalk; or
- Wells identified in the DI Desktop database as horizontal wells.

The DOE EIA formation type crosswalk used in this analysis may be found in Attachment A. This methodology is consistent with the methodology used to identify the number of hydraulically fractured well completions in the "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2011 (April 12, 2013)".

Using this approach, 15,979 hydraulically fractured (or unconventional) well completions were identified for 2011.

Oil Wells Hydraulically Fractured in 2011

Once the population of hydraulically fractured wells completed in 2011 was identified, each well was then classified as either an oil well or a gas well. Gas wells were defined as those wells with an average gas to liquids ratio greater than or equal to 12,500 standard cubic feet per barrel over the lifetime of the well, and oil wells were defined as those wells with an average gas to liquids ratio less than 12,500 standard cubic feet per barrel over the lifetime of the well. Note that the "liquids" quantity used in this analysis does not include produced water. This methodology is consistent with the gas-oil ratio methodology used in the 2012 Oil and Natural Gas Sector NSPS development.

Using this approach, 6,169 hydraulically fractured (or unconventional) oil well completions were identified for 2011.

Daily Gas Production of Oil Wells Hydraulically Fractured in 2011

Once the population of hydraulically fractured oil wells completed in 2011 was identified, the average daily gas production for each well was calculated based on the cumulative gas production from each well during its first year of production. This information was then averaged at the county-level, as well as at the national level. Nationally, the average daily gas production at an oil well that was hydraulically fractured in 2011 was 152 MCF.

Summary Information

Table 1 below presents a state-level summary of the derived information on hydraulically fractured oil wells completed in 2011. Attachment B contains the same information at the county and national level.

Table 1. Summary of Gas Production at Hydraulically Fractured (or unconventional) Oil Wells

State	Number of Counties	Number of Unconventional Oil Well Completions	Average Associated Gas Production over the 1st year (MCF/Day) [a]
AR	2	19	110.03
CO	12	1057	95.46
FL	1	1	5.81
KS	3	5	0.80
LA	17	24	111.87
MI	4	7	5.58
MS	1	1	0
MT	13	95	31.21
ND	14	1299	138.14
NM	6	337	114.89
NY	1	19	0
OH	32	214	4.43
OK	14	89	143.62
PA	5	7	78.38
SD	1	2	42.79
TX	88	2855	284.09
WV	5	11	173.15
WY	14	127	48.62

[a] Determined by taking the total production from the first 12 months of production and dividing by 365 days.

Observations

The analysis conducted under this task was performed in accordance with the procedures described above. With respect to qualitative observations made while implementing these procedures, ERG notes the following:

- In some instances, the date (month) of 1^{st} production only included oil production, with no corresponding gas production recorded for that month;
- In some instances, there were months within the 1^{st} year of production where there was no production (of oil, gas, or both) recorded for the well;
- For 415 oil wells hydraulically fractured and completed in 2011, there was no gas production reported for the well during the 1^{st} year of production.

The net effect of these situations is that the average daily gas production values may be skewed low, for example, due to a well being shut in for some period of time after initially being brought into production.

In the case of the 415 wells where there was no gas production reported for the well during the 1^{st} year of production, summary data is presented in Attachment B excluding these records. This data is reflected in the summary sheets indicating "WITHOUT ZERO". The effect of this differentiation is easily seen in the "UNCONV_OIL_NATIONWIDE" sheet, which shows an average daily gas production of 152 (MCF/day) for all records, and an average daily gas production of 189 (MCF/day) when including only those records with some gas production.

Attachment A: DOE EIA Formation Type Crosswalk

(Formation Crosswalk-Memo Counts 2012 08 28_From ECR.xlsx)

Attachment B: National and County-level Summary of Average Daily Gas Production from Hydraulically Fractured Oil Well Completions in 2011

(Task 2 Summary.xlsx)

UNCONVENTIONAL OIL COUNTY WITH ZERO

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
05027	AR	Columbia	17	220.06
05139	AR	Union	2	-
08001	CO	Adams	8	75.81
08005	CO	Arapahoe	1	100.28
08013	CO	Boulder	4	173.39
08014	CO	Broomfield	12	194.15
08043	CO	Fremont	4	15.34
08057	CO	Jackson	1	281.19
08069	CO	Larimer	14	24.35
08077	CO	Mesa	1	0.43
08081	CO	Moffat	2	73.42
08087	CO	Morgan	1	14.65
08103	CO	Rio Blanco	3	62.57
08123	CO	Weld	1006	129.94
12087	FL	Monroe	1	5.81
20073	KS	Greenwood	1	-
20097	KS	Kiowa	1	-
20125	KS	Montgomery	3	2.40
22009	LA	Avoyelles	2	1.12

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
22011	LA	Beauregard	1	141.90
22015	LA	Bossier	1	-
22017	LA	Caddo	2	5.65
22019	LA	Calcasieu	1	-
22023	LA	Cameron	1	77.58
22027	LA	Claiborne	3	1.56
22037	LA	East Feliciana	1	23.45
22047	LA	Iberville	1	68.21
22075	LA	Plaquemines	1	44.28
22079	LA	Rapides	1	6.08
22091	LA	St. Helena	1	77.15
22097	LA	St. Landry	3	44.34
22101	LA	St. Mary	1	10.77
22111	LA	Union	1	5.58
22119	LA	Webster	1	1,382.30
22127	LA	Winn	2	11.78
26075	MI	Jackson	3	22.32
26091	MI	Lenawee	2	-
26141	MI	Presque Isle	1	-
26147	MI	St. Clair	1	-
28063	MS	Jefferson	1	-
30005	MT	Blaine	4	-

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
30009	MT	Carbon	2	9.60
30021	MT	Dawson	1	29.33
30025	MT	Fallon	1	138.62
30035	MT	Glacier	9	29.37
30065	MT	Musselshell	1	-
30069	MT	Petroleum	4	-
30073	MT	Pondera	1	-
30083	MT	Richland	32	94.43
30085	MT	Roosevelt	27	102.11
30087	MT	Rosebud	2	-
30091	MT	Sheridan	10	2.30
30099	MT	Teton	1	-
35005	NM	Chaves	6	90.22
35015	NM	Eddy	206	317.14
35025	NM	Lea	121	160.97
35039	NM	Rio Arriba	2	57.02
35043	NM	Sandoval	1	-
35045	NM	San Juan	1	64.03
36009	NY	Cattaraugus	19	-
38007	ND	Billings	22	157.36
38009	ND	Bottineau	10	2.69
38011	ND	Bowman	4	84.54

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
38013	ND	Burke	42	83.17
38023	ND	Divide	74	144.13
38025	ND	Dunn	208	156.73
38033	ND	Golden Valley	3	131.73
38053	ND	McKenzie	297	355.17
38055	ND	McLean	11	102.95
38061	ND	Mountrail	329	176.74
38075	ND	Renville	2	-
38087	ND	Slope	1	140.16
38089	ND	Stark	28	184.08
38105	ND	Williams	268	214.53
39005	OH	Ashland	23	-
39007	OH	Ashtabula	1	20.94
39009	OH	Athens	3	2.47
39019	OH	Carroll	6	4.31
39029	OH	Columbiana	1	6.35
39031	OH	Coshocton	8	0.75
39035	OH	Cuyahoga	7	12.35
39055	OH	Geauga	7	4.13
39067	OH	Harrison	3	1.57
39073	OH	Hocking	2	-
39075	OH	Holmes	14	0.23

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
39081	OH	Jefferson	6	-
39083	OH	Knox	13	1.67
39089	OH	Licking	17	-
39093	OH	Lorain	1	-
39099	OH	Mahoning	3	4.72
39101	OH	Marion	1	-
39103	OH	Medina	12	0.72
39105	OH	Meigs	1	2.08
39111	OH	Monroe	13	1.05
39115	OH	Morgan	6	0.16
39119	OH	Muskingum	9	0.79
39121	OH	Noble	1	-
39127	OH	Perry	2	0.40
39133	OH	Portage	10	10.29
39151	OH	Stark	22	6.70
39153	OH	Summit	8	25.92
39155	OH	Trumbull	4	19.92
39157	OH	Tuscarawas	2	2.52
39167	OH	Washington	6	0.35
39169	OH	Wayne	1	0.47
39175	OH	Wyandot	1	10.79
40011	OK	Blaine	4	138.44

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
40015	OK	Caddo	2	-
40017	OK	Canadian	24	59.77
40029	OK	Coal	14	-
40039	OK	Custer	4	73.81
40043	OK	Dewey	5	25.28
40045	OK	Ellis	13	82.28
40051	OK	Grady	4	-
40069	OK	Johnston	1	273.04
40095	OK	Marshall	1	758.99
40125	OK	Pottawatomi e	1	-
40129	OK	Roger Mills	4	60.26
40149	OK	Washita	11	25.78
40151	OK	Woods	1	513.08
42019	PA	Butler	1	3.00
42083	PA	McKean	1	2.85
42123	PA	Warren	1	1.17
42125	PA	Washington	2	322.21
42129	PA	Westmorela nd	2	62.65
46063	SD	Harding	2	42.79
48003	TX	Andrews	18	27.20
48009	TX	Archer	4	7.96
48013	TX	Atascosa	70	119.71

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
48033	TX	Borden	1	-
48041	TX	Brazos	17	88.27
48051	TX	Burleson	15	25.89
48055	TX	Caldwell	29	-
48077	TX	Clay	3	75.75
48079	TX	Cochran	3	0.73
48097	TX	Cooke	99	297.95
48103	TX	Crane	19	110.50
48105	TX	Crockett	20	151.12
48109	TX	Culberson	1	2,500.75
48123	TX	DeWitt	145	1,332.05
48127	TX	Dimmit	322	379.76
48135	TX	Ector	15	12.91
48149	TX	Fayette	13	79.71
48151	TX	Fisher	2	1.68
48163	TX	Frio	72	105.01
48165	TX	Gaines	1	3.92
48169	TX	Garza	1	-
48173	TX	Glasscock	19	272.15
48177	TX	Gonzales	207	98.80
48181	TX	Grayson	4	367.12
48183	TX	Gregg	3	23.02

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
48185	TX	Grimes	7	586.87
48187	TX	Guadalupe	2	-
48195	TX	Hansford	3	93.42
48197	TX	Hardeman	2	74.00
48201	TX	Harris	1	1.84
48203	TX	Harrison	2	13.53
48211	TX	Hemphill	15	390.47
48225	TX	Houston	1	127.46
48235	TX	Irion	87	112.45
48237	TX	Jack	22	122.06
48241	TX	Jasper	2	1,387.63
48255	TX	Karnes	309	388.35
48263	TX	Kent	1	-
48273	TX	Kleberg	2	33.10
48283	TX	La Salle	216	185.29
48285	TX	Lavaca	13	83.04
48287	TX	Lee	5	25.93
48289	TX	Leon	19	61.86
48295	TX	Lipscomb	84	403.67
48297	TX	Live Oak	89	731.54
48301	TX	Loving	28	276.40
48311	TX	McMullen	130	276.52

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
48313	TX	Madison	21	173.35
48317	TX	Martin	1	50.01
48323	TX	Maverick	23	110.15
48329	TX	Midland	1	12.33
48331	TX	Milam	3	34.19
48337	TX	Montague	119	362.22
48351	TX	Newton	2	2,539.85
48353	TX	Nolan	24	20.97
48355	TX	Nueces	3	1,746.66
48357	TX	Ochiltree	82	261.41
48363	TX	Palo Pinto	3	244.63
48365	TX	Panola	2	220.47
48367	TX	Parker	1	20.61
48371	TX	Pecos	8	42.56
48373	TX	Polk	4	1,394.01
48383	TX	Reagan	15	66.05
48389	TX	Reeves	39	184.15
48393	TX	Roberts	21	445.09
48395	TX	Robertson	15	22.76
48401	TX	Rusk	3	5.40
48405	TX	San Augustine	1	1,052.92
48413	TX	Schleicher	1	171.38

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
48415	TX	Scurry	5	84.33
48417	TX	Shackelford	1	-
48425	TX	Somervell	2	1.29
48429	TX	Stephens	2	27.98
48433	TX	Stonewall	18	0.61
48439	TX	Tarrant	1	60.16
48449	TX	Titus	1	-
48457	TX	Tyler	2	1,099.59
48459	TX	Upshur	1	49.13
48461	TX	Upton	12	3.26
48475	TX	Ward	73	375.79
48477	TX	Washington	1	276.18
48479	TX	Webb	44	874.17
48483	TX	Wheeler	60	965.66
48493	TX	Wilson	33	36.46
48495	TX	Winkler	7	137.90
48497	TX	Wise	3	342.57
48503	TX	Young	2	-
48507	TX	Zavala	52	26.70
54001	WV	Barbour	1	1.05
54051	WV	Marshall	1	782.02
54053	WV	Mason	1	1.40

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
54085	WV	Ritchie	1	-
54103	WV	Wetzel	7	81.30
56003	WY	Big Horn	1	10.12
56005	WY	Campbell	29	282.44
56007	WY	Carbon	2	3.52
56009	WY	Converse	45	190.09
56013	WY	Fremont	3	2.17
56015	WY	Goshen	4	11.56
56017	WY	Hot Springs	1	0.11
56019	WY	Johnson	2	29.93
56021	WY	Laramie	22	56.63
56025	WY	Natrona	2	0.02
56027	WY	Niobrara	2	20.77
56029	WY	Park	3	5.60
56031	WY	Platte	2	8.15
56037	WY	Sweetwater	9	59.59

UNCONVENTONAL OIL COUTTY WITHOUT ZERO

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
05027	AR	Columbia	17	220.06
08001	CO	Adams	8	75.81
08005	CO	Arapahoe	1	100.28
08013	CO	Boulder	4	173.39
08014	CO	Broomfield	12	194.15
08043	CO	Fremont	4	15.34
08057	CO	Jackson	1	281.19
08069	CO	Larimer	14	24.35
08077	CO	Mesa	1	0.43
08081	CO	Moffat	2	73.42
08087	CO	Morgan	1	14.65
08103	CO	Rio Blanco	1	187.70
08123	CO	Weld	1000	130.72
12087	FL	Monroe	1	5.81
20125	KS	Montgomery	3	2.40
22009	LA	Avoyelles	1	2.24
22011	LA	Beauregard	1	141.90
22017	LA	Caddo	1	11.31
22023	LA	Cameron	1	77.58
22027	LA	Claiborne	1	4.67
22037	LA	East Feliciana	1	23.45
22047	LA	Iberville	1	68.21

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
22075	LA	Plaquemines	1	44.28
22079	LA	Rapides	1	6.08
22091	LA	St. Helena	1	77.15
22097	LA	St. Landry	2	66.51
22101	LA	St. Mary	1	10.77
22111	LA	Union	1	5.58
22119	LA	Webster	1	1,382.30
22127	LA	Winn	2	11.78
26075	MI	Jackson	2	33.48
30009	MT	Carbon	1	19.19
30021	MT	Dawson	1	29.33
30025	MT	Fallon	1	138.62
30035	MT	Glacier	7	37.76
30083	MT	Richland	30	100.73
30085	MT	Roosevelt	27	102.11
30091	MT	Sheridan	7	3.28
35005	NM	Chaves	5	108.26
35015	NM	Eddy	205	318.68
35025	NM	Lea	112	173.90
35039	NM	Rio Arriba	2	57.02
35045	NM	San Juan	1	64.03
38007	ND	Billings	22	157.36

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
38009	ND	Bottineau	5	5.38
38011	ND	Bowman	4	84.54
38013	ND	Burke	42	83.17
38023	ND	Divide	74	144.13
38025	ND	Dunn	208	156.73
38033	ND	Golden Valley	3	131.73
38053	ND	McKenzie	295	357.58
38055	ND	McLean	11	102.95
38061	ND	Mountrail	329	176.74
38087	ND	Slope	1	140.16
38089	ND	Stark	28	184.08
38105	ND	Williams	268	214.53
39007	OH	Ashtabula	1	20.94
39009	OH	Athens	2	3.70
39019	OH	Carroll	4	6.46
39029	OH	Columbiana	1	6.35
39031	OH	Coshocton	3	2.00
39035	OH	Cuyahoga	7	12.35
39055	OH	Geauga	7	4.13
39067	OH	Harrison	2	2.36
39075	OH	Holmes	4	0.82
39083	OH	Knox	8	2.71

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
39099	OH	Mahoning	2	7.08
39103	OH	Medina	2	4.31
39105	OH	Meigs	1	2.08
39111	OH	Monroe	8	1.71
39115	OH	Morgan	3	0.32
39119	OH	Muskingum	4	1.78
39127	OH	Perry	1	0.79
39133	OH	Portage	9	11.43
39151	OH	Stark	17	8.67
39153	OH	Summit	7	29.62
39155	OH	Trumbull	4	19.92
39157	OH	Tuscarawas	1	5.04
39167	OH	Washington	2	1.04
39169	OH	Wayne	1	0.47
39175	OH	Wyandot	1	10.79
40011	OK	Blaine	4	138.44
40017	OK	Canadian	8	179.30
40039	OK	Custer	2	147.61
40043	OK	Dewey	2	63.20
40045	OK	Ellis	9	118.85
40069	OK	Johnston	1	273.04
40095	OK	Marshall	1	758.99

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
40129	OK	Roger Mills	3	80.35
40149	OK	Washita	1	283.55
40151	OK	Woods	1	513.08
42019	PA	Butler	1	3.00
42083	PA	McKean	1	2.85
42123	PA	Warren	1	1.17
42125	PA	Washington	2	322.21
42129	PA	Westmoreland	2	62.65
46063	SD	Harding	1	85.59
48003	TX	Andrews	16	30.60
48009	TX	Archer	1	31.86
48013	TX	Atascosa	69	121.44
48041	TX	Brazos	17	88.27
48051	TX	Burleson	6	64.72
48077	TX	Clay	3	75.75
48079	TX	Cochran	3	0.73
48097	TX	Cooke	99	297.95
48103	TX	Crane	19	110.50
48105	TX	Crockett	19	159.07
48109	TX	Culberson	1	2,500.75
48123	TX	DeWitt	143	1,350.68
48127	TX	Dimmit	317	385.75

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
48135	TX	Ector	15	12.91
48149	TX	Fayette	12	86.35
48151	TX	Fisher	2	1.68
48163	TX	Frio	58	130.36
48165	TX	Gaines	1	3.92
48173	TX	Glasscock	19	272.15
48177	TX	Gonzales	196	104.35
48181	TX	Grayson	3	489.50
48183	TX	Gregg	3	23.02
48185	TX	Grimes	7	586.87
48195	TX	Hansford	3	93.42
48197	TX	Hardeman	1	147.99
48201	TX	Harris	1	1.84
48203	TX	Harrison	1	27.06
48211	TX	Hemphill	15	390.47
48225	TX	Houston	1	127.46
48235	TX	Irion	87	112.45
48237	TX	Jack	22	122.06
48241	TX	Jasper	2	1,387.63
48255	TX	Karnes	303	396.04
48273	TX	Kleberg	2	33.10
48283	TX	La Salle	214	187.02

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
48285	TX	Lavaca	13	83.04
48287	TX	Lee	3	43.21
48289	TX	Leon	16	73.46
48295	TX	Lipscomb	82	413.52
48297	TX	Live Oak	89	731.54
48301	TX	Loving	26	297.66
48311	TX	McMullen	125	287.58
48313	TX	Madison	20	182.01
48317	TX	Martin	1	50.01
48323	TX	Maverick	18	140.75
48329	TX	Midland	1	12.33
48331	TX	Milam	2	51.29
48337	TX	Montague	115	374.82
48351	TX	Newton	2	2,539.85
48353	TX	Nolan	22	22.87
48355	TX	Nueces	3	1,746.66
48357	TX	Ochiltree	82	261.41
48363	TX	Palo Pinto	3	244.63
48365	TX	Panola	2	220.47
48367	TX	Parker	1	20.61
48371	TX	Pecos	8	42.56
48373	TX	Polk	4	1,394.01

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
48383	TX	Reagan	14	70.77
48389	TX	Reeves	37	194.11
48393	TX	Roberts	21	445.09
48395	TX	Robertson	12	28.45
48401	TX	Rusk	1	16.21
48405	TX	San Augustine	1	1,052.92
48413	TX	Schleicher	1	171.38
48415	TX	Scurry	5	84.33
48425	TX	Somervell	2	1.29
48429	TX	Stephens	2	27.98
48433	TX	Stonewall	15	0.74
48439	TX	Tarrant	1	60.16
48457	TX	Tyler	2	1,099.59
48459	TX	Upshur	1	49.13
48461	TX	Upton	12	3.26
48475	TX	Ward	73	375.79
48477	TX	Washington	1	276.18
48479	TX	Webb	44	874.17
48483	TX	Wheeler	59	982.03
48493	TX	Wilson	28	42.98
48495	TX	Winkler	7	137.90
48497	TX	Wise	3	342.57

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
48507	TX	Zavala	45	30.86
54001	WV	Barbour	1	1.05
54051	WV	Marshall	1	782.02
54053	WV	Mason	1	1.40
54103	WV	Wetzel	7	81.30
56003	WY	Big Horn	1	10.12
56005	WY	Campbell	27	303.36
56007	WY	Carbon	1	7.03
56009	WY	Converse	45	190.09
56013	WY	Fremont	1	6.52
56015	WY	Goshen	4	11.56
56017	WY	Hot Springs	1	0.11
56019	WY	Johnson	2	29.93
56021	WY	Laramie	21	59.33
56025	WY	Natrona	1	0.03
56027	WY	Niobrara	1	41.54
56029	WY	Park	3	5.60
56031	WY	Platte	2	8.15
56037	WY	Sweetwater	8	67.04

UNCONVENTIONAL OIL NATIONWIDE

NATIONWIDE UNCONVENTIONAL OIL WELL COMPLETIONS (WITH ZERO)

GEOGRAPHIC	NUMBER_OF_STATES	NUMBER_OF_COUNTIES	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
NATIONWIDE	18	233	6169	152.19

NATIONWIDE UNCONVENTIONAL OIL WELL COMPLETIONS (WITHOUT ZERO)

GEOGRAPHIC	NUMBER_OF_STATES	NUMBER_OF_COUNTIES	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
NATIONWIDE	16	195	5754	189.35

Oil and Natural Gas Sector Leaks

Report for Oil and Natural Gas Sector Leaks

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 air 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 air 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.

Oil and gas production from unconventional formations such as shale deposits or plays has grown rapidly over the last decade. Oil and natural gas production is projected to steadily increase over the next two decades. Specifically, natural gas development is expected to increase by 44% from 2011 through 2040 (U.S. EIA, 2013b) and crude oil and natural gas liquids are projected to increase by approximately 25% through 2019 (U.S. EIA, 2013b). According to the U.S. Energy Information Administration (EIA), over half of new oil wells drilled co-produce natural gas (U.S. EIA, 2013a).The projected growth is primarily led by the increased development of shale gas, tight gas, and coalbed methane resources utilizing new production technology and techniques such as horizontal drilling and hydraulic fracturing.

Along with the increase in number of wells, the amount of related equipment that has the potential to leak will increase as well. The emissions that occur from leaks are in the form of gasses or evaporated liquids that escape to the atmosphere. Some of the potential leak emissions from these sources include methane and VOCs. The proportion of the different types of air emissions is affected by the composition of the gas in the formation. For example, there tends to be a higher concentration of VOCs in wet gas plays than in dry gas plays.

The emissions data and the mitigation techniques in this paper are based on the onshore natural gas leak emissions that occur from natural gas production, processing, transmission, and storage. However, some of these emissions estimates and mitigation techniques are also applicable to oil wells that co-produce natural gas.

For the purposes of this paper, leaks are defined as VOC and methane emissions that occur at onshore facilities upstream of the natural gas distribution system (i.e., upstream of the city gate). This includes leak emissions from natural gas well pads, oil wells that co-produce natural gas, gathering and boosting stations, gas processing plants, and transmission and storage infrastructure. Potential sources of leak emissions from these sites include agitator seals, compressors seals, connectors, pump diaphragms, flanges, hatches, instruments, meters, open-ended lines, pressure relief devices, pump seals, valves, and improperly controlled liquids storage.[1] For the purposes of this paper, emissions from equipment intended to vent as part of normal operations, such as gas driven pneumatic controllers, are not considered leaks. The definition of leak emissions in this paper was derived by reviewing the various approaches taken in the available literature. Many studies and data sources define leak emissions differently, therefore, in the discussion of these various sources in Section 2 the definition each study uses is compared to the definition presented here.

Leak emissions occur through many types of connection points (e.g., flanges, seals, threaded fittings) or through moving parts of valves, pumps, compressors, and other types of process equipment. Changes in pressure, temperature and mechanical stresses on equipment may eventually cause them to leak. Leak emissions can also occur when connection points are not fitted properly, which causes leaks from points that are not in good contact. Other leaks can occur due to normal operation of equipment, which over time can cause seals and gaskets to

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[1] Emissions from storage vessels are often required to be controlled by state or federal regulations (e.g., reduced by 95%). Emissions beyond the required level of control from control equipment that is not operating properly, such as leaking vapor recovery units or improperly sized combustors, are considered leaks for the purposes of this white paper.

wear. Weather conditions can also affect the performance of seals and gaskets that are intended to prevent leaks. Lastly, leak emissions can occur from equipment that is not operating correctly, such as storage vessel thief hatches that are left open or separator dump valves that are stuck open.

This document provides a summary of the EPA's understanding of VOC and methane leak emissions at onshore oil and natural gas production, processing, and transmission facilities. This includes available emission data, estimates of VOC and methane emissions and available mitigation techniques. Section 2 of this document describes the EPA's understanding of emissions from leaks at onshore oil and natural gas production, processing, and transmission facilities, and Section 3 discusses available mitigation techniques to reduce emissions from leaks at these facilities. 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 picture of VOC and methane emissions from leaks and available mitigation techniques.

2.0 OIL AND NATURAL GAS SECTOR LEAKS EMISSIONS DATA AND EMISSIONS ESTIMATES

There are a number of published studies that have estimated leak emissions from the natural gas production and petroleum, processing and transmission sector. These studies have used different methodologies to estimate these emissions, including the use of equipment counts and emission factors, extrapolation of emissions from equipment, and measurement and analysis of leaks. In some cases the studies focus on different portions of the natural gas production and petroleum, processing and transmission and storage sector (e.g., well sites), while others try to account for all leak emissions across the oil and gas sectors. Some of these studies are listed in Table 2-1, along with an indication of the type of information contained in the study (i.e., activity level).

Table 2-1. Summary of Major Sources of Leaks Emissions Information

Name	Affiliation	Year of Report	Activity Factor
Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995)	U.S. Environmental Protection Agency	1995	None
Methane Emissions from the Natural Gas Industry: Equipment Leaks (GRI/U.S. EPA, 1996)	Gas Research Institute (GRI)/ U.S. Environmental Protection Industry	1996	Nationwide
Greenhouse Gas Reporting Program (U.S. EPA, 2013)	U.S. Environmental Protection Agency	2013	Facility
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)	U.S. Environmental Protection Agency	2014	Regional
Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)	Multiple Affiliations, Academic and Private	2013	Nationwide
City of Fort Worth Natural Gas Air Quality Study, Final Report (ERG, 2011)	City of Fort Worth	2011	Fort Worth, TX
Measurements of Well Pad Emissions in Greeley, CO (Modrak, 2012)	ARCADIS/Sage Environmental Consulting/U.S. Environmental Protection Agency	2012	Colorado
Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (CL, 2013)	Carbon Limits	2013	Canada and the U.S.
Mobile Measurement Studies in Colorado, Texas, and Wyoming (Thoma, 2012)	U.S. Environmental Protection Agency	2012 and 2014	Colorado, Texas, and Wyoming
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014)	ICF International	2014	Nationwide

Name	Affiliation	Year of Report	Activity Factor
Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants (Clearstone, 2002)	Clearstone Engineering, Ltd.	2002	4 gas processing plants
Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites (Clearstone, 2006)	Clearstone Engineering, Ltd.	2006	5 gas processing plants, 12 well sites, 7 gathering stations

Although methane emissions from oil and natural gas production operations have been measured, analyzed and reported in studies spanning the past few decades, VOC emissions from these operations are not as well represented.

2.1 Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995)

The EPA protocol provides standard procedures for estimating the total organic compound mass emissions from leaks at oil and natural gas production facilities. The protocol provides four different approaches for estimating leak mass emissions at oil and natural gas production sites. The correlation equations and emission factors were developed from leak data collected from refineries, marketing terminals, oil and gas production operations and synthetic organic chemical manufacturing industry (SOCMI) facilities.

Emission factors and correlations have been developed for the following equipment types: valves, pumps, compressors, pressure relief valves, connectors, flanges, and open-ended lines. An "others" category has also been developed for the petroleum industry. Development of emission factor and correlation equations for the oil and natural gas production facilities were derived from data from six gas plants that were screened by the EPA and the American Petroleum Institute [2] and from leak emission measurement data from 24 oil and natural gas

[2] DuBose, D.A., J.I. Steinmetz, and G.E. Harris (Radian Corporation). Frequency of Leak Occurrence and Emission

production facilities collected by the American Petroleum Institute.[3,4] The emissions calculated from these emission factors and correlation equations are leak emissions that occur at onshore oil and natural gas production and natural gas processing facilities.

Protocol Leak Estimation Approaches

The protocol document provides four approaches that can be used to estimate mass emissions from leaks.

Average Emission Factor Approach

The first approach involves counting the components by type (e.g., valves, pump seals, connectors, flanges, and open-ended lines) and service (e.g., gas, heavy oil, light oil, and water/oil) at the facility and applying the appropriate average oil and gas production operations emission factors to these counts (see Table 2-4 in U.S. EPA, 1995) to calculate the total organic compound emissions from leaking equipment. There is also an "other" equipment type emission factor that was derived for compressors, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents.

Although the average emission factors are in units of kilogram per hour per individual source, it is important to note that these factors are most valid for estimating emissions from a population of equipment (U.S. EPA, 1995). The average factors are not intended to be used for estimating emissions from an individual piece of equipment over a short time period (e.g., 1 hour).

Factors for Natural Gas Liquid Plants. Final Report. Prepared for U.S. Environmental Protection Agency. Research Triangle Park, NC. EMB Report No. 80-FOL-1. July 1982.

3 Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations, API 4589, Star Environmental, Prepared for American Petroleum Institute, 1993.

4 Emission Factors for Oil and Gas Production Operations, API 4615, Star Environmental, Prepared for American Petroleum Institute, 1995.

Screening Ranges Approach

The second approach to estimating leak emissions is the screening range approach. This approach is intended primarily to aid in the analysis of old datasets that were collected for older regulations that used 10,000 parts per million by volume (ppmv) as the leak definition. This approach uses the results from EPA Method 21 measurement of leak concentration of components to determine the number of components with a leak greater than or equal to 10,000 parts per million (ppm) and the number of components with a leak less than 10,000 ppm. The estimated emissions are then calculated using the count of components by type, service, and screening value (≥10,000 ppm or <10,000 ppm) at the facility and applying the appropriate average oil and gas production operations emission factors to these counts (see Table 2-8 in U.S. EPA, 1995).

This screening range approach is a better indication of the actual leak rate from individual equipment than the average emission factor approach (U.S. EPA, 1995). However, available data indicate that measured mass emission rates can vary considerably from the rates predicted by use of these screening range emission factors.

EPA Correlation Approach

The third approach is a correlation approach that uses the measured Method 21 screening value (in ppm) for each component and inputs that screening value into correlation equations that calculate the emission rate (see Table 2-10 in U.S. EPA, 1995). This approach offers an additional refinement to estimating emissions from leaks by providing an equation to predict mass emission rate as a function of concentration determined by EPA Method 21 screening for a particular equipment type. Correlations for the petroleum industry apply to refineries, marketing terminals and oil and gas production operations. The petroleum industry correlation equations estimate total organic compound (TOC) emission rates.

The EPA Correlation Approach is preferred when actual screening values (in ppm) are available. Correlations can be used to estimate emissions for the entire range of non-zero screening values, from the highest potential screening value to the screening value that represents the minimum detection limit of the monitoring device. This approach involves entering the non-zero, non-pegged screening value into the correlation equation, which predicts the TOC mass emission rate based on the screening value. Default zero emission rates are used for screening values of zero ppmv and pegged emission rates are used for pegged screening values, where the screening value is beyond the upper limit measured by the portable screening device.

The "default-zero" leak rate is the mass emission rate associated with a screening value of zero. (Note that any screening value that is less than or equal to ambient background concentration is considered a screening value of zero.) The correlations mathematically predict zero emissions for zero screening values. However, data collected by the EPA show this prediction to be incorrect (U.S. EPA, 1995), because mass emissions have been measured from equipment having a screening value of zero. A specific goal when revising the petroleum industry correlations was to collect mass emissions data from equipment that had a screening value of zero. These data were used to determine a default-zero leak rate associated with equipment with zero screening values.

Unit Specific Correlation Approach

The fourth approach calls for developing unit-specific correlations and corresponding mass emission rates. This is done by measuring the screening value in ppm and measuring the mass emission rate by “bagging” the component. A component is bagged by enclosing the component to collect leaking vapors. Measured emission rates from bagged equipment coupled with screening values can be used to develop unit-specific screening value/mass emission rate correlation equations. Unit-specific correlations can provide precise estimates of mass emissions from leaks at the process unit. However, it is recommended that unit-specific correlations are only developed in cases where the existing EPA correlations do not give reasonable mass emission estimates for the process unit (U.S. EPA, 1995).

2.2 GRI/EPA Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks (GRI/U.S. EPA, 1996)

This report provides an estimate of annual methane emissions from leaks from the natural gas production sector using the component method. The component method uses average emission factors for components and the average number of components per facility to estimate the average facility emissions. The average facility emissions were then extrapolated to a national estimate using the number of natural gas production facilities.

The study used two approaches to estimate component emissions for the onshore natural gas production, offshore natural gas production, natural gas processing, natural gas transmission and natural gas storage sectors. The first approach involved screening components using a portable hydrocarbon analyzer and using EPA correlation equations (U.S. EPA, 1995) to estimate the leaking emissions. The EPA correlation equations provide an average leak rate per source using the equipment type (e.g., connectors, flanges, open-ended lines, pumps, valves, other), type of material (e.g., gas, heavy oil, light oil, water/light oil), the leak definition used, and the leak fraction determined by the screening. This approach was used to determine component emission factors for some onshore production sources, natural gas processing and the offshore production sector.

The screening of components involved using a portable instrument to detect leaks around, flanges, valves, and other components by traversing the instrument probe over the entire surface of the component. The components were divided into the following categories:

- Valves (gas/vapor, light liquid, heavy liquid)
- Pump Seals (light liquid, heavy liquid)
- Compressor Seals (gas/vapor)
- Pressure Relief Valves (gas/vapor)
- Connectors, which include flanges and threaded unions (all services)
- Open-Ended Lines (all services)
- Sampling Connections (all services)

All components associated with an equipment source or facility were screened using the procedures specified in EPA Method 21. The maximum measured concentration was recorded using a portable instrument that met the specifications and performance criteria in EPA Method 21. In general, an organic vapor analyzer (OVA) that used a flame ionization detector (FID) was used for conducting the screening measurements. A dilution probe was used to extend the upper range of the instrument from 10,000 to 100,000 ppmv.

The second approach used the GRI Hi-Flow^{TM} (trademark of the Gas Research Institute) sampler or a direct flow measurement to replace data measured using the enclosure method. This method was used to determine emission factors for some of the offshore production sources. The sampler has a high flow rate and generates a flow field around the component that captures the entire leak. As the sample stream passes through the instrument, both the flow rate and the total hydrocarbon (THC) concentration are measured. The mass emission rate can then be determined using these measurements. Offshore leak emissions are not covered in this paper; therefore, the estimates derived from this method will not be discussed further.

For onshore natural gas production, the facilities were broken up into two categories; eastern natural gas production and western gas production to account for regional differences in the methane content of the natural gas. The sources of these leak emissions include gas wells, separators, heaters, dehydrators, metering runs and gathering compressors.

A summary of the average equipment emissions, activity factor, and annual methane emissions for the onshore production sector is presented in Table 2-2. These factors have been used in other reports and studies of methane emissions from the oil and gas sector, including the Inventory of U.S. Greenhouse Gas Emissions and Sinks, which will be discussed in more detail in Section 2.1.4.

As shown in the tables, the study estimated that 15,512 million standard cubic feet per year (MMscf/yr) of methane are emitted as leaks from 271,928 onshore natural gas production wells in the U.S. for the 1992 base year. This converts to approximately 292,930 metric tons (MT) of methane emitted to the atmosphere in the base year.

Table 2-2. GRI/EPA National Annual Emission Estimate for Onshore Natural Gas Production in the United States (1992 Base Year)[a]

Equipment	Average Equipment Methane Emissions (scf/yr)	Activity Factor, Equipment Count	Annual Methane Emissions (MMscf)	Annual Methane Emissions (MT)[b]	90% Confidence Interval
Eastern U.S.					
Gas Well	2,595	129,157	335	6,326	27%
Separator	328	91,670	30.1	568	36%
Heater	5,188	260	1.35	25.5	218%
Dehydrator	7,938	1,047	8.31	157	41%
Meters/Piping	3,289	76,262	251	4,740	109%
Gathering Compressors	4,417	129	0.570	10.8	44%
Eastern U.S. Total			626	11,827	46%
Western U.S.					
Gas Well	13,302	142,771	1,899	35,859	25%
Separator	44,536	74,674	3,326	62,805	69%
Heater	21,066	50,740	1,069	20,186	110%
Dehydrator	33,262	36,777	1,223	23,094	32%
Meters/Piping	19,310	301,180	5,816	109,823	109%
Sm Gathering Compressors[c]	87,334	16,915	1,477	27,895	93%
Lg Gathering Compressors[d]	552,000	96	53.0	1,001	136%
Gathering Stations[e]	1,940,487	12	23.3	440	176%
Western U.S. Total			14,886	281,103	45%
Total			15,512	292,930	-

a - Derived from Tables 5-2 and 5-3 (GRI/U.S. EPA, 1996).
b – Annual methane emissions calculated assuming methane density of 41.63 lb/Mscf.
c – Sm. gathering compressor emission factor does not include compressor seal emissions.
d – Lg. gathering compressor emission factor does not include compressor seal or compressor blowdown emissions.
e – Gathering station emission factor does not include site blowdown line emissions.

The national annual methane emissions from natural gas processing were calculated using published statistics from the Oil and Gas Journal. The 1992 data from the journal listed the total number of natural gas processing plants to be 726. The national methane emissions were calculated using this activity factor and the average facility methane emissions for a natural gas processing plant. The plant methane emissions were calculated using average component counts for gas processing equipment (e.g., valves, connectors, open-ended lines, pressure relief valves, blowdown open-ended lines, compressor seals and miscellaneous). For natural gas processing plants, the average emissions from equipment was estimated to be 2.89 MMscf/yr (18.9 MT). The annual methane emissions from the equipment associated with reciprocating compressors and the equipment associated with centrifugal compressors located at natural gas processing plants were estimated to be 0.538 MMscf/yr (10.2 MT) and 0.031 MMscf/yr (0.585 MT), respectively, in 1992. These methane emissions from the gas processing plant and compressors do not include emissions from starter lines, blowdown lines or compressor seals, which are considered to be vented emissions and not leaks for the purposes of this paper. The ratio of reciprocating and centrifugal compressors located at these plants was based on site visit data from 11 natural gas processing plants. The ratio determined from this data was calculated to be 85% reciprocating and 15% centrifugal. Table 2-3 summarizes the national annual methane emissions from natural gas processing plants, which was estimated to be 3,968 MMscf or 74,921 MT.

Table 2-3. GRI/EPA National Annual Emission Estimate for Natural Gas Processing Plants in the United States (1992 Base Year)[a]

Equipment	Average Facility Methane Emissions (MMscf/yr)	Activity Factor, Number of Plants/ Compressors	Annual Methane Emissions (MMscf)	Annual Methane Emissions (MT)[b]	90% Confidence Interval
Gas Processing Plant[c]	2.40	726	1,744	32,925	27%
Reciprocating Compressors[d]	0.538	4,092	2,201	41,571	36%
Centrifugal Compressors[e]	0.031	726	22.5	425	218%
Total			3,968	74,921	46%

a - Derived from Table 5-5 (GRI/U.S. EPA, 1996).
b – Annual methane emissions calculated assuming methane density of 41.63 lb/Mscf.
c – Gas processing plant emission factor does not include site blowdown emissions.
d – Reciprocating compressor emission factor does not include rod packing, blowdown or starter emissions.
e – Centrifugal compressor emission factor does not include compressor seal, blowdown or starter emissions.

The annual methane emission from transmission compressor stations was calculated using activity data based on statistics by the Federal Energy Regulatory Commission (FERC). The data reported to FERC account for 70% of the total transmission pipeline mileage. The split between reciprocating and turbine compressors was estimated using data from the GRI TRANSDAT database. The average methane emissions from compressor station equipment were estimated to be 3.01 MMscf/yr (56.8 MT) in 1992. The annual methane emissions from the equipment associated with reciprocating compressors and the equipment associated with centrifugal compressors located at transmission stations were estimated to 0.552 MMscf/yr (10.4 MT) and 0.018 MMscf/yr (0.34 MT), respectively. Table 2-4 summarizes the national annual methane leak emissions from natural gas transmission stations, which was estimated to be 50,733 MMscf or 957,999 MT. These methane emissions from the compressor station and compressors do not include emissions from starter lines, blowdown lines or compressor seals, which are considered to be vented emissions and not equipment leaks for the purposes of this paper.

Table 2-4. GRI/EPA National Annual Emission Estimate for Natural Gas Transmission Compressor Stations in the United States (1992 Base Year)[a]

Equipment	Average Facility Methane Emissions (MMscf/yr)	Activity Factor, Number of Stations/ Compressors	Annual Methane Emissions (MMscf)	Annual Methane Emissions (MT)[b]	90% Confidence Interval
Compressor Stations[c]	1.94	1,700	3,298	62,276	103%
Reciprocating Compressors[d]	0.552	6,799	3,753	70,869	68%
Centrifugal Compressors[e]	0.018	681	12.3	231	44%
Total			50,733	957,999	52%

a - Derived from Table 5-6 (GRI/U.S. EPA, 1996).
b – Annual methane emissions calculated assuming methane density of 41.63 lb/Mscf.
c – Compressor station emission factor does not include site blowdown emissions.
d – Reciprocating compressor emission factor does not include rod packing, blowdown or starter emissions.
e – Centrifugal compressor emission factor does not include compressor seal, blowdown or starter emissions.

For natural gas storage facilities, the annual methane emissions were calculated using activity data based on published data in Gas Facts. The number of compressors and injection/withdrawal wells located at natural gas storage facilities were estimated using data collected from site visits to eight facilities. The average methane emissions from natural gas storage facilities were estimated to be 6.80 MMscf/yr (128 MT). The annual average methane emissions from an injection/withdrawal well were estimated to be 0.042 MMscf/yr (0.79 MT). The annual methane emissions from equipment for reciprocating and centrifugal compressors were estimated to be 0.47 MMscf/yr (8.9 MT) and 0.017 MMscf/yr (0.32 MT), respectively, in 1992. The national methane emissions from storage facilities were estimated to be 4,644 MMscf or 87,713 MT and are provided in Table 2-5. These methane emissions from the storage facility and compressors do not include emissions from starter lines, blowdown lines or compressor seals, which are considered to be vented emissions and not leaks for the purposes of this paper.

Table 2-5. GRI/EPA National Annual Emission Estimate for Natural Gas Storage Facilities in the United States (1992 Base Year)[a]

Equipment	Average Facility Emissions (MMscf/yr)	Activity Factor, Number of Facilities/ Compressors	Annual Methane Emissions (MMscf)	Annual Methane Emissions (MT)[b]	90% Confidence Interval
Storage Facilities[c]	6.80	475	3,230	61,004	100
Injection/Withdrawal Wells	0.042	17,999	756	14,275	76
Reciprocating Compressors[d]	0.47	1,396	656	12,390	80
Centrifugal Compressors[e]	0.017	136	2.3	43.7	130
Total			4,644	87,713	57

a - Derived from Table 5-7 (GRI/U.S. EPA, 1996).
b – Annual methane emissions calculated assuming methane density of 41.63 lb/Mscf.
c – Storage facility emission factor does not include site blowdown emissions.
d – Reciprocating compressor emission factor does not include rod packing, blowdown or starter emissions.
e – Centrifugal compressor emission factor does not include compressor seal, blowdown or starter emissions.

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

In October 2013, the EPA released the 2012 greenhouse gas (GHG) data for Petroleum and Natural Gas Systems[5] 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.

The GHGRP covers a subset of national emissions, as facilities are required to submit annual reports only if total GHG emissions are 25,000 metric tons carbon dioxide equivalent (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. In some cases, facilities have a choice of using one of the multiple available calculation methods for an emission source provided.

[5] The implementing regulations of the Petroleum and Natural Gas Systems source category of the GHGRP are located at 40 CFR Part 98, subpart W.

Methods for calculating emissions from leaks depend on the industry segment. Facilities in the onshore petroleum and natural gas production segment use population counts and population emission factors for calculating emissions from leaks. Population counts are determined based on either (1) a count of all major equipment (wellheads, separators, meters/piping, compressors, in-line heaters, dehydrators, heater-treaters, and headers) multiplied by average component counts specified in the subpart W regulations, or (2) a count of each component individually for the facility. Emissions are then calculated by multiplying population count by the appropriate population emission factor specified in the subpart W regulations.

Facilities in the onshore gas processing and gas transmission segments use counts of leaking components and leak emission factors for calculating emissions from leaks. The counts of leaking components are identified during an annual leak survey using an optical gas imaging (OGI) instrument, EPA Method 21, infrared (IR) laser beam illuminated instrument, or an acoustic leak detection device. Once the leaking components have been identified and counted, the emissions are calculated by multiplying the count of a specific type of leaking component by the appropriate leak emission factor specified in the subpart W regulations.

For the 2012 reporting year, reported methane emissions from leaks from onshore petroleum and natural gas production were 364,453 MT, onshore natural gas processing were 13,527 MT, and onshore natural gas transmission compression were 15,868 MT.

2.4 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. 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).

The natural gas production system covers all equipment that process or transport natural gas from oil and gas production sites. (All equipment that process or transport hydrocarbon liquids are covered in the oil systems section of the GHG Inventory.) The natural gas production segment is broken into six regions (North East, Midcontinent, Rocky Mountain, South West, West Coast, and Gulf Coast) and includes estimates for gas wells, separation equipment, gathering compressors, gathering pipelines, drilling and well completions, normal operations, condensate tank vents, well workovers, liquids unloading, vessel blowdowns, and process upsets.

For the natural gas production segment, only methane emissions from gas wells, field separation equipment, and gathering compressor systems will be discussed from the GHG Inventory. Leaks from gas wells include emissions from various components, such as connectors and valves, on a wellhead. Field separation equipment includes heaters, separators, dehydrators, meters and piping. Gathering compressor systems include reciprocating compressors, equipment such as scrubbers and coolers associated with the compressors, and the piping. Leaks from field separation equipment and gathering compressor systems include emissions from components in these equipment and systems. The only exception is the gathering compressors source that includes both leak emissions and vented emissions from compressor seals in the GHG Inventory. (Note: Vented emissions from compressors are not defined as leaks in this paper, but are discussed in the white paper on compressors.) The 2014 GHG Inventory (published in 2014; containing emissions data for 1990-2012) calculates potential[6] methane leak emissions from gas wells and field separation equipment using emission factors from the GRI/EPA study (GRI/U.S. EPA, 1996). The emission factors from the GRI/EPA study are split regionally into Eastern and Western factors. These emission factors are adapted in the 2014 GHG Inventory for each of the NEMS regions by adjusting the GRI/EPA emission factors for the NEMS region-specific methane content in produced natural gas. All of the emission factors from the GRI/EPA study assume methane content of 78.8% in the produced natural gas. However, the 2014 GHG

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[6] The calculation of emissions for each source of in the GHG Inventory generally involves first the calculation of potential emissions (methane that would be emitted in the absence of controls), then the compilation of emissions reductions data, and finally the calculation of net emissions by deducting the reductions data from the calculated potential emissions. This approach was developed to ensure an accurate time series that reflects real emission trends. Key data on emissions from many sources are from GRI/U.S. EPA 1996, and since the time of this study practices and technologies have changed. While the study still represents best available data for some emission sources, using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. As updated emission factors reflecting changing practices are not available for most sources, the GRI/U.S. EPA 1996 emission factors continue to be used for many sources for all years of the GHG Inventory, but they are considered to be potential emissions factors, representing what emissions would be if practices and technologies had not changed over time.

Inventory uses regional methane contents obtained from a 2001 study by the Gas Technology Institute (GTI) on unconventional gas and gas composition[7] to adjust the GRI/EPA emission factors to account for the regional methane content differences. The GHG Inventory emissions are then calculated by applying the modified GRI/EPA emission factors to component counts for each year of the GHG Inventory. Because component counts are not available for each year of the GHG Inventory, a set of industry activity data drivers was developed and used to update activity data.[8] The 2014 GHG Inventory, emission factors, and methane emissions are presented by region in Table 2-6. The 2014 GHG Inventory estimated 332,662 MT of potential methane leak emissions from gas wells and field separation equipment from natural gas production activities in 2012.

Table 2-6. 2011 Data and Calculated Methane Potential Leak Emissions for the Natural Gas Production Segment by Region[a]

Region	Activity	Activity Data	Emission Factor	Calculated Potential Emissions (MT)
North East	Associated Gas Wells	38,770	NA	NA
	Non-associated Gas Wells	112,607	7.67 scfd/well	6,071
	Gas Wells with Hydraulic Fracturing	46,367	7.54 scfd/well	2,457
	Heaters	318	15.38 scfd/heater	34
	Separators	112,872	0.97 scfd/separator	771
	Dehydrators	22,164	23.53 scfd dehydrator	3,665
	Meters/Piping	7,910	9.75 scfd/meter	542

[7] GRI-01/0136 GTI's Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases. Second Edition. August, 2001.
[8] For example, recent data on various types of field separation equipment in the production stage (i.e., heaters, separators, and dehydrators) are unavailable. Each of these types of field separation equipment was determined to relate to the number of gas wells. Using the number of each type of field separation equipment estimated by GRI/EPA in 1992, and the number of gas wells in 1992, a factor was developed that is used to estimate the number of each type of field separation equipment throughout the time series. The annual well count data used for these sources were obtained from a production database maintained by DrillingInfo, Inc. (DrillingInfo, 2012).

Region	Activity	Activity Data	Emission Factor	Calculated Potential Emissions (MT)
Midcontinent	Associated Gas Wells	27,470	NA	NA
	Non-associated Gas Wells	77,896	7.45 scfd/well	4,080
	Gas Wells with Hydraulic Fracturing	30,156	8.35 scfd/well	1,771
	Heaters	43,869	14.9 scfd/heater	4,596
	Separators	47,003	0.94 scfd/separator	311
	Dehydrators	15,064	95.54 scfd dehydrator	10,118
	Meters/Piping	143,186	9.45 scfd/meter	9,509
Rocky Mountain	Associated Gas Wells	32,598	NA	NA
	Non-associated Gas Wells	9,665	35.05 scfd/well	2,381
	Gas Wells with Hydraulic Fracturing	73,755	40.72 scfd/well	21,115
	Heaters	38,040	56.73 scfd/heater	15,172
	Separators	41,627	120 scfd/separator	35,099
	Dehydrators	11,630	89.58 scfd dehydrator	7,324
	Meters/Piping	97,399	52.01 scfd/meter	35,609
South West	Associated Gas Wells	155,119	NA	NA
	Non-associated Gas Wells	13,860	37.24 scfd/well	3,628
	Gas Wells with Hydraulic Fracturing	27,627	37.24 scfd/well	7,232
	Heaters	11,243	58.97 scfd/heater	4,661
	Separators	23,316	125 scfd/separator	20,435
	Dehydrators	5,784	93.11 scfd dehydrator	3,786
	Meters/Piping	55,885	54.06 scfd/meter	21,237

Region	Activity	Activity Data	Emission Factor	Calculated Potential Emissions (MT)
West Coast	Associated Gas Wells	29,726	NA	NA
	Non-associated Gas Wells	1,999	42.49 scfd/well	597
	Gas Wells with Hydraulic Fracturing	95	42.49 scfd/well	28
	Heaters	2,094	67.29 scfd/heater	991
	Separators	1,529	142 scfd/separator	1,529
	Dehydrators	292	106 scfd dehydrator	218
	Meters/Piping	3,994	61.68 scfd/meter	1,732
Gulf Coast	Associated Gas Wells	39,709	NA	NA
	Non-associated Gas Wells	27,024	7.96 scfd/well	1,512
	Gas Wells with Hydraulic Fracturing	49,862	7.96 scfd/well	2,789
	Heaters	17,222	64.60 scfd/heater	7,821
	Separators	50,591	136.57 scfd/separator	48,571
	Dehydrators	10,719	102.00 scfd dehydrator	7,686
	Meters/Piping	90,288	59.21 scfd/meter	37,584

[a] Derived from ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories (U.S. EPA, 2014).

The gas processing and gas transmission segments are not broken into regions like the gas production segment in the 2014 GHG Inventory. Instead, these segments provide national level emission estimates for their individual emission sources. For both segments, leak emissions include emissions from all components in the gas plants and on compression systems. The transmission segment leaks include leaks from transmission pipelines. The 2014 GHG Inventory calculates potential methane emissions from these sources using emission factors from the GRI/EPA study (GRI/U.S. EPA, 1996) and a 2010 ICF International (ICF) memo to the EPA on centrifugal compressors (ICF, 2010). The GHG Inventory emissions are calculated by applying the emission factors to activity counts (in this case, gas plants, compressor station counts, compressor counts, and pipeline miles) for each year of the inventory. Because some component counts are not available for each year of the GHG Inventory, a set of industry activity data drivers was developed and used to update activity data.[9] The 2014 GHG Inventory gas processing and gas transmission sources, emission factors, and methane emissions are presented in Table 2-7. For 2012, the 2014 GHG Inventory estimated 33,681 MT of potential methane emissions from gas processing leak emissions and 114,348 MT of potential methane emissions from gas transmission leak emissions.

Table 2-7. 2011 Data and Calculated Methane Potential Leak Emissions for the Natural Gas Processing and Natural Gas Transmissions Segments[a]

Segment	Activity	Activity Data	Emission Factor	Calculated Potential Emissions (MT)
Gas Processing	Plants	606	7,906 scfd/plant	33,681
Gas Transmission	Pipeline Leaks	303,126	1.55 scfd/mile	3,311
	Station	1,799	8,778 scfd/station	111,037

[a] Derived from ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories, pg. A-177 (U.S. EPA, 2014).

For 2012, the 2014 GHG Inventory data estimates that potential emissions from leaks in production, processing and transmission are approximately 480,691 million MT of methane or about 8% of overall potential methane emissions from oil and gas.

2.5 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. This study used direct

[9] For example, individual compressor counts and compressor station counts are not available. Instead, these are obtained using a ratio of compressors to gas plants (for processing) and ratios of stations to pipeline miles and compressors to pipeline miles (for transmission) in the base year 1992. The 1992 ratios are then multiplied by the activity drivers, i.e., gas plant count or miles of pipeline, in the current year to estimate activity in current year.

measurements of methane emissions at 190 onshore natural gas sites in the U.S. (150 production sites, 27 well completion flowbacks, 9 well unloadings, and 4 workovers). The study covered the natural gas production segment.

For leak emissions, the study collected emissions data from 150 sites, 146 sites with wells and 4 sites with separators and other equipment on site. Leak emissions data from piping, valves, separators, wellheads, and connectors are provided in Table 2-8. The first step used to identify leaks from natural gas production sites was to scan the site using an OGI camera. The threshold for detection of a leak with the camera was 30 g/hr (Allen et al., 2013). After leaks were identified by the camera, the flow rate and the concentration of the leaks were measured using a Hi-Flow Sampler™ and the mass emission rate calculated. The instrument was calibrated using samples consisting of pure methane in ambient air. To account for the effect of ethane, propane, butane and higher alkanes on the leak measurements, gas composition data were collected for each natural gas production site that was visited. Based on the gas composition, the percentage of carbon accounted for by methane in the sample stream was determined. This percentage, multiplied by the total gas flow rate reported by the instrument, was the methane flow.

Table 2-8. Summary of Emissions from Leaks

	Emissions Per Well[a]				
	Appalachian	**Gulf Coast**	**Midcontinent**	**Rocky Mountain**	**All Facilities**
Number of Sites with Wells Visited (number of wells with leaks detected)	47 (30)	54 (31)	26 (19)	19 (17)	146 (97)
Methane Emission Rate (scf/min/well)	0.098 ± 0.059	0.052 ± 0.030	0.046 ± 0.024	0.035 ± 0.026	0.064 ± 0.023
Whole Gas Emissions Rate (based on site specific gas composition) (scf/min/well)	0.100 ± 0.060	0.058 ± 0.033	0.055 ± 0.034	0.047 ± 0.034	0.070 ± 0.024

[a] All leaks detected with the OGI camera, and does not include emissions from pneumatic pumps and controllers.

The study authors concluded the average values of leak emissions per well reported in Table 2-8 are comparable to the average values of potential emissions per well for gas wells, separators, heaters, piping and dehydrator leaks (0.072 scf methane/min/well) from the 2013 GHG Inventory, calculated by dividing the potential emissions in these categories in the 2013 GHG Inventory by the number of wells (Allen et al., 2013).

2.6 City of Fort Worth Natural Gas Air Quality Study (ERG, 2011)

The city of Fort Worth solicited a study that reviewed air quality issues associated with natural gas exploration and production. The goals of the study were to answer the following four questions:

- How much air pollution is being released by natural gas exploration in Fort Worth?
- Do sites comply with environmental regulations?
- How do releases from these sites affect off-site air pollution levels?
- Are the city's required setbacks for these sites adequate to protect public health?

To answer these questions, the study collected ambient air monitoring and direct leak and vented emissions measurements and performed air dispersion modeling. The study collected data from 375 well pads, 8 compressor stations, a gas processing plant, a saltwater treatment facility, a drilling operation, a hydraulic fracturing operation, and a completion operation. The point source test data was collected using an OGI camera, a toxic vapor analyzer (TVA), a Hi-Flow Sampler™ and stainless steel canisters. Each site was surveyed with an OGI camera and, if a leak was observed by the camera, the concentration of the leak was measured using the TVA. In addition, 10% of the total valves and connectors and the other components were surveyed using the TVA to determine leaks at or above 500 ppmv. The emission rates of the leaks identified by the OGI camera and the TVA survey were determined using a Hi-Flow Sampler™ to measure the volumetric flow rate of the leak. Gas samples from selected leaks were collected in stainless steel canisters for VOC and HAP analysis by a gas chromatograph/mass spectrometer (GC/MS).

Based on the results of the point source leak survey, the study estimated the total organic emissions to be 20,818 tons per year or 18,819 megagrams per year (Mg/yr), with well pads accounting for more than 75% of the total emissions. Hydrocarbons with low toxicities (methane, ethane, propane, and butane) accounted for approximately 98% of the emissions from this study. A summary of the average and maximum emissions from each of the site types is provided in Table 2-9. Table 2-10 provides a summary of the measured emissions by equipment type (e.g., connector, valve, other). Valves include manual valves, automatic actuation valves, and pressure relief valves. Connectors include flanges, threaded unions, tees, plugs, caps and open-ended lines where the plug or cap was missing. The category "Other" consists of all remaining components such as tank thief hatches, pneumatic valve controllers, instrumentation, regulators, gauges, and vents.

Table 2-9. Average and Maximum Point Source Emission Rates by Site Type[a]

Site Type	TOC (tons/yr)		VOC (Tons/yr)	
	Average	**Maximum**	**Average**	**Maximum**
Well Pad	16	445	0.07	8.6
Well Pad with Compressor(s)	68	4,433	2	22
Compressor Station	99	276	17	43
Processing Facility	1,293	1,293	80	80

a - Derived from Table 3.5-1 (ERG, 2011).

Table 2-10. Average and Maximum Point Source Emission Rates by Equipment Type[a]

Equipment Type	Methane (lb/yr)		VOC (lb/yr)	
	Average	Maximum	Average	Maximum
Connectors	8,918	169,626	27.6	171
Other	20,914	497,430	142	4,161
Valves	27,585	570,083	29.7	123

a - Derived from Emissions Calculation Workbook spreadsheet.

Some general observations of the well pad data provided in the Fort Worth report are:

- At least one leak was detected at 283 out of the 375 well pads monitored with an OGI technology with an average of 3.2 leaks detected per well pad;
- The TVA detected at least one leak greater than 500 ppm at 270 of the 375 well pads that were monitored with an average of 2.0 leaks detected per well pad;
- The number of wells located on well pads ranged from 0 to 13 with the average number of wells being 2.98 with a 99% confidence level of 0.31;
- The average number of components at each well site was 212 valves, 1596 connectors, 3 storage tanks, and 0.4 compressors;
- 124 out of the 375 well pads had at least one compressor onsite;
- There were 17 different owners of the 375 well sites in the Fort Worth area with the average number of well sites per owner being 22;
- Of the 1,330 leaks that were detected using either OGI technology or the TVA, 200 (15%) were classified as connector type leaks, 90 (7%) were classified as valve type leaks, and 1,040 (78%) were classified as other type leaks.
- Of these 1,330 leaks that were detected using OGI technology or the TVA, 1,018 (77%) were classified as non-tank leaks and the remaining 312 (23%) were classified as tank leaks.

2.7 Measurements of Well Pad Emissions in Greeley, CO (Modrak, 2012)

An onsite direct measurement study of emissions from 23 well pads in areas near

Greeley, CO (Weld County) was performed over a one-week period in July 2011. This study used the same source testing contractor and non-invasive leak detection and measurement procedures (OGI and Hi-Flow Sampler™) as in the City of Fort Worth Natural Gas Air Quality Study (ERG, 2011). Other than the number of production pads investigated (375 vs. 23), there were three major differences in the studies.

- The City of Forth Worth Air Quality Study was conducted in a predominately dry gas area of the Barnett shale whereas the Greeley study was conducted in an area with much higher relative condensate/oil production rates (wet gas). A typical leak or vented emission in a dry gas area is likely to have a higher methane to VOC ratio compared to an emission in a wet gas area.
- The State of Colorado requires emissions from condensate/oil tanks to be collected and controlled (e.g. routed to an enclosed combustors). In the City of Forth Worth Air Quality Study, most storage tanks contained produced water and were not controlled.
- The City of Fort Worth Air Quality Study used the EPA Compendium Method TO-15 and ASTM 1945 (for methane) for source canister analysis, whereas the Greeley study used the Ozone Precursor method (EPA/600-R-98/161) coupled with ASTM 1946/D1945 analysis of methane, ethane and propane. The canister analysis set used in the Greeley study had significantly more overlap for oil and gas product-related compounds (i.e. ethane, propane, other alkanes), whereas the TO-15 method provided more coverage for HAP compounds.

The objectives of the limited scope Greeley well pad study were to improve understanding of methane and speciated VOC emissions and investigate the use of commercially available non-invasive measurement approaches for application to wet gas production operations (including tank emissions).

The average production pad in the Greeley study consisted of 5 wells, 258 valves, 2,583 connectors, 3 condensate tanks, 1 produced water tank, 4 thief hatches, 5 pressure relief devices, 3 separators and 1 enclosed combustor control device. A total of 93 emission points were found with OGI technology at the 23 production sites and the emission rates were measured using a high volume sampler with a subset of 33 additionally sampled using evacuated canisters. A disproportionate number of detected emissions were found to be associated with storage tanks (72%). For the purposes of this white paper, a tank-related air emission is considered a leak if it exceeds the state or local emission limits. The study authors concluded condensate tank-related emissions observed in the Greeley study were not effectively collected and controlled. However, due to single point and instantaneous nature of the measurements, it is not known if these uncollected emissions exceed the state allowance.

Considering only emissions measurements with canister analysis, the average methane emissions from all storage tanks, excluding samples of known flash emissions, were much lower in the Greeley study compared to the City of Fort Worth Air Quality Study, 0.77 tons/year (n=21) and 21.9 tons/year (n=54), respectively. In contrast, the average VOC tank related emissions were much higher in the Greeley study compared to the City of Fort Worth Air Quality Study, 5.38 tons/year and 0.48 tons/year, respectively. Non-tank emissions followed similar trends: emissions of methane were higher in the City of Fort Worth Air Quality Study (7.73 tons/year (n=92) and 1.01 tons/year in the Greeley study (n=5)), while VOC emissions were higher in the Greeley study (0.46 tons/year in the Greeley study and 0.02 tons/year in the City of Fort Worth Air Quality Study). The authors noted that these emission estimates are based on instantaneous measurements. Because tank-related emissions vary diurnally and by season and may contain a residual flash emissions component, the extrapolation to yearly values (i.e., tons/year) is for informational purposes only and should not be used for comparison to permit or control limits. A journal article with additional analysis of these studies is in preparation (Modrak, 2012; Brantley et al., 2014a).

2.8 Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (CL, 2013)

The study presented a summary of 4,293 surveys from two private sector firms that provide gas emission detection and measurement services to oil and gas facilities in the U.S. and Canada. These surveys only covered certain regions of the U.S. and Canada. The surveys included three categories of facilities: gas processing plants (614 surveys), compressor stations (1,915 surveys; includes both gas transmission and gas gathering systems), and well sites (1,764 surveys; includes single well heads and sites with up to 15 well heads). The surveys were conducted using OGI technology to locate leaking components and the leak rates were measured using a high-volume sampler. In some cases, where the facility owners did not need a precise volume measurement or where the leaking component was difficult to access for measurement, an estimate (evaluated visually using OGI technology based on the extensive experience of the operators) was used to make the decision to repair.

The study found that of the 58,421 components that were identified in the surveys, 39,505 (68%) were either leaking or venting gas. A summary of the leak rates for each of the categories is provided in Table 2-11. As the table shows, the study found that gas processing plants had the highest leak rate, followed by compressor stations and then well sites. The study noted that vents are the most common source of gas emissions from the identified emission sources, and about 40% of the vent emissions come from instrument controllers and compressor rod packing. Other vent sources come from production/storage tanks, lube oil vents, compressors, pumps, and engines. (Note: vented emissions are not considered leaks for the purposes of this paper).

Table 2-11. Distribution of Facilities Within Each Category by Leak Rate (in Mcf of gas per facility per year)[a]

Category	No leaks	≤ 99	100-499	500-1499	≥ 1500
Gas processing plants	3%	17%	32%	25%	23%
Compressor stations	11%	30%	36%	15%	9%
Well sites & well batteries	36%	38%	18%	5%	2%

a - Derived from Table 3 (CL, 2013).

The study results show that, for the facilities in the study, gas processing plants are the most likely to have leaks and the most likely to have large leaks, followed by compressor stations, and, lastly, well sites.

2.9 Mobile Measurement Studies in Colorado, Texas, and Wyoming (Thoma, 2012)

As will be described in detail in Section 3.4, emerging mobile measurement technologies are providing new capability for detection and measurement of emissions from upstream oil and gas production and other sectors. The EPA developed and applied one such mobile inspection technique as part of its Geospatial Measurement of Air Pollution (GMAP) program. (Thoma, 2012; Brantley et al., 2014b). Designed to be a rapidly-deployed inspection approach that can cover large areas, OTM 33A can locate unknown emissions (e.g., pipeline leaks or malfunctions) and can provide an emission rate assessment for upstream oil and gas sources, such as well pads located in relatively open areas. With measurements executed from stand-off observation distances of 20 m to 200 m, the mobile approach is not as accurate as onsite direct measurements but can provide source strength assessments with an accuracy of +/- 30% under favorable conditions with repeat measurements. OTM 33A relies on statistically representative downwind plume sampling, relatively obstruction-free line of sight observation, and a knowledge of the distance to the source (Thoma, 2012; Brantley et al., 2014b).

The EPA used OTM 33A to conduct several survey field campaigns in Weld County, CO in July 2010 and July 2011; areas near Fort Worth, TX (Wise, Parker, Tarrant, and Denton Counties) in September 2010 and 2011; in Sublette County, WY in June 2011, July 2012 and June 2013; and in the Eagle Ford, TX area (Maverick, Dimmit, La Salle, Webb, and Duval Counties) in September 2011. A total of 84 methane emission assessments were conducted in the Fort Worth area, 216 in WY, 93 in CO, and 22 in the Eagle Ford with offsite canister acquisition. Additionally, VOC emission estimates were executed at approximately 46% of these measurements. A subset of these field studies are described in (Thoma, 2012) with an expanded discussion, and slight revision of results to be published in (Brantley et al., 2014b). These data are primarily from well pads and represent an integration of all emissions (leak and vented) on the site. (Note: Vented emissions are not defined as “leaks” in this paper, therefore, the emission rates presented below include emissions that are not considered leaks in this paper). The study authors note, as with all instantaneous measurement approaches, the OTM 33A assessment may capture emissions that are short-term in nature (i.e., flash emissions) so extrapolation to annual emissions is difficult.

The preliminary results from the study (Thoma, 2012) show median methane emission rates of 0.21 grams per second (g/s), 0.43 g/s and 0.79 g/s and VOC emission rates of 0.16 g/s, 0.04 g/s and 0.30 g/s for the CO, TX, and WY studies, respectively (excluding Eagle Ford).

The study authors note that using improved analysis procedures, the above median rates will likely be revised slightly lower in a future publication. Offsite OGI was used in many cases to positively identify the origin of emissions. The study authors concluded that many of the high emission values were attributed to maintenance-related issues such as open thief hatches, failed pressure relief valves, or stuck dump valves. The difference in VOC emissions between the TX studies and the CO and WY studies is a result of the natural gas from the TX well sites being a dry natural gas. Additional analysis of the emission measurements including comparisons to natural gas, condensate/oil, and produced water production will be contained in a forthcoming article (Brantley et al., 2014b).

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

The Environmental Defense Fund (EDF) commissioned 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. Well site leaks (includes heaters, separators, dehydrators and meters/piping) and pipeline leaks are two of the 22 emission sources that are included in the study.

The study relied on the 2013 GHG Inventory for methane emissions data for the oil and natural gas sector. The emissions data were revised to include updated information from the GHGRP (U.S. EPA, 2013) 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. One of the major differences in the revised 2011 baseline methane emissions estimate developed by ICF is the inclusion of a separate category for gathering and boosting operations. The 2013 GHG Inventory includes gathering and boosting operations in the onshore production segment and is based on the GRI/EPA measurement study (GRI/U.S. EPA, 1996).

The 2011 baseline methane inventory developed by ICF used the wellhead emission factor developed from the University of Texas study (Allen et al., 2013) to estimate leak emissions from well sites, which was reported as 97.6 scf/day. This emissions factor was applied to the natural gas well counts obtained from World Oil magazine to estimate the total methane leak emissions from well sites. These changes resulted in an estimated14 billion cubic feet (264,000 MT) of methane emissions from wellheads in comparison.

Leak emissions from heater, separators, dehydrators, and meters/piping in the natural gas production sector were calculated using the GRI/EPA emissions factors for each of these emission sources. The study estimated methane emissions were 15 billion cubic feet (283,000 MT) from these sources.

Natural gas processing plant leak emission were determined by ICF using data from the GHGRP (U.S. EPA, 2013) and a list of processing plants maintained by the EIA. The study by ICF determined that there are 909 gas processing and treatment facilities in the U.S. The study estimated methane emissions from processing facilities to be 3 billion cubic feet (56,600 MT).

The study did not provide specific equipment leak information for the natural gas transmission and storage sectors. However, the report did provide information on pipeline leaks from transmission of natural gas. The report estimated methane emissions of 0.2 billion cubic feet (3,800 MT).

The estimate of total national emissions from leaks in the natural gas production, processing, transmission and storage segments for 2011was 604,000 MT of methane.

2.11 Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants (Clearstone, 2002)

This study, referred to as "Clearstone I,"[10] presented the results of the implementation of a comprehensive directed inspection and maintenance (DI&M) program at four gas processing

[10] "Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants." Prepared for GTI and the U.S. EPA under grant 827754-01-0, by Clearstone Engineering. June 20, 2002. Also, note that a follow-up study, referred to as Clearstone II, was released in 2006, which studied five processing plants, one being a repeat from the plants studied in Clearstone I.

plants in the western U.S. in 2000. The work done during this study involved a survey of all gas service equipment components, as well as the measurement or engineering calculation of gas flows into the vent and flare systems. This study did not focus on hydrocarbon liquid services. In total, 101,193 individual gas service components were screened, along with 5 process vents, 28 engines, 7 process heaters, and 6 flare/vent systems.

The leak survey was conducted using bubble tests with soap solution, portable hydrocarbon gas detectors, and ultrasonic leak detectors. A screening value of 10,000 ppm or greater was used as the leak definition. The majority of components were screened using soap solution, but if a component was determined to be emitting gas, a hydrocarbon gas analyzer was used to determine if the component would be classified as a leaker per the above definition. Most leak rates were measured using a Hi-Flow™ Sampler, unless the leak was above the upper limit of the unit's design (14 m^3/hour). If the Hi-Flow™ Sampler could not be used, bagging or other direct measurement techniques were used, as appropriate.

From the survey, approximately 2,630 of the 101,193 screened components (2.6%) were determined to be leaking. The study states that "components in vibrational, high-use or heat-cycle gas service were the most leak prone." The majority of the leaks were attributed to a relatively small number of leaking components. Table 2-12 presents the breakdown of leak emissions by component type.

Table 2-12. Distribution of Natural Gas Emissions from Leaking Component Types

Component Type	Percent of Leak Emissions
Valves	30.0%
Connectors	24.4%
Compressor Seals[a]	23.4%
Open-Ended Lines	11.1%
Crankcase Vents (on Compressors)	4.2%
Pressure Relief Valves	3.5%
Other (Pump Seals, Meters, Regulators)	3.4%

[a] For the purposes of this paper, compressor seal emissions are not considered leaks.

The study also provided an analysis of the payback periods for fixing the identified leaks. That analysis is discussed in Section 3.2 of this paper.

2.12 Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites (Clearstone, 2006)

This study, referred to as "Clearstone II,"[11] presented the results of a comprehensive emissions measurement program at 5 gas processing plants, 12 well sites, and 7 gathering stations in the U.S. in 2004 and 2005. This work was done as follow up on a study done in 2000, referred to as Clearstone I, in which four gas processing plants were surveyed. (Note: one of the gas processing plants surveyed in the Clearstone I study was also surveyed in the Clearstone II study.) The work done involved a survey of all gas service equipment components at these 24 sites. The goal was to identify cost-effective opportunities for reducing natural gas losses and process inefficiencies. In total, 74,438 individual components were screened.

The leak survey was conducted using bubble tests with soap solution, portable hydrocarbon gas detectors, and ultrasonic leak detectors. A screening value of 10,000 ppm or greater was used as the leak definition. The majority of components were screened using soap solution, but if a component was determined to be emitting gas, a hydrocarbon gas analyzer was used to determine if the component would be classified as a leaker per the above definition. Most leak rates were measured using a Hi-Flow™ Sampler, unless the leak was above the upper limit of the unit's design (14 m^3/hour). For consistency, both the Clearstone I and Clearstone II surveys used the same Hi-Flow™ Sampler. If the Hi-Flow™ Sampler could not be used, bagging or other direct measurement techniques were used, as appropriate.

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[11] "Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites." Prepared for the U.S. EPA under grant XA-83046001-1, by National Gas Machinery Laboratory, Clearstone Engineering, and Innovative Environmental Solutions, Inc. March 2006. Note: This study, referred to as "Clearstone II", was a follow up to a study released in 2002, referred to as "Clearstone I," which surveyed four processing plants, one of which was resurveyed in Clearstone II.

Secondarily to the above leak detection methodology, for all five surveys of gas processing plants in the study, OGI cameras were also used in order to compare the performance of the OGI cameras with conventional leak detection methods. Although no quantitative comparison was done, the study concluded that the cameras are able to screen components about three times as quickly as the other methods, find leaks that are inaccessible to the other methods, and allow for rapid leak source identification.

From the survey, approximately 1,629 of the 74,438 screened components (2.2%) were determined to be leaking. The study states, similarly to Clearstone I, that “components in vibrational, high-use, and heat-cycle gas service were the most leak prone.” Further, the majority of the leak emissions could be attributed to a relatively small number of the leaking components. Table 2-13 presents the breakdown of natural gas leak emissions by component type.

Table 2-13. Distribution of Natural Gas Emissions from Leaking Component Types

Component Type	Percent of Leak Emissions
Open-Ended Lines	32%
Connectors	30%
Compressor Seals	20%
Block Valves	15%
Other (PRVs, Meters, Regulators, etc.)	3%

The study also provides a comparison for the one gas plant that was surveyed in both studies. This plant was resurveyed in order to investigate changes in its leak characteristics. It was noted that about 30% of the equipment components in the plant had been decommissioned between the surveys due to the replacement of old process units with newer ones. Generally, the replacement process units and equipment components had substantially reduced emission rates compared to the decommissioned units. The overall reduction for the new units was an 80% decrease in total hydrocarbon (THC) emissions compared to the old units. However, the THC emissions for the plant as a whole increased about 50% between the two surveys. The study gives several possible reasons for this, including the fact that the five-year timeframe between surveys exceeded the mean repair life for most of the components. The study also states that there may have been inadequate follow-up to maintenance recommendations provided during the first survey, as the documentation of repairs indicated it was “unclear what maintenance activities were undertaken in response to the Phase I survey.”

3.0 AVAILABLE EMISSIONS MITIGATION TECHNIQUES

There are a number of technologies available that can be used to identify leaks and a number of approaches to repairing those leaks. The technologies for identifying leaks and the approaches to repairing leaks are discussed in separate sections below.

3.1 Leak Detection

A variety of approaches are used for leak detection. For many regulations with leak detection provisions, the primary method for monitoring to detect leaking components is EPA Reference Method 21 (40 CFR Part 60, Appendix A). Method 21 is a procedure used to detect VOC leaks from process equipment using an analyzer, such as a TVA or an OVA. In addition, other monitoring tools such as OGI cameras, soap solution, acoustic leak detection, ambient monitors and electronic screening devices can be used to monitor process components. A summary of these technologies is presented below.

3.1.1 Portable Analyzers

Description

A portable monitoring instrument is used to detect hydrocarbon leaks from individual pieces of equipment. These instruments are intended to locate and classify leaks based on the leak definition of the equipment as specified in a specific regulation, and are not used as a direct measure of mass emission rate from individual sources. The instruments provide a reading of the concentration of the leak in either ppm, parts per billion (ppb), or percent concentration. For portable analyzers, EPA Reference Method 21 requires the analyzer to respond to the compounds being processed, be capable of measuring the leak definition concentration specified in the regulation, be readable to ±2.5% of the specified leak definition concentration and be equipped with an electrically driven pump to ensure that a sample is provided to the detector at a constant flow rate.

The portable analyzers can be used to estimate the mass emissions leak rate by converting the screening concentration in ppm to a mass emissions rate by using the EPA correlation equations from the Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995). The correlation equations in the Protocol can be used to estimate emissions rates for the entire range of screening concentrations, from the detection limit of the instrument to the "pegged" screening concentration, which represents the upper limit of the portable analyzers (U.S. EPA, 2003a).

The portable analyzers must be calibrated using a reference gas containing a known compound at a known concentration. Methane in air is a frequently used reference compound. The calibration process also determines a response factor for the instrument, which is used to correct the observed screening concentration to match the actual concentration of the leaking compound. For example, a response factor of "one" means that the screening concentration read by the portable analyzer equals the actual concentration at the leak (U.S. EPA, 2003a). Screening concentrations detected for individual components are corrected using the response factor (if necessary) and are entered into the EPA correlation equations to extrapolate a leak rate measurement for the component (U.S. EPA, 2003a).

Applications

The portable monitoring instruments operate on a variety of detection principles, with the three most common being ionization, IR absorption and combustion (U.S. EPA, 1995). The ionization detectors operate by ionizing the sample and then measuring the charge (i.e., number of ions) produced. Two methods of ionization currently used are flame ionization and photoionization. A standard flame ionization detector (FID) measures the total carbon content of the organic vapor sampled. Certain portable FID instruments are equipped with gas chromatograph (GC) options making them capable of measuring total gaseous non-methane organics or individual organic components (U.S. EPA, 1995). The photoionization detector (PID) uses ultraviolet light (instead of a flame) to ionize organic vapors. As with FIDs, the detector response varies with the functional group in the organic compounds. Photoionization detectors have been used to detect leaks in process units in the Synthetic Organic Chemical Manufacturing Industry (SOCMI), especially for certain compounds, such as formaldehyde, aldehydes, and other oxygenated compounds, which may not give a satisfactory response on a FID or combustion-type detector (U.S. EPA, 1995).

Nondispersive infrared (NDIR) instruments operate on the principle of light absorption characteristics of certain gases. These instruments are usually subject to interference because other gases, such as water vapor and CO_2, may also absorb light at the same wavelength as the compound of interest (U.S. EPA, 1995). These detectors are generally used only for the detection and measurement of single components. For this type of detection, the wavelength at which a certain compound absorbs IR radiation is predetermined and the device is preset for that specific wavelength through the use of optical filters (U.S. EPA, 1995).

Combustion analyzers are designed either to measure the thermal conductivity of a gas or to measure the heat produced by combustion of the gas. The most common method in which portable VOC detection devices are used involves the measurement of the heat of combustion. These detection devices are referred to as hot wire detectors or catalytic oxidizers. Combustion analyzers, like most other detectors, are nonspecific for gas mixtures (U.S. EPA, 1995). In addition, combustion analyzers exhibit reduced response (and, in some cases, no response) to gases that are not readily combusted, such as formaldehyde and carbon tetrachloride (U.S. EPA, 1995).

The typical types of portable analyzers used for detecting leaks from components are OVAs and TVAs. An OVA is an FID, which measures the concentration of organic vapors over a range of 9 to 10,000 ppm (U.S. EPA, 2003a). A TVA combines both a FID and a PID and can measure organic vapors at concentrations exceeding 10,000 ppm. Toxic vapor analyzers and OVAs measure the concentration of methane in the area around a leak (U.S. EPA, 2003a).

Screening is accomplished by placing a probe inlet at an opening where leakage can occur. Concentration measurements are observed as the probe is slowly moved along the interface or opening, until a maximum concentration reading is obtained. The maximum concentration is recorded as the leak screening value. Screening with TVAs and OVAs can be a slow process, requiring approximately one hour for every 40 components, and the instruments require frequent calibration.

Costs

The costs of the portable analyzers vary based on the type of analyzer used to measure leak concentrations. The documentation for the EPA National Uniform Emission Standards for Equipment Leaks (40 CFR part 65, subpart J) provides a cost of $10,800 for a portable monitoring analyzer (RTI, 2011). Additional costs would also include labor costs associated with performing the screening and would depend on the number of components screened.

3.1.2 Optical Gas Imaging (IR Camera)

Description

Optical gas imaging (OGI) is a technology that operates much like a consumer video-camcorder and provides a real-time visual image of gas emissions or leaks to the atmosphere. The OGI camera works by using spectral wavelength filtering and an array of IR detectors to visualize the IR absorption of hydrocarbons and other gaseous compounds. As the gas absorbs radiant energy at the same waveband that the filter transmits to the detector, the gas and motion of the gas is imaged. The OGI instrument can be used for monitoring a large array of equipment and components at a facility, and is an effective means of detecting leaks when the technology is used appropriately. The EPA has worked extensively with OGI technology and is in the process of further evaluating its capabilities. Information presented below, unless otherwise cited, is based on that evaluation work.

Applications

The detection capability of the OGI camera is based on a variety of factors such as detector capability, gas characteristics of the leak, optical depth of the plume and temperature differential between the gas and background. The EPA is currently studying OGI technology in order to determine its capabilities and limitations.

The OGI system provides a technology that can potentially reduce the time, labor and costs of monitoring components. The capital cost of purchasing an OGI system is estimated to be $85,000 (Meister, 2009). The ICF economic analysis estimated the capital cost of the OGI system to be $124,000 (ICF International, 2014). The EPA estimated that the OGI can monitor 1,875 pieces of equipment per hour at a petroleum refinery (RTI, 2012). This study assumes for every hour of video footage, the operator would spend an additional 1.4 hours conducting activities for calibration, OGI adjustments, tagging leaks and other activities. Another estimate, (ICF Consulting, 2003) stated that OGI can monitor 35 components per minute (2,100 components per hour). In comparison, the average screening rate using a handheld TVA or OVA is roughly 700 components per day (ICF Consulting, 2003). However, the EPA's recent work with OGI systems suggests these studies underestimate the amount of time necessary to thoroughly monitor components for leaks using OGI technology. Additionally, the number of pieces of equipment that could be monitored per hour at an upstream oil and gas facility would likely be less than at a refinery given that equipment tends to be farther apart at these facilities than at a refinery.

By increasing the number of pieces of equipment that can be viewed per hour, the OGI system could potentially reduce the cost of identifying leaks in upstream oil and gas facilities when compared to using a handheld TVA or OVA. A recent study (CL, 2013) analyzed 4,293 leak detection surveys completed for the oil and gas industry using OGI systems. These surveys were completed by external contractors hired by the owner or operator of the oil and gas facility. This study estimated the average abatement cost to be approximately $0 per ton of VOC and approximately -$375 per ton of VOC for well sites and compressor stations, respectively. These estimates assume all leaks that are found are repaired and the recovered methane can be sold for $4/Mcf. The average costs of performing the OGI surveys in the study are $2,300 for a compressor station, $1,200 for multi-well batteries, $600 for single well batteries and $400 for well sites (CL, 2013). (Note: Only a prepublication draft was available of this report when the EPA was completing this white paper.)

Another advantage of OGI for detecting leaks is finding leaks not directly related to components while in the process of surveying the overall site. Leaks such as degradation in the exterior of tanks or leaks in lines buried underground would be seen with OGI but very hard to locate with a handheld TVA or OVA.

For the application of this technology to this sector, the gas characteristics are well suited for the typical OGI camera technology because the leaks tend to be almost all methane, alkane or aromatics. Methane, alkanes and aromatics are all detectable due to having carbon-hydrogen bonds.

OGI Operational Considerations

While the operator or inspector using OGI technology can see leaking emissions from equipment, quantifying the emissions is difficult. To quantify emissions with an OGI camera, extensive metadata, such as apparent background temperature, gas leak temperature, leak size and wind speed must also be taken. These parameters would then be used with a developed and evaluated algorithm to quantify emissions. The EPA is not aware of the existence or evaluation of such an algorithm at this time. However, in addition to algorithms, operators can use quantification equipment such as a Hi-Flow™ Sampler.

The OGI system is also sensitive to the ambient conditions around the equipment that is being inspected. The larger the temperature differential between the leaking gas and the contrasting background (e.g., sky, ground or equipment), the easier the leaking gas is to see. The apparent temperature of the sky, a commonly used background, is also highly dependent on weather conditions such as cloud cover, ambient temperature and relative humidity. Additionally, high or variable wind conditions can reduce the optical depth and make it difficult for gas leaks to be identified, because the gas plume is quickly carried away from the source of the leak. Both these characteristics could result in operators being unable to identify leaks if the ambient conditions are not optimal.

Lastly, the effectiveness of an OGI instrument is dependent on the training and expertise of the operator. Well-trained and experienced operators are able to detect leaks with the OGI system that lesser experienced operators do not detect.

Current OGI Usage in the Oil and Gas Industry

The EPA is not aware of any studies that estimate the extent of the usage of OGI systems in the oil and natural gas production sector. However, certain proposed and existing regulations allow OGI systems as an option for fulfilling leak detection requirements, and some companies are using the technology voluntarily such as through the Natural Gas STAR program. Additionally, the GHGRP subpart W allows for the use of OGI technology in some circumstances and the Alternative Work Practice regulation (40 CFR Part 60, subpart A) allow the use of OGI technology along with an annual Method 21 survey as an alternative to a traditional leak detection and repair (LDAR) program using Method 21.

The State of Colorado recently proposed regulations that would require leak inspections at all well sites, compressor stations upstream of the processing plant and storage vessels. These proposed regulations allow OGI inspections, Method 21 or other "[d]ivision approved instrument based monitoring device or method" to detect leaks (CO Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, Proposed November 18, 2013).

The State of Wyoming, as part of its permitting guidance, requires facilities with emissions greater than 4 tpy of VOCs in the Upper Green River Basin, the Jonah-Pinedale Anticline Development Area and Normally Pressured Lance to conduct quarterly leak emissions inspections, and OGI inspections are allowed in addition to Method 21 inspections or audio-visual-olfactory inspections (Wyoming Department of Environmental Quality, Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance, September 2013).

The Alberta Energy Regulator requires that a "licensee of a facility must develop and implement a program to detect and repair leaks." These programs must "meet or exceed" the Canadian Association of Petroleum Producer's (CAPP) best management practice (BMP) for leak emissions management (CAPP, 2011). The CAPP BMP allows OGI technology for performing these leak inspections (CAPP, 2007).

Lastly, the EPA has found that owners and operators are voluntarily using OGI systems to detect leaks. However, the EPA does not know the extent of these voluntary efforts within the industry on a national level.

3.1.3 Acoustic Leak Detector

Description

Acoustic leak detectors are used to detect the acoustic signal that results when pressurized gas leaks from a component. This acoustic signal occurs due to turbulent flow when pressurized gas moves from a high-pressure to a low-pressure environment across a leak opening (U.S. EPA, 2003a). The acoustic signal is detected by the analyzer, which provides an intensity reading on the meter. Acoustic detectors do not measure leak rates, but do provide a relative indication of leak size measured by the intensity of the signal (or how loud the sound is) (U.S. EPA, 2003a).

Applications

Generally, two types of acoustic leak detection methods are used; high frequency acoustic leak detection and ultrasound leak detection. High frequency acoustic detection is best applied in noisy environments where the leaking components are accessible to a handheld sensor (U.S. EPA, 2003a). Ultrasound leak detection is an acoustic screening method that detects airborne ultrasonic signals in the frequency range of 20 kHz to 100 kHz and can be aimed at a potential leak source from a distance of up to 100 feet (U.S. EPA, 2003a). Ultrasound detectors can be sensitive to background noise, although most detectors typically provide frequency tuning capabilities so that the probe can be tuned to a specific leak in a noisy environment (U.S. EPA, 2003a).

A URS Corporation/University of Texas at Austin (URS/UT) study described a "through-valve acoustic leak detection device" or VPAC that was used to measure leaks at six sites (four gathering/boosting stations and two natural gas processing plants) (URS/UT, 2011). Leak measurements were made using the VPAC device and high volume sample to compare the readings from the two devices. The study authors found that there was no statistically significant correlation between the VPAC and the direct flow measurements, and the study authors determined that the VPAC method was not considered to be an accurate alternative to direct measurement for the sources tested (URS/UT, 2011).

Costs

No cost data for acoustic leak detectors were available in the studies or research documents.

3.1.4 Ambient/Mobile Monitoring

Description

A growing number of research and industry groups are using mobile measurement approaches to investigate a variety of source emissions and air quality topics. For oil and natural gas applications, a vehicle can be equipped with at minimum a methane measurement instrument and GPS to facilitate discovery of previously unknown sources and in more advanced forms, provide information on source emission rates.

Applications

Mobile leak detection techniques sample emission plumes from stand-off (sometimes offsite) observing locations and are, therefore, generally less accurate than direct (onsite) source measurements. Mobile leak detection techniques can cover large survey areas and can be particularly useful in identifying anomalous operating conditions (e.g., pipeline leaks and well pad malfunctions) in support of onsite OGI and safety programs. All mobile techniques require downwind vehicle access and favorable wind conditions for plume transport to the observing location. The presence of trees or other obstructions can limit the efficacy of mobile leak detection techniques and in some cases prevent the application of remote source emission rate assessment.

Mobile leak detection instrument packages require some expertise for operation, especially in source emission rate measurement applications. Additionally, while mobile leak detection techniques can detect emissions around a site, such as a well site or gathering station, it cannot necessarily pinpoint the equipment that is the source of those emissions. Mobile leak detection techniques might be best used in conjunction with OGI technology; an OGI inspection would be triggered by the detection of above normal emissions by the mobile leak detection technique. In conversations with operators of upstream oil and natural gas facilities, the EPA has discovered that some companies are voluntarily using this two-phase approach to detect and then pinpoint VOC and methane leaks. It is believed that future forms of mobile leak detection techniques for the oil and gas sector may include lower cost, work truck-mounted systems that provide fully autonomous detection capability for anomalous emissions in support of such an onsite OGI inspection (Thoma, 2012).

An example of a mobile leak detection technique applicable to the upstream oil and gas sector is being developed under the EPA's Geospatial Measurement of Air Pollution (GMAP) program (Thoma, 2012). The near-field OTM 33A produces a 20-minute "snapshot" measure of emissions from near ground level point sources at observation distances of approximately 20 to 200 m. With strict application and favorable conditions, this type of point sensor-based remote measurement has source emission rate measurement accuracies in the ± 30% range with ensemble averages achieving accuracies within ± 15% by reducing random error effects. Although future, fixed deployment, low cost sensor systems may provide long-term emission level monitoring capability for oil and gas production sites,[12] current mobile assessment approaches can only provide a "snapshot" of emissions. Because some oil and gas upstream sources possess significant temporal and seasonal variability, the short-term nature of observation must be considered to avoid error in exportation of instantaneous emissions (e.g., to tons per year estimates). Results of well pad measurements from multiple oil and gas fields using mobile measurement are presented in Section 2.

Costs

Current mobile measurement instrument packages can range in cost from approximately $20,000 - $100,000 depending on the capability of the package.

3.2 Repair

After a leak is detected, the owner or operator of the facility must decide whether or not to fix the leak, unless they are required to fix the leak due to regulatory or permitting obligations.

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[12] A collaborative request for proposal (RFP) was released in the spring of 2014 by Apache Corporation, BG Group, EDF, Hess Corporation, Noble Energy, and Southwestern Energy called the "Methane Detectors Challenge: Continuous Methane Leak Detection for the Oil and Gas Industry." The "Challenge" is "designed to spur the development of cutting-edge, new technologies that provide continuous detection of methane emissions." Available at: http://www.edf.org/energy/natural-gas-policy/methane-detectors-challenge

This decision can be based on several factors, including, the cost of fixing the leak and the size of the leak. A number of studies discuss costs and effectiveness of various leak repair options.

3.2.1 Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (CL, 2013)

This study, discussed previously in Section 2, provided an analysis of the net present values (NPVs) of repairing all of the identified leaks in the surveys using the estimated repair cost and the value of the recovered gas. The study found that over 90% of gas emissions from leaks can be repaired with a payback period of less than one year, assuming a value of $3 per thousand cubic feet ($/Mcf) for the recovered gas. However, when compared with the cost of the monitoring (estimated to be $600 to $1,800 per facility), the economic benefits of repairing the leaks at most facilities are less than the total cost of the survey. For well sites and well batteries, the study estimated that 1,424 of the sites (81%) had a negative NPV, which averaged -$1,160 per facility. However, when the all of the individual well sites and well batteries are aggregated into a group, the aggregated NPV is positive, which suggests that a minority of sites have high leak rates and, thus, a positive NPV for monitoring and fixing leaks. These sites skew the mean NPV to a positive value.

The study also analyzed two alternative repair strategies: only repair leaks that are economic to repair (e.g., NPV > 0 for the repair) or repair of leaks that exceeded a certain threshold (e.g., 20 thousand cubic feet per year (Mcf/yr)). A summary of the findings for each of the scenarios is provided in Table 3-1.

Table 3-1. Comparison of Three Hypothetical Repair Strategies for Multi-Well Batteries[a]

Category	Repair all leaks	Repair leaks with a NPV>0	Repair leaks > 20 Mcf
Potential leak reductions after survey	94.5%	92.6%	88.1%
Methane abatement cost ($/ton CO_2e)	1	0.8	1.7
VOC abatement cost ($/ton VOC)	46	41	79
Average number of leaks to repair	3.8	3.5	2.9

a - Derived from Table 3 (CL, 2013).

The study concludes that the potential leak reductions after survey, methane abatement cost, VOC abatement cost, and average number of leaks to repair are similar under each of the three strategies. The study authors conclude that the results are similar because once a leak is found it is almost always economic to repair it.

The study also provided costs of repair and leak detection based on the survey data. The average cost of hiring an external service provider to perform a survey using OGI technology was determined to be $1,200 for multi-well batteries, $600 for single well batteries, and $400 for a well site. The range of costs of repair for well sites is shown in Table 3-2.

Table 3-2. Total Average Leak Rate and Repair Costs by Components at Well Sites

Component	Leak rate (cfm)	Repair Costs			
		Minimum	**Average**	**Median**	**Maximum**
Connector/Connection	0.11	$15	$56	$50	$5,000
Instrument Controller	0.03	$20	$129	$50	$2,000
Valve	0.04	$20	$90	$50	$5,500
Open-Ended Line	0.02	---[b]	---[b]	---[b]	---[b]
Regulator	0.02	$20	$189	$125	$1,000

a - Derived from Tables 6 and 7 (CL, 2013).
b – Repair costs for open-ended lines were not provided in the document.

3.2.2 Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants (Clearstone, 2002)

The Clearstone I study, discussed in Section 2, provided analysis of the payback periods for fixing the identified leaks, and what level of emission reductions could be achieved. Overall, the study estimated that up to 95% of total natural gas losses can be reduced cost-effectively (assumed gas price of $4.50 per Mcf), which corresponds to methane reductions of nearly 80%. The study also presents scenarios where only those reduction opportunities having a certain payback period (e.g., 6 months or 1 year) are implemented. For those cases, the estimated percent of total natural gas loss reduction and corresponding reductions in methane are presented in Table 3-3. One caveat from the study is that the payback periods do not take into account the cost of the leak detection survey, only factoring in cost of repair and benefit of the gas captured.

Table 3-3. Achievable Emission Reduction Percentages for Given Positive Payback Periods

Emission Type Reduction	Payback Period			
	< 6 months	**< 1 year**	**< 2 years**	**< 4 years**
Natural Gas	78.8%	92.3%	93.1%	94.9%
Methane	71.9%	78.1%	79.2%	79.5%

The study estimated that implementing all of the cost-effective repair opportunities identified would result in gross annual cost savings of approximately $1.1 million across the plants in the study (based on a gas value of $4.50 per Mcf). This amounts to over 50% of total cost-effective loss reduction opportunities identified for all emission sources (leaks, flaring, combustion equipment, and storage tanks) at the plants, and results in an average annual net savings of approximately $280,000 per site (the site-specific values range between $180,000 and $330,000).

3.2.3 Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites (Clearstone, 2006)

The Clearstone II study, discussed in Section 2, analyzed the cost-effectiveness of repairing the leaks identified in the surveys that were performed. The study estimated that up to 96.6% of total natural gas losses could be reduced cost-effectively (assuming a gas price of $7.15 per Mcf), which corresponds to methane reductions of 61%. The study also estimated that the average annual lost gas values from the sites surveyed were $536,270 per gas plant, $49,018 per gathering station, and $3,183 per well site.

This study also provided the base repair cost and mean repair life for 16 types of components. The values for several of the more common components reported in the study are summarized in Table 3-4.

Table 3-4. Basic Repair Costs and Mean Repair Life for Several Common Leaking Components

Component Type	Basic Repair Costs		Mean Repair Life (years)
	Low	High	
Compressor Seals[a]	$2,000	$2,000	1
Flanges	$25	$400	2
Open-End Lines	$60	$1,670	2
Pressure Relief Valves	$79	$725	2
Threaded Connections	$10	$300	2
Tubing Connections	$15	$25	4
Valves	$60	$2,229	2 - 4
Vents	$2,000	$5,000	1

[a] For the purposes of this paper, compressor seal emissions are not considered leaks.

3.2.4 Natural Gas STAR Directed Inspection and Maintenance (U.S. EPA, 2003a, U.S. EPA, 2003b, and U.S. EPA, 2003c)

For detecting and repairing leaks, the Natural Gas STAR program recommends implementation of a DI&M program to economically reduce methane emissions from leaking components (U.S. EPA, 2003a, U.S. EPA, 2003b, and U.S. EPA, 2003c). A DI&M program, which can be implemented at any facility in the upstream or downstream sector of the industry, starts with a comprehensive baseline emissions survey. This survey involves screening all of the components at the facility to identify the leaking components, as well as measuring the identified leaks to determine emission rates. Determining an emissions rate is an important step that allows the economic evaluation of mitigation techniques. Natural Gas STAR partners have reported using OGI technology to effectively scan large numbers of components in a short span of time. The choice of leak detection equipment typically depends on the number of components to be scanned. Optical gas imaging technology is popular at facilities that have thousands of components, such as at processing plants. From previous field studies conducted by the EPA and Natural Gas STAR partners, the EPA has observed that typically 20% of the top leaking components account for approximately 80% of the emissions from a facility. This provides a strong basis to conduct DI&M at facilities because fixing a small number of leaks can significantly reduce the total leak emissions from a facility.

Once the leaking sources have been identified, the next step recommended is the economic analysis of mitigation techniques. The estimated repair costs for the identified leaks can be compared to the potential savings from fixing the leaks based on the value of natural gas, and the leaks that are determined to be economical to fix by the owner can be repaired.

Not all leaks identified can be fixed immediately. For example, leaks on a flange on a transmission pipeline cannot be fixed without shutting down the system and purging the pipeline of all the natural gas. The identification of leaks before a shutdown through a DI&M program helps facilities focus on specific areas during a shutdown cycle. Shutdown cycles are usually short, lasting from a day up to a week.

The Natural Gas STAR program also lists average emission rates, repair cost ranges, and payback periods for fixing leaks at several different facilities. Tables 3-5 and 3-6 show the emission rates and repair costs for several common leaking components at gas processing plants, transmission compressor stations, and gate stations.

Table 3-5. Total Average Leak Rate and Repair Costs by Component at Processing Plants

Component	Average Component Leak Rate by Location (Mcf/yr)			Average Repair Cost
	Non-Compressor	Reciprocating Compressor	Centrifugal Compressor	
Connections	6.7	-	-	$25
Flanges	88.2	89.7	115	$150
Pressure Relief Valves	3.9	308	-	$150
Other Valves	25	127	63.4	$130
Compressor Seal[a]	-	1,440	485	$2,000
Open-Ended Line (OEL)	43	-	-	$65
Compressor Blowdown OEL	-	1,417	2,887	$5,000

Note: Adapted from exhibit 5 in "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations" Lessons Learned document. Available online: http://epa.gov/gasstar/documents/ll_dimgasproc.pdf
[a] For the purposes of this paper, compressor seal emissions are not considered leaks.

Table 3-6. Total Average Leak Rate and Repair Costs by Component at Compressor Stations

Component	Average Component Leak Rate by Location (Mcf/yr)		Average Repair Costs	
	On Compressor	Off Compressor	Low	High
Ball/Plug Valves	0.64	5.33	$40	$120
Blowdown Valve	-	207.5	$200	$600
Compressor Valve	4.1	-	$60	$60
Unit Valve	-	3,566	$70	$2,960
Flange	0.81	0.32	$300	$1,250
Open-Ended Line	-	81.8	$45	$45
Pressure Relief Valve	-	57.5	$1,000	$1,000
Connection	0.74	0.6	$10	$30

Note: Adapted from exhibits 4 and 5 in "Directed Inspection and Maintenance at Compressor Stations" Lessons Learned document. Available online: http://epa.gov/gasstar/documents/ll_dimcompstat.pdf.

3.2.5 Update of Fugitive Equipment Leak Emission Factors (CAPP, 2014)

In February of 2014, CAPP issued a report on emission factors for leaks at upstream oil and gas facilities in Alberta and British Columbia. This report served as an update to similar factors that were developed in 2005, prior to the implementation of DI&M BMPs in both these provinces. The report compares the 2005 leak emission factors to the 2014 leak emission factor in order to draw conclusions regarding the effectiveness of the DI&M BMPs in Alberta and British Columbia.

Leak survey results provided by eight industry participants in Alberta and British Columbia were the basis of the emission factors. The results came from 120 facilities and included approximately 276,947 components. All surveys were conducted after 2007. The study authors used this data to develop average emission factors for each type of component and then compared those factors to the factors developed in 2005. Table 3-7 provides a comparison of the emission factors for each type of component from the 2005 study and the 2014 study.

Table 3-7. Comparison of Total Hydrocarbon Leak Emission Factors for Upstream Oil and Gas Facilities that have Implemented DI&M BMPs

Sector	Component	Service[a]	2014 Emission Factor (kg/hour)	2005 Emission Factor (kg/hour)	Ratio of 2014 to 2005 Emission Factors
Gas	Compressor Seal[b]	GV	0.04669	0.71300	0.065
Gas	Connector	GV	0.00082	0.00082	1.000
Gas	Connector	LL	0.00016	0.00055	0.298
Gas	Control Valve	GV	0.03992	0.01620	2.464
Gas	Open-Ended Line	All	0.04663	0.46700	0.100
Gas	Pressure Relief Valve	All	0.00019	0.01700	0.011
Gas	Pump Seal	All	0.00291	0.02320	0.125
Gas	Regulator	All	0.03844	0.00811	4.740
Gas	Valve	GV	0.00057	0.00281	0.205
Gas	Valve	LL	0.00086	0.00352	0.245
Oil	Compressor Seal	GV	0.01474	0.80500	0.018
Oil	Connector	GV	0.00057	0.00246	0.232
Oil	Connector	LL	0.00013	0.00019	0.684
Oil	Control Valve	GV	0.09063	0.01460	6.207
Oil	Open-Ended Line	All	0.15692	0.30800	0.509
Oil	Pressure Relief Valve	All	0.00019	0.01630	0.012
Oil	Pump Seal	All	0.00230	0.02320	0.099
Oil	Regulator	All	0.52829	0.00668	79.085
Oil	Valve	GV	0.00122	0.00151	0.809
Oil	Valve	LL	0.00058	0.00121	0.479

Note: Adapted from Table 10 in "Update of Fugitive Equipment Leak Emission Factors" document (CAPP, 2014). Available online: http://www.capp.ca/getdoc.aspx?DocId=238773&DT=NTV

[a] GV = Gas/Vapor, LL = Light Liquid

[b] For the purposes of this paper, compressor seal emissions are not considered leaks.

The study authors conclude that emissions from leaks have decreased 75% among the survey participants since the implementation of the DI&M programs in Alberta and British Columbia. The leak factors for almost all categories of equipment decreased. The authors did not use this data to develop national or regional estimates of total leak emissions.

4.0 SUMMARY

The EPA has used the information presented in this paper to inform its understanding of leak emissions and potential techniques that can be used to identify and mitigate leaks in the oil and natural gas production, processing, transmission and storage sectors. The following are characteristics the Agency believes are important to understanding this source of VOC and methane emissions:

- The 2014 GHG Inventory estimates there are approximately 332,662 MT of potential methane leak emissions from gas production, 33,681 MT of potential methane leak emissions from gas processing, and 114,348 MT of potential methane leak emissions gas transmission.
- Several studies suggest that the majority of methane and VOC emissions from leaks come from a minority of components (CL, 2013; Clearstone, 2002; and Clearstone, 2006). Furthermore, one study concludes that the majority of methane and VOC emissions from leaks come from a minority of sites (CL, 2013). One study found that the majority of leak emissions from these sites may be attributed to maintenance-related issues such as open thief hatches, failed pressure relief valves, or stuck dump valves (Thoma, 2012).
- The methane and VOC leak emissions from well sites depend on a number of different factors including: the number of wells located at the site, the number of compressors located at the well site and the number and type of processing equipment (separators, heaters, etc.) used at the site.
- Currently, portable analyzers provide an effective approach for both locating and measuring the concentration of leaks from oil and natural gas production sites.
- There are several other technologies being used to detect leaks for the oil and natural gas sectors. These technologies include OGI and ambient/mobile monitoring.

- OGI is being increasingly used to locate leaks in the oil and gas industry. The technology can potentially provide a more time and cost efficient method for locating leaks than traditional technologies, such as portable analyzers. However, there may be limitations to this technology.
    - The technology must be used methodically in order to address certain limitations, such as sensitivities to ambient conditions.
    - OGI technology does not quantify emissions. It may be possible to develop algorithms to quantify emissions with data from OGI, but, to the EPA's knowledge, such algorithms are not currently available.
- Ambient/mobile monitoring and OGI technology might be most effective when used in tandem. In such cases, an OGI inspection could be triggered by the detection of above normal emissions by the ambient/mobile monitoring equipment. This approach potentially could reduce or eliminate OGI inspections at facilities with minimal leak emissions.
- Available information suggests that once a leak is found it is almost always economical to repair the leak. According to the studies reviewed, the cost of detecting the leak is generally far larger than the cost of fixing the leak.
- The CAPP 2014 study and experience through the Natural Gas STAR program suggest DI&M programs can effectively decrease leak emissions.

5.0 CHARGE QUESTIONS FOR REVIEWERS

1. Did this paper appropriately characterize the different studies and data sources that quantify VOC and methane emissions from leaks in the oil and natural gas sector?
2. Please comment on the approaches for quantifying emissions and on the emission factors used in the data sources discussed. Please comment on the national estimates of emissions and emission factors for equipment leaks presented in this paper. Please comment on the activity data used to calculate these emissions, both on the total national and regional equipment counts.
3. Are the emission estimating procedures and leak detection methods presented here equally applicable to both oil and gas production, processing, and transmission and storage sectors?

4. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from leaks and available techniques for detecting those leaks? Please list the additional studies you are aware of.

5. Are there types of wells sites, gathering and boosting stations, processing plants, and transmission and storage stations that are more prone to leaks than others? Some factors that could affect the potential for leaks are the number and types of equipment, the maintenance of that equipment, and the age of the equipment, as well as factors that relate to the local geology. Please discuss these factors and others that you believe to be important.

6. Did this paper capture the full range of technologies available to identify leaks at oil and natural gas facilities?

7. Please comment on the pros and cons of the different leak detection technologies. Please discuss efficacy, cost and feasibility for various applications.

8. Please comment on the prevalence of the use of the different leak detection technologies at oil and gas facilities. Which technologies are the most commonly used? Does the type of facility (e.g., well site versus gathering and boosting station) affect which leak detection technology is used?

9. Please provide information on current frequencies of revisit of existing voluntary leak detection programs in industry and how the costs and emission reductions achieved vary with different frequencies of revisit.

10. Please comment on the potential for using ambient/mobile monitoring technologies in conjunction with OGI technology. This would be a two-phase approach where the ambient/mobile monitoring technology is used to detect the presence of a leak and the OGI technology is used to identify the leaking component. Please discuss efficacy, cost and feasibility.

11. Please comment on the cost of detecting a leak when compared to the cost to repair a leak. Multiple studies described in this paper suggest that detecting leaks is far more costly than repairing leaks and, due to generally low costs of repair and the subsequent product recovery, it is almost always economical to repair leaks once they are found. Please comment on this overall conclusion.

12. If the conclusion is correct that it is almost always economical to repair leaks once they are found, then how important is the quantification of emissions from leaks when implementing a program to detect and repair leaks?

13. Please comment on the state of innovation in leak detection technologies. Are there new technologies under development that are not discussed in this paper? Are there significant advancements being made in the technologies that are not described in this paper?

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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

[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,

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[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.

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[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.

Applicability

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).

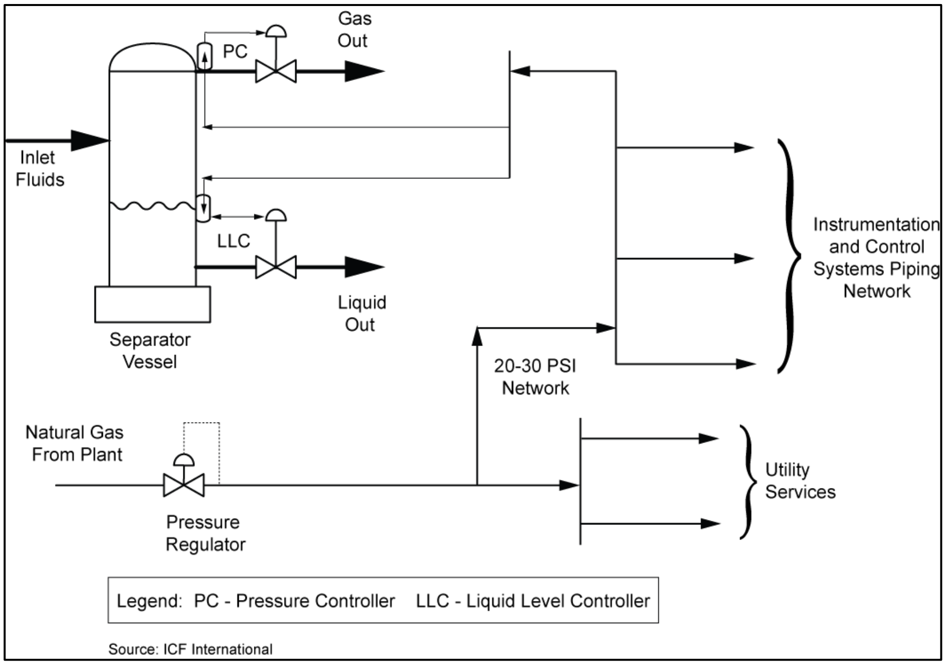

Figure 3-1 Natural Gas Pneumatic Control System

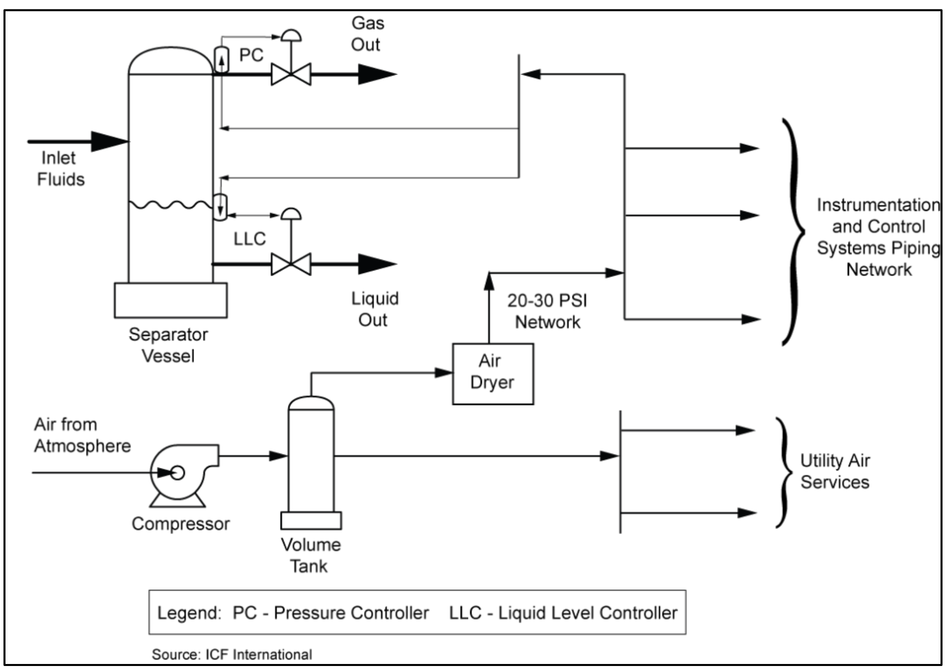

Figure 3-2. Compressed Instrument Air System

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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