Petroleum and Natural Gas Systems
2012 Data Summary

Greenhouse Gas Reporting Program

Introduction

In October 2013, the U.S. Environmental Protection Agency (EPA) released 2012 greenhouse gas (GHG) data for Petroleum and Natural Gas Systems[1] collected under the Greenhouse Gas Reporting Program (GHGRP). The GHGRP, which was required by Congress in the FY2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain greenhouse gases and products that would emit GHGs if released or combusted.

The data show 2012 GHG emissions from over 2,000 facilities conducting Petroleum and Natural Gas Systems activities, such as production, processing, transmission, and distribution. In total, these facilities accounted for GHG emissions of 217 million metric tons of carbon dioxide equivalent (CO_2e). This is an increase of 3% compared to 2011 GHG emissions from this sector.

The data represent a significant step forward in better understanding GHG emissions from Petroleum and Natural Gas Systems. The EPA is working to improve the quality of data from this sector and expects that the GHGRP will be an important tool for the Agency and the public to analyze emissions, identify opportunities for improving the data, and understand emissions trends.

When reviewing this data and comparing it to other data sets or published literature, it is important to understand the GHGRP reporting requirements and the impacts of these requirements on the reported data. 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 data does 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. Emission changes may not solely be due to the change in the number of facilities, and could be the result of a number of factors. 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.

[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.

Petroleum and Natural Gas Systems in the GHG Reporting Program

The Petroleum and Natural Gas Systems source category of the GHGRP requires reporting from the following eight industry segments, 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.

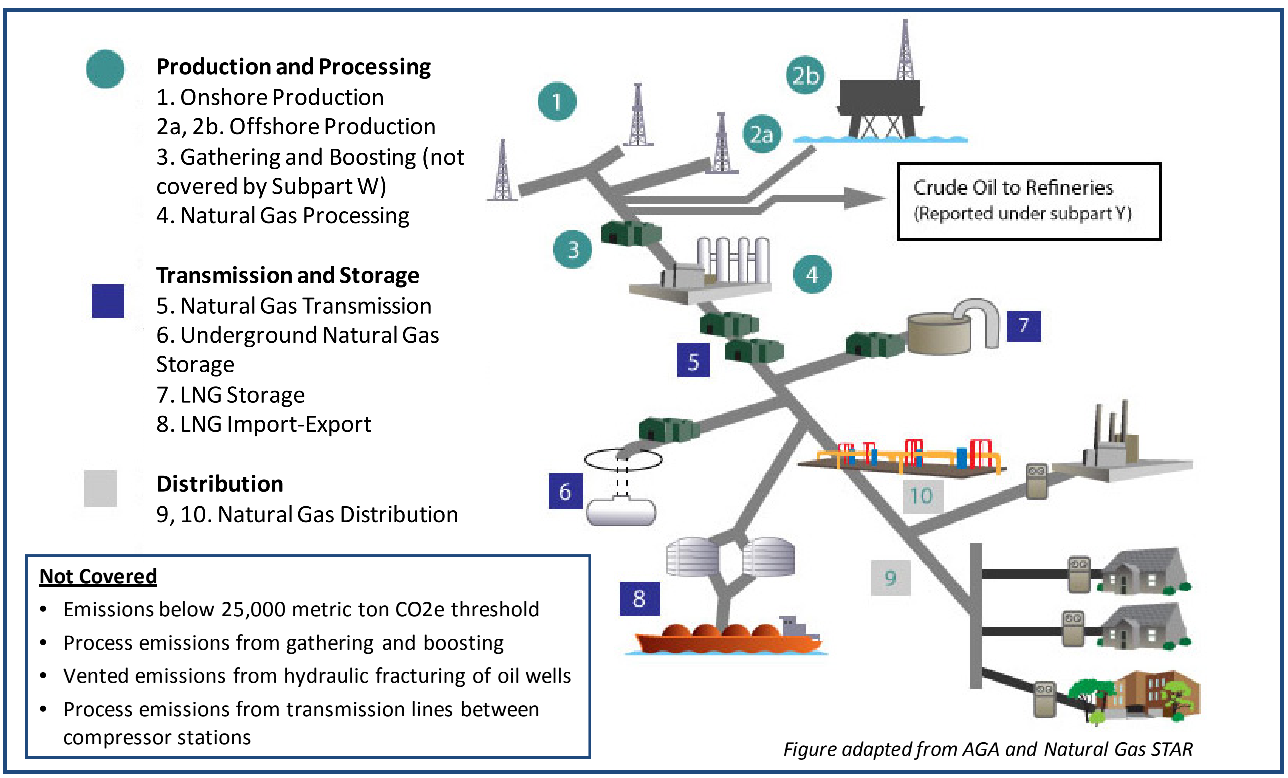


Figure adapted from AGA and Natural Gas STAR

Other segments of the petroleum and natural gas industry are covered by the GHGRP, but not included in the Petroleum and Natural Gas Systems 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).

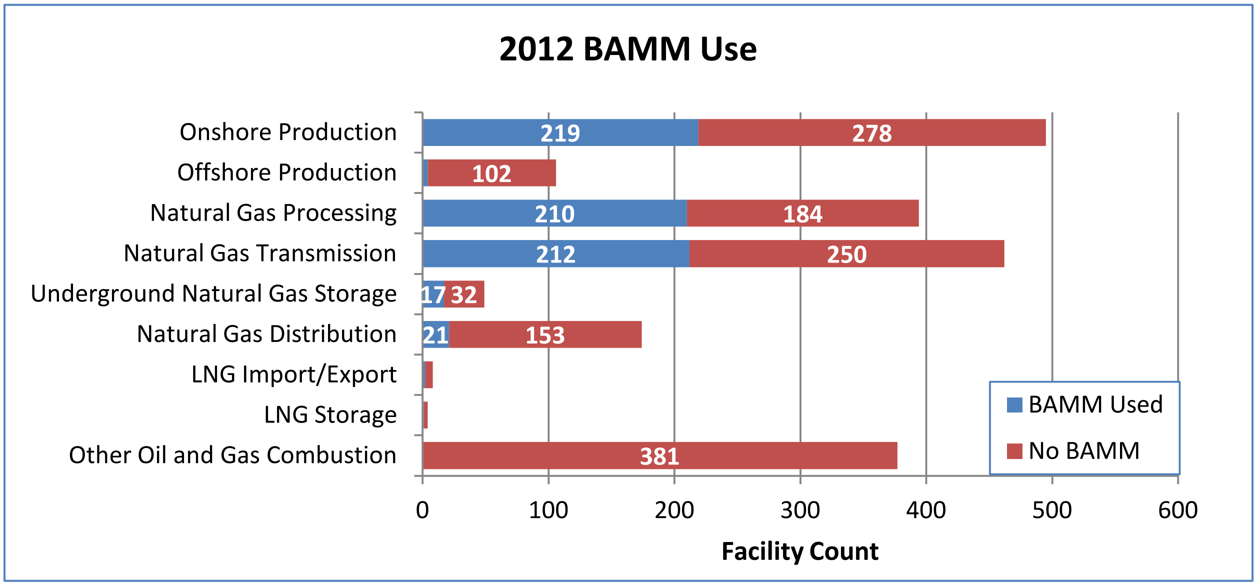
The GHGRP also includes reporting of stationary fuel combustion emissions from facilities that are associated with the petroleum and natural gas industry, but that do not report process emissions from any of the above source categories, such as certain facilities that have a North American Industry Classification 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. It also does not include vented emissions from hydraulic fracturing of oil wells. In addition, the GHGRP does not cover process emissions from transmission lines between compressor stations. The petroleum and natural gas industry is growing and changing rapidly and there could be other sources of emissions that are not currently covered. The Agency will continue to review regulatory requirements to ensure the reporting of high quality data.

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. 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.

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. Facilities used BAMM in different ways and for different parameters depending on their unique or unusual circumstances.

In 2012, 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 2012, 33% of facilities in the petroleum and natural gas source category reported using BAMM. The largest number of facilities in Petroleum and Natural Gas Systems was in the onshore production, natural gas transmission, and natural gas processing segments, and these three segments also represented the segments with the largest frequency of BAMM use. The onshore production segment had 44% of facilities reporting BAMM use, natural gas transmission had 46% of facilities reporting BAMM use, and natural gas processing had 53% of facilities reporting BAMM use. The remaining segments had a lower number of facilities and proportionally lower BAMM use. 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.



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 2012 calendar year.

Reported Emissions by Industry Segment

The 2012 calendar year was the second year that GHG emissions from Petroleum and Natural Gas Systems activities were required to be collected. Annual reports were due to the EPA by April 1, 2013. The EPA received reports from over 2,000 facilities[2] with Petroleum and Natural Gas Systems activities, with total reported GHG emissions of 217 Million Metric Tons (MMT) CO_2e.

The largest industry segment in terms of reported GHG emissions was onshore production, with a total of 88 MMT CO_2e, followed by natural gas processing, with reported emissions of 60 MMT CO_2e. Other oil and gas combustion accounted for 24 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 13 MMT CO_2e. The remaining segments accounted for total reported emissions of less than 10 MMT CO_2e.

[2] In general, a "facility" for purposes of the GHGRP means all co-located emission sources that are commonly owned or operated. However, the GHGRP has developed 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).

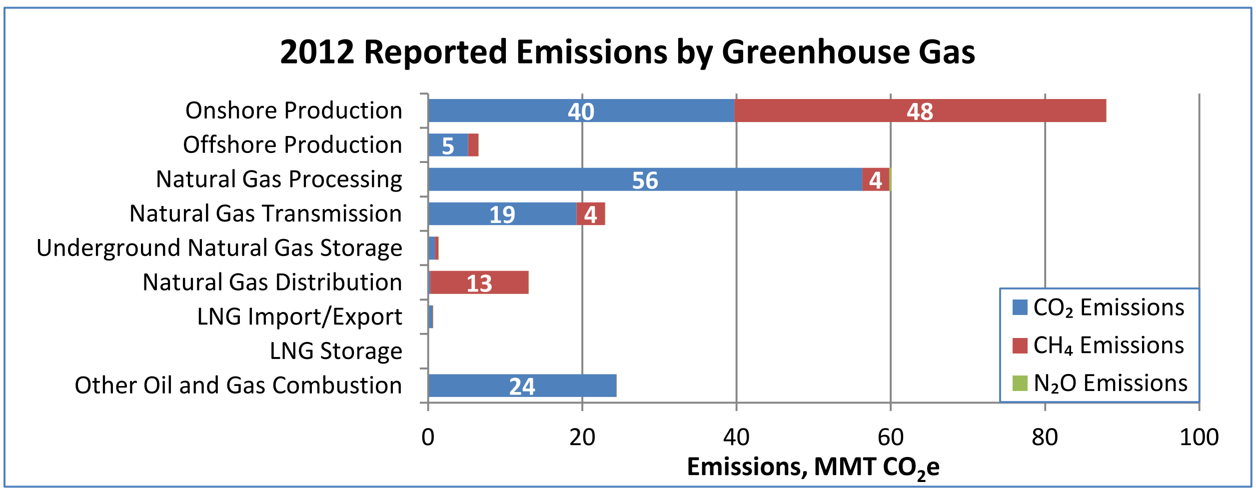
2012 Reported Emissions by Industry Segment

Segment	Number of Facilities	Reported Emissions (Million Metric Tons CO_2e)
Onshore Production	497	88
Offshore Production	106	7
Natural Gas Processing	394	60
Natural Gas Transmission	462	23
Underground Natural Gas Storage	49	1
Natural Gas Distribution	174	13
LNG Import/Export	8	1
LNG Storage	4	< 1
Other Oil and Gas Combustion	381	24
Total	**2,058**	**217**

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 non-zero emissions under any segment.

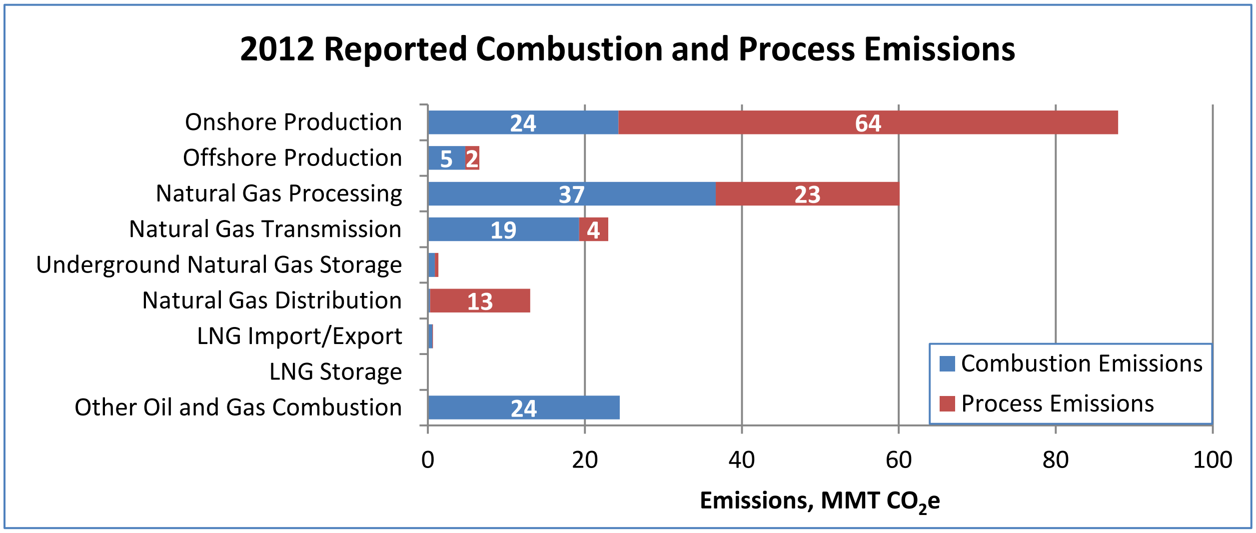
Reported Emissions by Greenhouse Gas

For all segments combined, carbon dioxide (CO_2) emissions accounted for 147 MMT CO_2e of reported emissions and methane (CH_4) emissions accounted for 70 MMT CO_2e of reported emissions. Emissions from onshore production were primarily methane while emissions from natural gas transmission and natural gas processing were primarily carbon dioxide.

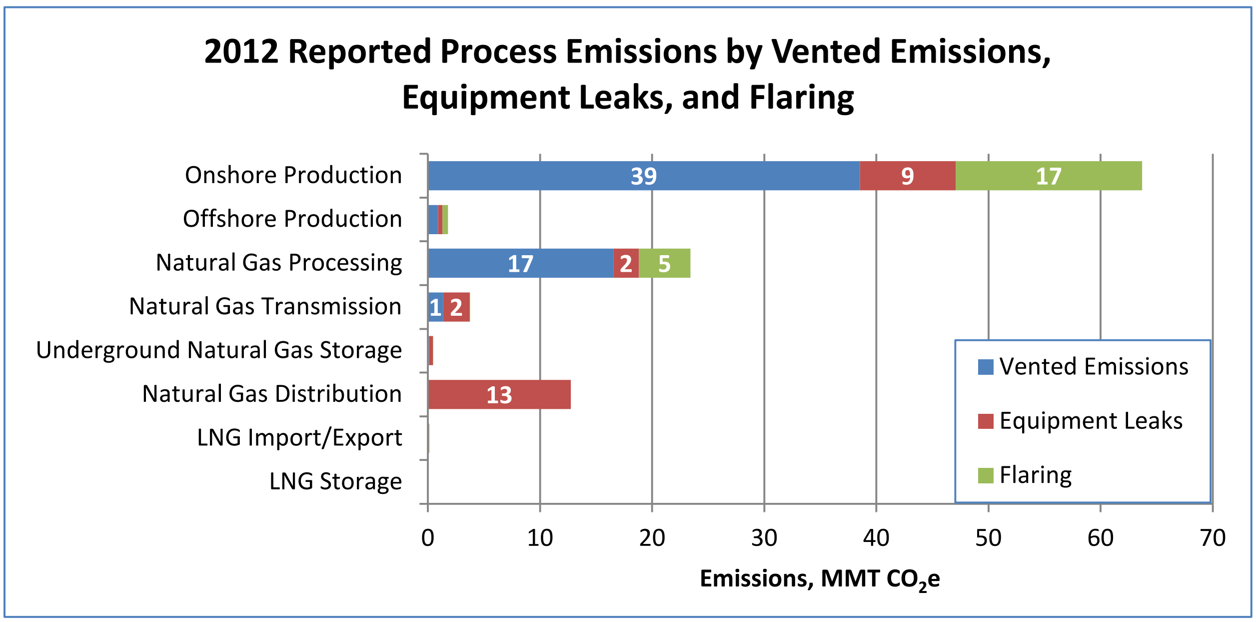


Reported Combustion and Process Emissions

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 111 MMT CO_2e and reported process emissions totaled 106 MMT CO_2e. The majority of combustion emissions were reported by natural gas processing, natural gas transmission, onshore production, and other oil and gas combustion. The majority of process emissions were reported by onshore production, natural gas processing, and natural gas distribution.



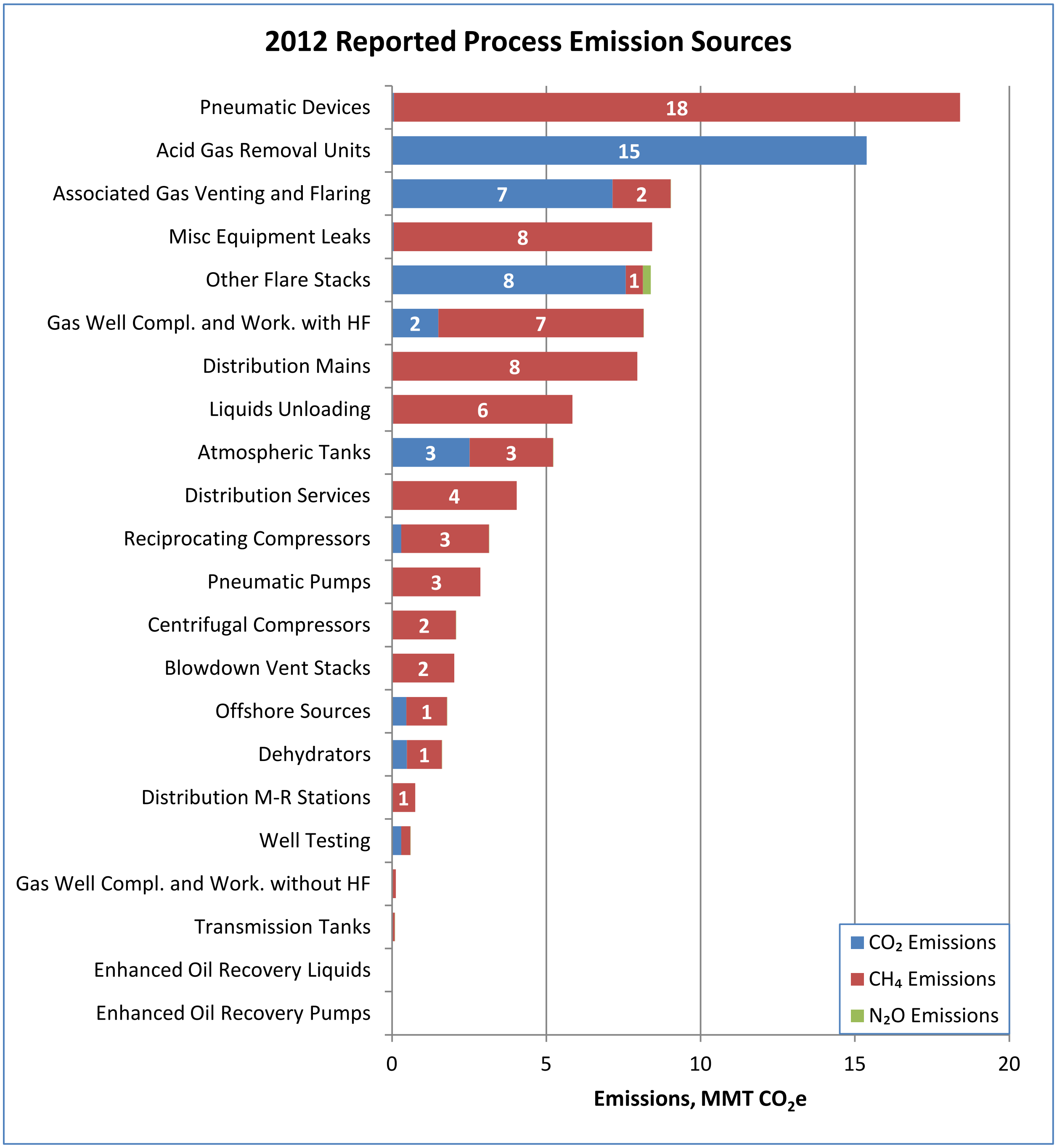
Process emissions may be further classified as vented emissions, equipment leaks, and flaring. Vented emissions totaled 57 MMT CO_2e, equipment leaks totaled 27 MMT CO_2e, and flaring emissions totaled 22 MMT CO_2e. Vented emissions in onshore production were primarily methane while vented emissions in natural gas processing were primarily carbon dioxide. Equipment leak emissions were primarily methane and flaring emissions were primarily carbon dioxide.



Reported Process Emission Sources

The Petroleum and Natural Gas Systems source category (Subpart W) specifies the methods that facilities must use to calculate emissions from applicable sources.

The top reported process emission source in Petroleum and Natural Gas Systems was pneumatic devices with reported emissions of 18.4 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.



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 (15.4 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.

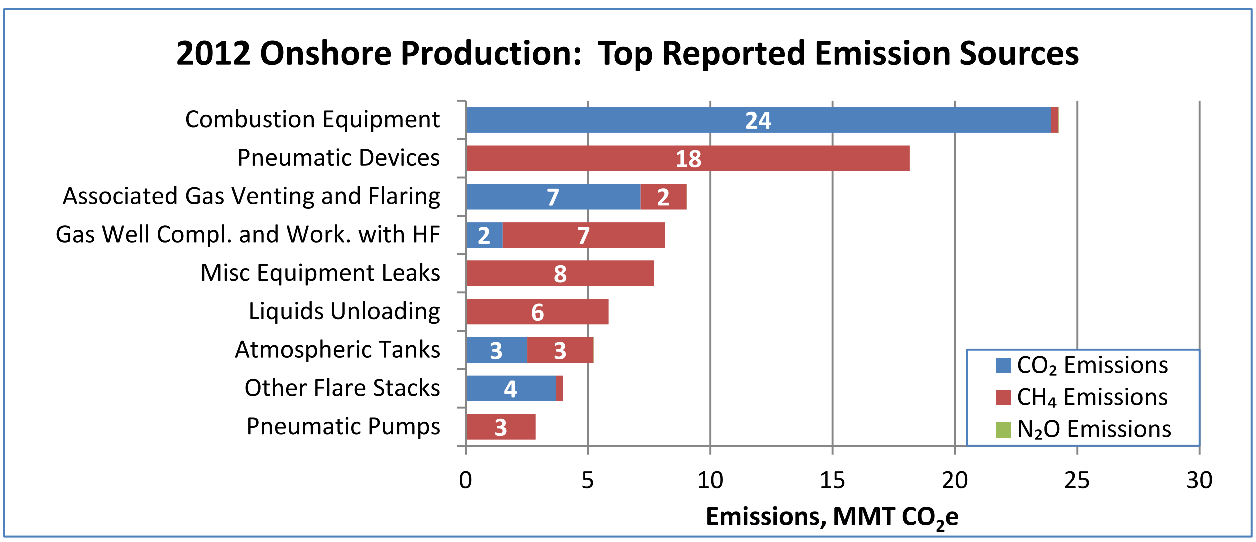
Associated gas and other flare stacks were the top reported sources of process emissions from flaring for Petroleum and Natural Gas Systems. Associated gas is natural gas that is produced out of petroleum wells, but due to proximity and pipeline limitations, may be vented or flared instead of being processed. The other flare stacks category is a catch-all category intended to cover all flares not otherwise reported in the onshore production and natural gas processing segments. 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. The majority of emissions from other flare stacks were from natural gas processing and onshore production.

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 497 facilities in the onshore production segment and reported emissions totaled 88.0 MMT CO_2e. Methane emissions totaled 48.2 MMT CO_2e and carbon dioxide emissions totaled 39.7 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 (24.3 MMT CO_2e) and pneumatic devices (18.1 MMT CO_2e) were the top reported emission sources, followed by associated gas venting and flaring (9.0 MMT CO_2e), gas well completions and workovers with hydraulic fracturing (8.1 MMT CO_2e), miscellaneous equipment leaks (7.7 MMT CO_2e), and liquids unloading (5.8 MMT CO_2e).



The basins with the top reported emissions were the Gulf Coast Basin with 12.2 MMT CO_2e, the Permian Basin with 9.3 MMT CO_2e, the Williston Basin with 9.3 MMT CO_2e, the San Juan Basin with 9.1 MMT CO_2e, and the Anadarko Basin with 9.1 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 208 onshore production facilities. Of these facilities 85 reported using BAMM to calculate emissions. The total reported emissions for gas well completions and workovers with hydraulic fracturing were 8.1 MMT CO_2e. Reported CO_2 emissions were 1.5 MMT CO_2e and reported CH_4 emissions were 6.6 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 use of BAMM.

2012 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	9,466	5,059	9,078	6,225,393	1,478,340	176,052	7,889,716
Gas Well Workovers with Hydraulic Fracturing	1,198	147	985	238,267	17,758	2,964	259,988
Total	**10,664**	**5,206**	**10,063**	**6,463,659**	**1,496,098**	**179,016**	**8,149,704**

Emission Source in Detail: Liquids Unloading

In mature gas wells, the accumulation of fluids in the well can impede and sometimes halt gas production. Liquids unloading is the process by which liquids are removed from the well through venting, the use of plunger lift systems, or other remedial treatments. The liquids unloading source within the GHGRP covers emissions from facilities that have wells that are venting or using plunger lifts.

A total of 251 facilities reported emissions for well venting for liquids unloading in onshore production. Of these facilities 120 reported using BAMM to calculate emissions. Total reported emissions for liquids unloading were 5.8 MMT CO_2e. A total of 0.04 MMT CO_2e reported emissions were from carbon dioxide and 5.8 MMT CO_2e were from methane.

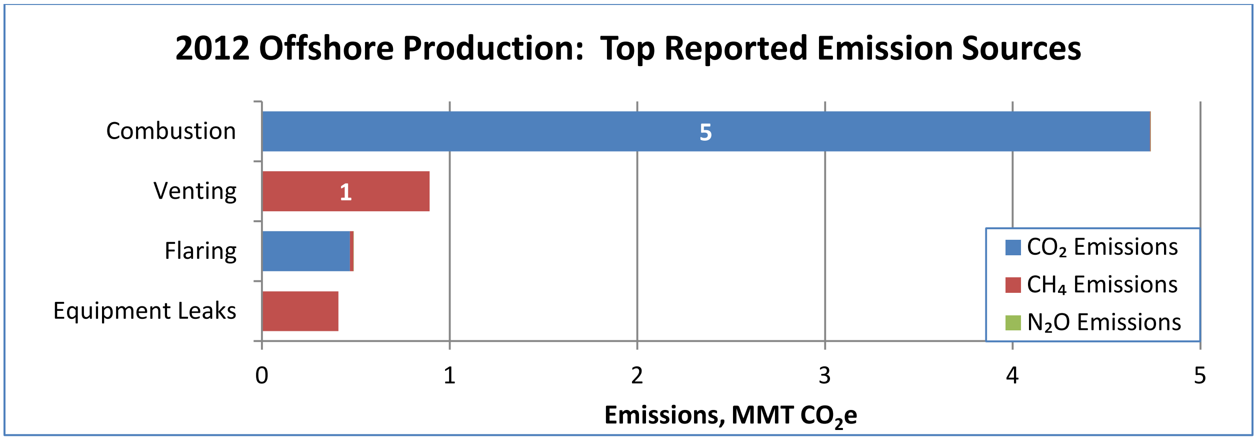
Facilities were given the option between three methods for calculating emissions from liquids unloading. The first calculation method involved using a representative well sample to calculate emissions for both wells with and without plunger lifts. The second and third calculation methods provided engineering equations for wells with plunger lifts and without plunger lifts. The following table shows total activity count and reported emissions for the different calculation methods.

2012 Reported Emissions from Liquids Unloading

Calculation Method	Number of Wells Venting During Liquids Unloading	Number of Wells Equipped With Plunger Lifts	Reported CO_2 Emissions (MT CO_2e)	Reported CH_4 Emissions (MT CO_2e)	Total Reported Emissions (MT CO_2e)
Method 1: Direct Measurement of Representative Well Sample	10,024	7,149	29,767	2,362,423	2,392,190
Method 2: Engineering Calculation for Wells without Plunger Lifts	23,536	0	6,523	1,503,451	1,509,974
Method 3: Engineering Calculation for Wells with Plunger Lifts	25,103	25,103	6,400	1,938,071	1,944,471
Total	**58,663**	**32,252**	**42,689**	**5,803,946**	**5,846,634**

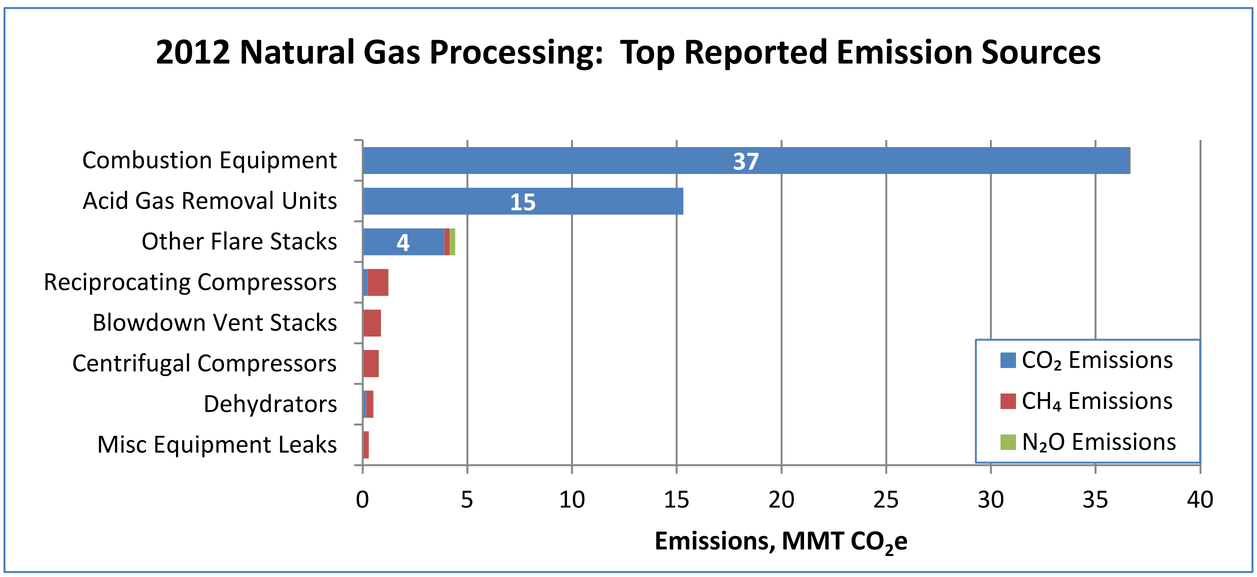
Offshore Production

The EPA received annual reports from 106 facilities in the offshore production segment and reported emissions totaled 6.5 MMT CO_2e. Methane emissions totaled 1.3 MMT CO_2e and carbon dioxide emissions totaled 5.2 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 (0.9 MMT CO_2e), flaring (0.5 MMT CO_2e), and equipment leaks (0.4 MMT CO_2e).



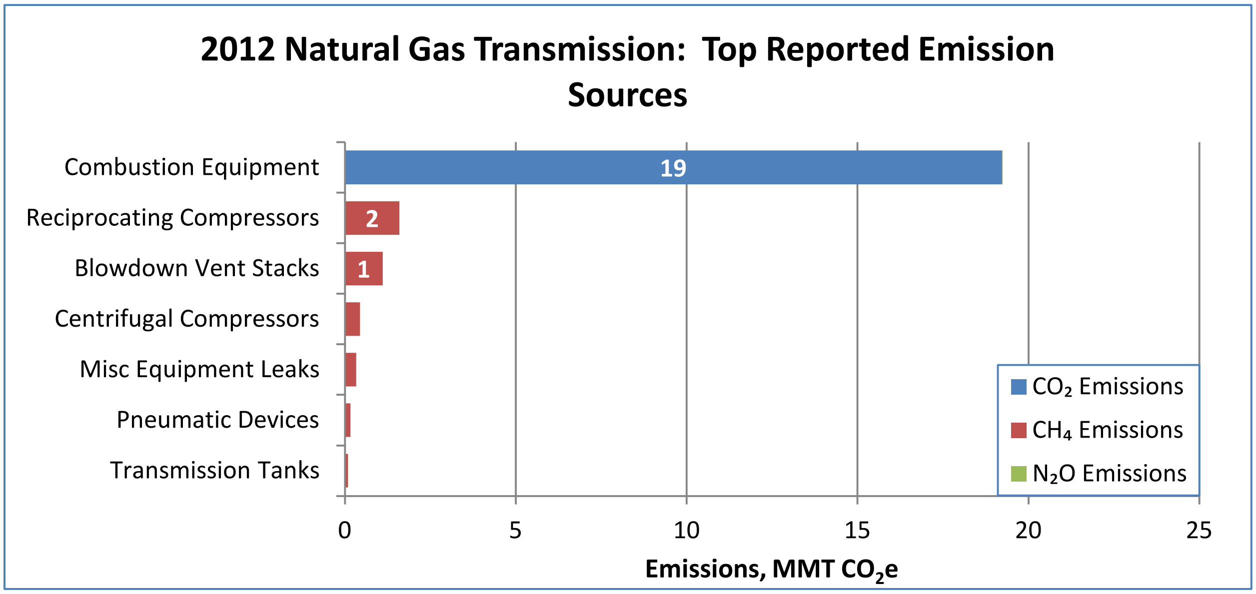
Natural Gas Processing

The EPA received annual reports from 394 facilities in the natural gas processing segment and reported emissions totaled 60.1 MMT CO_2e. Methane emissions totaled 3.5 MMT CO_2e and carbon dioxide emissions totaled 56.3 MMT CO_2e. The top reported emission sources were combustion equipment (36.7 MMT CO_2e), acid gas removal units (15.3 MMT CO_2e), and other flare stacks (4.4 MMT CO_2e). Emissions from the three top reported sources were primarily in the form of CO_2. Emissions from compressors were the top reported source of methane emissions, but reported emissions from reciprocating compressors (1.2 MMT CO_2e) and centrifugal compressors (0.8 MMT CO_2e) were smaller than the three top reported sources from this segment.



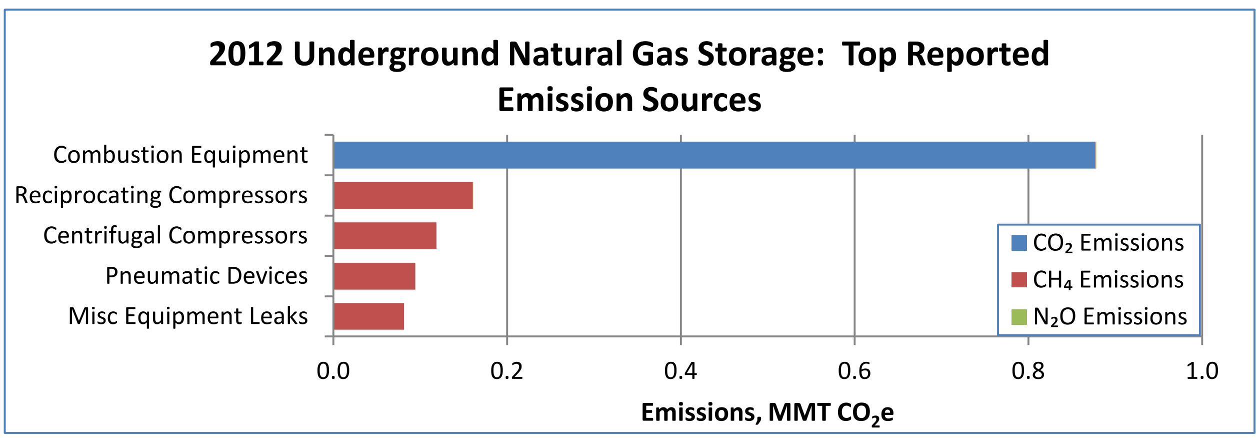
Natural Gas Transmission

The EPA received annual reports from 462 facilities in the natural gas transmission segment and reported emissions totaled 33.0 MMT CO_2e. Methane emissions totaled 3.7 MMT CO_2e and carbon dioxide emissions totaled 19.2 MMT CO_2e. Combustion emissions (19.2 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 (1.1 MMT CO_2e).



Underground Natural Gas Storage

The EPA received annual reports from 49 facilities in the underground natural gas storage segment and reported emissions totaled 1.3 MMT CO_2e. Methane emissions totaled 0.5 MMT CO_2e and carbon dioxide emissions totaled 0.9 MMT CO_2e. Combustion equipment (0.9 MMT CO_2e) was the top reported source of emissions for underground natural gas storage, followed by reciprocating compressors (0.2 MMT CO_2e).



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 can also be a source of process emissions. The primary source of process emissions from compressors are from leaks in 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 5.1 MMT CO_2e. Reported carbon dioxide emissions were 0.2 MMT CO_2e and reported methane emissions were 4.9 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 0.9 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 4,493 reciprocating compressors, including 2,149 reciprocating compressors in natural gas processing, 2,008 reciprocating compressors in natural gas transmission, and 309 reciprocating compressors in underground natural gas storage. Of these reciprocating compressors, 1,854 reported using BAMM to calculate emissions, including 993 in natural gas processing, 790 in natural gas transmission, and 64 in underground natural gas storage.

2012 Reported Process Emissions from Reciprocating Compressors

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)	Total Reported Process Emissions (MT CO_2e)
Natural Gas Processing	2,149	993	107,777	1,009,045	1,117,065
Natural Gas Transmission	2,008	790	3,270	1,591,990	1,595,261
Underground Natural Gas Storage	309	64	290	160,809	161,192
LNG Import/Export	23	7	10.9	7477.7	7,950
LNG Storage	4	0	8.3	90.4	99
Total	**4,493**	**1,854**	**111,356**	**2,769,412**	**2,881,568**

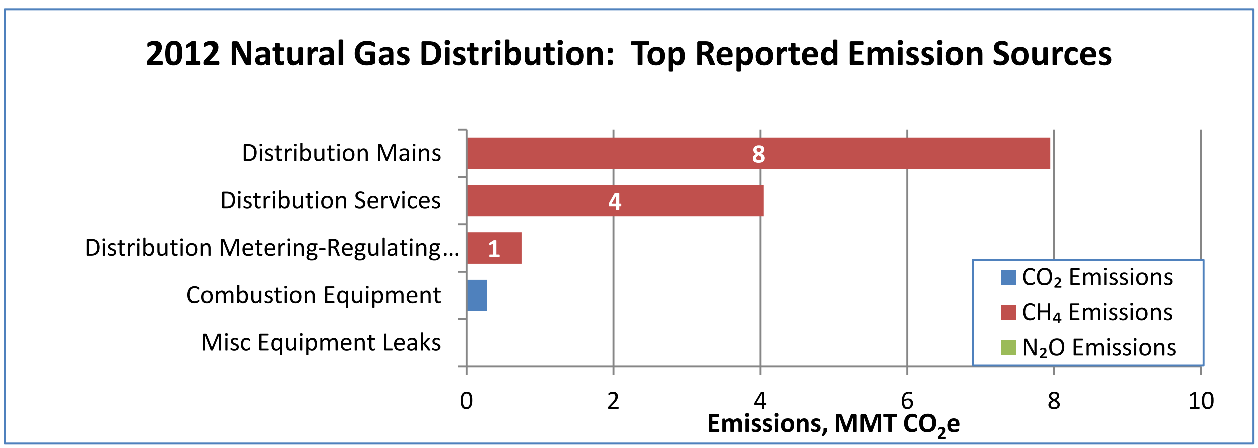
The table below shows activity data and emissions for centrifugal compressors by industry segment. For centrifugal compressors the number of compressors with wet seals is also shown. Overall emissions from centrifugal compressors were lower than those for reciprocating compressors, but the total number of reported compressors was lower as well. The EPA received data from 1,203 centrifugal compressors, including 428 centrifugal compressors in natural gas processing, 724 centrifugal compressors in natural gas transmission, and 39 centrifugal compressors in underground natural gas storage. Of these centrifugal compressors, 547 reported using BAMM to calculate emissions, including 234 in natural gas processing, 292 in natural gas transmission, and 12 in underground natural gas storage.

2012 Reported Process Emissions from Centrifugal Compressors

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)	Total Reported Process Emissions (MT CO_2e)
Natural Gas Processing	428	234	274	13,775	752,054	766,100
Natural Gas Transmission	724	292	291	661	439,714	440,375
Underground Natural Gas Storage	39	12	23	166	118,500	118,666
LNG Import/Export	10	9	5	51	37031.9	37,083
LNG Storage	2	0	2	0	0	0
Total	**1,203**	**547**	**595**	**14,653**	**1,347,300**	**1,362,224**

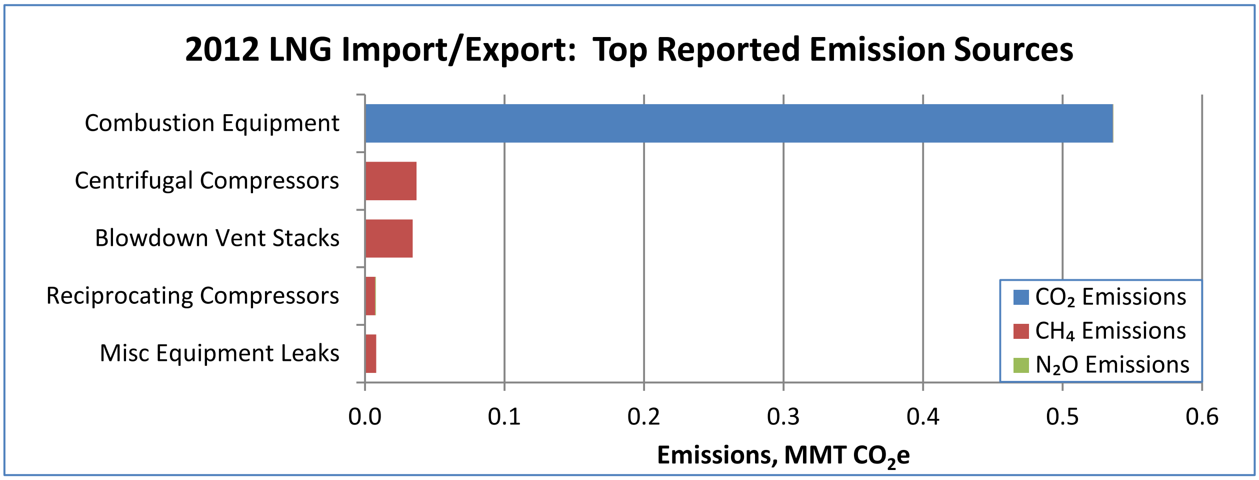
Natural Gas Distribution

The EPA received annual reports from 174 facilities in the natural gas distribution segment and reported emissions totaled 13.0 MMT CO_2e. Methane emissions totaled 12.7 MMT CO_2e and carbon dioxide emissions totaled 0.3 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 (7.9 MMT CO_2e) and distribution services (4.0 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.



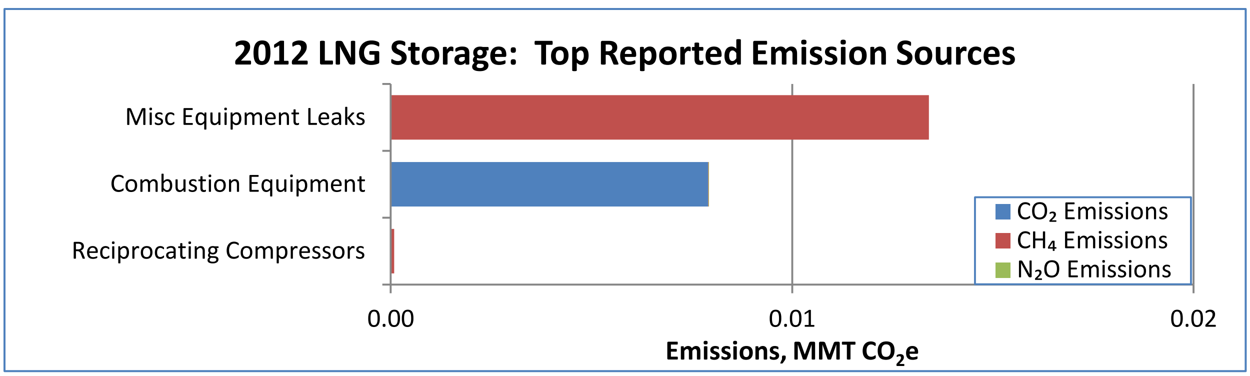
LNG Import/Export

The EPA received emission reports from 8 LNG import/export terminals and reported emissions totaled 0.6 MMT CO_2e. Methane emissions totaled 0.1 MMT CO_2e and carbon dioxide emissions totaled 0.5 MMT CO_2e. The top reported source of emissions was combustion equipment (0.5 MMT CO_2e), followed by centrifugal compressors (0.04 MMT CO_2e), blowdown vent stacks (0.03 MMT CO_2e), and reciprocating compressors (0.01 MMT CO_2e).



LNG Storage

LNG storage had the fewest number of facilities of the industry segments that comprise Petroleum and Natural Gas Systems, with 4 facilities reporting. Total reported emissions from LNG storage were 0.02 MMT CO_2e. Equipment leaks (0.01 MMT CO_2e) was the top reported source of emissions, followed by combustion equipment (0.01 MMT CO_2e).



Changes from 2011 to 2012

The following section describes changes between the reported data for the 2011 and 2012 calendar years for Petroleum and Natural Gas Systems. The EPA received resubmissions of 2011 data from certain facilities and the resubmitted 2011 data is reflected below.

Changes in Number of Facilities

In 2012, the number of facilities in Petroleum and Natural Gas Systems increased from 1,904 facilities to 2,052 facilities. The largest increases occurred in onshore production (42), natural gas transmission (34), and natural gas processing (20).

The increased number of facilities is primarily a result of facilities triggering the 25,000 metric ton CO_2e reporting threshold. 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 Number of Facilities by Industry Segment: 2011 to 2012

Segment	Number of Facilities 2011	Number of Facilities 2012	Change in Number of Facilities
Onshore Production	455	497	42
Offshore Production	99	106	7
Natural Gas Processing	374	394	20
Natural Gas Transmission	428	462	34
Underground Natural Gas Storage	45	49	4
Natural Gas Distribution	173	174	1
LNG Import/Export	8	8	0
LNG Storage	4	4	0
Other Oil and Gas Combustion	338	381	43
Total	**1,904**	**2,058**	**154**

In addition to the increase in number of facilities, an increase was also seen in total reported emissions as discussed below. This does not necessarily indicate that total national emissions increased; rather it may indicate a larger percentage of total Petroleum and Natural Gas Systems emissions are covered by the GHGRP.

Changes in Reported Emissions

Total reported emissions increased by 7.1 MMT CO_2e from 2011 to 2012. The largest increases occurred in onshore production (5.4 MMT CO_2e), natural gas processing (1.9 MMT CO_2e), and other oil and gas combustion (1.5 MMT CO_2e). The largest decreases were seen in natural gas distribution (-0.9 MMT CO_2e) and natural gas transmission (-0.8 MMT CO_2e). The emission changes correspond to a reduction in reported methane emissions of 0.5 MMT CO_2e and increase in reported carbon dioxide emissions of 7.7 MMT CO_2e.

Changes in Reported Emissions by Industry Segment: 2011 to 2012

Segment	2011 Reported Emissions ($MMT\ CO_2e$)	2012 Reported Emissions ($MMT\ CO_2e$)	Change in Reported Emissions ($MMT\ CO_2e$)
Onshore Production	83	88	5.4
Offshore Production	6	7	0.2
Natural Gas Processing	58	60	1.9
Natural Gas Transmission	24	23	-0.8
Underground Natural Gas Storage	1	1	-0.1
Natural Gas Distribution	14	13	-0.9
LNG Import/Export	1	1	-0.1
LNG Storage	< 1	< 1	0.0
Other Oil and Gas Combustion	23	24	1.5
Total	**210**	**217**	**7.1**

Emission changes may not solely be due to the change in the number of facilities, and could be the result of a number of factors, such as operational changes (e.g. increased flaring), calculation method changes (e.g. reduced BAMM use or increased direct measurement), and changes in the regulatory landscape.

Changes in BAMM Use

There was a decrease in the number of facilities using BAMM between 2011 and 2012. The number of facilities reporting BAMM use decreased from 1,055 facilities in 2011 to 685 facilities in 2012, with reductions seen across Petroleum and Natural Gas Systems industry segments.

Changes in BAMM Use by Industry Segment: 2011 to 2012

Segment	2011 BAMM Use	2012 BAMM Use	Change in BAMM Use
Onshore Production	73%	44%	-40%
Offshore Production	15%	4%	-75%
Natural Gas Processing	84%	53%	-37%
Natural Gas Transmission	71%	46%	-35%
Underground Natural Gas Storage	56%	35%	-38%
Natural Gas Distribution	36%	12%	-66%
LNG Import/Export	50%	25%	-50%
LNG Storage	75%	25%	-67%
Other Oil and Gas Combustion	0%	0%	0%
Total	**55%**	**33%**	**-40%**

Changes in Reported Emissions by Emission Source

The increase in emissions between 2011 and 2012 is not attributable to any individual emission source. Several sources saw increased emissions, including combustion equipment (2.7 MMT CO_2e), other flare stacks (2.3 MMT CO_2e), atmospheric tanks (1.4 MMT CO_2e), and associated gas venting and flaring (1.2 MMT CO_2e). The sources with the largest changes occurred in the onshore production segment.

Changes in Reported Emissions by Emission Source: 2011 to 2012

Emission Source	2011 Reported Emissions (MMT CO_2e)	2012 Reported Emissions (MMT CO_2e)	Changes in Reported Emissions (MMT CO_2e)
Combustion Equipment	108.4	111.1	2.7
Pneumatic Devices	17.9	18.4	0.5
Acid Gas Removal Units	15.9	15.4	-0.5
Associated Gas Venting and Flaring	7.8	9.0	1.2
Misc Equipment Leaks	9.0	8.4	-0.6
Other Flare Stacks	6.0	8.4	2.3
Gas Well Completions and Workovers with Hydraulic Fracturing	7.2	8.1	0.9
Distribution Mains	8.6	7.9	-0.6
Liquids Unloading	6.2	5.8	-0.4
Atmospheric Tanks	3.8	5.2	1.4
Distribution Services	4.4	4.0	-0.3
Reciprocating Compressors	2.3	3.1	-0.1
Pneumatic Pumps	2.5	2.9	0.4
Centrifugal Compressors	1.8	2.1	0.3
Blowdown Vent Stacks	1.3	2.0	0.7
Offshore Sources	1.9	1.8	-0.1
Dehydrators	1.7	1.6	-0.1
Distribution Meter-Regulating Stations	0.7	0.8	0.1
Well Testing	0.7	0.6	-0.1
Gas Well Completions and Workovers without Hydraulic Fracturing	0.7	0.1	-0.6
Transmission Tanks	0.1	0.1	0.0
Enhanced Oil Recovery Liquids	<0.1	<0.1	0.0
Enhanced Oil Recovery Pumps	<0.1	<0.1	0.0
Total	**209.9**	**217.0**	**7.1**

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.

Data shown in this document reflect the most recent report submissions from facilities as of September 1, 2013.