PETROLEUM AND NATURAL GAS SYSTEMS

Introduction

On September 30, 2014, the U.S. Environmental Protection Agency (EPA) released 2013 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.

All emissions presented here are as of 8/18/2014 and exclude biogenic CO_2. All GHG emissions data displayed in units of carbon dioxide equivalent (CO_2e) reflect the global warming potential (GWP) values from IPCC AR4.

The data show 2013 GHG emissions from over 2,100 facilities conducting Petroleum and Natural Gas Systems activities, such as production, processing, transmission, and distribution. In total, these facilities accounted for GHG emissions of 224 million metric tons of carbon dioxide equivalent (CO_2e). This is a decrease of 1% compared to 2012 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 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 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

[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.

limitations and differences when using this data, particularly when attempting to draw broad conclusions about emissions from this sector.

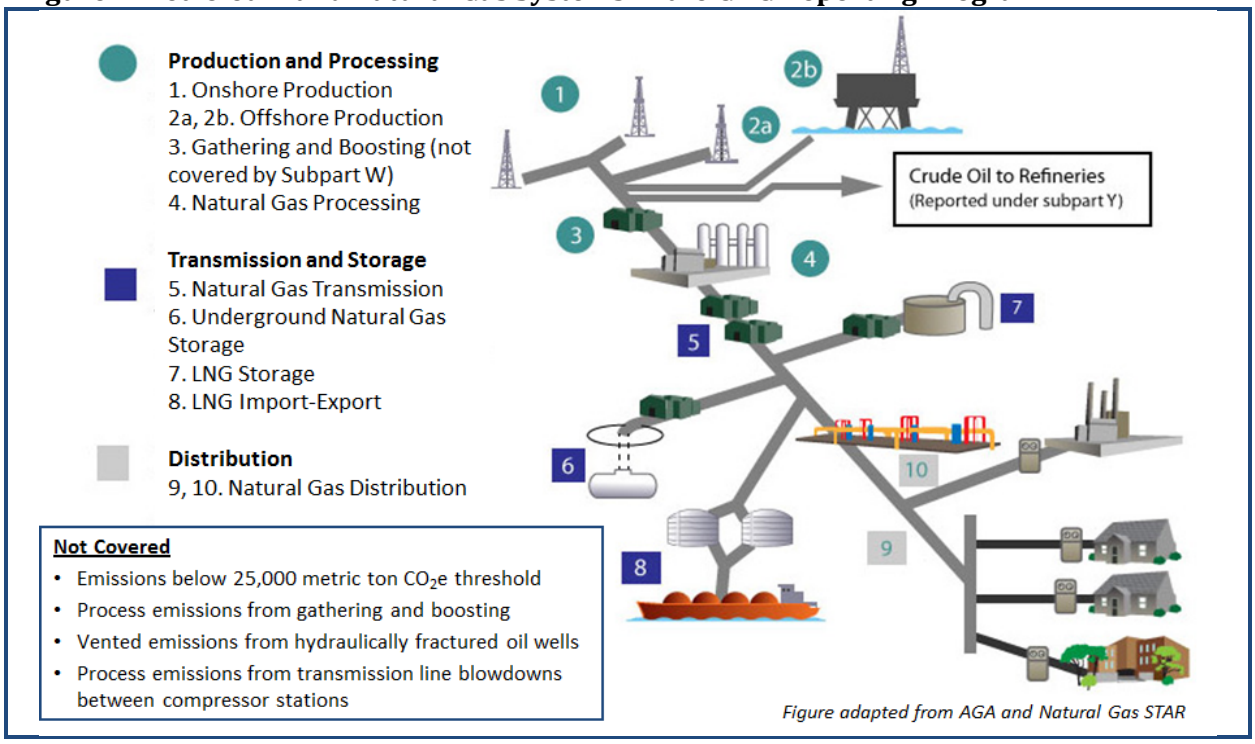
Petroleum and Natural Gas Systems in the GHG Reporting Program

The Petroleum and Natural Gas Systems source category of the GHGRP 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 1: Petroleum and Natural Gas Systems in the GHG Reporting Program



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.[2] 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.

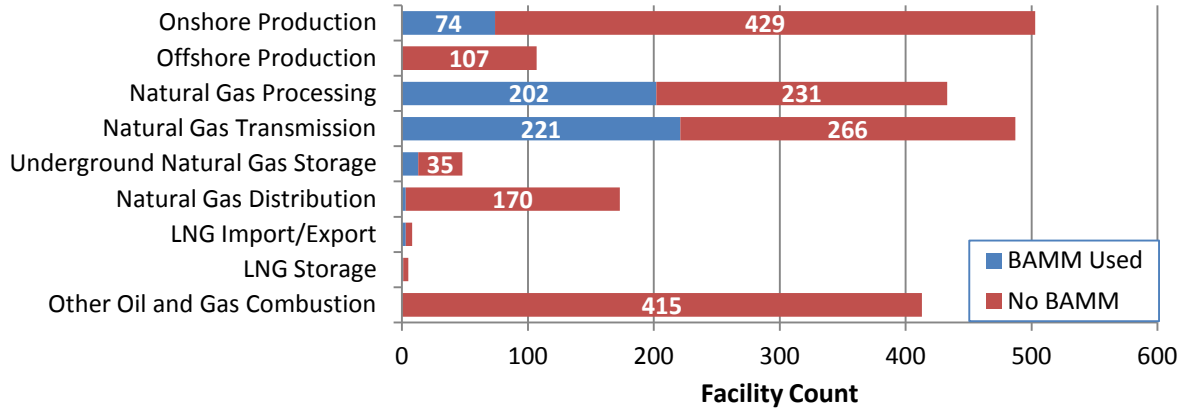
In order to provide facilities with time to adjust to the requirements of the GHGRP, the EPA made available the optional use of BAMM for unique or unusual circumstances.[3] Where a facility used BAMM, it was required to follow emission calculations specified by the EPA, but was allowed to use alternative 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 2013, 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 2013, 24% of facilities in the petroleum and natural gas source category reported using BAMM. The natural gas processing and natural gas transmission segments represented the segments with the largest frequency of BAMM use. Natural gas processing had 47% of facilities reporting BAMM use and natural gas transmission had 45% of facilities reporting BAMM use. The remaining segments had

[2] For more information on verification, see:
http://epa.gov/ghgreporting/documents/pdf/2014/documents/GHGRP_Verification_Factsheet.pdf
[3] For more information on BAMM, see:
http://epa.gov/ghgreporting/documents/pdf/2014/documents/GHGRP_BAMM_Factsheet.pdf

proportionally lower BAMM use. LNG import/export had 38% of facilities reporting BAMM use, underground natural gas storage had 27% of facilities reporting BAMM use, LNG storage had 20% of facilities reporting BAMM use, onshore production had 15% of facilities reporting BAMM use, and natural gas distribution had 2% 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.

Figure 2: 2013 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 2013 calendar year.

Reported Emissions by Industry Segment

The 2013 calendar year was the third 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, 2014. The EPA received reports from over 2,100 facilities[4] with Petroleum and Natural Gas Systems activities, with total reported GHG emissions of 224 Million Metric Tons (MMT) CO_2e.

The largest industry segment in terms of reported GHG emissions was onshore production, with a total of 95 MMT CO_2e, followed by natural gas processing, with reported emissions of 59 MMT CO_2e. Other oil and gas combustion accounted for 25 MMT CO_2e. The next largest segment was natural gas transmission, with reported emissions of 23 MMT CO_2e. Reported emissions from

[4] 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).

natural gas distribution totaled 15 MMT CO_2e. The remaining segments accounted for total reported emissions of less than 10 MMT CO_2e.

Table 1: 2013 Reported Emissions by Industry Segment

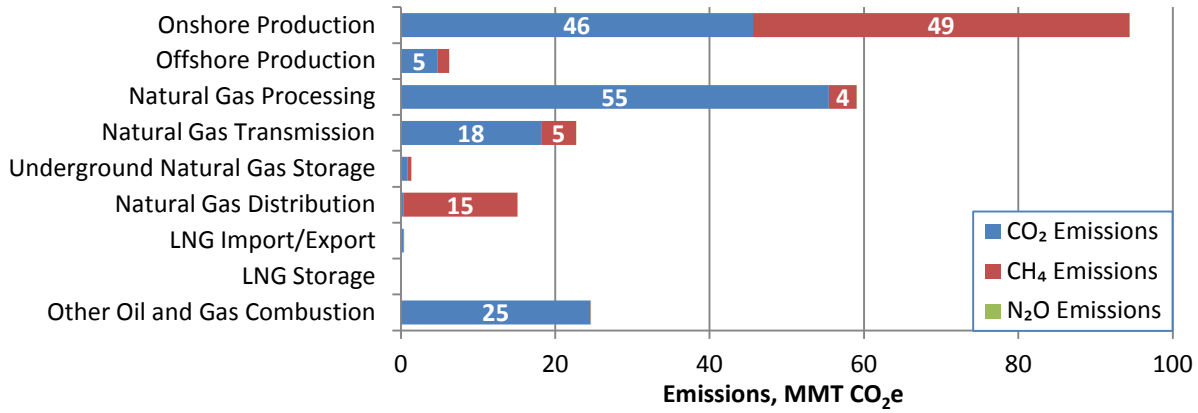
Industry Segment	Number of Facilities	Reported Emissions (Million Metric Tons CO_2e)
Onshore Production	503	95
Offshore Production	107	6
Natural Gas Processing	433	59
Natural Gas Transmission	487	23
Underground Natural Gas Storage	48	1
Natural Gas Distribution	173	15
LNG Import/Export	8	< 1
LNG Storage	5	< 1
Other Oil and Gas Combustion	415	25
Total	**2,164**	**224**

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 150 MMT CO_2e of reported emissions and methane (CH_4) emissions accounted for 74 MMT CO_2e of reported emissions. Reported emissions from onshore production and natural gas distribution were primarily methane while reported emissions from natural gas transmission and natural gas processing were primarily carbon dioxide.

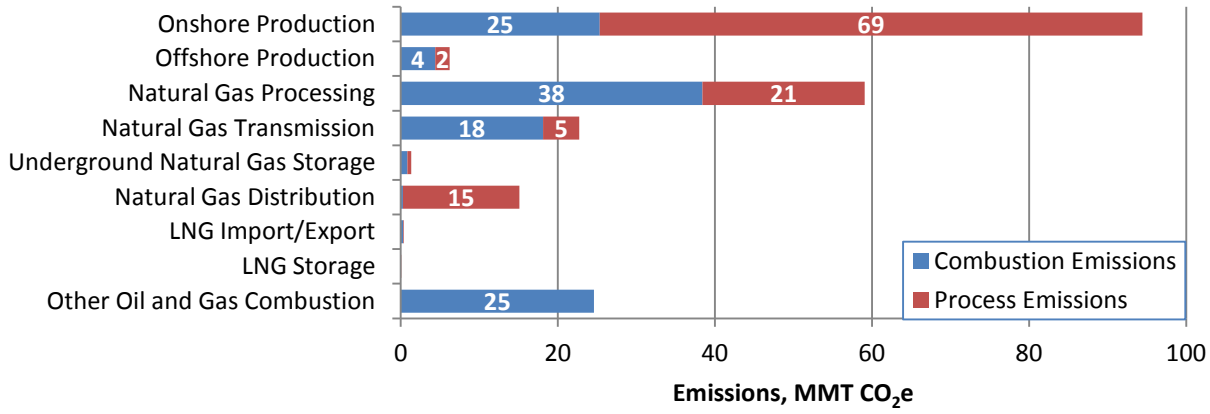
Figure 3: 2013 Reported Emissions by Greenhouse Gas



Reported Combustion and Process Emissions

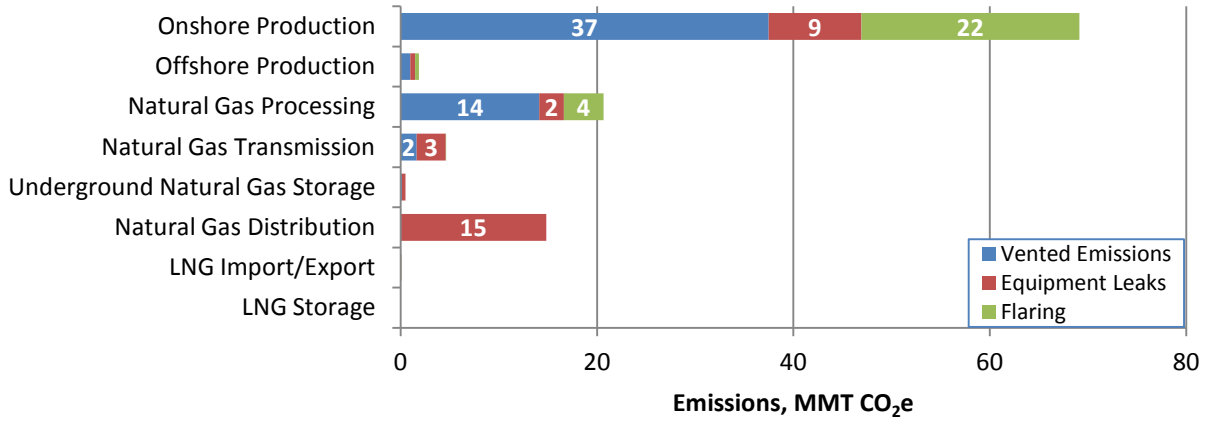
Each segment of Petroleum and Natural Gas Systems has unique emission sources. Emissions may result from the combustion of fossil fuels or from process sources that result in the direct emission of GHGs. Reported combustion emissions in Petroleum and Natural Gas Systems totaled 112 MMT CO_2e and reported process emissions totaled 112 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: 2013 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 31 MMT CO_2e, and reported flaring emissions totaled 27 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.

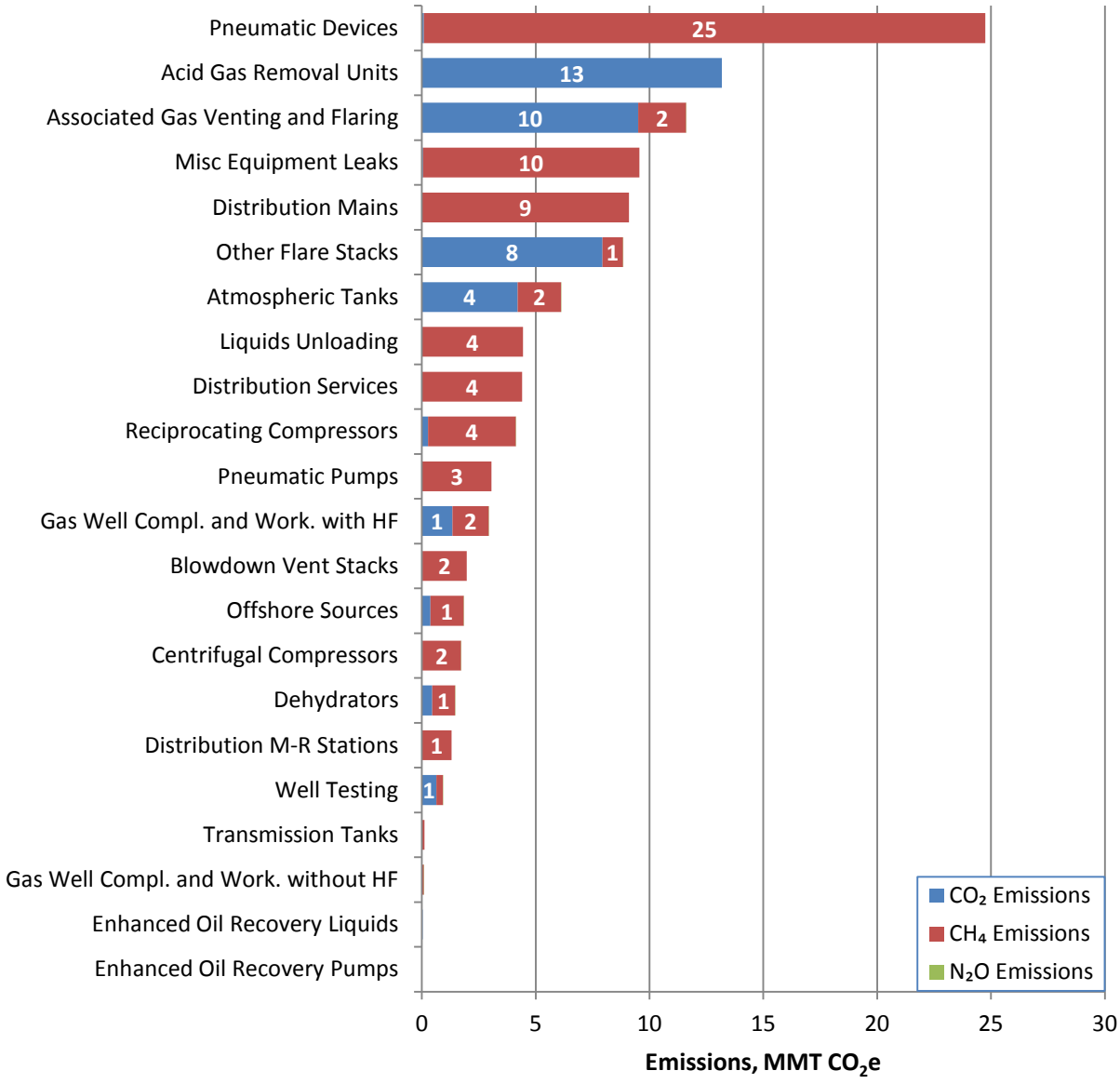
Figure 5: 2013 Reported Process Emissions by Vented Emissions, Equipment Leaks, and Flaring



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: 2013 Reported Process Emission Sources



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.

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.

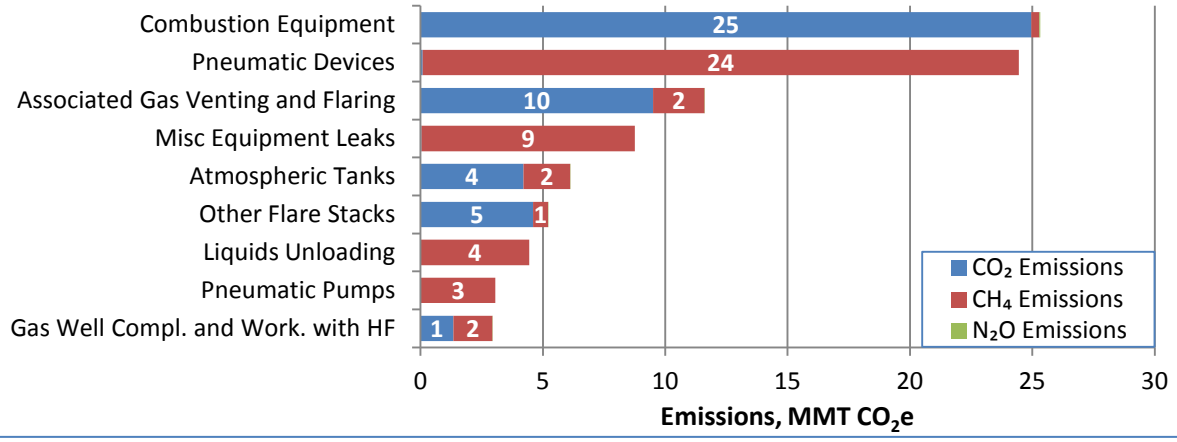
Reported GHG Emissions by Industry Segment and Source

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 503 facilities in the onshore production segment and reported emissions totaled 95 MMT CO_2e. Methane emissions totaled 49 MMT CO_2e and carbon dioxide emissions totaled 46 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 (25.3 MMT CO_2e) and pneumatic devices (24.4 MMT CO_2e) were the top reported emission sources, followed by associated gas venting and flaring (11.6 MMT CO_2e), miscellaneous equipment leaks (8.8 MMT CO_2e), atmospheric tanks (6.1 MMT CO_2e), and other flare stacks (5.2 MMT CO_2e).

Figure 7: 2013 Onshore Production: Top Reported Emission Sources



The basins with the top reported emissions were the Williston Basin with 12.8 MMT CO_2e, Gulf Coast Basin with 12.6 MMT CO_2e, the San Juan Basin with 10.1 MMT CO_2e, the Anadarko Basin with 9.2 MMT CO_2e, and the Permian Basin with 9.2 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 174 onshore production facilities. There were 40 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 2.9 MMT CO_2e. Reported CO_2 emissions were 1.3 MMT CO_2e and reported CH_4 emissions were 1.6 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 some reporters used BAMM.

Table 2: 2013 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	7,053	4,961	3,976	1,367,592	1,330,722	184,495	2,887,546
Gas Well Workovers with Hydraulic Fracturing	732	312	136	36,607	10,525	1,556	48,831
Total	**7,785**	**5,273**	**4,112**	**1,404,198**	**1,341,247**	**186,051**	**2,936,377**

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 255 facilities reported emissions for well venting for liquids unloading in onshore production. Of these facilities 32 reported using BAMM to calculate emissions. Total reported emissions for liquids unloading were 4.4 MMT CO_2e.

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 without plunger lifts and with plunger lifts, respectively. The following table shows total activity count and reported emissions for the different calculation methods.

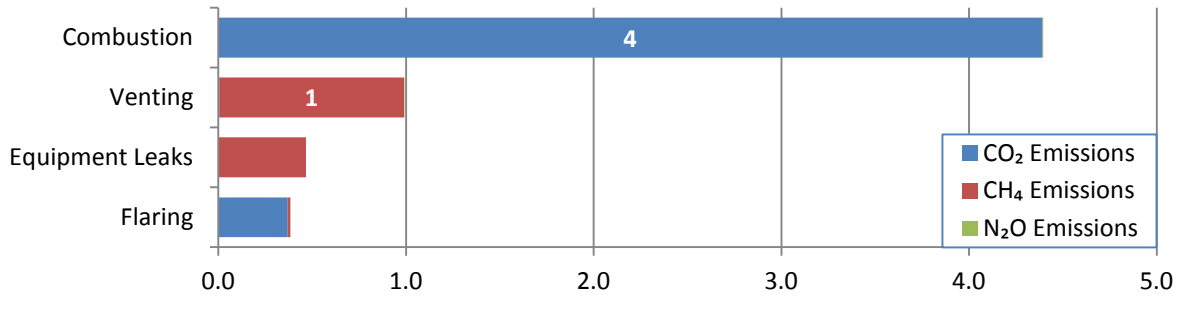
Table 3: 2013 Reported Emissions from Liquids Unloading

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	4,344	2,404	1,285	111,323	112,608
Method 2: Engineering Calculation for Wells without Plunger Lifts	25,539	N/A	4,407	1,990,894	1,995,300
Method 3: Engineering Calculation for Wells with Plunger Lifts	25,610	25,610	3,904	2,333,021	2,336,925
Total	**55,493**	**28,014**	**9,596**	**4,435,237**	**4,444,833**

Offshore Production

The EPA received annual reports from 107 facilities in the offshore production segment and reported emissions totaled 6.2 MMT CO_2e. Methane emissions totaled 1.5 MMT CO_2e and carbon dioxide emissions totaled 4.7 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 (4.4 MMT CO_2e), followed by venting (1.0 MMT CO_2e), equipment leaks (0.5 MMT CO_2e), and flaring (0.4 MMT CO_2e).

Figure 8: 2013 Offshore Production: Top Reported Emission Sources

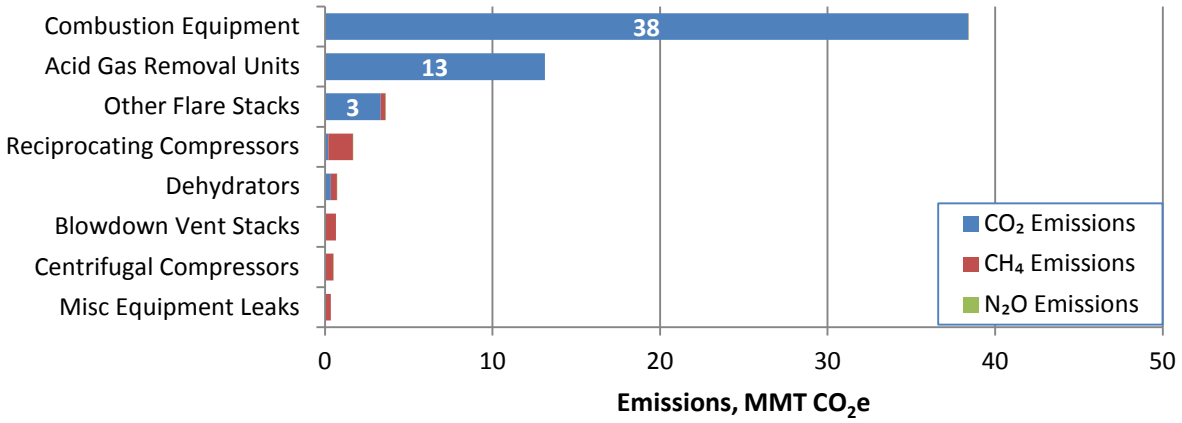


Natural Gas Processing

The EPA received annual reports from 433 facilities in the natural gas processing segment and reported emissions totaled 59 MMT CO_2e. Methane emissions totaled 3.6 MMT CO_2e and carbon dioxide emissions totaled 55.4 MMT CO_2e. The top reported emission sources were combustion equipment (38.4 MMT CO_2e), acid gas removal units (13.1 MMT CO_2e), and other flare stacks (3.6

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 (1.5 MMT CO_2e) and centrifugal compressors (0.5 MMT CO_2e) were smaller than the three top reported sources from this segment.

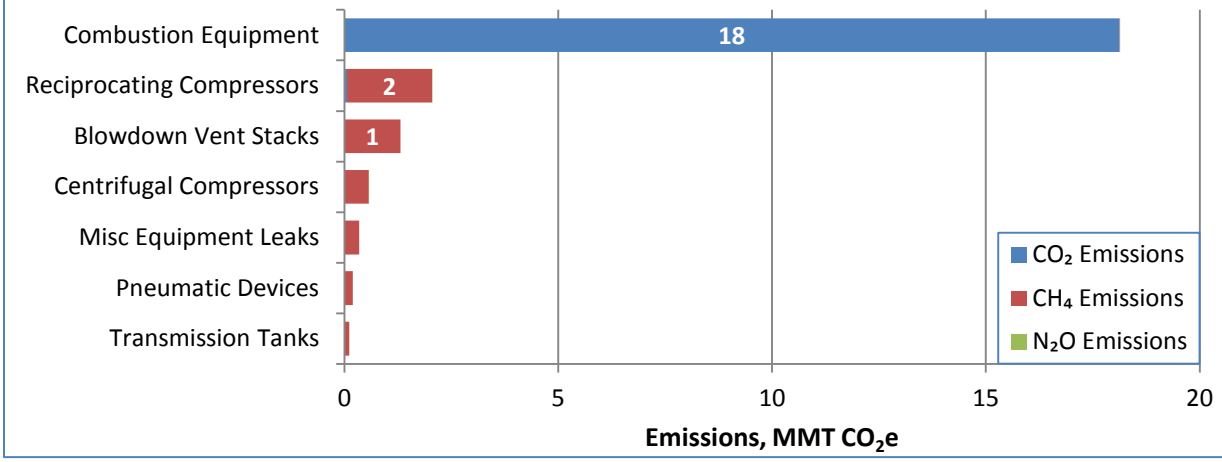
Figure 9: 2013 Natural Gas Processing: Top Reported Emission Sources



Natural Gas Transmission

The EPA received annual reports from 487 facilities in the natural gas transmission segment and reported emissions totaled 23.0 MMT CO_2e. Methane emissions totaled 4.5 MMT CO_2e and carbon dioxide emissions totaled 18.1 MMT CO_2e. Combustion emissions (18.1 MMT CO_2e) were larger than process emissions. Following combustion equipment, the top reported emission sources were reciprocating compressors (2.0 MMT CO_2e) and blowdown vent stacks (1.3MMT CO_2e).

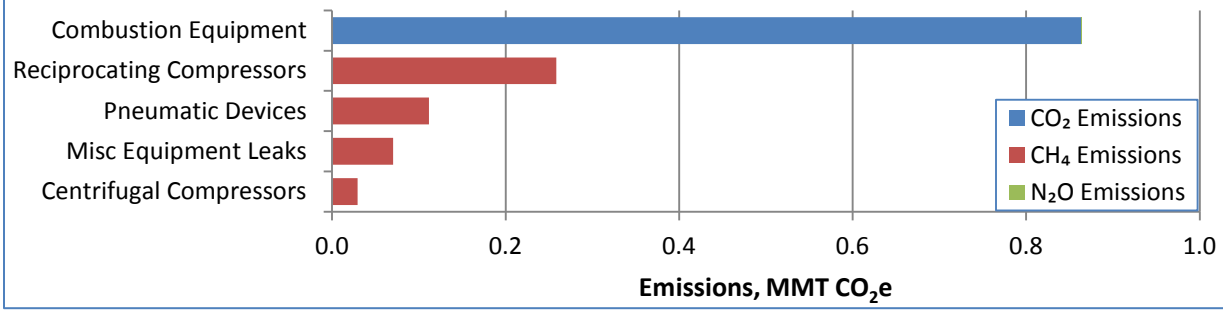
Figure 10: 2013 Natural Gas Transmission: Top Reported Emission Sources



Underground Natural Gas Storage

The EPA received annual reports from 48 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 (0.3 MMT CO_2e).

Figure 11: 2013 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 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 5.7 MMT CO_2e. Reported carbon dioxide emissions were 0.1 MMT CO_2e and reported methane emissions were 5.6 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 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 4,986 reciprocating compressors, including 2,518 reciprocating compressors in natural gas processing, 2,111 reciprocating compressors in natural gas transmission, and 318 reciprocating compressors in underground natural gas storage. Of these reciprocating compressors, 1,779 reported using BAMM to calculate emissions, including 881 in natural gas processing, 814 in natural gas transmission, and 73 in underground natural gas storage.

Table 4: 2013 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)	Total Reported Process Emissions (MT CO_2e)
Natural Gas Processing	2,518	881	97,089	1,471,562	1,568,710
Natural Gas Transmission	2,111	814	29,999	1,989,781	2,019,796
Underground Natural Gas Storage	318	73	299	257,845	258,144
LNG Import/Export	26	11	9	18,964	18,975
LNG Storage	11	0	71	619	691
Total	**4,984**	**1,779**	**127,467**	**3,738,773**	**3,866,315**

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 1,288 centrifugal compressors, including 460 centrifugal compressors in natural gas processing, 779 centrifugal compressors in natural gas transmission, and 34 centrifugal compressors in underground natural gas storage. Of these centrifugal compressors, 574 reported using BAMM to calculate emissions, including 232 in natural gas processing, 321 in natural gas transmission, and 9 in underground natural gas storage.

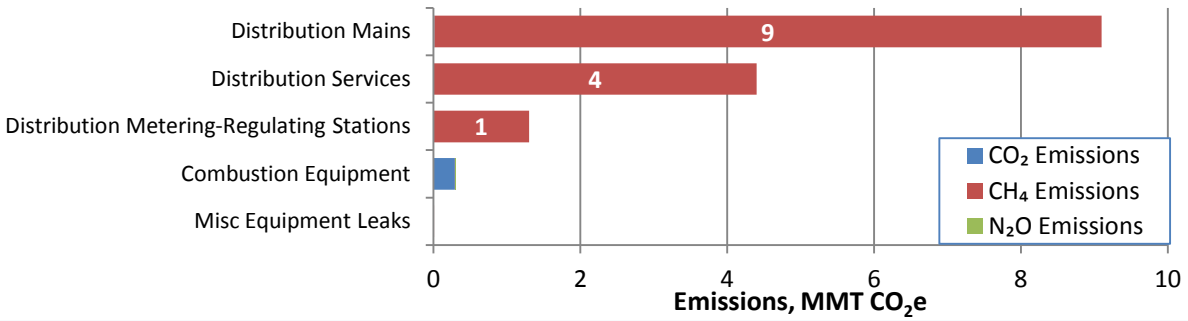
Table 5: 2013 Reported Process Emissions from Centrifugal Compressors in Natural Gas Processing, Natural Gas Transmission, Underground Natural Gas Storage, LNG Import/Export, and LNG Storage

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)	Total Reported Process Emissions (MT CO_2e)
Natural Gas Processing	460	232	278	15,104	475,878	491,104
Natural Gas Transmission	779	321	310	678	568,300	568,981
Underground Natural Gas Storage	34	9	20	36	29,415	29,451
LNG Import/Export	13	12	4	41	38,780	38,821
LNG Storage	2	0	2	0	0	0
Total	**1,288**	**574**	**614**	**15,860**	**1,112,372**	**1,128,357**

Natural Gas Distribution

The EPA received annual reports from 173 facilities in the natural gas distribution segment and reported emissions totaled 15.1 MMT CO_2e. Methane emissions totaled 14.8 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 (9.1 MMT CO_2e) and distribution services (4.4 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.

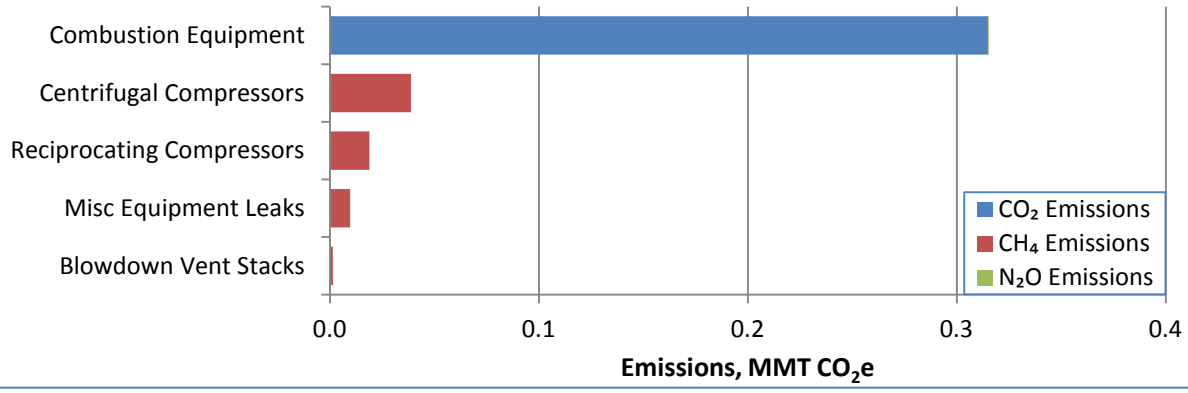
Figure 12: 2013 Natural Gas Distribution: Top Reported Emission Sources



LNG Import/Export

The EPA received emission reports from 8 LNG import/export terminals and reported emissions totaled 0.4 MMT CO_2e. Methane emissions totaled 0.1 MMT CO_2e and carbon dioxide emissions totaled 0.3 MMT CO_2e. The top reported source of emissions was combustion equipment (0.3 MMT CO_2e), followed by centrifugal compressors (0.04 MMT CO_2e), reciprocating compressors (0.02 MMT CO_2e), and equipment leaks (0.01 MMT CO_2e).

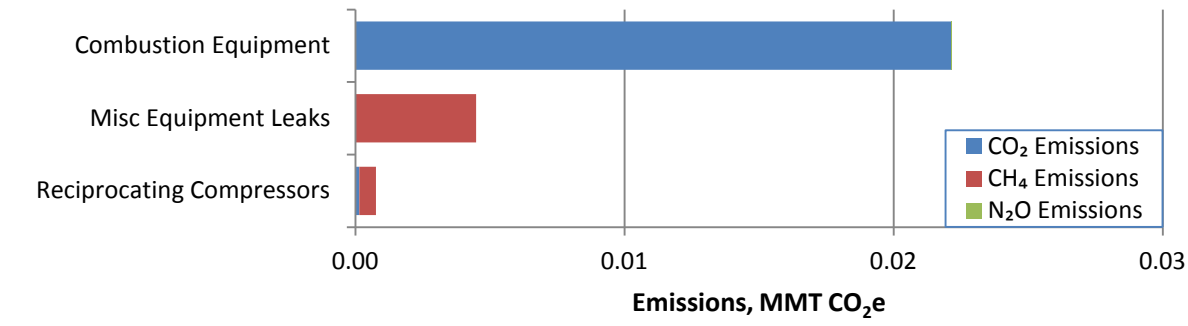
Figure 13: 2013 LNG Import/Export: Top Reported Emission Sources



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 0.03 MMT CO_2e. Combustion equipment (0.02 MMT CO_2e) was the top reported source of emissions, followed by equipment leaks (0.01 MMT CO_2e).

Figure 14: 2013 LNG Storage: Top Reported Emission Sources



Changes from 2011 to 2013

The following section describes changes between the reported data for the 2011 through 2013 calendar years for Petroleum and Natural Gas Systems. The EPA received resubmissions of 2011 and 2012 data from certain facilities and the resubmitted 2011 and 2012 data is reflected below.

Changes in Number of Facilities

From 2011 to 2013, the number of facilities in Petroleum and Natural Gas Systems increased from 1,913 facilities to 2,162 facilities. The largest increases occurred in natural gas transmission (62), and natural gas processing (59), onshore production (45).

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.

Table 6: Changes in Number of Facilities by Industry Segment: 2011 to 2013

Industry Segment	2011 Number of Facilities	2012 Number of Facilities	2013 Number of Facilities	2012-13 Change in Number of Facilities	2011-13 Change in Number of Facilities
Onshore Production	458	502	503	1	45
Offshore Production	99	106	107	1	8
Natural Gas Processing	374	396	433	37	59
Natural Gas Transmission	425	460	487	27	62
Underground Natural Gas Storage	45	49	48	-1	3
Natural Gas Distribution	179	181	173	-8	-6
LNG Import/Export	8	8	8	0	0
LNG Storage	6	5	5	0	-1
Other Oil and Gas Combustion	340	384	415	31	75
Total	**1,913**	**2,074**	**2,164**	**90**	**251**

Changes in Reported Emissions

Total reported emissions slightly increased from 2011 to 2013. The largest increases occurred in onshore production (2.2 MMT CO_2e) and other oil and gas combustion (1.7 MMT CO_2e). The largest decreases were seen in natural gas transmission (-1.5 MMT CO_2e) and natural gas distribution (-1.4 MMT CO_2e).

Table 7: Changes in Reported Emissions by Industry Segment: 2011 to 2013

Industry Segment	2011 Reported Emissions (MMT CO_2e)	2012 Reported Emissions (MMT CO_2e)	2013 Reported Emissions (MMT CO_2e)	2012-13 Change in Reported Emissions (MMT CO_2e)	2011-13 Change in Reported Emissions (MMT CO_2e)
Onshore Production	92	93	95	1.5	2.2
Offshore Production	7	7	6	-0.5	-0.4
Natural Gas Processing	58	60	59	-1.5	0.2
Natural Gas Transmission	24	24	23	-0.9	-1.5
Underground Natural Gas Storage	1	1	1	-0.1	-0.2
Natural Gas Distribution	17	16	15	-0.5	-1.4
LNG Import/Export	1	1	< 1	-0.3	-0.4
LNG Storage	< 1	< 1	< 1	0.0	0.0
Other Oil and Gas Combustion	23	25	25	0.0	1.7
Total	**223**	**226**	**224**	**-2.3**	**0.2**

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 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 2013. The number of facilities reporting BAMM use decreased from 1,053 facilities in 2011 to 515 facilities in 2013.

Table 8: Changes in BAMM Use by Industry Segment: 2011 to 2013

Industry Segment	2011 BAMM Use	2012 BAMM Use	2013 BAMM Use	2012-2013 Change in BAMM Use	2011-2013 Change in BAMM Use
Onshore Production	73%	44%	15%	-66%	-78%
Offshore Production	15%	4%	0%	-100%	-100%
Natural Gas Processing	84%	53%	47%	-3%	-36%
Natural Gas Transmission	71%	45%	45%	6%	-26%
Underground Natural Gas Storage	56%	35%	27%	-24%	-48%
Natural Gas Distribution	34%	12%	2%	-86%	-95%
LNG Import/Export	50%	25%	38%	50%	-25%
LNG Storage	50%	20%	20%	0%	-67%
Other Oil and Gas Combustion	0%	0%	0%	0%	0%
Total	**55%**	**33%**	**24%**	**-24%**	**-51%**

Changes in Reported Emissions by Emission Source

The change in emissions from 2011 to 2013 is not attributable to any individual emission source. Several sources saw increased emissions, including combustion equipment (3.6 MMT CO_2e), associated gas venting and flaring (3.5 MMT CO_2e), pneumatic devices (3.3 MMT CO_2e), and other flare stacks (3.0 MMT CO_2e). Other sources saw decreased emissions. For gas well completions and workovers with hydraulic fracturing, total reported emissions decreased by 5.9 MMT CO_2e (including a decrease in reported methane emissions of 4.2 MMT CO_2e). Overall, reported methane emissions from Petroleum and Natural Gas Systems have decreased by 12 percent since 2011, with the largest methane reductions coming from gas well completions and workovers with hydraulic fracturing which have decreased by 73 percent.

Table 9: Changes in Reported Emissions by Emission Source: 2011 to 2013

Emission Source	2011 Reported Emissions (MMT CO_2e)	2012 Reported Emissions (MMT CO_2e)	2013 Reported Emissions (MMT CO_2e)	2012-13 Change in Reported Emissions (MMT CO_2e)	2011-13 Change in Reported Emissions (MMT CO_2e)
Combustion Equipment	108.8	111.4	112.4	1.0	3.6
Associated Gas Venting and Flaring	8.1	11.0	11.6	0.6	3.5
Pneumatic Devices	21.4	22.4	24.7	2.4	3.3
Other Flare Stacks	5.8	8.2	8.8	0.7	3.0
Atmospheric Tanks	4.2	5.6	6.1	0.5	1.9
Distribution Metering-Regulating Stations	0.8	0.9	1.3	0.4	0.5
Blowdown Vent Stacks	1.5	2.4	2.0	-0.4	0.5
Reciprocating Compressors	3.7	3.5	4.0	0.5	0.3
Well Testing	0.8	0.7	0.9	0.2	0.1
Pneumatic Pumps	3.0	3.4	3.1	-0.3	0.1
Enhanced Oil Recovery Pumps	< 0.1	< 0.1	< 0.1	0.0	0.0
Enhanced Oil Recovery Liquids	< 0.1	< 0.1	< 0.1	0.0	0.0
Transmission Tanks	0.1	0.1	0.1	0.0	0.0
Offshore Sources	2.2	2.0	1.8	-0.2	-0.4
Centrifugal Compressors	2.1	2.5	1.7	-0.7	-0.4
Dehydrators	1.9	1.6	1.5	-0.1	-0.4
Gas Well Completions and Workovers without Hydraulic Fracturing	0.8	0.2	0.1	-0.1	-0.7
Distribution Services	5.2	4.8	4.4	-0.4	-0.8
Distribution Mains	10.2	9.7	9.1	-0.6	-1.1
Misc Equipment Leaks	10.7	9.8	9.6	-0.3	-1.1
Acid Gas Removal Units	15.9	15.4	13.2	-2.2	-2.7
Liquids Unloading	7.4	6.0	4.4	-1.5	-2.9
Gas Well Completions and Workovers with Hydraulic Fracturing	8.9	4.6	2.9	-1.6	-5.9

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