PETROLEUM AND NATURAL GAS SYSTEMS

Introduction

All emissions presented here are as of 8/16/2015. All GHG emissions data displayed in units of carbon dioxide equivalent (CO_2e) reflect the global warming potential (GWP) values from IPCC AR4.

On October 6, 2015, the U.S. Environmental Protection Agency (EPA) released 2014 greenhouse gas (GHG) data for Petroleum and Natural Gas Systems[1] collected under the Greenhouse Gas Reporting Program (GHGRP). The GHGRP, which was required by Congress in the FY2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain greenhouse gases and products that would emit GHGs if released or combusted.

The data show 2014 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 236 million metric tons of carbon dioxide equivalent (CO_2e). This is an increase of 3.5% compared to 2013 GHG emissions from this sector.

For the first time, for many emission categories, Petroleum and Natural Gas Systems reporters submitted activity data from their facilities, including activity data from previous years that were subject to deferred reporting until March 2015. This information includes equipment counts, operational parameters, and other data that are used to calculate GHG emissions.

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. In order to provide facilities with time to adjust to the requirements of the GHGRP, the EPA made available the optional use of Best Available Monitoring Methods (BAMM) for unique or unusual circumstances. Where a facility used BAMM, it was required to follow emission calculations specified by the EPA, but was allowed to use alternative methods for determining inputs to calculate emissions.

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,

[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.

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 from previous years. While many facilities in this sector submitted deferred data, certain facilities might not have reported this information for legitimate reasons. 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. It is important to be aware of these limitations and differences when using this data, particularly when attempting to draw broad conclusions about emissions from this sector.

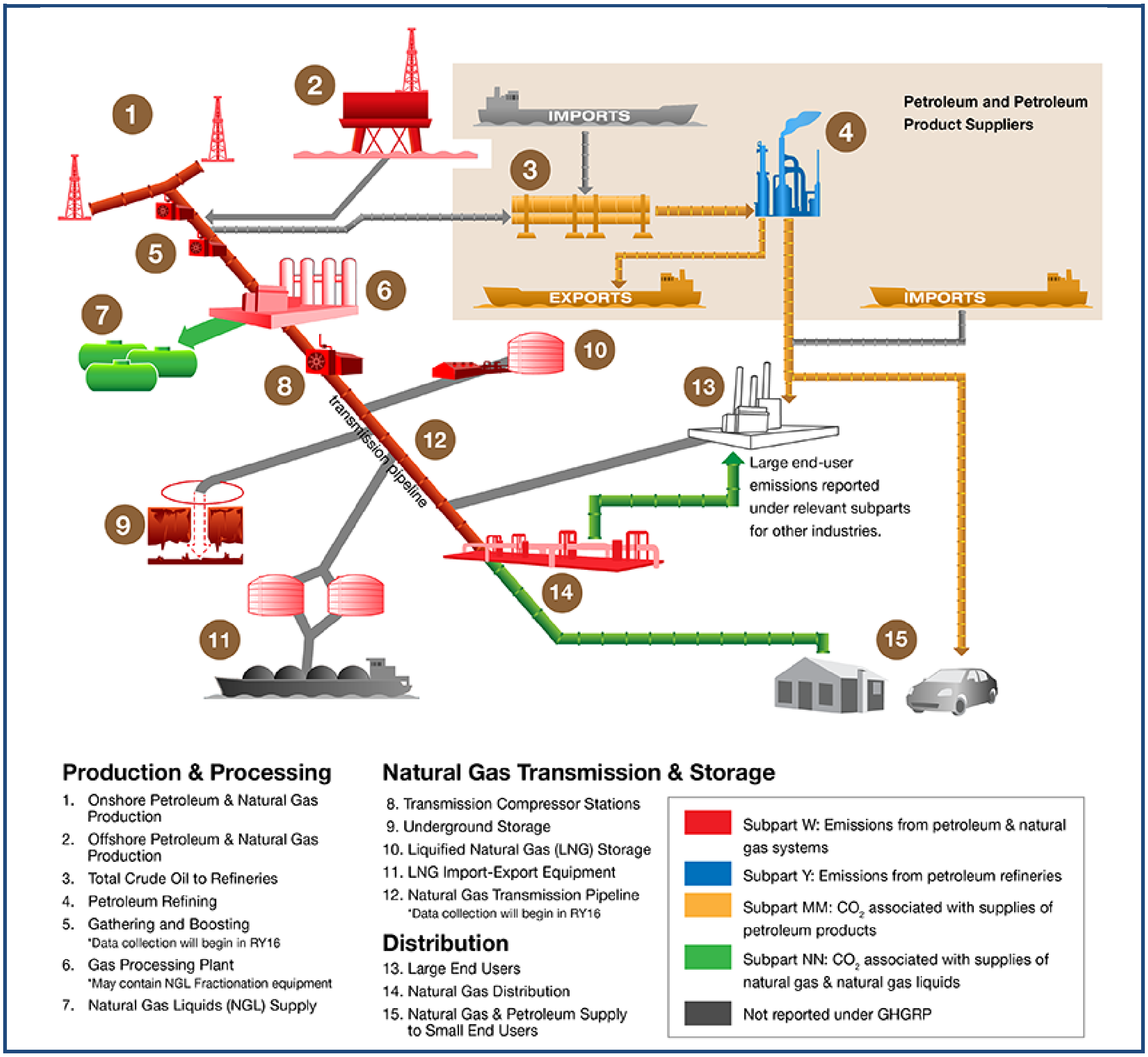
Petroleum and Natural Gas Systems in the GHG Reporting Program

The Petroleum and Natural Gas Systems source category of the GHGRP (Subpart W) requires reporting from the following eight industry segments for 2014, 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.
- Liquified Natural Gas (LNG) Import/Export: Liquified Natural Gas import and export terminals.
- LNG Storage: Liquified Natural Gas storage equipment.

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

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.

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, including potential mistakes related to deferred data. In addition, because of the nature of the petroleum and natural gas industry, there can be variation in emissions from facility to facility.

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.[4] 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. Facilities used BAMM in different ways and for different parameters depending on their unique or unusual circumstances. Note that the EPA has removed the option to use BAMM beyond 2014 except for targeted circumstances where the EPA has made recent changes to GHGRP regulatory requirements for Petroleum and Natural Gas Systems.

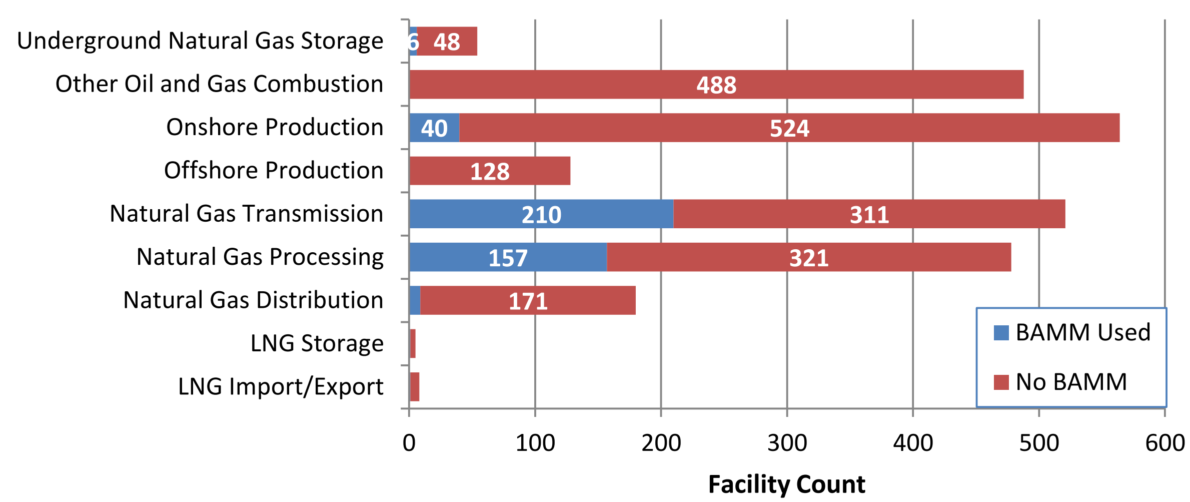
In 2014, facilities were required to receive approval from the EPA prior to using BAMM for the Petroleum and Natural Gas Systems source category and these facilities were required to specify in their GHG annual reports when BAMM was used for an emission source. In 2014, 18% of facilities in the petroleum and natural gas source category reported using BAMM. The natural gas transmission and natural gas processing segments represented the segments with the largest frequency of BAMM use. Natural gas transmission had 40% of facilities reporting BAMM use and natural gas processing had 33% of facilities reporting BAMM use. The remaining segments had proportionally lower BAMM use. LNG storage had 20% of facilities reporting BAMM use, LNG import/export had 13% of facilities reporting BAMM use, underground natural gas storage had 11% of facilities reporting BAMM use, onshore production had 7% of facilities reporting BAMM use, and natural gas distribution had 5% of facilities reporting BAMM use. No facilities in the offshore production segment reported BAMM use. In addition, facilities in the other oil and gas combustion category were not permitted to use BAMM. For purposes of this document, facilities are recorded as using BAMM if they indicated the use of BAMM for any piece of equipment from any emission source.

[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/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf

[4] For more information on BAMM, see: http://www.epa.gov/sites/production/files/2015-08/documents/ghgrp_bamm_factsheet.pdf

Figure 2: 2014 BAMM Use by Segment



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 2014 calendar year.

Reported Emissions by Industry Segment

The 2014 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, 2015. The EPA received reports from over 2,400 facilities[5] with Petroleum and Natural Gas Systems activities, with total reported GHG emissions of 236 Million Metric Tons (MMT) CO_2e.

The largest industry segment in terms of reported GHG emissions was onshore production, with a total of 103 MMT CO_2e, followed by natural gas processing, with reported emissions of 60 MMT CO_2e. Other oil and gas combustion accounted for 28 MMT CO_2e. The next largest segment was natural gas transmission, with reported emissions of 22 MMT CO_2e. Reported emissions from natural gas distribution totaled 15 MMT CO_2e. The remaining segments accounted for total reported emissions of less than 12 MMT CO_2e.

[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).

Table 1: 2014 Reported Emissions by Industry Segment

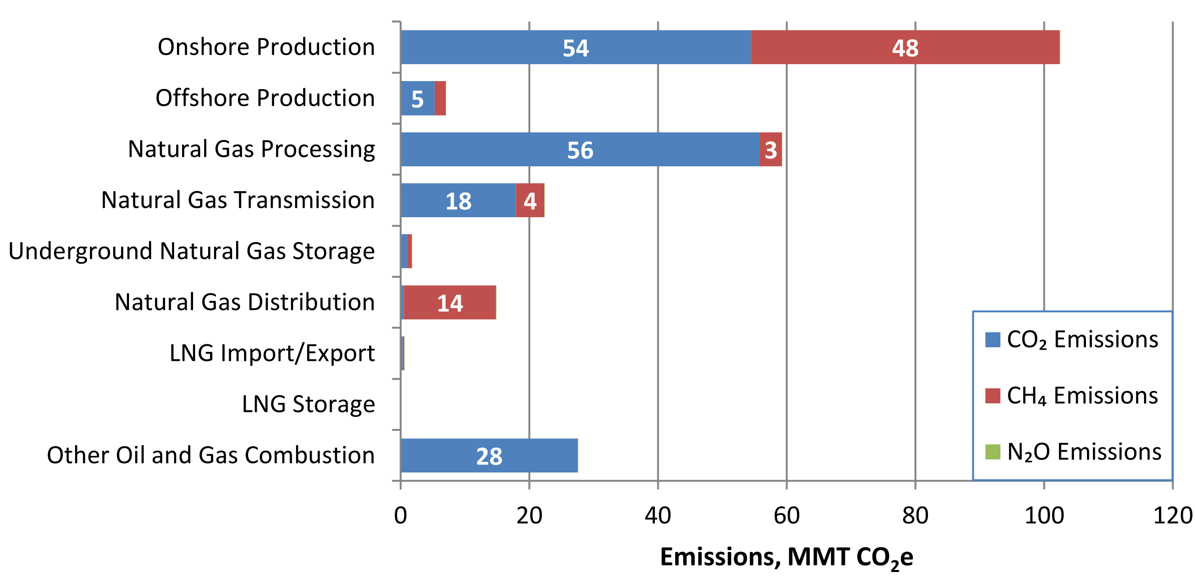
Industry Segment	Number of Facilities	Reported Emissions (Million Metric Tons CO_2e)
Onshore Production	564	103
Offshore Production	128	7
Natural Gas Processing	477	60
Natural Gas Transmission	520	22
Underground Natural Gas Storage	54	2
Natural Gas Distribution	180	15
LNG Import/Export	8	1
LNG Storage	5	<1
Other Oil and Gas Combustion	488	28
Total	**2,405**	**236**

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 163 MMT CO_2e of reported emissions and methane (CH_4) emissions accounted for 73 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.

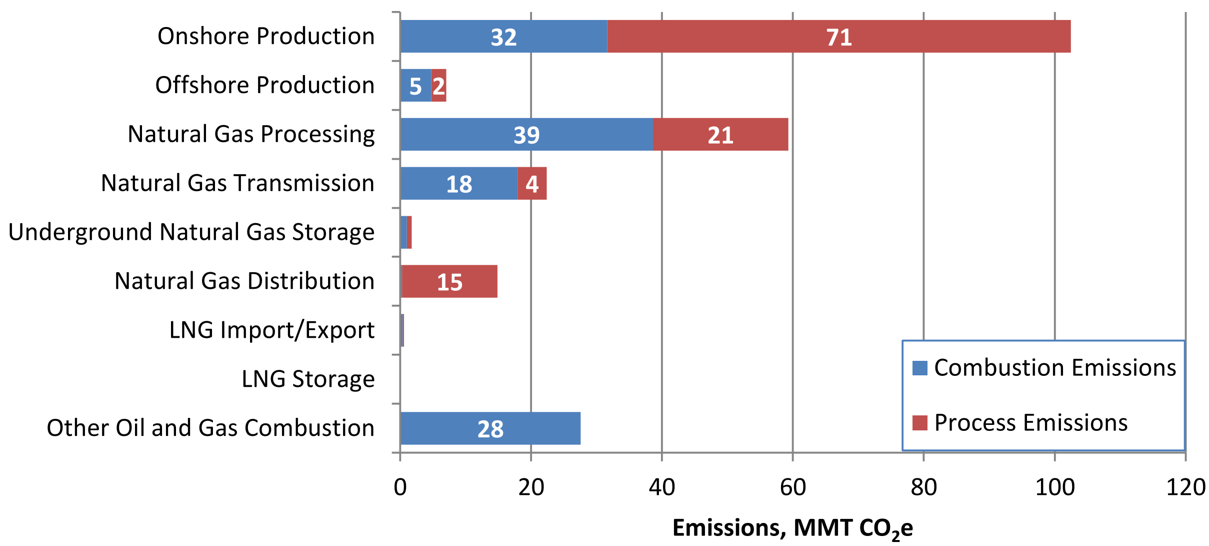
Figure 3: 2014 Reported Emissions by Greenhouse Gas



Reported Combustion and Process Emissions

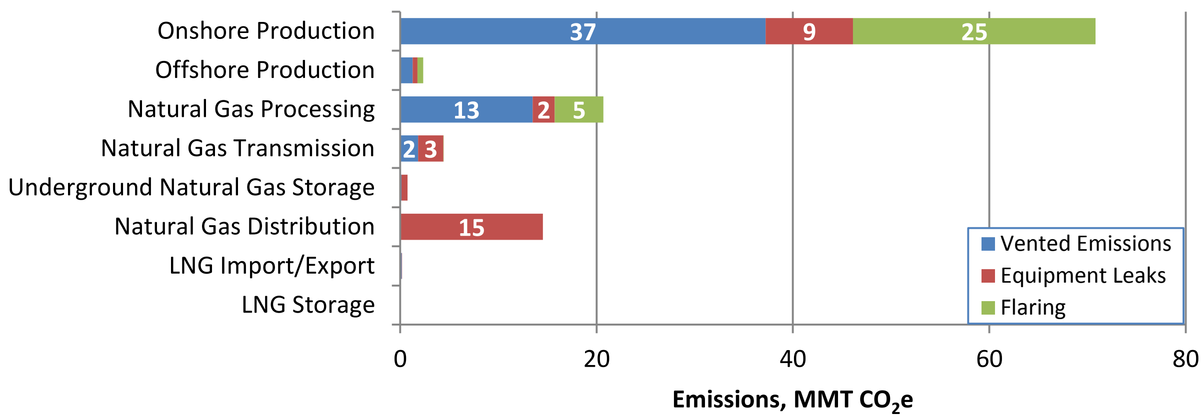
Each segment of Petroleum and Natural Gas Systems has unique emission sources. Emissions may result from the combustion of fossil fuels or from process sources that result in the direct emission of GHGs. Reported combustion emissions in Petroleum and Natural Gas Systems totaled 124 MMT CO_2e and reported process emissions totaled 114 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 4: 2014 Reported Combustion and Process Emissions



Process emissions may be further classified as vented emissions, equipment leaks, and flaring. Reported vented emissions totaled 54 MMT CO_2e, reported equipment leaks totaled 29 MMT CO_2e, and reported flaring emissions totaled 30 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.

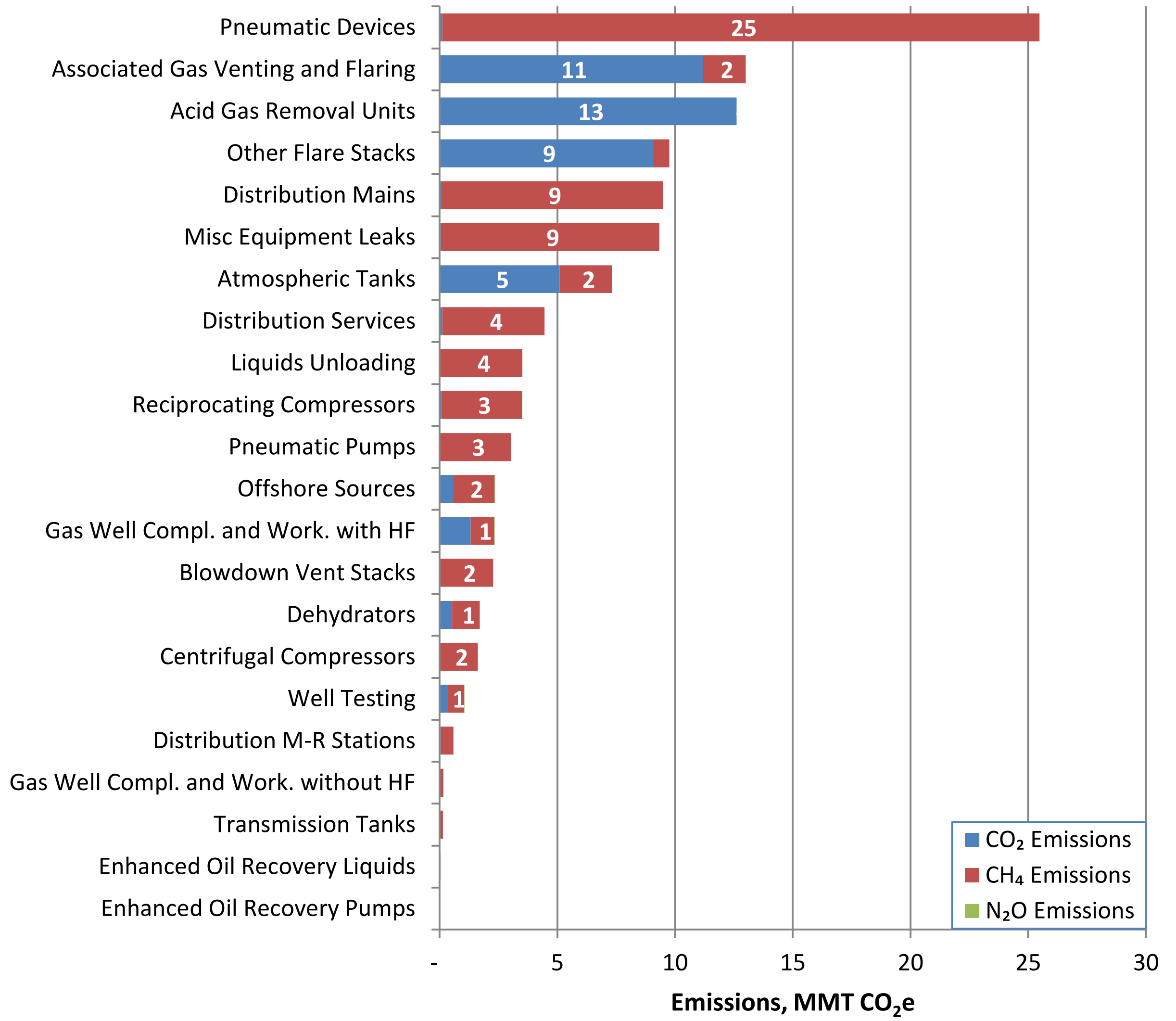
Figure 5: 2014 Reported Process Emissions by Vented Emissions, Equipment Leaks, and Flaring



Reported Process Emission Sources

The top reported process emission source in Petroleum and Natural Gas Systems was pneumatic devices with reported emissions of 25 MMT CO_2e. 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. Emissions from natural gas pneumatic devices are calculated by applying a facility determined population count to a default emission factor.

Figure 6: 2014 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 and natural gas processing segments and it is intended to cover all flares not otherwise reported for other sources at these facilities. For example, flaring for gas well completions and workovers with hydraulic fracturing would be reported under the gas well completions and workovers with hydraulic fracturing emission source rather than the other flare stacks emission source.

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 (13 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.

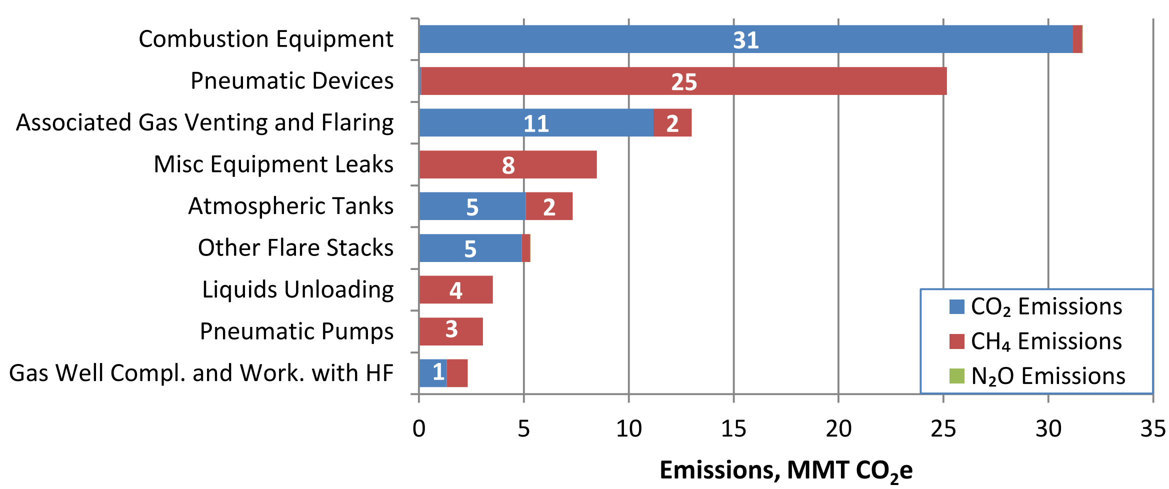
Reported GHG Emissions by Industry Segment and Source

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 564 facilities in the onshore production segment and reported emissions totaled 103 MMT CO_2e. Methane emissions totaled 48 MMT CO_2e and carbon dioxide emissions totaled 54 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 (31.6 MMT CO_2e) and pneumatic devices (25.1 MMT CO_2e) were the top reported emission sources, followed by associated gas venting and flaring (13.0 MMT CO_2e), miscellaneous equipment leaks (8.4 MMT CO_2e), atmospheric tanks (7.3 MMT CO_2e), and other flare stacks (5.3 MMT CO_2e).

Figure 7: 2013 Onshore Production: Top Reported Emission Sources



The five basins with the top reported emissions were the Williston Basin with 16.4 MMT CO_2e, Gulf Coast Basin with 15.6 MMT CO_2e, the Permian Basin with 10.9 MMT CO_2e, the Anadarko Basin with 9.4 MMT CO_2e, and the San Juan Basin with 7.3 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 backflow, 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 backflow rate in order to report emissions using an engineering calculation. Alternatively, the backflow vent or flare volume may be measured directly.

The EPA received information on gas well completions and workovers with hydraulic fracturing from 183 onshore production facilities. There were 22 facilities that reported using BAMM to calculate emissions from the gas well completions and workovers emissions source. The total reported emissions for gas well completions and workovers with hydraulic fracturing were 2.3 MMT CO_2e. Reported CO_2 emissions were 1.3 MMT CO_2e and reported CH_4 emissions were 1.2 MMT CO_2e.

Emissions were reported by GHG for flaring and venting activities. Facilities were also required to report the total count of completions and workovers. In addition, facilities provided a count of the number of completions or workovers employing purposely designed equipment that separates natural gas from the backflow (RECs).

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 and some reporters used BAMM.

Table 2: 2014 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	7,139	4,928	6,533	902,202	1,230,755	177,903	2,145,152
Gas Well Workovers with Hydraulic Fracturing	445	138	133	83,612	83,563	4,100	171,427
Total	**7,584**	**5,066**	**6,666**	**985,813**	**1,314,318**	**182,003**	**2,316,580**

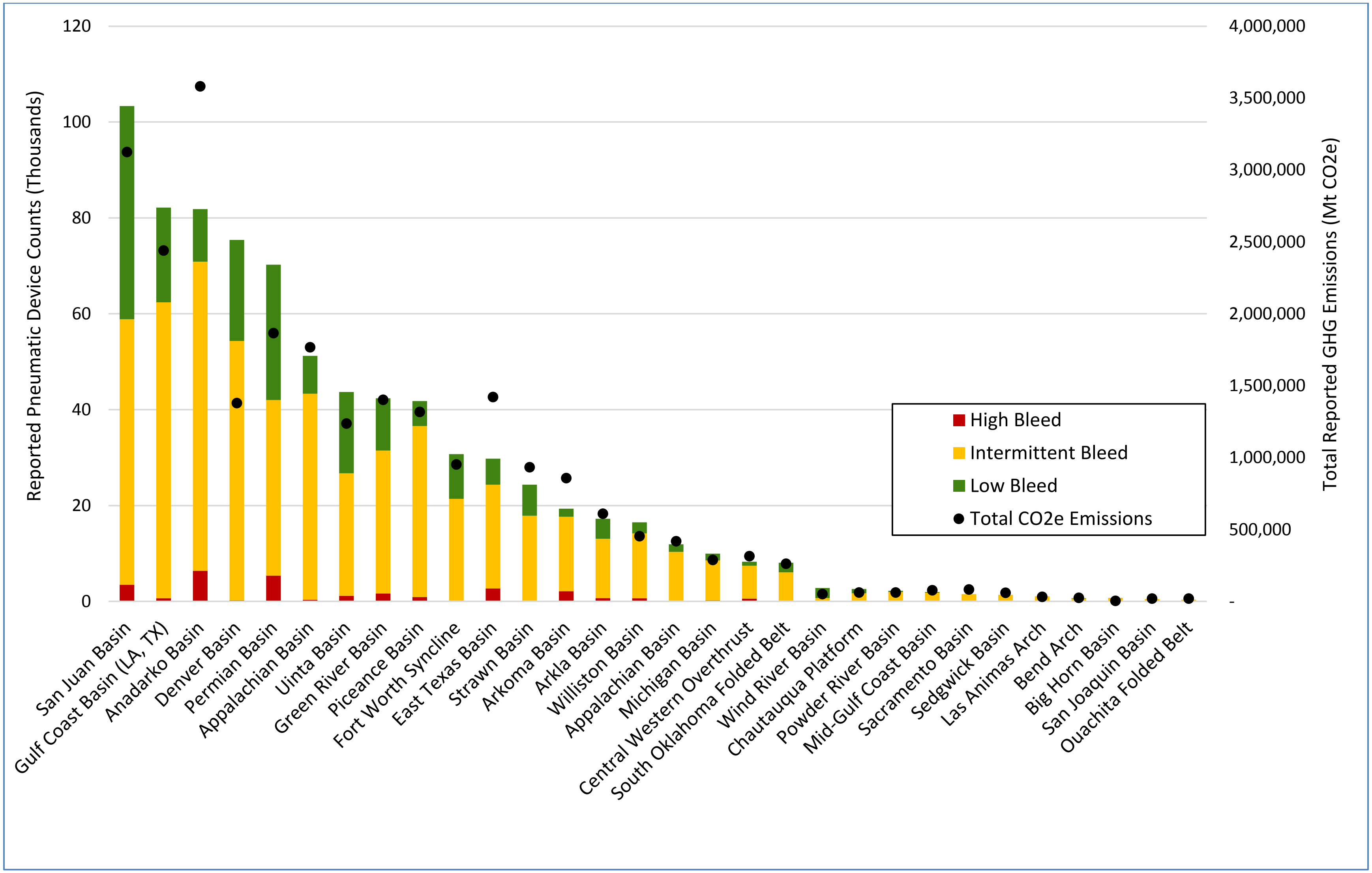
Emission Source in Detail: Counts of Pneumatic Devices

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

Counts of these devices for each basin-level facility in the Onshore Petroleum and Natural Gas Production segment were previously deferred, but are now reported to the EPA.

Figure 8: 2014 Onshore Production Reported Pneumatic Device Counts and Reported Emissions

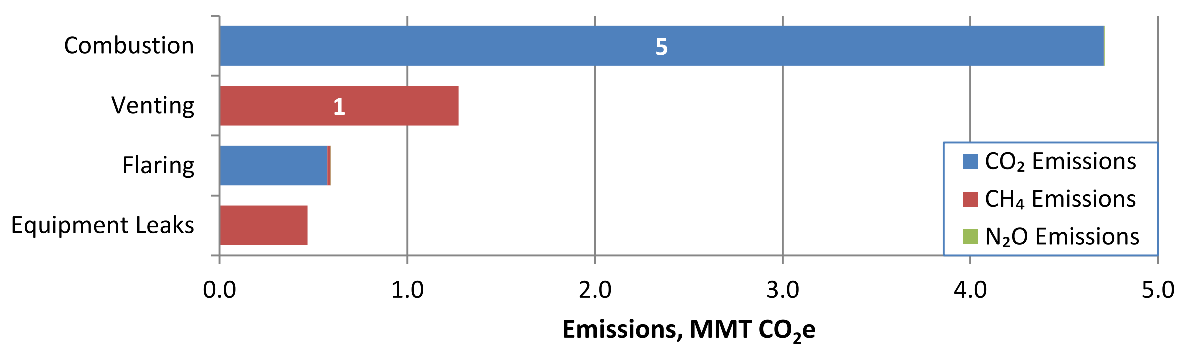


Note: Chart does not include basins with fewer than 300 pneumatic devices.

Offshore Production

The EPA received annual reports from 128 facilities in the offshore production segment and reported emissions totaled 6.8 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 (4.7 MMT CO_2e) followed by venting (1.3 MMT CO_2e).

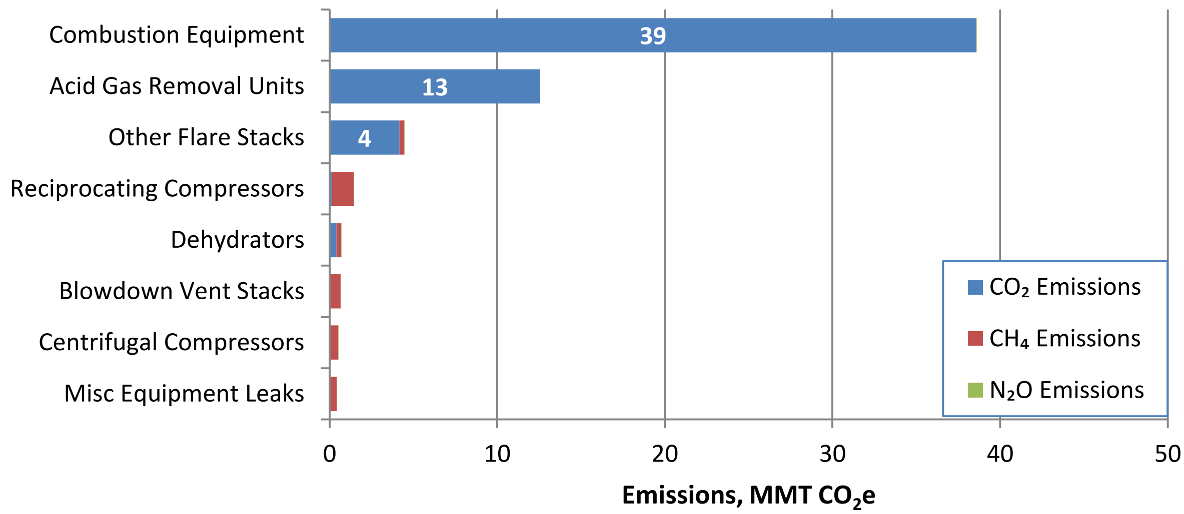
Figure 9: 2014 Offshore Production: Top Reported Emission Sources



Natural Gas Processing

The EPA received annual reports from 478 facilities in the natural gas processing segment and reported emissions totaled 59 MMT CO_2e. Methane emissions totaled 3.4 MMT CO_2e and carbon dioxide emissions totaled 55.9 MMT CO_2e. The top reported emission sources were combustion equipment (38.6 MMT CO_2e), acid gas removal units (12.6 MMT CO_2e), and other flare stacks (4.5 MMT CO_2e). Emissions from compressors were the top reported source of methane emissions, with reported emissions from reciprocating compressors (1.4 MMT CO_2e) and centrifugal compressors (0.5 MMT CO_2e).

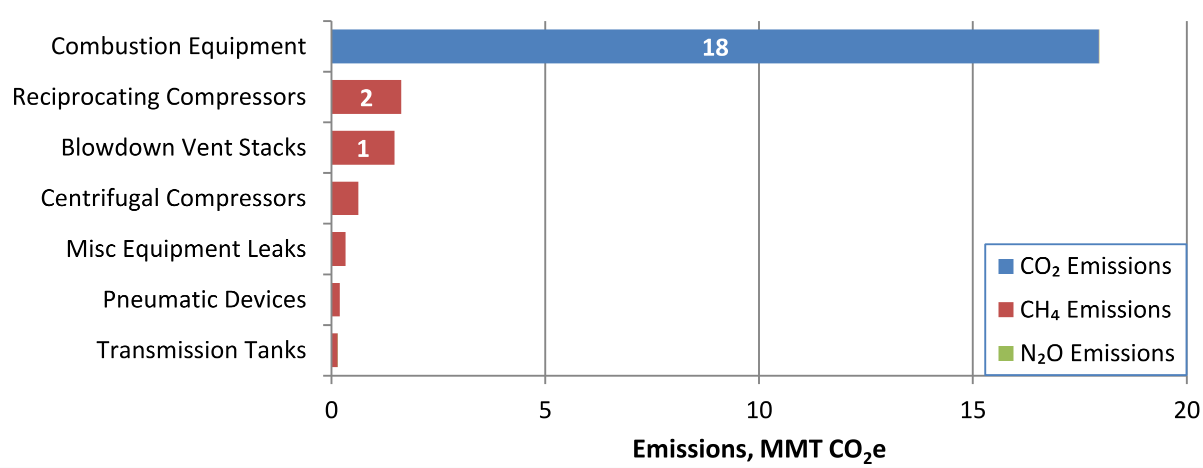
Figure 10: 2014 Natural Gas Processing: Top Reported Emission Sources



Natural Gas Transmission

The EPA received annual reports from 521 facilities in the natural gas transmission segment and reported emissions totaled 22.4 MMT CO_2e. Methane emissions totaled 4.4 MMT CO_2e and carbon dioxide emissions totaled 18.0 MMT CO_2e. Combustion emissions (18.0 MMT CO_2e) were larger than process emissions. Following combustion equipment, the top reported emission sources were reciprocating compressors (1.6 MMT CO_2e) and blowdown vent stacks (1.5 MMT CO_2e).

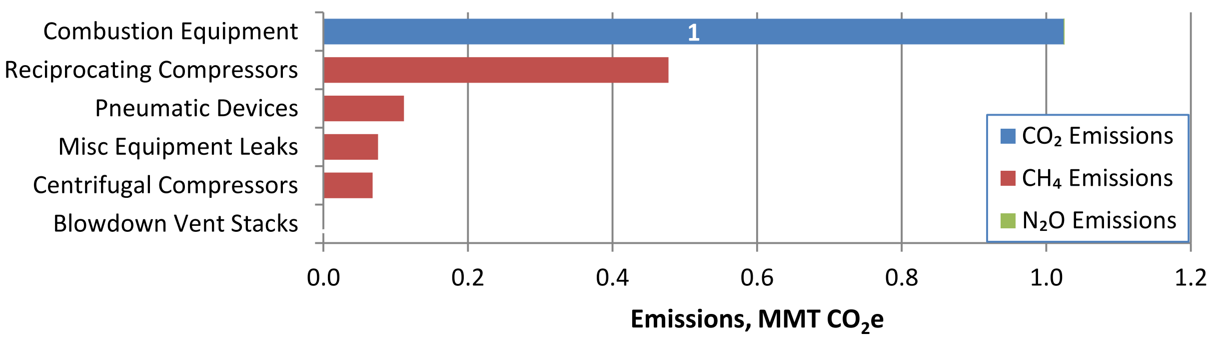
Figure 11: 2014 Natural Gas Transmission: Top Reported Emission Sources



Underground Natural Gas Storage

The EPA received annual reports from 54 facilities in the underground natural gas storage segment and reported emissions totaled 1.7 MMT CO_2e. Methane emissions totaled 0.7 MMT CO_2e and carbon dioxide emissions totaled 1.0 MMT CO_2e. Combustion equipment (1.0 MMT CO_2e) was the top reported source of emissions for underground natural gas storage, followed by reciprocating compressors (0.5 MMT CO_2e).

Figure 12: 2014 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 vents, 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 4.7 MMT CO_2e. Reported carbon dioxide emissions were 0.1 MMT CO_2e and reported methane emissions were 4.6 MMT CO_2e. 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 1.2 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 5,184 reciprocating compressors, including 2,635 reciprocating compressors in natural gas processing, 2,165 reciprocating compressors in natural gas transmission, and 351 reciprocating compressors in underground natural gas storage. Of these reciprocating compressors, 1,460 reported using BAMM to calculate emissions, including 834 in natural gas processing, 589 in natural gas transmission, and 31 in underground natural gas storage.

Table 3: 2014 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	Number of Reciprocating Compressors that used BAMM	Reported CO_2 Emissions (MT CO_2e)	Reported CH_4 Emissions (MT CO_2e)
Natural Gas Processing	2,635	834	65,881	1,301,605
Natural Gas Transmission	2,165	589	1,902	1,623,941
Underground Natural Gas Storage	351	31	513	476,706
LNG Import/Export	22	6	2	18,920
LNG Storage	11	0	29	266
Total	**5,184**	**1,460**	**68,327**	**3,421,439**

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 1,378 centrifugal compressors, including 489 centrifugal compressors in natural gas processing, 841 centrifugal compressors in natural gas transmission, and 36 centrifugal compressors in underground natural gas storage. Of these centrifugal compressors, 420 reported using BAMM to calculate emissions, including 193 in natural gas processing, 223 in natural gas transmission, and 2 in underground natural gas storage.

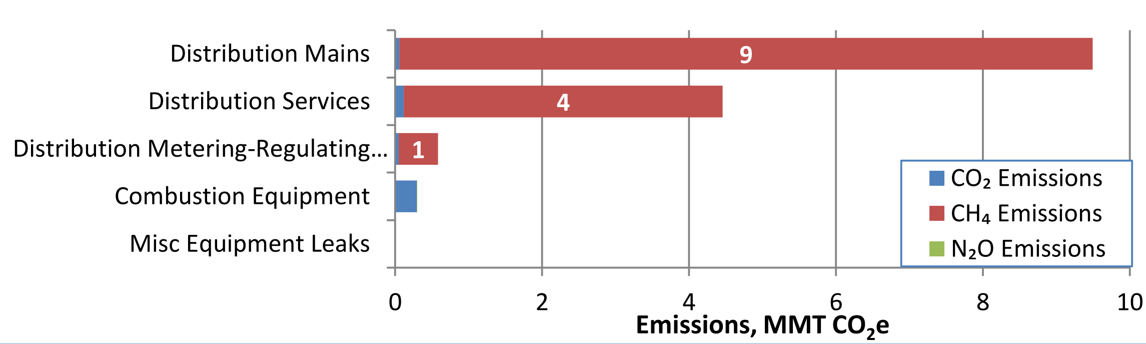
Table 4: 2014 Reported Process Emissions from Centrifugal Compressors in Natural Gas Processing, Natural Gas Transmission, Underground Natural Gas Storage, LNG Import/Export, and LNG Storage

Industry Segment	Total Number of Centrifugal Compressors	Number of Centrifugal Compressors that used BAMM	Number of Centrifugal Compressors with Wet Seals	Reported CO_2 Emissions (MT CO_2e)	Reported CH_4 Emissions (MT CO_2e)
Natural Gas Processing	489	193	275	14,513	501,181
Natural Gas Transmission	841	223	336	722	629,632
Underground Natural Gas Storage	36	2	19	79	68,011
LNG Import/Export	10	2	4	2	1,326
LNG Storage	2	0	2	0	0
Total	**1,378**	**420**	**636**	**15,316**	**1,200,151**

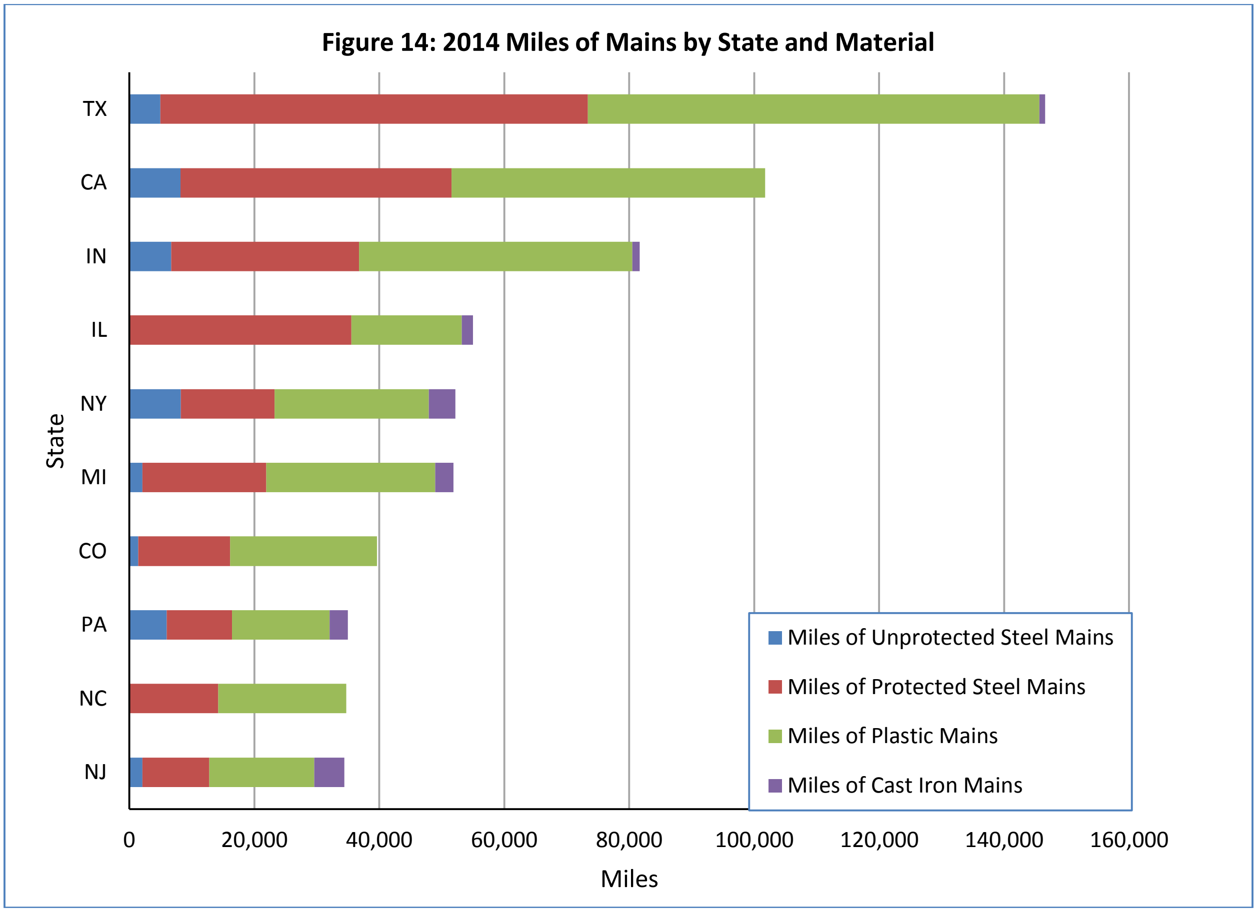
Natural Gas Distribution

The EPA received annual reports from 180 facilities in the natural gas distribution segment and reported emissions totaled 14.8 MMT CO_2e. Methane emissions totaled 14.3 MMT CO_2e and carbon dioxide emissions totaled 0.5 MMT CO_2e. For the natural gas distribution segment, combustion emissions (0.3 MMT CO_2e) were relatively lower compared to other industry segments. The primary sources of emission for natural gas distribution were distribution mains (9.5 MMT CO_2e) and distribution services (4.5 MMT CO_2e), which are caused by natural gas equipment leaks and calculated by multiplying population counts by default emission factors that are specific to pipe material.

Figure 13: 2014 Natural Gas Distribution: Top Reported Emission Sources



As part of the activity data collected with 2014 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.

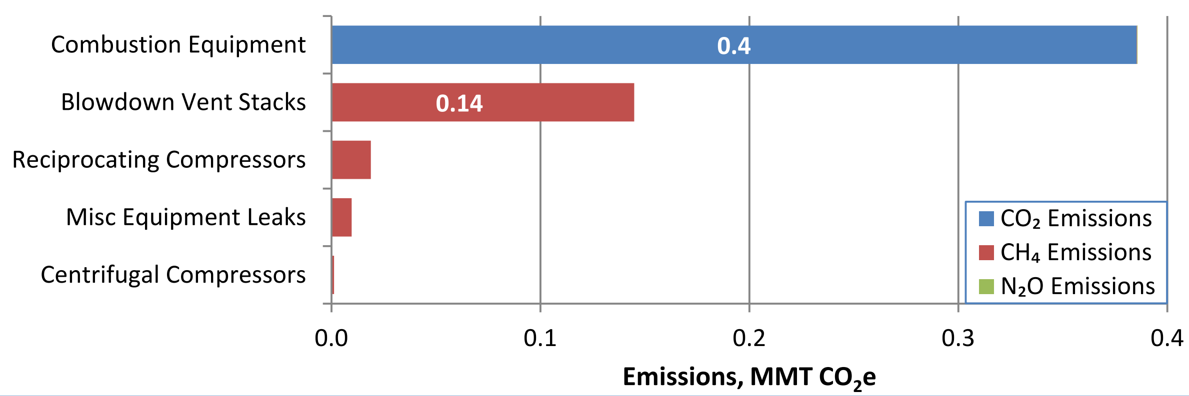


Note: Only the 10 states with the largest total miles of distribution mains are shown.

LNG Import/Export

The EPA received emission reports from 8 LNG import/export terminals and reported emissions totaled 0.6 MMT CO_2e. Methane emissions totaled 0.2 MMT CO_2e and carbon dioxide emissions totaled 0.4 MMT CO_2e. The top reported source of emissions was combustion equipment (0.4 MMT CO_2e), followed by blowdown vent stacks (0.14 MMT CO_2e), reciprocating compressors (0.02 MMT CO_2e), and equipment leaks (0.01 MMT CO_2e).

Figure 15: 2014 LNG Import/Export: Top Reported Emission Sources



LNG Storage

LNG storage had the fewest number of facilities of the industry segments that comprise Petroleum and Natural Gas Systems, with 5 facilities reporting. Total reported emissions from LNG storage were less than 0.01 MMT CO_2e.

Changes from 2011 to2014

The following section describes the reported data for the 2011 through 2014 calendar years for Petroleum and Natural Gas Systems.[6] The EPA also received deferred activity data for 2011, 2012, and 2013. Select activity data are summarized below.

Changes in Number of Facilities

From 2011 to 2014, the number of facilities in Petroleum and Natural Gas Systems increased from 1,913 facilities to 2,405 facilities. The largest increases occurred in other oil and gas combustion (148), onshore production (108), natural gas processing (104), and natural gas transmission (99).

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

[6] The EPA received resubmissions of 2011, 2012, and 2013 data from certain facilities and this section describes the 2011-2014 time series updated to include the resubmitted data.

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.

Table 5: Changes in Number of Facilities by Industry Segment: 2011 to 2014

Industry Segment	2011 Number of Facilities	2012 Number of Facilities	2013 Number of Facilities	2014 Number of Facilities	2013-14 Change in Number of Facilities	2011-14 Change in Number of Facilities
Onshore Production	456	502	503	564	61	108
Offshore Production	100	107	108	128	20	28
Natural Gas Processing	373	403	437	477	40	104
Natural Gas Transmission	421	457	487	520	33	99
Underground Natural Gas Storage	49	52	51	54	3	5
Natural Gas Distribution	183	183	175	180	5	-3
LNG Import/Export	8	8	8	8	0	0
LNG Storage	6	5	5	5	0	-1
Other Oil and Gas Combustion	340	389	421	488	67	148
Total	**1918**	**2090**	**2180**	**2405**	**225**	**487**

Changes in Reported Emissions

Total reported emissions slightly increased from 2011 to 2014. The largest increases occurred in onshore production (10.9 MMT CO_2e) and other oil and gas combustion (4.8 MMT CO_2e). The largest decreases were seen in natural gas transmission (-1.9 MMT CO_2e) and natural gas distribution (-1.1 MMT CO_2e).

Table 6: Changes in Reported Emissions by Industry Segment: 2011 to 2014

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)	2013-14 Change in Reported Emissions (MMT CO_2e)	2011-14 Change in Reported Emissions (MMT CO_2e)
Onshore Production	92	93	97	103	5.5	10.9
Offshore Production	6	7	6	7	0.3	0.4
Natural Gas Processing	59	60	59	60	0.3	0.5
Natural Gas Transmission	24	24	23	22	-0.4	-1.9
Underground Natural Gas Storage	2	2	2	2	0.2	0.0
Natural Gas Distribution	16	15	16	15	-1.1	-1.1
LNG Import/Export	1	1	<1	1	0.2	0.0
LNG Storage	<1	<1	<1	<1	0.0	0.0
Other Oil and Gas Combustion	23	25	25	28	2.8	4.8
Total	**222**	**226**	**228**	**236**	**7.9**	**13.7**

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 BAMM Use

There was a decrease in the number of facilities using BAMM between 2011 and 2014. The number of facilities reporting BAMM use decreased from 1,053 facilities in 2011 to 424 facilities in 2014.

Table 7: Changes in BAMM Use by Industry Segment: 2011 to 2014

Industry Segment	2011 BAMM Use	2012 BAMM Use	2013 BAMM Use	2014 BAMM Use	2013-2014 Change in BAMM Use	2011-2014 Change in BAMM Use
Onshore Production	73%	44%	15%	7%	-46%	-88%
Offshore Production	15%	4%	0%	0%	0%	-100%
Natural Gas Processing	84%	52%	46%	33%	-22%	-50%
Natural Gas Transmission	71%	46%	45%	40%	-5%	-30%
Underground Natural Gas Storage	51%	33%	25%	11%	-54%	-76%
Natural Gas Distribution	33%	11%	2%	5%	200%	-85%
LNG Import/Export	50%	25%	38%	13%	-67%	-75%
LNG Storage	50%	20%	20%	20%	0%	-67%
Other Oil and Gas Combustion	0%	0%	0%	0%	0%	0%
Total	**55%**	**33%**	**24%**	**18%**	**-18%**	**-60%**

Changes in Reported Emissions by Emission Source

The change in emissions from 2011 to 2014 is not attributable to any individual emission source. Several sources saw increased emissions, including combustion equipment (16.3 MMT CO_2e), associated gas venting and flaring (4.9 MMT CO_2e), pneumatic devices (3.7 MMT CO_2e), and other flare stacks (4.0 MMT CO_2e). Other sources saw decreased emissions. For gas well completions and workovers with hydraulic fracturing, total reported emissions decreased by 6.5 MMT CO_2e (including a decrease in reported methane emissions of 4.8 MMT CO_2e). Overall, reported methane emissions from Petroleum and Natural Gas Systems have decreased by 13 percent since 2011, with the largest methane reductions coming from gas well completions and workovers with hydraulic fracturing which have decreased by 83 percent.

Table 8: Changes in Reported Emissions by Emission Source: 2011 to 2014

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)	2013-14 Change in Reported Emissions (MMT CO_2e)	2011-14 Change in Reported Emissions (MMT CO_2e)
Combustion Equipment	107.5	112.3	114.8	123.8	9.0	16.3
Associated Gas Venting and Flaring	8.1	11.1	11.7	13.0	1.3	4.9
Pneumatic Devices	21.8	22.6	25.4	25.5	0.0	3.7
Other Flare Stacks	5.7	7.8	9.0	9.8	0.8	4.0
Atmospheric Tanks	4.0	5.6	6.1	7.3	1.2	3.3
Distribution Metering-Regulating Stations	0.8	0.7	1.2	0.6	-0.6	-0.2
Blowdown Vent Stacks	1.5	2.4	2.0	2.3	0.3	0.8
Reciprocating Compressors	3.7	3.5	4.1	3.5	-0.6	-0.2
Well Testing	0.8	0.7	0.9	1.0	0.2	0.2
Pneumatic Pumps	2.9	3.4	3.0	3.0	0.0	0.1
Enhanced Oil Recovery Pumps	<0.1	<0.1	<0.1	<0.1	0.0	0.0
Enhanced Oil Recovery Liquids	<0.1	<0.1	<0.1	<0.1	0.0	0.0
Transmission Tanks	0.1	0.1	0.1	0.1	0.0	0.0
Offshore Sources	2.2	2.1	1.9	2.3	0.5	0.1
Centrifugal Compressors	1.1	1.4	1.2	1.2	0.05	0.1
Dehydrators	2.1	1.7	1.4	1.7	0.3	-0.4
Gas Well Completions and Workovers without Hydraulic Fracturing	0.8	0.2	0.1	0.2	0.1	-0.7
Distribution Services	4.9	4.8	4.6	4.5	-0.1	-0.5
Distribution Mains	9.8	9.7	9.7	9.5	-0.2	-0.3
Misc Equipment Leaks	10.6	10.5	10.2	9.3	-0.8	-1.3
Acid Gas Removal Units	16.1	15.6	13.2	12.6	-0.6	-3.5
Liquids Unloading	7.4	6.1	4.6	3.5	-1.1	-3.8
Gas Well Completions and Workovers with Hydraulic Fracturing	8.9	4.7	3.8	2.3	-1.5	-6.5

Examples of Reported Activity Data for Certain Emission Sources

Many activity data were subject to deferred reporting until March 2015. As noted earlier, while many facilities in this sector submitted deferred data covering four years, there are legitimate reasons why certain facilities might not have reported this information. These include certain changes in ownership and not having reported to the GHGRP in a previous year for a valid reason. As with all GHGRP data, these data are published as reported to the EPA.

Table 9: Examples of Reported Activity Data Counts by Industry Segment: 2011 to 2014

Industry Segment	Source Type	2011 Count	2012 Count	2013 Count	2014 Count
Onshore Production	Reporting Facilities	456	502	503	564
	Pneumatic Devices	574,057	628,890	707,974	785,113
	Pneumatic Pumps	64,490	77,538	77,355	79,881
	Wells	375,445	406,262	425,125	499,023
	Atmospheric Tanks	184,203	223,447	219,632	275,532
	Centrifugal Compressors	156	139	105	69
	Reciprocating Compressors	14,107	18,129	20,156	23,318
Natural Gas Processing	Reporting Facilities	373	403	437	477
	Centrifugal Compressors	457	458	489	489
	Reciprocating Compressors	2,039	2,197	2,514	2,635
Natural Gas Transmission	Reporting Facilities	421	457	487	520
	Pneumatic Devices	11,187	11,105	11,115	13,392
	Centrifugal Compressors	630	727	789	841
	Reciprocating Compressors	1,900	1,978	2,087	2,165
Underground Natural Gas Storage	Reporting Facilities	49	52	51	54
	Pneumatic Devices	2,894	2,958	2,985	3,635
	Centrifugal Compressors	36	40	36	36
	Reciprocating Compressors	301	338	341	351
Natural Gas Distribution	Reporting Facilities	183	183	175	180
	Miles of Unprotected Steel Mains	59,599	58,426	60,216	55,568
	Miles of Protected Steel Mains	396,775	412,299	416,756	415,491
	Miles of Plastic Mains	512,917	531,902	548,414	563,156
	Miles of Cast Iron Mains	30,401	29,282	29,650	28,909

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

2014 Petroleum and Natural Gas Systems Data Highlights Page:
http://www.epa.gov/ghgreporting/ghgrp-2014-petroleum-and-natural-gas-systems

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