PETROLEUM AND NATURAL GAS SYSTEMS

Introduction

In October 2016, the U.S. Environmental Protection Agency (EPA) released 2015 greenhouse gas (GHG) data for Petroleum and Natural Gas Systems[1] collected under the Greenhouse Gas Reporting Program (GHGRP). The GHGRP, which was required by Congress in the Fiscal Year 2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain greenhouse gases and products that would emit GHGs if released or combusted.

All emissions presented here reflect the most recent information reported to EPA as of 8/13/2016. The reported emissions exclude biogenic CO_2. GHG data displayed here in units of carbon dioxide equivalent (CO_2e) reflect the global warming potential (GWP) values from Table A-1 of 40 CFR 98, which is generally based on the IPCC AR4, with the addition of GWPs from the IPCC AR5 for fluorinated GHGs that did not have GWPs in the AR4.

The data show 2015 GHG emissions from over 2,400 facilities conducting Petroleum and Natural Gas Systems activities, such as production, processing, transmission, and distribution. In total, these facilities accounted for GHG emissions of 231 million metric tons of carbon dioxide equivalent (CO_2e). This is a decrease of 1.6% compared to 2014 GHG emissions from this sector.

The GHG data represent a significant step forward in better understanding GHG emissions from Petroleum and Natural Gas Systems. The EPA expects that the GHGRP will be an important tool for the Agency and the public to analyze emissions and understand emissions trends.

When reviewing these data and comparing it to other data sets or published literature, it is important to understand the GHGRP reporting requirements and the impacts of these requirements on the reported data. Facilities used uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors derived from direct measurement. In some cases, facilities had a choice of calculation methods for an emission source.

Petroleum and Natural Gas Systems is one of the more complex source categories within the GHGRP because of the number of emission sources covered, technical complexity, and variability across facilities. It is expected that there can be differences in reported emissions from one facility to another. It is not uncommon for a handful of facilities to contribute the majority of the national reported emissions total for a specific emission source. As described in more detail below, there is a reporting threshold and the reporting requirements do not cover certain emission sources, and therefore the data does not represent the entire universe of emissions from Petroleum and Natural Gas Systems. There is also variability in the methods used which could impact cross-segment, cross-source, or cross-facility comparisons. While emission changes in the total number of reporting facilities can cause changes in total reported emissions from year to year, a number of factors such as those detailed above contribute to differences as well. There are also considerations to keep in mind when drawing conclusions about the deferred activity data reported for 2011-2013 as part of the reporting year 2014 submissions. While many facilities in this sector submitted deferred data, certain facilities might not have reported this information for legitimate reasons.

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

These include changes in ownership and not having reported to the GHGRP in a previous year for a valid reason. It is important to be aware of these limitations and differences when using this data, particularly when attempting to draw broad conclusions about emissions and activities from this sector.

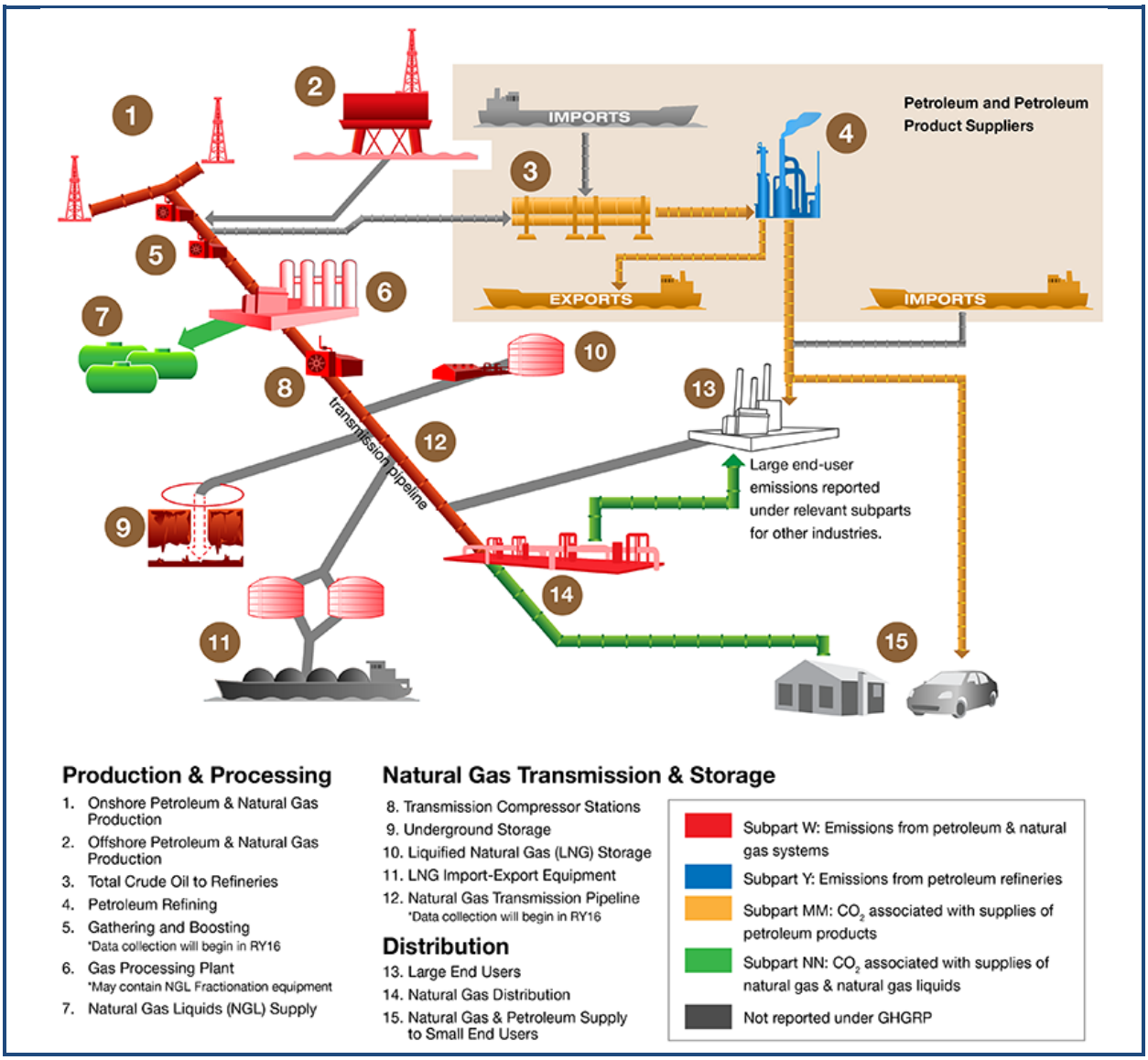
Petroleum and Natural Gas Systems in the GHG Reporting Program

The Petroleum and Natural Gas Systems source category of the GHGRP (Subpart W) requires reporting from the following eight industry segments for 2015, which account for most of the largest emission sources:

- Onshore Production: Production of petroleum and natural gas associated with onshore production wells and related equipment.
- Offshore Production: Production of petroleum and natural gas from offshore production platforms.
- Natural Gas Processing: Processing of field-quality gas to produce pipeline-quality natural gas.
- Natural Gas Transmission: Compressor stations used to transfer natural gas through transmission pipelines.
- Underground Natural Gas Storage: Facilities that store natural gas in underground formations.
- Natural Gas Distribution: Distribution systems that deliver natural gas to customers.
- Liquefied Natural Gas (LNG) Import/Export: Liquefied Natural Gas import and export terminals.
- LNG Storage: Liquefied Natural Gas storage equipment.

The diagram below illustrates the segments of the Petroleum and Natural Gas Systems source category that were required to report under the GHGRP for 2015.

Figure 1: Petroleum and Natural Gas operations covered by the GHG Reporting Program



Note: Certain petroleum and/or natural gas operations are covered by subparts of the GHGRP other than Subpart W or will begin reporting GHG data starting with the 2016 reporting year.

Other segments of the petroleum and natural gas industry are covered by the GHGRP, but not included in the Petroleum and Natural Gas Systems (Subpart W) source category, such as Petroleum Refineries (Subpart Y), Petrochemical Production (Subpart X), Suppliers of Petroleum Products (Subpart MM), and Suppliers of Natural Gas and Natural Gas Liquids (Subpart NN).

As noted above, the GHGRP also includes reporting of stationary fuel combustion emissions from facilities that are associated with the petroleum and natural gas industry, but that do not report process emissions from any of the above source categories, such as certain facilities that have a North American Industry Classification System (NAICS) code beginning with 211 (the general NAICS for oil and gas extraction). These facilities are referred to as "Other Oil and Gas Combustion" in this document.

The GHGRP covers a subset of national emissions from Petroleum and Natural Gas Systems. A facility in the Petroleum and Natural Gas Systems source category is required to submit annual reports if total emissions are 25,000 metric tons carbon dioxide equivalent (CO_2e) or more. In addition, the Petroleum and Natural Gas Systems source category does not currently include process emissions from the gathering and boosting segment, vented emissions from hydraulic fracturing of oil wells, or process emissions from transmission lines between compressor stations. These emission sources will be covered starting with the 2016 data.[2]

The EPA has a multi-step data verification process, including automatic checks during data-entry, statistical analyses on completed reports, and staff review of the reported data.[3] Based on the results of the verification process, the EPA follows up with facilities to resolve mistakes that may have occurred. In addition, because of the nature of the petroleum and natural gas industry, there can be variation in emissions from facility to facility.

The EPA made available the optional use of BAMM for targeted circumstances where the EPA made recent changes to GHGRP monitoring requirements for Petroleum and Natural Gas Systems.[4] In previous reporting years, in order to provide facilities with time to adjust to the requirements of the GHGRP, the EPA made available the optional use of BAMM for unique or unusual circumstances. Where a facility used BAMM, it was required to follow emission calculations specified by the EPA, but was allowed to use alternative methods for determining inputs to calculate emissions. Inputs are the values used by facilities to calculate equation outputs. Examples of BAMM include monitoring methods used by the facility that do not meet the specifications of 40 CFR Part 98 Subpart W, supplier data, engineering calculations, and other company records.

Reported GHG Emissions from Petroleum and Natural Gas Systems

The following section provides information on reported GHG emissions by industry segment, by greenhouse gas, by combustion and process emissions, and by emission source for the 2015 calendar year.

Reported Emissions by Industry Segment

The 2015 calendar year was the fourth year that GHG emissions from Petroleum and Natural Gas Systems activities were required to be collected. Annual reports were due to the EPA by March 31, 2016. The EPA received reports from over 2,400 facilities[5] with Petroleum and Natural Gas Systems activities, with total reported GHG emissions of 231 million metric tons (MMT) CO_2e.

The largest industry segment in terms of reported GHG emissions was onshore production, with a total of 97 MMT CO_2e, followed by natural gas processing, with reported emissions of 58 MMT CO_2e.

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[2] For more information on Subpart W rulemakings, see: http://www.epa.gov/ghgreporting/subpart-w-rulemaking-resources

[3] For more information on verification, see: http://www.epa.gov/ghgreporting/ghgrp-methodology-and-verification

[4] For more information on BAMM, see: http://www.epa.gov/ghgreporting/ghgrp-methodology-and-verification

[5] In general, a "facility" for purposes of the GHGRP means all co-located emission sources that are commonly owned or operated. However, the GHGRP has developed specialized facility definitions for natural gas distribution and onshore production. For natural gas distribution, the "facility" is a local distribution company as regulated by a single state public utility commission. For onshore production, the "facility" includes all emissions associated with wells owned or operated by a single company in a specific hydrocarbon producing basin (as defined by the geologic provinces published by the American Association of Petroleum Geologists).

Other oil and gas combustion accounted for 29 MMT CO_2e. The next largest segment was natural gas transmission, with reported emissions of 23 MMT CO_2e. Reported emissions from natural gas distribution totaled 14 MMT CO_2e. The remaining segments accounted for total reported emissions of approximately 10 MMT CO_2e.

Table 1: 2015 Reported Emissions by Industry Segment

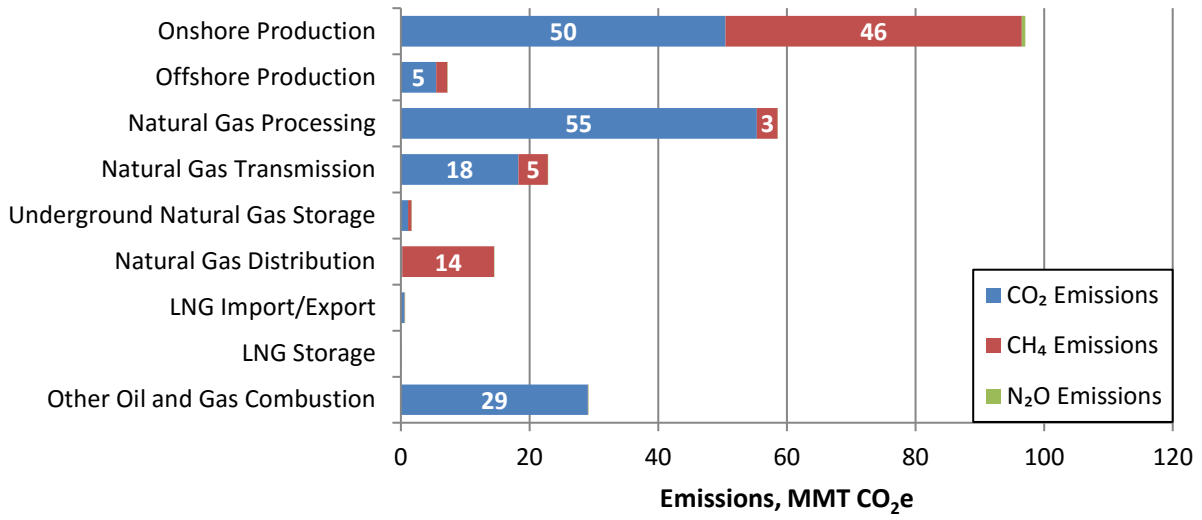
Industry Segment	Number of Facilities	Reported Emissions (Million Metric Tons CO_2e)
Onshore Production	534	97
Offshore Production	133	7
Natural Gas Processing	467	58
Natural Gas Transmission	521	23
Underground Natural Gas Storage	53	2
Natural Gas Distribution	177	14
LNG Import/Export	7	1
LNG Storage	7	<1
Other Oil and Gas Combustion	541	29
Total	**2,413**	**231**

Note: Total number of facilities is smaller than the sum of facilities from each segment because some facilities reported under multiple segments. A facility is included in the count of number of facilities if it reported emissions (even if the reported emissions were zero) under a given segment.

Reported Emissions by Greenhouse Gas

For all segments combined, carbon dioxide (CO_2) emissions accounted for 161 MMT CO_2e of reported emissions and methane (CH_4) emissions accounted for 70 MMT CO_2e of reported emissions. Reported emissions from natural gas distribution were primarily methane while reported emissions from onshore production, natural gas transmission, and natural gas processing were primarily carbon dioxide.

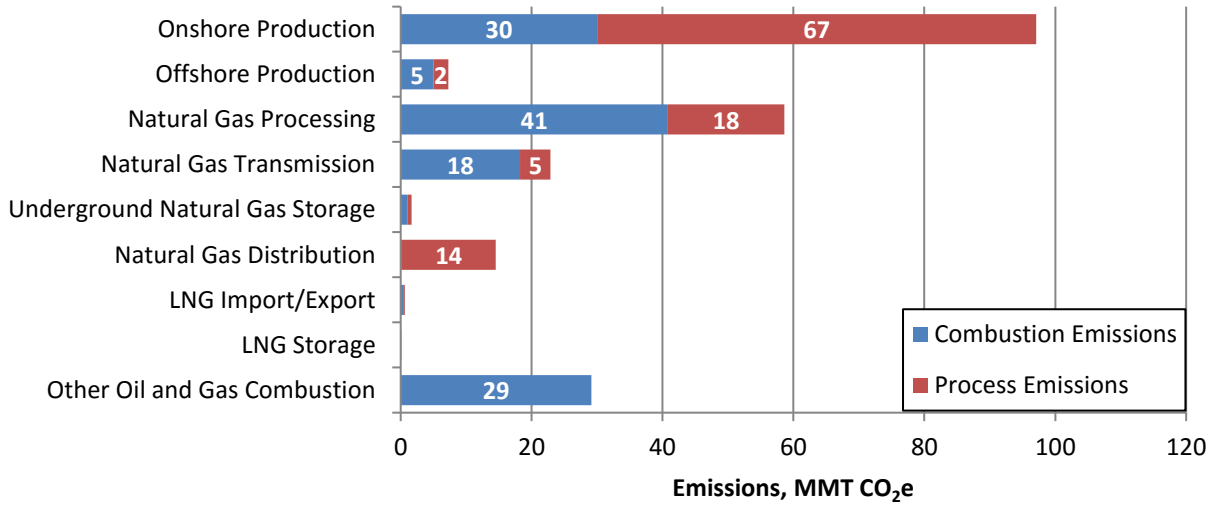
Figure 2: 2015 Reported Emissions by Greenhouse Gas



Reported Combustion and Process Emissions

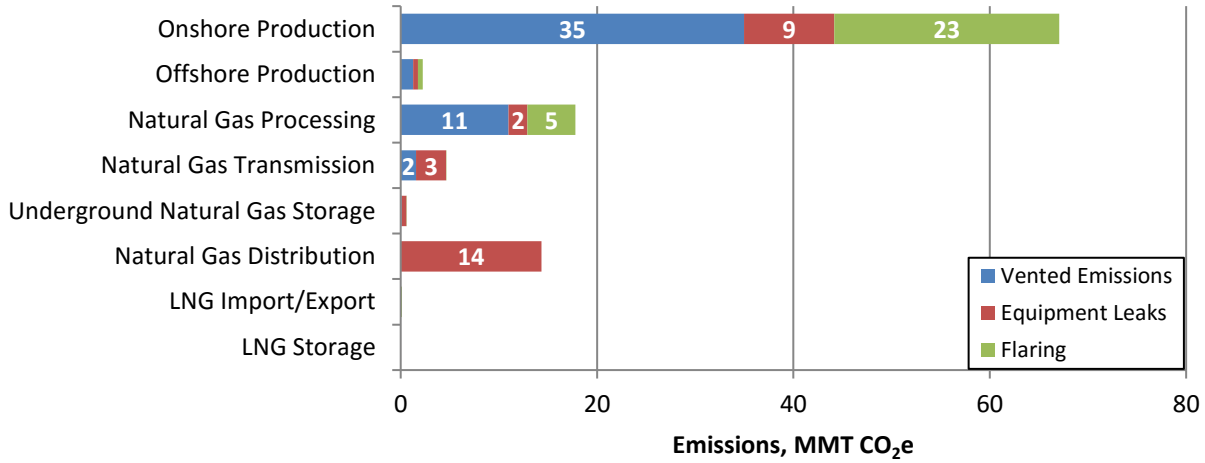
Each segment of Petroleum and Natural Gas Systems has unique emission sources. Emissions may result from the combustion of fossil fuels or from process sources that result in the direct emission of GHGs. Reported combustion emissions in Petroleum and Natural Gas Systems totaled 125 MMT CO_2e and reported process emissions totaled 107 MMT CO_2e. The majority of combustion emissions were reported by natural gas processing, onshore production, other oil and gas combustion, and natural gas transmission. The majority of process emissions were reported by onshore production, natural gas processing, and natural gas distribution.

Figure 3: 2015 Reported Combustion and Process Emissions



Process emissions may be further classified as vented emissions, equipment leaks, and flaring. Reported vented emissions totaled 49 MMT CO_2e, reported equipment leaks totaled 30 MMT CO_2e, and reported flaring emissions totaled 28 MMT CO_2e. Reported vented emissions in onshore production were primarily methane while reported vented emissions in natural gas processing were primarily carbon dioxide. Reported equipment leak emissions were primarily methane and reported flaring emissions were primarily carbon dioxide.

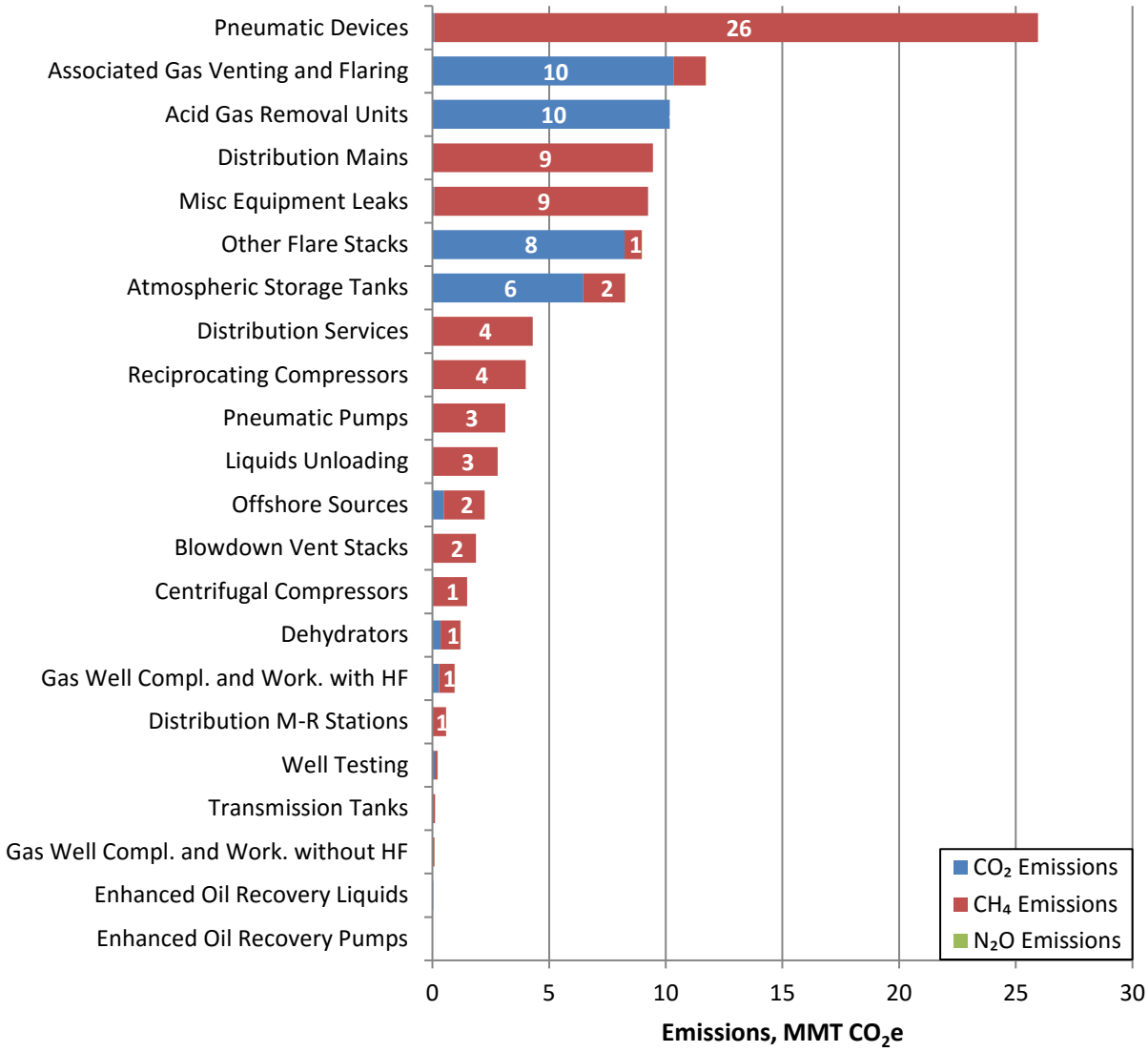
Figure 4: 2015 Reported Process Emissions by Vented Emissions, Equipment Leaks, and Flaring



Reported Process Emission Sources

The top reported process emission source in Petroleum and Natural Gas Systems was pneumatic devices with reported emissions of 26 MMT CO_2e. Natural gas pneumatic devices are automated instruments used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Emissions from natural gas pneumatic devices are calculated by applying a facility determined population count to a default emission factor.

Figure 5: 2015 Reported Process Emission Sources



Associated gas and other flare stacks were the top reported sources of process emissions from flaring for Petroleum and Natural Gas Systems. Associated gas is natural gas that is produced out of oil wells, but due to proximity and pipeline limitations, may be vented or flared instead of being processed. The other flare stacks category is a catch-all category applicable to the onshore production, natural gas processing, natural gas transmission, underground natural gas storage, LNG import/export and LNG storage segments, and it is intended to cover all flares not otherwise reported for other sources at these facilities.

Acid gas removal units were the top reported contributor to CO_2 emissions from non-combustion sources and the top reported source of process emissions in the natural gas processing segment (10 MMT CO_2e). Acid gas removal units are process units that separate hydrogen sulfide, carbon dioxide or both hydrogen sulfide and carbon dioxide from sour natural gas using absorbents or membrane separators. The CO_2 emitted from acid gas removal units is a part of the gas stream that

is produced at the wellhead. Natural gas processing creates pipeline quality natural gas and removal of CO_2 from the gas streams is a key step in this process.

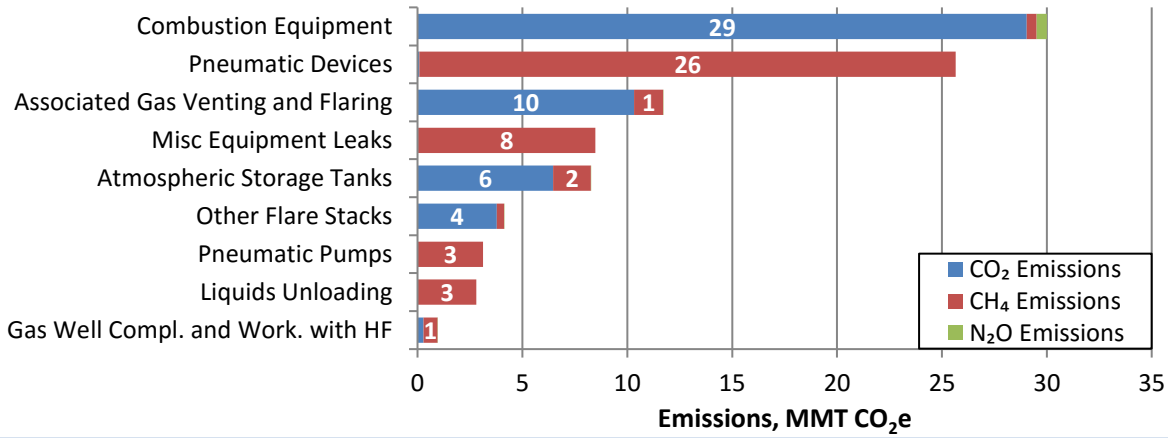
Reported GHG Emissions by Industry Segment and Source

The following section provides information on reported GHG emissions organized by industry segment. For each segment, the top reported emission sources are presented, as well as additional information on emission sources for which stakeholders have expressed interest. Over time, we hope to provide additional information on other emission sources of interest to stakeholders.

Onshore Production

The EPA received annual reports from 534 facilities in the onshore production segment and reported emissions totaled 97.3 MMT CO_2e. Methane emissions totaled 46.1 MMT CO_2e and carbon dioxide emissions totaled 51.2 MMT CO_2e. The top reported emission sources for onshore production were generally consistent with the top reported emission sources for Petroleum and Natural Gas Systems. Combustion equipment (30 MMT CO_2e) and pneumatic devices (25.7 MMT CO_2e) were the top reported emission sources, followed by associated gas venting and flaring (11.7 MMT CO_2e), miscellaneous equipment leaks (8.5 MMT CO_2e), atmospheric tanks (8.3 MMT CO_2e), and other flare stacks (4.1 MMT CO_2e).

Figure 6: 2015 Onshore Production: Top Reported Emission Sources



The five basins with the top reported emissions were the Williston Basin with 15.9 MMT CO_2e, Gulf Coast Basin with 12.9 MMT CO_2e, Anadarko Basin with 11 MMT CO_2e, Permian Basin with 10.4 MMT CO_2e, and San Juan Basin with 6.5 MMT CO_2e.

Emission Source in Detail: Gas Well Completions and Workovers with Hydraulic Fracturing

The data reported to the GHGRP includes gas well completions and workovers with hydraulic fracturing. In the hydraulic fracturing process, a mixture of water, chemicals and a "proppant" (usually sand) is pumped into a well at high pressures to fracture rock and allow natural gas to escape. During a stage of well completion known as "flowback," fracturing fluids, water, and reservoir gas come to the surface at a high velocity and volume. Specialized equipment can be

employed that separates natural gas from the flowback, known as a "Reduced Emission Completion" (REC) or "green completion".

The GHGRP provides facilities options for calculating emissions for gas well completions and workovers with hydraulic fracturing. Facilities may measure or estimate the flowback rate in order to report emissions using an engineering calculation. Alternatively, the flowback vent or flare volume may be measured directly.

The EPA received information on gas well completions and workovers with hydraulic fracturing from 180 onshore production facilities. The total reported emissions for gas well completions and workovers with hydraulic fracturing were 0.96 MMT CO_2e. Reported CO_2 emissions were 0.29 MMT CO_2e and reported CH_4 emissions were 0.67 MMT CO_2e.

Emissions were reported by GHG for flaring and venting activities. Facilities were required to report the total count of completions and workovers by the well type-combination which classifies wells using by following categories: vertical or horizontal; venting or flaring; and REC or no REC.

The table below shows reported activity data and emissions nationally for gas well completions and workovers with hydraulic fracturing. Data collected by the GHGRP also allows for county-level analysis of reported data. As noted earlier, when reviewing the data it is important to be aware of the GHGRP reporting requirements and the impacts of these requirements on the reported data. For example, the GHGRP covers a subset of national emissions and there is variability in the methods used in calculating emissions.

Table 2: 2015 Reported Emissions from Gas Well Completions and Workovers with Hydraulic Fracturing

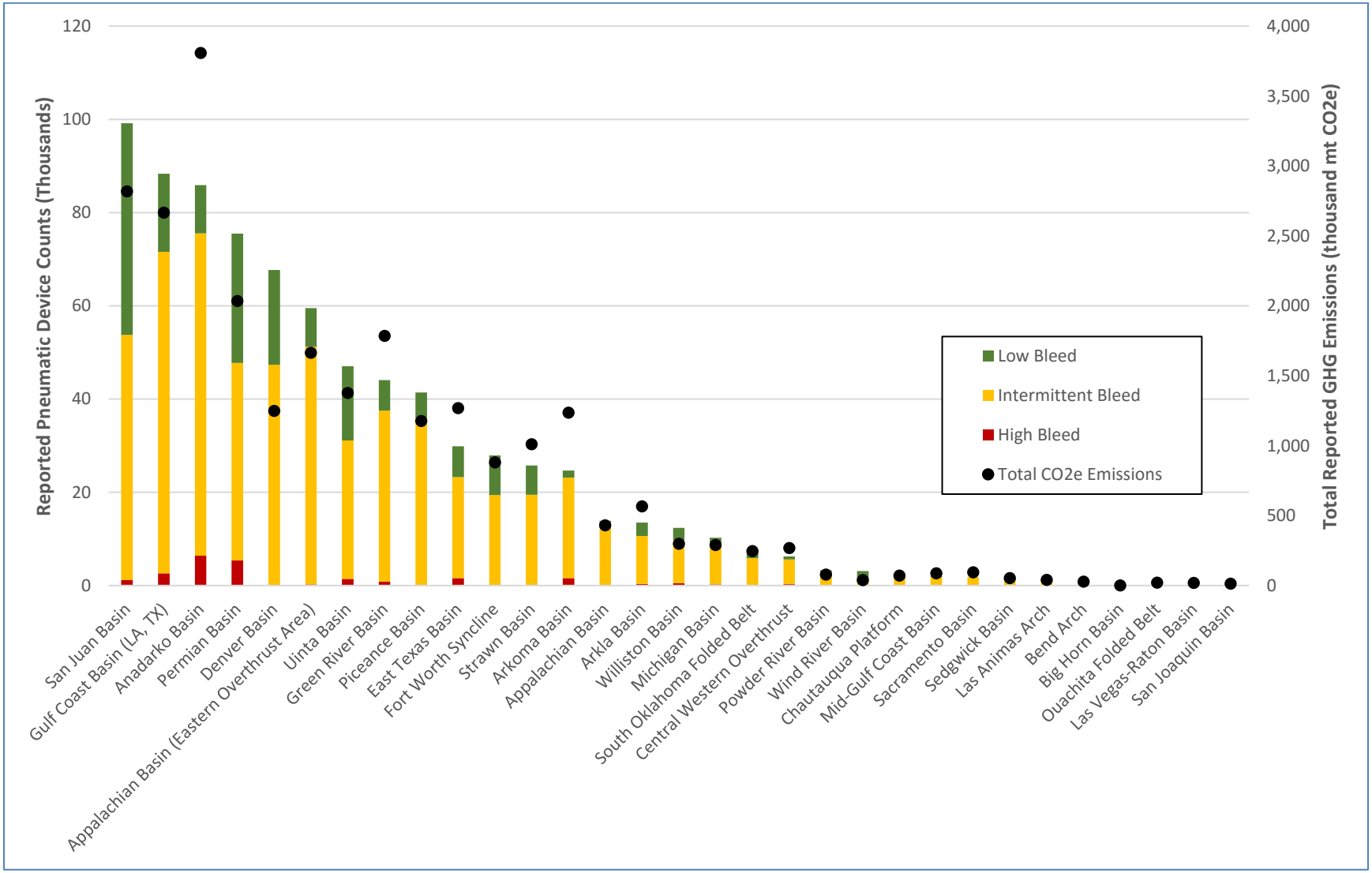
Activity	Total Number	Number of RECs	Reported Venting CO_2 Emissions (MT CO_2e)	Reported Venting CH_4 Emissions (MT CO_2e)	Reported Flaring CO_2 Emissions (MT CO_2e)	Reported Flaring CH_4 Emissions (MT CO_2e)	Total Reported Emissions (MT CO_2e)
Gas Well Completions with Hydraulic Fracturing	5,275	4,839	796	413,860	282,255	245,525	944,915
Gas Well Workovers with Hydraulic Fracturing	375	231	53	9,713	1,667	276	11,727
Total	**5,650**	**5,070**	**849**	**423,573**	**283,922**	**245,801**	**956,642**

Emission Source in Detail: Counts of Pneumatic Devices

As mentioned previously, natural gas pneumatic devices are automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. There are three types of natural gas pneumatic devices reported for Petroleum and Natural Gas Systems:

- *High-bleed pneumatic devices*: automated, continuous bleed flow control devices with a bleed rate of more than 6 standard cubic feet per hour
- *Intermittent-bleed pneumatic devices*: automated flow control devices that discharge intermittently when control action is necessary (but do not bleed continuously)
- *Low-bleed pneumatic devices*: automated, continuous bleed flow control devices with a bleed rate equal to or less than 6 standard cubic feet per hour

Figure 7: 2015 Onshore Production Reported Pneumatic Device Counts and Reported Emissions

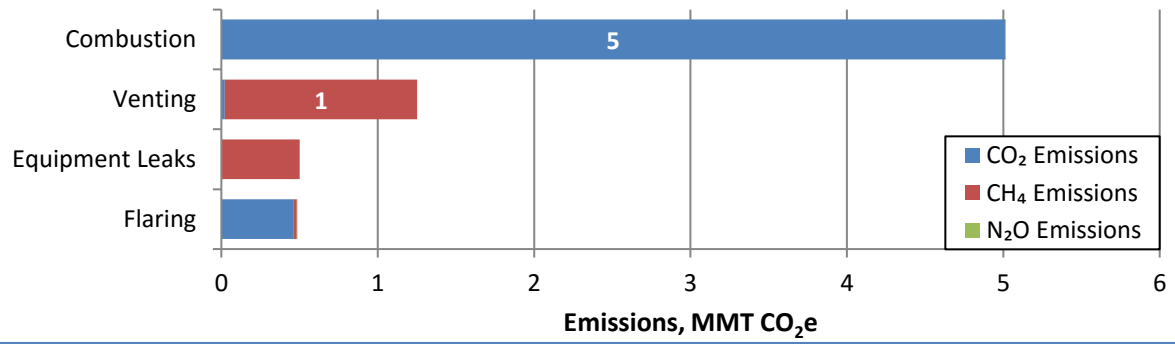


Note: Chart does not include basins with fewer than 300 pneumatic devices.

Offshore Production

The EPA received annual reports from 133 facilities in the offshore production segment and reported emissions totaled 7.3 MMT CO_2e. For offshore production, facilities calculate process emissions using requirements that were established by the Bureau of Ocean Energy Management (BOEM). In addition, the GHGRP collects data on combustion emissions. The full list of process emission sources is extensive, but can generally be categorized into vented emissions, flaring and equipment leaks. The top reported source of emissions for offshore production was from combustion (5 MMT CO_2e) followed by venting (1.3 MMT CO_2e).

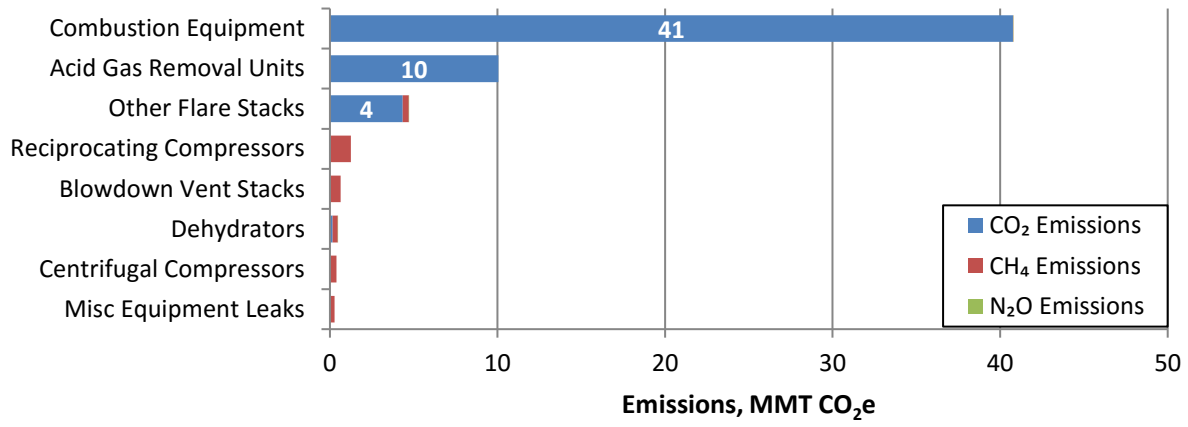
Figure 8: 2015 Offshore Production: Top Reported Emission Sources



Natural Gas Processing

The EPA received annual reports from 467 facilities in the natural gas processing segment and reported emissions totaled 58.5 MMT CO_2e. Methane emissions totaled 3.2 MMT CO_2e and carbon dioxide emissions totaled 55.3 MMT CO_2e. The top reported emission sources were combustion equipment (40.8 MMT CO_2e), acid gas removal units (10 MMT CO_2e), and other flare stacks (4.7 MMT CO_2e). The top reported methane emissions sources were reciprocating compressors (1.2 MMT CO_2e) and blowdown vent stacks (0.6 MMT CO_2e).

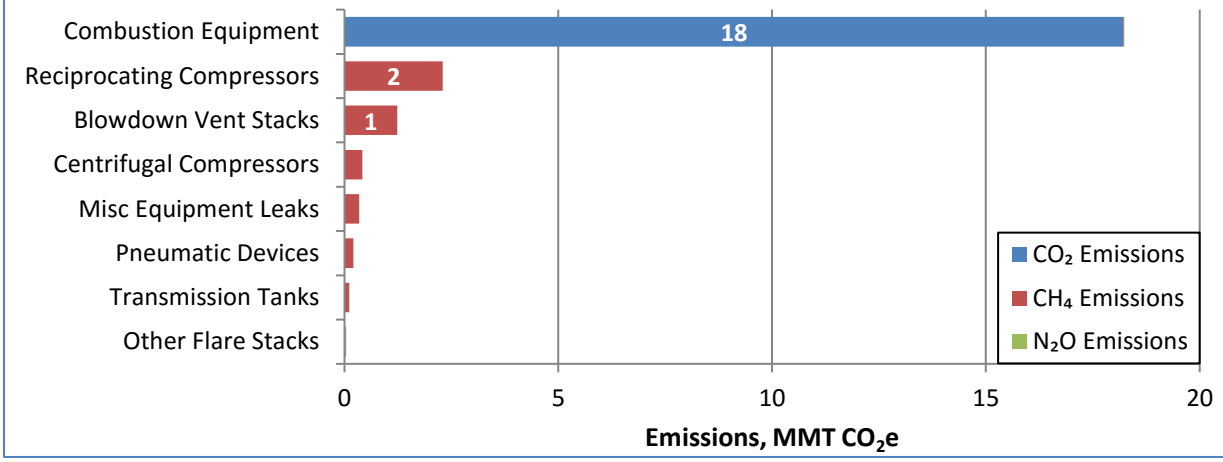
Figure 9: 2015 Natural Gas Processing: Top Reported Emission Sources



Natural Gas Transmission

The EPA received annual reports from 521 facilities in the natural gas transmission segment and reported emissions totaled 22.9 MMT CO_2e. Methane emissions totaled 4.6 MMT CO_2e and carbon dioxide emissions totaled 18.2 MMT CO_2. Combustion emissions (18.2 MMT CO_2e) were larger than process emissions. Following combustion equipment, the top reported emission sources were reciprocating compressors (2.3 MMT CO_2e) and blowdown vent stacks (1.2 MMT CO_2e).

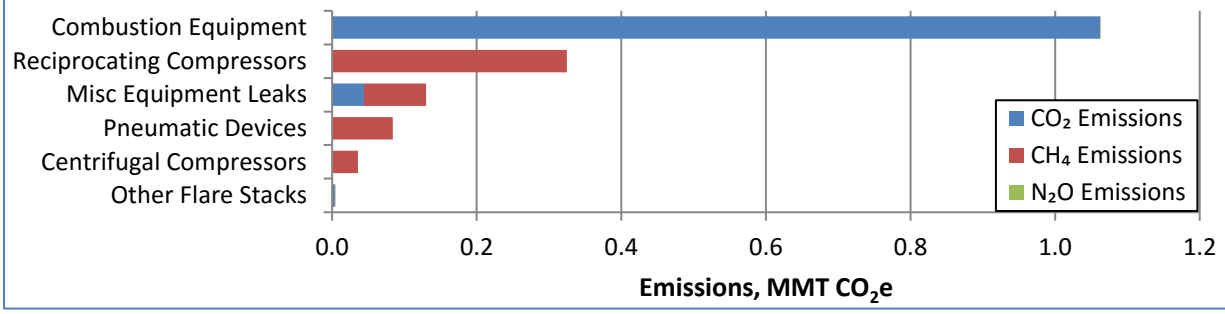
Figure 10: 2015 Natural Gas Transmission: Top Reported Emission Sources



Underground Natural Gas Storage

The EPA received annual reports from 53 facilities in the underground natural gas storage segment and reported emissions totaled 1.6 MMT CO_2e.[6] Methane emissions totaled 0.5 MMT CO_2e and carbon dioxide emissions totaled 1.1 MMT CO_2e. Combustion equipment (1.1 MMT CO_2e) was the top reported source of emissions for underground natural gas storage, followed by reciprocating compressors (0.3 MMT CO_2e).

Figure 11: 2015 Underground Natural Gas Storage: Top Reported Emission Sources



Emission Source in Detail: Compressors

Compressors are used in the production, processing, transmission, and storage segments to keep pipelines at a high enough pressure so natural gas will continue flowing through the pipelines. The two primary types of compressors in use in the petroleum and natural gas industry are reciprocating compressors and centrifugal compressors.

Compressors are a large source of combustion emissions in Petroleum and Natural Gas Systems, and combustion emissions for Petroleum and Natural Gas Systems were presented earlier in this document. Compressors are also a source of process emissions. The primary source of process emissions from compressors are from rod packing (reciprocating compressors), emissions from wet or dry seals (centrifugal compressors), emissions from blowdown valve leakage, and emissions from isolation valve leakage. The source of emissions may vary based on the mode of operation that the compressor is in. A compressor in operating mode may have different emissions from a compressor in a shutdown depressurized mode. Because the emissions are from seal leakage, even compressors of the same manufacture can have different emissions based on the quality of the compressor seals. Emissions can be mitigated through rigorous maintenance practices and leak surveys, routing emissions to a flare, or capturing emissions.

Total reported compressor emissions from all industry segments were 5.5 MMT CO_2e. The reported emissions are predominantly methane, as the carbon dioxide emissions total to about 0.02

[6] The Southern California Gas Company - Aliso Canyon facility's actual 2015 emissions were higher than those reported to the GHGRP. The GHGRP provides well-vetted average emission factors to calculate emissions. The facility followed these GHGRP calculation methods for 2015 reporting. Actual emissions differ from those reported due to an exceptional leak event. See California Air Resource Board's Aliso Canyon Natural Gas Leak webpage for more information: https://www.arb.ca.gov/research/aliso_canyon_natural_gas_leak.htm.

MMT CO_2. The calculation method varied by industry segment. Emissions from compressors in onshore production were calculated by using population counts multiplied by an emission factor and accounted for 0.7 MMT CO_2e of reported emissions. Emissions from compressors in the other industry segment were calculated by the use of direct measurement.

The table below shows activity data and emissions for reciprocating compressors by industry segment (excluding onshore production which used population counts). The EPA received data from 5,240 reciprocating compressors, including 2,658 reciprocating compressors in natural gas processing, 2,198 reciprocating compressors in natural gas transmission, and 357 reciprocating compressors in underground natural gas storage.

Table 3: 2015 Reported Process Emissions from Reciprocating Compressors in Natural Gas Processing, Natural Gas Transmission, Underground Natural Gas Storage, LNG Import/Export, and LNG Storage

Industry Segment	Total Number of Reciprocating Compressors	Reported CO_2 Emissions (MT CO_2e)	Reported CH_4 Emissions (MT CO_2e)
Natural Gas Processing	2,658	7,818	1,240,951
Natural Gas Transmission	2,198	2,109	2,566,756
Underground Natural Gas Storage	357	351	324,426
LNG Import/Export	17	17	13,350
LNG Storage	10	<1	209
Total	**5,240**	**10,296**	**4,145,691**

The table below shows activity data and emissions for centrifugal compressors by industry segment. For centrifugal compressors the number of compressors with wet seals is also shown. Overall emissions from centrifugal compressors were lower than those for reciprocating compressors, but the total number of reported compressors was lower as well. The EPA received data from 1,326 centrifugal compressors, including 478 centrifugal compressors in natural gas processing, 801 centrifugal compressors in natural gas transmission, and 35 centrifugal compressors in underground natural gas storage.

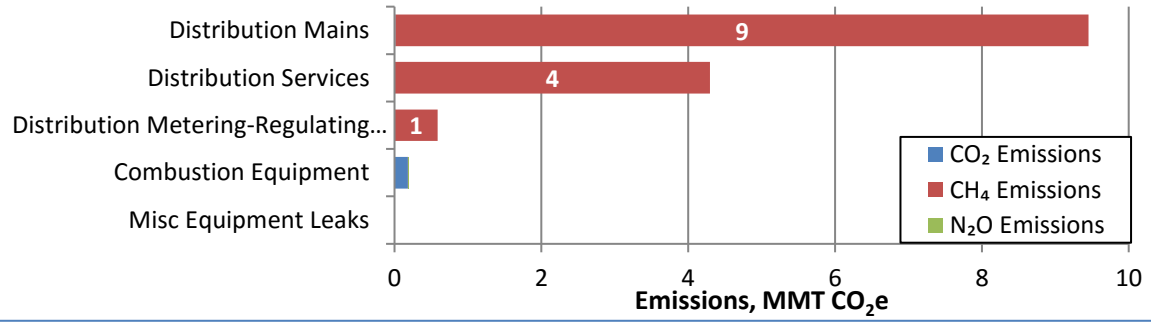
Table 4: 2015 Reported Process Emissions from Centrifugal Compressors in Natural Gas Processing, Natural Gas Transmission, Underground Natural Gas Storage, LNG Import/Export, and LNG Storage

Industry Segment	Total Number of Centrifugal Compressors	Number of Centrifugal Compressors with Wet Seals	Reported CO_2 Emissions (MT CO_2e)	Reported CH_4 Emissions (MT CO_2e)
Natural Gas Processing	478	264	1,279	393,906
Natural Gas Transmission	801	309	2,968	418,249
Underground Natural Gas Storage	35	20	41	35,833
LNG Import/Export	10	4	16	14,238
LNG Storage	2	2	0	0
Total	**1,326**	**599**	**4,305**	**862,226**

Natural Gas Distribution

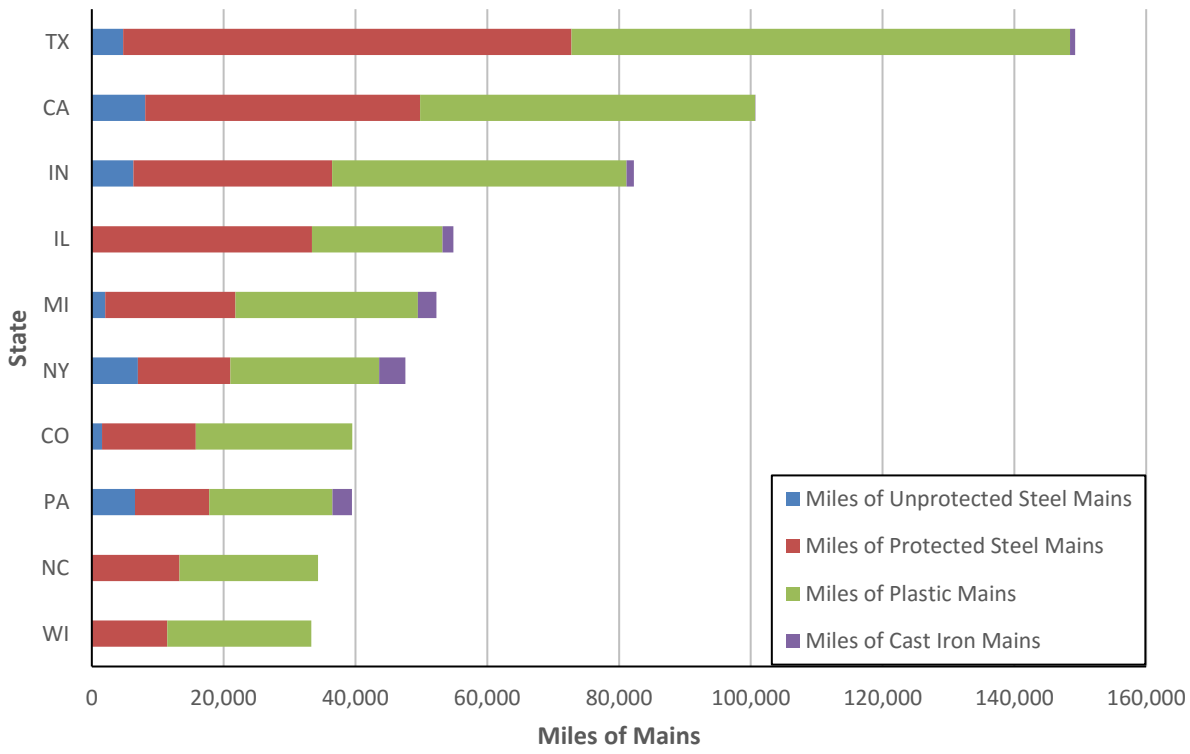
The EPA received annual reports from 177 facilities in the natural gas distribution segment and reported emissions totaled 14.3 MMT CO_2e. Methane emissions totaled 14 MMT CO_2e and carbon dioxide emissions totaled 0.2 MMT CO_2e. For the Natural Gas Distribution segment, combustion emissions (0.2 MMT CO_2e) were relatively lower compared to other industry segments. The primary sources of emission for natural gas distribution were distribution mains (9.4 MMT CO_2e) and distribution services (4.3 MMT CO_2e), which are caused by natural gas equipment leaks and calculated by multiplying mileage by default population emission factors that are specific to pipe material.

Figure 12: 2015 Natural Gas Distribution: Top Reported Emission Sources



As part of the activity data collected with 2015 reports, the EPA received data from Natural Gas Distribution facilities subject to the GHGRP covering the miles of distribution mains by material. The pipeline materials included are: unprotected steel, protected steel, plastic, and cast iron. Since Natural Gas Distribution facilities report their data at the state-level, the EPA is able to summarize the information across all reporters per state.

Figure 13: 2015 Miles of Mains by State and Material



Note: Only the 10 states with the largest total miles of distribution mains are shown.

LNG Import/Export

The EPA received emission reports from 7 LNG import/export terminals and reported emissions totaled 0.6 MMT CO_2e. Methane emissions totaled 0.03 MMT CO_2e and carbon dioxide emissions totaled 0.6 MMT CO_2e. The top reported source of emissions was combustion equipment (0.5 MMT CO_2e).

LNG Storage

The EPA received emission reports from 7 LNG storage facilities. Total reported emissions from LNG storage were less than 0.01 MMT CO_2e.

Changes from 2011 to 2015

The following section describes the reported data for the 2011 through 2015 calendar years for Petroleum and Natural Gas Systems[7].

Changes in Number of Facilities

From 2011 to 2015, the number of facilities in Petroleum and Natural Gas Systems increased from 1,922 facilities to 2,413 facilities. The largest increases occurred in other oil and gas combustion (201), natural gas transmission (100), natural gas processing (93), and onshore production (75). Annual reported facility counts can be seen in Table 5 below.

The increased number of facilities is primarily a result of facilities triggering the 25,000 metric ton CO_2e reporting threshold in more recent years. Emissions can be variable in the Petroleum and Natural Gas Systems sector and it is not unexpected that emissions for a facility may go above 25,000 metric tons CO_2e in a given year. Once the reporting threshold is triggered, facilities must report to the GHGRP until emissions are below the threshold for a period of time specified in the regulations, or until all emission sources at a facility cease operation. As a result, the number of facilities reporting to the GHGRP may vary from year to year.

Changes in Reported Emissions

Total reported emissions slightly increased from 2011 to 2015. The largest increases occurred in onshore production (5.2 MMT CO_2e) and other oil and gas combustion (6.5 MMT CO_2e). The largest decreases were seen in natural gas transmission (-1.3 MMT CO_2e) and natural gas distribution (-1.2 MMT CO_2e). Annual reported emissions values by industry segment are shown below in Table 6. Emission changes are the result of a number of factors, such as changes in the number of facilities, operational changes (e.g. increased flaring), calculation changes (e.g. reduced BAMM use), and changes in the regulatory landscape.

Changes in Reported Emissions by Emission Source

The change in emissions from 2011 to 2015 is not attributable to any individual emission source. Several sources saw increased emissions, including combustion equipment (16.9 MMT CO_2e), associated gas venting and flaring (3.6 MMT CO_2e), pneumatic devices (4.2 MMT CO_2e), and other flare stacks (3.3 MMT CO_2e). Other sources saw decreased emissions. For gas well completions and workovers with hydraulic fracturing, total reported emissions decreased by 7.5 MMT CO_2e (including a decrease in reported methane emissions of 5.2 MMT CO_2e). Annual reported emissions values by emission source are shown below in Table 7.

[7] The EPA received resubmissions of 2011 through 2014 data from certain facilities and this section describes the 2011-2015 time series updated to include the resubmitted data.

Table 5: Changes in Number of Facilities by Industry Segment: 2011 to 2015

Industry Segment	2011 Number of Facilities	2012 Number of Facilities	2013 Number of Facilities	2014 Number of Facilities	2015 Number of Facilities	2014-15 Change in Number of Facilities	2011-15 Change in Number of Facilities
Onshore Production	459	506	507	568	534	-34	75
Offshore Production	100	107	108	128	133	5	33
Natural Gas Processing	374	403	438	479	467	-12	93
Natural Gas Transmission	421	457	487	521	521	0	100
Underground Natural Gas Storage	49	52	51	54	53	-1	4
Natural Gas Distribution	183	183	176	181	177	-4	-6
LNG Import/Export	8	8	8	8	7	-1	-1
LNG Storage	6	5	5	5	7	2	1
Other Oil and Gas Combustion	340	390	421	492	541	49	201
Total	**1,922**	**2,095**	**2,186**	**2,417**	**2,413**	**-4**	**491**

Note: Total number of facilities is smaller than the sum of facilities from each segment because some facilities reported under multiple segments. A facility is included in the count of number of facilities if it reported emissions (even if the reported emissions were zero) under a given segment.

Table 6: Changes in Reported Emissions by Industry Segment: 2011 to 2015

Industry Segment	2011 Reported Emissions (MMT CO_2e)	2012 Reported Emissions (MMT CO_2e)	2013 Reported Emissions (MMT CO_2e)	2014 Reported Emissions (MMT CO_2e)	2015 Reported Emissions (MMT CO_2e)	2014-15 Change in Reported Emissions (MMT CO_2e)	2011-15 Change in Reported Emissions (MMT CO_2e)
Onshore Production	92	93	98	101	97	-4.0	5.2
Offshore Production	6	7	6	7	7	0.2	0.9
Natural Gas Processing	59	60	59	60	58	-1.4	-0.6
Natural Gas Transmission	24	24	23	22	23	0.6	-1.3
Underground Natural Gas Storage	2	2	2	2	2	-0.1	-0.1
Natural Gas Distribution	16	15	15	15	14	-0.4	-1.2
LNG Import/Export	1	1	<1	1	1	0.0	-0.2
LNG Storage	<1	<1	<1	<1	<1	0.0	0.0
Other Oil and Gas Combustion	23	25	25	28	29	1.5	6.5
Total	**222**	**226**	**228**	**235**	**231**	**-3.6**	**9.2**

Table 7: Changes in Reported Emissions by Emission Source: 2011 to 2015

Emission Source	2011 Reported Emissions (MMT CO_2e)	2012 Reported Emissions (MMT CO_2e)	2013 Reported Emissions (MMT CO_2e)	2014 Reported Emissions (MMT CO_2e)	2015 Reported Emissions (MMT CO_2e)	2014-15 Change in Reported Emissions (MMT CO_2e)	2011-15 Change in Reported Emissions (MMT CO_2e)
Combustion Equipment	108.0	110.7	113.2	122.2	124.9	2.7	16.9
Pneumatic Devices	21.8	22.7	25.5	25.7	26.0	0.3	4.2
Atmospheric Tanks	4.3	5.6	6.4	7.1	8.3	1.2	4.0
Associated Gas Venting and Flaring	8.1	11.4	11.7	12.7	11.7	-1.0	3.6
Other Flare Stacks	5.7	7.8	8.9	9.7	9.0	-0.7	3.3
Blowdown Vent Stacks	1.5	2.4	2.0	2.2	1.9	-0.3	0.4
Pneumatic Pumps	2.9	3.4	3.0	3.0	3.1	0.1	0.2
Reciprocating Compressors	3.9	3.7	4.1	3.6	4.0	0.4	0.1
Transmission Tanks	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Enhanced Oil Recovery Pumps	<0.1	<0.1	<0.1	<0.1	<0.1	0.0	0.0
Enhanced Oil Recovery Liquids	<0.1	<0.1	<0.1	<0.1	<0.1	0.0	0.0
Offshore Sources	2.2	2.1	1.9	2.3	2.2	-0.1	0.0
Distribution Metering-Regulating Stations	0.7	0.7	0.4	0.6	0.6	-0.1	-0.1
Distribution Mains	9.8	9.7	9.7	9.5	9.5	0.0	-0.3
Well Testing	0.8	0.7	0.9	1.0	0.2	-0.8	-0.6
Centrifugal Compressors	2.2	2.4	1.8	1.6	1.5	-0.1	-0.7
Gas Well Completions and Workovers without Hydraulic Fracturing	0.8	0.2	0.1	0.2	0.1	-0.1	-0.7
Distribution Services	5.0	4.8	4.7	4.5	4.3	-0.2	-0.7
Dehydrators	2.1	1.7	1.5	1.8	1.2	-0.6	-0.9
Misc. Equipment Leaks	10.7	10.5	10.2	9.4	9.2	-0.2	-1.4
Liquids Unloading	7.4	5.2	4.6	3.5	2.8	-0.7	-4.6
Acid Gas Removal Units	16.1	15.7	13.2	12.6	10.2	-2.4	-5.9
Gas Well Completions and Workovers with Hydraulic Fracturing	8.5	4.4	3.4	1.8	1.0	-0.8	-7.5

Additional Information

Access GHGRP data: http://www.epa.gov/ghgreporting/

Additional information about Petroleum and Natural Gas Systems in the GHGRP, including reporting requirements and calculation methods:
http://www.epa.gov/ghgreporting/reporters/subpart/w.html

2015 Petroleum and Natural Gas Systems Data Highlights Page:
http://www.epa.gov/ghgreporting/ghgrp-2015-petroleum-and-natural-gas-systems

Facility Level Information on Greenhouse Gases Tool (FLIGHT): http://ghgdata.epa.gov/

GLOSSARY

IPCC AR4 refers to the Fourth Assessment Report by the Intergovernmental Panel on Climate Change. *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, Pachauri, R.K. and Reisinger, A. (eds)]. IPCC, Geneva, Switzerland, 2007.* The AR4 values also can be found in the current version of Table A-1 in subpart A of 40 CFR part 98.

IPCC AR5 refers to the Fifth Assessment Report by the Intergovernmental Panel on Climate Change. *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.*