

Finding the Facts on Methane Emissions: A Guide to the Literature

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Prepared for

The Natural Gas Council

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Sponsors' Note

The purpose of this report is to show the range and results of methane studies in the public literature. The results and findings in the studies referenced in this report vary significantly. Scientific methods and uncertainty principles need to be employed rigorously in evaluating these studies. Given the significant variation in results, we caution against the use of any single study as the basis for policy choices that have potential implications for U.S. energy/environmental policy and the U.S. economy.

Neither this report nor the studies discussed herein represent the positions of the sponsors, the Natural Gas Council as a group, or as individual organizations.

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Acronyms and Abbreviations

Acronym / Abbreviation	Stands For
AF	Activity Factor
API	American Petroleum Institute
AR-4	IPCC Fourth Assessment Report
AR-5	IPCC Fifth Assessment Report
Bbl	Barrel
Bcf	Billion Cubic Feet
CCAC	Climate and Clean Air Coalition
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CSSD	Center for Sustainable Shale Development
EF	Emission Factor
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FAR	IPCC First Assessment Report
GCM	General Circulation Model
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GRI	Gas Research Institute
GTP	Global Temperature Potential
GWP	Global Warming Potential
HAP	Hazardous Air Pollutant
Hp	Horsepower
IPCC	Intergovernmental Panel on Climate Change
LCA	Life-cycle Analysis
LDC	Local Distribution Companies
LNG	Liquefied Natural Gas
M&R	Metering and Regulation
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
$MMTCH_4$	Million Metric Tonnes Methane
$MMTCO_2e$	Million Metric Tonnes CO_2 equivalent
NESHAP	National Emission Standards for Hazardous Air Pollutants

Acronym / Abbreviation	Stands For
NGS	Natural Gas STAR
NSPS	New Source Performance Standards
SAR	IPCC Second Assessment Report
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
scfm	Standard Cubic Feet per Minute
TAR	IPCC Third Assessment Report
UNEP	United Nations Environmental Programme
UNFCCC	United Nations Framework Convention on Climate Change
WMO	World Meteorological Organization

1. Executive Summary

With the dramatically increased development of shale gas resources and a new period of low and stable natural gas prices, natural gas has taken on an expanded role in the U.S. economy as a low cost, clean-burning, flexible fuel for many applications. While natural gas has the lowest direct emissions of all fossil fuels when combusted, concerns have been raised about the emissions of methane in the gas production, processing, and delivery segments. This heightened interest has resulted in new studies of the methane emissions profile of natural gas systems by a multitude of entities, including government, industry, academia and non-government organizations. Many of these studies are highly technical, some relying on significant assumptions or uncertainties embedded in the study. Unfortunately, results of some of the studies are contradictory, creating confusion for policymakers, industry and the general public.

The goal of this report is to examine these analyses through a "study of studies," and provide context for their respective conclusions. Therefore this report includes a guide to 75 different studies. In addition to our study of the literature, and in order to provide perspective on methane emissions, this report also examines the sources of methane emissions in the natural gas sector, reviewing recent data on emissions, discussing efforts underway to reduce emissions from natural gas systems and identifying over-arching conclusions from this activity. Overall, the report finds that the natural gas industry continues to reduce methane emissions through voluntary actions and in response to existing regulation by the federal and state governments.

This report addresses the following topics:

- The sources of methane from the natural gas industry. (Chapter 2)
- Background on greenhouse gases (GHGs). (Chapter 3)
- U.S. government sources of data on methane emissions. (Chapter 4)
- Recent studies of methane emissions. (Chapter 5)
- Voluntary and regulatory efforts to reduce methane emissions. (Chapter 6)

Results and Conclusions

The key results of the study address the role of natural gas in U.S. methane emissions, the environmental benefits associated with greater use of natural gas, and the results of the overview of recent studies.

The Role of Natural Gas Systems in U.S. Methane Emissions

The U.S. EPA *Inventory of Greenhouse Gas Emissions and Sinks*[1] is the official inventory of U.S. human-influenced ("anthropogenic") GHG emissions and the only economy-wide, national inventory of those GHGs. The EPA *Inventory*'s most recent report (2016 estimate of 2014 inventory) estimates that methane emissions comprise 10.6% of U.S. anthropogenic GHG emissions and methane emissions from the natural gas industry comprise 2.6% of total emissions.

- The EPA analysis of natural gas systems is based in large part on emission factors developed from discrete samples and equipment counts from the 1990s. The most recent edition of the *Inventory* includes many updates with more recent information, and further updates are expected in the future.
- The *Inventory* estimates that methane emissions from natural gas systems were equal to 1.4% of the volume of methane in U.S. natural gas produced in 2014.[i]
- According to the EPA *Inventory*, methane emissions from the natural gas industry have been declining continuously since the early 1990s. Absolute emissions declined by 15% between 1990 and 2014. Methane emissions per unit of gas produced declined by 43% over that same period.
- Reasons for the decline in methane emissions include: turnover and replacement of equipment, voluntary actions by industry to reduce emissions, and the co-benefit of recent regulations requiring reductions in volatile organic compound (VOC) emissions.

Environmental Benefits Associated With Greater Use of Natural Gas

Natural gas, whether produced from shale or other sources, often replaces other fuels or energy sources that emit higher levels of carbon dioxide and criteria pollutants than are emitted by natural gas. Its use also contributes to fewer overall emissions by enabling greater penetration of intermittent energy sources such as solar and wind energy.

Combusted vs Non-Combusted Methane Emissions

Methane is the primary component of natural gas – comprising more than 95% of the delivered natural gas that is used in homes, businesses, industrial facilities and electric power plants. When natural gas is efficiently combusted to produce energy and heat in homes, businesses and electric power plants, any associated methane emissions are very small.
In contrast, there are a variety of circumstances when methane is released without combustion: EPA's Inventory of Greenhouse Gases provides an annual snapshot of these emissions. EPA's GHG Inventory reveals that the largest source of U.S. methane emissions is agricultural sources in livestock and farming. The natural gas industry is second, representing about 24% of total U.S. human-influenced ("anthropogenic") methane emissions in 2014, according to EPA's GHG Inventory.

[i] Calculated as methane emissions/(gross natural gas withdrawals * methane content of 83%)

- Natural gas combustion releases significantly less carbon dioxide and criteria pollutants such as sulfur dioxide, nitrogen oxides, particulate matter (soot) and mercury compared to other fossil fuels.
- According to the Energy Information Administration, U.S. carbon dioxide emissions are near 20-year lows, due in large part to increased use of natural gas in the U.S. power sector.
- The most detailed and authoritative life-cycle analyses show that the life-cycle emissions of natural gas are 40 to 50% lower than coal on a 100-year basis.
- The use of natural gas for power generation enables greater penetration of clean, renewable energy sources that are intermittent. Because natural gas-fired power plants have the ability to quickly cycle off and on, they provide the dependable partner that solar and wind energy require in the event that conditions are unfavorable to renewable power generation.

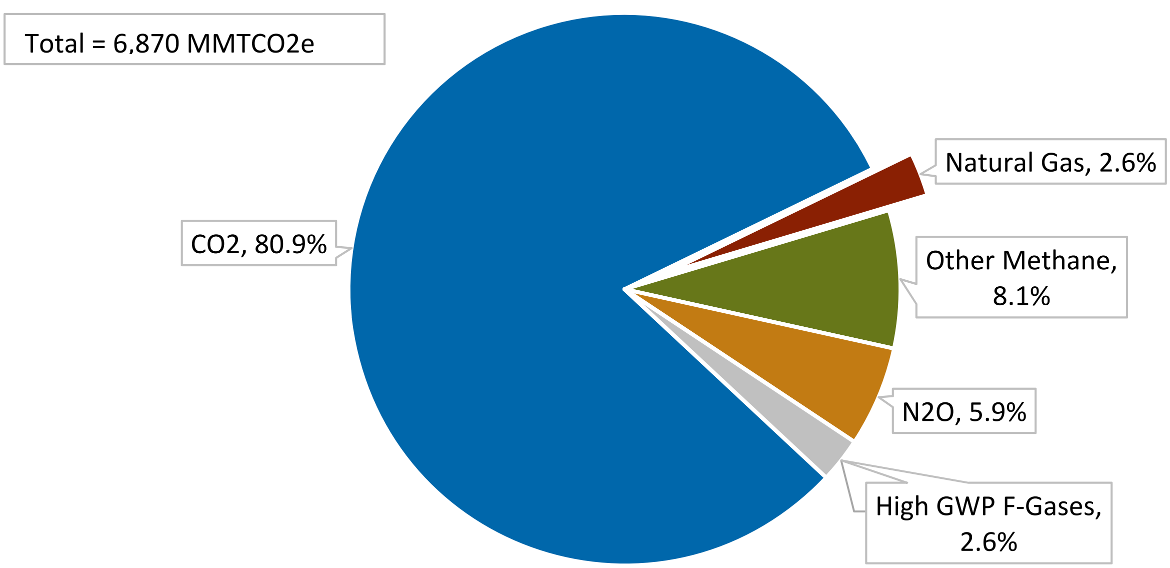
The meta-analysis of 75 different methane emissions studies identified four major categories, with the following characteristics:

- **Direct ("on-site") measurement studies** of emissions from natural gas operations show that most sources and facilities have emissions lower than the factors utilized in the EPA inventory, but a small number of sources – referred to as "super emitters" – inflate or significantly skew the emission profile. Direct measurement studies also show that some segments and source categories have been under-represented in the inventory, though this is being addressed in the most recent inventory publication.
- **Ambient air measurement studies** from all sources show a range of results – from locally higher methane emissions than in the EPA GHG inventory, to much lower emissions. The results are affected by a variety of uncertainties including weather, estimates of other sources of methane, and estimates of natural gas production in the regions being measured.
- **Life-cycle analyses** draw on other sources to provide one integrated measure of emissions from the entire natural gas value chain, from production to use at the burner tip. (Sometimes referred to as "site-to-source.") The most complete studies estimate that overall emissions from natural gas are significantly lower than emissions from coal.
- **Meta-analyses** examine numerous studies to search for overarching trends, recurring facts and similar findings. Recent studies are attempting to reconcile the ambient air studies and the direct measurement studies.

2. Introduction

Methane is a greenhouse gas (GHG) that accounted for 10.6% of total U.S. GHG emissions on a CO_2 equivalent basis in the EPA's *Inventory* for 2014, the most recent available. Agricultural sources in livestock and farming operations are the largest U.S. sources of methane in the EPA *Inventory*, accounting for 32% of methane emissions and 3.5% of total U.S. GHG emissions in 2014. The natural gas industries accounted for 24% of methane emissions, or 2.6% of all U.S. GHG emissions in 2014, according to EPA's *Inventory*.

Figure 2-1 - Methane Emissions from the Natural Gas Industries Were 2.6% of Total GHG Emissions in 2014 ($MMTCO_2e$)



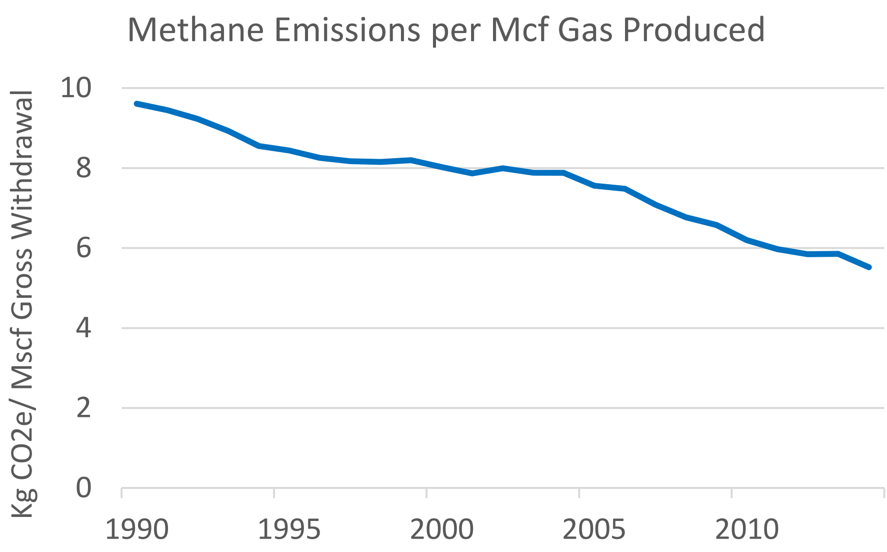
With the development of shale gas resources and a new period of low and stable natural gas prices, natural gas has assumed an expanded role in the U.S. economy as a low cost, low emitting, flexible fuel for many applications. While natural gas has the lowest direct GHG emissions of all fossil fuels when combusted (see Section 3.1), concerns have been raised about the emissions of methane in the gas production, processing and delivery segments. Methane is an odorless and colorless gas that comprises more than 95% of the natural gas that is used in homes, commercial and industrial facilities, and electric power plants. The primary concern around methane as a GHG is when it is emitted directly to the atmosphere without combustion.

Natural gas is extracted from diverse geologic reservoirs either as a primary product or as a co-product of crude oil development. According to the EPA *Inventory*, methane emissions in 2014 were equal to 1.4% of the methane content of natural gas produced in the U.S. or 5.5 kg CO_2e

Methane emissions per unit of gas produced have declined by 43% since 1990.

methane/Mcf of gas produced (gross withdrawals). This rate of methane emissions has been declining continuously since 1990, dropping by 42.6% between 1990 and 2014. There are multiple reasons for this decline. First, equipment turnover typically results in improved performance in most sectors as newer, more efficient, and lower-emitting equipment replaces older equipment. Second, the natural gas industry has been engaging in voluntary reduction activities since 1993 that focus on reducing the loss of natural gas from the value chain. (See Section 6.1). Third, new regulations have taken effect in recent years to require further reductions in VOC emissions that have a co-benefit of reducing methane emissions. (See Section 6.3).

Figure 2-2 - Methane Emissions per Unit of Natural Gas Produced Have Declined Continuously Since 1990



Data Source: EPA Inventory of GHG Emissions, Energy Information Administration

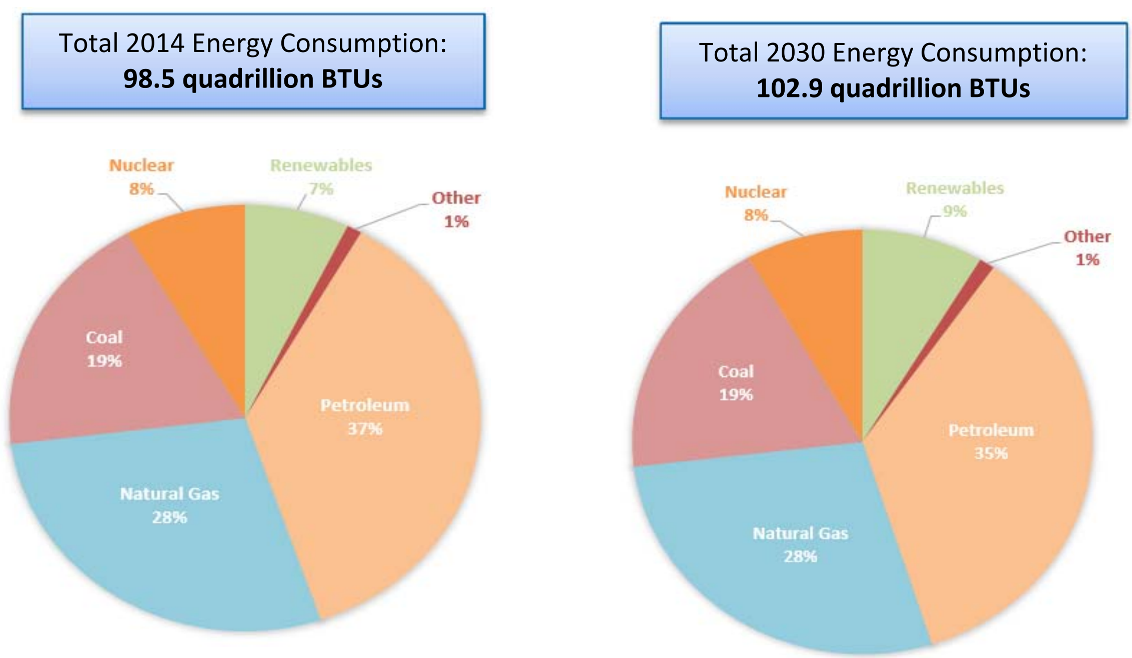
The increased interest in methane emissions from the natural gas industry has resulted in new studies measuring or estimating the quantity of methane emissions from the natural gas sector and related environmental implications. Many of these studies are very technical and some are contradictory. **The goal of this report is to provide context for this information, describe the sources of methane emissions in the natural gas sector, review the recent studies and data on these emissions, and discuss the implications for natural gas as a low emissions fuel.**

The remainder of this chapter provides background on the role of natural gas in the U.S. economy and an overview of the natural gas value chain and the sources of methane. Chapter 3 provides background on GHGs. Chapter 4 discusses the U.S. government sources of data on methane emissions. Chapter 5 discusses recent studies that are attempting to improve our understanding of methane emissions and their implications for natural gas. Chapter 6 discusses voluntary and regulatory efforts to reduce methane emissions. Chapter 7 provides some conclusions. The Appendix provides a summary of a larger number of the recent studies.

2.1. Uses and Markets for Natural Gas

Natural gas plays a significant role in the U.S. economy that is important to consider in assessing the emissions associated with its use. Natural gas is the second largest primary source of energy in the United States, behind petroleum (oil) and ahead of coal, with a total consumed energy value of approximately 27.9 quadrillion Btus in 2014. (Figure 2-3.) According to projections of U.S. energy consumption to the year 2030, performed by the Energy Information Administration (EIA), natural gas is expected to remain the second largest primary energy source in the country during this time.

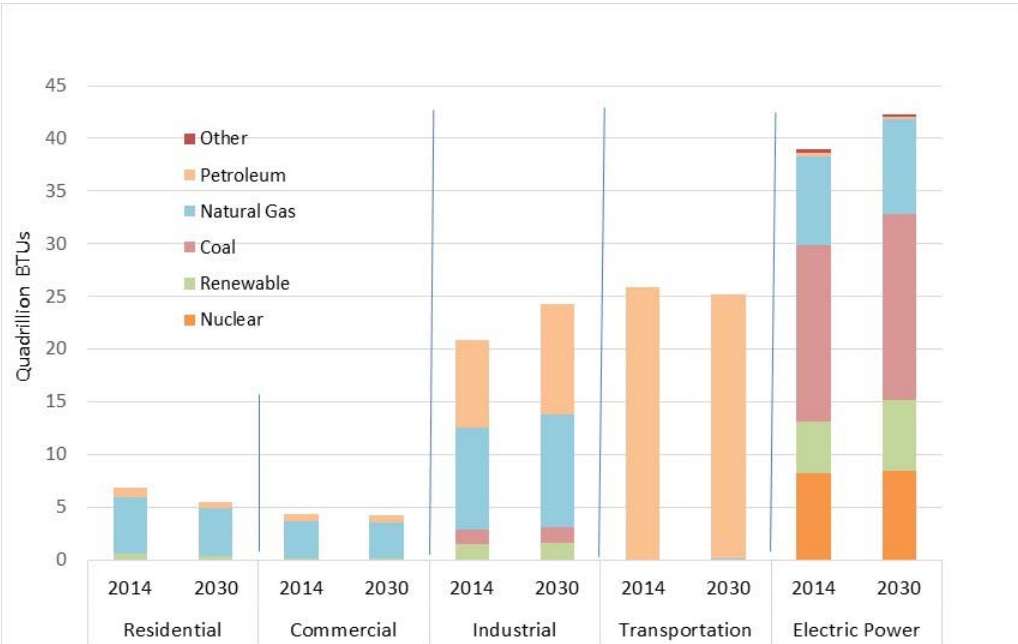
Figure 2-3 - U.S. Energy Mix – 2014 and 2030 projection



Data source: U.S. Energy Information Administration, Annual Energy Outlook, 2015

Moreover, natural gas is unique among the energy sources shown in that it plays a major role in multiple, diverse sectors of the economy. Figure 2-4 shows that in the United States, coal is almost exclusively used by the electric power sector to generate electricity, along with hydro and nuclear power, while petroleum is primarily used for transportation fuels and secondarily as a petrochemical feedstock and fuel in the industrial sector. Natural gas and its byproducts, by contrast, are used widely as a fuel in the residential, commercial, power, and industrial sectors, in addition to significant use as a chemical feedstock to make a variety of goods, such as medical supplies, plastics, and fertilizer. This diversity of end uses means that natural gas has a direct and significant impact on many sectors of the broader economy. Figure 2-4 shows that the forecasted utilization of natural gas as an energy source is expected to increase.

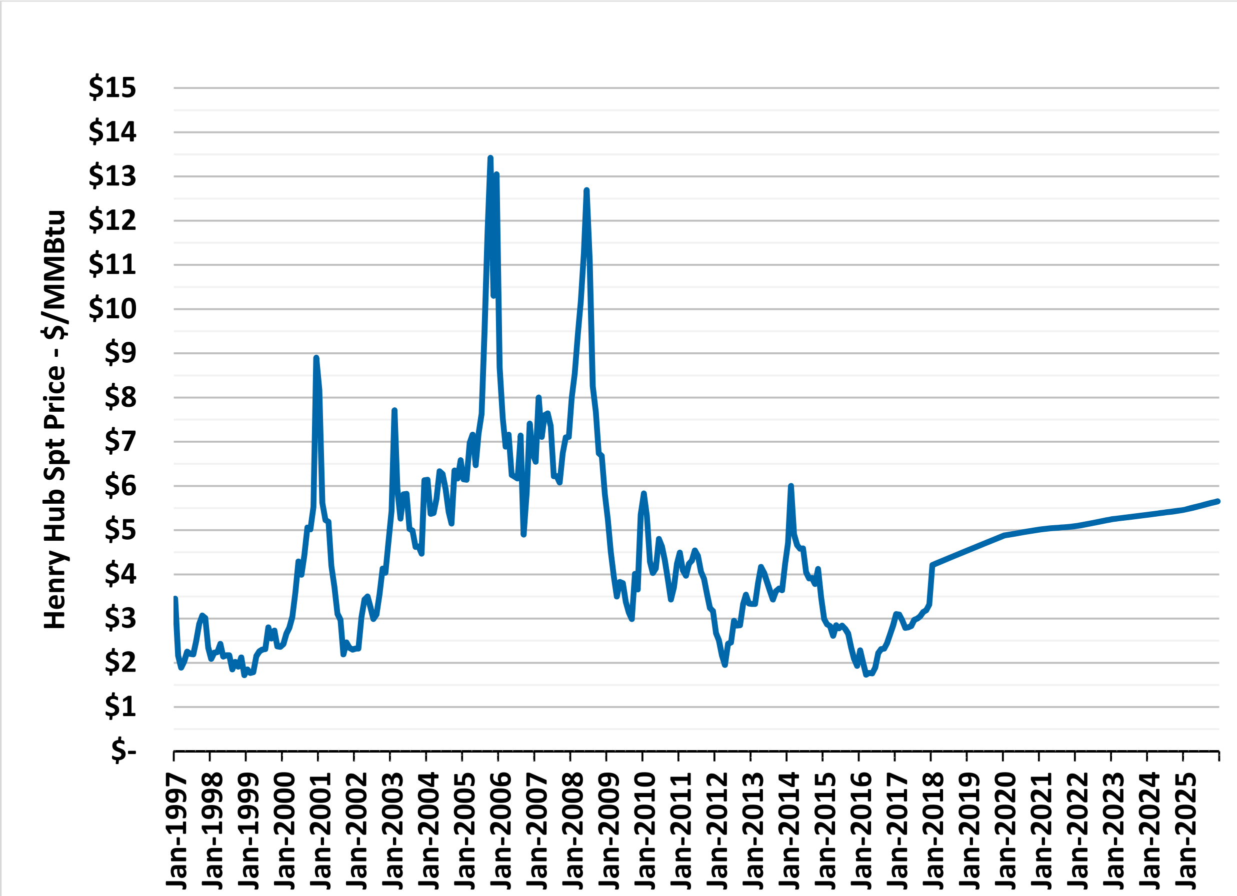
Figure 2-4 - U.S. Energy Consumption by Sector – 2014 and 2030 projections



Source: Energy Information Administration, Annual Energy Outlook 2015

Figure 2-5 shows historical U.S. natural gas prices from 1997 through the beginning of 2016 and U.S. EIA projections through 2025. It shows a period of gas prices around $2 per million Btu (MMBtu) through about 2000, at which point variability increases due to a tight supply/demand balance. Prices declined somewhat thereafter but then increased gradually through the decade. There were several sharp peaks related to hurricane disruptions and broader commodity price fluctuations. Prices have declined sharply since 2008 and remain generally below $3.50/MMBtu due to the surge in natural gas production from shale gas. The projections show continuing moderate prices, though the post-2018 projections, from early in 2015, may be on the high side as they do not include the most recent price and economic growth trends.

Figure 2-5 - U.S. Natural Gas Price Trends Have Declined in Recent Years



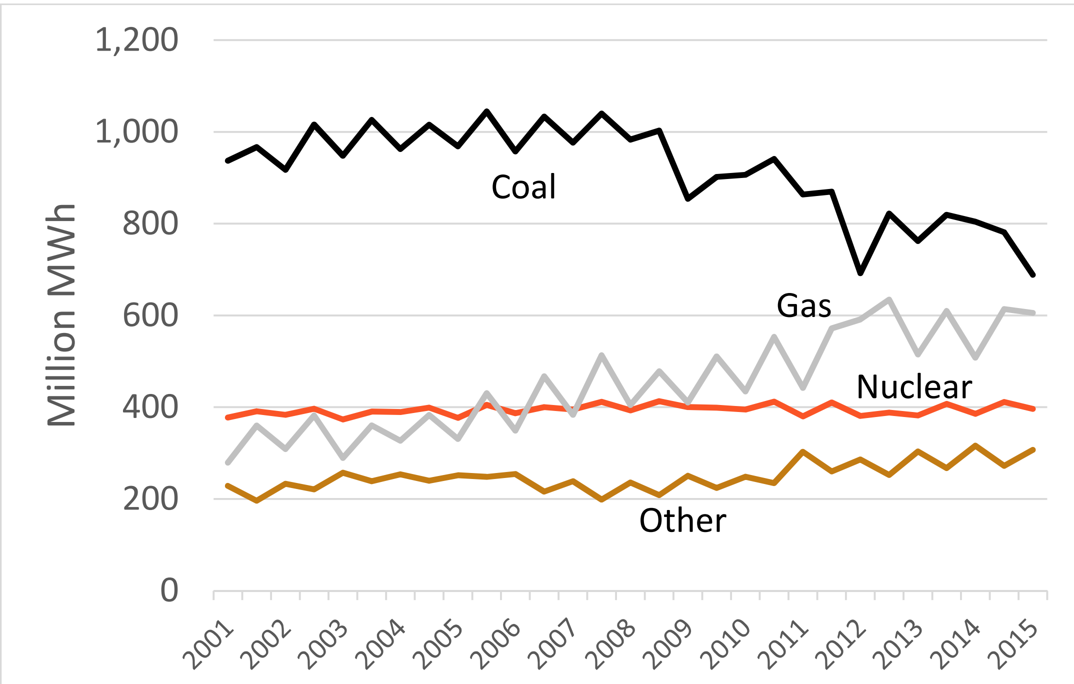
Data Source: U.S. Energy Information Administration – Natural Gas Monthly, Short Term Energy Outlook, Annual Energy Outlook 2015

Higher gas use for power generation due to lower gas prices has resulted in an 8% reduction in power sector CO_2 emissions since 2005.

Declining natural gas prices have been a significant driver of increased use of natural gas in the electricity generating sector. As natural gas prices have declined, the dispatch cost of highly efficient natural gas combined cycle power plants (NGCC) has become cost-competitive with that of coal plants. This, along with the lower cost of building new natural gas-fired plants and pressure on coal from environmental regulation, has resulted in significant growth in gas-fired generation, shown in Figure 2-6. Since coal consumption in the power sector is by far the largest source of U.S. GHG emissions, the shift from coal to natural gas has resulted in a nationwide 8% reduction in CO_2 emissions from the power sector since 2005. This is an important demonstration of the value of the low emissions characteristics of natural gas.

Natural gas also plays a critical role in the shift to increased renewable energy. Fast-acting gas-fired peaking units are key to maintaining electric grid stability during changes in generation from intermittent renewable generating technologies. As photovoltaic generation increases market share, a large amount of peaking generation is expected to be required on a daily basis to meet load in the afternoon and evening as the sun goes down. Base load power plants typically cannot respond quickly enough to follow these large load shifts and are less efficient at part load.

Figure 2-6 – Electricity Generation with Natural Gas is Increasing



Data source: U.S. Energy Information Administration

Despite measurable improvements in the overall U.S. GHG emissions profile with greater use of natural gas, some have questioned whether natural gas retains its environmental advantages when upstream methane emissions are included. The studies discussed in the report address this concern.

2.2. The Natural Gas Value Chain and Sources of Methane[ii]

There are many sources of methane emissions across the entire natural gas supply chain. These emissions are characterized as either:

- Fugitive emissions – methane that "leaks" unintentionally from equipment or components such as flanges, valves, or other equipment.
- Vented emissions – methane that is released due to equipment design or operational procedures, such as from pneumatic device bleeds, blowdowns, and equipment venting.
- Uncombusted emissions – small amounts of uncombusted methane in the exhaust of natural gas combustion equipment in the production, processing and transmission segments.

Although these sources are sometimes referred to as "leaks", we use the more narrow technical definitions in this report. Figure 2-7 illustrates the major segments of the natural gas industry and examples of the primary sources of methane emissions as gas is produced, processed, and delivered to consumers.

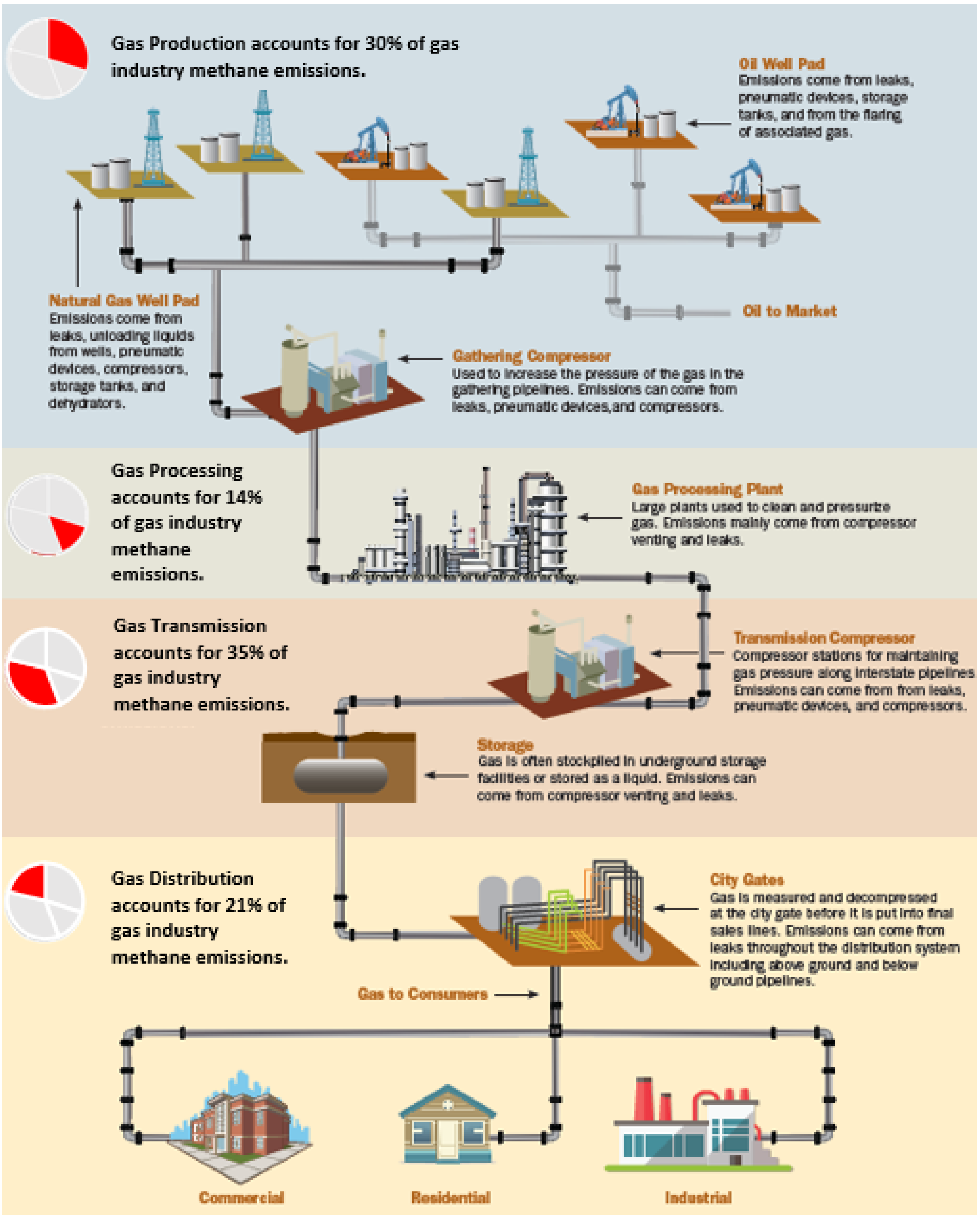
Natural gas is produced along with oil in most oil wells (as "associated gas") and also in natural gas wells that do not produce oil (as "non-associated gas"). For the last 100 years, domestic natural gas production has been primarily in the Southwest, Gulf of Mexico, and the Rockies. More recently, mid-continent and northeastern shale plays have been a growing source of natural gas, as the focus of new development has turned to the extraction of gas from shale formations.

Shale is a sedimentary rock composed of compacted mud, clay and organic matter. Over time, the organic material can produce natural gas and/or petroleum, which can slowly migrate into formations where it can be recovered from conventional oil and gas wells. The shale rock itself is not sufficiently permeable to allow the gas to be economically recovered through conventional wells; that is, natural gas will not flow sufficiently freely through the shale to a well for production.

Gas from shale formations is recovered by hydraulically fracturing the shale rock to release the hydrocarbons. This involves pumping water and additives at high pressure into the well to "fracture" the shale, creating small cracks that allow the gas to flow out. When the water "flows back" out of the well during development, methane is entrained and historically may have been vented.

[ii] This overview is based on ICF's Report entitled "Assessment of New York City Natural Gas Market Fundamentals and Life Cycle Fuel Emissions"

Figure 2-7 - Natural Gas Industry Processes and Example Methane Emission Sources



Source: Adapted from Clean Air Task Force "Waste Not"
http://www.catf.us/resources/publications/files/WasteNot.pdf

For these reasons, the increased production of shale gas was at one time seen as a potential source of increased GHG emissions. Federal regulations promulgated in 2012 require the majority of new hydraulically fractured gas wells to capture or flare the flow-back gas. These regulations and other federal and state regulations also require control of other methane-emitting processes, though many apply only to new sources and to those wells that primarily produce natural gas, rather than wells that produce natural gas along with oil.

Although some of the produced natural gas is pure enough to be used as-is, most natural gas is transported by gathering pipeline from the wellhead to a natural gas processing plant. These pipeline gathering systems may have pneumatic devices and compressors that vent gas, as well as fugitive emissions. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including CO_2, in order to produce pipeline-quality natural gas to be compressed and transported. These gathering and processing facilities are another potential source of fugitive and vented emissions.

From the gas processing plant, natural gas is transported, generally over long distances by interstate pipeline to the “city gate” hub and then to consumers. The vast majority of compressors that pressurize the pipeline to move the gas are fueled by natural gas, although a small share is powered by electricity. Compressors emit CO_2 and small amounts of methane emissions during fuel combustion and are also a source of fugitive and vented methane emissions through compressor seals, valves, connections, and through venting that occurs during operations and maintenance. Compressor stations constitute the primary source of vented and fugitive methane emissions in natural gas transmission.

Some power plants and large industrial facilities receive gas directly from transmission pipelines, while others, such as residential and commercial consumers, have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some methane emissions do occur due to leakage from older distribution lines and valves, connections, and metering equipment. This is especially true for older systems that have cast iron or unprotected steel distribution mains.

Many of the emission sources from domestic oil production are similar to those in gas production – completion emissions, pneumatic devices, processing equipment and engine/compressors. Crude oil contains natural gas and the gas is separated from the oil stream at the wellhead and can be captured for sale, vented, or flared. Venting or flaring is most common in regions that do not have gas gathering infrastructure. This is the case currently in North Dakota, where rapid growth in oil production has taken place in a region with little gas gathering infrastructure. While new gathering lines are being built, production is still ahead of the gathering capacity, resulting in continued flaring.

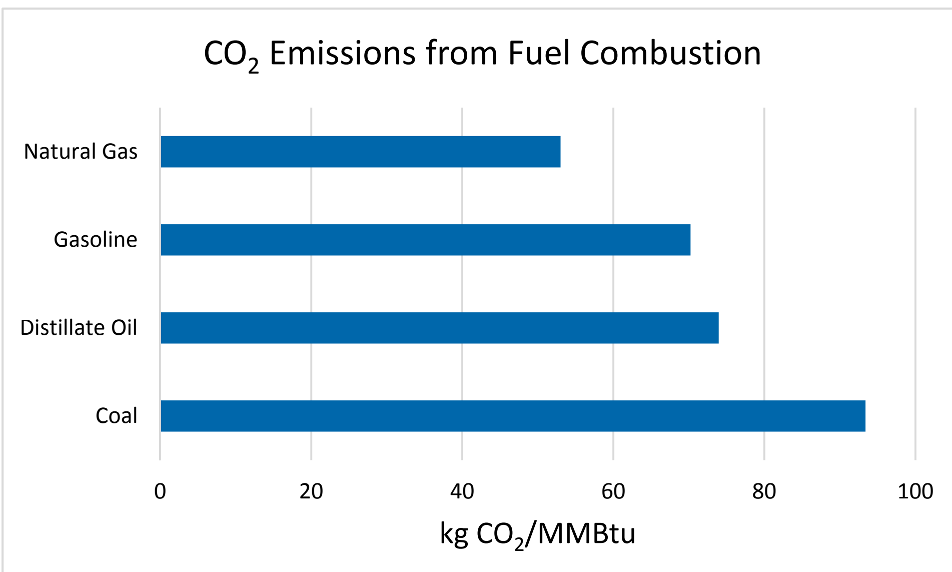
3. Introduction to Greenhouse Gases and Other Environmental Factors

Greenhouse gases (GHGs) are gases that trap heat within the earth's atmosphere. Carbon dioxide (CO_2) is the primary GHG but there are others that are emitted in lower quantities and have a stronger warming effect. This chapter discusses the emissions of different GHGs and how they are expressed and tracked.

3.1. Combustion Emissions

Carbon dioxide (CO_2) is a by-byproduct of the combustion process in which hydrocarbon fuel is converted into heat and the combustion products of carbon dioxide and water. As shown in Figure 3-1, natural gas combustion results in the lowest CO_2 emissions of all fossil fuels – approximately 43% less than those of coal and approximately 25-30% less than common liquid petroleum fuels[2]. Natural gas also typically has lower emissions of conventional pollutants than other fossil fuels, such as nitrogen oxides, sulfur dioxide and particulate matter. These lower emissions have contributed to declining national CO_2 emissions as gas has displaced coal and oil, especially in the electricity sector.

Figure 3-1- Natural Gas has the Lowest Direct CO_2 Emissions of All Fossil Fuels



Data source: Greenhouse Gas Reporting Rule

3.2. Non-CO_2 Greenhouse Gases and Global Warming Potential

Greenhouse gases absorb and re-emit solar radiation, trapping heat in the earth's atmosphere and resulting in an overall warming effect. Different gases have different warming effects and different lifetimes in the atmosphere, making it difficult to compare their effects on a consistent basis. A factor called global warming potential (GWP) is often used for this purpose. GWP can be defined as the amount of total energy added to the climate by a gas relative to the impact of the baseline gas, CO_2, which is assigned a GWP of 1. The GHG emissions weighted by the GWP are expressed as CO_2 equivalent (CO_2e).

The science and policy communities have historically looked to the U.N. Intergovernmental Panel on Climate Change (IPCC) assessment reports as the authoritative basis for GWP values. The IPCC is the chief international organization for climate change issues, and was established in 1988 by the United Nations Environmental Programme (UNEP) and the World Meteorological Organization (WMO). Governments, organizations, and climate experts from all around the world voluntarily contribute to these reports. Five Assessment reports have been published:

- IPCC First Assessment Report 1990 (FAR)
- IPCC Second Assessment Report 1995 (SAR)
- IPCC Third Assessment Report 2001 (TAR)
- IPCC Fourth Assessment Report 2007 (AR-4)
- IPCC Fifth Assessment Report 2014 (AR-5)

Two key factors in determining the effect of a GHG are its warming effect and the length of time that it remains active in the atmosphere. CO_2 is the least potent of the GHGs but it remains in the atmosphere for thousands of years and moves between different parts of the air-ocean-land system. Even though it is the least potent, CO_2 is the largest GHG source, especially from large users of fossil fuels, and thus it has been a focal point for initiatives to regulate GHG emissions. On the other hand, methane has a stronger warming effect than CO_2, but its lifetime in the atmosphere is only about 12 years. Other GHGs have much greater warming effect than methane and may have longer or shorter lifetimes. Table 3-1 was developed by the U.S. EPA[3] to describe the characteristics and lifetimes of major greenhouse gases based on the IPCC's Fifth Assessment Report.

The IPCC calculates the GWP based on a 100 year and 20 year lifetime to provide alternative bases for analyzing emission impacts. Depending on the lifetime of the individual gas, the 20 year GWP can be higher or lower than the 100 year GWP. Both of these values are correct but they reflect a different snapshot of the warming effect of the subject gases. While there is no scientific imperative for selecting one or the other GWP life, the GWP for a time horizon of 100 years was adopted as a metric to implement the multi-gas approach embedded in the United Nations Framework Convention on Climate Change (UNFCCC) and was made operational in the 1997 Kyoto Protocol. The 100 year GWP is also the standard for reporting national emissions to the UNFCCC and is the standard used in most national GHG reporting and regulatory programs.

Table 3-1 – Greenhouse Gas GWPs and Lifetime

Greenhouse Gas	How It's Produced	Average Lifetime in the Atmosphere	100-Year GWP
Carbon Dioxide	Produced mainly by the burning of fossil fuels (oil, natural gas, and coal), solid waste, and trees and wood products. Land-use changes, deforestation, and soil degradation also contribute to its production.	Carbon dioxide's lifetime is not defined because it continues to move between different parts of the ocean-atmosphere-land system instead of being destroyed.	1
Methane	Emitted during the production and transport of coal, natural gas, and oil, as well as from livestock, agricultural practices, and the anaerobic decay of organic waste in solid waste landfills.	12 years	28
Nitrous Oxide	Produced during agricultural and industrial activities, and during the combustion of fossil fuels and solid waste.	121 years	265
Fluorinated Gases	Synthetic gases containing fluorine, such as hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. They are emitted from various industrial processes and commercial and household uses.	A few weeks to thousands of years	Varies (Sulfur hexafluoride is the highest at 23,500)

Source: http://www.epa.gov/climatechange/glossary.html

Most countries and international agencies (including the U.S. EPA) follow inventory protocols set by the IPCC, which still use the AR-4 100 year GWP of 25. That said, the AR-5 is the most recent assessment and includes some changes in the treatment of the methane GWP. The first major change in AR-5 is fully including carbon cycle feedback in calculating the GWP. As the temperature increases, the biosphere retains less CO_2, which enters the atmosphere and causes further warming. This feedback was included for CO_2 (the denominator in the GWP) in earlier reports but not for the other gases. Including it for the other gases increases the calculated GWP for each GHG.

The second change is specific to methane. When methane oxidizes in the atmosphere, it creates CO_2, which has an additional warming effect. Thus methane emissions have a direct and then an indirect effect on the Earth's climate due to the CO_2 that is created. The primary GWP values for methane listed in the AR-5 are for biogenic methane, for which the CO_2 is assumed to have been absorbed from the biosphere and therefore the oxidation does not constitute a net increase. For fossil methane, however, the methane oxidation effect adds 1 to the 20 year GWP and 2 to the 100 year GWP.

The AR-5 100-year value GWP value for methane without feedback or oxidation adjustment is 28 (slightly higher than the AR-4 value of 25). With the adjustment for fossil methane it is 30. The value with feedback and adjustment for oxidation is 36. The 20 year values in the AR-5 are 84 without feedback or oxidation and 87 with feedback and oxidation. These results are summarized in Table 3-2. These new findings in the AR-5 have not been accepted by all parties and many entities, including some government and regulatory agencies, use the values without feedback, while few organizations are currently using the values with the feedback and oxidation factor.

Table 3-2 - Global Warming Potentials for Methane for Different Lifetimes (including feedbacks)

IPCC AR	Year Published	20 – Year GWP	100 - Year GWP
AR-4	2007	72	25
AR-5*	2014	84/86/87	28/34/36

*Without feedback/With feedback/With oxidation
Source: IPCC

3.3. Emissions Measurement and Reporting

Methane emissions can be measured and reported in a variety of units and formats. The most common are listed below with the most recent values from the U.S. EPA's 2016 *GHG Inventory* for emissions in 2014:

- Volumetric basis: Expresses emissions in units of cubic feet (ft^3) or meters (m^3). The *Inventory* reports 366 billion cubic feet (Bcf) of methane emitted from natural gas operations in 2014.
- Mass basis: Expresses the mass of methane emissions in units such as kilotonnes or gigagrams (Gg). The *Inventory* reports 7,045 kilotonnes (kT) of methane emitted from natural gas operations in 2014.
- CO_2e basis: Expresses the mass of GWP-weighted methane emissions in units of million metric tons of CO_2 equivalent ($MMTCO_2e$). The 2013 *Inventory* reports 176.1 $MMTCO_2e$ emitted from natural gas operations (using a GWP of 25) in 2014.
- Percent of production: Expresses methane emissions as a percentage of natural gas produced annually in the U.S. or the methane content thereof - sometimes referred to as a "leakage rate". The *Inventory* methane emissions were equivalent to 1.4% of the methane (83%) in gross natural gas withdrawals in 2014.

4. Federal Reporting of GHG Emissions

4.1. EPA Inventory of GHG Emissions

The U.S. EPA *Inventory of U.S. Greenhouse Gas Emission and Sinks* [1] is an annual report that quantifies greenhouse gas emissions from all sectors of the U.S. economy and is the only national, economy-wide estimate of U.S. GHG emissions in general and methane emissions specifically. Emissions are estimated using national level data collected across many different sources. Each year, the inventory is submitted to the United Nations Framework Convention on Climate Change (UNFCCC) to fulfill the U.S. commitment to the reporting requirements for annual emission inventories established by the UNFCCC. In addition to serving as the official U.S. accounting of GHG emissions, the inventory serves as a reference and source of information on opportunities for reduction and a measure of progress on voluntary and regulatory programs.

The EPA GHG inventory provides methane emissions estimates by source across the entire economy including the natural gas industry. Emissions are tabulated by source and equipment type and are split across each of the different segments to provide a U.S. national estimate. The inventory structure includes over 200 source categories for the oil and gas industries. Data is available on an annual basis dating from 1990 to the year of publication. Emissions and activity data are updated each year for every source over the entire time span when the EPA GHG *Inventory* is released. For instance, the 2016 version of the EPA GHG *Inventory* includes revised data not only for the latest year, 2014, but also revisions to all sources and activity dating back to 1990.

Emissions are generated using an activity factor (AF) and emission factor (EF). The AF depicts the population of sources – number of wells, miles of pipeline, etc. The EF is the emission rate per unit of activity – e.g., cubic feet emitted per well, device, or mile. The equation is:

$$Emissions = Activity\ Factor\ x\ Emission\ Factor$$

The AFs in the EPA GHG Inventory are driven by a number of different national level data sources including the Energy Information Administration (EIA), the Oil and Gas Journal (OGJ), and the Pipeline and Hazardous Materials Safety Administration (PHMSA). Many of the EFs have historically been based on a measurement study performed by the Gas Research Institute (GRI) and EPA[4] in the 1990s. This study performed site level measurements across multiple emission sources to estimate average emission rates for each type of equipment. The emissions estimates based on these sources are then adjusted to account for both voluntary and regulatory reductions undertaken by industry. The voluntary reduction estimates are primarily based on reductions reported to the EPA Gas STAR program (See Section 6.1).

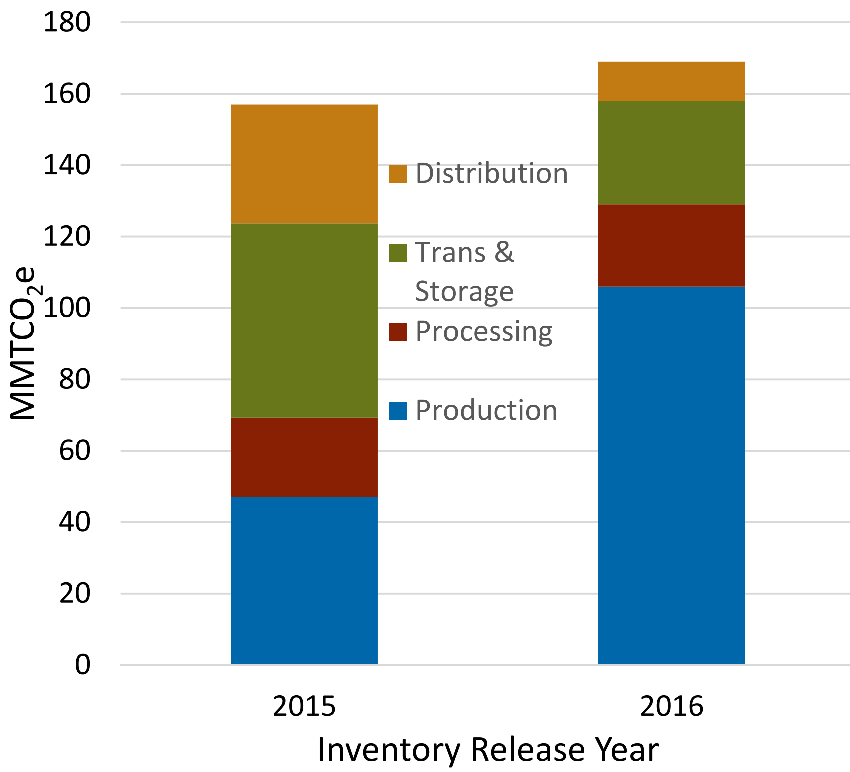
The estimates are revised each year based on the most recent activity data. The EPA also reviews new data on emissions to identify better emission factors. There are limits to the kinds of data that can be used, however. The data must be public, citable, nationally applicable, and able to be applied over the entire historical series. In recent years, the EPA has been reviewing and adopting multiple new sources of data, especially the Greenhouse Gas Reporting Program (GHGRP) to identify potential updates to the Inventory.

The EPA implemented many changes for the most recent edition of the *Inventory*, released in 2016 with data for 2014. The changes included data from the GHGRP as well as results of some of the recent emission measurement studies described in Chapter 5. The changes included updated equipment counts, especially for pneumatic controllers, and some updated emission factors. The change was especially significant for gathering and boosting facilities, which are included in the production segment of the *Inventory*. The original GRI data estimated a relatively small population of gathering facilities. More recent data resulted in a significant increase in the estimated population and an increase in the estimated emission factors, with a corresponding large increase in overall estimated emissions, included in the production segment of the *Inventory*. On the other hand, recent measurement studies showed large reductions in emission rates in the transmission and distribution segments, offsetting some of the upstream increases. Figure 4-1 shows the effect of these changes on the emissions from natural gas systems for 2013, the most recent year for which both versions are available.

The estimate of 2013 methane emissions for natural gas systems in the 2016 version is 12% higher than in the prior year. The natural gas industry methane emissions as a share of total U.S. GHG emissions in 2013 increased only slightly, from 2.4% in the 2015 estimate to 2.6% in the 2016 estimate. The natural gas industry share of methane emissions for 2013 went down very slightly in the 2016 estimate, from 24.7% to 24.3%.

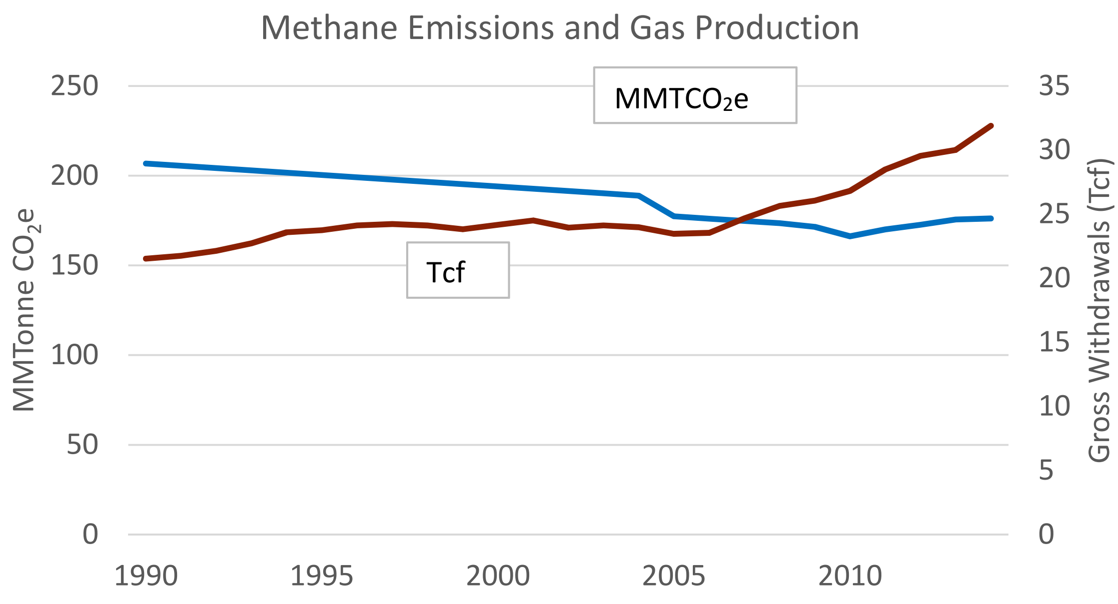
The decrease in distribution system emissions reflects company efforts to reduce leaks and replace older equipment. Gas distribution companies also have been reducing leaks by replacing old cast iron pipe, which is leak-prone, at the rate of roughly 3% per year. Leak repair of old cast-iron pipe is difficult and costly because most of the pipe is in older, congested urban areas, mostly in the Northeast. Companies must receive approval from state regulators to make these investments and the regulators' primary concern is safety and cost to consumers rather than emissions. That said, many states and distribution companies are developing or have implemented accelerated pipeline replacement programs, which have contributed to the reductions.

Figure 4-1 – Changes to 2016 EPA GHG Inventory for Natural Gas Systems for Emissions in 2013



As described above, the EPA must also adjust the emission estimate back to 1990. Because detailed data on the updated factors were not available for all of the intervening years, a portion of the emission curve between 1990 and 2005 was linearly interpolated, resulting in a straight line estimate. Figure 4-2 below displays total emissions reported annually for the natural gas industry since 1990 to the 2014 estimate of 366 Bcf or 176.1 $MMTCO_2e$ of methane from the natural gas industry. The absolute emissions have been declining for most of the period, with a slight uptick in the last years. However, this trend does not take into account the changes in natural gas production and throughput during this period, especially during the last few years as shale gas production has increased, as shown in the chart.

Figure 4-2 -- Methane Emissions Have Been Declining While Production Increases

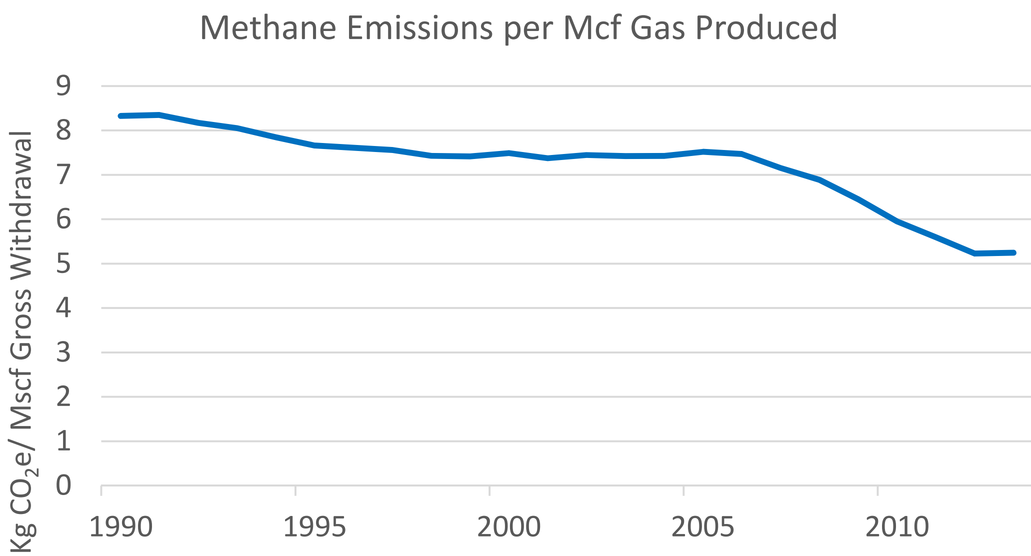


Data source: Greenhouse Gas Inventory Data Explorer; http://www3.epa.gov/climatechange/ghgemissions/inventoryexplorer/#energy/allgas/source/all , U.S. Energy Information Administration

Figure 4-3 displays natural gas emissions per thousand cubic feet (Mcf) of gas produced. As U.S. natural gas production has increased rapidly in recent years, the ratio of estimated emissions per cubic foot of production has gone down. The emissions per unit of production were nearly 43% lower in 2014 than in 1990. Factors contributing to this reduction include equipment turnover and replacement, voluntary reductions of natural gas losses by the gas industry, and recent regulations to limit volatile organic compounds (VOCs), which have the co-benefit of reducing methane emissions. In addition, methane emissions in many parts of the industry are not highly correlated to throughput so increased production and use tend to reduce emissions per unit of natural gas throughput[iii].

[iii] Commenters from the gas distribution Industry have stated that the EPA Inventory has incorrectly assumed a correlation between throughput and emissions in at least one instance related to distribution companies. The commenters state that the EPA assumption that higher throughput during cold weather leads to higher gas pressure and higher emissions is not correct. Pressure is typically lower during these conditions due to high demand.

Figure 4-3 – Methane Emissions per Mcf of Production Have Declined Sharply



4.2. Greenhouse Gas Reporting Program (GHGRP)

The GHGRP was finalized by the EPA in October 2010 in response to a Congressional mandate. This rule establishes a mandatory program that requires the reporting of greenhouse gas emissions on a facility-level basis from all sectors of the economy. The rule does not require control measures to reduce methane. The reporting requirement applies to facilities that emit 25,000 metric tonnes (25 $MTCO_2e$) or more of carbon dioxide equivalent per year of all GHGs. Therefore, a facility must include emissions from all sources when evaluating the threshold to determine if it is necessary to report. Many facilities in the natural gas industry do not exceed the threshold and therefore the GHGRP is an incomplete depiction of the industry.

The threshold is on a facility basis, and not by source category or subpart. A "facility" is a physical property, plant, building, structure, source, or stationary equipment located in a contiguous area under common ownership which can have multiple source categories subject to regulation. The exceptions to this in the oil and gas industry are for onshore production, where a facility is defined as a producing basin, and for natural gas distribution, where a facility includes all of the LDC operations within a state. The first reporting occurred in 2012 and represented 2011 emissions.

The rule has 43 subparts, including the general provisions in Subpart A and 42 subparts, each representing a source of emissions from a particular industry or process. Each subpart sets requirements for data directly related to the source category, which must be reported to EPA. The reporting system for methane emissions from petroleum and natural gas systems is included in "Subpart W." Under Subpart W, oil and gas facilities report methane emissions from specific emission sources across the natural gas/oil supply chain, including: onshore and offshore petroleum and natural gas production, onshore natural gas processing, natural gas transmission and underground storage, liquefied natural gas (LNG) storage, LNG import and export, and natural gas distribution facilities. The original subpart W did not include gathering facilities, however a modification to the rule in 2015 added these facilities to the reporting requirements, beginning in 2016.

Subpart W requires reporting of emissions from sources such as compressors, dehydrators, pneumatic devices, and storage tanks. This data is sent directly to EPA, which confirms the reported information. Reporting entities are subject to significant penalties and possible fines or imprisonment for submitting false statements[iv]. Data within these subparts is developed by reporters using a variety of methods including direct measurements, engineering calculations, and emission factors specified in the rule.

Because many gas industry facilities do not exceed the 25,000 $MTCO_2e$ threshold, the GHGRP provides an incomplete estimate of total U.S. emissions. In addition, some types of equipment are not included in the reporting requirements, further limiting the completeness of the program and the comparability of *Inventory* and GHGRP data. For example, the EPA *Inventory* for 2013[5] reports 2,588 Gg of methane emissions from petroleum systems and 7,023 Gg of methane emissions from natural gas systems. However, the GHGRP subpart W data for 2013 reports only 2,948 Gg of methane emissions from 2,169 total reporting facilities in the oil and natural gas sectors, including:

- 2,010 Gg of methane emissions from onshore and offshore petroleum and natural gas production (601 total reporting facilities)
- 935 Gg from natural gas processing, transmission, storage and distribution (1,141 reporting facilities)[6].

While EPA's annual GHGRP system is not directly comparable to the GHG Inventory it does provide detailed and current information on activity factors and emission rates for many processes at the facilities that must report. This is an extremely valuable source of data.

[iv] See 40 C.F.R. §98.4(e) Certification of the GHG emissions report (Subpart A, General Provisions).

5. Measurement and Analysis of Methane Emissions

Increased interest in methane emissions from the natural gas value chain has resulted in a surge of research and analysis over the last five years. This report has identified 75 relevant studies of different kinds that focus on methane emissions from natural gas sector sources or activities that were reviewed for this report. Many of the studies are highly technical and some are contradictory. This chapter summarizes some of the most significant studies in four categories:

- On-site direct measurement ("bottom up") studies – studies in which emissions are measured directly at the facility, usually at the component level
- Ambient air measurement ("top down") studies – studies that measure methane in the atmosphere from planes, tall towers, or measurement points above or downwind from gas industry facilities or basins
- Life-cycle analysis – studies that estimate the total emissions from the facilities that produce, process, transport, and use natural gas to estimate emissions from "wellhead to burnertip".
- Meta-analysis – studies that review and synthesize the results of other studies

A listing of all the studies reviewed for this report, indicating the scope of each project, as well as primary conclusions is provided in the Appendix**.**

5.1. On-Site Direct Measurement Studies

On-site measurement studies involve direct measurement of emissions from specific pieces of equipment and processes in the natural gas value chain (e.g. valve leaks, hydrocarbon storage tank vents, liquids unloading). Measurement studies range in scope from focusing on one type of equipment, such as pneumatic controllers, to addressing emissions from an entire segment in the U.S. natural gas industry, such as the natural gas distribution system. On-site measurement studies can form the basis for development and updating of emission factors from equipment/ processes. On-site measurement studies often present results of emissions sampling in terms of average emissions from specific equipment/process, or facility type, and researchers compare/analyze these results with emission values published in previous studies/inventories, such as the annual EPA GHG inventory. Several of the recent on-site studies are summarized in this section.

Many emission factors currently used in emission inventories were developed from the series of on-site measurement studies published in 1996 by the EPA and the Gas Research Institute (GRI), now known as the Gas Technology Institute (GTI).[v] In a more recent study[7], GTI measured leaks

[v] GTI was formed in 2000 by a merger of GRI and the Institute of Gas Technology.

from polyethylene gas distribution pipes. The study found the emission factor for polyethylene pipes to be 70% less than estimated in the 1996 EPA/GRI study, which is the basis for emission factors in the EPA *Inventory* and GHGRP. After evaluating a variety of factors, the study found a weak or no relationship between the leak rate and the pipeline operating pressure, pipe age, soil characteristics, and temperature.

Several studies have used an extremely sensitive measurement device (cavity ring-down spectroscopy) to identify leaks from the gas distribution system at the street level. The Environmental Defense Fund (EDF) has joined with Google to link these leak studies with Google street maps in several cities[8]. A similar but more detailed study[9] performed on the distribution system in Washington, DC in 2014 reported nearly 6,000 leaks.

The measurement equipment used in these studies is extremely sensitive and can detect methane even at levels lower than safety levels, which are often the trigger for leak repair. In the Washington, DC study, more than 4,000 of the reported leaks were below 5 parts per million (ppm) whereas the lower explosive limit (LEL) for natural gas is 50,000 ppm. As another point of comparison, the emission level at which methane leaks in new and modified natural gas processing plants must be repaired under mandatory inspection and maintenance programs was reduced in 2012 from 10,000 ppm to 500 ppm. In other words, the majority of the leaks in this study were 100 times below the threshold for action or the regulatory definition of a "leak" if they were in processing facility subject to a mandatory inspection and maintenance program. The study did identify 12 enclosed locations (manholes) where gas had accumulated to above the LEL and four locations where they calculated more significant leakage. These studies are primarily computing the concentration of methane at a given point, but calculating the actual volume of methane requires additional calculations based on time, wind, and dispersion, methodologies which are still under development.

Many of these LDC leak studies have been performed in cities, which like Washington, DC, have very old gas distribution systems that include cast iron pipe. Old cast iron pipe is known to be leak-prone and gas distribution companies are implementing programs to replace the many thousands of miles of leak-prone pipe. In the meantime, they perform continuous leak surveys and promptly repair any leaks that present an immediately safety risk Gas distribution companies have been replacing leak-prone pipe at the rate of roughly 3% per year. (See Chapter 6 for more detail on cast-iron replacement programs.)

Perhaps the most extensive recent work on direct measurement is a series of 16 studies organized by EDF with a variety of researchers, including several universities, and published in peer-reviewed journals[10]. The studies address each of the gas industry segments at facilities of companies that participated in the studies. Some of the major components of these studies are summarized below:

- "Measurements of methane emissions at natural gas production sites in the United States" – David T. Allen et al. (2013). This study measured emissions from natural gas well sites operated by nine companies in different parts of the U.S. From direct measurements of well completion flowback emissions, the study estimated a range of methane emissions from 0.01 Mg to 17 Mg. The study showed that companies could reduce flowback emissions by 99%.The upper range of the study's methane emissions estimate for this source (17 Mg) is nearly 80% smaller than the average emissions per event of 81 Mg, cited in the 2011 EPA Inventory. The study noted, "there was significant geographical variability in the emissions rates from pneumatic pumps and controllers, but these regional differences were not as pronounced for equipment leaks." Extrapolating the results to the national level, the study estimated the overall emissions to be comparable to the EPA inventory, with lower emissions from well completions offsetting higher estimates from other components.
- "Measurements of Methane Emissions at Natural Gas Production Sites in the United States: Liquids Unloading" – David T. Allen et. al. (2014) – The study measured liquids unloading emissions for a sample of natural gas production wells (107 wells total) across the United States. The study's estimate for total methane emissions was consistent with estimates in national emissions inventories such as the EPA Inventory. The study estimated total annual methane emissions from liquids unloading events at 14.4 Bcf/yr, a value very similar to both the 2012 EPA National Emissions Inventory (NEI) and the Greenhouse Gas Reporting Program (GHGRP) values of approximately 14 Bcf/yr and 14.3 Bcf/yr, respectively.

  The study indicated that a majority of emissions attributed to liquids unloading events may come from a smaller percentage of wells, stating: "Emissions estimates…suggest that a small fraction of wells, in particular geographic regions, and at particular times in a well's life cycle, account for a large fraction of unloading emissions[11]." The study references an American Petroleum Institute/America's Natural Gas Alliance (API/ANGA) study that found a similar result, "three percent of wells accounted for half of emissions from this type of well [wells without plunger lifts] and half of the wells accounted for more than 90% of emissions[12]."
- "Measurements of Methane Emissions at Natural Gas Production Sites in the United States: Pneumatic Controllers" – David T. Allen et. al. (2014). This study focused on emissions from pneumatic controllers and estimated higher average emissions per controller (17% greater) and a higher number of pneumatic controllers per well (2.7 vs. 1.0) than those reflected in the EPA's *Inventory* at the time. (The most recent Inventory has increased the number of pneumatic controllers based on GHGRP data.) The study found that less than 20% of high bleed pneumatic devices accounted for 95% of measured methane emissions. Additionally, the study found that pneumatic devices used in two particular applications, for separator (e.g. of oil/water/gas) level controllers and compressors, exhibited higher emission rates than pneumatic devices used in other processes. The study states, "More than half (51%) of the controllers had an emissions rate less than 0.001 scf/h over the 15 min sampling period; 62% had an emissions rate less than 0.01 scf/h over the 15 min sampling period[13]." 231 sampled pneumatic devices

out of the total sample size of 377 exhibited no detectable emissions during the sampling period. Some of these were intermittent devices that did not actuate during the sampling period. The study found that some of the pneumatic devices with the highest emissions were behaving in a manner inconsistent with the manufacturer's design[14].

- "Measurement of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results" – Mitchell et al. (2015)[15]. "Methane Emissions from U.S. Natural Gas Gathering and Processing" – Marchese et al (2015)[16]. These two studies addressed measurement (Mitchell) and analysis (Marchese) of methane emissions from 114 natural gas gathering facilities and 16 natural gas processing plants. The Mitchell study found that normalized emissions (as a percentage of total methane throughput) were less than 1% for 85 gathering facilities and 19 had normalized emissions less than 0.1%. Normalized emissions for processing plants were less than 1% in all cases. Some of the gathering facilities had very small throughput, which tends to inflate the normalized emission rate. This makes it difficult to use the normalized values to extrapolate the results to a national level. The Marchese analysis used a Monte Carlo simulation and a randomization process to attempt to address this variability. It also used updated information on facility populations based on state permit data. Additional data on both activity data and emission factors would improve the understanding of the gathering segment, however, this analysis found that the gathering system emissions were higher than reported in the EPA *Inventory* for 2012 (though the gathering system emissions have been significantly revised upwards in the most recent *Inventory*). The analysis found that emissions from processing plants were 1.7 times lower than reported in the *Inventory*, mostly due to fewer reciprocating compressors.
- "Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA GHGRP" – R. Subramanian et. al. (2015). This study combined on-site direct measurements at natural gas transmission pipeline and storage compressor stations. The study also used tracer flux techniques, which estimate on-site methane emissions from ambient air sampling in downwind plumes from the measurements sites. The study found that these two independent estimates agreed within experimental uncertainty. The study states, "the highest emitting 10% of sites (including two super-emitters) contributed 50% of the aggregate methane emissions, while the lowest emitting 50% of sites contributed less than 10% of the aggregate emissions[17]… however, we lack the data to determine whether the magnitude or frequency of the super-emitters encountered in this study are representative of the entire T&S sector[18]."
- "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States" – Brian K. Lamb et. al. (2015). The study of 13 distribution systems across the U.S. arrived at a methane emissions estimate from LDC systems that was 36-70% less than that published for the sector in the 2011 EPA *Inventory*. The report states, "[this estimate] reflects significant upgrades at metering and regulating stations, improvements in leak detection and maintenance activities, as well as potential effects from differences in methodologies between the two studies[19]." For underground pipeline leaks, the researchers produced EFs that "were about two times lower than reported in the 1992 EPA/GRI study[20]." For metering and regulating (M&R)

facilities, the study found emission factors for larger emitting sources to be 14 times less than the same sources published in the 1992 EPA/GRI study. The study measured emissions from nine facilities sampled in the EPA/GRI study and found emission reductions from the stations ranging from 2-50% from the 1992 values. The study attributed these emission reduction to upgrades at the sites. To understand any correlation between reduced emission factors identified in their study and distribution infrastructure upgrades, project researchers surveyed study partner LDCs and LDC members of the American Gas Association (AGA). The survey results indicated that 60% of sites represented in returned surveys had undergone "some equipment change since 1992[21]." The report found that three large leaks (34.9, 22.2, and 4.9 g/min – respectively, 1.8, 1.2, and 0.25 scfm – from unprotected steel main, protected steel main, and cast iron main leaks, respectively) accounted for 50% of the total measured emissions from pipeline leaks[22].

While the EDF and other studies found lower emissions from several source categories than reflected in the EPA inventory, they found that a small number of higher emitters (often called "super-emitters") accounted for the majority of emissions in most segments while the majority of sources had much lower emissions. They found high variability of emissions within similar source categories or emission types. The studies also found that some sources or types of equipment are misidentified or underrepresented in reporting as well as evidence of malfunction or different operation than designed. Like all "bottom up studies", the EDF series of equipment and facility measurement studies reflect a relatively small, self-selected sample of industry facilities that could be difficult to extrapolate to the national level. That said, they are much more current and robust than other similar sources and provide a wealth of improved data that can be used to improve the EPA *Inventory* and GHG Reporting Program (GHGRP). The 2016 revisions to the EPA *Inventory* made use of several of these studies.

5.2. Ambient Air Measurement Studies

As opposed to direct measurement of emissions from a site-specific piece of equipment or process, ambient ("top-down") studies use air sampling methods to estimate emissions on a larger scale, such as from an oil or gas production region. The studies measure the concentration of methane in the atmosphere and use atmospheric modeling to estimate the source. They must also attempt to differentiate methane derived from natural gas systems from methane derived from agricultural or other sources. This is done through analysis of other hydrocarbons or isotopes mixed with the methane that indicate the presence of natural gas. Ambient measurement study techniques (typically measuring methane concentration from aircraft, towers, or other remote sampling stations) are limited in their ability to identify site-specific emissions and have other challenges not associated with direct measurement techniques, such as limited sampling time, weather conditions, extent of pollutant dispersion, and presence of other potential sources of methane, such as those related to livestock, agriculture, or landfills. Most recent ambient measurement studies estimate higher emissions from the natural gas production/oil production chain than similar estimates from on-site, direct measurement studies and the EPA *Inventory*. Some of the significant recent ambient measurement studies include:

- "Methane Emissions Estimate from Airborne Measurements over a Western United States Natural Gas Field" – Karion et al (2013). The study used airplane measurements in Uintah county Utah to estimate emissions from oil and gas production. Although ten flights were planned, measurements were based on only two days due to inconsistent meteorological conditions. The study deducted estimated emissions associated with cattle and natural seepage to estimate methane emissions from oil and gas operations, thus the final result is based on assumptions about other poorly defined sources of methane. The study then calculated emissions as a percentage of hourly February gas production in the county. Methane emissions from oil and natural gas production were estimated by the authors to be 8.8% ± 2.6% of total production from oil and gas operations in the region. These estimates were almost 38 times higher than losses reported to the U.S. Department of Interior Oil and Gas Operations Report (OGOR) and nearly twice the Western Regional Air Partnership (WRAP) phase III inventory. The authors stated that this estimate was not thought to be typical because the production operations in this region are not representative of national operations, however the study is often incorrectly cited as typical and often at the high end of the uncertainty range (>11%).
- "A New Look at Methane and Nonmethane Hydrocarbon Emissions from Oil and Natural Gas Operations in the Colorado Denver-Julesburg Basin" - Petron et al. The study developed top down estimates of hydrocarbon emissions from the densely drilled Denver-Julesburg basin using airborne measurements and calculations. The study estimated a loss of 4.1% of gas produced from the region based on two days of data collection. This is more than twice as much as estimates from the EPA *Inventory* or from the GHGRP data for the same region, but only half as much as the 8.8% reported by Karion for the Uintah study. An estimated 75% of the total methane emissions were attributed to oil and gas operations in this study.
- "Quantifying Atmospheric Methane Emissions from the Haynesville, Fayetteville, and Northeastern Marcellus Shale Gas Production Regions" - Peischl et al.(2015). The study took airborne emissions measurements over three regions, the Haynesville (TX), Fayetteville (AR), and northeastern Marcellus (PA), all of which contain unconventional shale gas production. The measurements were found to be equivalent to measurements in regions addressed in the Karion and Petron studies, however the production in these regions is higher, resulting in lower estimates of the loss percentage – 1.0 to 2.1% in the Haynesville, 1.0 to 2.8% in the Fayetteville, and 0.18 to 0.41% in the Marcellus. This is consistent with the earlier observations in this report about low correlation between throughput and emissions.
- "Methane Emissions from Natural Gas Infrastructure and Use in the Urban Region of Boston Massachusetts" - McKain et al. (2015) [23]. The study measured ambient methane levels from tall towers or buildings at four locations in the Boston area (two near the urban center and two outside it) to determine an emissions value related to natural gas delivery and end use. Ethane concentrations were used to determine emissions associated with natural gas. Because ethane is a typical component of natural gas, using ethane

concentrations can serve as an indicator of natural gas emissions as there are no other known sources of ethane in the region. Boston has no geological seeps, oil and gas production, or refining, and low rates of biomass burning. The emissions were estimated to be 2.7% of consumed natural gas in the Boston urban region. This was two to three times higher than predicted by existing inventories such as the Massachusetts State GHG Inventory. That said, the study was not able to attribute a specific source of the emissions (i.e., delivery systems vs. end use) and the total consumption of gas (denominator in the percent leakage calculation) was estimated from a variety of secondary sources.

In summary, ambient measurement studies can provide a useful supplement to direct measurement in estimating methane emissions from oil and gas systems. They also have several challenges:

- They may require complex atmospheric modeling to convert the measured methane concentration to a quantity of methane.
- They require data to account for other sources of methane (e.g., agriculture, landfills, seeps) that may be more limited than the data on gas operations.
- They do not allow attribution of the methane emissions to specific sources or processes.
- If expressed as a percent of production (or consumption), they are very sensitive to the level of production (or consumption) in the relevant region, which may also be difficult to estimate and may not be well correlated to emission rates.

In general, most ambient measurement studies have found emissions higher than the national average of the U.S. EPA *Inventory* or than extrapolations from on-site measurement studies, though there is great variability and at least one study found much lower emissions. This discrepancy has been difficult to resolve, though one notable study has addressed this issue (See Section 5.4.)

5.3. Life-Cycle Analysis (LCA) Studies

Life-cycle GHG emissions are the aggregate quantity of GHGs related to the full fuel cycle, including all stages of fuel and feedstock production and distribution, from feedstock extraction through processing, distribution, and delivery and use of the finished fuel. It is also sometimes called "site-to-source" emissions. Life-cycle emissions are especially important for natural gas because methane is the primary component in natural gas, so any losses of the product along the value chain are sources of GHG emissions, which are amplified due to methane's higher GWP. Methane is also emitted from coal and oil production and processing as well from natural gas, though in lower amounts. LCAs are often used to compare the overall emissions of different fuels. LCAs typically use emission factors for each stage of the fuel value chain to compile an estimate of the GHG emissions for the production, processing, and delivery of the fuel. This can include CO_2 emissions from combustion processes (e.g., gas compressor exhaust, oil refinery emissions, coal processing emissions) as well as emissions of other GHGs, such as methane.

The LCA can be calculated for the fuel at the point of delivery to the end user ("burner-tip") or can be calculated to also include efficiency at the point of use. Because gas is a large and growing source of fuel for power generation and is seen as a lower-emitting alternative to coal, many LCA studies focus on gas compared to coal for power generation including the conversion from fuel to electricity. Natural gas combined cycle power plants are almost twice as efficient as coal-fired plants. This higher end-use efficiency makes the total site-to-source, end use emissions for gas even more favorable than the burner-tip emissions (which do not include the higher end-use efficiency for gas). This is true for some but not all other natural gas applications compared to other fuels.

While there had been several fairly high-level LCA studies on natural gas through 2010, the release of new emission factors during development of the GHGRP caused renewed interest in life-cycle analysis. Howarth, et al released a study in 2011[24], which estimated that the life-cycle emissions of shale-derived natural gas were higher than those of coal due to the upstream methane emissions under certain assumptions. This study heightened concern over methane emissions.

The Howarth study analyzed the life-cycle emissions from shale gas production and estimated that 3.6% to 7.9% of methane from shale gas production escapes into the atmosphere through vents and leaks during a well's lifetime, and that these emissions are at least 30% more than those from conventional gas. This calculation was particularly driven by high estimated methane emissions during flow-back during hydraulic fracturing and during the "drill out" after the fracturing occurs. The study estimated the LCA emissions from shale gas to be 20% greater than conventional gas when using the 20 year GWP and almost the same as conventional gas when using the 100 year GWP. The study also stated that emissions from gas were slightly higher than from coal on a 100 year basis and almost twice as high on a 20 year basis.

Several studies have criticized and/or rebutted Howarth's analysis[25, 26] and there are several items that, in retrospect, significantly affect the study's conclusions, including:

- The study used a variety of lesser-known and sometimes poorly-supported assumptions for its emission factors. The emission factors for flow-back emissions were derived from limited well production data. Some of the fugitive emissions data was based on anecdotal estimates of "lost and unaccounted for" gas, which is largely an accounting adjustment and not a measurement of emissions. The study did not use the EPA *Inventory* or other established emissions data sources for most sources.
- The study assumed that all emissions from shale gas well completion were vented, even though at least one state was requiring capture or flaring, and companies had reported that they were voluntarily capturing or flaring the gas.

- The study did not use the then accepted (AR-4) GWP for methane. It used a 20 year GWP of 105, over 20% higher than the highest value now accepted under the AR-5. This played a large role in shaping the conclusions.

Changes in gas production practices, improved emissions data, and subsequent regulation of emissions from key production processes have made much of this analysis moot.

Among the subsequent LCA analyses, the National Energy Technology Laboratory, has completed a series of very detailed and well-documented LCAs of different fuels, with several focusing specifically on natural gas.

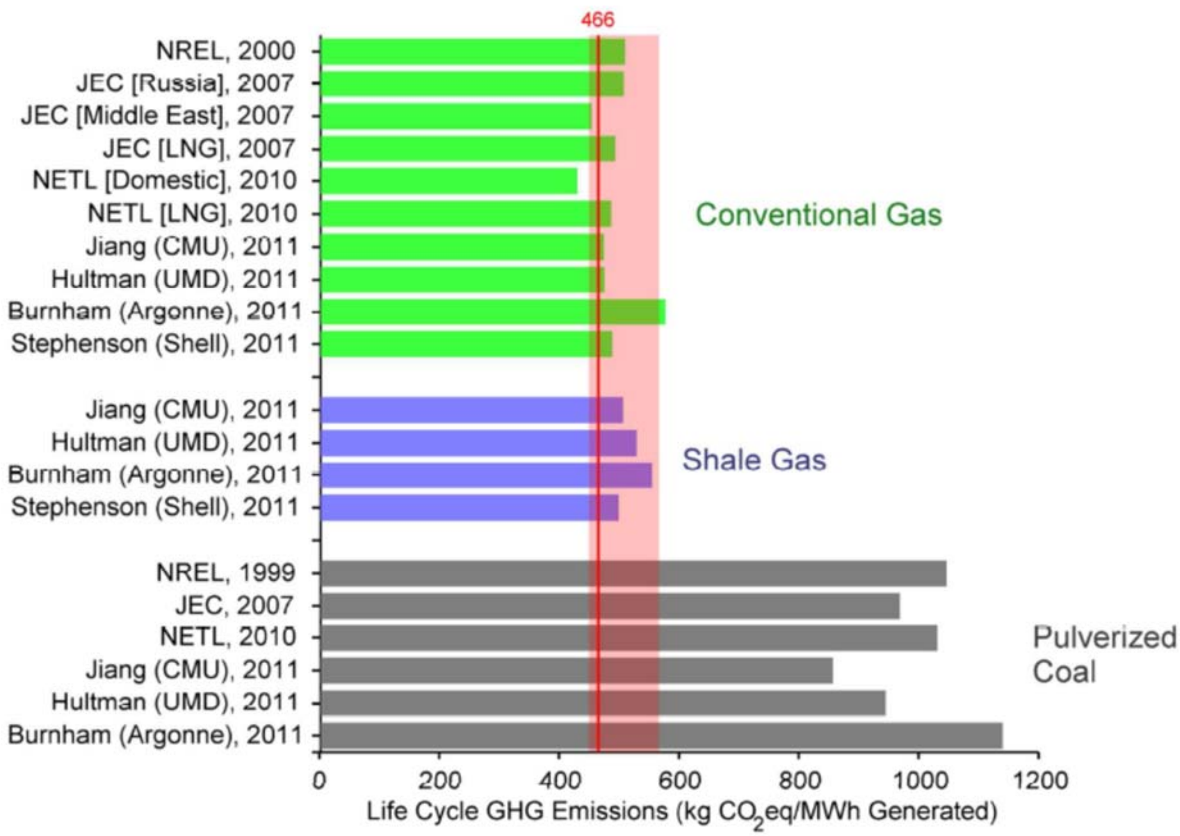
The first of these, in 2011[27], focused on natural gas as a fuel for electricity generation. It found that while the upstream emissions of natural gas, including methane emissions, were higher than those of coal, the total emissions including combustion of the fuel and the higher efficiency of gas-fired power plants showed 42%-53% lower emissions for gas than for coal on a 100 year GWP basis. The study also found that natural gas-fired electricity produces greenhouse gas emissions 39% lower than coal using the 20-year GWP, even when that natural gas-fired electricity is generated from shale gas sources.

A more recent study came to a similar conclusion[28]. This study is a life-cycle assessment of Marcellus shale gas used for power generation based on actual gas production and power generation. The shale gas life-cycle analysis includes drilling, well completion, wastewater disposal, production, treatment and processing, transmission, and power generation at a natural gas combined cycle gas turbine power plant. The study finds that the Marcellus gas life-cycle "yields 466 kg CO_2eq/MWh of greenhouse gas emissions and 224 gal/MWh of freshwater consumption." The "footprint of Marcellus gas is 53% lower than coal, and its freshwater consumption is about 50% of coal." The study also includes a summary of other LCA studies showing similar results (Figure 5-1).

Several studies have focused on liquefied natural gas (LNG) exports. Some have suggested that the upstream methane emissions and methane combustion emissions associated with liquefaction, transport, and regasification of LNG makes the life-cycle emissions of such exports higher than those of coal combustion in the target countries. An NETL study in 2014[29] evaluated this question for different U.S. LNG export locations and different European and Asian destinations and concluded that U.S. LNG exports for power production in European and Asian markets do not result in increased lifecycle GHG emissions in comparison to regional coal extraction and consumption used to generate electricity.

A 2015 study[30] on the same topic was prepared by Pace Global for the Center for Liquefied Natural Gas and came to similar conclusions. The study compared the life-cycle emissions for coal and U.S. LNG-fueled power plants in Japan, South Korea, China, India, and Germany with a variety of high and low LNG cases and new and existing coal plant cases. The study found that the life-cycle emissions for LNG were significantly lower in all cases, less than half the coal-based emissions in nearly all of the cases.

Figure 5-1 – Multiple Studies Shows Life-cycle Burner Tip Emissions from Gas Lower than Coal



Source: Laurenzi and Jersey[28]

One other notable LCA was performed by Alvarez et. al. in 2012[31]. This study did not use GWPs to compare different GHGs. Instead, it proposed the use of "technology warming potentials" (TWPs), which allow the comparison of the time-dependent climate effects of different fuels and technologies. The TWP accounts for the time-dependent effects of different GHGs as they enter the atmosphere with a high climate forcing potential and then decay over time. The analysis then determined over what time period natural gas can have a lower climate forcing impact than other fuels. It determined that at then current methane emission levels equaling 3% of annual production (based on 2009 emissions estimates in the 2010 EPA Inventory) gas would have a lower climate forcing impact than coal at all times. However, the analysis predicted that at emission levels reported in the 2010 Inventory, switching to compressed natural gas vehicles from gasoline vehicles would result in a greater radiative forcing of the climate for 80 years, before there are any apparent benefits. Similarly, at emission levels reported in the 2010 Inventory, shifting to compressed natural gas vehicles from efficient diesel vehicles would result in a greater radiative forcing for 280 years, before any benefits are produced. The study found that the national methane emission level would need to be reduced to 1% or less for gas to have immediate climate benefits compared to diesel-fueled vehicles.

In summary, the recent and most-detailed LCA studies consistently show that natural gas has lower GHG emissions than coal at the burner tip, and even more so for generated electricity at both the 20-year and 100-year lifetimes. The benefits of natural gas relative to petroleum depend on the methane emissions level assumed, the technology being compared, methodology used and the atmospheric lifetime assumed.

5.4. Meta-Analysis

Meta-analysis is the study of multiple studies to synthesize conclusions. This section addresses three different kinds of meta-analysis related to methane emissions.

The first study, by Heath et. al.[32], compares the greenhouse gas emissions from shale and conventionally-produced natural gas or coal by analyzing eight peer-reviewed LCA studies reporting ten original estimates of life-cycle GHG emissions from the use of shale gas for electricity generation. These studies have emission estimates ranging from about 440 to 760 g CO_2e/kWh for shale gas due to different assumptions, comparison baselines, and system boundaries (the definition of which upstream operations are included). The report normalizes and compares the emission estimates across the different studies through a process called "harmonization." The result is an analytically-consistent comparison of life-cycle GHG emissions for electricity (on a per unit electrical output basis) from shale gas, conventionally produced natural gas, and coal. The harmonization process consists of normalizing emissions to a consistent metric of grams carbon dioxide-equivalent per kilowatt-hour of electrical output (g CO_2e/kWh) and adjusting the estimates to use the same assumptions (such as GWP) where possible.

The main conclusions are that the median estimates of GHG emissions from shale gas-generated electricity are close to those from conventional gas, while the emissions from shale gas-generated and conventional natural-gas generated electricity are almost half that of electricity from coal. Although the harmonization process results in greater consistency across the reports, there are still differences between the studies that have not been taken into account, such as gas type and gas play assessed, evaluation year, methane leakage rate, the inclusion of co-products, as well as the variability between the assumed emission rates from different parts of the natural gas supply chain. The analysis also indicates that the Howarth study is an outlier relative to the other studies, even after the harmonization.

Another meta-analysis was done by Brandt et. al. in 2015[33]. This study reviewed 20 years of "top-down" and "bottom-up" studies of methane emissions from the natural gas industry. The study concluded that "(i) measurements at all scales show that official inventories consistently underestimate actual CH4 emissions, with the NG [natural gas] and oil sectors as important contributors; (ii) many independent experiments suggest that a small number of "super-emitters" could be responsible for a large fraction of leakage; (iii) recent regional atmospheric studies with very high emissions rates are unlikely to be representative of typical NG system leakage rates; and (iv) assessments using 100-year impact indicators show system-wide leakage is unlikely to be large enough to negate climate benefits of coal-to-NG substitution." The study also highlighted the difficulty of disaggregating methane emissions from natural gas operations versus those from other sources. The study estimated that methane emissions from all sources were 1.25 to 1.75 times higher than the EPA *Inventory* at that time, though again it is difficult to determine how much is from natural gas operations. It should be noted that much of the data used in the study was from older studies, prior to the recent adoption of voluntary and required emission reduction actions.

The third type of study is yet a different kind of meta-analysis, perhaps better described as an "integrative analysis". In two studies coordinated by EDF, the researchers attempted to reconcile the direct measurement and ambient measurement approaches for a specific area through a set of coordinated direct and ambient measurements at the same time in a single region: the Barnett shale region in Texas. This effort was coordinated with a detailed inventory and analysis of all of the methane sources in the region (oil, gas, and other). Data from five EDF direct measurement studies were combined with airplane measurements, and ground-based ambient measurements. The researchers were able to reconcile the direct measurements and ambient measurements accounting for all of the different methane sources.

Using results from both top-down and bottom-up studies, the earlier analysis by Harriss et al[34], estimated 50% greater methane emissions from oil and gas operations in the Barnett shale region than calculated based on the EPA *Inventory* at that time. The largest contributor to this higher estimate was a much larger population of large gathering system compressors than estimated in the EPA *Inventory*. (The subsequent revision in the 2016 EPA *Inventory* has increased the estimated emissions from gathering systems so these estimates are likely more aligned.) A secondary factor was higher emission factors for gas production sites. The study also found that Barnett shale oil and gas emissions account for 1.2% (1.0-1.4%) of gas production volume. Excluding oil production site emissions, the natural gas emissions rate of production decreased to 1.1% (1.0-1.3%) of gas produced.

In a second study using the same data, Zavala-Araiza, et al[35] used a different statistical method to estimate the distribution of super-emitters, resulting in a higher emissions estimate, 90% higher than a calculation based on the EPA *Inventory* and equal to 1.5% of production. The study estimated that at any one time, 2% of the facilities were responsible for half the emissions and

10% were responsible for 70% of the emissions. The studies were focused only the Barnett producing region and emission patterns are likely different in other producing regions.

The Barnett region studies are potentially the most useful of these studies because they are based on new, direct measurement data and attempt to reconcile it with data on other sources of methane. Some of this information has already been incorporated into the 2016 EPA GHG *Inventory*, which could result in better alignment between the *Inventory* and the measurement studies. That said, work remains to be done to understand the distribution of super-emitters and their effect on overall emissions. Extending a similar analysis to other regions would be a useful comparison and verification of the approach and results, but would likely require a coordinated and intensive measurement campaign.

6. Efforts to Reduce Methane Emissions

Since methane is the primary constituent of natural gas, reducing methane emissions through recovery of otherwise lost gas can often result in savings that improve industry profitability. Thus there has always been an incentive to reduce and capture emissions and in some parts of the industry, companies have made emission reductions part of their operating procedures. For example, companies were already using reduced emission completions (REC) prior to the 2012 regulations requiring its use. Avoiding and reducing methane emissions is also a safety issue in many cases, and companies have invested large amounts of capital for safety programs that have also reduced emissions. Beyond these safety and operational drivers however, companies have participated in voluntary programs focused specifically on reducing methane emissions. More recently, state and federal regulators have started to promulgate regulations specifically focused on methane emission reductions. This chapter addresses both voluntary and regulatory programs.

6.1. Federal Voluntary Programs

6.1.1. The Natural Gas STAR (NGS) Program

The NGS Program is a voluntary partnership established by the EPA in 1993 that encourages domestic and international oil and natural gas companies to implement "proven and cost-effective technologies and practices that improve operational efficiency and methane emissions[36]." The program focuses on studying and reducing emissions from the exploration and production, gathering and processing, and transmission, storage, and distribution segments of the natural gas industry. Through this program, companies share experience, know-how, and success stories for methane reduction. The techniques are documented at the EPA Gas STAR website to spread the knowledge and encourage other companies to implement the techniques. Companies report and track their reductions through the program. Since the program began, the EPA estimates that 109 domestic partners have eliminated 1.15 trillion cubic feet of methane emissions by adopting roughly 150 technologies and mitigation practices.[37]

6.1.2. Natural Gas STAR International and the Global Methane Initiative (GMI)

The NGS Program was opened up to interested international members in 2006, and has helped support international companies to mitigate 98 billion cubic feet of methane emissions to date through the Natural Gas STAR International Program. The GMI was launched in 2004 and established a commitment between the United States and 13 other countries to advance cost-effective methane recovery/use in five main methane emission sources: agriculture (animal waste management), coal mining, landfill, municipal wastewater, and the oil and gas sectors. For the oil and gas value chains, participation in GMI is under the NGS International program, which applies partnership goals/programs established in the domestic Natural Gas STAR program to international oil and gas sectors sector operations. The GMI has helped support international companies to mitigate 77.8 billion cubic feet of methane emissions[38]. Voluntary industry participation and support of the both the NGS domestic and international programs has spurred further federal efforts to work with industry on methane emissions, including the NGS Methane Challenge Program (described below).

6.1.3. The Climate and Clean Air Coalition (CCAC) Oil and Gas Methane Partnership (OGMP)

The CCAC OGMP is a voluntary partnership between industry and government launched in 2014, whose goals include better understanding of methane emissions in the oil and gas industry, continued systematic emissions reduction, and the creation of a platform to demonstrate leadership in reduction practices to the public and other stakeholders. The program is organized under the United Nations Environmental Programme joined in the U.S. by the EPA and State Department. The seven founding oil and gas companies of the CCAC Oil and Gas Methane Partnership include BG-Group, ENI, PEMEX, Southwestern Energy, Statoil, PTT, and Total[39].

The CCAC OGMP serves as a forum for knowledge-sharing between industry partners and representatives of prominent national/international methane reduction programs, including the Environmental Defense Fund, the U.S. EPA (Natural Gas STAR Program and Global Methane Initiative), and the World Bank's Global Gas Flaring Reduction Program[40]. Industry members' actions in the program include identification of emissions for nine core emission sources in upstream operations, evaluation of cost-effective emission control technology for "uncontrolled" emission sources, and sharing of project survey reports and emission reduction successes/findings. In partnering with CCAC, industry members are contributing towards CCAC's "next steps," which aim to establish international standards for emission reduction control in the oil and gas industry[41].

6.1.4. Natural Gas STAR Methane Challenge Program ("Methane Challenge")

In March of 2016, the U.S. EPA launched a new voluntary methane emissions reduction program, called "Methane Challenge" [42]. The new program is described as a "platform for leading companies," in promoting cost-effective methane emissions reduction from the oil and gas industry. As part of the program, industry partners will set specific emission reduction goals and track progress through federal emission reporting requirements (Subpart W of the Greenhouse Gas Reporting Program). Collective goals of this program include "ambitious commitments" on the part of industry members and "transparency," thereby promoting public sharing of accomplishments and progress. The program will allow participants to focus their commitment on one or more sources and select from Best Management Practice mitigation options for each source. Companies will set the target year for company-wide implementation of best practices (within five years of start date), and establish the timeframe for implementation and relevant milestones. An alternative participation option through the One Future program is also envisioned (See Section 6.2.2). While the program has launched with over 30 participants, some aspects of the structure are still being refined.

6.2. Industry Voluntary Programs

6.2.1. The Center for Sustainable Shale Development (CSSD)

The CSSD is a nonprofit organization consisting of industry partners and non-governmental environmental organizations whose objective is to set and achieve industry-leading environmental performance standards for developing shale resources in the Appalachian Basin. The CSSD's performance standards address well construction, water, waste, and conventional pollutants as well as methane emissions. The methane standards address flaring limitations, use of green completions, and storage tank emission controls[43]. The performance standards incorporated by CSSD partners were developed to achieve greater results than those established by both state and federal government requirements/standards. CSSD standards are to undergo a process of continuous improvement, through collaborative efforts with stakeholders including: operators, regulators, CSSD auditors, and environmental groups to ensure they continue to drive leading practices[44]. CSSD partners include the Benedum Foundation, Chevron, Clean Air Task Force, CONSOL Energy, Environmental Defense Fund, EQT Corporation, Group Against Smog and Pollution, Pennsylvania Environmental Council, and Shell.

6.2.2. Our Nation's Energy Future Coalition (ONE Future)

ONE Future is a coalition of companies in the natural gas sector that are committed to "identifying policy and technical solutions that yield continuous improvement in the management of methane emissions associated with the production, processing, transmission, and distribution of natural gas[45]." Members of ONE Future include: Southwestern Energy Company, AGL Resources, Hess Corporation, Apache Corporation, Kinder Morgan, Inc., BHP Billiton, Columbia Pipeline Group, and National Grid. ONE Future member companies are committed to reducing methane emissions from their operations across the natural gas supply chain, thereby increasing operational efficiency and process cost effectiveness. ONE Future aims to achieve 99% efficiency in the natural gas supply chain, defined as "achieving an average rate of methane emissions across the entire natural gas value chain that is one percent or less of total natural gas production[46]." ONE Future members base this target on factors including: feasibility/cost effectiveness of this emissions reduction target using existing technologies and practices, and scientific findings that advance this emission reduction goal for greenhouse gas reduction benefits[47].

6.3. Federal and State Regulations

The Obama Administration in 2014 issued an Executive Order focusing on reductions of methane from all sources. In January 2015, the Obama Administration expressed a policy commitment to take action to reduce methane emissions from the oil and gas industry by 40-45% from 2012 emission levels by 2025 through a variety of regulatory and non-regulatory actions[48]. The primary regulatory focus is through regulation by the EPA. Though not described here, other federal regulatory efforts aimed at reducing emissions from oil and natural gas operations include the Department of Interior's Bureau of Land Management's (BLM) proposed standard to reduce emission from oil/gas wells on public lands[49], the Department of Transportation (Pipeline and Hazardous Materials Safety Administration) new research into pipeline safety (including better detection of leaks/methane fugitives)[50], and the Department of Energy's (DOE) research and support for emissions reduction from transportation and distribution infrastructure.

Under the Clean Air Act, the U.S. EPA is responsible for establishing air quality standards, including emission standards known as "New Source Performance Standards (NSPS) for "new and modified stationary pollution sources in source categories that significantly endanger public health or welfare[51]." In recent years, the EPA has used these provisions to indirectly and directly regulate methane emissions from the natural gas industry.

6.3.1. NSPS, Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution (2012)

The Clean Air Act requires the EPA to issue regulations to reduce specified air pollutants from industry sources under the NSPS program. The NSPS identifies specific control requirements for new and modified emission sources. On April 17, 2012, the EPA issued NSPS OOOO ("Quad O") to address pollutants from oil and gas industry sources including gas well completions, pneumatic controllers, leaks from gas processing plants, sweetening units at processing plants, reciprocating compressors, centrifugal compressors, and storage vessels. NSPS OOOO regulates volatile organic compounds (VOCs) and sulfur dioxide emissions from the oil and natural gas industry, but not methane. However, methane emissions are reduced as a co-benefit of the VOC reductions resulting from this regulation. Perhaps the most significant component of the new rule was the requirement to reduce emissions from completion flowback at hydraulically fractured wells by use of flaring or capturing the gas through reduced emission completions (REC).

The final updates and clarifications to the 2012 NSPS OOOO rules were issued on December 19, 2014. These standards were expected to decrease VOC emissions by 95% from "more than 11,000 new hydraulically fractured gas wells each year[52]." While the regulations do not directly address methane, the methane is contained in the same gas streams as the VOCs, so the regulations have the co-benefit of reducing methane as well as VOCs. Table 6-1 provides an overview of the VOC NSPS OOOO for processes and equipment at natural gas facilities[53].

Table 6-1 – Overview of NSPS OOOO Provisions

Affected Facility	Standards Overview
Hydraulically fractured wildcat and delineation wells	Route flowback emissions to completion combustion device
Hydraulically fractured low pressure wells, non-wildcat and non-delineation wells	Route flowback emission to completion combustion device
All other hydraulically fractured gas wells	Route flowback emissions to completion combustion device
All other hydraulically fractured gas wells	Use REC and route flowback emissions to completion combustion device
Centrifugal compressors with wet seals	Reduce emissions by 95%
Reciprocating compressors	Change rod packing after 26,000 hours or after 36 months
Continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants	Natural gas bleed rate of 0
Continuous bleed natural gas-driven pneumatic controllers with a bleed rate greater than 6 scfh between wellhead and natural gas processing plant	Natural gas bleed rate less than 6 scfh
Storage vessels with VOC emissions equal to or greater than 6 tpy	Reduce emissions by 95%
Equipment leaks at onshore natural gas processing plants	Leak Detection and Repair program (LDAR)
Sweetening units at onshore natural gas processing plants	Reduce SO_2 emissions based on sulfur feed rate and sulfur content of acid gas

Source: EPA

6.3.2. NESHAP, Subpart HH – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities (2012)

Along with NSPS OOOO, the EPA revised the NESHAP Subpart HH. The NESHAP rules include emission reduction targets for compounds classified as hazardous air pollutants (HAPs)[54]. NESHAP Subpart HH regulations require emissions control from sources including equipment leaks, storage vessels, and glycol dehydrators, to reduce BTEX (benzene, toluene, mixed xylenes, ethylbenzene) and n-hexane from oil and natural gas production, transmission and storage facilities. As with NSPS Subpart OOOO, the NESHAP regulations do not directly regulate methane emissions, though there will be a similar co-benefit reduction in methane emissions.

The NESHAP Subpart HH regulations outlined in Table 6-2 are those regulations that are specifically applicable to natural gas production, and describe HAP emission standards for glycol dehydrators and equipment leaks. The most recent changes to these standards were summarized by the EPA and are shown below:

Table 6-2 - Summary of NESHAP HH Requirements

Affected Source	Nature of Change	Standard
Small glycol dehydrators	Established MACT standards for previously unregulated source	BTEX emission limit: New sources – 4.66 x 10^{-6} g/scm[1]-ppmv[2] Existing sources – 3.28 x 10-4 g/scm-ppmv
Associated equipment	Revised definition to exclude all storage vessels	N/D
Valves – equipment leaks	Revised definition of leak	Leak Detection and Repair (LDAR)[3] for valves must be applied at 500 ppm
All affected sources	Eliminated exemption from compliance during periods of startup, shutdown and malfunction	Standards apply at all times

Source: EPA

6.3.3. NSPS Proposed Regulations OOOOa (2015)

On August 18, 2015, the EPA proposed updates to NSPS Subpart OOOO for oil and gas operations to further reduce methane and VOC emissions for new and modified sources in the oil and gas industry. EPA has proposed creating NSPS OOOOa, which would regulate methane directly as a pollutant. NSPS OOOOa proposes emission standards for new methane emission sources not currently covered by the NSPS, as well as methane emission rules for emission sources that are currently covered by NSPS for VOCs[55]. The new rules have a basis in a set of EPA technical white papers, which cover specific emission sources such as compressors, hydraulically fractured oil well completions and associated gas, leaks, liquids unloading, and pneumatic devices[56].

Specifically, NSPS OOOOa proposes emission or compliance standards for the following:

- Pneumatic controllers and compressors at natural gas transmission/storage;
- Hydraulically fractured oil wells and gas wells;

[1] Standard cubic meters
[2] Parts per million by volume
[3] Leak Detection and Repair

- Leak detection for well sites, gathering and boosting stations and transmission compressor stations;
- Natural gas-driven pneumatic pumps from all segments, if a control device is already present (zero emissions from processing); and
- Performance testing and monitoring of control devices used to control storage vessel emissions[57].
- Minimum of annual leak surveys with optical gas imaging on perhaps 1,000 compressor station component parts and, depending on the results of those surveys, leak repairs to be made within 15 days of detection, regardless of leak size.

Stakeholders have submitted comments and a final rule is expected in 2016.

6.3.4. NSPS for Existing Sources

On March 10, 2016, the EPA announced its intent to regulate methane emissions from existing facilities in the oil and gas industries. This would be accomplished under section 111(d) of the Clean Air Act NSPS provisions. The first step in this initiative will be a formal process to require companies operating existing oil and gas sources to provide information through an Information Collection Request (ICR) to assist in the development of comprehensive regulations to reduce methane emissions. The ICR process is expected to take at least one year, which will be followed by the regulatory development process.

6.4. State Regulation of Methane Emissions

Several states have issued regulations and/or guidance on methane emissions from oil and gas operations with varying levels of methane-specificity and stringency. The majority of states do not include language specific to reduction of methane in existing regulations. The most notable exception to this generalization is Colorado, which became the first state to regulate methane emissions directly as a GHG. Colorado's rules for methane emissions are in the Colorado Department of Public Health and Environment's Regulation Number 7, "Control of Ozone Via Ozone Precursors And Control of Hydrocarbons Via Oil and Gas Emissions[58]." The state's rules include provisions for emissions-type/equipment/processes in the upstream parts of the industry, including:

- Associated gas;
- Centrifugal compressor seals (wet and dry);
- Above ground equipment fugitive emissions;
- Flares;
- Gas-driven pneumatic controllers;
- Glycol Dehydrators;
- Hydrocarbon storage tanks;
- Liquids unloading events;
- Rod-packing on reciprocating compressors; and

- Gas well completion

Pennsylvania has also been an early actor in regulating methane emissions. Since February 2013, Pennsylvania has regulated CH_4 emissions from compressor stations through the revised General Permit 5 (GP-5). This general permit for non-major sources establishes requirements for reducing emissions including CH_4 and VOC emissions from new sources, and contains terms and conditions requiring periodic inspection, a Leak Detection and Repair (LDAR) program, performance testing, and recordkeeping and reporting obligations for affected owners and operators. Pennsylvania's current LDAR program requires operators to conduct LDAR inspections monthly using audible, visual, and odor detection methods. Pennsylvania is evaluating additional requirements through GP-5 and other regulations.

Though not directly regulating methane, several states regulate VOC emissions from oil/gas operations, which result in reduction of methane emissions, depending on the regulated process/equipment and process/equipment operating conditions. Several other states are developing regulations related to methane emissions. Several states have also passed legislation or regulation related to methane emissions from distribution systems.

- California Senate Bill No. 1371 was passed on September 21, 2014 and outlines rules and procedures "governing the operation, maintenance, repair, and replacement of commission-regulated gas pipeline facilities that are intrastate transmission and distribution lines to minimize leaks." The objective of the bill is to reduce natural gas emissions from gas facilities to support achievement of the greenhouse gas reductions outlined in the California Global Warming Solutions Act of 2006. This Act aims to decrease California's GHG emissions to 1990 levels by 2020, which amounts to a 15% reduction. The bill requires gas companies to file a report that summarizes: utility leak management practices, a list of new methane leaks in 2013 by grade, a list of open leaks that are being monitored or are scheduled to be repaired, and a best estimate of gas loss due to leaks. In addition, the bill states that "it would require the commission to commence a proceeding by January 15, 2015 to adopt these rules and procedures." This proceeding is in progress.
- Oregon Bill No.844 was passed by the Oregon State Senate on June 19, 2013, and was signed by the governor on July 1, 2013.The bill states that "the PUC shall establish a voluntary emission reduction program for the purposes of incentivizing public utilities that furnish natural gas to invest in projects that reduce emissions and providing benefits to customers of public utilities that furnish natural gas."
- Massachusetts Bill No. 4164 was passed on June 13, 2012 and applies to intrastate pipelines and gathering lines. While it does not specifically focus on emissions, the bill outlines a natural gas leak classification system and a priority repair system. The bill also requires gas companies to prioritize the repair of gas leaks within school zones, which is defined as any area within "50 feet of any school property." In addition, the gas companies have to annually report the location of all these leaks to the Department of Public Utilities. Gas companies may also file a Gas System Enhancement Plan (GSEP),

which outlines their plan for replacing leak-prone infrastructure within 20 years, which includes infrastructure constructed from non-cathodically protected steel, cast iron, and wrought iron. The Department of Public Utilities is responsible for evaluating the progress and the reporting made by the gas companies regarding their GSEPs.

7. Conclusions

The main conclusions of this review include:

- Natural gas has the lowest direct emissions of CO_2 of all fossil fuels as well as lower emissions of conventional pollutants.
  - The contribution of natural gas to reducing CO_2 and other criteria pollutants is an important consideration when analyzing natural gas emissions of methane.
- Recent development of North American shale gas resources has increased the availability and reduced the price of natural gas.
- Methane makes up more than 95% of delivered natural gas as used in homes and businesses. Methane is a greenhouse gas that has a climate-forcing effect 28 to 36 times greater than CO_2 according to the most recent global warming factors adopted by the International Protocol on Climate Change. Methane's lifetime in the atmosphere is about 12 years.
- Methane from natural gas is a concern as a GHG if it is emitted directly to the atmosphere without combustion. However when natural gas is efficiently combusted to produce energy and heat, its methane emissions are very small.
- The U.S. EPA *Inventory of Greenhouse Gases* is the official inventory of U.S. GHG emissions and the only economy-wide, national inventory. Its most recent estimate is that methane emissions from the gas industry were 2.6% of total U.S. GHG emissions and 1.4% of the methane in U.S. natural gas produced in 2014.
  - The EPA *Inventory* is based in large part on emission factors from the 1990s. The 2016 edition incorporated new information from recent studies discussed in this report. The estimate of emissions from production increased due to more recent data on equipment counts and the number of compression facilities for gathering systems. The estimates for transmission and distribution declined based on recent information reflecting reduced emissions in those segments. Overall, the estimate of emissions increased by 12% due to the revisions.
  - According to the EPA *Inventory*, methane emissions per unit of gas produced have been declining continuously since the early 1990s despite increased production and use. Absolute emissions declined by 15% between 1990 and 2014. Reasons for the decline include: turnover and replacement of equipment, voluntary actions by industry to reduce natural gas emissions, and the co-benefit of recent regulations targeting VOC reductions.
  - Methane emissions per unit of gas produced have declined by 43% between 1990 and 2014.
- Increased use of natural gas to replace coal in the power sector has resulted in CO_2 emissions dropping by 8% between 2008 and 2015.

- Interest in methane emissions from the gas industry has resulted in an increase in research and new information on this topic, albeit with some differing and sometimes conflicting conclusions. The studies surveyed for this report were divided into four categories:
  - **Direct measurement** studies of emissions from gas operations show that some sources and facilities have emissions lower than the factors in the EPA *Inventory* but a small number of sources – "super-emitters" – dominate the emission profile. They also show that some segments and source categories have been under-represented in the *Inventory*, although this has been largely addressed in the most recent publication.
  - **Ambient air measurement** studies show a range of results – from locally higher methane emissions than in the EPA *Inventory* to much lower emissions. The results are affected by a variety of uncertainties including weather, other sources of methane, and estimates of gas production in the regions being measured. This comparison also needs to be reevaluated in light of the recent modifications to the *Inventory* estimates.
  - Two recent **meta-analyses** of a systematic effort to reconcile simultaneous top-down and bottom-up measurements theorized that methane emissions in one major gas-producing region could be 50% to 90% higher than the estimates based on EPA calculations. The analyses attributed this difference in estimates to an under-representation of sources in the EPA estimate and the influence of super-emitters. The former has been at least partially addressed in the most recent EPA *Inventory*.
- The most detailed and authoritative life-cycle analyses show that the life-cycle emissions of natural gas are 40 to 50% lower than coal on a 100-year GWP basis.
- The gas industry is continuing to reduce methane emissions through voluntary actions and in response to regulation by the federal and state governments.

8. Appendix

This Appendix summarizes 75 recent studies related to methane emissions from the natural gas industries. The studies are listed chronologically, from oldest to most recent.

1) A Commitment to Air Quality in the Barnett Shale. The Texas Commission of Environmental Quality. (May 2010). Published online by the TCEQ.

Texas Commission on Environmental Quality studied air emissions in the Barnett Shale region near Dallas-Fort Worth. They concluded that that emissions levels were less than public health limits.

2) Southwestern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report. Pennsylvania Department of Environmental Protection, Bureau of Air Quality. (November 2010). Published online by the PDEP.

Since 2005, natural gas exploration activities in the Marcellus Shale Formation have increased significantly in the Commonwealth of Pennsylvania. The Pennsylvania Department of Environmental Protection (PA DEP or Department) launched a short-term, screening level air quality sampling initiative in the southwest region in April 2010; the project was completed in August 2010. This report provides findings of the air sampling surveys in Greene and Washington counties; background air samples were collected in Washington County. The key findings are as follows:

- Short-term sampling did detect concentrations of certain natural gas constituents including methane, ethane and propane, and associated compounds such as benzene, in the air near Marcellus Shale drilling operations.
- Most of the compounds were detected during short-term sampling at two compressor stations in Greene and Washington counties.
- Certain compounds, mainly methyl mercaptan, were detected at levels which generally produce odors.
- Results of the limited ambient air sampling initiative conducted in the southwest region did not identify concentrations of any compound that would likely trigger air-related health issues associated with Marcellus Shale drilling activities.
- Sampling for carbon monoxide, nitrogen dioxide and ozone, did not detect levels above National Ambient Air Quality Standards at any of the sampling sites. The Department has not yet determined if the potential cumulative emissions of these pollutants from many natural gas exploration activities will result in violations of the health and welfare-based federal standards.
- A specialized infrared camera that can detect emissions of certain pollutants from a source that otherwise may be invisible to the naked eye, did detect fugitive emissions from sources at the Energy Corp. Compressor Station. These emissions could contribute to the ambient concentrations detected at the site.

3) Northeastern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report: Pennsylvania Department of Environmental Protection, Bureau of Air Quality. (January 2010). Published online by the PDEP.

In response to the increased number of well sites and concerns about the impact of the Marcellus Shale natural gas development activities on air quality, the Pennsylvania Department of Environmental Protection (PA DEP or Department) launched a short-term, screening- level air quality sampling initiative in the northeast region in August 2010 culminating in October 2010. The key findings of the short-term air sampling surveys are follows:

- Concentrations of certain natural gas constituents including methane, ethane, propane and butane, and associated compounds, in the air near Marcellus Shale drilling operations were detected during the four sampling weeks.
- Elevated methane levels were detected in the ambient air during short-term sampling conducted at two compressor stations (the Lathrop and Teel compressor stations) and two well sites (Carter Road and Loomis well sites).
- Certain compounds, mainly methyl mercaptan, were detected at levels which generally produce odors.
- Results of the limited ambient air sampling initiative in the northeast region did not identify concentrations of any compound that would likely trigger air-related health issues associated with Marcellus Shale drilling activities.
- Sampling for carbon monoxide, nitrogen dioxide, sulfur dioxide and ozone, did not detect concentrations above National Ambient Air Quality Standards at any of the sampling sites. However, the Department is unable to determine at this time whether the potential cumulative emissions of criteria pollutants from natural gas exploration activities will result in violations of the health and welfare-based federal standards.
- A specialized infrared camera that can detect emissions of certain pollutants from a source that otherwise may be invisible to the naked eye, did detect fugitive and direct emissions from the well equipment at the Carter Road well.

4) Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations: Robert Howarth and Anthony Ingraffea. (June 2011). Climate Change: Volume 106, Issue 4, pages 679-690.

This study uses emissions estimates from prior investigations to conclude that the lifecycle GHG footprint of shale gas is at least 20% greater than coal and perhaps more than twice as large on a 20-year basis; the lifecycle emissions associated with shale gas production were also found to be larger than conventional gas. The report states, "3.6% to 7.9% of the methane from shale gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas[59]." The study concludes that “substituting shale gas for other fossil fuels (oil or coal) may not have the desired effect of mitigating climate warming[60],” and cites, “we urge more direct measurements and refined accounting to better quantify for lost and unaccounted for gas[61].”

5) Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development: Robert Howarth and Anthony Ingraffea. (June 2011). Published online by Cornell University.

This study analyzes the indirect emissions of carbon dioxide associated with shale gas development without direct measurement, focusing on the Marcellus shale region. The study concludes that "methane dominates the GHG footprint of shale gas, at least when viewed over the 20-year time horizon[62]." “Our estimated indirect CO_2 emissions from shale gas are 0.04 to 0.45 g C/MJ greater than that reported for conventional gas (Woods et al., 2011). Still, a far greater part of the GHG footprint of shale gas comes from methane venting and leakage (Howarth et al., 2011)[63]." "The indirect CO_2 emissions from developing shale gas are not trivial, but they are small compared to direct CO_2 emissions as the gas is burned. A far greater part of the greenhouse gas footprint of shale gas comes from methane venting and leakage[64]." The largest component of indirect CO_2 emissions was found to come from production engines (0.59 g C/MJ).

6) City of Fort Worth Natural Gas Air Quality Study: Eastern Research Group, Sage Environmental Consulting. (July 2011). Published online by the EPA.

"In this study [2010], air pollution levels of nearly 140 pollutants (including over 40 Hazardous Air Pollutants - HAPs - were measured over a two month period with ambient monitoring stations at eight different locations in Fort Worth[65]." The report estimated total city-wide methane emissions/year to be 19,030 tons/year (0.9 Bcf/year). The report recommended emission mitigation efforts to reduce air pollution from natural gas production operations in the area; including: 1.) installing vapor recovery units on storage tanks, 2.) using electricity to power compressor engines; and 3.) installing low bleed or no bleed pneumatic valve controllers. The report states “this study did not reveal any significant health threats beyond setback distances[66]."

7) Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas. Jiang et. al. (August 2011) Environmental Research Letters: Volume 6, Number 3.

This study estimates the life-cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compares its emissions with national average U.S. natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. The study estimates that the development and completion of a typical Marcellus shale well results in roughly 1.8 g CO_2e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life-cycle emissions when combustion is included. Green completion and capturing the gas for market that would otherwise be flared or vented, could reduce the emissions associated with completion and thus would significantly reduce the largest source of emissions specific to Marcellus shale preproduction. Natural gas from the Marcellus shale has generally lower life-cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability.

8) Coal to Gas: Influence of Methane Leakage. Tom Wigley. (August 2011)
Climate Change: Volume 108, Issue 3, pages 601-608

This study finds that methane emissions from the oil and gas sectors offsets the reductions associated with the transition of coal to natural gas-generated power. The study report states: "Our results show that the substitution of gas for coal as an energy source results in increased rather decreased global warming for many decades - out to the mid-22nd century for the 10% leakage case. This is in accordance with Hayhoe et al. (2002) and the less well-established claims of Howarth et al. (2011) who based their analysis on Global Warming Potentials rather than the direct modeling of the climate[67]." Based on analyses performed in the study, the report states, "the temperature differences between the baseline and coal-to-gas scenarios are small (less than 0.1° C) out to at least 2020. The most important result, however, in accord with the above authors, is that, unless leakage rates for new methane can be kept below 2%, substituting gas for coal is not an effective means for reducing the magnitude of future climate change[68]."

9) Mismeasuring Methane: Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development. Mary Marcela, Samantha Gross, and Surya Raja. (August 2011). Published online.

This study states that although natural gas is acknowledged to be the cleanest-burning fossil fuel owing to its low carbon content, attention has recently focused on upstream emissions of methane during well drilling, testing, and completion operations The study concludes that:

- EPA’s current methodology for estimating gas field methane emissions is not based on methane emitted during well completions, but paradoxically is based on a data sample of methane captured during well completions.
- The assumptions underlying EPA's methodology do not reflect current industry practices. As a result, its estimates of methane emissions are dramatically overstated and it would be unwise to use them as a basis for policymaking. The recent Howarth study on methane emissions makes similar errors.
- If methane emissions were as high as EPA and Howarth assume, extremely hazardous conditions would be created at the well site. Such conditions would not be permitted by industry or regulators. For this reason, if no other, the estimates are not credible.
- EPA has proposed additional regulation of hydraulically fractured gas wells under the Clean Air Act. For the most part, the proposed regulations are already standard industry practice and are unlikely to significantly reduce upstream GHG emissions. However,

measured emissions could be significantly lower than EPA-inflated estimates. The greatest benefit of the proposed regulations is likely to be better documentation of actual GHG emissions from upstream natural gas development.

10) The Greenhouse Impact of Unconventional Gas for Electricity Generation. Hultman et. al (October 2011). Environmental Research Letters: Volume 6, Number 4.

New techniques to extract natural gas from unconventional resources have become economically competitive over the past several years, leading to a rapid expansion in natural gas production. In this report, the GHG footprints of conventional natural gas, unconventional natural gas (i.e. shale gas that has been produced using the process of hydraulic fracturing, or 'fracking'), and coal are compared in a transparent and consistent way, focusing primarily on the electricity generation sector. The report shows that electricity generation the GHG impacts of shale gas are 11% higher than those of conventional gas, and only 56% that of coal for standard assumptions.

11) Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure. Alvarez et. al (December 2011). Proceedings of the National Academy of Sciences of the United States: Volume 109, Number 17, pages 6435-6440.

This study proposes that technology warming potentials (TWPs) instead of global warming potentials (GWPs) are a better way to compare the cumulative radiative forcing created by alternative technologies fueled by natural gas and oil or coal. While GWPs are a valuable tool to compare the radiative forcing of different gases, they are not sufficient when thinking about fuel-switching scenarios. TWPs provide a transparent, policy-relevant analytical approach to examine the time-dependent climate influence of different fuel technology choices. In addition, this study shows that while CH_4 leakage from natural gas infrastructure and use remains uncertain, it appears that current leakage rates are higher than previously thought. Because CH_4 initially has a much higher effect on radiative forcing than CO_2, maintaining low rates of CH_4 leakage are critical to maximizing the climate benefits of natural gas fuel-technology pathways.

12) Venting and Leaking of Methane from Shale Gas Development. Howarth et. al (February 2012). Climate Change: Volume 113, Issue 2, pages 537-549

In April 2011, Howarth et. al published the first comprehensive analysis of greenhouse gas (GHG) emissions from shale gas obtained by hydraulic fracturing, with a focus on methane emissions. Howarth's analysis was challenged by Cathles et al. (2012). This report responds to those criticisms, standing by Howarth's initial approach and findings. The paper states that the latest EPA estimate for methane emissions from shale gas falls within the range of the original Howarth estimates but not those of Cathles et al. which are substantially lower. Cathles et al. believe the focus should be just on electricity generation, and the global warming potential of methane should be considered only on a 100-year time scale. The Howarth analysis covered both electricity (30% of U.S. natural gas usage) and heat generation (the largest usage), and evaluated both 20- and 100-year integrated time frames for methane. Using all available information and the latest climate science, Howarth still concludes that for most uses, the GHG footprint of shale gas is greater than that of other fossil fuels on time scales of up to 100 years. When used to generate electricity, the shale-gas footprint is still significantly greater than that of coal at decadal time scales but is less at the century scale according to the paper.

13) Air Sampling Reveals High Emissions from Gas Field. Jeff Tollefson (February 2012). Nature: Volume 482, Issue 7384, pages 139-140.

This article discusses U.S. government scientists sampling of the air from a tower north of Denver, Colorado, and eventually linked the pollution to a nearby natural-gas field. Led by researchers at the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado, Boulder, the study estimates that natural-gas producers in an area known as the Denver-Julesburg Basin are losing about 4% of their gas to the atmosphere — not including additional losses in the pipeline and distribution system. This is more than double the official inventory, but roughly in line with estimates made in 2011 that have been challenged by industry.

14) Press Release: Response to Howarth et al's Reply. Cathles et. al (February 2012). Published online by Cornell University.

In April of 2011 Howarth, Ingraffea and Santoro published online a letter in the journal Climatic Change to argue that coal is a "cleaner" fuel than natural gas in terms of greenhouse gas emissions. This is a commentary on flaws in Howarth's analysis, which can be summarized as:

- Unrealistically high estimates of fugitive emissions associated with unconventional gas production based on a cryptic presentation of relatively few and poor primary sources
- An unsupported and, according to the authors, inappropriate, choice of the time interval for estimating greenhouse impacts of fugitive methane
- A dismissive discussion of new technologies now in use to reduce such emissions
- Comparison of gas to coal on a basis (heat rather than electricity) that is basically irrelevant to evaluation of the relative greenhouse effects of these two options.

15) Assessing the Greenhouse Gas Impact of Natural Gas. L.M. Cathles (June 2012) Geochemistry, Geophysics, and Geosystems: Volume 13, Issue 6.

This study shows that the substitution of natural gas [for coal] reduces global warming by 40% of that which could be attained by the substitution of zero carbon sources. At methane leakage rates that are ~1% of production, which is similar to today's probable leakage rate of ~1.5% of production, the 40% benefit is realized as gas substitution occurs. For short transitions of 40 years, the leakage rate must be more than 10% to 15% for gas substitution not to reduce warming.

16) Climate Impact of Potential Shale Gas Production in the E.U.: Daniel Forster and Jonathan Perks (July 2012). Report for the European Commission Directorate-General for Climate Action. Published online.

The objective of this study was to provide state-of-the-art information to the European Commission on the potential climate implications of possible future shale gas production in Europe. Some studies have concluded that the lifecycle GHG emissions from shale gas may be larger than conventional natural gas, oil, or coal when used to generate heat and viewed over the time scale of 20 years. The majority of studies suggest that emissions from shale gas are lower than coal, but higher than conventional gas, based on other assumptions. This study determined that:

- One of the key assumptions that can influence the scale of emissions estimated in the life-cycle analysis is the assumed management practices and technologies employed at the shale gas extraction site. The use of best practice techniques has the potential to significantly reduce emissions relative to other practices.
- The overview analysis of the EU legal acts identified as relevant to shale gas has shown that there are very few requirements applicable specifically to GHG emissions from shale gas projects.
- In order to ensure the effective control of GHG emissions from potential shale gas development in Europe it is important to ensure that emissions, where they arise, are reported.

17) Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Terri Shires and Miriam Lev-On (September 2012). Published online by the American Petroleum Institute (API) and the America's Natural Gas Alliance (ANGA).

American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) members conducted this study to develop new and better data about natural gas production, because they believe that Environmental Protection Agency's (EPA's) current methane emissions estimates for the natural gas production sector were overstated due to erroneous activity data in several key areas - including liquids unloading, well re-fracturing, centrifugal compressors, and pneumatic controllers. Members worked cooperatively to gather information through two data requests tailored to focus on these areas and collect reasonably accessible information about industry activities and practices. The survey resulted in liquids unloading and unconventional gas well re-fracture rates that are substantially lower than EPA's estimated emissions from natural gas production.

18) Shale Gas Production: Potential Versus Actual Greenhouse Gas Emissions. Francis O' Sullivan and Sergey Paltsev. (November 2012). Environmental Research Letters: Volume 7, Number 4.

This report assesses the level of GHG emissions from shale gas well hydraulic fracturing operations in the United States during 2010. Data from each of the approximately 4,000 horizontal shale gas wells brought online that year is used to show that about 900 Gg CH_4 of potential fugitive emissions were generated by these operations, or 228 Mg CH_4 per well—a figure inappropriately used in analyses of the GHG impact of shale gas. Along with simply venting gas produced during the completion of shale gas wells, two additional techniques are widely used to handle these potential emissions - gas flaring and reduced emissions "green" completions. The use of flaring and reduced emission completions reduces the levels of actual fugitive emissions from shale well completion operations to about 216 Gg CH_4, or 50 Mg CH_4 per well, a release substantially lower than several widely quoted estimates.

19) Comment on "Hydrocarbon Emissions Characterization in the Colorado Front Range" – A Pilot Study. Michael Levi (November 2012). Journal of Geophysical Research: Volume 117, Issue D21.

Petron et al. [2012] have recently observed and analyzed alkane concentrations in air in Colorado's Weld County and used them to estimate the volume of methane vented from oil and gas operations in the Denver-Julesburg Basin. They conclude that the emissions of the species are most likely underestimated in current inventories. Petron et al. study's estimates of methane venting rely on unfounded assumptions about the composition of vented natural gas. This study states that changing the assumptions in the Petron et al. study results in a new set of estimates that are consistent with current inventories but inconsistent with the estimates in Petron et al.

20) Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas. Ian J. Laurenzi and Gilbert R. Jersey (April 2013). Environmental Science & Technology: Volume 47, Issue 9, pages 4896-4903.

The primary goal of this study was to assess GHG emissions over the life-cycle of Marcellus shale gas from the well pad to generation of electricity at a combined cycle gas turbine (CCGT) power plant. The secondary goal of the study was to assess the life-cycle freshwater consumption associated with shale gas. This includes water consumed for (1) hydraulic fracturing and (2) evaporative cooling at the power plant where the gas is used. Results indicate that a typical Marcellus gas yields 466 kg CO2eq/MWh (80% confidence interval: 450−567 kg CO2eq/MWh) of greenhouse gas (GHG) emissions and 224 gal/MWh (80% CI: 185−305 gal/MWh) of freshwater consumption. Operations associated with hydraulic fracturing constitute only 1.2% of the life-cycle GHG emissions, and 6.2% of the life-cycle freshwater consumption. These results are influenced most strongly by the estimated ultimate recovery (EUR) of the well and the power and the power plant efficiency: increase in either quantity will reduce both life-cycle freshwater consumption and GHG emissions relative to power generated at the plant.

21) Natural Gas and Climate Change. Eric D. Larson (May 2013). Published online by Climate Central.

Climate Central developed an interactive graphic that makes it easy to visualize the greenhouse benefits of converting power generation from coal to natural gas for different assumptions of methane leak rates and coal-to-gas conversion rates while also considering methane's greenhouse potency over time. The EPA recently estimated methane leaks in the natural gas system at 1.5 percent. A 1.5 percent leak rate would achieve an immediate 50 percent reduction in greenhouse gas (GHG) emissions, at the individual power plant level.

However, according to the article, EPA's estimate contains significant uncertainty, and like all estimates available in the peer-reviewed literature, lacks sufficient real-world measurements to guide decision-making at the national level. Climate Central found that the ongoing shift from coal to gas in power generation in the U.S. is unlikely to provide the 50 percent reduction in GHG emissions typically attributed to it over the next three to four decades, unless gas leakage is maintained at the lowest estimated rates (1 to 1.5 percent) and the coal replacement rate is maintained at recent high levels (greater than 5 percent per year).

22) Redrawing the Energy-Climate Map. Faith Birol et. al (June 2013). World Energy Outlook Special Report. Published online by the International Energy Agency.

The world is not on track to meet the target agreed by governments to limit the long term rise in the average global temperature to 2 degrees Celsius (°C). Despite positive developments in some countries, global energy-related CO_2 emissions increased by 1.4% to reach 31.6 gigatonnes (Gt) in 2012, a historic high. The report identifies four energy policies that can keep the 2 °C target alive:

- Adopting specific energy efficiency measures (49% of the emissions savings).
- Limiting the construction and use of the least-efficient coal-fired power plants (21%)
- Minimizing methane (CH_4) emissions from upstream oil and gas production (18%)
- Accelerating the (partial) phase–out of subsidies

This report also concludes that targeted energy efficiency measures would reduce global energy-related emissions by 1.5 Gt in 2020, a level close to that of Russia today. Ensuring that new subcritical coal-fired plants are no longer built, and limiting the use of the least efficient existing ones, would reduce emissions by 640 Mt in 2020 and also help efforts to curb local air pollution. Methane releases into the atmosphere from the upstream oil and gas industry would be almost halved in 2020, compared with levels otherwise expected. In addition, accelerated action towards a partial phase-out of fossil-fuel subsidies would reduce CO_2 emissions by 360 Mt in 2020 and enable energy efficiency policies. The report also concludes that the energy sector is not immune from the physical impacts of climate change and must adapt, and that the financial implications of stronger climate policies are not uniform across the energy industry and corporate strategy will need to adjust accordingly. Delaying stronger climate action to 2020 would come at a cost: $1.5 trillion in low-carbon investments. Investments would be avoided before 2020, but $5 trillion in additional investments would be required thereafter to get back on track.

23) Leveraging Natural Gas to Reduce Greenhouse Gas Emissions. Center for Climate and Energy Solutions (June 2013). Published online by the Center for Climate and Energy Solutions.

This study states that natural gas is a potent greenhouse gas and the direct release of methane during production, transmission, and distribution may offset the potential climate benefits of its expanded use across the economy. This study concludes that the expanded use of natural gas as a replacement for coal and petroleum can help out efforts to reduce GHG emissions. Along with substituting natural gas for other fossil fuels, direct releases of methane into the atmosphere must be minimized.

24) The President's Climate Action Plan (June 2013). Published online by the Executive Office of the President.

In 2009, the Obama Administration made a commitment to reduce U.S. greenhouse gas emissions in the range of 17 percent below 2005 levels by 2020. This document outlines additional steps the Administration will take – in partnership with states, local communities, and the private sector – to continue on a path to meeting the President's 2020 goal. Achieving this goal includes the following: cutting carbon pollution in America, building a 21st-century transportation sector, cutting energy waste in homes, businesses, and factories, reducing other greenhouse gas emissions, leading at the federal level, preparing the U.S. for the impacts of climate change, and leading international efforts to address global climate change.

25) Measurements of Methane Emissions at Natural Gas Production Sites in the United States. Allen et al. (August 2013). Proceedings of the National Academy of Science of the United States of America: Volume 110, Number 44, pages 17768-17773.

This measurement study indicated that well completion emissions are lower than previously estimated. The data also showed that emissions from pneumatic controllers and equipment leaks are higher than EPA national emission projections. These measurements will help inform policymakers, researchers, and industry, providing information about some of the sources of methane emissions from production of natural gas.

26) Methane Emission Estimates from Airborne Measurements over a western United States Natural Gas Field. Karion et al. (August 2013). Geophysical Research Letters: Volume 40, Issue 16, pages 4393-4397.

This study used atmospheric measurements in a mass balance approach to estimate CH_4 emissions from a natural gas and oil production field in Uintah County, Utah. Gas emissions were determined to be 8.8 ± 2.6% of natural gas production in the Uintah County, Utah natural gas field. This emissions estimate is 1.8 to 3.8 times the inventory-based estimate from this region and five times the U.S. EPA nationwide average estimate of leakage from the production and processing of natural gas. This study demonstrates the mass balance technique as a valuable tool for estimating emissions from oil and gas production regions and illustrates the need for further atmospheric measurements to determine the representativeness of our single-day estimate and to better assess inventories of CH_4 emissions.

27) Anthropogenic Emissions of Methane in the United States. Miller et al. (October 2013) Proceedings of the National Academy of Sciences of the United States: Volume 110, Number 50, pages 20018-20022.

This ambient measurement study estimates anthropogenic CH_4 emissions over the United States for 2007 and 2008 using comprehensive CH_4 observations at the surface, on telecommunications towers, and from aircraft, combined with an atmospheric transport model and a geostatistical inverse modeling (GIM) framework. This study estimates a mean annual U.S. anthropogenic CH_4 budget for 2007 and 2008 of 33.4 ± 1.4 Tg $C\cdot y^{-1}$ or ∼7–8% of the total global CH_4 source. This estimate is a factor of 1.5 and 1.7 larger than Environmental Protection Agency's (EPA's) inventory and the Emissions Database for Global Anthropogenic Research (EDGAR) v4.2, respectively.

28) Improving Methane Emission Estimates for Natural Gas Distribution Companies, Phase II - PE Pipes: Gas Technology Institute: (November 2013). Published online.

The study found the EF for polyethylene (PE) pipes to be 70% less than that estimated in the 1996 EPA/GRI study (a basis for the EPA Inventory EF) – 3.72 scf/leak-hour as opposed to the value of 12.45 scf/leak-hour in the EPA/GRI study. Additionally, when compared to both the EF for Subpart W (2010) and the EPA Inventory (2008), the study identified EFs approximately 77% less for leaks from PE pipes.

29) Why Every Serious Environmentalist Should Favor Fracking. Richard Muller (December 2013). Published online by the Center for Policy Studies.

This report states that shale gas can not only reduce greenhouse gas emissions, but also reduce a pollutant known as PM2.5 that is currently killing over three million people each year, primarily in the developing world. This report also concludes that environmentalists should recognize the shale gas revolution as beneficial to society and lend their full support to helping it advance.

30) Reduced Emissions of CO_2, NOx, and SO_2 from U.S. power plants owing to switch from coal to natural gas with combined cycle technology. NOAA (January 2014).
Earth's Future: Volume 2, Issue 2, pages 75-82.

The aim of this study was to compare emission rates from U.S. power plant electricity generation units for three air pollutants/GHGs (direct or indirect): CO_2, NO_x, and SO_2, using published continuous emission measurement system (CEMS) data. The study concluded that combined cycle power plants using natural gas emit on average 44% less CO_2, compared with coal power plants. A caveat of the study was that these benefits in emission reductions due to switching from coal to natural gas should be "weighed against the increase in emissions of methane, volatile organic compounds and other trace gases that are associated with the production, processing, storage and transport of natural gas."

31) Methane Leaks from North American Natural Gas Systems. Brandt et al. (February 2014) Science. Volume 343, Number 6172, pages 733-735.

This meta-study reported that methane emissions from both the U.S. and Canadian natural gas systems appear larger than official estimates. The study notes four reasons why methane emissions inventories may be under-predicting: 1.) unrepresentativeness of sampled devices with respect to current technologies and practices; 2.) Wide confidence intervals for many EPA factors; 3.) Small sample sizes; and 4.) "Activity and device counts used in inventories are contradictory, incomplete, and of unknown representativeness." The study reports that high methane emitting sources are a major source of emissions from the industry and that methane reduction opportunities exist "if scientists and engineers can develop reliable (possibly remote) methods to identify and fix the small fraction of high-emitting sources."

32) GHG Emissions Associated With Shale Gas: South Africa's Department of Environmental Affairs (February 2014). Published online by the Republic of South Africa.

This study was performed in response to the South African cabinet's decision to pursue research related to hydraulic fracturing in South Africa and its environmental impacts. The country is looking to develop national gas resources and reduce its dependence on coal. The report analyzes emissions estimates from previously performed LCA studies and provides emissions estimates associated with various shale gas end uses (gas to liquids, electricity generation, direct use, and LNG export). The report concludes that the substitution of coal for shale gas for electricity is favorable in terms of GHG emissions reductions. A caveat is made in the report: "Overall, more research is required, particularly on direct measurements of GHG emissions, in order to better understand the GHG emissions intensity of shale gas extraction, production, and use in South Africa ."

33) Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (March 2014) Prepared for Environmental Defense Fund by ICF International

This study developed a marginal abatement cost (MAC) curve for methane reductions from U.S. oil and gas sectors. The study projected methane emissions to 2018 and then identified and characterized available and technically feasible methane reduction technologies to address the largest emitting sectors. The projection estimated that over 90% of emissions in 2018 were from sources that were in place in 2012. Approximately 80% of the projected emissions were from 20 of the over 100 source categories. Industry sources provided information on cost and performance of the technologies. The analysis estimated that methane emissions could be reduced by 40% at a net annualized cost of $0.66/Mcf of methane reduced.

34) Energy Systems Assessment: Intergovernmental Panel on Climate Change (April 2014). Published online by the Intergovernmental Panel on Climate Change.

This report presents and analyzes previously published emissions data/studies. It found that hydraulic fracturing and horizontal drilling have contributed to the reduction of GHG emissions in the United States and mentions that increased natural gas use has spurred discussion of fugitive methane emissions from conventional and shale gas. The study concluded that GHG emissions can be reduced from the power generation sector with replacement of coal-fired power plants with natural gas combined cycle (NGCC) power plants or combined heat and power (CHP) plants, under the conditions that natural gas is available and "fugitive emissions associated with its extraction and supply are low or mitigated ." The report acknowledges gaps in understanding of methane emissions associated with power generation, stating, "There is a gap in our knowledge concerning fugitive CH_4 emissions as well as adverse side effects associated with the increasing exploitation of unconventional fossil fuels."

35) Toward a better understanding and quantification of methane emissions from shale gas development. Robert Howarth and Anthony Ingraffea (April 2014). Climate Change: Volume 106, Issue 4, pages 670-690.

In this study, ambient methane emission measurements were collected from southwestern PA in the Marcellus shale in June 2012. The study identified average methane emissions of 34 g CH_4/s (~1.8 ft^3/s) per well in the drilling phase, identified to be 2 to 3 orders of magnitude greater than the U.S. EPA estimate for this emissions category. The study also estimated the percentage of fugitive methane emissions with respect to natural gas production in the region. The study report states, "Using our top-down flux measurements, the assumed range of methane from natural gas contribution (22-62%), and industry reported production rates, we estimate a possible range for the fugitive methane emission rate of 2.8-17.3% of production in this region, which applies only to these two specific study dates .”

36) National Climate Assessment: U.S. Federal Government Advisory Committee (May 2014). Published online.

Methane emissions from the oil and gas sectors was covered at a high level in this comprehensive federal report on climate change in the U.S. The report was produced from research by 13 U.S. federal departments and agencies, including the EPA, DOE, and DOT. The study reported that increased natural gas consumption could reduce U.S. GHG emissions, compared with use of other fossil fuels. The report states, “as an energy source, natural gas (methane) can have a major advantage over coal and oil; when combusted, it emits less CO_2 per unit energy than other fossil fuels, and fewer pollutants like black carbon (soot) and mercury." The study posits, “There is considerable uncertainty about these estimates, and it is an active area of research. While technological improvements may reduce this leakage rate, leakage makes the comparison between natural gas and coal more complex from a climate perspective.”

37) A New Look At Methane and Nonmethane Hydrocarbon Emissions From Oil and Natural Gas Operations in the Colorado Denver-Julesberg Basin. Petron et al. (June 2014). Journal of Geophysical Research: Volume 119, Issue 11, pages 6836-6852.

This ambient measurement study collected atmospheric samples using aircraft and ground-based methods from “the most densely drilled area” of the Denver-Julesberg Basin in northeastern Colorado. Oil and gas emissions attributed to the region were estimated to be 19.3 t/h, close to 3 times higher than an hourly estimate based on the Environmental Protection Agency's GHGRP data for 2012. The study concluded: "More top-down studies are needed to evaluate (1) hydrocarbon emission inventories for dry gas/wet gas/oil production regions and (2) the actual impacts of emission mitigation regulations and best management practices including Leak Detection and Repair programs[69]."

38) CO_2, Methane, and Brine Leakage Through Subsurface Pathways: Exploring Modeling, Measurement, and Policy Options. Mary Kang (June 2014). Published online.

Methane emission measurements were collected from 19 abandoned oil and gas wells. The study identified between 280,000-970,000 abandoned oil and gas wells in Pennsylvania, based on historical records. The study used measured emissions data and applied rates to the total estimated number of oil and gas wells. “When the mean flux rate from the measured wells is applied to these estimated total number of wells in Pennsylvania, methane emissions are 4 to 13% of currently estimates annual statewide anthropogenic methane emissions[70]." High-emitting abandoned oil and gas well were identified in the study. "Three of the 19 measured wells are high emitters. Because high emitters govern the average flux, more field measurements are needed. Such measurement plans should be aimed at identifying attributes that aid in finding these emitters. Leakage was found to occur in both plugged and unplugged wells[71]." The study states that there is high uncertainty regarding methane emissions from abandoned oil and gas wells due to uncertainties in the number of wells drilled over the years and variability in methane emissions per well. Regarding the fact that abandoned oil and gas wells are not included in any emission inventories, the study states, "This is not surprising since methane emissions from these wells are not included in any emissions inventories, and the implied assumption in abandonment regulations is that leakage will not occur. The result is a lack of information to quantify methane emissions from these wells, which depend on the number of wells and the methane emissions per well. Both of these are uncertain, which makes evaluating the effectiveness of any emissions reduction strategies difficult[72]."

39) Natural Gas Fugitive Emissions Rates Constrained by Global Atmospheric Methane and Ethane. NOAA. (June 2014). Environmental Science & Technology. Volume 48, Issue 14, pages 7714-7722.

This study used a top down approach to estimate a global methane leakage rate as a percentage of production, from an estimated mass balance of methane and ethane emissions in the period 1985-2011. The emissions estimates were based on atmospheric methane and ethane emissions data collected by NOAA as well as data published in literature. The study concluded that emissions from the natural gas value chain are between 2-4%, with a clear downward trend since 2000. This estimate is higher than comparable inventories cited in the report, which estimated a leakage rate of 1.1-3.2%. The researchers stated in the report "A more formal uncertainty analysis of key parameters (atmospheric lifetimes, natural gas emissions and composition), would provide a more detailed characterization of fugitive emission rate uncertainties. This requires composition data by well type (NG, oil) that are not currently available at this level of detail."

40) Evaluation of Impact of Shale Gas Operations in the Barnett Shale Region on Volatile Organic Compounds in Air and Potential Human Health Risks: A.G. Bunch et al. (July 2014) Science of the Total Environment. Volume 468-469, pages 832-842.

The objective of this study was to evaluate community-wide exposures to volatile organic compounds (VOCs) in the Barnett Shale region. The highlights of this study include

- VOCs associated with shale gas were all below health-based comparison values.
- VOCs associated with shale gas showed acceptable chronic risk and hazard.
- Shale gas activities have not resulted in VOC levels that pose health concerns.
- Findings useful for understanding potential health risks in other shale plays.

41) Assessment and Risk Analysis of Casing and Cement Impairment in Oil and Gas Wells in Pennsylvania, 2000-2012: Anthony Ingrafea (July 2014). Proceedings of the National Academy of Sciences of the United States: Volume 111, Number 30, pages 10955-10960.

This study analyzed 75,505 well compliance reports for 41,381 conventional and unconventional gas wells in Pennsylvania drilled in the time period January 2000-December 2012. The aim of the project was to determine statistics regarding incidence of well casing and cement impairment. The study does not provide methane emissions estimates from analyzed wells. Shale gas wells were found to have higher incidence rates of cement and/or casing issues. The report states "Statewide data show a six fold higher incidence of cement and/or casing issues for shale gas wells relative to conventional wells[73]."

42) Harmonization of Initial Estimates of Shale Gas Lifecycle GHG Emissions for Electric Power Generation: National Renewable Energy Laboratory (NREL) (July 2014). Proceedings of the National Academy of Sciences of the United States: Volume 111, Number 31, pages E3167-E3176.

This study used findings/results of previous GHG emissions studies to produce new estimates for lifecycle GHG emissions for electricity produced from shale gas, conventionally produced natural gas, and coal. The study found that nearly 50% less lifecycle GHG emissions were associated with shale gas-generated electricity than power generated from coal. Estimated emissions from a few sources were found to have the greatest influence on lifecycle emissions comparisons: natural gas well completion and re-completion, including hydraulic fracturing, and well liquids unloading. The report recommends that initial emission estimates “be confirmed through methane emissions measurements at components and in the atmosphere and through better characterization of EUR and practices[74]."

43) The effect of natural gas supply on US renewable energy and CO_2 emissions: University of CA, Irvine and Stanford University (August 2014). Environmental Research Letters: Volume 9, Number 9.

This study used natural gas supply modeling for three different types and levels of climate policy (no policy, a moderate carbon tax, and a strict carbon cap) to examine projected characteristics of the U.S. power sector and GHG emissions. The study concluded that “increased natural gas use for electricity will not substantially reduce U.S. GHG emissions, and by delaying deployment of renewable energy technologies, may actually exacerbate the climate change problem in the long term.” The study stated that, “the effect of a more abundant natural gas supply on GHG emissions is so small that the quantity of methane leaked may ultimately determine whether the overall effect is to slightly reduce or actually increase cumulative emissions.”

44) Up in Flames - U.S. Shale Oil Boom Comes at the Expense of Wasted Natural Gas, Increased CO_2: Earthworks: Oil and Gas Accountability Project (August 2014). Published online by Earthworks.

The focus of this report was improved flaring policies in Texas (Eagleford shale formation) and North Dakota (Bakken formation). The study found that ND oil companies have flared more than $854 million of natural gas since 2010. The study makes the following recommendations to reduce flaring: 1. Drillers must have a plan in place to limit flaring before drilling begins; 2 Companies should pay taxpayers full market value for gas that is flared; 3. States should track how much tax drillers pay on flared gas and which drillers are paying; 4. States should implement measures to track the amount of gas flared and vented; 5. Regulators should tighten enforcement on companies that flare illegally in main natural gas producing regions in the U.S.

45) Greenhouse Gas Reporting Program: Environmental Protection Agency (September 2014). Program data available online by the EPA.

The GHGRP is mandated by the U.S. Congress and described in the U.S. Code of Federal Regulations Title 40, Part 98, established by EPA in 2009. This regulation requires operators across various industrial sectors to report GHG emissions from specific emission sources. Reporting requirements for methane emission sources in the oil and gas sectors are described in Subpart W of the federal regulations. The reporting requirements are applicable to facilities that emit 25,000 metric tons or greater of GHG emissions (expressed in CO_2e) across one of the eight oil and gas segments: onshore production, offshore production, natural gas processing, natural gas transmission, natural gas storage, natural gas distribution, liquefied natural gas (LNG) import and export, and LNG storage. In 2014, 2,369 facilities across all oil/gas segments reported a total of 236.1 million metric tons (MMT) of GHG emissions (CO_2e), including methane emissions of 73.0 MMT CO_2e .

46) Remote Sensing of Fugitive Methane Emissions from Oil and Gas Production in North American Tight Geologic Formations. (October 2014). Oliver Schneising et al. Earth's Future: Volume 2, Issue 10, pages 548-558.

This report states that positive methane anomalies associated with the oil and gas industries can be detected from space and that corresponding regional emissions can be constrained using satellite observations. On the basis of a mass-balance approach, this study estimates that methane emissions for two of the fastest growing production regions in the United States, the Bakken and Eagle Ford formations, have increased by 990±650 ktCH4 yr−1 and 530±330 ktCH4 yr−1 between the periods 2006–2008 and 2009–2011. Relative to the respective increases in oil and gas production, these emission estimates correspond to leakages of 10.1% ±7.3% and 9.1% ±6.2% in terms of energy content, calling immediate climate benefit into question and indicating that current inventories likely underestimate the fugitive emissions from Bakken and Eagle Ford.

47) Reducing Methane Pollution from Fossil-Fuel Production on America's Public Lands. Claire Mose, Nidhi Thakar, and Matt Lee-Ashley. (October 2014). Published online by the Center for American Progress.

This publication provides new estimates of methane emissions from energy production on federal lands and waters and cites that flaring activities have significantly increased in the past five years based on review of U.S. Department of Interior (DOI) data. The publication cites that methane emissions may have been as high as 8.1 million metric tons in 2012 (~420 billion cubic feet). The article states, "policymakers have yet to seriously address the larger problem of fugitive methane emissions from energy production on public lands and waters." The article also states that fugitive methane emissions from "well-site processing, production, and other upstream, midstream, and downstream activities" are greater than "even the highest estimates of methane emitted from venting and flaring."

48) Renewables cutting US emissions more than gas as coal consumption drops. Zachary Davies Boren and Lauri Myllvirta. (October 2014). Published online by Greenpeace.

This report presents findings from a new analysis by EnergyDesk, which asserts that "renewable energy, not shale gas, is the biggest cause of the fall in U.S. emissions from coal use." The report states, "Between 2007-13 the US experienced the largest fall in coal usage ever experienced by any country, with renewables, energy efficiency and shale gas together picking up the slack," and that "the data shows that the fall in US coal consumption since 2007 is to a larger extent due to reductions in demand and an increase in renewable generation than to use of shale gas."

49) Limited Impact On Decadel-Scale Climate Change from Increased Use of Natural Gas. Haewon McJeon et al. (October 2014). Nature: Volume 514, Issue 7523, pages 482-485.

The most important energy development of the past decade has been the wide deployment of hydraulic fracturing technologies that enable the production of previously uneconomic shale gas resources in North America. This article states that the climate implications of such abundant natural gas have been hotly debated. Some researchers have observed that abundant natural gas substituting for coal could reduce carbon dioxide (CO_2) emissions. Others have reported that the non-CO_2 greenhouse gas emissions associated with shale gas production make its lifecycle emissions higher than those of coal. This study shows that the market-driven increases in global supplies of unconventional natural gas do not discernibly reduce the trajectory of greenhouse gas emissions or climate forcing. The results, based on simulations from five state-of-the-art integrated assessment models of energy–economy–climate systems independently forced by an abundant gas scenario, project large additional natural gas consumption of up to +170 per cent by 2050. The impact on CO_2 emissions is found to be much smaller (from -2 per cent to +11 per cent), and a majority of the models reported a small increase in climate forcing (from -0.3 per cent to +7 per cent) associated with the increased use of abundant gas. The results show that although market penetration of globally abundant gas may substantially change the future energy system, it is not necessarily an effective substitute for climate change mitigation policy.

50) Four corners: The largest US methane anomaly viewed from space. Eric A. Kort et al. (October 2014). Geophysical Research Letters: Volume 41, Issue 9, pages 6898-6903.

This article summarizes satellite data analysis conducted by NASA and the University of Michigan on methane concentrations in the vicinity of hydrocarbon production sites in the U.S. The article describes that scientists discovered one "hot spot," covering an area of approximately 2,300 square miles near the Four Corners intersection of Arizona, Colorado, New Mexico, and Utah is "responsible for producing the largest concentration of greenhouse gas methane seen over the United States – more than triple the standard ground-based estimate." Specific identified/compared methane concentrations were not cited in the online article.

51) Fifth Assessment Report (AR5): Intergovernmental Panel on Climate Change (November 2014). Published online by the IPCC.

This report publishes updated Global Warming Potentials (GWPs) for GHG gases. The report concludes that "continued emission of greenhouse gases will cause further warming and long-lasting changes in all components of the climate system, increasing the likelihood of severe, pervasive and irreversible impacts for people and ecosystems. Limiting climate change would require substantial and sustained reductions in greenhouse gas emissions which, together with adaptation, can limit climate change risks." Regarding GHG mitigation, the reports posits, "Mitigation options are available in every major sector. Mitigation can be more cost-effective if using an integrated approach that combines measures to reduce energy use and the greenhouse gas intensity of end-use sectors, decarbonize energy supply, reduce net emissions and enhance carbon sinks in land-based sectors."

52) Fracking Fumes: Air Pollution from Hydraulic Fracturing Threatens Public Health and Communities. Tanja Srebotnjak and Miriam Rotkin-Ellman. (December 2014). Published online by the Natural Resources Defense Council.

This report states that there is mounting evidence that air pollution from oil and gas operations threaten the health of nearby communities and immediate protections are needed. They should have the right to protect themselves by restricting or prohibiting these techniques within their jurisdictions. Where possible, ongoing unconventional oil and gas development should be put on hold to conduct comprehensive health assessments before determining whether or how these technologies should be allowed to proceed. In areas already bearing the brunt of fracking-related pollution and with no moratoria, strong safeguards are needed to control emissions and limit pollution.

53) Methane Emissions Decline in Top Oil and Gas Basins. Katie Brown. (December 2014). Published online by Energy in Depth®.

This is an infographic by "Energy in Depth" showing methane emissions decline in top oil and gas basins: Raton Basin (Las Vegas), Andarko Basin, Appalachian Basin, San Juan Basin, Permian Basin, Gulf Coast Basin, and Arkoma Basin. The graphic shows a linear decrease in methane emissions from 2011 to 2013 in what are identified as top oil and gas basins.

54) Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers. David T. Allen et al. (December 2014). Environmental Science & Technology: Volume 49, Number 1, pages 633-640.

For this project, emissions from 377 gas actuated pneumatic devices were measured at natural gas and oil production sites. The study found that higher average emissions per control and average controllers per well than estimated in the 2012 U.S. Inventory. The study concluded that emissions from pneumatic controllers could be 17% higher than the estimate in the U.S. Inventory, based on multiplying the average measured pneumatic controller emission rate by the count of pneumatic devices published in the 2012 U.S. Inventory. The study found that a small subset of devices (19%) accounted for 95% of emissions.

55) Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings. David T. Allen et al. (December 2014). Environmental Science & Technology: Volume 49, Number 1, pages 641-648.

In this study, methane emissions from liquids unloading operations for 107 wells (with and without installed plunger lift systems). The study concluded that "the data suggest that the central estimate of emissions from unloadings are within a few percent of emissions estimated in the EPA GHGI, with emissions dominated by wells with high frequencies of unloadings ." The study found that the majority of wells without plunger lifts unloaded less than 10 times per year with emissions averaging 21,000−35,000 scf methane (0.4−0.7 Mg) per event. For wells with plunger lifts, average emissions were between 1,000−10,000 scf methane (0.02−0.2 Mg) per event.

56) Quantifying Atmospheric Methane Emissions from the Haynesville, Fayetteville, and Northeastern Marcellus Shale Gas Production Regions. J. Peischl et al. (February 2015). Journal of Geophysical Research: Volume 120, Issue 5, pages 2119-2139.

This study discusses measurements of methane (CH_4) taken aboard a NOAA WP-3D research aircraft in 2013 over the Haynesville shale region in eastern Texas/northwestern Louisiana, the Fayetteville shale region in Arkansas, and the northeastern Pennsylvania portion of the Marcellus shale region, which accounted for the majority of Marcellus shale gas production that year. The study calculates emission rates from the horizontal CH_4 flux in the planetary boundary layer downwind of each region after subtracting the CH_4 flux entering the region upwind.

The natural gas loss rates from the Haynesville, Fayetteville, and Marcellus study regions were within the range of emissions estimated by Howarth et al. [2011] from the routine venting and equipment leaks of shale gas wells of 0.3–1.9%, which would represent the minimum day-to-day emission from a production region. In addition, the loss rates are lower than the threshold set by Alvarez et al.[2013] of 3.2%, below which the climate impact of using natural gas as a fuel in power plants would be less than that of coal.

57) Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA GHGRP Protocol. Subramanian et al. (February 2015). Environmental Science & Technology: Volume 45, Number 5, pages 3252-3261.

Site level methane emissions were concurrently measured with downwind-tracer-flux techniques at 45 compressor stations in the natural gas transmission and storage sector. The reports indicates that at most sites, these two independent estimates agreed within experimental uncertainty. This study found general agreements between measured results from the study and U.S. emissions estimates published in the U.S. Inventory, though emission rates among measured sites were found to be highly skewed as the highest emitting 10% of sites (including two super-emitters) contributed to 50% of the aggregate methane emissions, while the lowest 50% of the sites contributed to less than 10% of the aggregate emissions. The study makes recommendations for reporting requirements for the GHGRP. "The value of the GHGRP data for emissions inventory development would be improved by requiring more direct measurements of emissions (as opposed to using counts and emission factors), avoiding the use of acoustic devices, eliminating exclusions such as rod-packing vents on standby pressurized reciprocating compressors, and using more appropriate EFs for exhaust methane from reciprocating engines ."

58) Methane Emissions from Natural Gas Infrastructure and Use in the Urban Region of Boston Massachusetts. McKain et al. (February 2015). Proceedings of the National Academy of Sciences of the United States: Volume 112, Number 7, pages 1941-1946.

In this study, atmospheric methane concentrations were measured continuously from September 2012 through August 2013 at two locations near the urban center of Boston and two locations outside of the city. The study concluded that downstream natural gas losses (including transmission, distribution, and end-use was 2.7% of the consumed natural gas in Boston. The study reported that this emissions estimate was higher than that indicated by Massachusetts state emissions inventory which reported methane emissions to be 1.1% of natural gas consumed in the state. The study report stated, “The full environmental benefits of using NG in place of other fossil fuels will only be realized through active measures to decrease direct losses to the atmosphere, including in receiving areas such as the Boston urbanized region."

59) Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results. Austin L. Mitchell et al. (February 2015). Environmental Science & Technology: Volume 49, Number 5, pages 3219-3227.

In this study, ambient measurement techniques were used to sample methane emissions from 114 gathering facilities and 16 processing plants. Measurements were made using a mobile laboratory to perform downwind tracer flux measurements, and the resulting plumes were analyzed to consider results. At gathering facilities, measured methane emission rates ranged from 0.7 to 700 kg per hour (kg/h) whereas emissions ranged from 3 to 600 kg/h at processing plants. A cumulative methane emissions rate from all gathering facilities was found to be 6,300 kg/h, and a cumulative methane emissions rate from all processing plants was found to be 2,700 kg/h.

60) Data Show Texas Ozone Levels Are Not Driven by Fracking. Steven Everly. (February 2015). Published online by Energy in Depth®.

This publication concluded that "a closer review of publicly available data suggests there is no credible link between ozone nonattainment and development of the Barnett shale, over which much of the Metroplex sits." The report states that "data from the Texas Commission on Environmental Quality (TCEQ) – which operates the most comprehensive air monitoring network in the area – show that vehicular emissions actually far exceed those emanating from Barnett Shale activities."

61) Air tests of 5 Barnett Shale wells being hydraulically fractured show no harmful emissions: (February 2015). Published online by the Barnett Shale Energy Education Council

In this study, air concentration of VOCs, suspended particulate matter, and methane were collected at a 600 foot radius from a well pad in the City of Mansfield, Texas. The study noted that both during hydraulic fracturing operations and the initial well flowback period, "none of the observed VOCs were noted above the comparison criteria." The study concluded that "the results demonstrate that hydraulic fracturing does not produce harmful levels of emissions."

62) Life Cycle Greenhouse Gas Emissions from U.S. Liquefied Natural Gas Exports: Implications for End Uses. Leslie S. Abrahams et al. (February 2015). Environmental Science & Technology: Volume 49, Number 5, pages 3237-3245.

This study analyzes how incremental U.S. liquefied natural gas (LNG) exports affect global greenhouse gas (GHG) emissions. The report finds that exported U.S. LNG has mean precombustion emissions of 37 g CO_2-equiv/MJ when regasified in Europe and Asia. Shipping emissions of LNG exported from U.S. ports to Asian and European markets account for only 3.5−5.5% of precombustion life cycle emissions, hence shipping distance is not a major driver of GHGs.

63) Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. Brian K. Lamb et al. (March 2015). Environmental Science and Technology: Volume 49, Number 8, pages 5161-5169.

The aim of this study was to estimate emissions from local distribution systems in the US, using direct measurements from 13 urban distribution systems and estimates for customer meters, maintenance and upsets, current pipeline miles, and number of facilities. From the study results, an estimate of 393 Gg/year (~20 Bcf/year) of emissions was calculated. "This estimate is 36% to 70% less than the 2011 EPA Inventory and reflects significant upgrades at metering and regulating stations, improvements in leak detection and maintenance activities, as well as potential effects from differences in methodologies between the two studies[75]." Regarding more specific emission sampling results, the study report states, "We found that three large leaks (34.9, 22.2, and 4.9 g/min - respectively, 1.8, 1.2, and 0.25, scfm - from unprotected steel main, protected steel main, and case iron main leaks, respectively, accounted for 50% of the total measured emissions from pipeline leaks[76]."

64) Cutting Greenhouse Gas From Fossil-Fuel Extraction on Federal Lands and Waters. Claire Moser et al. (March 2015). Published online by the Center for American Progress.

This study concludes that federal lands and waters could have accounted for 24 percent of all energy-related greenhouse gas emissions in the United States in 2012. Combustion of coal from federal lands accounts for more than 57 percent of all emissions from fossil-fuel production on federal lands. Methane pollution from venting and flaring from onshore federal leases rose more than 51 percent between 2008 and 2013, according to government data.

65) Untapped Potential - Reducing Global Methane Emissions from Oil and Natural Gas Systems. Kate Larsen, Michael Delgado, and Peter Marsters. (April 2015). Published online by the Rhodium Group

The report asserts that significant profits are lost due to escaped natural gas from global oil/gas operations. It concludes, “based on the best currently available data, around 3.6 trillion cubic feet (Tcf) of natural gas escaped into the atmosphere in 2012 from global oil and gas operations. This wasted gas translates into roughly $30 billion of lost revenue at average 2012 delivered prices, and about 3% of global natural gas production.” The reports also notes, “The global methane emissions estimates included in this report, while more detailed and robust than anything currently available, are limited by a lack of credible, up-to-date estimates for most countries. Better national inventory practices and more regular reporting are critical to improve our understanding of the scale of the methane leakage challenge and to inform effective mitigation strategies."

66) Union Township Air Monitoring Report. Professional Service Industries, Inc. (April 2015). Published online.

Professional Service Industries, Inc. (PSI) conducted ambient air quality monitoring in three selected locations near the EQT Trax Farm Marcellus Drilling Site located in Finleyville, Union Township, Washington County, PA. The monitoring was conducted on three properties adjoining the drilling/fracking site while fracking operations were scheduled. Ambient area monitoring was requested for likely airborne contaminants from the drilling and fracking process, including: total airborne particulates (dust), gases (hydrogen sulfide (H_2S), NO_X, carbon monoxide and methane (%LEL)) and total volatile organic compounds (TVOCs) in three locations in close proximity to the site by PSI between February 4-9, 2015 following concerns of poor air quality by residents in the vicinity of the well.

67) Unconventional Drilling Emissions Inventory. Pennsylvania Department of Environmental Protection. (April 2015). Published online by the PDEP.

This study is a collected database containing air emissions data from natural gas operations in Pennsylvania. A methane emissions inventory is available in Excel form reported on a facility level in which data is reported on an annual basis. The 2013 data shows the following difference from 2012 levels:

- Sulfur dioxide – 57% increase
- Volatile Organic Compounds – 19% increase
- Particulate matter – 12% increase
- Methane – 13% decrease
- Nitrogen oxides -- 8% increase
- Carbon monoxide – 10% decrease

68) Spatial distribution of unconventional gas wells and human populations in the Marcellus Shale in the United States. Yelena Ogneva-Himmelberger and Liyao Huang. (May 2015). Applied Geography: Volume 60, pages 165-174.

The goal of this study was to use Geographic Information Systems (GIS) and spatial analysis to determine sociographic indicators of rural populations in the vicinity of unconventional gas production sites in Pennsylvania, West Virginia, and Ohio. The study identified localized clusters of poorer and elderly residents in the vicinity of gas production sites in Pennsylvania and West Virginia, and those of children and individuals with a lower level of education in the vicinity of sites in West Virginia and/or Ohio.

69) Using Multi-Scale Measurements to Improve Methane Emission Estimates from Oil and Gas Operations in the Barnett Shale Region, Texas. Robert Harriss et al. (July 2015). Environmental Science & Technology: Volume 48, pages 7524-7526.

This meta-study concluded that methane emissions from the Barnett shale region were approximately 1.5 times higher than those estimated in the U.S. Inventory, by comparing and analyzing both previous top-down and bottom-up emissions studies. The study stated that the main reason the bottom-up inventory emissions estimate exceeded the *Inventory* estimate was due to the inclusion of more gathering compressor stations, "whose emissions are comparable to mainline transmission compressor stations."

70) A Comparative Analysis: Methane Emissions Studies of Natural Gas Industry Operations. Innovative Environmental Solutions, Inc. (September 2015). Published online by the Interstate Natural Gas Association of America (INGAA).

This report is a comparative review of papers published in the past five years related to methane emissions from natural gas operations. According to this report:

- In 2011 and 2012, life-cycle analysis studies reached a variety of conclusions. These studies did not introduce new emission data but relied on data from the 1996 Gas Research Institute-Environmental Protection Agency report and EPA's Natural Gas STAR program. Conclusions from these "bottom-up" studies generally were driven by assumptions used in the analysis. Some studies concluded that methane emission estimates from natural gas operations were under-estimated.
- Reports published in 2012 and 2013 discussed methane inventory estimates that are based on atmospheric measurements. There are uncertainties with these "top-down" studies because of the "inability to attribute methane measured to natural gas operations, and extrapolation of short duration (e.g., hourly measurements) to a regional annual inventory."
- Papers published in 2014 reviewed all available literature and stated that data gaps have limited the ability to determine the differences between the studies. 2014 studies used the term "super emitter" to describe "large leak sources that result in a skew or 'fat tail' in emissions distributions." The authors of these studies state that data gaps need to be analyzed to better understand nominal emissions and large emission sources.
- Some publications published in 2014 and 2014 used new data. These publications include new measurement data from the Environmental Defense Fund, academic institutions, and industry. Data is also available from measurements of natural gas operations that are reported to EPA under Subpart W of the EPA GHG Reporting Program.
- 2014 publications state that there are data gaps, and a combination of both top-down and bottom-up studies to confirm emission estimates. Other recommendations include "data collection utilizing sensors on equipment sites, mobile monitoring schemes, and regional atmospheric monitoring on an ongoing basis."
- The main conclusion across all studies (regardless of the study type or the year of its release) is that more direct measurements are required.

71) Methane and CO_2 Emissions from the Natural Gas Supply Chain. (September 2015). Published online by the Sustainable Gas Institute.

The Sustainable Gas Institute (SGI) reviewed information on the extent of methane and CO_2 emissions in the natural gas supply chain. The review focused on “the range of emission estimates, the associated uncertainty, and the methodological differences.” The study looked at conventional and unconventional wells, and included the “exploration, extraction, processing, transmission, storage and distribution of stages of the natural gas supply chain, as well as the Liquefied Natural Gas (LNG) process.” The key findings were:

- The range of estimated greenhouse gas emissions across the supply chain is vast: between 2 and 42 g CO_2 eq./ MJ HHV (Higher Heating Value) assuming a global warming potential of 34 for methane.
- The key emission sources identified within the literature are from well completions, liquids unloading, pneumatic devices and compressors.
- Super-emitters are a small number of high-emitting facilities that are skewing the emissions profile at every stage.
- This report estimates that the total supply chain emissions should lie within the range of 2.7–32.8 g CO_2 eq./ MJ HHV with a central estimate of 13.4 g CO_2 eq./ MJ HHV, if modern equipment with appropriate operation and maintenance regimes were used. However, there is significant potential for further reductions.
- Emissions estimates also vary greatly due to methodological differences in estimation.
- Whilst there has been a recent drive to collect primary emissions data, there is still an incomplete and unrepresentative data set for a number of key emission sources.
- Further research is required in order to determine how much supply chain GHG emissions could be reduced.

72) LNG and Coal Life Cycle Assessment of Greenhouse Gas Emissions. (October 2015) Pace Global for the Center for Liquefied Natural Gas.

This study was prepared by Pace Global for the Center for Liquefied Natural Gas[77]. It evaluated GHG emissions from the LNG life cycle and compared them with GHG emissions from the coal life cycle. It included an estimate of the total life-cycle GHG emissions for each segment of the LNG supply chain from the wellhead, to the liquefaction plant, aboard a tanker for export, at the LNG receiving terminal, and as end-use for power generation. A coal LCA was performed to calculate emissions throughout the life-cycle process of coal extraction, transportation, and end-use combustion for power generation. The study compared the life-cycle emissions for coal and U.S. LNG-fueled power plants in Japan, South Korea, China, India, and Germany with a variety of high and low LNG cases and new and existing coal plant cases. The study found that the life-cycle emissions for LNG were significantly lower in all cases, less than half the coal-based emissions in nearly all of the cases.

73) The Facts About Fugitive Methane. Elizabeth A. Muller and Richard A. Muller. (October 2015). Published online by the Centre for Policy Studies.

This paper attempts to answer the question "how much leakage would negate the global warming benefits of using natural gas as compared to coal?" This study makes the following conclusions:

- Replacing coal-fired electric power plants with ones using natural gas as a fuel can help reduce global greenhouse emissions. New high efficiency natural gas plants reduce emissions of carbon dioxide by 63% if they replace a typical 33% efficient U.S., UK, or European coal plant, for the same electric power generated. If they replace future coal plants, carbon dioxide reductions are about 50%.
- Methane has a high greenhouse potential, and opponents argue that even if one or two percent of the gas leaks, the advantage of natural gas over coal would be negated.
- This estimate is incorrect; over a 100 year time span, an implausible 12% of the produced natural gas used today would have to leak in order to negate an advantage over coal. The best current estimates for the average leakage across the whole supply chain are below 3%; even at 3% leakage natural gas would produce less than half the warming of coal averaged over the 100 years following emission. Half this 100 year average comes from the first 10 years; three-quarters from the first 20 years; the warming at 100 years is almost entirely from the (relatively low) CO_2 produced from burned methane, not from the leaked methane itself.
- An additional reason to produce electric power from natural gas is that the legacy advantage of natural gas is enormous; after 100 years, only 0.03% of leaked gas remains in the atmosphere, compared to 36% for remnant carbon dioxide.

74) Reconciling divergent estimates of oil and gas methane emissions. Daniel Zavala-Araiza et al. (November 2015) PNAS Early Edition www.pnas.org/cgi/doi/10.1073/pnas.1522126112

This work analyzed datasets of top-down and bottom-up emissions collected from the Barnett shale region in 2013 to understand the larger estimates associated with top-down emissions estimates. The study researchers also created a new bottom-up emissions inventory of the Barnett shale region and compared this to the EPA GHG Inventory and other published methane emissions estimates for the region's emissions. The study found that "the mean difference between the [top-down] TD and [bottom-up] BU estimates for total CH_4 emissions, expressed as a percentage of the average TD estimate is 0.1% ± 21% (95% CI) ." A high percentage of total emissions was found to come from a lower percentage of facilities; the study report states: "Two percent of oil and gas facilities in the Barnett account for half of methane emissions at any given time…and 10% are responsible for 90% of emissions ." Production sites, compressor stations, and processing plants were found to be the highest emitters. The study found 90% higher methane emissions from the Barnett region compared with estimates based on the EPA GHG Inventory. The reports lists elements that contributed to convergence of bottom-up and top-down emissions estimates, including: better methodology to distinguish between fossil CH_4 (from the oil and gas industry) and biogenic CH_4 (e.g. from organic matter decomposition by methanogenic bacteria), inclusion of more facilities in the bottom-up estimate, and derivation of emission factors (EFs) that account for the effect of high-emitters. The researchers concluded that "these convergent emission estimates provide greater confidence that we can accurately characterize the sources of emissions, including the large impact that a small proportion of high emitters have on total emissions and determine the implications for mitigation." The study recommended future work to understand the causes/characteristics of high-emitting facilities.

75) U.S. Greenhouse Gas Inventory Report (1990-2014): Environmental Protection Agency (April 2016). Published online by the EPA.

EPA develops an annual report called the Inventory of U.S. Greenhouse Gas Emissions and Sinks (Inventory). This report tracks total annual U.S. emissions and removals by source, economic sector, and greenhouse gas going back to 1990. Key findings from the 1990-2014 U.S. Inventory include:

- In 2014, U.S. greenhouse gas emissions totaled 6,870.5 million metric tons of carbon dioxide equivalent.
- U.S. emissions of all GHGs increased by 1.0 percent from 2013 to 2014. Recent trends can be attributed to multiple factors including a cold winter, an increase in miles traveled by on-road vehicles, and an increase in industrial production.
- Greenhouse gas emissions in 2014 were 8.6 percent below 2005 levels.

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