CLEAN AIR TASK FORCE

CoMAT Methodology

Version: Feb 2024

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Abbreviations

AD	Activity Data
AGR	Acid Gas Removal
Bcf	Billion cubic feet
Bcm	Billion cubic meters
DRE	Destruction Removal Efficiency
EF	Emission Factor
GHGRP	United States Greenhouse Gas Reporting Program
HF	Hydraulic Fracturing
Kg	Kilogram
Kt	Kiloton (thousand metric tons)
LDAR	Leak Detection and Repair
Mcm	Million cubic meters
MMbbls	Million barrels
mmcf	Million cubic feet
MMHPhr	Million horsepower hour
MMscf	Million standard cubic feet
OGI	Optical Gas Imaging
REC	Reduced Emission Completion
USEPA	United States Environmental Protection Agency
USGHGI	United States Greenhouse Gas Inventory
VRU	Vapor Recovery Unit

CoMAT Introduction

CoMAT Process

In recent years, recognition of the methane problem has also been on the rise. Spurred by leadership from the United States, United Kingdom, and European Union in 2021, more than 150 countries signed on to the Global Methane Pledge, a breakthrough commitment to reducing global methane emissions 30% by 2030.

But while important progress has been made since this critical moment, several barriers remain for countries eager to turn their methane ambitions into action, including:

- Emissions Estimates: successful methane mitigation will require robust estimates of national emissions and abatement potential.
- Mitigation Policy: Emissions reduction and country-specific mitigation plans require the development and implementation of effective national policies and regulatory tools which are often missing and/or countries interested in taking action need support identifying and designing.

To help overcome these challenges, CATF is engaging governments, industry, and civil society around the world – and has created the Country Methane Abatement Tool (CoMAT) to help government regulators and ministries turn their ambition into action. CoMAT is a powerful, free tool designed to make it easier for countries to quickly estimate their methane emissions and abatement potential, develop comprehensive mitigation approaches, and design methane reduction policy strategies. CATF's CoMAT application offers a unique combination of estimation and policy design tools that allow a country to collect, examine, check, analyze, and evaluate data, gain valuable insights and build consensus around best mitigation solutions that can help them meet their climate goals.

Using publicly available data, the platform is set up with estimates of a country's oil and gas sector emissions and access to a newly digitized library of leading methane policy and proven best practices, backed by the hands-on support of CATF's world-class methane team. CoMAT allows government regulators to continually refine their emissions inventories and explore variables and specific policy and regulatory options that can drive pollution reduction.

CATF continues to actively work with its partners to reduce methane emissions and uses CoMAT to establish a common language between policymakers, companies, and regulators. The tool is a user-friendly and intuitive knowledge-based platform that offers a high level of granularity, transparency, and the opportunity to explore regulatory tools that allow countries to plan ahead and make significant progress in designing mitigation approaches that achieve their climate and emissions decarbonization goals.

Calculation methodology

An emission source is a specific piece of equipment or process at an oil and gas site that leads to the emission of methane. Emissions for each source are calculated by adding up emissions for each emission contributor within that source using an Industry Information, Activity Data, and Emission Factors. Industry information is collected based on publicly available sources or provided directly by the country. If industry data is not available, it is estimated in the CoMAT application using Proxies. Activity data is estimated by combining industry information and activity drivers. Emission factors are based on previous measurement studies or engineering estimates.

Most of the information for activity data and emission factors is derived from the US GHG Inventory (US GHGI). These defaults represent current numbers for the US oil and gas industry or estimates of activity data and emission factors before the US oil and gas industry was subject to regulation—regulation for new/modified sources began starting in 2012, so the pre-regulatory baseline is based on 2011 data.

This equation is the general formula used to calculate methane emissions from all emission contributors.

Methane emissions = Industry Contributor * Activity Driver(s) * Emission Factor

Methane emissions = Activity Data (AD) * Emission Factor (EF)

Note that emission sources in CoMAT have between zero and four activity drivers. In the case where there are zero activity factors, the industry contributor acts directly as the activity data.

Example 1: This is the specific equation for high bleed pneumatic controllers in the gas production subsegment, an emission source with two activity drivers:

Methane emissions from high bleed controllers =

(# of active gas wells) * (# of natural gas powered pneumatic controllers per well) * (% of pneumatic controllers that are high bleed) * (Methane emissions per high bleed controller)

Methane emissions = (# of high bleed pneumatic controllers) * (Methane emissions per high bleed controller)

Example 2: This is the specific equation for abnormal process condition emissions in the gas production subsegment, an emission source with zero activity drivers:

Methane emissions from abnormal process condition emissions = (# of active gas wells) * (Abnormal process condition methane emissions per active gas well)

Details of each emission contributor can be found in the "Emissions Sources" section of this document.

Top-down measurements

As described above, much of the calculation in CoMAT is building a bottom-up equipment-based inventory. But there are a few items that are based on top-down measurement data, so it is worth calling those out directly.

First, CoMAT estimates methane emissions from associated gas venting and flaring, and by default it uses satellite data on flaring from NOAA.[1] This data is reported in billion cubic meters of gas flared. CoMAT then has three other factors that can be modified to estimate methane emissions from associated gas venting and flaring: average flaring efficiency, average gas composition, and amount of associated gas that is vented not flared.

CoMAT also uses a default assumption for emissions from abnormal process conditions, which include malfunctions upstream of the point of emissions and equipment issues. These emissions are responsible for the gap between the component level bottom-up inventory (e.g. the official US GHG Inventory) and atmospheric measurements of methane emissions.[2] These emissions are estimated in CoMAT using a the factor based on Alvarez 2018.[3] We use the data from this study to estimate methane emissions from abnormal process conditions per well for the oil and gas production subsegments and to estimate emissions from abnormal process conditions per station for the gathering and boosting subsegment. These factors can be replaced with country-specific top-down measurement data if that is available.

[1] Global Gas Flaring Tracker Report. *World Bank Global Gas Flaring Reduction Partnership* https://www.worldbank.org/en/programs/gasflaringreduction/global-flaring-data (2023).
[2] Zavala-Araiza, D., Alvarez, R., Lyon, D. *et al.* Super-emitters in natural gas infrastructure are caused by abnormal process conditions. *Nat Commun* **8**, 14012 (2017). https://doi.org/10.1038/ncomms14012 https://www.nature.com/articles/ncomms14012
[3] Ramón A. Alvarez et al. Assessment of methane emissions from the U.S. oil and gas supply chain.Science361,186-188(2018).DOI:10.1126/science.aar7204

Other data considerations

Before a country site can be created in CoMAT, the following two choices must be made: which system of measurement is used (metric or imperial) and which year will be used for input data (this is typically 1-2 years before the current year and should be the most recent year for which a full dataset is available).

Industry Segments

Gas Exploration and Production

The gas exploration process involves the search for rock formations associated with natural gas deposits through detailed geological and geophysical surveys and exploratory drilling to determine nature of hydrocarbon presence. Gas production is the process of extracting hydrocarbons via drilling and hydraulic fracturing, and separating the mixture liquid hydrocarbons, gas, water, and solids. Table 1 shows the information used in CoMAT for the gas exploration and production segment.

Table 1: Data used for the gas exploration and production segment

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
Gas Production	Gross production	Onshore Gas Production	Country-specific: EIA	
	Marketed/dry production			
	Offshore gas production	Offshore Gas Production	Country-specific: Rystad *Note: outdated data, should be updated by country.	
Gas wells	Total Gas Wells	Gas Exploration, Onshore Gas Production	Country-specific or Proxy	3.9 Mcm (138 mmcf) per well. CATF judgement of global average
	Gas wells with hydraulic fracturing		Country-specific or Proxy	Assume 5% of wells are hydraulically fractured.
	Gas wells with hydraulic fracturing		Country-specific or Proxy	
	Gas wells drilled per year		Country-specific or Proxy	Assume that 5% of total well count is drilled per year.
Well Blowouts		Gas Exploration	Country-specific. Default zero if no information.	

Condensate Production	Onshore Gas Production	Country-specific: EIA	[redacted]
Gathering and boosting stations	Gathering and Boosting	Country-specific or Proxy	143 Mcm (5,046 mmcf) processed per gathering and boosting station. US average.

Oil Exploration and Production

Oil exploration process involves the search for rock formations associated with oil deposits through detailed geological and geophysical surveys and exploratory drilling to determine nature of hydrocarbon presence. Oil production is the process of extracting hydrocarbons via drilling and hydraulic fracturing, and separating the mixture liquid hydrocarbons, gas, water, and solids. Table 2 shows the information used in CoMAT for the oil exploration and production segment.

Table 2: Data used for the oil exploration and production segment

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
Oil Production	Total oil production	Onshore Oil Production	Country-specific: EIA	[redacted]
	Onshore Oil production			
	Offshore oil production	Offshore Oil Production	Country-specific: Rystad *Note: outdated data, should be updated by country.	
Oil wells	Total Oil Wells	Oil Exploration, Onshore Oil Production	Country-specific or Proxy	3.9 Mcm (138 mmcf) per well. CATF judgement of global average
	Oil wells with hydraulic fracturing		Country-specific or Proxy	Assume 5% of wells are hydraulically fractured.
	Oil wells with hydraulic fracturing		Country-specific or Proxy	
	Oil wells drilled per year		Country-specific or Proxy	Assume that 5% of total well count is drilled per year.
Flaring Volume	Flaring Volume	Onshore Oil Production	Country-specific: NOAA Global Gas Flaring	[redacted]

Gas Processing

A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include acid gas removal (AGR), dehydration, hydrocarbon liquids removal, and compression operations. When feasible, vapor recovery units capture vented gas and send it to flares. The size and complexity of processing plants are variable; in some cases, processing occurs near production sites, while in other cases a central processing facility receives natural gas from gathering and boosting facilities.

Table 3: Data used for the gas processing segment

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
Number of Processing Plants		Gas Processing	Country-specific or Proxy	Marketed/Dry gas production / Amount of natural gas processed per processing plant. Assume 1,265.5 Mcm (44,682 mmcf) natural gas processed per processing plant. US average.

Gas Transmission and Storage

Transmission compressor stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas to move it through the pipelines. These stations consist of centrifugal and reciprocating compressors; most pipeline compressors are powered by natural gas, but some are powered by electricity. Underground gas storage includes wells in depleted oil and gas fields, hollowed-out salt domes, or other geological formations. Underground storage facilities consist of pneumatic devices and compressors, and fugitive emissions coming from flanges, connectors, open-ended lines, and valves for both the storage station and wellhead.

Table 4: Data used for the gas transmission and storage segment

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
Transmission Pipeline Distance		Gas Transmission	Country-specific or Proxy	(Gross onshore gas production + Offshore gas production) / Natural gas throughput per transmission compressor station * Transmission pipeline distance per transmission compressor station.

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
				Assume 1,862.1 Mcm (65,758.8 mmcf) natural gas processed per transmission compressor station and 161 km (100 miles) per transmission compressor station. US average.
Stations	Transmission compressor stations	Gas Transmission	Country-specific or Proxy	Transmission pipeline distance / Transmission pipeline distance per transmission compressor station. Assume 161 km (100 miles) per transmission compressor station. US average.
	Gas storage compressor stations	Underground Gas Storage	Country-specific or Proxy	(Gross onshore gas production + Offshore gas production)/Amount of natural gas stored per storage compressor station. Assume 2,438.2 Mcm (86,102.6 mmcf) natural gas processed per storage compressor stations. US average.
Gas Consumption*	Total natural gas consumption	Gas Transmission, Underground Distribution Pipelines	Country-specific: EIA	[redacted]
	Residential natural gas consumption		Country-specific or Proxy	Assume 16 percent of total natural gas consumption. US average.
	Commercial natural gas consumption		Country-specific or Proxy	Assume 11 percent of total natural gas consumption. US average.
	Industrial natural gas consumption		Country-specific or Proxy	Assume 28 percent of total natural gas consumption. US average.
	Residential natural gas customers		Country-specific or Proxy	Residential natural gas consumption / Natural gas consumption per residential customer. Assume 1798.6 m3 (63,515.8 cf) natural gas consumed per residential customer. US average.
	Commercial natural gas customers		Country-specific or Proxy	Commercial natural gas consumption / Natural gas consumption per commercial customer. Assume 16,083.7 m3 (567,991.6 cf) natural gas consumed per commercial customer. US average.
	Industrial natural gas customers		Country-specific or Proxy	Industrial natural gas consumption / Natural gas consumption per industrial customer.

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
				Assume 1,158,952 m3 (40,928,043 cf) natural gas consumed per industrial customer. US average.

*Same industry information used in both Gas Transmission and Gas Distribution

LNG

Liquified Natural Gas (LNG) facilities include LNG import and export terminals, and LNG storage facilities. LNG export terminals receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location. LNG import terminals receives imported LNG via ocean transport, stores LNG, regasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system.

Table 5: Data used for the liquefied natural gas segment

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
LNG	LNG Storage Stations	LNG Storage	Country-specific: Global Energy Monitor	[redacted]
	LNG Import Terminals	LNG Import Terminals	Country-specific: Global Energy Monitor	
	LNG Export Terminals	LNG Export Terminals	Country-specific: Global Energy Monitor	

Gas Distribution

Natural gas distribution means the distribution pipelines and metering-regulating stations to supply gas to end users.

Table 6: Data used for the gas distribution segment

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
	Total natural gas consumption		Country-specific: EIA	[redacted]

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
Gas Consumption*	Residential natural gas consumption	Aboveground Distribution Stations	Country-specific or Proxy	Assume 16 percent of total natural gas consumption. US average.
	Commercial natural gas consumption		Country-specific or Proxy	Assume 11 percent of total natural gas consumption. US average.
	Industrial natural gas consumption		Country-specific or Proxy	Assume 28 percent of total natural gas consumption. US average.
	Residential natural gas customers		Country-specific or Proxy	Residential natural gas consumption / Natural gas consumption per residential customer. Assume 1798.6 m3 (63,515.8 cf) natural gas consumed per residential customer. US average.
	Commercial natural gas customers		Country-specific or Proxy	Commercial natural gas consumption / Natural gas consumption per commercial customer. Assume 16,083.7 m3 (567,991.6 cf) natural gas consumed per commercial customer. US average.
	Industrial natural gas customers		Country-specific or Proxy	Industrial natural gas consumption / Natural gas consumption per industrial customer. Assume 1,158,952 m3 (40,928,043 cf) natural gas consumed per industrial customer. US average.
Mains & Services	Mains - Cast Iron	Underground Distribution Pipelines, Aboveground Distribution Stations	Country-specific or Proxy	Number of residential natural gas customers * total mains distance per customer * percent of cast iron mains. Assume 0.03 km (0.02 miles) of mains per residential customer and 2.04 percent of total mains distance is composed of cast iron. US average.
	Mains - Protected Steel		Country-specific or Proxy	Number of residential natural gas customers * total mains distance per customer * percent of Protected Steel mains. Assume 0.03 km (0.02 miles) of mains per residential customer and 37.35 percent of total mains distance is composed of Protected Steel. US average.

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
	Mains - Unprotected Steel		Country-specific or Proxy	Number of residential natural gas customers * total mains distance per customer * percent of Unprotected Steel mains. Assume 0.03 km (0.02 miles) of mains per residential customer and 4.46 percent of total mains distance is composed of Unprotected Steel. US average.
	Mains - Plastic		Country-specific or Proxy	Number of residential natural gas customers * total mains distance per customer * percent of Plastic mains. Assume 0.03 km (0.02 miles) of mains per residential customer and 56.15 percent of total mains distance is composed of Plastic. US average.
	Services - Protected Steel		Country-specific or Proxy	Number of residential natural gas customers * total number of service lines per customer * percent of Protected Steel service lines. Assume 0.97 services per residential customer and 21 percent of total number of services is composed of Protected Steel. US average.
	Services - Unprotected Steel		Country-specific or Proxy	Number of residential natural gas customers * total number of service lines per customer * percent of Unprotected Steel service lines. Assume 0.97 services per residential customer and 5 percent of total number of services is composed of Unprotected Steel. US average.
	Services - Plastic		Country-specific or Proxy	Number of residential natural gas customers * total number of service lines per customer * percent of Plastic service lines. Assume 0.97 services per residential customer and 73 percent of total number of services is composed of Plastic. US average.
	Services - Copper		Country-specific or Proxy	Number of residential natural gas customers * total number of service lines per customer * percent of copper service lines.

Industry Contributor Group	Industry Contributor	Industry Subsegment	Default Source	Proxy details
				Assume 0.97 services per residential customer and 1.27 percent of total number of services is composed of Copper. US average.
	Total Service Distance		Country-specific or Proxy	Assume 0.02 km (0.01 miles) of pipeline per service

*Same industry information used in both Gas Transmission and Gas Distribution

Emission Sources

CoMAT enables users to create a granular bottom-up inventory of methane emissions sources in the oil and gas industry. It uses the industry information collected in the previous section to build a robust equipment inventory, and applies default emission factors to estimate methane emissions. All activity information and emission factors can be updated by the user if data is available that is country-specific or more applicable to that country's oil and gas inventory.

Whether the user entered the industry information in metric or imperial units, methane emissions are always reported in metric units (metric tons or kilotonnes) in order to be consistent with UNFCCC reporting requirements. However, because most of the default emission factors are taken from the US GHG Inventory (US GHGI), the emission factors include both metric and imperial units (e.g. kg/mmcf or kg/mmbbl).

Below, we describe each emission source quantified in CoMAT, and provide details on activity data and emission factors for each emission contributor.

Associated Gas Venting and Flaring

Operators often vent and flare natural gas at oil wells. This waste occurs when oil producers, driven by the rush to sell oil, simply dispose of the gas from producing oil wells instead of building infrastructure (such as pipelines) to capture gas as soon as production begins. (In some cases, pipelines are never built and all the gas the well produces over its lifetime is wasted in this way, as can be seen in sales records for individual wells available from state regulators.) Venting is even more harmful than flaring, since methane warms the 80 times more than CO_2, and VOC and toxic pollutants are released unabated.

Estimating methane emissions from associated gas flaring requires measurement or estimation of three components: 1) gas flow to flare, 2) gas composition, and 3) flare efficiency. Flaring entails the burning of natural gas, but the flare will not burn all the gas; the gas which is not combusted at the flare is known as methane slip. Gas that is sent directly to a vent stack rather than a flare is considered associated gas venting. A third category of methane emission can occur when gas is sent to a flare stack that is unlit or malfunctioning in some way. Careful accounting must be done to ensure that you are including all sources of associated gas venting and flaring, while also not double counting. Emissions from associated gas venting that occurs when a flare is unlit can be treated in different ways. The Oil and Gas Methane Partnership 2.0 (OGMP) Guidance Document for Flare Efficiency notes that when the flare is not lit, emissions should be reported as venting.[4] On the other hand, the U.S. Environmental Protection Agency (USEPA) Greenhous Gas Reporting Program (GHGRP) treats gas vented from an unlit flare as emissions from a flare, but considers them separately from the determination of flare combustion efficiency, which is only based on efficiency while the flare is lit.[5] CoMAT is built to be flexible, so data about unlit flares can be represented as a lower flaring efficiency or higher venting percentage.

Table 7: Industry contributors, activity drivers, and emission factors for the associated gas venting and flaring emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore oil production	Associated Gas Flaring	Flaring Volume	10% methane slip from flare 63% gas percent methane by volume	Methane slip based on literature.[6] Gas composition average for oil	0.019415 kg/ft3	Note: not a true "emission factor", a conversion, so should not be changed
	Associated Gas Venting		3% of associated vented not flared 63% gas percent methane by volume	Percent not flared CATF expert judgement. Gas composition average for oil	0.019415 kg/ft3	Note: not a true "emission factor", a conversion, so should not be changed

Blowdown Venting

Methane released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

[4] OGMP Technical Guidance Document - Flare Efficiency. (2021, June 24). Retrieved from https://ogmpartnership.com/wp-content/uploads/2023/02/Flare-efficiency-TGD-Approved-by-SG.pdf.
[5] 40 C.F.R. §§ 98.232, Eq. W-19. https://www.law.cornell.edu/cfr/text/40/part-98/subpart-W.
[6] Methane slip is the amount of methane that is not burned in the flare. It can also be thought of as 1 minus the destruction removal efficiency (DRE). See e.g.: https://doi.org/10.1126/science.abq0385

Table 8: Industry contributors, activity drivers, and emission factors for the blowdown venting emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gas Processing	Blowdowns/Venting - Processing	Number of Processing Plants	-	-	52,334.9 kg/plant	2012 emission factor from 2022 US GHGI
Onshore gas production	Compressor Blowdowns - Gas Production	Total gas wells	0.08 compressors per well	GHGRP subpart W	76.9 kg/compressor	GRI/EPA 1996
Onshore oil production	Compressor Blowdowns - Oil Production	Total oil wells	0.01 compressors per oil well	GHGRP subpart W	72.7 kg/compressor	GRI/EPA 1996
Gathering and Boosting	GB Pipeline Blowdowns	Gathering and Boosting Stations	56.3 miles per station	GHGRP subpart W	37.03 kg/mile	x EPA GHGRP Subpart W 2020
Gathering and Boosting	GB Station Station Blowdowns	Gathering and Boosting Stations	53.5 blowdown evens per station	GHGRP subpart W and scaling factor from Zimmerle 2019	100.8 kg/event	EPA GHGRP Subpart W
LNG Export Terminals	LNG Export Terminal Blowdowns	LNG Export Terminals	-	-	40,881.4 kg/terminal	EPA GHGRP Subpart W
LNG Import Terminals	LNG Import Terminal Blowdowns	LNG Import Terminals	-	-	1,229,560 kg/terminal	EPA GHGRP Subpart W
LNG Storage	LNG Station Blowdowns	LNG Storage Stations	-	-	83,954.3 kg/facility	GRI/EPA 1996
Aboveground Distribution Stations	Pipeline Blowdown	Total miles of distribution pipeline (mains + services)	-	-	0.9 kg/mile	GRI/EPA 1996
Onshore gas production	Vessel Blowdowns - Gas Production	Total gas wells	0.8 heaters + separators + dehys per well	Sum of heaters, separators, and dehydrators from GHGRP subpart W	1.6 kg/vessel	GRI/EPA 1996
Onshore oil production	Vessel Blowdowns - Oil Production	Total oil wells	0.5 separators + heater treaters per well	Sum of heavy crude separators, light crude separators, and heater treaters	1.5 kg/vessel	GRI/EPA 1996

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
				from GHGRP subpart W		
Gas Transmission	Pipeline venting - Transmission	Gas Transmission	-	-	610 kg/mile	2012 EF from 2022 US GHGI

Centrifugal Compressors

Centrifugal compressors use a spinning turbine to pressurize gas. The rapidly rotating main shaft of the compressor is generally sealed with one of two technologies. Wet seals circulate oil to seal the narrow gap between the shaft and its housing. This oil absorbs significant amounts of the high-pressure natural gas that must be removed from the oil before recirculation. Typically, the gas removed from the seal oil is vented, resulting in substantial emissions. Dry seals, in contrast, use a more modern design to avoid the use of seal oil, with much lower emissions.

Table 9: Industry contributors, activity drivers, and emission factors for the centrifugal compressors emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gas Processing	Centrifugal Compressors (wet seals) - Processing	Number of Processing Plants	1.03 centrifugal compressors per plant 54.6 percent wet seal	GHGRP subpart W	57,143.7 kg/compressor	2012 EF from 2022 US GHGI
Gas Processing	Centrifugal Compressors (dry seals) - Processing	Number of Processing Plants	1.03 centrifugal compressors per plant 45.4 percent dry seal	GHGRP subpart W	31,738.3 kg/compressor	EPA GHGRP Subpart W
Gas Transmission	Centrifugal Compressors (wet seals) - Transmission	Transmission compressor stations	1.2 centrifugal compressors per station 46.2 percent wet seal	GHGRP subpart W	68,000 kg/compressor	Zimmerle et al. 2015 report

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gas Transmission	Centrifugal Compressors (dry seals) - Transmission	Transmission compressor stations	1.2 centrifugal compressors per station 53.8 percent dry seal	GHGRP subpart W	44,000 kg/compressor	Zimmerle et al. 2015 report
Underground Gas Storage	Centrifugal Compressors (dry seals) - Storage	Gas storage compressor stations	*0 centrifugal compressors per station 53.8 percent dry seal	*None in US GHGI, Percent from transmission	68,000 kg/compressor	2012 EF from 2022 US GHGI
Underground Gas Storage	Centrifugal Compressors (wet seals) - Storage	Gas storage compressor stations	*0 centrifugal compressors per station 46.2 percent wet seal	*None in US GHGI, Percent from transmission	44,000 kg/compressor	2012 EF from 2022 US GHGI

Combustion Exhaust

Combustion exhaust emissions resulting from the use of fossil fuels in equipment (e.g., heaters, engines, furnaces, etc.) to power on-site operations.

Table 10: Industry contributors, activity drivers, and emission factors for the combustion exhaust emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Oil Exploration	Well Drilling - Oil	Oil wells drilled	-	-	47.2 kg/well	Radian/API 1992
Gathering and Boosting	GB Station Combustion Slip	Gathering and Boosting Stations	2.7 units per station	GHGRP subpart W, scaling factor from Zimmerle 2019	20,400 kg/unit	Zimmerle 2019
Onshore gas production	Gas Engines - Gas Production	Total gas wells	0.12 MMHPhr per well	GRI/EPA 1996 factors, GHGRP subpart W	4,301.6 kg/MMHPhr	2012 EF from 2022 US GHGI, GRI/EPA 1996

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore oil production	Gas Engines - Oil Production	Total oil wells	0.01 compressors per oil well 6.3 MMhp per hr per compressor	Radian/EPA 1999, GHGRP subpart W	4,622.4 kg/MMHP-hr	GRI/EPA 1996
Onshore oil production	Heaters - Oil Production	Total Oil production	-	-	0.01 kg/bbl	EPA 1997
Gas Processing	Gas Engines - Processing	Number of Processing Plants	78.6 MMhp-hr per plant	GHGRP subpart W	4,622.4 kg/MMHPhr	GRI/EPA 1996
Gas Processing	Gas Turbines - Processing	Number of Processing Plants	57.2 MMhp-hr per plant	GHGRP subpart W	109.8 kg/MMHPhr	GRI/EPA 1996
Gas Transmission	Engines (Transmission)	Residential natural gas consumption	0.01 HPhr per residential gas consumption	GRI/EPA 1996, EIA 2021	0.003 kg/HPhr	GRI/EPA 1996
Underground Gas Storage	Engines (Storage)	Residential natural gas consumption	0.001 HPhr per residential gas consumption	GRI/EPA 1996 factors, EIA 2021	0.005 kg/HPhr	GRI/EPA 1996
Gas Transmission	Generators (Engines)	Residential natural gas consumption	0.001 HPhr per residential gas consumption	GRI/EPA 1996 factors, EIA 2021	0.005 kg/HPhr	GRI/EPA 1996
Gas Transmission	Generators (Turbines)	Residential natural gas consumption	0.000007 HPhr per residential gas consumption	GRI/EPA 1996 factors, EIA 2021	0.0001 kg/HPhr	GRI/EPA 1996
Gas Transmission	Turbines (Transmission)	Residential natural gas consumption	0.003 HPhr per residential gas consumption	GRI/EPA 1996 factors, EIA 2021	0.0001 kg/HPhr	GRI/EPA 1996
Underground Gas Storage	Turbines (Storage)	Residential natural gas consumption	0.0004 HPhr per residential gas consumption	GRI/EPA 1996 factors, EIA 2021	0.0001 kg/HPhr	GRI/EPA 1996
LNG Storage	LNG Station Engine Exhaust	LNG Storage Stations	1.2 Million horsepower hours per station	GHGRP subpart W	4,622.4 kg/MMHPhr	2012 EF from 2022 US GHGI, GRI/EPA 1996

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
LNG Storage	LNG Station Turbine Exhaust	LNG Storage Stations	9.7 Million horsepower hours per station	GHGRP subpart W	110 kg/MMHPhr	2012 EF from 2022 US GHGI, GRI/EPA 1996
LNG Import Terminals	LNG Import Terminal Engine Exhaust	LNG Import Terminals	6.7 Million horsepower hours per station	GHGRP subpart W	4,622 kg/MMHPhr	2012 EF from 2022 US GHGI, GRI/EPA 1996
LNG Import Terminals	LNG Import Terminal Turbine Exhaust	LNG Import Terminals	3.4 Million horsepower hours per station	GHGRP subpart W	110 kg/MMHPhr	2012 EF from 2022 US GHGI, GRI/EPA 1996
LNG Export Terminals	LNG Export Terminal Engine Exhaust	LNG Export Terminals	42.2 Million horsepower hours per station	GHGRP subpart W	4,622 kg/MMHPhr	2012 EF from 2022 US GHGI, GRI/EPA 1996
LNG Export Terminals	LNG Export Terminal Turbine Exhaust	LNG Export Terminals	2550 Million horsepower hours per station	GHGRP subpart W	110 kg/MMHPhr	2012 EF from 2022 US GHGI, GRI/EPA 1996

Dehydrators

Dehydrators remove water from the natural gas stream by contacting high pressure wet gas with a liquid absorbent (including ethylene glycol, diethylene glycol, or triethylene glycol). When emissions from glycol dehydrators, the type most commonly used, are not controlled, the dehydrators vent a large amount of methane and other pollutants. Dehydrators are also large sources of VOC, and particularly large sources of toxic air pollutants.

Table 11: Industry contributors, activity drivers, and emission factors for the dehydrators emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore gas production	Dehydrator Vents	Total gas wells	0.03 dehydrators per well 328.5 MMscf per dehydrator	GHGRP subpart W, GRI/EPA 1996	5.2 kg/MMscf	2012 EF from 2022 US GHGI, GRI/EPA 1996

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gathering and Boosting	GB Station Dehydrator Vents - Large units	Gathering and Boosting Stations	0.04 dehydrators per station 87.6 % large dehydrators with vents	GHGRP subpart W, Zimmerle 2019 report	24,325.3 kg/dehydrator	2022 US GHGI
Gathering and Boosting	GB Station Dehydrator Vents - Small units	Gathering and Boosting Stations	0.04 dehydrators per station 12.4 % small dehydrators with vents	GHGRP subpart W, Zimmerle 2019 report	1,249.9 kg/dehydrator	2022 US GHGI
Gathering and Boosting	GB Station Desiccant Dehydrators	Gathering and Boosting Stations	0.008 desiccant dehydrators per station	2012 activity factor from 2022 US GHGI	126.2 kg/desiccant dehydrator	2022 US GHGI
Gas Processing	Dehydrators - Processing	Number of Processing Plants	-	-	25,346.7 kg/plant	2022 US GHGI
Gas Transmission	Dehydrator vents (Transmission)	Transmission compressor stations	0.1 dehydrators per transmission station 5,402 MMscf per dehydrator	GRI/EPA 1996	1.8 kg/MMscf	2022 US GHGI, GRI/EPA 1996
Underground Gas Storage	Dehydrator vents (Storage)	Gas storage compressor stations	0.1 dehydrators per transmission station 45,354.4 MMscf per dehydrator	Zimmerle 2015	2.3 kg/MMscf	2022 US GHGI, GRI/EPA 1996

Leaks

A huge portion of emissions from oil and gas arise from leaks — a broad category that includes what we typically think of as a "leak" (that is, gas escaping past a seal that is failing, through a crack or corroded material on a vessel, etc.), in addition to other improper operations and "mistakes" such as valves that are stuck open, hatches that are left open, flares that are unlit, and other problems on site that lead to emissions.

While EPA's U.S. Emissions Inventory estimates that the oil and gas industry leaks 3 million tons of methane per year (37% of industry emissions),[7] a host of independent, peer-reviewed research has demonstrated that this figure is far too low. In 2018, a study in *Science* written by twenty-four scientists at sixteen universities and institutions analyzed on-the-ground methane measurements from over 400 wellpads and other facilities across the gas industry, and aircraft based studies of several oil and natural gas production basins; these basins account for over 30% of U.S. natural gas production. Their analysis showed that nationwide methane emissions from the oil and gas industry are actually 60% higher than EPA estimates, and the 'missing emissions' are largely due to leaks and improper venting.[8] This means that an enormous quantity of methane – 7.1 million tons – arises from leaks and improper venting. Over the near-term, the methane from these leaks heats our climate as much as 160 coal-fired power plants.

Leaks are widespread, and there is no single cause for these leaks. Thermal or mechanical stresses can degrade seals, valves, flanges, etc. They can be caused by human error (e.g., improper installation, operation, or maintenance) as well as normal operations and exposure to weather conditions can wear out equipment over time. Leaks will eventually occur at all oil and gas facilities; failing to fix them in a timely matter is a wasteful and harmful practice that leads to clearly avoidable emissions. The biggest source of these emissions are very large, but uncommon, "super-emitters" which happen due to some improper operation (stuck valve, hatch left open). Research has demonstrated that super-emitters cannot be predicted and can occur at any site.[9]

Table 12: Industry contributors, activity drivers, and emission factors for the leaks emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore gas production	Abnormal Conditions	Total gas wells	-	-	4,436 kg/well	Alvarez, 2018
	Dehydrator Leaks	Total gas wells	0.03 dehydrators per well	GHGRP subpart W	418 kg/dehydrator	2012 EF from 2022 US GHGI, GRI/EPA 1996

[7] Environmental Protection Agency. 2023. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021*. Retrieved from https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2017
[8] Ramón A. Alvarez et al. , *Assessment of methane emissions from the U.S. oil and gas supply chain*. Science361,186-188(2018).DOI:10.1126/science.aar7204 https://science.sciencemag.org/content/361/6398/186
[9] Daniel Zavala-Araiza, David Lyon, Ramón A. Alvarez, Virginia Palacios, Robert Harriss, Xin Lan, Robert Talbot, and Steven P. Hamburg. Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. Environmental Science & Technology 2015 49 (13), 8167-8174. DOI: 10.1021/acs.est.5b00133 https://pubs.acs.org/doi/abs/10.1021/acs.est.5b00133

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
	Gas Wells with Hydraulic Fracturing	Gas wells with hydraulic fracturing	-	-	133 kg/well	2012 EF from 2022 US GHGI, GRI/EPA 1996
	Gas Wells without Hydraulic Fracturing	Gas wells without hydraulic fracturing	-	-	96 kg/well	2022 US GHGI, GRI/EPA 1996
	Heaters	Total gas wells	0.13 heaters per well	GHGRP subpart W	227 kg/heater	2012 EF from 2022 US GHGI, GRI/EPA 1996
	Meters/Piping	Total gas wells	0.84 meters of piping per well	GHGRP subpart W	196 kg/meter	2012 EF from 2022 US GHGI, GRI/EPA 1996
	Separators	Total gas wells	0.71 separators per well	GHGRP subpart W	378 kg/separator	2012 EF from 2022 US GHGI, GRI/EPA 1996
Onshore oil production	Abnormal Conditions	Total oil wells	-	-	3,275 kg/well	Alvarez, 2018
Onshore oil production	Headers[10]	Total oil wells	0.23 headers per oil well 24.39 percent in heavy crude 75.61 percent in light crude	GHGRP subpart W	0.54 kg/header (heavy crude) 76.31 kg/header (light crude)	2022 US GHGI, Consensus of Industry Review Panel and API Workbook 4638 (API 1996)
Onshore oil production	Heater Treaters (light crude)	Total oil wells	0.19 heater treaters per oil well	GHGRP subpart W	134.93 kg/(Heater Treater)	2022 US GHGI, Consensus of Industry Review Panel and API Workbook 4638 (API 1996)
Onshore oil production	Oil Wellheads	Total oil wells	7.05 percent of oil wells that are heavy crude	GHGRP subpart W, Radian/EPA 1999	0.89 kg/well (heavy crude)	2022 US GHGI, Consensus of Industry Review

[10] An oil header consists of multiple valves connected to each well flow line that directs the oil production to either the test separator, pig receiving trap, or group separator. The number of wells connected to a header depends on the volume of the oil produced per month for each well.

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
			92.95 percent of oil wells that are light crude		116.91 kg/well (light crude)	Panel and API Workbook 4638 (API 1996)
Onshore oil production	Separators	Total oil wells	0.36 separators per well 9.90 percent heavy crude 90.10 percent light crude	GHGRP subpart W	1.08 kg/separator (heavy crude separators) 97.38 kg/separator (light crude separators)	2022 US GHGI, Consensus of Industry Review Panel and API Workbook 4638 (API 1996)
Gathering and Boosting	Abnormal Conditions	Gathering and Boosting Stations	-	-	74,866 kg/station	Alvarez, 2018
Gathering and Boosting	GB Station Dehydrator Leaks	Gathering and Boosting Stations	0.04 dehydrators per station	GHGRP subpart W, Zimmerle 2019 report.	498 kg/dehydrator	Zimmerle 2019
Gathering and Boosting	Separators	Gathering and Boosting Stations	2 separators per station	GHGRP subpart W	92 kg/separator	Zimmerle 2019
Gathering and Boosting	Yard Piping	Gathering and Boosting Stations	-	-	12,553 kg/station	Zimmerle 2019
Gas Processing	Plant Fugitives	Number of Processing Plants	-	-	23,445 kg/plant	2012 EF from 2022 US GHGI
Gas Transmission	Meter/Regulator Station (Farm Taps and Direct Sales)	Transmission pipeline distance	1.69 M&R (Farm Taps + Direct Sales) per transmission mile	GHGRP subpart W, ICF 2008 report.	219 kg/station	GRI/EPA 1996
Gas Transmission	Meter/Regulator (Transmission Company Interconnect)	Transmission pipeline distance	0.06 M&R (Trans. Co. Interconnect) per transmission mile	GHGRP subpart W, ICF 2008 report.	28,007 kg/station	GRI/EPA 1996
Gas Transmission	Station and Compressor Fugitive Emissions	Transmission compressor stations	-	-	64,000 kg/station	2022 US GHGI, Zimmerle 2015

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Underground Gas Storage	Station and Compressor Fugitive Emissions	Gas storage compressor stations	-	-	71,000 kg/station	2022 US GHGI, Zimmerle 2015
Underground Gas Storage	Wells (Storage)	Gas storage compressor stations	48.2 storage wells per station	Zimmerle 2015	805 kg/well	GRI/EPA 1996
LNG Storage	LNG Stations	LNG Storage Stations	-	-	14,027 kg/facility	EPA GHGRP Subpart W
LNG Import Terminals	LNG Import Terminals	LNG Import Terminals	-	-	57,731 kg/terminal	2012 EF from 2022 US GHGI
LNG Export Terminals	LNG Export Terminals	LNG Export Terminals	-	-	800,720 kg/terminal	2012 EF from 2022 US GHGI
Aboveground Distribution Stations	Customer Meters: Commercial	Commercial natural gas customers	100 percent meters outdoors	EIA 2021	23 kg/meter	GTI 2009, and Clearstone 2011
Aboveground Distribution Stations	Customer Meters: Industrial	Industrial natural gas customers	100 percent meters outdoors	EIA 2021	105 kg/meter	GTI 2009, and Clearstone 2011
Aboveground Distribution Stations	Customer Meters: Residential	Residential natural gas customers	79 percent meters outdoors	GRI/EPA 1996, EIA 2021	1.49 kg/meter	GRI/EPA 1996, GTI 2009, and Clearstone 2011
Aboveground Distribution Stations	Meter/Regulator	Main total distance	0.1 aboveground station per main miles	GHGRP subpart W	- 2,143 kg/station (M&R >300 psi) - 995 kg/station (M/R 100-300) - 727 kg/station (M&R <100 psi) - 869 kg/station (Reg Station >300) - 51 kg/station (R-Vault >300) - 143 kg/station (Reg Station 100-300) - 51 kg/station (R-Vault 100-300)	GRI/EPA 1996, and Lamb et al. 2015

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
					- 164 kg/station (Reg Station 40-100) - 51 kg/station (R-Vault 40-100) - 22 kg/station (Reg Station <40)	

Liquids Unloading

Methane emissions from a process used to remove liquids (produced water, oil, or condensate) that may accumulate in the well production tubing downhole.

Table 13: Industry contributors, activity drivers, and emission factors for the liquids unloading emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore gas production	Liquids Unloading with Plunger Lifts	Total gas wells	0.1 unloadings per well 63.1 percent with plunger lift	2012 activity factor from 2022 US GHGI	3,794 kg/well	2012 EF from 2022 US GHGI
Onshore gas production	Liquids Unloading without Plunger Lifts	Total gas wells	0.1 unloadings per well 36.9 percent with plunger lift	2012 activity factor from 2022 US GHGI	3,065.3 kg/well	2012 EF from 2022 US GHGI

Offshore

Emissions associated with all upstream oil and natural gas production from on offshore platforms.

Table 12: Industry contributors, activity drivers, and emission factors for the offshore emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Offshore gas production	Offshore Gas Vent/Leak	Offshore Gas production	-	-	0.0003 kg/scf	2022 US GHGI
Offshore gas production	Offshore Gas Flaring	Offshore Gas production	-	-	4E-07 kg/scf	2022 US GHGI
Offshore oil production	Offshore Oil Vent/Leak	Offshore oil production	-	-	0.3 kg/bbl	2022 US GHGI
Offshore oil production	Offshore Oil Flaring	Offshore oil production	-	-	0.0008 kg/bbl	2022 US GHGI

Pneumatic Controllers

Gas-driven automatic pneumatic equipment uses the pressure energy of natural gas in pipelines to control and operate valves and operate pumps. This approach allows operators to automate equipment at sites without electricity – which is very typical for oil and gas sites in some nations. In these nations, pneumatic equipment is ubiquitous at oil and gas production and compression facilities, and it is designed to vent natural gas to the atmosphere. Pneumatic valve controllers automatically operate valves based on factors like liquid level in a liquid-gas separator, pressure, or temperature.

Table 13: Industry contributors, activity drivers, and emission factors for the pneumatic controllers emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore gas production	Pneumatic Controllers - High Bleed	Total gas wells	1.98 controllers per well 8% high	2012 data from 2022 US GHGI	4,371 kg/controller	2022 US GHGI
Onshore gas production	Pneumatic Controllers - Intermittent Bleed	Total gas wells	1.98 controllers per well 62% intermittent	2012 data from 2022 US GHGI	1,535 kg/controller	2022 US GHGI
Onshore gas production	Pneumatic Controllers - Low Bleed	Total gas wells	1.98 controllers per well 30% low	2012 data from 2022 US GHGI	161 kg/controller	2022 US GHGI

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore gas production	Pneumatic Controllers - Zero Bleed	Total gas wells	Zero		Zero	
Gathering and Boosting	GB Station High-bleed Pneumatic Devices	Gathering and Boosting Stations	20 pneumatics per station 8% high	2012 data from 2022 US GHGI, Zimmerle 2019	5,089 kg/device	2022 US GHGI
Gathering and Boosting	GB Station Intermittent Bleed Pneumatic Devices	Gathering and Boosting Stations	20 pneumatics per station 62% intermittent	2012 data from 2022 US GHGI, Zimmerle 2019	1,721 kg/device	2022 US GHGI
Gathering and Boosting	GB Station Low-Bleed Pneumatic Devices	Gathering and Boosting Stations	20 pneumatics per station 30% low	2012 data from 2022 US GHGI, Zimmerle 2019	178 kg/device	2022 US GHGI
Gathering and Boosting	GB Station Zero Bleed Pneumatic Devices	Gathering and Boosting Stations	Zero		Zero	
Onshore oil production	High-bleed Pneumatic Devices	Total oil wells	0.96 pneumatic devices per oil well 8% high	2012 data from 2022 US GHGI	4,370.7 kg/device	2022 US GHGI
Onshore oil production	Intermittent Bleed Pneumatic Devices	Total oil wells	0.96 pneumatic devices per oil well 62% intermittent	2012 data from 2022 US GHGI	1,534.7 kg/device	2022 US GHGI
Onshore oil production	Low-Bleed Pneumatic Devices	Total oil wells	0.96 pneumatic devices per oil well 30% low	2012 data from 2022 US GHGI	160.6 kg/device	2022 US GHGI
Onshore oil production	Pneumatic Controllers - Zero Bleed	Total oil wells	Zero		Zero	
Gas Processing	Percent natural gas driven controllers	Number of Processing Plants	100% plants using gas driven controllers		3,173 kg/plant	2022 US GHGI
Gas Transmission	Pneumatic Controllers - High bleed - Transmission	Transmission compressor stations	25 pneumatics per transmission station 8% high	GHGRP subpart W	2,600 kg/controller	2012 EF from 2022 US GHGI

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gas Transmission	Pneumatic Controllers - Intermittent bleed - Transmission	Transmission compressor stations	25 pneumatics per transmission station 62% intermittent	GHGRP subpart W	344 kg/controller	2012 EF from 2022 US GHGI
Gas Transmission	Pneumatic Controllers - Low bleed - Transmission	Transmission compressor stations	25 pneumatics per transmission station 30% low	GHGRP subpart W	207 kg/controller	2012 EF from 2022 US GHGI
Gas Transmission	Pneumatic Controllers - Zero Bleed - Transmission	Transmission compressor stations	Zero		Zero	
Underground Gas Storage	Pneumatic Controllers - High bleed - Storage	Gas storage compressor stations	68 pneumatics per storage station 8% high	GHGRP subpart W	2,929 kg/controller	2022 US GHGI
Underground Gas Storage	Pneumatic Controllers - Intermittent bleed - Storage	Gas storage compressor stations	68 pneumatics per storage station 62% intermittent	GHGRP subpart W	373 kg/controller	2022 US GHGI
Underground Gas Storage	Pneumatic Controllers - Low bleed - Storage	Gas storage compressor stations	68 pneumatics per storage station 30% low	GHGRP subpart W	220 kg/controller	2022 US GHGI
Underground Gas Storage	Pneumatic Controllers - Zero Bleed - Storage	Gas storage compressor stations	Zero		Zero	

Pneumatic Pumps

Pneumatic pumps *use the* pressure of natural gas to supply the energy required to circulate and pressurize liquids. For example, they are used to introduce liquid chemicals such as corrosion inhibitors into gas pipelines.

Table 14: Industry contributors, activity drivers, and emission factors for the pneumatic pumps emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gathering and Boosting	GB Station Pneumatic Pumps	Gathering and Boosting Stations	2 pumps per station 100% gas driven	GHGRP subpart W, Enverus	1,661 kg/pump	2022 US GHGI

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
				DrillingInfo dataset, Zimmerle 2019		
Onshore gas production	Chemical Injection Pumps - Gas Production	Total gas wells	0.18 pumps per gas well 100% gas driven	GHGRP subpart W	1,521 kg/pump	2022 US GHGI
Onshore gas production	Kimray Pumps	Total gas wells	0.03 dehydrators per well 328.5 MMscf per dehydrator 89.10% of throughput 100% gas driven	GHGRP subpart W, GRI/EPA 1996	11 kg/MMscf	2012 EF from 2022 US GHGI, GRI/EPA 1996
Onshore oil production	Chemical Injection Pumps - Oil Production	Total oil wells	0.09 pumps per oil well 100% gas driven	GHGRP subpart W, Enverus DrillingInfo dataset	1,515.3 kg/pump	2022 US GHGI

Reciprocating Compressors

Reciprocating compressors use pistons to compress gas. These compressors have seals on the rods that transmit motion from the engine to the pistons inside the high-pressure compressor cylinders; these seals are often referred to as rod packing and are a large source of emissions. Even when new, the seals let some gas escape.

Table 15: Industry contributors, activity drivers, and emission factors for the reciprocating compressors emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore gas production	Compressors - Gas Production	Total gas wells	0.08 compressors per well	GHGRP subpart W	1,989 kg/compressor	2012 EF from 2022 US GHGI, GRI/EPA 1996
Gathering and Boosting	GB Station Compressors	Gathering and Boosting Stations	3 compressors per station	GHGRP subpart W, Enverus	16,118 kg/compressor	2022 US GHGI, Zimmerle 2019

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
				DrillingInfo dataset Zimmerle 2019		
Onshore oil production	Compressors - Oil Production	Total oil wells	0.005 compressors per oil well	GHGRP subpart W, EIA dataset	702.99 kg/compressor	2022 US GHGI, Consensus of Industry Review Panel data
Gas Processing	Reciprocating Compressors - Processing	Number of Processing Plants	6.1 reciprocating compressors per plant	GHGRP subpart W	17,756 kg/compressor	2012 EF from 2022 US GHGI
Gas Transmission	Reciprocating Compressor - Transmission	Transmission compressor stations	2.9 reciprocating compressors per station	Zimmerle 2015 report	65,000 kg/compressor	2022 US GHGI, Zimmerle 2015
Underground Gas Storage	Reciprocating Compressors - Storage	Gas storage compressor stations	4.3 reciprocating compressors per station	Zimmerle 2015 report	70,000 kg/compressor	2022 US GHGI, Zimmerle 2015

Tanks

Storage tanks are used to hold oil, condensate, and produced water from oil and gas wells. These wells are usually kept at a high pressure, but oil, water, and other liquids are typically stored at wellsites in tanks held at or near atmospheric pressure. When the liquids are moved from the high-pressure well to the atmospheric-pressure tank, methane and other volatile hydrocarbons that are dissolved in the liquids bubble or “flash” out of the liquid, just as bubbles come out of soda when you take the cap off the bottle, reducing the pressure in the bottle. Many tanks have no controls, so the methane is released into the atmosphere, together with the other volatile hydrocarbons. These other hydrocarbons are potent precursors of regional ozone smog, and they also include toxic air pollutants.

Tanks emissions can be controlled, and the hydrocarbons conserved for sale, by using vapor recovery units – small compressors that are designed to capture these hydrocarbon vapors so that they can be pressurized and sent into a pipeline.

Table 16: Industry contributors, activity drivers, and emission factors for the tanks emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gathering and Boosting	GB Station Tanks	Gathering and Boosting Stations	5 tanks per station	GHGRP subpart W, Enverus DrillingInfo dataset, Zimmerle 2019	5,606 kg/tank	2022 US GHGI, Zimmerle 2019
Onshore gas production	Malfunctioning Separator Dump Valves - Gas Production	Condensate Production	93.1 percent condensate sent to tanks 82 percent large tanks	GHGRP subpart W	0.00007 kg/bbl	2012 EF from 2022 US GHGI
Onshore gas production	Large Tanks with Flares - Gas Production	Condensate Production	93.1 percent condensate sent to tanks 82 percent large tanks 65 percent tanks with flares	GHGRP subpart W	0.005 kg/bbl	2012 EF from 2022 US GHGI
Onshore gas production	Large Tanks with Vapor Recovery Units - Gas Production	Condensate Production	93.1 percent condensate sent to tanks 82 percent large tanks 5 percent tanks with VRU	GHGRP subpart W	0.003 kg/bbl	2022 US GHGI
Onshore gas production	Large Tanks without Control - Gas Production	Condensate Production	93.1 percent condensate sent to tanks 82 percent large tanks 30 percent tanks without control	GHGRP subpart W	0.18 kg/bbl	2012 EF from 2022 US GHGI

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore gas production	Small Tanks with Flares - Gas Production	Condensate Production	93.1 percent condensate sent to tanks 18 percent small tanks 20 percent tanks with flares	GHGRP subpart W	0.006 kg/bbl	2012 EF from 2022 US GHGI
Onshore gas production	Small Tanks without Flares - Gas Production	Condensate Production	93.1 percent condensate sent to tanks 18 percent small tanks 80 percent tanks without flares	GHGRP subpart W	0.5 kg/bbl	2012 EF from 2022 US GHGI
Onshore oil production	Floating Roof Tanks	Total oil wells	4.3E-05 floating roof tanks per oil well	GHGRP subpart W, Industry panel, Entropy tank survey	6,515.78 kg/tank	2022 US GHGI, AP-42 Compilation of Air Pollutant Emission Factors report and API Workbook 4638 (1996)
Onshore oil production	Large Tanks with Flares - Oil Production	Total Oil production	62.7 percent of oil sent to tank 94 percent of tank throughput from large tanks 65 percent of large tanks with flares	GHGRP subpart W, EIA dataset	0.01 kg/bbl	2012 EF from 2022 US GHGI
Onshore oil production	Large Tanks without Control - Oil Production	Total Oil production	62.7 percent of oil sent to tank 94 percent of tank throughput from large tanks	GHGRP subpart W, EIA dataset	0.15 kg/bbl	2012 EF from 2022 US GHGI.

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
			30 percent of large tanks without control			
Onshore oil production	Large Tanks with VRU	Total Oil production	62.7 percent of oil sent to tank 94 percent of tank throughput from large tanks 5 percent of large tanks with VRU	GHGRP subpart W, EIA dataset	0.01 kg/bbl	2012 EF from 2022 US GHGI
Onshore oil production	Malfunctioning Separator Dump Valves - Oil Production	Total Oil production	62.7 percent of oil sent to tank 94 percent of tank throughput from large tanks	GHGRP subpart W	0.003 kg/bbl	2012 EF from 2022 US GHGI
Onshore oil production	Small Tanks with Flares - Oil Production	Total Oil production	62.7 percent of oil sent to tank 6 percent of tank throughput from small tanks 20 percent of small tanks with Flares	GHGRP subpart W	0.002 kg/bbl	2012 EF from 2022 US GHGI
Onshore oil production	Small Tanks without Flares - Oil Production	Total Oil production	62.7 percent of oil sent to tank 6 percent of tank throughput from small tanks 80 percent of small tanks without Flares	GHGRP subpart W	0.04 kg/bbl	2012 EF from 2022 US GHGI

Well Completions and Workovers

Methane emissions resulting from a process, including hydraulic fracturing (HF), that allows for the flowback of petroleum or natural gas to expel drilling and reservoir fluids and test the reservoir flow characteristics. Completions occur at newly drilled wells, while workovers are done at existing wells to increase production.

Table 17: Industry contributors, activity drivers, and emission factors for the well completions and workovers emission source

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gas Exploration	HF Completions - Non-REC with Venting - Gas	Gas wells with hydraulic fracturing	4.1 percent of HF wells completed or worked over in year 46.5 percent of HF completions that vent without REC	GHGRP subpart W	24,998 kg/event	2012 EF from 2022 US GHGI
Gas Exploration	HF Completions - Non-REC with Flaring - Gas	Gas wells with hydraulic fracturing	4.1 percent of HF wells completed or worked over in year 12.6 percent of HF completions that flare without REC	GHGRP subpart W	3,702 kg/event	2012 EF from 2022 US GHGI
Gas Exploration	HF Completions - REC with Venting - Gas	Gas wells with hydraulic fracturing	4.1 percent of HF wells completed or worked over in year 29.5 percent of HF completions that vent with REC	GHGRP subpart W	4,851 kg/event	2012 EF from 2022 US GHGI
Gas Exploration	HF Completions - REC with Flaring - Gas	Gas wells with hydraulic fracturing	4.1 percent of HF wells completed or worked over in year 11.4 percent of HF completions that flare with REC	GHGRP subpart W	2,301 kg/event	2012 EF from 2022 US GHGI
Gas Exploration	Non-HF Completions - Vented - Gas	Gas wells without hydraulic fracturing	0.46 percent of wells completed in year	GHGRP subpart W, ICF 1997 report	14,312 kg/event	2012 EF from 2022 US GHGI

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
			31 percent non-HF workover vented			
Gas Exploration	Non-HF Completions - Flared - Gas	Gas wells without hydraulic fracturing	0.46 percent of wells completed in year 69 percent non-HF workover flared	GHGRP subpart W, ICF 1997 report	39 kg/event	2012 EF from 2022 US GHGI
Oil Exploration	Non-HF Completions - Vented - Oil	Total oil wells	0.0056 events per oil well	GHGRP subpart W, Enverus DrillingInfo dataset	14 kg/event	2022 US GHGI, GRI/EPA 1996.
Oil Exploration	HF Completions: Non-REC with Venting - Oil	Oil wells with hydraulic fracturing	0.097 events per HF oil well 51 percent of HF completions that vent without REC	GHGRP subpart W, Enverus DrillingInfo dataset	40,449 kg/event	2012 EF from 2022 US GHGI
Oil Exploration	HF Completions: Non-REC with Flaring - Oil	Oil wells with hydraulic fracturing	0.097 events per HF oil well 11 percent of HF completions that flare without REC	GHGRP subpart W, Enverus DrillingInfo dataset	1,254 kg/event	2012 EF from 2022 US GHGI
Oil Exploration	HF Completions: REC with Venting - Oil	Oil wells with hydraulic fracturing	0.097 events per HF oil well 15 percent of HF completions that vent with REC	GHGRP subpart W, Enverus DrillingInfo dataset	1,437 kg/event	2012 EF from 2022 US GHGI
Oil Exploration	HF Completions: REC with Flaring - Oil	Oil wells with hydraulic fracturing	0.097 events per HF oil well 22 percent of HF completions that flare with REC	GHGRP subpart W, Enverus DrillingInfo dataset	1,473 kg/event	2012 EF from 2022 US GHGI
Onshore gas production	HF Workovers - Non-REC with Venting - Gas Production	Gas wells with hydraulic fracturing	1.0% workover rate	GHGRP subpart W	24,998 kg/event	2012 EF from 2022 US GHGI

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
			55 percent of HF workovers that vent without REC			
Onshore gas production	HF Workovers - Non-REC with Flaring - Gas Production	Gas wells with hydraulic fracturing	1.0% workover rate 26 percent of HF workovers that flare without REC	GHGRP subpart W	3,702 kg/event	2012 EF from 2022 US GHGI
Onshore gas production	HF Workovers - REC with Venting - Gas Production	Gas wells with hydraulic fracturing	1.0% workover rate 19 percent of HF workovers that vent with REC	GHGRP subpart W	4,851 kg/event	2012 EF from 2022 US GHGI
Onshore gas production	HF Workovers - REC with Flaring - Gas Production	Gas wells with hydraulic fracturing	1.0% workover rate 0.2% percent of HF workovers that flare with REC	GHGRP subpart W	2,301 kg/event	2012 EF from 2022 US GHGI
Onshore gas production	Non-HF Workovers - Vented - Gas Production	Gas wells without hydraulic fracturing	.35% workover rate 96 percent non-HF workover vented	GHGRP subpart W	191 kg/event	2012 EF from 2022 US GHGI
Onshore gas production	Non-HF Workovers - Flared - Gas Production	Gas wells without hydraulic fracturing	4.35% workover rate 4 percent non-HF workover flared	GHGRP subpart W	1 kg/event	2012 EF from 2022 US GHGI.
Onshore oil production	HF Workovers: Non-REC with Venting - Oil Production	Total oil wells	0.003 workovers per well 52 percent of HF workovers that vent without REC	GHGRP subpart W	40,448.58 kg/event	2012 EF from 2022 US GHGI
Onshore oil production	HF Workovers: REC with Venting - Oil Production	Total oil wells	0.003 workovers per well 27 percent of HF workovers that vent with REC	GHGRP subpart W	1,436.95 kg/event	2012 EF from 2022 US GHGI.

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore oil production	Non-HF Well Workovers - Oil Production	Total oil wells	7.50% workovers per well	GHGRP subpart W, Radian/EPA 1999	1.85 kg/event	2022 US GHGI, Radian/EPA 1999
Onshore oil production	HF Workovers: Non-REC with Flaring - Oil Production	Total oil wells	0.003 workovers per well 8 percent of HF workovers that flare without REC	GHGRP subpart W	1,254.35 kg/event	2012 EF from 2022 US GHGI
Onshore oil production	HF Workovers: REC with Flaring - Oil Production	Total oil wells	0.003 workovers per well 13 percent of HF workovers that flare with REC	GHGRP subpart W	1,472.65 kg/event	2012 EF from 2022 US GHGI

Other

Other methane emissions sources in the oil and gas industry, not covered by one of the other emission sources.

Table 18: Industry contributors, activity drivers, and emission factors for other emission sources

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gas Exploration	Non-completion Well Testing - Flared - Gas	Total gas wells	0.00002 events per gas well	GHGRP subpart W	1,715 kg/event	2012 EF from 2022 US GHGI
Gas Exploration	Non-completion Well Testing - Vented - Gas	Total gas wells	0.00094 events per gas well	GHGRP subpart W	5,262 kg/event	2012 EF from 2022 US GHGI
Gas Exploration	Well Blowouts - Gas	Well Blowouts	-	-	26,900,000 kg/event	2019 EF from 2022 US GHGI
Gas Exploration	Well Drilling - Gas	Gas wells drilled	-	-	52 kg/well	2012 EF from 2022 US GHGI, Radian/API 1992.
Oil Exploration	Non-completion Well Testing - Vented - Oil	Total oil wells	0.032 events per oil well	GHGRP subpart W	410 kg/event	2012 EF from 2022 US GHGI

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Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Oil Exploration	Non-completion Well Testing - Flared - Oil	Total oil wells	0.002 number of events per oil well	GHGRP subpart W	524 kg/event	2012 EF from 2022 US GHGI
Gathering and Boosting	GB Station Flare Stacks	Gathering and Boosting Stations	0.67 flares per station	GHGRP subpart W, Zimmerle 2019	1,871 kg/flare	2022 US GHGI
Gathering and Boosting	GB Station Acid Gas Removal Units	Gathering and Boosting Stations	0.02 AGR unit per station	GHGRP subpart W, Zimmerle 2019	598 kg/AGR	2022 US GHGI, Zimmerle 2019
Gathering and Boosting	GB Pipeline Leaks	Gathering and Boosting Stations	56 miles per station	GHGRP subpart W, GRI/EPA 1996 factors	289 kg/mile	2022 US GHGI
Onshore gas production	Compressor Starts - Gas Production	Total gas wells	0.08 compressors per well	GHGRP subpart W	172 kg/compressor	2022 US GHGI, GRI/EPA 1996
Onshore gas production	Pressure Relief Valves - Gas Production	Total gas wells	2.4 PRV per well	GHGRP subpart W, GRI/EPA 1996 factors	0.69 kg/PRV	2022 US GHGI, GRI/EPA 1996
Onshore gas production	Miscellaneous Production Flaring - Gas Production	Gross onshore gas production	100 Percent of gas production in basin	Total natural gas production in year	-	-
Onshore oil production	Miscellaneous Production Flaring - Oil Production	Total Oil production	-	-	0.004 kg/bbl	2012 EF from 2022 US GHGI
Onshore oil production	Battery Pumps	Total oil wells	0.3 battery pumps per oil well	GHGRP subpart W, Industry Review Panel	1.7 kg/pump	2022 US GHGI, API 1995
Onshore oil production	Compressor Starts - Oil Production	Total oil wells	0.005 compressors per oil well	GHGRP subpart W	162.6 kg/compressor	2022 US GHGI, GRI/EPA 1996
Onshore oil production	Pipelines	Total oil wells	0.03 miles per oil well	GHGRP subpart W, annual Oil and Gas Journal Pipeline Economics issue 2021	-	-
Onshore oil production	Pressure Relief Valves - Oil Production	Total Oil production	8.4E-05 valves per bbl production	GHGRP subpart W, Industry Review Panel	0.67 kg/valve	2022 US GHGI, GRI/EPA 1996

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore oil production	Sales Areas	Total Oil production	0.0008 loadings per bbl	GHGRP subpart W, EIA datasets	0.78 kg/loading	2022 US GHGI, Industry Review Panel data
Oil Exploration	Well Blowouts - Oil	Oil wells drilled	0.003 blowouts per oil wells drilled	GHGRP subpart W, Industry Review Panel	48,150 kg/event	2022 US GHGI
Onshore oil production	Produced Water - Regular Pressure Oil Wells	Total Oil production	8.2E-06 bbls of produced water per bbls of oil produced 27 percent from regular pressure wells	GHGRP subpart W, Enverus DrillingInfo dataset	14,197.6 kg/bbl	2022 US GHGI, EPA's Oil & Gas Tool for the 2017 NEI.
Onshore oil production	Produced Water - Low Pressure Oil Wells	Total Oil production	8.2E-06 bbls of produced water per bbls of oil produced 73 percent from low pressure wells	GHGRP subpart W, Enverus DrillingInfo dataset	1,496.9 kg/bbl	2022 US GHGI, EPA's Oil & Gas Tool for the 2017 NEI
Gas Exploration	Thermal Desorption Units Gas Stack - Gas	Gas Wells drilled	2,972.4 bbl mud per well drilled	Okoro EE, Dosunmu A, Iyuke SE 2018.	0.00000006 kg/bbl mud	Ogbuagu DH, Esinulo AC, Job SE 2016
Oil Exploration	Thermal Desorption Units Gas Stack - Oil	Oil wells drilled	2,972.4 bbl mud per well drilled	Okoro EE, Dosunmu A, Iyuke SE 2018.	0.00000006 kg/bbl mud	Ogbuagu DH, Esinulo AC, Job SE 2016
Gas Processing	Acid Gas Removal Unit Vents - Processing	Number of Processing Plants	0.5 AGR vents per plant	GHGRP subpart W, GRI/EPA 1996 factors.	42,763 kg/AGR	2022 US GHGI, GRI/EPA 1996
Gas Processing	Flares - Processing	Number of Processing Plants	-	-	29,249 kg/plant	2012 EF from 2022 US GHGI
Gas Transmission	Flaring (Transmission)	Transmission compressor stations	-	-	176 kg/station	2012 EF from 2022 US GHGI
Underground Gas Storage	Flaring (Storage)	Gas storage compressor stations	-	-	3,299 kg/station	2022 US GHGI

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Gas Transmission	Pipeline Leaks - Transmission	Transmission pipeline distance	-	-	11 kg/mile	2022 US GHGI, GRI/EPA 1996 report.
Gas Transmission	Station Venting Transmission	Transmission compressor stations	-	-	81,902 kg/station	2012 EF from 2022 US GHGI, GRI/EPA 1996
Underground Gas Storage	Station Venting Storage	Gas storage compressor stations	-	-	83,954 kg/station	2022 US GHGI, GRI/EPA 1996
Underground Distribution Pipelines	Underground Pipeline Leaks - Mains - Cast Iron	Mains - Cast Iron	-	-	1,157 kg/mile	2022 US GHGI, Lamb et al. 2015, GRI/EPA 1996
Underground Distribution Pipelines	Underground Pipeline Leaks - Mains - Unprotected steel	Mains - Unprotected steel	-	-	861 kg/mile	2022 US GHGI,
Underground Distribution Pipelines	Underground Pipeline Leaks - Mains - Protected steel	Mains - Protected steel	-	-	97 kg/mile	Lamb et al. 2015, GRI/EPA 1996
Underground Distribution Pipelines	Underground Pipeline Leaks - Mains - Plastic	Mains - Plastic	-	-	29 kg/mile	2022 US GHGI
Underground Distribution Pipelines	Underground Pipeline Leaks - Services - Unprotected steel	Services - Unprotected steel	-	-	14 kg/service	Lamb et al. 2015. GRI/EPA 1996
Underground Distribution Pipelines	Underground Pipeline Leaks - Services Protected steel	Services Protected steel	-	-	1 kg/service	2022 US GHGI
Underground Distribution Pipelines	Underground Pipeline Leaks - Services - Plastic	Services - Plastic	-	-	0.3 kg/service	Lamb et al. 2015, GRI/EPA 1996
Underground Distribution Pipelines	Underground Pipeline Leaks - Services - Copper	Services - Copper	-	-	5 kg/service	2022 US GHGI, GRI/EPA 1996
Underground Distribution Pipelines	Mishaps (Dig-ins)	Service + Main Length	-	-	30 kg/mile	2022 US GHGI, GRI/EPA 1996
Aboveground Distribution Stations	Pressure Relief Valve Releases	Main total distance	-	-	1 kg/mile	2022 US GHGI, GRI/EPA 1996

Industry Subsegment	**Emission Contributor**	Industry Contributor	Default Activity Driver	Default Activity Driver Source	Default Emission Factor (EF)	Emission Factor (EF) Source
Onshore gas production	Produced Water - Natural Gas Wells	Gross onshore gas production	1.3E-10 mmbbls produced water per cf of gas produced	GHGRP subpart W	50,529 kg/MMbbl produced water	2012 EF from 2022 US GHGI

Mitigation Plan

The CoMAT application estimates potential abatement for each emission source. For each of the emissions sources in this section, we describe the abatement measures available to reduce emissions and then describe the method that CoMAT uses to quantify methane reductions. In all cases, the initial abatement estimate is based on the Compendium of Leading Policies, which is a compilation of policy items from jurisdictions around the world. CoMAT will also give the user the ability to tailor the stringency of the policy for each emission source and will estimate emission reduction associated with this change. While this functionality is *currently under development* in the application, users can work with the legacy CoMAT excel document to create a customized mitigation plan on request.

Associated Gas Venting and Flaring

While a substantial portion of this gas is flared off — wasting energy and producing large amounts of carbon dioxide and other pollutants — some is just dumped into the air or vented. Even in cases where a gas pipeline is not connected, there are a variety of other technologies that operators can use to reduce associated gas flaring at oil wells.[11]

Venting of this gas should be prohibited in all cases as an unnecessary source of harmful air pollution. There are numerous low-cost (and usually profitable) ways to utilize natural gas from oil wells. Flaring should be a last resort: only in the most extreme cases should oil producers be allowed to flare gas, and it should be strictly a temporary measure.

CoMAT estimates emission reduction from associated gas venting and flaring by applying an overall percent reduction, and then adjusting 2 key pieces of activity data. The following are the reductions applied based on the Compendium/Best Practice policies.

- Percent reduction of flaring: 80%
- Flare efficiency: 98%
- Percent of associated gas that is vented rather than flared: 1%

Blowdown Venting

[11] Carbon Limits AS. (October. 2015). *Improving utilization of associated gas in US tight oil fields*. Clean Air Task Force. October 2015. Retrieved from https://www.catf.us/resource/putting-out-the-fire/

Emissions from blowdown venting can be reduced by designing a system that routes vented gas to a vapor recovery unit or combustion device. Alternatively, a temporary compressor handle gas would otherwise be vented during a maintenance blowdown, either by temporarily storing the gas or inserting it into the pipeline past the maintenance activities.
Reductions are applied using a simple abatement percentage combustion exhaust, representing the stringency of the policy. Because policies for this emission source are still evolving, the Compendium/Best Practice policies does not apply a percent reduction to emissions from this source.

Centrifugal Compressors

Methane emissions can be cheaply and substantially reduced by requiring centrifugal compressors to use dry seals or to redirect gas that would be vented from a wet-seal compressor back into the pipeline system or another use. Reductions are applied using a simple abatement percentage for all wet seal centrifugal compressors, representing the stringency of the policy. The Compendium/Best Practice policies result in a 95% reduction.

Combustion Exhaust

Reductions can be achieved by increasing the combustion efficiency of combustion sources at oil and gas sites. Alternatively, combustion emissions can be significantly reduced through site electrification, which make it unnecessary to burn throughput gas or diesel to power the site. Because policies for this emission source are still evolving and because the starting conditions of each jurisdiction vary significantly, the Compendium/Best Practice policies does not apply a percent reduction to emissions from this source.

Dehydrators

Cleaning up methane from dehydrators will reduce HAP emissions too, with important benefits for air quality. There are a number of approaches to reducing emissions from dehydrator venting, such as adjusting circulation rates of the glycol fluid; routing the vent gas to a burner used to heat the glycol, so methane and toxics are combusted; use of a condenser to capture heavier VOC and toxics from the vent gas (which does not capture methane); and routing emissions to a flare or incinerator.

Reductions are applied using a simple abatement percentage for all dehydrators, representing the stringency of the policy. The Compendium/Best Practice policies result in a 95% reduction.

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Leaks

Fortunately, most leaks are straightforward to repair (and fixing leaks is paid for by the value of the gas that is saved by repairing them).[12] Further, finding leaks has become efficient with modern technology. The standard approach today is to use special cameras that can detect infrared light (think of night-vision goggles) which are tuned to make methane, which is invisible to our eyes, visible. They allow inspectors to directly image leaking gas in real time, with the ability to inspect entire components (not just connections and other areas most likely to leak) and pinpoint the precise source, making repair more straightforward. And technology promises to make this process even more efficient (and cheaper) over the coming years.[13]

LDAR inspections can be conducted with an optical gas imaging (OGI) camera that is able to see methane leaks that are otherwise invisible. By providing a visual image the operator is able quickly to see the component that is leaking and either initiate repair immediately or tag the component for follow up repair. LDAR can also be conducted using Method 21, which is for the determination of VOC leaks from process equipment. This method is typically more sensitive to smaller leaks but surveying an entire site using this method is much more time consuming. The key driver or abatement potential for leaks is the frequency of inspection.

LDAR programs require operators to regularly survey all of their facilities for leaks and improper emissions and repair all the leaks they identify in a reasonable time. For example, California requires operators to survey all sites four times a year.[14] Colorado has a different approach, requiring operators of the largest sites to survey them monthly, but requiring less frequent inspections for sites with smaller potential emissions.[15]

Reductions are applied using a simple abatement percentage for all leaks, representing the frequency of instrument-based inspections in policy. The actual reduction from an LDAR program depends on a number of factors, including the type of site, the baseline number of leaks, the distribution of the size of leaks, how long it takes to repair the leaks, and the experience level of the OGI camera

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[12] Carbon Limits. (2014). *Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs using Infrared Cameras*. Clean Air Task Force. Retrieved from https://www.catf.us/resource/quantifying-cost-effectiveness-ldar/

[13] Lyon, D., Nowlan, A., & Paranhos, E. (2019, April). *Pathways for Alternative Compliance: A Framework to Advance Innovation, Environmental Protection, and Prosperity*. Environmental Defense Fund & Environmental Council of the States Shale Gas Caucus. Retrieved from https://www.edf.org/sites/default/files/documents/EDFAlternativeComplianceReport_0.pdf

[14] California Air Resources Board, California Final Regulation Order, 17 C.C.R., (March 10, 2017), available at https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasfro.pdf.

[15] Colorado Air Quality Control Commission Regulation Number 7, 5 C.C.R. 1001-9, ("Colorado regulation"), available at https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=9417

operator.[16] Early LDAR regulations used a rule of thumb to estimate reductions from leaks: 40% reduction for annual inspections, 60% reduction for bi-annual inspections, and 80% reduction for quarterly inspections.[17] A recent proposal from the US EPA relied on more sophisticated modeling (FEAST model[18]) to estimate reductions from different types of facilities.[19] For the purposes of quantifying reductions in CoMAT, we stick with the simple "rule of thumb", with extensions added to estimate triannual inspections (70%) and monthly inspections (90%).

The Compendium/Best Practice policy is quarterly LDAR, resulting in an 80% reduction across all applicable subsegments. CoMAT allows the user to adjust the inspection frequency (and therefore the abatement percentage) for each individual subsegment, reflecting the stringency of the country's policy.

Liquids Unloading

Emissions from liquids unloading can be minimized using equipment to capture gas that would otherwise be vented to the atmosphere. Reductions are applied using a simple abatement percentage, representing the stringency of the policy. The Compendium/Best Practice policies result in a 95% reduction from this source.

Offshore

Reductions are applied using a simple abatement percentage for combustion exhaust, representing the stringency of the policy. Because policies for this emission source are still evolving, the Compendium/Best Practice policies does not apply a percent reduction to emissions from this source.

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[16] Ravikumar, A. P., Sreedhara, S., Wang, J., Englander, J., Bell, C., Zimmerle, D., Lyon, D., Mogstad, I., Ratner, B., & Brandt, A. R. (2019*). Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge*. Elementa: Science of the Anthropocene, 7. https://doi.org/10.1525/elementa.373, https://online.ucpress.edu/elementa/article/doi/10.1525/elementa.373/112505/Single-blind-inter-comparison-of-methane-detection

[17] Colorado Air Quality Control Commission, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7, February 7, 2014.

[18] Chandler E. Kemp, Arvind P. Ravikumar, and Adam R. Brandt. *Comparing Natural Gas Leakage Detection Technologies Using an Open-Source "Virtual Gas Field" Simulator.* Environmental Science & Technology 2016 50 (8), 4546-4553. DOI: 10.1021/acs.est.5b06068. https://pubs.acs.org/doi/10.1021/acs.est.5b06068

[19] U.S. Environmental Protection Agency. (October 2022). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.

Pneumatic Controllers

Pneumatic controllers can be classified based on whether and how rapidly they vent or "bleed" natural gas and whether they bleed continuously or intermittently (typically only when performing some function). Controllers can either be classified as high-bleed or low-bleed, and it has been demonstrated that the conversion from high- to low-bleed is feasible and cost-effective in almost all cases.[20] However, it has also been shown that controllers specified as "low-bleed" often malfunction, causing emissions that are much higher than the low-bleed threshold.[21]

Thus, a more effective mitigation strategy is the use of "zero-bleed" controllers, which vent no natural gas, by either utilizing compressed air or electrical power to operate instead of pressurized natural gas, or by capturing for further use the natural gas that would otherwise be vented. Some zero-bleed devices are powered with solar-generated electricity, while others require electricity from the grid or an on-site gas-powered generator, or air compressed with a natural gas-powered engine. Significant methane emission reductions can be achieved by replacing natural gas-driven pneumatic controllers with zero-bleed devices, including at wellsites that are off-the-grid.[22]

Reductions are applied by adjusting the percent for each of the four types of controllers: high-, intermittent-, low-, and zero-bleed. Policies that require a higher the percentage of zero- and low-bleed controllers will achieve lower the overall emissions from this source.

Pneumatic Pumps

Pneumatic pumps *use the* pressure of natural gas to supply the energy required to circulate and pressurize liquids. For example, they are used to introduce liquid chemicals such as corrosion inhibitors into gas pipelines. Electric pumps, which are often solar-powered, completely eliminate methane emissions and are technically feasible in many locations.

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[20] US EPA. (October 2006). *Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry*. Retrieved from: 19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_pneumatics.pdf .

[21] Ramón A. Alvarez et al. , *Assessment of methane emissions from the U.S. oil and gas supply chain*. Science361,186-188(2018). DOI:10.1126/science.aar7204. https://science.sciencemag.org/content/361/6398/186

[22] Carbon Limits AS. (2016). *Zero Emission Technologies for Pneumatic Controllers in the USA: Applicability and Cost Effectiveness*. https://www.catf.us/resource/zero-emission-technologies-for-pneumatic-controllers-usa/

Several jurisdictions have implemented strong standards to reduce emissions from pneumatic controllers and pneumatic pumps. For example, California requires all new pneumatic equipment to be zero emitting, and it requires all existing pumps to emit below the low-bleed threshold.[23] Operators must measure emissions from each device annually to ensure that they are in fact emitting below this threshold. British Columbia also requires that all new pneumatic equipment to be zero emitting, and it also requires zero bleed controllers at all large compressor stations (>3 MW).[24]

Emissions from pneumatic pumps can be reduced through conversion to zero-bleed options. Reductions are applied using a simple abatement percentage, representing the stringency of the policy. The Compendium/Best Practice policies result in a 95% reduction from this source.

Reciprocating Compressors

Over time the seals of reciprocating compressors wear, letting more gas out. If not regularly replaced, emissions can become very large: the older the seals are, the more methane they emit. Fortunately, these methane emissions can easily be reduced. First, proper maintenance practices— regular replacement of rod-packing—minimize emissions and should be required. An available additional or alternative approach is to capture gas that escapes from rod packing and utilize it, such as by adding it to the fuel/air mixture for the compressor engine. This can be a superior approach since some gas escapes even from newly installed rod-packing.

Emissions from reciprocating compressors can be minimized using equipment to capture gas that would otherwise be vented to the atmosphere. Reductions are applied using a simple abatement percentage, representing the stringency of the policy. The Compendium/Best Practice policies result in a 95% reduction from this source.

Tanks

Emissions from tanks can be controlled by routing vented gas to a vapor recovery unit (VRU) or, where this is not feasible, routing to a flare. Reductions from tanks are estimated in CoMAT by adjusting the percent of tanks with a VRU, a flare, or no control.

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[23] California Air Resources Board, California Final Regulation Order, 17 C.C.R., (March 10, 2017), available at https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasfro.pdf.

[24] British Columbia Oil and Gas Commission (BC OCG). Amendment to Drilling and Production Regulation, B.C. Reg. 282/2010. ("BC regulation"), (December 17, 2018), available at: http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg286_2018.

Well Completions and Workovers

Methane emissions from hydraulically fractured oil and gas wells can be significant. Fortunately, there are low-cost and effective waste mitigation measures for this source. The same Reduced Emissions Completions (REC) approach to gas well completions — whereby operators capture natural gas with specialized equipment and direct it into pipelines, instead of allowing it to escape into the air — can be applied to associated gas produced during oil well completions. RECs reduce methane emissions from both oil and gas wells by more than 95%.

Reductions from well completions and workovers are estimated in CoMAT by adjusting the percent of events that utilize RECs, flares, or no control.

Other

This category includes a variety of emission sources that don't fall within one of the previous categories. CoMAT does not apply a percent reduction to emissions from this source. If policies and technologies become available to reduce methane emissions from these sources, abatement quantification will be added to the CoMAT application.

Appendix A: Compendium of Leading Policies

English: https://cdn.catf.us/wp-content/uploads/2021/09/12161320/leading-methane-abatement-policies-for-oil-and-gas-operations.pdf

Spanish: https://cdn.catf.us/wp-content/uploads/2021/04/12161403/politicas-principales-de-reduccion-de-metano-para-operaciones-de-petroleo-y-gas-natural.pdf

Appendix B: Oil and Gas Industry Information Input Worksheet

The following information is needed to estimate methane emissions from the oil and gas supply chain. If country-specific data is not available, a proxy will be used to estimate the data. To ensure consistency, select the year for data collection, representing the most recent year for which full data is available. In addition, select whether data will be entered in Metric or Imperial units.

Country: ______________ Year:______________ Units: Metric or Imperial (circle one)

Industry Segment	Contributor Group	Industry Contributor	Initial Value	Unit	Data source or proxy	Updated Value	Source
Gas Exploration and Production	Gas Production	Gross production		Mcm (or mmcf)	Country-specific: EIA		
		Marketed/dry gas production		Mcm (or mmcf)			
		Offshore gas production		Mcm (or mmcf)	Country-specific: Rystad (old)		
	Gas wells	Total Gas Wells		# of wells	Proxy		
		Gas wells with hydraulic fracturing		# of wells	Proxy		
		Gas wells without hydraulic fracturing		# of wells	Proxy		
		Gas wells drilled per year		# of wells drilled per year	Proxy		
	Well Blowouts			# of events	Default zero if no information.		
	Condensate Production			Mcm (or MMbbl)	Country-specific: EIA		
	Gathering and boosting stations			# of stations	Proxy		
Oil Exploration and Production	Oil Production	Total oil production		Mcm (or MMbbl)	Country-specific: EIA		
		Onshore Oil production		Mcm (or MMbbl)	Country-specific: EIA		

Industry Segment	Contributor Group	Industry Contributor	Initial Value	Unit	Data source or proxy	Updated Value	Source
		Offshore Oil Production		Mcm (or MMbbl)	Country-specific: Rystad (old)		
	Oil wells	Total Oil Wells		# of wells	Country-specific or Proxy		
		Oil wells with hydraulic fracturing		# of wells	Country-specific or Proxy		
		Oil wells without hydraulic fracturing		# of wells	Country-specific or Proxy		
		Oil wells drilled per year		# of wells per year	Country-specific or Proxy		
	Flaring Volume			Mcm (or mmcf)	Country-specific: NOAA Global Gas Flaring		
Gas Processing	Number of Processing Plants			# plants	Country-specific or Proxy		
Gas Transmission and Storage	Transmission Pipeline Distance			km (or miles)	Country-specific or Proxy		
	Stations	Transmission compressor stations		# of stations	Country-specific or Proxy		
		Gas storage compressor stations		# of stations	Country-specific or Proxy		
	Gas Consumption*	Total natural gas consumption		Mcm (or mmcf)	Country-specific: EIA		
		Residential natural gas consumption		Mcm (or mmcf)	Country-specific or Proxy		
		Commercial natural gas consumption		Mcm (or mmcf)	Country-specific or Proxy		
		Industrial natural gas consumption		Mcm (or mmcf)	Country-specific or Proxy		
		Residential natural gas customers		# of customers	Country-specific or Proxy		
		Commercial natural gas customers		# of customers	Country-specific or Proxy		
		Industrial natural gas customers		# of customers	Country-specific or Proxy		
Liquefied Natural Gas (LNG)	LNG	LNG Storage Stations		# of stations	Country-specific: Global Energy Monitor		

Industry Segment	Contributor Group	Industry Contributor	Initial Value	Unit	Data source or proxy	Updated Value	Source
		LNG Import Terminals		# of terminals	Country-specific: Global Energy Monitor		
		LNG Export Terminals		# of terminals	Country-specific: Global Energy Monitor		
Gas Distribution	Gas Consumption (see industry input in Gas Transmission and Storage Section) *						
	Mains & Services	Mains - Cast Iron		km (or miles)	Country-specific or Proxy		
		Mains - Protected Steel		km (or miles)	Country-specific or Proxy		
		Mains - Unprotected Steel		km (or miles)	Country-specific or Proxy		
		Mains - Plastic		km (or miles)	Country-specific or Proxy		
		Services - Protected Steel		# of services	Country-specific or Proxy		
		Services - Unprotected Steel		# of services	Country-specific or Proxy		
		Services - Plastic		# of services	Country-specific or Proxy		
		Services - Copper		# of services	Country-specific or Proxy		

*Same industry information used in both Gas Transmission and Gas Distribution

Appendix C: Mitigation Plant Calculation Worksheet

Emissions Source	Segment	Subsegment	% Reduction	Description of activity-based reduction	Quantify (a)	Quantify (b)	Quantify (c)	Quantify (d)
Associated Gas Venting and Flaring	Oil Exploration and Production	Onshore oil production	80%	Adjust (a) flare efficiency and (b) percent of associated gas that is vented	98%	1%		
Blowdown Venting	Gas Exploration and Production	Onshore gas production	0%					
Blowdown Venting	Gas Exploration and Production	Gathering and Boosting	0%					
Blowdown Venting	Oil Exploration and Production	Onshore oil production	0%					
Blowdown Venting	Gas Processing	Gas Processing	0%					
Blowdown Venting	Liquified Natural Gas (LNG)	LNG Export Terminals	0%					
Blowdown Venting	Liquified Natural Gas (LNG)	LNG Import Terminals	0%					
Blowdown Venting	Liquified Natural Gas (LNG)	LNG Storage	0%					
Blowdown Venting	Gas Distribution	Aboveground Distribution Stations	0%					
Centrifugal Compressors	Gas Processing	Gas Processing	95%					
Centrifugal Compressors	Gas Transmission and Storage	Gas Transmission	95%					
Centrifugal Compressors	Gas Transmission and Storage	Underground Gas Storage	95%					
Combustion Exhaust	Gas Exploration and Production	Gas Exploration	0%					

Emissions Source	Segment	Subsegment	% Reduction	Description of activity-based reduction	Quantify (a)	Quantify (b)	Quantify (c)	Quantify (d)
Combustion Exhaust	Gas Exploration and Production	Onshore gas production	0%					
Combustion Exhaust	Gas Exploration and Production	Gathering and Boosting	0%					
Combustion Exhaust	Oil Exploration and Production	Oil Exploration	0%					
Combustion Exhaust	Oil Exploration and Production	Onshore oil production	0%					
Combustion Exhaust	Gas Processing	Gas Processing	0%					
Combustion Exhaust	Gas Transmission and Storage	Gas Transmission	0%					
Combustion Exhaust	Gas Transmission and Storage	Underground Gas Storage	0%					
Combustion Exhaust	Liquified Natural Gas (LNG)	LNG Export Terminals	0%					
Combustion Exhaust	Liquified Natural Gas (LNG)	LNG Import Terminals	0%					
Combustion Exhaust	Liquified Natural Gas (LNG)	LNG Storage	0%					
Dehydrators	Gas Exploration and Production	Onshore gas production	95%					
Dehydrators	Gas Exploration and Production	Gathering and Boosting	95%					
Dehydrators	Gas Processing	Gas Processing	95%					
Dehydrators	Gas Transmission and Storage	Gas Transmission	95%					
Dehydrators	Gas Transmission and Storage	Underground Gas Storage	95%					
Leaks	Gas Exploration and Production	Onshore gas production	80%					

Emissions Source	Segment	Subsegment	% Reduction	Description of activity-based reduction	Quantify (a)	Quantify (b)	Quantify (c)	Quantify (d)
Leaks	Gas Exploration and Production	Gathering and Boosting	80%					
Leaks	Oil Exploration and Production	Onshore oil production	80%					
Leaks	Gas Processing	Gas Processing	80%					
Leaks	Gas Transmission and Storage	Gas Transmission	80%					
Leaks	Gas Transmission and Storage	Underground Gas Storage	80%					
Leaks	Liquified Natural Gas (LNG)	LNG Export Terminals	80%					
Leaks	Liquified Natural Gas (LNG)	LNG Import Terminals	80%					
Leaks	Liquified Natural Gas (LNG)	LNG Storage	80%					
Leaks	Gas Distribution	Aboveground Distribution Stations	80%					
Liquids Unloading	Gas Exploration and Production	Onshore gas production	95%					
Offshore	Gas Exploration and Production	Offshore gas production	0%					
Offshore	Oil Exploration and Production	Offshore oil production	0%					
Pneumatic Controllers	Gas Exploration and Production	Onshore gas production		Change activity data for (a) zero-bleed, (b) low, (c) intermittent, and (d) high bleed controllers	55%	20%	20%	5%
Pneumatic Controllers	Gas Exploration and Production	Gathering and Boosting		Change activity data for (a) zero-bleed, (b) low, (c) intermittent, and (d) high bleed controllers	60%	20%	15%	5%
Pneumatic Controllers	Oil Exploration and Production	Onshore oil production		Change activity data for (a) zero-bleed, (b) low, (c) intermittent, and (d) high bleed controllers	55%	20%	20%	5%

Emissions Source	Segment	Subsegment	% Reduction	Description of activity-based reduction	Quantify (a)	Quantify (b)	Quantify (c)	Quantify (d)
Pneumatic Controllers	Gas Processing	Gas Processing		Change activity data for (a) percent gas driven	5%			
Pneumatic Controllers	Gas Transmission and Storage	Gas Transmission		Change activity data for (a) zero-bleed, (b) low, (c) intermittent, and (d) high bleed controllers	60%	20%	15%	5%
Pneumatic Controllers	Gas Transmission and Storage	Underground Gas Storage		Change activity data for (a) zero-bleed, (b) low, (c) intermittent, and (d) high bleed controllers	60%	20%	15%	5%
Pneumatic Pumps	Gas Exploration and Production	Onshore gas production	95%					
Pneumatic Pumps	Gas Exploration and Production	Gathering and Boosting	95%					
Pneumatic Pumps	Oil Exploration and Production	Onshore oil production	95%					
Reciprocating Compressors	Gas Exploration and Production	Onshore gas production	95%					
Reciprocating Compressors	Gas Exploration and Production	Gathering and Boosting	95%					
Reciprocating Compressors	Oil Exploration and Production	Onshore oil production	95%					
Reciprocating Compressors	Gas Processing	Gas Processing	95%					
Reciprocating Compressors	Gas Transmission and Storage	Gas Transmission	95%					
Reciprocating Compressors	Gas Transmission and Storage	Underground Gas Storage	95%					
Tanks	Gas Exploration and Production	Onshore gas production		Change activity data for tanks with large tanks only (a) VRU, large tanks only (b) flare, large tanks, (c) flare, small tanks only, or (d) no control/no flare	95%	5%	100%	0%
Tanks	Gas Exploration and Production	Gathering and Boosting	95%					
Tanks	Oil Exploration and Production	Onshore oil production		Change activity data for tanks with large tanks only (a) VRU, large tanks only (b) flare, large	95%	5%	100%	0%

Emissions Source	Segment	Subsegment	% Reduction	Description of activity-based reduction	Quantify (a)	Quantify (b)	Quantify (c)	Quantify (d)
				tanks, (c) flare, small tanks only, or (d) no control/no flare				
Well Completions and Workovers	Gas Exploration and Production	Gas Exploration		Change activity data for wells that use (a) reduced emission completions, (b) flare, or (c) vent	95%	5%	0%	
Well Completions and Workovers	Gas Exploration and Production	Onshore gas production		Change activity data for wells that use (a) reduced emission completions, (b) flare, or (c) vent	95%	5%	0%	
Well Completions and Workovers	Oil Exploration and Production	Oil Exploration		Change activity data for wells that use (a) reduced emission completions, (b) flare, or (c) vent	95%	5%	0%	
Well Completions and Workovers	Oil Exploration and Production	Onshore oil production		Change activity data for wells that use (a) reduced emission completions, (b) flare, or (c) vent	95%	5%	0%	

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