Methane Emissions in the Natural Gas Life Cycle

FINAL REPORT

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1. Introduction

In recent years, the development of unconventional gas resources in the United States has led to significant growth in the country's production of natural gas. At the same time, policymakers have become increasingly aware of the risks posed by climate change and taken steps to mitigate those risks. According to the Environmental Protection Agency's (EPA's) 2014 inventory, electricity production is responsible for 31 percent of domestic greenhouse gas (GHG) emissions.[1] As a result, the electric sector has been a focus of climate change policy.

Natural gas has been widely described as a "bridge fuel" to a lower carbon electric sector, as it produces roughly half the carbon dioxide (CO_2) of coal when used to generate electricity. While natural gas maintains an end-use climate advantage over coal, the rapid growth of gas production has led to concerns about upstream GHG emissions from the natural gas industry. Because these emissions consist primarily of methane (CH_4), which has greater radiative forcing impacts than CO_2 per unit emitted, significant emissions from upstream gas systems have the potential to outweigh the end-use GHG advantage of gas.

The Western Interstate Energy Board (WIEB) and the State-Provincial Steering Committee (SPSC) commissioned this report to better understand the life cycle GHG emissions of natural gas and coal used for electricity generation. WIEB/SPSC asked M.J. Bradley & Associates (MJB&A) to evaluate and summarize the current state of knowledge about methane leakage throughout the natural gas fuel cycle, with a particular focus on the differences between methane emission estimates developed from bottom-up analyses and top-down inventories of methane and other hydrocarbons. One of WIEB/SPSC's major objectives was to identify the key reasons for the significant variability in total methane leakage estimates from prominent published studies, and to put these differences into context. With this understanding, WIEB/SPSC asked MJB&A to identify key methane emission points within the natural gas fuel cycle and review strategies and technologies available to reduce these emissions.

This report begins with a review of the literature on methane emissions from natural gas systems. A key aspect is a discussion of the differences and relationship between bottom-up and top-down emissions estimates. Life cycle emissions from natural gas and coal used for power generation are then compared based on data from recent emissions studies. While upstream GHG emissions from the coal industry are also discussed, the primary focus is on natural gas-related emissions.

After reviewing the literature, MJB&A developed an estimate of the percent of methane leaked throughout the natural gas life cycle using information from EPA's 2014 Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory). Using this leak rate and assumptions consistent with those in several recently published life cycle emissions reports, MJB&A estimated life cycle emissions for natural gas used to produce electricity in the United States in 2012. These life cycle emissions are compared to estimates of life cycle emissions for coal-based electricity.

The report then describes major sources of methane emissions from the natural gas life cycle, as well as the costs and effectiveness of known emissions controls. The focus is on sources that are not currently controlled by regulations at the national level, and therefore do not include emissions from activities such as hydraulically fractured gas well completions. Information in this section is based on five technical white papers released by EPA in April 2014 on potentially significant sources of emissions from the oil and gas sector.

Following the discussion on emission sources, MJB&A describes recently adopted policies that reduce methane emissions along with a variety of additional policy options that are under consideration for further reductions, including state actions and recently outlined federal regulations and voluntary programs. The report concludes by summarizing the findings of this study in terms of implications for policymakers.

2. Background on Life Cycle Assessments

Life cycle assessment (LCA) is a technique used to assess the environmental impacts of a product, process, or service across its entire value chain. By providing a platform to evaluate potential environmental impacts, LCAs help policymakers and other decision makers assess the broader environmental impacts of different policies and strategies. LCAs can focus on a variety of environmental impacts (e.g., water use, air emissions, toxics, etc.); the focus of this report is on life cycle greenhouse gas emissions related to natural gas-fired electricity generation as compared to coal-based electricity generation.

Figure 1 provides an overview of the natural gas value chain. The light blue boxes highlight the pathway from production to generation of electricity. Natural gas in the electric power sector moves from production (including drilling and exploration) through the processing and transmission and storage segments to the power plant. Other end uses of natural gas, such as distribution to homes, use in vehicles, or liquefaction for export or storage, are outside the scope of this report.

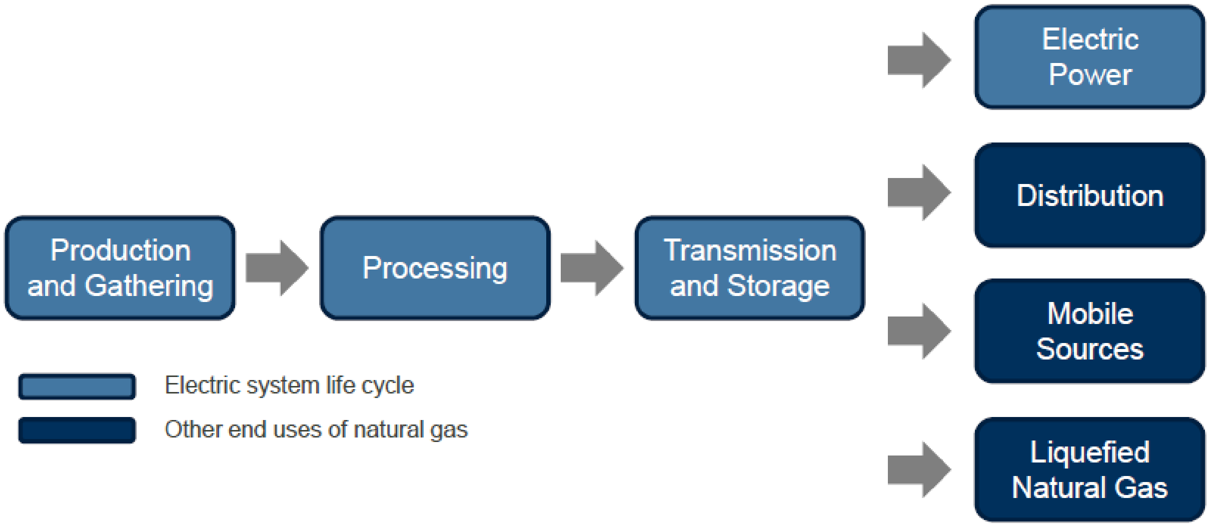

Figure 1. Natural Gas Value Chain

In the natural gas value chain, the two gases that contribute most to life cycle GHG emissions are methane and carbon dioxide. The methane content of natural gas varies depending on the specific characteristics of the formation from which it is extracted. As an example, for the purposes of estimating GHG emissions EPA uses values that range from about 78 percent to more than 91 percent depending on the region of the country. Methane content increases to above 95 percent after the gas is processed and put into transmission pipelines. Because the methane content of natural gas changes during the natural gas life cycle, the GHG impact of emissions also changes at different stages of the life cycle. Methane emissions occur at almost every stage of the electric power generation natural gas life cycle, from vented and fugitive emissions during well drilling to leaks from pipelines during transport. Adding these emissions together allows for the development of a system-wide leakage rate that represents the amount of methane leaked as a percentage of all the gas that is produced.

While CO_2 is a component of natural gas and is emitted in vented or fugitive gas, the vast majority of CO_2 emissions, and the majority of life cycle GHG emissions, are the result of fossil fuel combustion. During gas production, diesel- and natural gas-fired engines power drilling rigs, pumps, separators and many other types of equipment. During gas processing and transmission, compressors and other engines emit CO_2. The most significant portion of CO_2 emissions and total life cycle GHG emissions associated with the power sector occur when gas is combusted at a power plant.

Life cycle electric power GHG emissions are usually displayed in grams (g), kilograms (kg) or pounds (lb) per kilowatt hour (kWh) or megawatt hour (MWh). These units show the amount of GHG emitted per generation of a unit of electricity. GHGs are measured using carbon dioxide equivalents (CO_2e), a common unit that accounts for variation in the radiative forcing impacts of different GHGs (see sidebar discussion of global warming potential). In this report, vented and fugitive CH_4 emissions are reported in gigagrams (Gg, equivalent to 1000 metric tons) and electric power life cycle emissions are expressed as kg CO_2e/MWh.

Below, we review recent studies of vented and fugitive emissions across the natural gas value chain - from drilling and fracturing to delivery to a power plant - and evaluate the impact of those leaks on the life cycle greenhouse gas emissions from natural gas used to generate electricity.

Global Warming Potential

A major factor in calculating GHG emissions from methane leaks is the selection of a global warming potential (GWP). Methane is a more significant radiative forcer when compared to CO_2 and is assigned a GWP, based on the ratio of methane's radiative force to that of CO_2, that reflects that impact. The resulting value is represented in carbon dioxide equivalents (CO_2e).

Because atmospheric methane breaks down over time, methane's climate impact, and thus its GWP, is highest when it is first emitted and then degrades over time. Depending on the impacts that stakeholders want to evaluate, they may look at the relative impact over a short period of time (20-year GWP) or a longer period of time (100-year GWP). Following international conventions, GHG emission studies and inventories, including EPA's annual GHG Inventory, use a 100-year GWP when calculating the climate impact of methane emissions.

Starting with its 2015 inventory of GHG emissions, EPA is using a 100-year GWP for methane of 25, reflecting the fourth assessment of the International Panel on Climate Change (IPCC). IPCC regularly updates its GWP for many different GHGs based on the latest science. For this report, WIEB/SPSC asked MJB&A to use the fifth IPCC assessment values of 86 for the 20-year GWP for methane and 34 for the 100-year GWP. This means that the climate impact of one ton of methane is equal to the climate impact of 34 tons of CO_2 over a 100-year time frame (100-year GWP) and 86 tons of CO_2 over a 20 year time frame (20-year GWP). These values included climate feedbacks. Feedbacks account for the secondary impacts of methane emissions that cause additional warming. For example, warmer temperatures caused by GHG emissions reduce the ability of oceans and soils to absorb CO_2, leading to additional warming.

3. Review of Research on Fugitive and Vented Methane Emissions from Natural Gas Systems

Over the past five years, with the expanded development of shale gas resources, there has been an increased focus on fugitive and vented methane emissions[i] from the natural gas supply chain (frequently referred to as methane leakage). In 2010, as part of the development of Subpart W of the Greenhouse Gas Reporting Program (GHGRP), EPA proposed changes to its methodology for estimating emissions from natural gas production[2] – particularly changes to estimates of emissions from liquids unloading and well completions.[ii] EPA incorporated those changes into its methodology for the annual U.S. Greenhouse Gas Inventory Report (GHG Inventory), and researchers interested in the life cycle impact of natural gas emissions incorporated the increased estimates into studies of the natural gas value chain. These studies, referred to as bottom-up studies, use emission factors and component counts to estimate emissions from the natural gas value chain. Interest in the life cycle GHG emissions from natural gas increased substantially after the publication of an LCA by Howarth et al. in 2011 that concluded that the life cycle greenhouse gas emissions of shale gas could potentially be greater than that of coal.[3] However, Howarth et al. did not account for the end-use efficiency advantage of natural gas combined cycle operation over coal boilers.

In the subsequent years, EPA has made further adjustments to its methodology and a number of studies challenging Howarth et al.'s findings have been published. In July 2014, researchers at the Joint Institute for Strategic Energy Analysis (JISEA) and the National Renewable Energy Laboratory (NREL) released a study (JISEA/NREL harmonization study) harmonizing eight natural gas LCAs that compared shale gas to conventional gas, including the Howarth et al. study.[4,iii] The harmonization process attempted to standardize the assumptions made in each study, allowing for a more consistent comparison of their life cycle GHG emission estimates. The JISEA/NREL study reported harmonized methane leakage rates of less than 3 percent for six of the studies, less than 4 percent for a seventh study and a range of 2.8 to 6.2 percent for Howarth et al. The harmonization study concluded that natural gas-generated electricity (shale or conventional) has life cycle emissions that are approximately half those from coal-generated electricity.[5] As discussed below, recent adjustments to the methodology used by EPA to develop the GHG Inventory may result in lower estimated emissions than those included in the harmonization study.

Over the same time period, researchers at the National Oceanic and Atmospheric Administration (NOAA) noted an increase in atmospheric concentrations of methane in the northern hemisphere.[6] As part of the ongoing efforts to identify the potential sources of methane, researchers have been conducting flyovers of natural gas basins to collect data on methane emissions. These top-down studies provide information on emissions from a particular geographic area at the time of the flyover. There is significant variability in the calculated methane leakage rate attributed to natural gas sources in these studies, but the rate is

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[i] Fugitive emissions are unintentional releases to the atmosphere, such as leaks in pipelines or storage tanks, while vented emissions are intentional releases, such as the release of natural gas from pneumatic controllers used to regulate pressure in a system.

[ii] Appendix A includes descriptions of key natural gas systems and technologies and definitions of key life cycle analysis terms. Liquids unloading refers to the removal of water and condensates that build up inside producing natural gas wells, slowing the flow of gas to the well head.

[iii] The NREL harmonization includes eight of the bottom-up studies discussed in this report: Burnham, Heath, Howarth, Hultman, Jiang, Laurenzi, Skone and Stephenson.

generally higher than the rates assumed in the bottom-up studies. The five top-down studies we reviewed as part of this report reported values ranging from less than one percent to greater than 17 percent leakage.

It is important to recognize that regardless of methodology (top-down or bottom-up), all studies rely on numerous assumptions to estimate vented and fugitive emissions based on limited test data. This is no less true of the top-down studies that rely on limited measurements of atmospheric methane concentration than it is of the bottom-up studies that rely on average emission rates and activity factors for various steps in the fuel cycle, all of which are developed based on limited information and test data.

Below, we summarize the changes and adjustments EPA has made to its annual emissions inventory over the past several years to provide context for the ongoing discussion of methane leakage from natural gas systems and to give some perspective on the degree of uncertainty in any estimate of natural gas fuel cycle GHG emissions. We then review methane leakage findings from some of the most significant bottom-up and top-down emission studies, focusing on the recent studies of shale gas-related emissions. Research on methane leakage from natural gas systems is ongoing, and important information from studies measuring component-level emissions throughout the value chain[iv], as well as additional flyovers of production regions[7], is expected to be published over the next year. In addition, each year, EPA collects and publishes industry reported data on methane emissions through the GHG Reporting Program.[v] Continued refinement of that program should add to stakeholder understanding of methane emissions throughout the value chain.

Changes to EPA's GHG Inventory

As it prepares its annual GHG Inventory, EPA makes an effort to update its methodologies to improve accuracy. In response to concerns it was incorrectly characterizing emissions from natural gas production, over the past six years EPA has made significant changes to its approach to estimating emissions associated with natural gas. Figure 2 shows emission estimates for the same year (2008) across five consecutive inventories (2010 to 2014), illustrating the impact that methodology changes can have on emissions estimates for a single year.[vi] Starting with the 2011 GHG Inventory, EPA made changes that increased the estimated vented and fugitive CH_4 emissions from natural gas production. In the 2010 GHG Inventory, EPA estimated 2008 methane emissions from natural gas production to be 674 gigagrams (Gg).[8] The 2011 GHG Inventory increased this estimate to 5,854 Gg (an increase of 769%).[9]

[iv] For example, studies led by Environmental Defense Fund in collaboration with academic and industry stakeholders. Described at: http://www.edf.org/climate/methane-studies.

[v] EPA published data collected through the GHG Reporting Program each fall. The most recent data are available at: http://www.epa.gov/ghgreporting/

[vi] By looking at the same emission year across five different inventories, it is possible to see the impact of changes in methodology as opposed to changes in production, technology, or regulation.

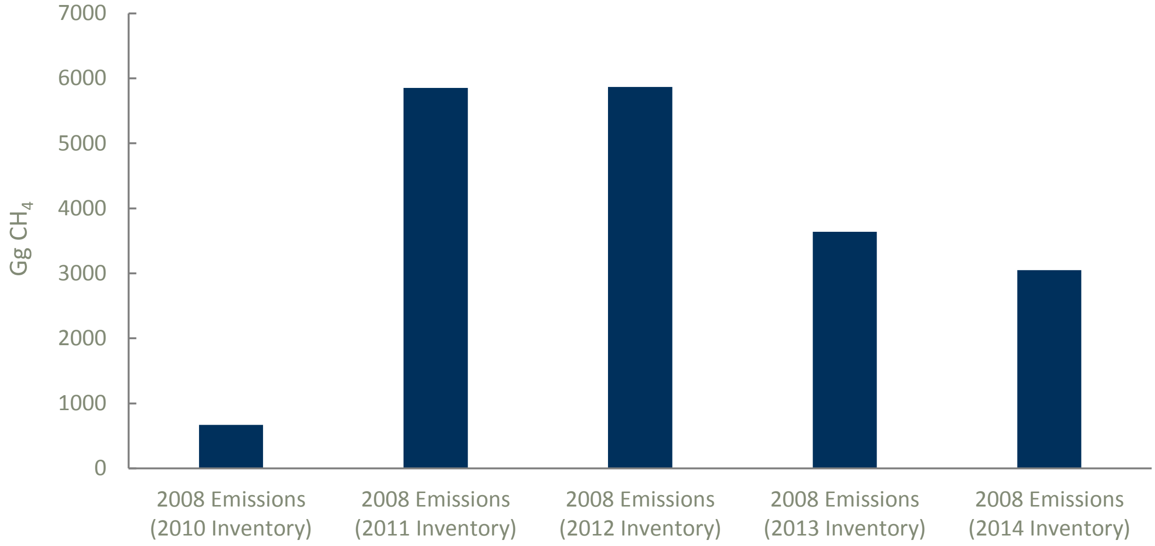

Figure 2. Reported 2008 Natural Gas System Production-stage Methane Emissions Across Five Consecutive GHG Inventories (2010-2014)

This dramatic change increased stakeholder interest and has resulted in a more coordinated annual effort by EPA to seek input on the best available data from the natural gas industry, government agencies, educational and research institutes, environmental groups, and other stakeholders. In the 2013 and 2014 GHG Inventories, new information also led to substantial changes in how emissions from certain activities are calculated.

In the 2013 GHG Inventory, a major update was made to the emissions estimate from liquids unloading during the production stage.[10] Previous inventories had assumed that the use of plunger lifts – the primary technology for reducing methane emissions during liquids unloading – was not widespread. However, a survey conducted by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA), published in June 2012, suggested that a large number of events were conducted with plunger lifts, and that EPA's assumptions were significantly overestimating emissions during liquids unloading.[11] The API/ANGA report included region-specific emission factors for liquids unloading. Data from the API/ANGA report and other industry sources also indicated that the rate of workovers using hydraulic fracturing (refractures) occurring in the field was one percent, not the 10 percent used by EPA in previous GHG Inventories. EPA incorporated these new data into the 2013 GHG Inventory.

The 2014 GHG Inventory included another major change to the methodology used to calculate production emissions. EPA used data from the 2011 and 2012 GHGRP on well completions and workovers with hydraulic fracturing to establish four technology-specific emissions factors: hydraulic fracturing completions and workovers that vent; hydraulic fracturing completions and workovers that flare; hydraulic fracturing completions and workovers with reduced emission completions (RECs);[vii] and hydraulic fracturing completions and workovers with RECs that flare. This methodology, which allows EPA to more accurately account for wells using RECs, is

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[vii] Reduced emission completions capture gas that would otherwise be vented. See Appendix A for a more detailed description.

the primary reason for a decrease in estimated production-related methane emissions in the 2014 Inventory.

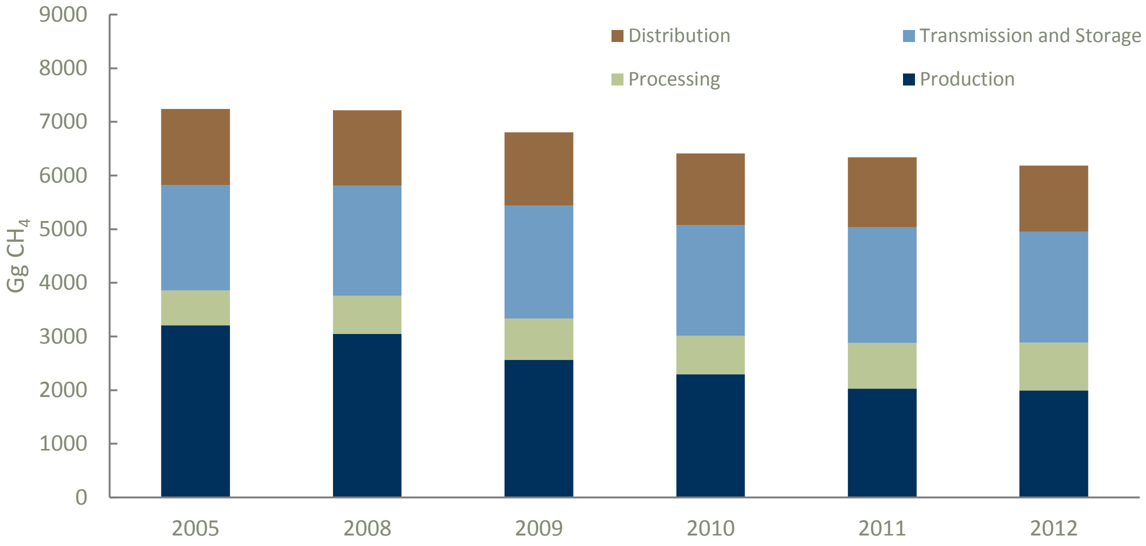

Figure 3. Methane Emissions from Natural Gas Systems in the 2014 GHG Inventory

When methane emissions from previous years are estimated using the 2014 GHG Inventory's methodology, system-wide emissions are shown to decrease year-over-year since 2008. With the methodology held constant, these changes reflect estimated emissions reductions stemming from both voluntary industry action and regulations. While there have been changes in emissions from all segments, Figure 3 shows that the majority of the estimated emissions reductions are associated with natural gas production.

On April 15, 2015, EPA released the final 2015 GHG Inventory. The methodology for estimating emissions from hydraulically fractured wells was further updated in the current draft using data from the 2013 GHGRP. This new data led to the development of lower emissions factors for three of the four categories of hydraulically fractured wells described above and showed fewer wells venting flowback emissions. EPA noted that it will continue updating the methodologies for certain sources, including liquids unloading and pneumatic controllers, using data from the GHGRP and peer-reviewed studies, including several of those examined in this report.

Bottom-up Studies

Following methodologies similar to those used by EPA in the GHG Inventory, a number of studies have estimated methane emissions throughout the natural gas value chain using emission factors and activity data. Collectively, studies that use emission factors and activity data to estimate emissions are known as bottom-up emission studies. For this report, MJB&A reviewed 14 bottom-up studies that provide estimates of leakage from the natural gas value chain. The studies were selected based on their use of recent data and assumptions, prominence, and discussions with WIEB/SPSC staff. Appendix B provides a summary of each study with references.

The bottom-up studies evaluated in this report can be further divided into life cycle analyses and direct emissions measurement studies. The LCAs we include use existing and, in some cases, original data (emissions factors, activity counts) to estimate life cycle GHG emissions from selected fuels. Direct measurement studies involve field surveys of natural gas infrastructure to quantify methane emissions and develop leakage rates. These surveys generally focus on specific components and activities or sectors of the natural gas system as opposed to looking at emissions across the natural gas value chain. While they may scale observed emissions to estimate national emissions from a specific sector, they do not estimate life cycle emissions.

Life Cycle Analyses

As highlighted in the JISEA/NREL harmonization study and documented elsewhere in the literature[viii], each LCA has a slightly different focus and methodology. The majority of the reviewed studies (eight out of nine) had an objective of comparing the life cycle leakage rates of shale or unconventional gas to conventional or national average gas (in many cases, these studies also included a comparison to coal). In one of the studies, Laurenzi and Jersey compared Marcellus shale gas to conventional coal used for electricity generation. In another reviewed study, Alvarez et al. used EPA data to develop leakage-related crossover points for where substituting national average natural gas for alternatives, such as diesel to natural gas for heavy-duty vehicles and coal to natural gas for electricity generation, had some climate benefits. Table 1 lists the primary authors of the reviewed LCAs (for ease of references, we refer to the studies by the lead author name throughout this report), as well as the key data sources and fuels compared.

Each of the studies reported in Table 1 calculated a leakage rate associated with the reviewed source of natural gas or included the information necessary to calculate a leak rate based on the study assumptions. However, the units used within each study are not consistent. In some cases, researchers divided the amount of methane lost by the amount of methane produced. In other cases, researchers divided the amount of methane lost by the amount of natural gas consumed. Table 2 shows the range of published leak rates for eight of the studies and a set of normalized leak rates developed as part of the JISEA/NREL harmonization study. In the JISEA/NREL harmonization study, Heath et al. normalized the leak rates to reflect vented and fugitive methane as a fraction of produced gas (not as a fraction of consumed gas).

As shown in Table 2, all but one of the shale gas leakage rates are less than 4 percent and six of the eight rates are less than 3 percent after normalization. The normalized leakage rates associated with conventional gas are all below 5 percent with four out of the seven values less than 3 percent. The range of values are the result of studies relying on different data sets and different emission factor assumptions for components of the natural gas system. For example, the upper bound of the leak rate estimated by Howarth et al. is high in part because the analysis uses very high emission rates for well completions and transmission pipelines (higher than those assumed by EPA in the GHG Inventory). In contrast, the estimate by Stephenson et al. includes lower assumed leak rates from production and transmission.

[viii] For example, Brandt et al. (2014).

Table 1. Life Cycle Studies, Data and Fuels

Lead Authors	Affiliation of Lead Author	Year Published	Key Emissions Data Source(s)	Focus Fuel	Comparison Fuel
Alvarez et al.	Environmental Defense Fund	2012	EPA	All produced gas, not specific to unconventional	Gasoline, diesel, or coal, based on end-use
Burnham et al.	Argonne National Laboratory	2011	EPA	Unconventional gas[a]	2009 national average conventional (onshore, offshore, and associated)
Howarth et al.	Cornell University	2011	EPA, GAO, Other	Unconventional gas	Conventional gas
Hultman et al.	University of Maryland	2011	EPA	2007 national average unconventional	2007 national average consumed gas (onshore, offshore, associated, and LNG imports)
Jiang et al.	Carnegie Mellon University	2011	Primary data collection, Other[c]	Marcellus shale	2008 national average (onshore, offshore, associated, unconventional, CBM)
Heath et al.	Joint Institute for Strategic Energy Analysis	2012	TCEQ inventories, EPA	2009 Barnett shale	Harmonized estimates from 42 conventional gas LCAs
Laurenzi and Jersey	ExxonMobil	2013	Primary data collection, EPA	2010-2011 Marcellus shale	Coal
Skone et al.	National Energy Technology Laboratory	2012	Primary data collection, EPA	2009 Barnett shale	2009 onshore, offshore, associated gas and production-weighted mixture
Stephenson et al.	Shell	2011	Primary data collection, EPA	U.S. shale gas	U.S. onshore conventional gas

Information in this table based on Table 1 in Heath et al. 2014 and MJB&A analysis. Additional information on each study, including full references, is available in Appendix B.

CBM = Coal Bed Methane

TCEQ = Texas Council on Environmental Quality

a. Burnham et al. estimated the ultimate recovery (EUR) for unconventional gas as the well-weighted average of Marcellus, Barnett, Haynesville, and Fayetteville shales. The researchers used general unconventional emission factors based on EPA.

b. Howarth et al. estimated production emissions based on shale gas from the Haynesville and Barnett Basins and tight gas from Piceance and Uinta Basins and other indirect emissions based on Marcellus Basin gas.

c. Jiang et al. used a study that included many of the same co-authors (Venkatesh et al.) as the basis for a number of assumptions.

As listed in Table 1, all of the reviewed studies except for one used EPA data or methodologies to estimate all or a portion of the methane vented and fugitive emissions. Given the timing of these studies, the underlying EPA assumptions for each study included data from the 2011 EPA GHG Inventory, which, as shown in Figure 2, included a significant increase in estimated emissions relative to the 2010 GHG Inventory. Alvarez et al. used the 2011 GHG Inventory to develop an estimate of the leakage rate associated with vented and fugitive emissions across the entire natural gas system, including conventional gas, shale gas, coal-bed methane, offshore gas, and associated gas (gas recovered during petroleum or heavy hydrocarbon production). Alvarez et al. found a leak rate of 2.4 percent (CH_4/CH_4 produced), assuming an average natural gas methane content of 84 percent. Following the conventions of the JISEA/NREL harmonization study, which normalizes leak rates to CH_4/NG produced, the normalized Alvarez et al. leakage rate would be 2 percent.

Table 2. Estimated Methane Emission Leak Rates in Key Life Cycle Analyses

Lead Authors[a]	**Unconventional Gas**		**Conventional Gas**	
	Published Leakage Rate (reported units)	**Normalized Leakage Rate (CH_4/NG produced)**[b]	**Published Leakage Rate (reported units)**	**Normalized Leakage Rate (CH_4/NG produced)**[b]
Burnham et al.	2.0% (CH_4/NG produced)	2.0%	2.8% (CH_4/NG produced)	2.8%
Howarth et al.	3.6% (low) 7.9% (high) (fugitive CH_4/CH_4 produced)	2.8% (low) 6.2% (high)	1.7% (low) 6.0% (high) (fugitive CH_4/CH_4 produced)	1.3% (low) 4.7% (high)
Hultman et al.	2.4% (CH_4/consumed gas)	2.8%	3.8% (CH_4/consumed gas)	4.6%
Jiang et al.	NR	NR	2.2% (CH_4/NG produced)	2.2%
Heath et al.	1.3% (CH_4/NG produced)	1.3%	NA	NA
Laurenzi et al.	1.7% (fugitive CH_4/gross CH_4 produced)	1.4%	NA	NA
Skone et al.	4.8% (fugitive NG/produced gas)	3.9%	5.6% (fugitive NG/produced gas)	4.5%
Stephenson et al.	0.65% (mixed units)	0.66%	0.51% (mixed units)	0.53%

Information in this table based on Supplemental Information Dataset S3 published by Heath et al. 2014.
NR = Not Reported
NA = Not Assessed
a. Alvarez et al. and Allen et al. were not part of the harmonization study because they did not separate out and compare shale gas to conventional gas. As discussed in the text, the normalized leak rate for Alvarez et al. would be 2%. Allen et al. focused on production and the associated leak rate is not comparable to these studies.
b. Heath et al. 2014 normalized the leak rates to reflect vented and fugitive methane as a fraction of produced gas.

Direct Emissions Measurement Studies

The range of leak rate estimates in the LCAs and the significant updates EPA made to its inventory methodology in recent years have led to increased efforts to measure fugitive and vented emissions throughout the natural gas life cycle. The most significant of these efforts are being led by EDF in collaboration with leading university researchers and industry partners. When all the work is complete, researchers in EDF-affiliated projects are expected to release 16 different studies. In September 2013, researchers at the University of Texas at Austin (UT

Austin) published the first major study from the collaboration that included direct field measurements. Researchers collected data on leaked and vented emissions from 190 natural gas sites across different U.S. shale basins.[12] Two additional studies by UT Austin, one on emissions from liquids unloading[13] and one on emissions from pneumatic controllers[14], were published in December 2014. Emissions reported from the three studies reflected measured emissions as opposed to estimates derived from emissions factors and component counts. Based on emissions factors developed from these measurements, the UT Austin researchers estimated total U.S. production stage emissions, which they found to have a methane leakage rate of 0.38 percent of all gas produced in the U.S. in 2012 (i.e., CH_4/NG produced). Using data from EPA's 2014 GHG Inventory, this compares to a production stage leak rate of 0.35 percent. A key finding of the Allen et al. studies was the presence of "super emitter" sources among surveyed equipment. Super emitters are sources that make up a minority of total sources surveyed but are responsible for the majority of observed methane emissions.

Table 3. Comparison of National Emissions from Select Sources in the 2013 and 2014 GHG Inventories and the UT Austin Studies

Emission Source	UT Austin Studies (Gg CH_4)	2014 GHG Inventory (Gg CH_4)	2015 GHG Inventory (Gg CH_4)[a]
Emissions Year	**2012**	**2012**	**2012**
Flowback from Hydraulically Fractured Wells	24	217	138
Chemical Pumps	73	64.6	63
Pneumatic Devices	600	334	557
Liquids Unloading	270	274	267
Other Sources	1,218	1,102	963
Total Production Emissions	2,185	1,992	1,988
Leak Rate (CH_4/ NG produced)	0.38%	0.35%	0.35%

a. UT studies scale emissions estimates to national level using activity data from 2014 GHG Inventory. Draft 2015 GHG Inventory retroactively adjusted 2012 activity data, notably for fractured wells. While activity data from UT studies and 2015 inventory are similar for many sources, this inconsistency accounts for some of the difference in emissions between the UT studies and the 2015 inventory.

As shown in Table 3, there are differences between the emissions estimates in the UT Austin studies and the EPA inventories. However, the differences between total production-stage emissions are not very significant. Total emissions estimates are similar, with the most notable differences being emissions estimates for individual sources and activities. For example, cumulative emissions from flowback are estimated to be 24 Gg CH_4/year in the UT Austin study, but 217 Gg CH_4/year in the 2014 GHG Inventory. This suggests that while EPA's estimate of total emissions are similar to estimates based on direct measurements, EPA's apportionment of emissions to specific sources may be an area for future updates. One such update is reflected in the 2015 GHG Inventory, which includes a significant increase in emissions from production-stage pneumatic devices that brings estimates more in line with those derived from the UT Austin measurements.

Two additional EDF-sponsored direct measurement studies were released in early 2015. One study measured methane emissions from compressor stations in the transmission and storage sector[15] while the other examined emissions from natural gas gathering facilities and processing plants.[16] Similar to the UT Austin production-stage findings, these studies also discovered super emitters, suggesting that these large emissions sources are present across the natural gas value chain. The compressor study found that, excluding two super emitter sources, average emissions from certain sources were comparable to or lower than the corresponding emissions factors in the GHG Inventory. However, if the two outlier emissions sources are factored in, the study-wide emissions factors would exceed those used by EPA, highlighting the potential impact of super emitters on broader emissions estimates. The data from these and the other EDF-sponsored direct emissions measurement surveys could potentially be used to update EPA's GHG Inventory methodologies in the future. While the studies did not estimate national emissions from the measured sources, companion papers are expected later in 2015 that will use the observed data to scale national emissions. Table 4 provides an overview of the direct measurement studies reviewed in this report.

Table 4. Bottom-up Direct Emission Measurement Studies

Lead Authors	Lead Author Affiliation	Year Published	Natural Gas Segment	Emissions Sources Measured
Allen et al.	University of Texas at Austin	2013	Production	Completion flowback, chemical pumps, pneumatic controllers[a]
Allen et al.	University of Texas at Austin	2014	Production	Pneumatic controllers
Allen et al.	University of Texas at Austin	2014	Production	Liquids unloadings
Mitchell et al.	Carnegie Mellon University	2015	Gathering and processing	Gathering facilities, processing plants
Subramanian et al.	Carnegie Mellon University	2015	Transmission and storage	Compressor stations

a. 2013 study by Allen et al. also estimated emissions from "equipment leaks" that were based on emissions from compressors at well sites.

An additional study led by the UT Austin researchers and published in January 2015 examined emissions from products co-produced at natural gas wells.[17] While areas may be developed with the primary goal of producing natural gas, certain gas fields also contain oil and natural gas liquids (NGLs). When this "wet" gas is produced, oil and NGLs are co-produced. The authors of the study argue that a portion of total methane emissions should be assigned to these liquids, which are outside the natural gas value chain.[ix] The UT Austin study uses data from the UT Austin Phase I report to allocate percentages of methane emissions to natural gas, oil, and NGLs. The authors of the study found that, nationally, 85 percent of methane emissions from shale gas production should be assigned to natural gas, with the remaining ten and five percent of emissions assigned to oil and NGLs, respectively. It is important to note that the UT Austin Phase I study focused on shale gas sources and found regional variability. Other sources of gas and regions could be drier or wetter than those observed in the study.

Uncertainties

Bottom-up estimates for the natural gas sector generally use emission factors multiplied by activity counts to estimate emissions from a facility, company, region, or the entire sector.

[ix] Similarly, emissions from natural gas co-produced at oil wells must be assigned to the natural gas sector. In the analysis in Section 5, MJB&A followed Alvarez et al.'s methodology of assigning 35 percent of methane emissions from oil production to natural gas.

Three challenges that increase the uncertainty associated with the estimates are (1) identifying emission sources, (2) collecting data from a representative sample of emission sources, and (3) accurately estimating the population of emission sources. As discussed below, each challenge introduces uncertainty into emissions estimates and much of the ongoing research is directed at trying to reduce that uncertainty.

Unlike industries with large point sources, such as the electric power sector, emissions from the natural gas sector are distributed across a range of different pieces of equipment, sometimes across a wide geographic area. The range and dispersion of sources creates challenges in developing an accurate estimate of emissions. To identify emission sources, researchers catalogue sources that vent emissions, such as pneumatic devices, but they also use infrared cameras to identify potential leaks. Within the 2014 GHG Inventory prepared by EPA, the production segment included 36 different emission sources, each with a different emission factor and activity count. EPA categorized ten of those emission sources as fugitive emissions, or emissions that are not intentionally released. The remainder are categorized as vented or combusted emissions. Fugitive emissions include leaks from connectors and valves. These emissions can be particularly difficult to identify since they are not designed to emit gas. Another source of emissions that is not part of the GHG Inventory but is related to the natural gas sector is emissions from abandoned wells. Abandoned wells could contribute to atmospheric methane but, since they are not captured by the GHG Inventory and are not a part of the system delivering gas to end users, they are not usually included in bottom-up estimates.[x]

To develop emission factors, researchers try to sample enough of the identified sources to develop a representative sample of each source of emissions. With limited emissions samples, there will always be uncertainty over whether observed emissions are similar to those from the same components or activities at different sites. In addition, there is growing evidence to suggest that a large percentage of total leakage from the natural gas supply system comes from a limited number of super emitter sites, which complicates the task of determining average emission rates for use in inventory models. When emissions are unevenly distributed across sources, it becomes more difficult to develop an accurate emissions factor. One of the criticisms of the recent studies completed in collaboration with EDF is that sampling was limited to sites owned and operated by industry partners. For example, the production studies involved the cooperation of nine natural gas companies out of thousands of producers that operate in the U.S. While the nine companies that participated were responsible for 16 percent of gross gas production in 2011, EDF has stated the studies "characterized the practices at particular sites operated by the participating companies, not industry at large." At the same time, EDF maintains that their use of the data to assess the national implications of the results is consistent with the historical use of data by EPA to develop emission inventories.[xi]

Activity counts add another layer of uncertainty, as the under or overestimation of activities or components will result in the under or overestimation of emissions estimates. Each year, EPA revisits its underlying data and asks stakeholders to report on new or updated sources of activity data for the annual inventory.

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[x] Natural seeps are another natural gas-related source not included in the GHG Inventory since they are not anthropogenic, or directly related to human activities.

[xi] EDF maintains a website responding to Frequently Asked Questions about the UT Austin study at: http://www.edf.org/climate/methane-studies/UT-study-faq

In addition to these three challenges, the composition of natural gas can also vary significantly; not only by location but also by processing step (i.e., leaks at the well head will typically have lower methane content and higher propane and butane content than leaks in the transmission system, due to removal of NGLs during processing). This can lead to challenges particularly if the methane estimate is based on the ratio of the methane to some other observed emission, such as volatile organic compounds (VOCs).

The sensitivity of these bottom-up leak estimates to input assumptions is demonstrated by changes to EPA's National GHG Emissions Inventory over the last several years, which has varied significantly as EPA has refined its assumptions based on collection of additional data, especially related to completion emissions from shale gas wells.

Variations in bottom-up estimates of life cycle emissions are further exacerbated by the fact that not all studies include the same life cycle stages where GHG emissions are present. For example, some studies include natural gas distribution systems while others assume power plants receive gas directly from transmission pipelines.[xii] The inclusion of emissions from well pad development, liquids unloading and other GHG-emitting activities varies from one LCA to another. While efforts such as NREL's recent LCA harmonization can normalize what emission activities are included and assumptions about emission rates from those activities, regional differences in geology, regulations, and infrastructure make it impossible to standardize all the factors that contribute to life cycle GHG emissions.

Top-down Studies

At the same time that research into bottom-up emissions estimates accelerated, atmospheric scientists noted an increase in the concentration of atmospheric CH_4 in the northern hemisphere. Figure 4 shows a three-dimensional representation of the latitudinal distribution of atmospheric methane developed by researchers at NOAA's Earth System Research Laboratory using data from a global monitoring network. As shown, the concentrations of methane in the northern hemisphere increased from 2000 to 2010 (note the shift in peak concentrations represented as yellow/orange at the beginning of the time series and orange/red at the end of the time series).

As part of an investigation into the source of the observed increase in atmospheric methane, researchers started to use top-down emission measurement techniques to better understand methane emission rates across discrete geographic areas. To complete top-down studies, researchers collect data on the concentration of gases in the atmosphere upwind and downwind of a target area. The data are collected using monitors on aircraft, vehicles, or stationary towers hundreds of feet tall. Using the collected information, researchers can estimate the methane concentrations above background levels across the target area. The difference in methane concentrations entering and exiting the target area is used to estimate the mass balance, or

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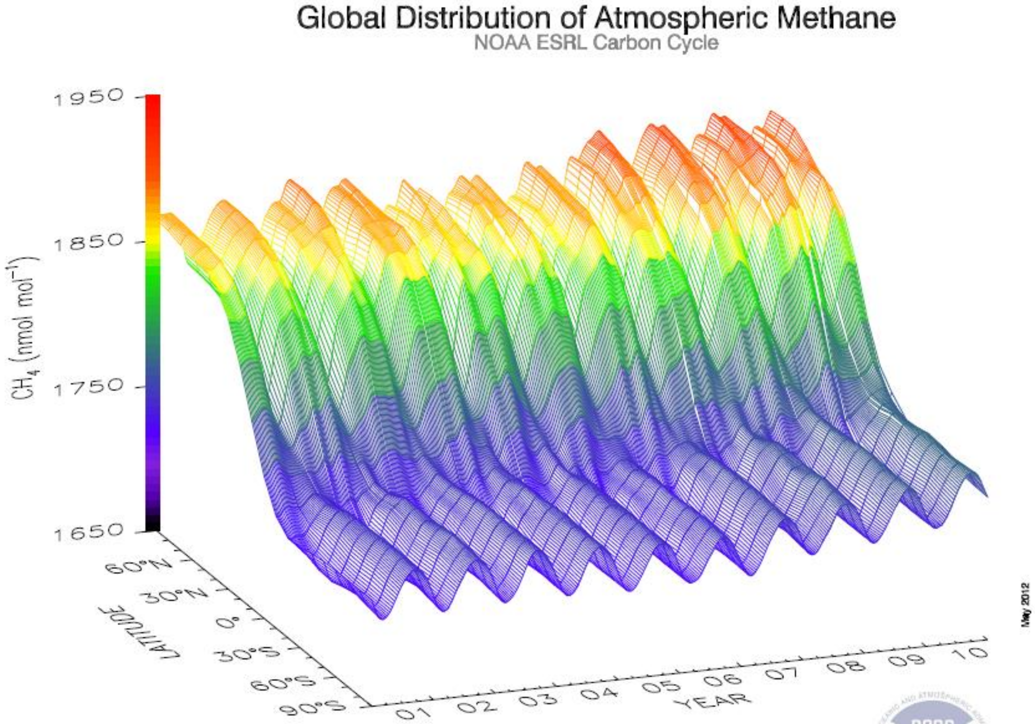
[xii] A 2011 report by the North American Electric Reliability Corporation (NERC) reported that most EGUs received gas from the transmission system due to gas pressure requirements, particularly at newer plants [NERC (2011). "2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States". Available at: http://www.nerc.com/files/gas_electric_interdependencies_phase_i.pdf.] A 2008 EIA report on natural gas distribution systems used 2006 data to conclude that 28 percent of natural gas (by volume) was provided to natural gas-fired EGUs via the local distribution system and 72 percent was provided by the transmission system [EIA (2008). "Distribution of Natural Gas: The Final Step in the Transmission Process". Available at: http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2008/ldc2008/ldc2008.pdf]

methane flux, across the target area to calculate total methane emissions. The flux measurements of entire regions or basins include methane emissions from all sources within the area surveyed.



Three-dimensional representation of the latitudinal distribution of atmospheric methane in the marine boundary layer. Data from the Carbon Cycle cooperative air sampling network were used. The surface represents data smoothed in time and latitude. Contact: Dr. Ed Dlugokencky, NOAA ESRL Carbon Cycle, Boulder, Colorado, (303) 497-6228, ed.dlugokencky@noaa.gov, http://www.esrl.noaa.gov/gmd/ccgg/.

Figure 4. NOAA Graphic of the Global Distribution of Atmospheric Methane [Source: NOAA Global Monitoring Division Carbon Cycle Group, used with permission]

Once the methane flux for the target area has been calculated, researchers allocate emissions to the various sources within the region. This usually involves using bottom-up emissions inventories from other methane sources in the region (e.g., agriculture, landfills, coal mines, etc.) to estimate non-oil and gas emissions that would be captured by the flux measurements. Non-oil and gas emissions are then subtracted from total emissions to estimate emissions attributed to oil and gas activities.[xiii]

Researchers also use the ratio of methane to non-methane hydrocarbons that are unique to oil and gas sources, such as propane, to help allocate methane emissions to oil and gas sources. Since propane is not a product of agriculture or other biogenic methane sources, it can be used as an alternative way to estimate the amount of methane that can be attributed to oil and gas operations. By comparing the observed methane-to-propane ratio to the same ratio in other samples of emissions from oil and gas operations, researchers can attempt to verify the estimates developed using the bottom-up methodology.

[xiii] If the target area is small enough (i.e., an individual well pad or cluster of pads), this step may not be necessary.

While LCAs that estimate national vented and fugitive emission rates often rely on existing inventories, atmospheric studies require original methane measurements that can be expensive and require significant planning and data analysis. As such, the number of major top-down studies is small compared to the number of published bottom-up studies, although a number of additional studies are planned or underway.

Compared to national leak rates in bottom-up studies, top-down studies generally show natural gas infrastructure to have higher rates of vented and fugitive emissions. Table 5 shows estimated leak rates from five recent peer-reviewed studies, with leak rates ranging from 0.18 percent to 17.3 percent (a summary of each study is available in Appendix C). It is important to note that these studies cover specific geographic areas at specific times and, unlike many of the bottom-up studies, do not attempt to establish nationwide leak rates or life cycle emissions estimates. Because the studies cover different regions, it is not surprising that they would develop different leak estimates due to differences in gas composition, production practices, and regulations. Within a specific geographic area other natural and man-made methane sources such as natural seeps of gas and emissions from abandoned wells, unrelated to delivering natural gas to current end users, may also influence the estimated methane flux rate used to calculate the reported leak rate.

Table 5. Estimated Methane Emission Leak Rates in Key Top-down Studies

Study Authors	Affiliation of Lead Author	Year Published	Estimated % Leakage (Source of Gas)
Petron et al.	NOAA	2012	2.3-7.7% (Denver Julesburg Basin)
Karion et al.	NOAA	2013	8.8±2.6% (Uinta Basin, UT)
Petron et al.	NOAA	2014	4.1±1.5% (Denver Julesburg Basin)
Caulton et al.	Purdue University	2014	2.8-17.3% (Marcellus Shale – Southwest Pennsylvania)
Peischl et al.	University of Colorado Boulder, NOAA	2015	0.18-2.8% (Fayetteville, Haynesville, and Marcellus Shale – Northeast Pennsylvania)

An important factor to consider when comparing regional estimates of leakage rates to national emissions estimates is the natural gas production associated with the emissions. The bottom-up leak rates summarized in Table 2, in most cases, reflect emissions divided by natural gas produced across multiple regions, and in some cases national emissions divided by total U.S. natural gas production. This methodology effectively averages out regional variability. If one basin has low emissions and high production, that basin would have a low leak rate. If another has high emissions and low production, that basin would have a high leak rate. When the two are combined on a production-weighted basis, the leak rate will be closer to the basin with the lower rate than the basin with the higher rate. Since top-down studies focus on individual basins – or parts of basins – the individual studies are not directly comparable to multi-basin or national bottom-up studies.

Production and emission rate data included in the Peischl et al. is useful for exploring this issue. As shown on the right side of Figure 5, the areas of the Fayetteville, Haynesville, and Marcellus shale formations that were sampled as part of the Peischl et al. study had significantly lower leak rates (represented by the green dots) and significantly higher production rates (represented by the blue bars) when compared to the studies of the Denver-Julesburg and Uinta basins. If the average data shown in Figure 5 is combined to develop a production-weighted vented and fugitive emission rate across the sampled basins, the rate would be about 1.7 percent.

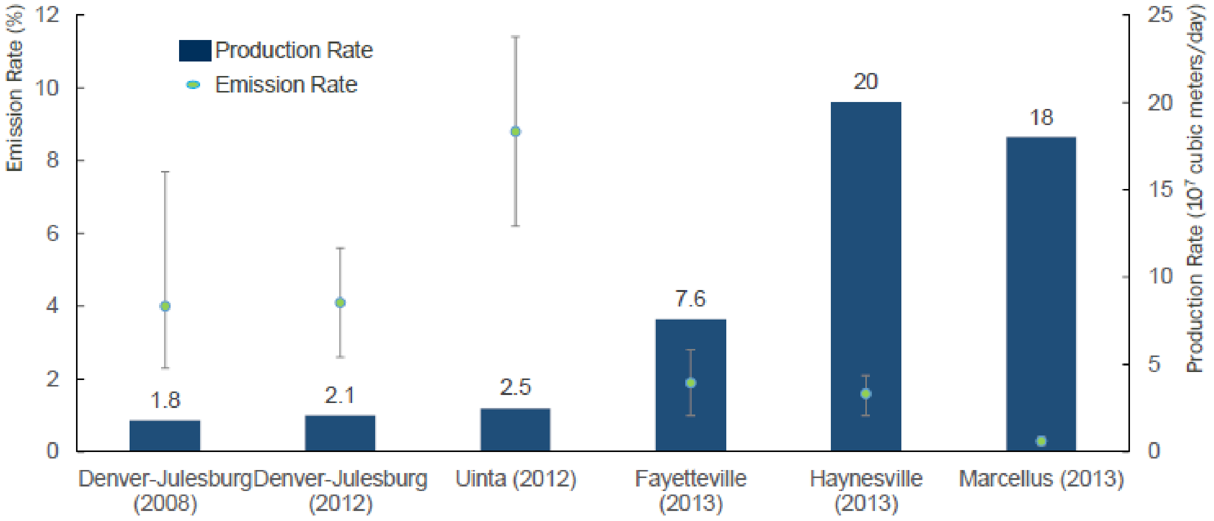
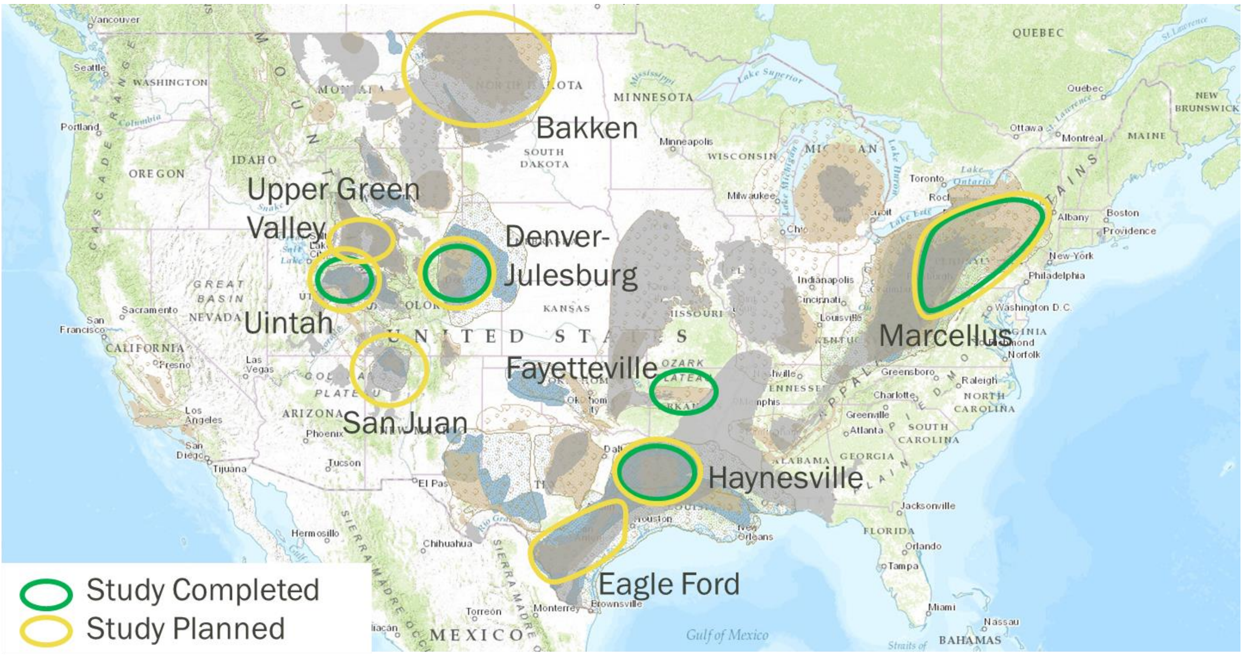


Figure 5. Estimated Basin Emission Rates by Production Rate

The Peischl et al. study did not include a review of the Caulton et al. study of emissions from the Marcellus in the southwest corner of Pennsylvania (a different area than that sampled by Peischl et al. who focus on the northwest corner of the state). Caulton et al. suggested that the high emission rates found in their study of the Marcellus formation in southwestern Pennsylvania may be the result of coal bed methane escaping unpressurized wellbores during drilling, a combination of unique geology and work practices. This reinforces the idea of regional variability, even within the same formation.

More research is needed to understand the underlying causes of regional variability. For example, Peischl et al. suggest that their leakage estimates may be lower, especially in the part of the Marcellus they observed, because production in the area is more recent and the use of newer and more efficient technologies may reduce leakage.[18] The basins surveyed by Peischel et al. are all shale gas plays, and differences in gas composition and regulations could also contribute to regional variability. Additionally, legacy natural gas and oil infrastructure may contribute to methane emissions in production areas. Areas that have been producing oil and gas for decades likely have older equipment with a greater potential for leaks. In addition to existing production-related equipment, legacy infrastructure also includes abandoned and unplugged wells, which are not accounted for in the GHG Inventory.

Continued study of top-down emissions will add to the understanding of emission rates. Figure 6 highlights areas with studies that have been recently published by researchers affiliated with NOAA as well as areas where studies are forthcoming. The new data will provide researchers with a comparison point for recent studies as well as coverage of new parts of the country.



Source: EIA, MJB&A Analysis

Figure 6. NOAA-led Top-Down Methane Measurement Studies

Uncertainties

Just as there are uncertainties in development of bottom-up estimates of emissions, there are uncertainties in the development of top-down estimates of emissions. The following discussion summarizes two main challenges that introduce uncertainty in top-down emissions estimates: timescale and attribution of atmospheric methane to specific source categories.

The timescale for top-down studies is often very short and fluctuating wind speed, direction and other atmospheric changes can result in unreliable flux measurements. The methane leakage rates in four of the top-down studies in Table 5 are derived from data collected on only one or two measurement flights. Because methane emissions fluctuate on a daily basis, it is difficult to determine if emissions observed on the day measurements were taken are representative of normal emissions from a particular region. This is similar to the challenge in bottom-up studies of having enough samples to draw statistically-significant conclusions. The 2012 study by Petron et al. differs from the other four in that it largely relies on data collected from a stationary tower that collected daily air samples and, therefore, represents a longer timeframe.

Another component of timescale is the mismatch in the atmospheric concentration and natural gas production data; concentration data is typically an average taken over only a few minutes or a few hours, while available production data is typically reported for an entire month. To calculate an average leak rate, top-down studies must correlate the correctly-apportioned atmospheric concentrations (and resulting estimated flux rates) at a point in time to production activity in the area at that time. Correlating a limited set of measured atmospheric concentrations to production is complicated by the fact that many methane leak sources are periodic, rather than continuous in nature, as well as being geographically disbursed.

Attribution of atmospheric methane to specific source categories represents another challenge for top-down studies. Many natural gas production areas have multiple sources of methane emissions. Landfills, agriculture, coal mines, wastewater treatment plants, abandoned wells and natural seeps all emit methane. Oil production, which is often interspersed with gas production, can also be a significant source of methane. Atmospheric measurements capture all of these emissions, and isolating the methane associated with natural gas production activities can be difficult. Top-down studies often use bottom-up inventories, or replicate bottom-up methodologies, to estimate total non-gas methane emissions within the study area, which are then subtracted from the measured amount of methane to calculate gas-related emissions. The uncertainties associated with bottom-up estimates can, in this way, influence the apportionment of atmospheric methane concentrations to specific source categories.

Top-down studies can also apportion atmospheric emissions to the oil and gas sector by correlating observations of other hydrocarbons which are not emitted by biogenic sources, such as propane, to estimated oil and gas-related methane emissions. This improves the source apportionment but does not provide a way to distinguish between natural gas system sources and other oil and gas sources such as petroleum sources, natural seeps, or abandoned wells.

Role of Bottom-up and Top-down Studies

A February 2014 study by Brandt et al.[19] examines the relationship between bottom-up and top-down methane studies. The study compares over 200 published methane emissions estimates on a wide range of scales, from emissions measured at individual devices to continental-scale atmospheric emissions readings. To account for the spatial and temporal variability inherent to top-down studies, Brandt et al. normalized the atmospheric studies to baselines derived from EPA's 2013 GHG Inventory. After normalization, the researchers found that national-scale atmospheric measurements typically estimated total U.S. methane emissions to be about 1.5 times greater (based on a range of 1.25 to 1.75 times) than total estimated methane emissions in in the 2013 GHG Inventory.

The study emphasizes that this comparison of atmospheric methane levels to GHG Inventory estimates includes more than just natural gas-related emissions. While natural gas systems were the second largest source of methane emissions in the 2014 GHG Inventory, the inventory includes estimates of methane emissions associated with enteric fermentation, coal mining, landfills, manure management, and other sources. The additional emissions found in atmospheric studies could be a result of underestimation of any one or a combination of the sources in the inventory, or they could be the result of emissions not included in the inventory. For example, EPA does not attempt to quantify emissions associated with natural geologic seeps of methane or leaks attributable to abandoned oil and gas wells.

The overall conclusion of the study follows the view held by many that bottom-up estimates seem to underestimate methane emissions while top-down estimates seem to overestimate emissions. Brandt et al. suggest that a better understanding and accounting of all methane sources is essential to accurately distinguishing and measuring methane specifically from the natural gas value chain.

While leak rates estimated by both bottom-up and top-down studies each have their uncertainties, together they provide a clearer picture of actual methane leakage from natural gas systems. With top-down studies generally finding higher leakage rates than bottom-up studies, work to determine the sources of this emissions gap is a key next step. New bottom-up studies, particularly those that measure individual components and develop updated emissions factors, continue to improve understanding of leaks from individual components, technologies, and activities. However, given the uncertainties, the development of an accurate, national leak rate remains a significant challenge.

Additional research on atmospheric methane levels and source-specific emissions is ongoing and new studies will be carried out over the next year. Included in these is a NOAA study that will analyze data from flights taken over the Bakken, Upper Green Valley, Uintah, Denver-Julesburg, Haynesville, Eagle Ford, and Marcellus basins in spring 2015.[xiv] These data will be used to develop region-specific top-down methane leak rates for each area, providing new information for certain regions and adding to existing data for others. Another study, part of the EDF-led initiative, includes both top-down and bottom-up measurements of methane emissions from the Barnett basin. This study will attempt to reconcile differences between the two types of measurements and provide new insights on allocating emissions to specific industries. Another NOAA top-down study of the Bakken, San Juan, and Denver-Julesburg regions was launched in 2014 and will continue in 2015 .[xv] These studies will improve understanding of methane emissions on both regional and national scales, and will help reconcile discrepancies between top-down and bottom-up estimates of methane emissions and methane leak rates.

A key component of new studies coordinating bottom-up and top-down research is the focus on specific regions. Given regional differences in geology, work practices, and regulations, regional emissions inventories informed by atmospheric methane measurements can provide more accurate emissions estimates than national inventories developed with generic emissions factors. The combination of bottom-up and top-down studies can help address the difficulties of accounting for super-emitters as well as non-natural gas system methane emissions. National inventories based on regional estimates may therefore more accurately portray actual emissions than estimates such as the GHG Inventory, which apply many identical assumptions to natural gas systems regardless of their location.

While researchers have emphasized the potential for using regional bottom-up and top-down studies to improve national emissions estimates, basin-specific studies may prove more useful to regional system planners and policymakers. Many regions source their natural gas from specific production areas and consideration of national emissions rates may not be as informative in the development of regional GHG policies.

[xiv] See NOAA's "SONGNEX 2015": http://www.esrl.noaa.gov/csd/projects/songnex/

[xv] See NOAA's "TOPDOWN 2014": http://www.esrl.noaa.gov/csd/groups/csd7/measurements/2014topdown/

4. Review of Research on Fugitive and Vented Methane Emissions from Coal Extraction

While much of the research focus in recent years has been on methane emissions from the natural gas life cycle, methane is also released during coal extraction. Coal mine methane emissions are usually directly related to the quality and depth of a coal deposit. Coal and methane form together underground, with methane filling the coal seam and surrounding rock. Higher quality coals (i.e., coals with a higher energy density) tend to have higher methane content, and the higher pressures found in deeper underground deposits increase the capacity of coal and rock to store methane. Consequently, below-ground coal mines generally emit more methane than surface mines. In 2012, underground mines made up 40 percent of total coal mines in the U.S. but accounted for over 80 percent of estimated coal mine methane emissions.[20]

Historically, coal mine methane concentrations have been controlled for safety, to reduce risk of explosion in mines. Federal regulations require all working places and air intakes at coal mines to maintain methane concentrations below one percent – this is typically done by ensuring adequate air movement through the mine using ventilation systems.[21] Ventilation systems pump fresh air into the mine to dilute methane concentrations. In these systems, methane escapes to the atmosphere through exhaust shafts. Degasification systems consist of well bores sunk into the coal seam to drain methane before, during and after mining.[22] If it is not captured, methane escapes through these wells to the atmosphere. More recently, efforts have been made to capture coal bed gas for use as a fuel, and to reduce climate impact.[xvi] For example, in 2012, 28 percent of methane emissions (738 Gg CH_4) from underground mines was captured and used, compared to eight percent in 1990.[23] At surface mines, methane is emitted from both the exposed coal and removed overburden. Due to the lower methane content and the nature of surface mining, methane venting or capture is not usually required or practical at surface coal mines.

A 2012 NREL harmonization (NREL, 2012) of life cycle GHG emissions estimates from coal used to generate electricity included methane emissions from coal mining. Using the studies that disaggregated coal mine methane emissions from their life cycle emissions estimates, NREL estimated that these emissions contribute on average 63 kg CO_2e/MWh (or about 6.3 percent) to coal's life cycle GHG emissions, assuming a GWP of CH_4 of 25.[24] Apart from their contribution to life cycle emissions, natural gas systems emit significantly more total methane than coal mines, with each source responsible for 23 percent and ten percent, respectively, of U.S. methane emissions in 2012.[25]

[xvi] For example, coal mine methane emissions are addressed in the Climate Action Plan released by the Obama Administration in 2014.

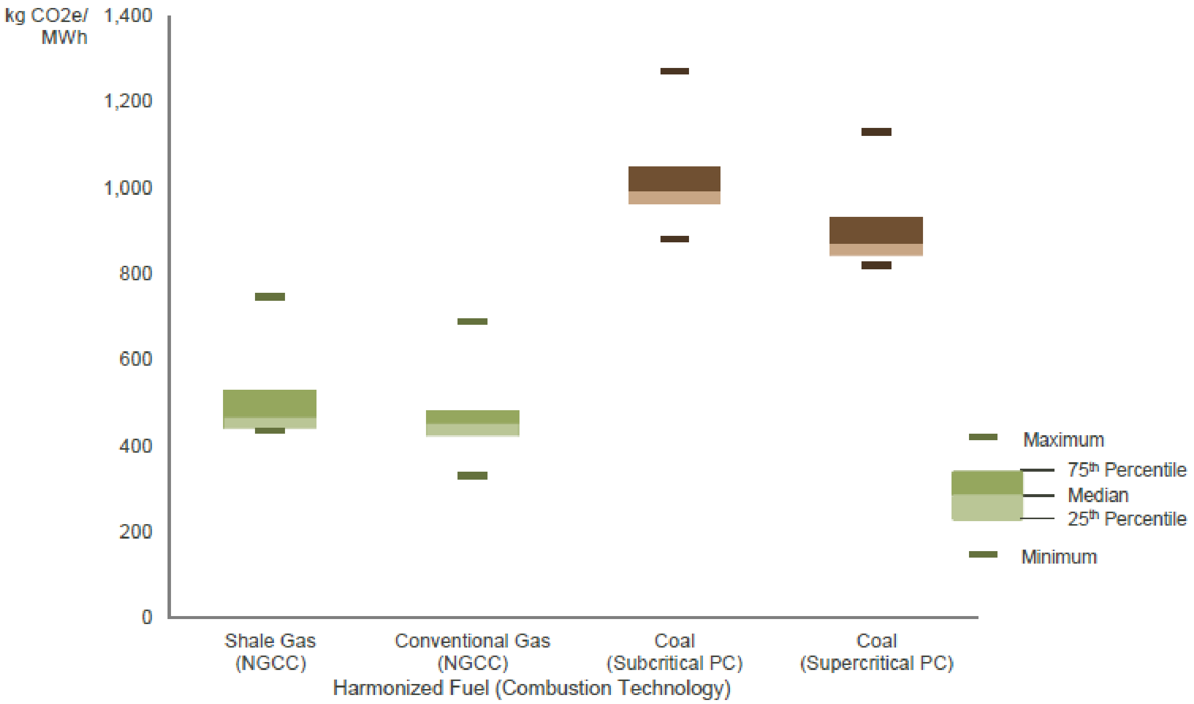
5. Life Cycle Electric Power Greenhouse Gas Emissions

This report focuses on the life cycle GHG emissions of natural gas used in a natural gas combined cycle (NGCC) unit for electricity generation as compared to coal used in a pulverized coal boiler for electricity generation. In addition to assessing average emissions from various natural gas sources, researchers have worked to identify life cycle emission differences between shale or unconventional gas and conventional gas. The majority of published literature indicates that life cycle emissions from unconventional and conventional gas are very similar, with unconventional gas having slightly higher emissions. The additional emissions are likely the result of hydraulic fracturing, and handling of flowback during completion operations, as these are two of the significant activities unique to unconventional gas.

Across the literature, studies that use a 100-year GWP have found that life cycle emissions for electricity produced from natural gas fired in a NGCC unit are about half the life cycle emissions associated with electricity produced from coal fired in a pulverized coal boiler. As part of the research effort at JISEA, researchers from NREL completed a series of harmonization studies - the most recent is the shale gas-related study referenced in the bottom-up discussion above. In addition, in January 2014, JISEA/NREL researchers published a review of 42 studies of life cycle emissions associated with conventional natural gas combusted for electricity generation.[26] The assessments build on an April 2012 NREL study that reviewed 53 studies of life cycle emissions associated with coal combusted for electricity generation. [27]

Figure 7 shows the estimated life cycle emissions associated with four different fuel/combustion technology combinations using data from the three harmonization studies (shale gas, conventional gas, and coal). The middle 50 percent values are highlighted for each study (between the 25th percentile and the 75th percentile). As shown, the median estimate of life cycle GHG emissions from electricity generated in an NGCC unit with shale or unconventional natural gas was 465 kg CO_2e/MWh (1025 lb CO_2e/MWh).[28] This compares to a median estimate of 450 kg CO_2e/MWh (992 lb CO_2e/MWh) for conventional gas combusted in an NGCC unit. Comparing those results to the harmonized estimates of life cycle GHG emissions associated with electricity generated using coal, the JISEA/NREL researchers found electricity from natural gas has approximately half the emissions associated with electricity from coal (980 kg CO_2e/MWh (2,161 lb CO_2e/MWh) across all combustion technologies). Figure 7 shows estimates for both coal in a subcritical pulverized coal boiler (the technology used by the vast majority of existing coal-fired power plants in the U.S.) and in a supercritical pulverized coal boiler. The median life cycle emissions estimate for coal in a subcritical boiler is 990 kg CO_2e/MWh (2,183 lb CO_2e/MWh) and 820 kg CO_2e/MWh (1,807 lb CO_2e/MWh) for coal in a supercritical boiler.[xvii]

[xvii] Note that the most recent JISEA/NREL harmonization study of shale or unconventional gas used a GWP for CH_4 of 30 while the previous studies used a GWP of 25. The sensitivity of these findings to GWP is reviewed below. If the conventional gas GWP was adjusted, the resulting life cycle emissions would be even closer to the shale gas emissions. If the coal GWP was adjusted the life cycle emissions would increase.



Adopted from Heath et al. 2014 by MJB&A using data from Heath et al. 2014, O'Donoughue et al. 2014, and Whitaker et al. 2012 (Corrected). Note that while all the studies use a 100-year GWP for CH_4, the shale gas study uses 30 and the conventional gas and the coal studies use 25.

Figure 7. Distribution of Harmonized Estimates of Life Cycle GHG Emissions for Natural Gas and Coal with Selected Technologies

Given the developing understanding of vented and fugitive emissions associated with the natural gas life cycle, a key question for stakeholders is whether there are threshold values at which natural gas system emission rates make electricity from natural gas fired in an NGCC unit more carbon intensive than coal fired in a pulverized coal boiler.

In 2012, a report by Alvarez et al. concluded that when used to generate electricity at an NGCC power plant, natural gas provides climate benefits over coal used to generate electricity over all time periods as long as leakage from natural gas systems, not including the distribution system, is less than 3.2 percent on a CH_4/CH_4 produced basis. Normalized to CH_4/NG produced, that is about 2.7 percent. The report found that when looking at a 100-year period, the time period used by most stakeholders, gas provides climate benefits over coal if leakage remains below 7.6 percent (6.4 percent on a normalized basis).

To explore this topic, MJB&A used data from EPA's 2014 GHG Inventory to estimate life cycle emissions associated with natural gas produced in the U.S. As shown in Table 6, we estimate a leakage rate of 1.2 percent in 2012 from production through distribution. This estimate includes all types of domestically produced gas: onshore and offshore conventional gas, shale gas, coal-bed methane, and associated gas. This leakage rate is used to quantify upstream methane emissions from natural gas systems, which are added to CO_2 emissions from upstream combustion and power plant combustion to calculate life cycle GHG emissions. In our analysis, natural gas power plants are assumed to receive gas directly from transmission pipelines. As such, the leakage rate used in our calculation is 0.96 percent and methane emissions from distribution systems are not accounted for in our life cycle estimate.

Table 6. Estimated 2012 Methane Emissions and Percent Leakage Rate Based on 2014 GHG Inventory

Segment	Estimated Methane Emissions (Gg CH_4)	Leakage Rate, U.S. Natural Gas (CH_4/NG Produced)[a]
Conventional (Onshore and Offshore) Gas, Shale Gas, and Coalbed Methane Production	1,992	0.35%
Associated Gas Production[b]	520	0.09%
Processing	892	0.16%
Transmission and Storage	2,071	0.37%
Distribution	1,231	0.22%
Total Natural Gas Life Cycle Vented and Fugitive Emissions	6,706	1.18%
Natural Gas Life Cycle Vented and Fugitive Emissions less Distribution	5,475	0.96%

Based on estimated emissions from Natural Gas Systems and Petroleum Systems in EPA's 2014 GHG Inventory, natural gas gross withdrawals by source as reported by EIA, and MJB&A analysis.
a. U.S. gross natural gas withdrawals (gas wells, shale gas wells, coalbed wells, and associated gas wells minus Alaska gas wells) reported by EIA as 29,434,440 million cubic feet in 2012.
b. Associated gas production-related emissions estimated as 35% of petroleum system production-related emissions following Alvarez et al.

Figure 8 shows the results of our analysis. The life cycle natural gas emissions are based on average U.S. natural gas fired in an NGCC unit with a 51 percent efficiency (consistent with the efficiency used in the JISEA/NREL harmonization study). To calculate upstream emissions on a CO_2e basis, we use the most recent IPCC 100-year GWP for CH_4, including climate feedbacks (34).[xviii] Upstream CO_2 emissions are assumed to be 45 kg CO_2/MWh (99 lb CO_2e/MWh) based on Heath et al. Upstream fugitive and vented CH_4 emissions are shown using two different scenarios: (1) a 2014 Inventory Scenario based on a fugitive and vented CH_4 rate of 0.96 percent and (2) an Extreme Scenario based on a fugitive and vented rate of just under four percent.

The Extreme Scenario reflects the 2014 Inventory Scenario with additional emissions based on the upper bound of atmospheric methane not accounted for in the GHG Inventory as found by Brandt et al. Brandt et al. estimated excess atmospheric emissions of seven to 21 teragrams (Tg) of CH_4. Adding the upper bound (21 Tg) to the estimated natural gas system emissions in the 2014 GHG Inventory (6.7 Tg), we get a maximum potential emissions estimate of 27.7 Tg. By multiplying the 2014 Inventory Scenario rate by 4.1 (27.7 divided by 6.7), we create a scenario where all observed excess atmospheric methane is attributed to the natural gas system. As discussed earlier, Brandt et al. emphasize that excess atmospheric methane could be attributed to a range of sources beyond the natural gas system. The researchers call the attribution of the entire excess to natural gas systems a worst-case scenario.[xix] By following this methodology, we believe we have created a scenario based on best available science that represents a maximum upper limit for potential emissions from the U.S natural gas system as it relates to the electric power sector.

[xviii] See the sidebar in Section 2 of this report for background on the GWP.

[xix] See page 29 of the Supplemental Materials for Brandt AR, et al. (2014) Energy and Environment. "Methane leaks from North American natural gas systems". Science 343(6172):733–735. Available at: http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf.

The life cycle coal emissions are calculated for an average U.S. pulverized coal unit (34 percent efficiency). Upstream fugitive and vented CH_4 emissions are based on Whitaker et al. (updated to use a 100-year GWP of 34) and upstream CO_2 emissions are based on Alverez et al.

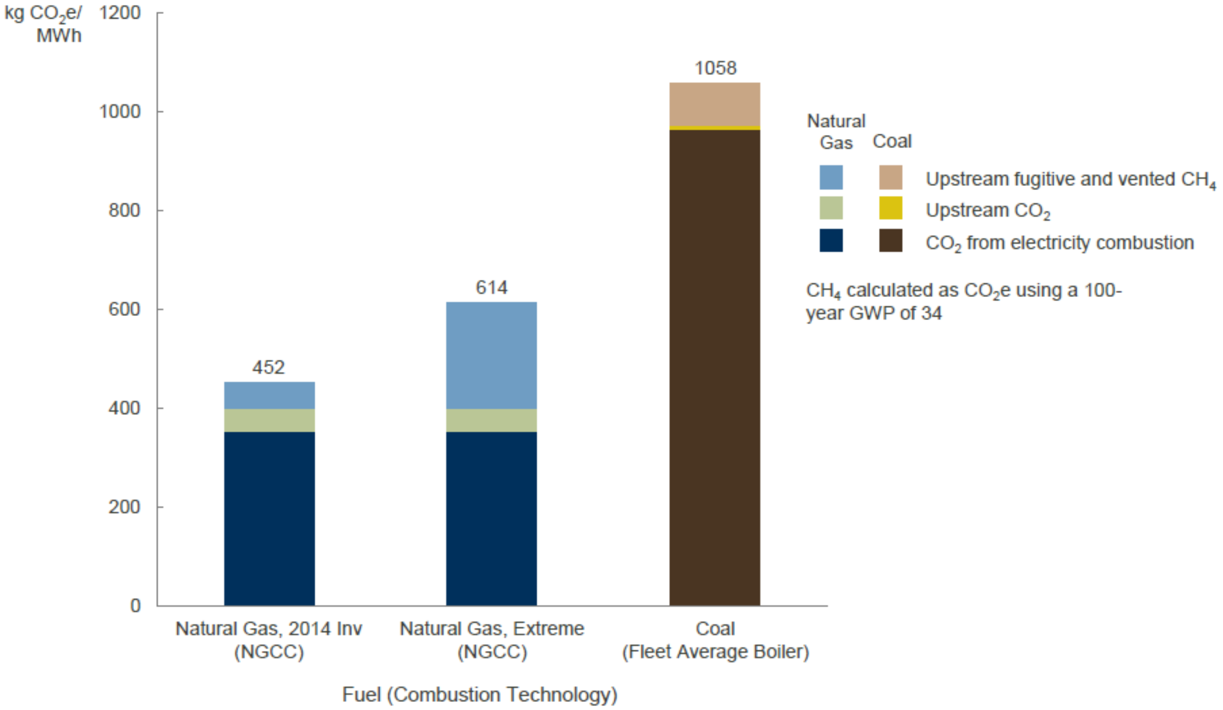


Figure 8. MJB&A Estimated Life Cycle Emissions for Natural Gas- and Coal-based Electricity Generation

The 2014 Inventory Scenario natural gas life cycle value is consistent with the harmonized values. It is slightly below the median shale gas and slightly above the conventional gas life cycle values in Figure 7 (465 and 450 kg CO_2e/MWh, or 1,025 and 992 lb CO_2e/MWh, respectively). The Extreme Scenario values are above the 75th percentile values reported in Figure 7. The coal values are slightly above the median subcritical coal value (990 kg CO_2e/MWh or 2,183 lb CO_2e/MWh). Some of the differences are the result of using updated GWP values for methane.

For both coal and natural gas, CO_2 from fuel combustion at a power plant generates the majority of life cycle emissions. While upstream methane leaks and combustion emissions contribute to total GHG emissions, power plant combustion accounts for approximately 80 percent of life cycle emissions for gas in the 2014 Inventory Scenario and 90 percent for subcritical coal. For natural gas, GHG-emitting upstream life cycle stages include preproduction, production, processing, and transmission. For coal, upstream stages are coal mining and mine reclamation, processing, and transport.

When burned in our model NGCC unit to generate electricity, natural gas emits roughly 60 percent less CO_2 relative to burning coal in an average boiler to generate electricity. For coal to provide climate benefits over natural gas, upstream emissions from gas must exceed this end-use emissions differential. Two variables that could significantly reduce this differential are an increase in the amount of vented and fugitive emissions associated with natural gas and upward adjustments in the GWP of CH_4 relative to CO_2. For the MJB&A modeled life cycle estimates, Figure 9 shows that the leak rate of vented and fugitive emissions from the natural gas value chain would have to be just over 12 percent for life cycle GHG emissions associated with NGCC to equal life cycle GHG emissions associated with a fleet-average coal-fired boiler. This is significantly higher than the one to four percent leak rates associated with the 2014 Inventory and Extreme Scenarios described above.

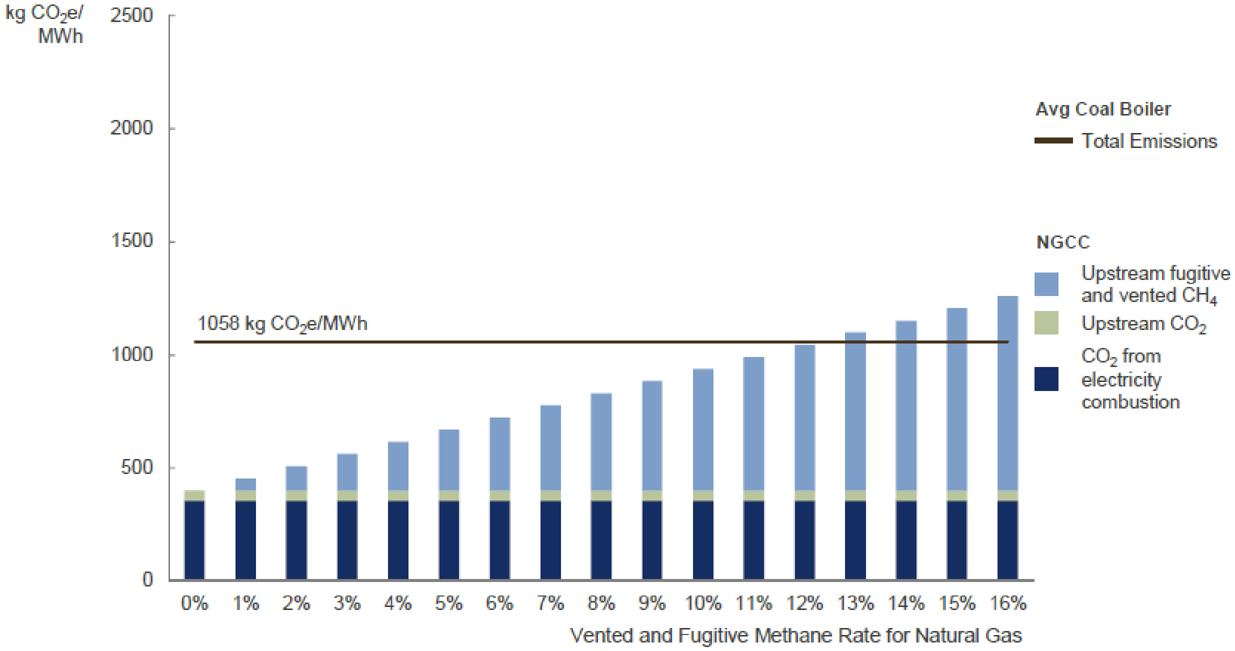


Figure 9. Life Cycle Emissions for NGCC at Various Methane Leak Rates, 100-year GWP

Figure 10 shows the same comparison using the most recent 20-year GWP, with climate feedbacks (86). Although the 100-year GWP is used by EPA and most domestic and international policymakers, understanding the impact of methane emissions over a 20-year period can be instructive when comparing options for reducing near-term climate risks. The change in GWP lowers the crossover point between the NGCC option and the coal-based options but also increases the estimated carbon intensity of the coal-based options. With a 20-year GWP, generating electricity with a fleet average coal boiler has a carbon intensity of 1,189 kg CO_2e/MWh (2,621 lb CO_2e/MWh). The methane leak rate at which electricity generated by a NGCC unit would have greater life cycle GHG emissions than a fleet-average coal boiler is about 6 percent.

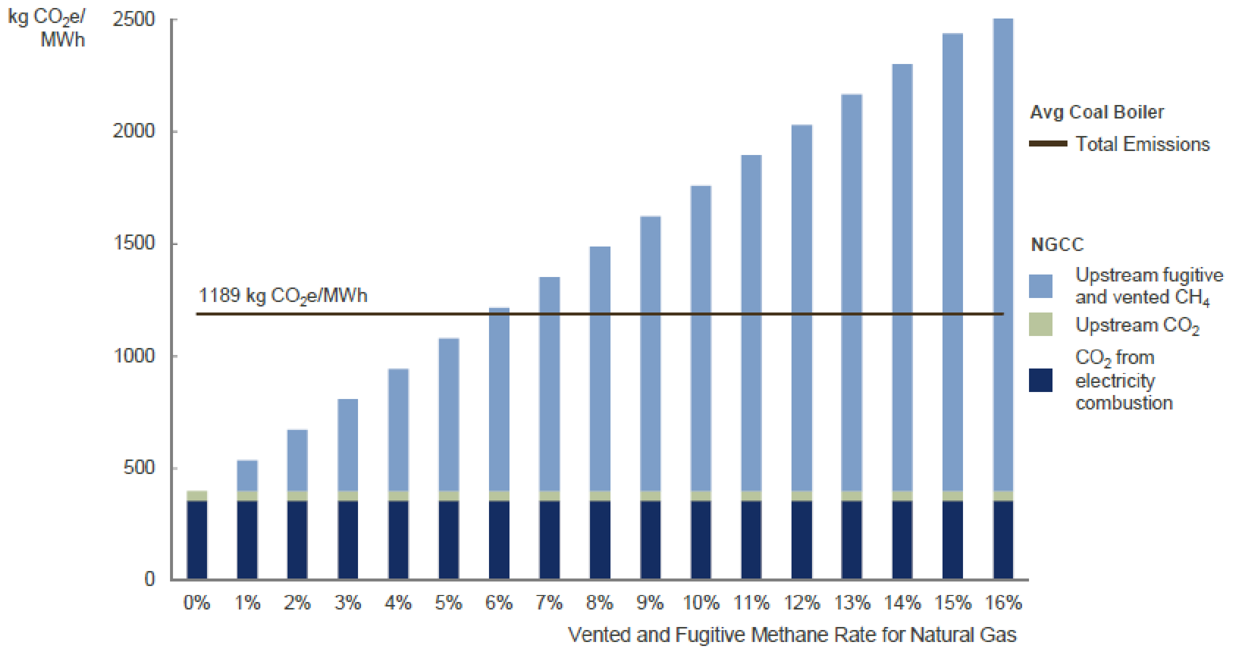


Figure 10. Life Cycle Emissions for NGCC at Various Methane Leak Rates, 20-year GWP

Another factor that could close the gap is an increase in coal plant efficiency or a decrease in gas plant efficiency. A report by the Carnegie Institution for Science published in November 2014 follows a different methodology to explore the climate impacts of natural gas and coal used to generate electricity.[29] In the report, Zhang et al. compare how natural gas and coal affect global mean temperature over a 100-year period across a range of upstream methane leakage and power plant efficiency scenarios. Assuming a power plant operating time of 40 years, the report found that natural gas provides long-term (100 year) climate benefits over coal under almost every scenario.[xx] Coal can provide short-term climate benefits over natural gas when there are higher rates of methane leakage from upstream natural gas systems. However, due to the relatively short life-span of atmospheric methane, the impacts of upstream methane emissions decrease after plant closure and CO_2 emissions are responsible for the majority of temperature change in the long term. As such, Zhang et al. found that power plant efficiency has a larger impact on climate effects than upstream methane leakage.

Zhang et al. conclude that when fired in the most efficient natural gas power plant (60 percent efficiency), natural gas has short and long term benefits over the average coal plant (34.3 percent efficiency) when upstream methane leakage is below approximately five to six percent. Leakage must be under two percent for gas to provide near-term benefits over the best performing coal plant, a non-commercial experimental IGCC unit with an efficiency of 51 percent. For the average gas plant evaluated by Zhang et al. (40.3 percent efficiency) to have benefits over the average coal plant in the near term, upstream emissions must be below three percent.

A key concept highlighted by the Zhang et al. study is the importance of power plant efficiency when evaluating life cycle emissions. Using the emission estimates described above, Figure 11

[xx] Coal was better than gas under all leakage rates when a typical gas plant (40.3 percent efficiency) was compared to the best coal plant (51 percent efficiency) over a 100 year period.

shows the 100-year GWP crossover point for a range of natural gas power plant efficiencies as compared to an average coal-fired boiler with an efficiency of 34 percent and a supercritical coal-fired boiler with an efficiency of 39 percent. As shown, less efficient natural gas power plants have a lower vented and fugitive emissions crossover point. However, from a system planning perspective it is important to keep in mind that power plants are not directly interchangeable. Lower efficiency gas turbines, such as simple cycle turbines, or NGCC power plants designed to cycle, may provide system flexibility as more variable resources, such as wind or solar projects, are added to the grid. In such cases, it could be informative to review the life cycle emissions of all electricity on the system, not just individual power plants.

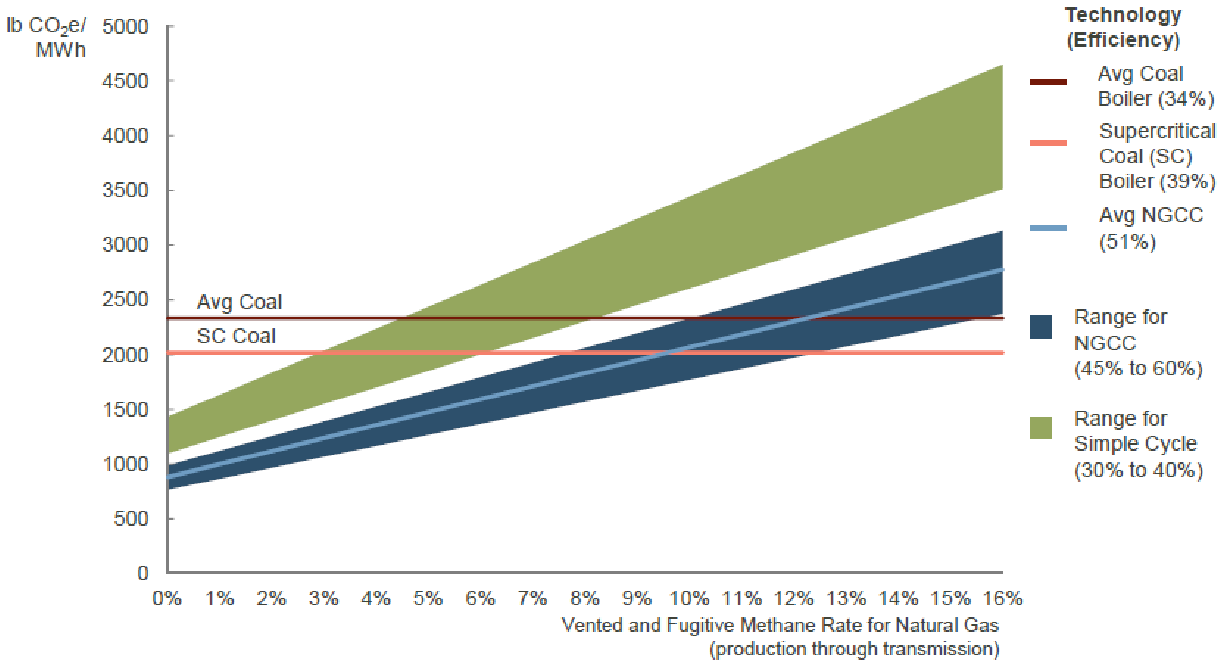
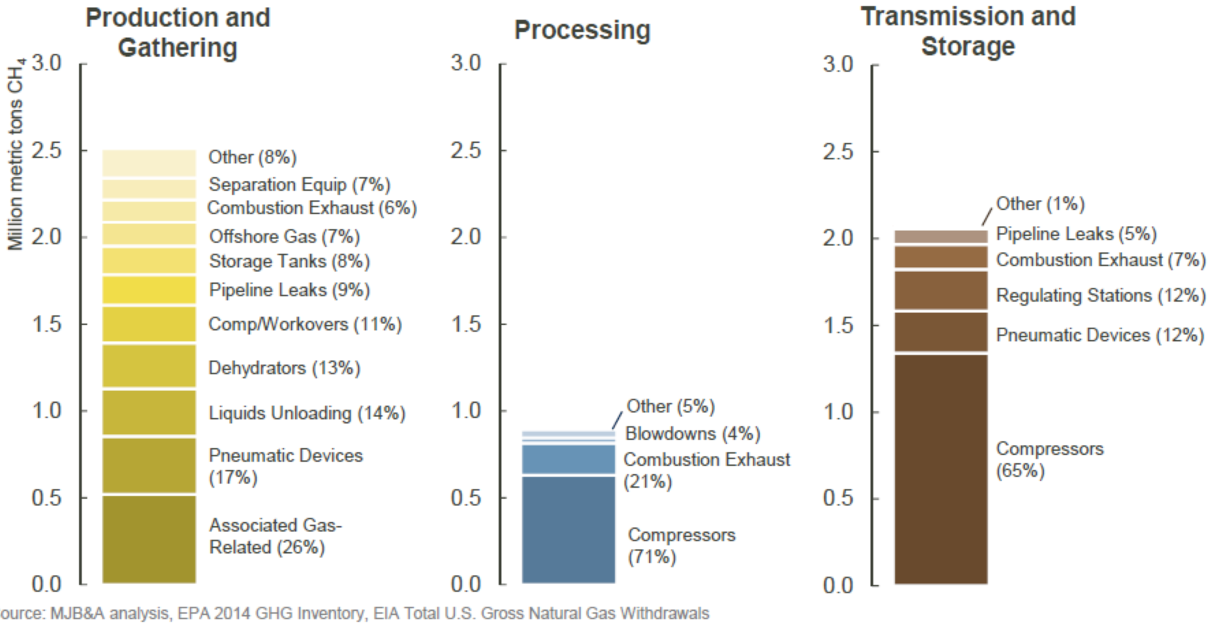


Figure 11. Life Cycle Emissions at Different Power Plant Efficiencies, 100-year GWP

6. Key Sources of Vented and Fugitive Emissions and Potential Control Technologies and Strategies

Underlying the 2014 GHG Inventory are emission factors and activity data for the major methane emission sources within the natural gas sector. Figure 12 shows the reported sources of methane across the natural gas system, excluding the distribution system which we did not include in our analysis of life cycle emissions associated with NGCC based on the assumption that the majority of power plants receive gas directly from transmission pipelines. About 46 percent of the upstream emissions we included in our analysis were from production and gathering. Another 38 percent are from transmission and storage, and the remaining 16 percent are from the processing segment.



Source: MJB&A analysis, EPA 2014 GHG Inventory, EIA Total U.S. Gross Natural Gas Withdrawals

Figure 12. Natural Gas System Emission Sources by Segment

As shown in Figure 12, the largest source of emissions in the production and gathering segment are the result of associated gas recovery. These emissions include emissions from the well completions and workovers at petroleum wells as well as pneumatic devices, compressors, and fugitive emissions used during petroleum production and associated gas recovery. Within the processing and transmission and storage segments, compressors are the largest source of emissions, accounting for 71 percent and 65 percent of emissions from each of the segments, respectively. Across all segments, the majority of methane emissions come from existing sources. A 2014 study by ICF International projected that despite recent growth in oil and gas production, existing sources (existing in 2011) will be responsible for nearly 90 percent of methane emissions in 2018.[30] Reductions from existing sources are therefore a key component of reducing overall emissions from the oil and gas industry.

In April 2014, EPA released five technical white papers on potential sources of significant methane emissions in the oil and gas sector.[xxi] The technical white papers were announced as part of the Obama Administration's Strategy to Reduce Methane Emissions, which directed EPA to collect information which would help determine how to best pursue methane emission reductions.[31] The technical white papers cover five categories of emission sources:

1) compressors;

2) hydraulically fractured oil wells;

3) leaks;

4) liquids unloading; and

5) pneumatic devices.

These sources cover many of the most significant sources identified in Figure 12. The paper focused on "leaks" covers fugitive emissions. In Figure 12, fugitive emissions correspond to a range of categories including separation equipment, storage tanks, pipeline leaks, and transmission stations. The papers detail how methane is emitted from each source category and known and emerging emission mitigation techniques. This section provides information on these emissions sources and control strategies, as provided in EPA's white papers. In the papers, EPA notes that reducing fugitive and vented emissions can result in more gas being delivered to sales and, therefore, EPA includes the revenue from additional gas sales when evaluating the costs of control technologies.

The 2014 ICF International report calculated the cost effectiveness of reducing methane emissions from sources throughout the oil and gas sector value chain. While EPA's white papers summarized capital costs for control strategies based on existing literature, the white papers contain little information on the cost effectiveness of those controls. Where appropriate, EPA included a summary of ICF's cost effectiveness data, but ICF's analysis did not include all of the control strategies reviewed by EPA. We would expect that any future EPA regulatory process would include technical information on the cost effectiveness of controls and provide stakeholders with an opportunity to provide feedback on the assumptions. Based on the technical feedback provided on the white papers, we expect the cost and effectiveness assumptions will be a key areas for stakeholder comment.

In its report, ICF found that the cost effectiveness of emission reduction strategies varies widely, based on the technique implemented and the segment targeted. For example, in gas production, control strategies ranged from a net cost of $3.51/Mcf methane reduced for leak detection and repair (LDAR) at gas wells to a net profit of $4.05/Mcf for electrifying Kimray pumps (by assuming captured or controlled methane is sold, ICF found some controls resulted in revenues that exceeded costs). As another example, replacing high bleed pneumatic devices in production and gathering and boosting netted gains of $2.78/Mcf and $2.83/Mcf, respectively, but had a net cost of $2.59/Mcf in natural gas transmission.

[xxi] The technical white papers are available at http://www.epa.gov/airquality/oilandgas/whitepapers.html.

EPA has posted a range of technical peer review responses to the white papers from academic, industry, and environmental organization experts.[xxii] Additionally, EPA opened a docket to catalog public responses to the technical white papers (docket ID # EPA-HQ-OAR-2014-0557). The summary below focuses on the white papers, not the range of responses to the technical white papers.

Compressors

Natural gas compressors are located throughout the natural gas value chain, from production through transmission and storage. Two types of compressors commonly used in the gas industry are reciprocating and centrifugal compressors. Reciprocating compressors use crankshaft-driven pistons to compress gas. The piston rods are fitted with a series of flexible rings set in metal cups, collectively known as rod packing, designed to create a seal between the gas compression chamber and the atmosphere. However, gas can escape around these seals, with leaks increasing as the rings wear with use. Centrifugal compressors use an impeller attached to a rotating shaft to increase the velocity of gas, which is then converted to increased pressure. Gas can escape from these compressors through seals where the compressor shaft exits the compressor housing.

Emissions from reciprocating compressors can be controlled by regularly replacing the piston rod packing or recovering the leaked gas. Although even new rod packing leaks, packing wears down over time with use so the control effectiveness of packing replacement is directly related to how often the packing is replaced. ICF's study found that rod packing replacement reduced emissions at existing compressors by 98 percent when performed every three years. The study also found that the payback period for rod packing replacement is seven months, assuming replacement every three years at a cost of $2,000 with an assumption that recovered natural gas can be sold for $4.00 per thousand cubic feet (Mcf). By contrast, depending on the use of the compressor, EPA found capital costs for rod packing replacement that ranged from $4,050 to $7,290 per compressor. Table 7 shows EPA estimates of emissions reductions and costs associated with replacing rod packing every four years.

Table 7. EPA Summary of Reciprocating Compressor Rod Packing Replacement Emission Reductions and Costs

Oil & Gas Segment	CH_4 Reduction per Compressor (tons/compressor-year)	Capital Cost per Compressor ($2008)	Value of Recovered Gas over Equipment Life per Compressor[a]
Production (well pads)	0.158	$6,480	$2,493
Gathering & Boosting	6.84	$5,346	$1,669
Processing	18.6	$4,050	$1,413
Transmission	21.7	$5,346	$1,669
Storage	21.8	$7,290	$2,276

Source: EPA White Paper-Oil and Natural Gas Sector Compressors
a. Assuming natural gas prices of $4/Mcf

Gas recovery systems are a second emission mitigation strategy employed to reduce methane leaks from reciprocating compressors. These systems capture gas that leaks through rod

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[xxii] The peer review responses are available with the technical white papers at http://www.epa.gov/airquality/oilandgas/whitepapers.html

packing, often allowing the gas to be sold or used as a fuel. EPA identifies three technologies used to capture rod packing emissions: a device made by REM technology that routes gas back to compressor to be used as fuel; vapor recovery units (VRU) that capture gas for sale or onsite use; and systems that capture gas and send it to a flare. EPA does not provide information on the cost or prevalence of any of these technologies, but notes that VRUs would only be economically attractive if an existing system can be retrofitted to capture gas from compressor rod packing. Table 8 provides information on the control effectiveness of rod packing gas capture systems.

Table 8. EPA Summary of Control Efficiency of Rod Packing Gas Capture Systems

Technology	Control Efficiency
REM Technology system	99%
VRU	95-100%
Flare	95%

Source: EPA White Paper-Oil and Natural Gas Sector Compressors

Methane emissions from centrifugal compressors can be controlled through the installation of dry seals, the flaring of leaked gas, or the capture and use of leaked gas. Centrifugal compressors with wet seals use oil circulated at high pressure around the rotating shaft to prevent gas from escaping. During this process, gas mixes with the oil and is released to the atmosphere as the oil recirculates. Replacing wet seals with dry seals eliminates oil degassing and significantly reduces methane emissions and operating costs. ICF reports the cost of installing a new dry seal compressor to be over $300,000 and the cost of retrofitting a wet seal compressor with a dry seal to cost $400,000. In its white paper on compressors, EPA finds that the price difference between a brand new wet seal compressor and a brand new dry seal compressor is about $75,000 per compressor and uses that as an estimate for the cost of installing dry seals on a wet seal compressor. The cost-effectiveness of dry seal compressors in the processing stage is improved by the value of gas that would otherwise be emitted.

Capturing and flaring or using the gas leaked from wet seal centrifugal compressors are two additional strategies to reduce methane emissions from these sources. EPA assumes that either of these strategies reduce methane emissions by 95 percent. Flaring reduces methane emissions but also eliminates the potential to sell or use the gas. Captured gas can be used to fuel compressors, fed back into the pipeline, or used to fuel other onsite engines. The cost of systems that capture and reuse gas are offset by the value of recovered gas. Table 9 shows EPA's reported emissions reductions and costs for centrifugal compressor wet seal gas capture systems.

Table 9. EPA Summary of Costs Associated with Controlling Emissions from Centrifugal Compressors

Segment	Captured Gas Sent to Flare		Captured Gas Reused	
	CH_4 Reduction / Compressor (tpy)	Cost/Compressor ($2008)	CH_4 Reduction / Compressor (tpy)	Cost/Compressor ($2008)
Processing	216	$67,918 $98,329 annual O&M	216	$22,000
Transmission & Storage	120	$67,918 $98,329 annual O&M	120	$22,000

Source: EPA White Paper-Oil and Natural Gas Sector Compressors

Hydraulically Fractured Oil Well Completions and Recompletions

Many oil wells in the United States also produce natural gas. At hydraulically fractured oil wells, this co-produced gas flows up the well during both the flowback and production phases. Because these wells are drilled to capture oil, infrastructure is often not developed to capture natural gas. In many circumstances it is more cost-effective for developers to flare or vent co-produced gas than to capture it. Oil well development also often outpaces the rate that gas infrastructure is built, or is in remote regions far from existing pipelines. For example, in 2014, gas co-produced at oil wells in North Dakota was flared at a monthly average of 28 percent total gas produced, equal to 10,652,632 thousand standard cubic feet (scf) flared per month.[32] Flaring significantly reduces methane emissions compared to direct venting of co-produced gas (in past rulemakings, EPA has assumed a 95 percent destruction rate for flaring), but still results in upstream GHG emissions in the form of CO_2.

Techniques to mitigate flowback-related methane emissions from hydraulically fractured oil well completions and recompletions are identical to those used at gas wells: RECs and flaring.[xxiii] The ability to perform RECs is limited by a well's proximity to natural gas pipelines, the pressure of the produced gas, and the concentration of inert gases in that gas. Gas captured by RECs must be sent into a pipeline—it is not practical or economical to store gas at the well site. Without access to pipelines, any co-produced gas from flowback is stranded and must be vented or flared. Even with pipeline access, low pressure flowbacks can prevent gas capture if flowback gas is not able to overcome backpressure from the pipeline. Unable to enter the pipeline, this gas must be flared or vented. Finally, high concentrations of inert gases in the flowback may exceed limits permitted in natural gas pipelines, prohibiting the flow of gas into those pipelines. Problems with pressure and inert gas concentration tend to dissipate over the course of the flowback period as the well approaches the production phase.

Information on control options for flowback-related methane emissions from hydraulically fractured oil wells can be found in Table 10. EPA notes that little information in available on the use of RECs at oil wells. Assumptions on control effectiveness and costs are based largely on data from RECs at gas wells, and more information is needed to develop figures unique to RECs at oil wells. Also, REC costs do not account for the value of captured gas.

[xxiii] RECs, or reduced emission completions, capture gas that would otherwise be vented. See Appendix A for a more detailed description.

Table 10. EPA Summary of Options for Controlling Flowback-Related Emissions from Hydraulically Fractured Oil Wells

Control Option	Applicability	Control Effectiveness	Costs	Prevalence
RECs	Access to gas pipelines, sufficient flowback pressure, low inert gas concentration	90% (EPA Gas STAR, based on RECs at gas wells) 98% (UT/Austin study, based on 2 co-producing wells)	$700-$6,500/day (2008 $, EPA, based on costs at gas wells)	Some co-producing wells with pipeline access, total numbers/percentage unknown
Flaring	All wells. Independent fuel source and continuous ignition device may be necessary if flowback gas has low energy content	95% (EPA 2012 Oil and Gas NSPS TSD)	$18,092 (EPA, based on industry survey. Assumes 1 flare/completion/year)	Some co-producing wells, total numbers/percentage unknown, but known to be most common emissions control strategy

Source: EPA White Paper-Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production

Emissions from these sources were not regulated as part of the 2012 new source performance standards (NSPS), which only require RECs at hydraulically fractured natural gas wells.

In the technical white papers, EPA also asks for information on strategies to control emissions from gas co-produced at oil wells during the production stage. When full production begins after the flowback period, natural gas can continue to flow from oil wells. Ideally, infrastructure allows for producers to direct any production-stage gas to a pipeline for sale. Without pipeline access, this gas must be flared or vented—similar to flowback emissions. However, a number of emerging technologies are being developed to use this stranded gas and reduce venting and flaring.

One potential strategy to control emissions from co-produced gas is converting it into liquefied natural gas (LNG). Liquefying natural gas requires cooling it to extremely low temperature. This process condenses natural gas, reducing the need for storage capacity. LNG is therefore a useful way to store stranded gas for onsite use or truck transport. This technology has the potential to control 100 percent of associated gas emissions and is limited only by storage capacity. However, EPA's white papers indicate that while LNG at the wellhead may be in development, there are no existing studies on the topic and provide no information on implementation or costs.

Another potential alternative to venting or flaring associated gas is injecting it back into the oil reservoir to boost oil production. Gas injection increases pressure in the reservoir and can improve the flow of oil up the well. Before reinjection, associated gas must be processed and stripped of NGLs, leaving only dry gas. This process of gas recovery and reinjection can be repeated throughout the life of the well. There is very little information available on reinjection's costs and ability to reduce methane emissions, and the process is limited by surface gas storage capacity and a well's reinjection requirements.

A final strategy for reducing associated gas methane emissions is using the gas for onsite electricity generation. This not only reduces methane emissions, but displaces diesel fuel that must be hauled to sites without access to local electricity grids. Although not always required, the first step in using gas to generate electricity is the removal of NGLs, which can be stored and sold separately. The dry gas can then be routed to a reciprocating engine or microturbine. As shown in Table 11, the primary cost for both systems is NGL removal and storage. The emissions control efficiency of such systems is limited by their gas intake capacity and onsite electricity demands. Excess electricity may also be sold onto the local grid if it is available.

Table 11. EPA Summary of the Estimated Costs of Using Associated Gas for Electricity Generation

Component	Reciprocating Engine		Microturbine	
	Capital Cost	Annual Cost	Capital Cost	Annual Cost
NGL Removal and Storage System	$2,500,000	$250,000	$2,500,000	$250,000
Electric Generator	$200,000	$20,000	$383,2000	$33,640
Other Infrastructure	$500,000	-	$500,000	-
Total Costs	$3,200,000	$270,000	$3,382,200	$283,640

Source: EPA White Paper-Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production

In addition to generating onsite electricity, associated gas can also be used to power onsite dual fuel engines or heat drilling fluids in the winter. While many types of equipment involved in oil production (drill rigs, fracturing pumps, etc.) have traditionally been powered by diesel, an increasing number of engines are able to use natural gas as well. These technologies provide operators with flexibility, reduce reliance on diesel, and use gas that might otherwise be vented or flared.

Overall, the most effective way to mitigate methane emissions from hydraulically fractured oil wells is to install pipelines that take the gas to market. However, the costs and difficulty of installing infrastructure to reach wells that are being rapidly developed, sometimes at remote locations, often makes immediately connecting wells pads to pipelines impossible.

Equipment Leaks

Fugitive emissions of methane, or methane leaks, occur at natural gas facilities across the upstream value chain, from well pads through transmission pipelines. Leaks can be found at many different kinds of components, including seals, connectors, valves, hatches, and meters. These components can leak for a variety of reasons, including improper fittings or connections, through seals worn by normal operation, or equipment that is not operating as designed (i.e., open thief hatches on storage tanks). Emissions from sources that are designed to vent methane under normal operations, such as pneumatic devices, are not considered leaks. Numerous methods and technologies have been developed to find and repair leaks, which can pose a threat to safety and result in loss of a valuable product.

Equipment leaks are generally addressed through two similar practices: leak detection and repair (LDAR) and directed inspection and maintenance (DI&M). Both programs involve using various technologies to identify and repair leaking equipment, with the key difference being that LDAR programs are mandated by regulations for certain types of facilities while DI&M is voluntary.

A number of different technologies can be used to detect methane leaks. Portable analyzers, optical gas imaging, acoustic detectors, and ambient/mobile monitoring systems can all be used to identify methane leaks. The capabilities and costs (both capital and operational) of these technologies vary, as do the leak detection scenarios in which they are most effective. While portable analyzers have long been the standard for Method 21, EPA's leak detection protocol, optical gas imaging and ambient/mobile systems are attracting attention as potential cost effective leak detection alternatives. Ongoing research continues to improve these systems and develop new leak detection technologies. Table 12 presents the capital costs of each technology, as reported in EPA's white paper on leaks.

Table 12. EPA Summary of Methane Leak Detector Capital Costs

Leak Detection Technology	Cost
Portable Analyzer	$10,800
Optical Gas Imaging (IR Camera)	$85,000-$124,000
Acoustic Detector	No data
Ambient/Mobile Monitor	$20,000-$100,000

Source: EPA White Paper-Oil and Natural Gas Sector Leaks

Portable analyzers have historically been the main tool used to identify leaks at natural gas facilities. These devices can detect methane at concentrations as low as 0.5 ppm and, when used in the context of Method 21, can be used to estimate methane leak rates based on correlation of measured gas concentrations to empirical data. While this quantitative data is very useful, the analyzer must be held in close proximity with each potential leak interface to return precise readings. This can make Method 21 leak scanning at certain facilities very time consuming.

Optical gas imaging involves the use of infrared (IR) cameras to make visible gas leaks that are invisible to the naked eye. This technology can be effective for quickly scanning large areas and identifying large leaks. IR cameras are only able to identify the presence of a leak and cannot quantify emissions rates or gas concentrations. While these cameras are often able to identify exact leak sources, additional effort may be needed to pinpoint leaks using portable analyzers at more congested facilities where potential leak sources are in close proximity, as well as to quantify leaks. Optical gas imaging is currently an accepted alternative work practice to Method 21 in mandated LDAR programs.

Acoustic sensors use ultrasonic gas leak detection (UGLD) technology to detect the airborne acoustic ultrasound generated when pressurized gas escapes from a leak. Unlike Method 21 and IR cameras, which can only detect leaks during an active search, UGLD provides an instantaneous notification of gas leaks as soon as they occur. This technology therefore allows for remote leak detection and notification, but is limited by the sensors' range (<100 feet) and the fact that it is applicable only at facilities with high pressure gas systems. In addition, UGLD typically can only alert operators to the existence of a leak somewhere at a facility; an IR camera or Method 21 check using a portable analyzer is typically required to pinpoint the leak for repair.

Ambient/mobile monitoring systems involve the use of methane detectors integrated with GPS and atmospheric sensors, usually mounted on a vehicle, to allow for rapid detection and recording of ambient methane concentrations over a wide geographic area. These systems can detect methane concentrations at the ppb-level, sometimes at a distance from the sensor. Current systems generally cannot pinpoint exact leak sources or quantify leak rates, but the technology is improving and these data may be available in the future. Today, vehicles equipped with these technologies are being used to search for leaks, which once identified are specifically located using IR cameras or portable analyzers. Stationary ambient monitors can also be used to detect leaks at remote locations, signaling an alarm when methane concentrations reach a threshold that indicates a leak at the facility. Again, pinpointing the location of, and quantifying, the identified leak would require additional effort using an IR camera and/or portable analyzer.

After leaks are identified, they must be repaired to reduce methane emissions. At some facilities, regulations require leaks of a certain size to be repaired. However, repairing leaks at facilities not covered by LDAR regulations is up to facility operators/owners. Such leaks may not be fixed if repairs are not determined to be cost effective. While the studies reviewed in EPA's white paper found that repairing most leaks is cost effective, these analyses did not factor in the costs of identifying leaks. This is critical because the cost of detecting leaks is generally greater than the cost of repairing them. Table 13 shows the costs of repairing leaks at components commonly found in natural gas infrastructure.

Table 13. EPA Summary of Leaking Component Repair Costs

Component Type	Repair Costs*	Mean Repair Life (years)
Compressor seals	$2,000	1
Flanges	$25-$400	2
Open-ended lines	$60-$1,670	2
Pressure relief valves	$79-$725	2
Threaded connections	$10-$300	2
Tubing connections	$15-$25	4
Valves	$60-$2,229	2-4
Vents	$2,000-$5,000	1

*Does not include leak detection costs

Source: Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. March 2006. As presented in EPA White Paper-Oil and Natural Gas Sector Leaks

When the full cost of a complete LDAR program is accounted for, the costs may be greater than the value of gas saved. One study summarized by EPA found that LDAR was not cost effective at 81 percent of well sites and tank batteries.[33] However, when all well sites and batteries were analyzed, LDAR resulted in net savings. These findings support the super emitter problem discussed earlier in this report and reflect a major hurdle to cost effective LDAR: costs are incurred scanning all potential leak sources, the majority of which have no or marginal leaks. Some the detection technologies described above (IR cameras, mobile monitoring) may be able to improve the cost effectiveness of leak detection compared to traditional Method 21 approaches by increasing the rate at which components are scanned or providing an alert when a leak is present—eliminating the need and expense of regularly scanning non-leaking components.

Liquids Unloading

During natural gas production, fluids continue to flow into the well with natural gas. Over time, these liquids can impede the flow of gas up the well and reduce gas production. To prevent this, fluids must be removed from the well, a process known as liquids unloading. Liquids unloading can result in the release of significant amounts of methane if emissions controls are not used. The primary method of unloading liquids without emissions controls is with a well blowdown. During a blowdown, the well is shut in to allow pressure in the well to build up. When well pressure is sufficient to remove built-up liquids, the well is vented, allowing large amounts of methane to escape along with the removed liquid.

A number of technologies have been developed to more effectively remove liquids that also have the benefit of reducing emissions. While these control options are effective at limiting emissions, their primary purpose is to improve well performance.[34] Effective controls include plunger lifts, artificial lifts, velocity tubing, and foaming agents. All of these technologies reduce emissions and are more effective at removing liquids compared to blowdowns. Because liquids unloading occurs at wells in production, gas forced up the well can usually be fed directly into the sales line, potentially eliminating all methane emissions. However, if well pressure is very low, gas removed during unloading may not be able to overcome the sales line pressure, in which case it must be captured by another means, or vented.

Plunger lifts remove liquids by sending a plunger to the bottom of the well that is then propelled back to the surface by the well's pressure. As its rises, the plunger pushes any accumulated liquids up and out of the well, allowing gas to flow more freely and improving production. Plunger lifts can be automated and clear wells whenever an accumulation of liquids is detected. Artificial lift systems use a variety of methods to reduce the pressure inside the production tubing. The lower pressure allows gas to flow more easily to the surface, carrying with it more liquid. Both plunger lifts and artificial lifts require an external power source to operate.

Velocity tubing and foaming agents can also be used to unload liquids, but are not as effective as the aforementioned lift technologies. Velocity tubing is small diameter pipe inserted into the production tubing to decrease its cross sectional area. Pressure in the tubing increases as gas and liquids are forced up through a smaller area. Under these higher pressures, gas carries more liquid to the surface. Velocity tubing can also be used as production tubing, with similar results. Foaming agents injected into the well reduce the surface tension and density of liquids, reducing the gas flow velocity needed to force liquids up the well. Foam agents only react with water, so are not as effective in wells with high concentrations of NGLs or oil. Velocity tubing and foaming agents are often used in conjunction to remove liquids.

Table 14 provides additional information on technologies used during liquids unloading. Again, these technologies were developed mainly to improve well production, not reduce methane emissions. However, their use usually eliminates the need to perform well blowdowns and therefore have the co-benefit of reducing methane vented to the atmosphere. When wells have sufficient pressure to unload into a pipeline, methane emissions can be completely eliminated.

EPA notes that flaring is another potential strategy to reduce emissions from liquids unloading. However, because unloadings are intermittent events, installation of a permanent flare may not be cost-effective. Research on flaring emissions from liquids unloading is ongoing, including new technologies such as mobile flares that could be used to flare emissions at stranded wells that would otherwise be vented.

Table 14. EPA Summary of Technologies to Control Emissions from Liquids Unloading

Technology	Applicability	Costs	Efficiency[a]
Plunger Lifts	On-site electricity. Sufficient well pressure to lift plunger	Automated: $15,000 capital cost, $100-$1,000 annual O&M, per well Non-automated: $7,500 capital cost, $1,000-$10,000 annual O&M, per well	Up to 100% when connected to pipeline. Up to 90% if emissions must be vented
Artificial Lifts	On-site electricity. Can be used at wells with inadequate pressure to operate plunger lifts	$58,000-$89,000, including pumping unit	100% when connected to pipeline
Velocity Tubing	Low volume wells producing less than 60 Mscf/day	$7,000-$64,000/well	100% when connected to pipeline
Foaming Agents	On-site electricity. Well liquids at least 50% water	$500-$3,880 capital costs, $6,000/well/year for foaming agent	100% when connected to pipeline

Source: EPA White Paper-Oil and Natural Gas Sector Liquids Unloading Process; ICF 2014.

a. All technologies have potential to eliminate emissions if gas is directed to a pipeline or otherwise captured. However, as currently deployed, operators frequently vent gas during the unloading process. Even when gas is vented, liquids unloading technologies can reduce emissions per unit of gas recovered compared to blowdowns.

Pneumatic Devices

Pneumatic devices are a major source of methane emissions and can be classified as either controllers or pumps. Many of these devices use pressurized natural gas to activate control valves or pumps. Pneumatic controllers are used to maintain a process condition, such as liquid level or a specific pressure. When the regulator system senses that an adjustment must be made, the gas-driven valve is actuated, and the pressurized gas used to actuate the valve is released to the atmosphere. Controllers have three different designs: continuous bleed, intermittent bleed, and zero bleed. Continuous bleed controllers leak gas at all times—even when control valves are not being activated. Intermittent bleed devices only vent gas during actuation. Zero bleed controllers are self-contained and release gas from actuation into a downstream pipeline rather than the atmosphere.

Numerous controls are available to reduce methane emissions from pneumatic controllers, but their applicability is limited by the function and location of individual controllers. For example, large, high pressure valves that need to make rapid adjustments to maintain process conditions may require continuous bleed devices. Zero bleed controllers are only applicable for low pressure valves. Using instrument air instead of natural gas requires electricity to power high volume air compressors and usually requires an operator to ensure proper system operation. While instrument air systems eliminate all methane emissions from pneumatic controllers, their limitations may prevent their use at off-grid and unattended facilities. Table 15 provides additional information on emissions mitigation strategies for pneumatic controllers.

Table 15. EPA Summary of Control Options for Pneumatic Controllers

Control Option	Applicability	Costs	Efficiency	Prevalence
Install zero bleed controller in place of continuous bleed controller	Only for low pressure control valves (gathering, M&R, city gates, distribution)	No data	100% emission reduction	No data, applicability limited
Install low bleed controller in place of high bleed controller	Depends on device's instrumentation function and whether is level, pressure or temperature controller. Not recommended for large valves that require fast/precise response to process changes. Usually used on large compressor discharge and bypass pressure controllers	$165 more than high bleed device (EPA). $3,000 per replacement (ICF)	Production: 6.6 less tpy methane Trans: 3.7 less tpy methane	No data
Convert to instrument air	At facilities with high concentration of pneumatic control valves with operator present and electricity (w/ backup NG pneumatic device)	Dependent on size, power needs, labor and other equipment. Annualized cost >$11,000	100% emission reduction	No data
Mechanical and solar systems in place of bleed controller	Limited because control must be near process measurement. Mechanical cannot handle large flow fluctuations. Electric valves need electricity.	$1,000-$10,000 per system depending on power needs (EPA)	100% emission reduction	No data

Source: EPA White Paper-Oil and Natural Gas Sector Pneumatic Devices

Emissions from certain pneumatic controllers are currently regulated under the 2012 Oil and Gas NSPS. That rule set standards for continuous bleed natural gas-driven controllers constructed or modified after August 23, 2011 in both the production and processing stages. All production-level controllers with bleed rates over six scf/hour are required to reduce their bleed rates to six scf/hour or less. The rule does allow exceptions for controllers demonstrated to require bleed rates above those set by the standard. In the processing sector, all pneumatic controllers must meet a bleed rate of zero scf/hour, achievable with the use of non-gas-driven controllers.

Pneumatic pumps are used to inject chemicals into gas wells and other equipment. These pumps are often driven by pressurized gas, which is vented to the atmosphere during operation. Pneumatic pumps generally fall into two categories: chemical injection pumps that inject a variety of chemicals needed to maintain proper operation of the well; and Kimray pumps that circulate glycol in gas dehydrators. Kimray pumps are usually larger than chemical injection pumps, required more gas to operate, and have higher methane emissions.

Techniques to reduce emissions from pneumatic pumps are similar to those used on controllers. These controls all involve eliminating natural gas as the force powering the pump and therefore eliminate all methane emissions from these sources. As with controllers, the control options for pumps are limited by a pump's function and location. More information on emissions controls for pneumatic pumps can be found in Table 16. The 2012 NSPS did not set emission standards for pneumatic pumps.

Table 16. EPA Summary of Control Options for Pneumatic Pumps

Control Option	Applicability	Costs	Efficiency	Prevalence
Convert to instrument air	Facilities with excess instrument air or able to install compressor. Requires electricity (w/backup NG pneumatic pump)	\$1,000-\$10,000 (operating costs \$100-\$1,000)	100% emission reduction. 2,500 Mcf/year for glycol circulation pumps and 183 Mcf/year for chemical injection pumps	No data
Replace with solar charged direct current pump	Small pumps limited to ≈5 gpy discharge @1,000psi, large pumps available with output of 38-100 gpy @1,200-3,000psi	\$2,000/pump, including pump, solar panels and batteries	100% emission reduction. Reduction of 182.5 Mcf/year per replacement	No data
Replace with electric pump	Constant source of electricity (typically at processing plants or large dehydration facilities)	\$10,000/pump, \$2,000/year in power costs (ICF)	100% emission reduction. Reduction of 5,000 Mcf/year when replace pneumatic pumps (ICF)	No data

Source: EPA White Paper-Oil and Natural Gas Sector Pneumatic Devices

7. Policies to Control Methane Emissions

On March 28, 2014, the Obama Administration announced a multi-faceted climate strategy called the Climate Action Plan. The Climate Action Plan described a number of initiatives to reduce U.S. greenhouse gas emissions, including actions by EPA to regulate carbon dioxide emissions from new and existing power plants. The Climate Action Plan also includes a Methane Strategy targeting reductions from four sectors: landfills, coal mines, agriculture, and oil and gas. In January 2015, the Administration provided an update to the Methane Strategy describing specific actions focused on emission reductions from the oil and gas sector.

The Administration's expressed goal is to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025. As summarized in Table 17, the strategy involves a range of agencies pursuing both regulatory and voluntary efforts. Most notably, the Administration directed EPA to promulgate new VOC and methane regulations targeting the emission sources highlighted in the technical white papers described in Section 6. The VOC portion of these regulations would follow up on the 2012 Oil and Gas NSPS.

Table 17. Summary of Administration Oil & Gas Methane Strategy

Agency	Rule/Program	Action	Likely Affected Segment (s)	Timeline
EPA	111(b) regulations for methane and VOC emissions	Regulatory (New Sources)	Production & Gathering, Processing, Transmission & Storage	Propose Summer 2015 Final Summer 2016
	Control Technology Guidelines	Regulatory (Existing Sources)	Production	Propose Summer 2015 Final 2016
	GHG Reporting Program	Regulatory (All Sources)	All Segments	Proposed December 9, 2014 Final 2015
	Enhanced Natural Gas STAR	Voluntary (All Sources)	All Segments	Stakeholder Outreach Summer 2015 Program Launch Fall 2015 Implementation January 2016
DOI (BLM)	Onshore Order 9	Regulatory	Production & Gathering	Propose late spring 2015
DOT	PHMSA Monitoring	Regulatory	Transmission	2015
DOE	Methane Roundtables	Pre-Regulatory	All segments	Spring 2014
	Natural Gas Modernization Initiative	Information Sharing	Transmission & Distribution	FOA to be issued with 2015 Appropriations

According to the 2014 GHG Inventory, methane makes up about nine percent of total U.S. GHG emissions. The oil and gas sector makes up about 30 percent of U.S. methane emissions. A 40 to 45 percent reduction from 2012 levels would be equivalent to about 3.1 to 3.5 million metric tons of methane reductions. The Administration has not described the magnitude of reductions it expects from each part of the strategy.

Below, we focus on the regulatory and voluntary activities being led by EPA. In brief, the other initiatives highlighted by Administration include the following:

- BLM Onshore Oil and Gas Order 9 would establish standards to limit the waste of vented and flared gas and to define the appropriate use of oil and gas for beneficial use. The rule will apply to both new and existing oil and gas wells on public lands. A proposed rule is expected in late spring 2015.
- Under DOT, the Pipeline Hazardous Materials Safety Administration (PHMSA) maintains a safety focus but is looking at rules that could have a climate benefit, including:
  - A rule on integrity management principles for transmission pipelines
  - State excavation damage rules, and
  - Rules regarding the use of flow valves.
- Under DOE, Secretary Moniz held a series of roundtables to discuss voluntary ways to reduce methane emissions and the department has plans to develop an information sharing portal on topics such as methane measurement, R&D, and infrastructure investment co-benefits – in addition to continued research on methane detection technologies.

2012 Federal Regulations

The federal government's most significant regulatory action related to air emissions from natural gas systems was the 2012 Oil and Gas NSPS and National Emission Standards for Hazardous Air Pollutants (NESHAP), which regulated VOC emissions from a range of upstream sources. At the time the rule was proposed and finalized, EPA touted the methane co-benefits of the rule but did not directly regulate methane. EPA estimated that when fully implemented, the NSPS would reduce annual methane emissions from affected sources by 1 to 1.7 million tons.[35]

The NSPS included the first national emissions standards for hydraulically fractured natural gas wells, requiring most wells to use RECs beginning in 2015.[xxiv] Prior to 2015, wells subject to the rule were required to either flare or use RECs and not vent flowback-related gas beginning in 2012. The NSPS and NESHAP also set standards for certain compressors, pneumatic controllers, and storage vessels. A summary of the sources regulated under the rules by segment is provided in Table 18.

Table 18. Sources Regulated Under the 2012 Oil and Gas NSPS and NESHAP

Emission Source Category	Natural Gas Production & Gathering	Oil and Associated Gas Production	Processing	Transmission & Storage	Distribution
Completions & Recompletions	✓				
Compressors (new or modified)	✓ (Gathering)				
Pneumatic Controllers	✓	✓	✓		

[xxiv] New exploratory and delineation wells, as well as low pressure wells, are not required to use RECs.

Emission Source Category	Natural Gas Production & Gathering	Oil and Associated Gas Production	Processing	Transmission & Storage	Distribution
(new or modified)					
Storage Vessels (new or modified)	✓	✓	✓	✓	
Leak Detection and Repair			✓		

A key aspect of the 2012 Oil and Gas NSPS is that it applies to new and modified sources, not existing sources. With the exception of well completions, which occur at the beginning of the life of a well and are considered "new" emission sources, control technologies and strategies required as part of the rule have not had a dramatic impact on the estimates of annual emission from the industry.

New Federal Methane and VOC Regulations for New Sources

The Obama Administration's Methane Strategy directs EPA to develop new Oil and Gas NSPS rules that regulate methane and VOC emissions from new and modified sources under the NSPS provisions of the Clean Air Act. These regulations would build on the information received during the technical white paper process described in Section 6, with a likely focus on emissions from: oil well completions, pneumatic pumps, liquids unloading, leaks from well sites, gathering and boosting stations, and compressor stations. EPA has indicated that it would propose regulations in the summer of 2015 and finalize them in the summer of 2016.

The most significant part of the forthcoming rulemaking is that it includes the regulation of methane from the oil and gas sector. Greenhouse gas emissions from oil and gas sources have not been previously regulated by EPA. Under the Clean Air Act, EPA has the authority to regulate emissions of criteria air emissions, like VOCs which are a precursor to ozone, from new and modified sources, but only states have the authority to regulate existing sources. However, GHGs, including methane, are not criteria emissions, and, under EPA's current interpretation of the law, the Agency can regulate existing sources under section 111(d) of the Clean Air Act through a process that includes the development of state plans. In establishing a timeline for regulating new and modified sources, EPA did not establish a timeline for regulating existing sources of methane.

New Federal VOC Guidelines for Existing Sources

While regulation of new sources will begin to reduce emissions as new facilities are developed and equipment turns over, the majority of emissions from the oil and gas sector are from existing sources. As discussed in Section 6, ICF projected that nearly 90 percent of emissions in 2018 will be from sources that existed in 2011. In the Methane Strategy, the Administration indicated that EPA will issue Control Technology Guidelines (CTGs) for sources in the oil and gas industry. EPA plans to propose CTGs for the oil and gas industry in summer 2015 and finalize them in 2016. Reducing VOCs from oil and gas sources generally provides a methane reducing co-benefit, so CTGs will also reduce methane emissions. CTGs provide states with strategies to reduce VOC emissions in areas that do not attain ozone NAAQS.

Ozone nonattainment areas must implement reasonably achievable control technology (RACT) on existing stationary sources covered under EPA CTGs as part of their attainment strategies. RACT represents the lowest emission level a source is capable of achieving using control technology that is reasonably available considering technological and economic feasibility. VOCs are a major contributor to ozone formation, and in the 1970s EPA began developing CTGs for individual source categories with significant VOC emissions. These guidelines serve as EPA's recommendation for VOC RACT for specific source categories. In developing CTGs, EPA reviews existing information on the source category, possible emissions reduction technologies, and the cost-effectiveness of the technologies. States can use EPA's CTGs to inform their own regulations for the source categories covered by CTGs.

Natural gas processing plants are the only source category in the natural gas sector currently covered by CTGs. These guidelines were issued in 1983, and like many other CTGs have not been updated since they were issued. The control strategies outlined include LDAR methods and equipment specifications for individual components. These specifications include techniques to reduce VOC emissions from pneumatic control valves, open-ended lines, and compressor seals.

EPA's new CTGs for oil and gas sources may cover the sources described in EPA's five methane white papers. As outlined in Section 6, the white papers detail methane emissions from pneumatic devices, liquids unloading, equipment leaks, hydraulically fractured oil wells, and compressors, and provide information on the effectiveness and costs of strategies to reduce those emissions. EPA may use the information in the white papers and feedback it received to develop CTGs for the sources examined. While some of these sources may be regulated under an updated oil and gas NSPS (for methane and VOCs), CTGs would target emissions from existing sources.

While CTGs will provide control strategies for different sources throughout the oil and natural gas industry, they will only be required in ozone nonattainment areas. Most states that have 2008 ozone NAAQS nonattainment regions are designated as marginal nonattainment and do not need to submit SIPs. Texas and California have regions, including areas of oil and gas production, designated as moderate or greater nonattainment and must submit SIPs to EPA in 2015 and 2016, respectively. With CTGs for oil and gas sources scheduled to be finalized 2016, they will not be included in the Texas SIP and therefore California may be the only state that includes oil and gas CTGs in its 2008 ozone NAAQS SIP. However, any states that submit subsequent SIP revisions after the CTGs are released will need to address them.

CTGs will likely play a much larger role in state planning for EPA's proposed revision to the ozone standard. The proposed standard is scheduled to be finalized by October 1, 2015, with attainment designations by October 2017. With SIPs generally due three or four years after attainment designations, oil and gas CTGs will be fully established and ready to be incorporated into state planning strategies. Figure 13 shows that EPA projects that a number of regions with oil and gas production would be out of attainment with the proposed standards based on current emissions data.[xxv] Any areas designated as moderate nonattainment or higher would be required to submit attainment SIPs, and therefore have to implement CTGs or alternative controls on sources of VOC emissions in the oil and gas industry. In most states, CTGs would only apply to nonattainment regions. However, for states in the Ozone Transport Region

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[xxv] EPA proposed two different standards, 70 ppb and 65 ppb. Nonattainment regions based on most recent data; actual designations will likely be based on 2014-2016 data. Map does not distinguish levels of nonattainment; only moderate and above need to submit SIPs.

(OTR)[xxvi], CTGs must be applied statewide, including in regions/counties that have attained the standard.

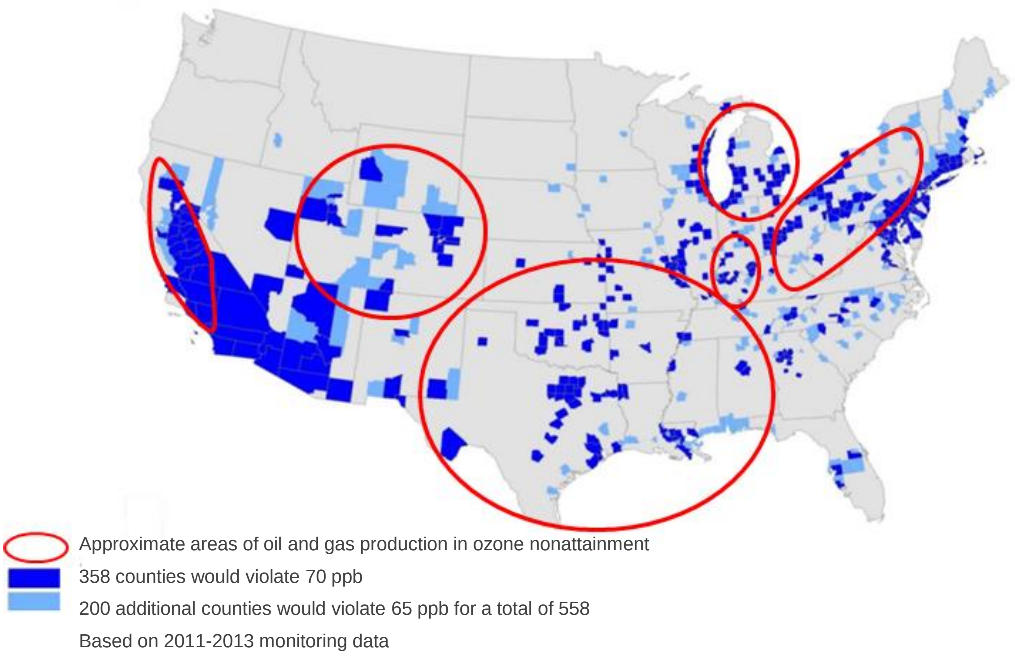

Figure 13. Nonattainment Areas Under the Proposed Ozone Standard

State Requirements

In addition to new federal regulations, a number of states have also taken action to regulate emission sources in the oil and gas sector. In the development of the 2012 Oil and Gas NSPS, EPA cited rules in place in Colorado and Wyoming in support of federal proposals. Future EPA rules for sources currently unregulated at the federal level may similarly borrow from state regulations.

Wyoming implemented VOC and HAP permitting requirements for certain production-stage sources in 1998 and has since regulated additional sources and upgraded existing standards.[xxvii] These include statewide rules for pneumatic pumps and controllers, glycol dehydrators, and liquids unloading. Sources in areas of the state with higher levels of oil and gas development are subject to additional requirements, including standards for emissions from storage tanks and best practices for well completions (i.e., RECs). In 2013, Wyoming finalized first-in-the-nation LDAR requirements mandating quarterly inspection of production facilities in regions with significant hydrocarbon development.

[xxvi] The OTR consists of 11 northeastern and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont), Washington, D.C., and parts of northern Virginia.

[xxvii] Wyoming's permitting guidelines for oil and gas production facilities can be found at: http://sgirt.webfactional.com/filesearch/content/Air%20Quality%20Division/Programs/New%20Source%20Review/Guidance%20Documents/2013-09_%20AQD_NSR_Oil-and-Gas-Production-Facilities-Chapter6-Section2-Permitting-Guidance.pdf

The Wyoming rules include a number of standards that are more stringent than the NSPS, including control of emissions from pneumatic pumps and the LDAR requirement. As with the NSPS, the state rules are limited to only new and modified sources and do not apply to existing production facilities. Unlike the NSPS, Wyoming requires certain oil wells to use RECs, capturing methane and VOCs. Certain Wyoming standards apply only to specific regions with concentrated oil and gas development. While RECs on gas wells will be required state-wide when the NSPS is implemented, state-specific regulations such as LDAR will not apply to all regions. Furthermore, Wyoming's rules affect only the production segment, and not sources in other segments.

Colorado has led all states in efforts to reduce methane emissions from the oil and gas industry, and is the only state to directly regulate methane emissions (as opposed to achieving co-benefits through VOC reductions). As in Wyoming, Colorado implemented REC requirements and standards for pneumatics years before the NSPS was finalized. In February 2014, Colorado made major revisions to its oil and gas regulations, including incorporating the 2012 Oil and Gas NSPS into state law and adopting additional requirements through a rule known as Regulation Number 7.[36] Colorado estimates that these regulations will reduce methane emissions by 65,000 tons per year.[37] Regulation Number 7 includes LDAR requirements for well production facilities and natural gas compressor stations. The rule also describes best management practices for well maintenance and liquids unloading. Other sources regulated by the state rule are also covered in the 2012 NSPS, but Regulation Number 7 imposes more stringent requirements.

A key component of the Colorado rule is that it applies to both new and existing sources. The 2012 NSPS and Wyoming rules affect only new and modified sources. Regulation Number 7 is similar to the Wyoming regulations in that the REC requirements apply to both oil and gas well completions. However, Colorado's rules for all sources apply to the entire state and extend beyond production to the processing and transmission segments.

Voluntary Action

A major driver of both existing and planned efforts to reduce methane emissions is voluntary industry action. The main component of these efforts is EPA's Natural Gas STAR program. Oil and gas companies participating in Natural Gas STAR adopt cost effective technologies and strategies to reduce methane emissions across the natural gas value chain, from pre-production through distribution. Natural Gas STAR provides companies with technical data on practices to reduce emissions, including implementation costs and payback periods. According to the 2014 GHG Inventory, Natural Gas STAR resulted in 2,211 Mg of CH_4 reductions from natural gas systems in 2012, representing 95 percent of total reductions from the industry.[38] Without these reductions, methane emissions from natural gas systems would have been 36 percent higher. These reductions are across a range of sources, both new and existing, and include the distribution segment.

In its January 2015 announcement, EPA laid out plans to bolster the Natural Gas STAR program. The draft program framework is scheduled for released by late spring 2015. Following additional stakeholder outreach and a public comment period, EPA is expected to release an updated proposal in August 2015. The program is expected to launch in fall 2015, with implementation beginning in 2016.

Other voluntary action includes conformance with standards and best work practices established by third parties. In March 2013, the Center for Sustainable Shale Development (CSSD) unveiled a set of 15 performance standards[xxviii] to protect human health and the environment for natural gas production operations in the Appalachian Basin. Companies can become CSSD certified through an audit of their operations in the Marcellus shale region that ensures all CSSD standards are being met. For gas producers, certification signifies environmental stewardship and adherence to standards that meet or exceed regulatory requirements. In addition to completion, storage tank, compressor, pneumatics, and DI&M standards for new and existing production-stage sources, CSSD includes standards related to wastewater and on- and off-road engines, such as fluid transport trucks and drill rig engines.

[xxviii] Available at: https://www.sustainableshale.org/wp-content/uploads/2014/08/8.19_Performance-Standards-v.-1.2.pdf

8. Implications for Policymakers

WIEB and SPSC commissioned this report to better understand the life cycle GHG emissions of natural gas and coal used for electricity generation. WIEB/SPSC asked MJB&A to evaluate and summarize the current state of knowledge about methane leakage throughout the natural gas fuel cycle, with a particular focus on the differences between methane emission estimates developed from bottom-up analyses and top-down inventories of methane and other hydrocarbons. One of WIEB/SPSC's major objectives was to identify the key reasons for the significant variability in total methane leakage estimates from prominent published studies, and to put these differences into context. With this understanding, WIEB/SPSC asked MJB&A to identify key methane emission points within the natural gas fuel cycle and review strategies and technologies available to reduce these emissions.

Sections 2 through 7 provide a detailed discussion of these issues. This section synthesizes the findings of the report into key takeaways for policymakers. The key takeaways are:

- Based on latest science and estimates of upstream methane leakage from natural gas systems, natural gas combined cycle power plants have about half the life cycle GHG emissions of coal-fired power plants.
- Emerging and ongoing research suggests a super emitter issue where a small percentage of sources across the natural gas value chain are responsible for a large percentage of emissions.
- There is significant regional variation in methane emissions from upstream natural gas systems. While much research has focused on improving estimates of national emissions, consideration of regional methane emissions may be more informative for local system planners and GHG policymakers.
- Allocation of methane emissions between natural gas and other products, such as petroleum or natural gas liquids, is an emerging research topic and will have implications for life cycle GHG emissions estimates.
- Significant actions have been taken by EPA, states, and companies in recent years to reduce emissions associated with the natural gas system.
- An upcoming rulemaking process at EPA will set new requirements for unregulated sources at new and modified facilities.
- While requirements for new and modified sources will reduce emissions over time as the system is expanded and upgraded, the majority of emissions come from existing sources. There is no comprehensive federal regulatory program to address these emissions; however, Wyoming and Colorado have been leaders in establishing state programs. New near-term federal policies addressing existing sources include guidelines for states with ozone nonattainment areas and voluntary programs.

To help inform state and regional policymakers as they consider the implications of upstream vented and fugitive methane emissions for resource and transmission planning, we include brief discussions of each of these takeaways along with implications.

NGCC Life Cycle Emissions

Upstream methane emissions and power plant efficiency are the primary drivers of life cycle GHG emissions, with EGU efficiency being the most significant factor. As discussed in Section 5 and shown in Figure 14, using a 100-year GWP and emission estimates associated with average U.S. natural gas, we find that life cycle NGCC emissions are about 40 percent of those from an average coal-fired boiler.[xxix] The advantage of NGCC over an average coal-fired boiler is robust across a range of upstream emission scenarios. In the extreme scenario, which assigned all observed excess atmospheric methane to natural gas systems, we found life cycle emissions associated with NGCC to be about 60 percent of life cycle emissions associated with an average coal-fired boiler. The gap between NGCC and an average coal-fired boiler is less when we use a 20-year GWP but there is still a benefit across the reviewed emission scenarios.

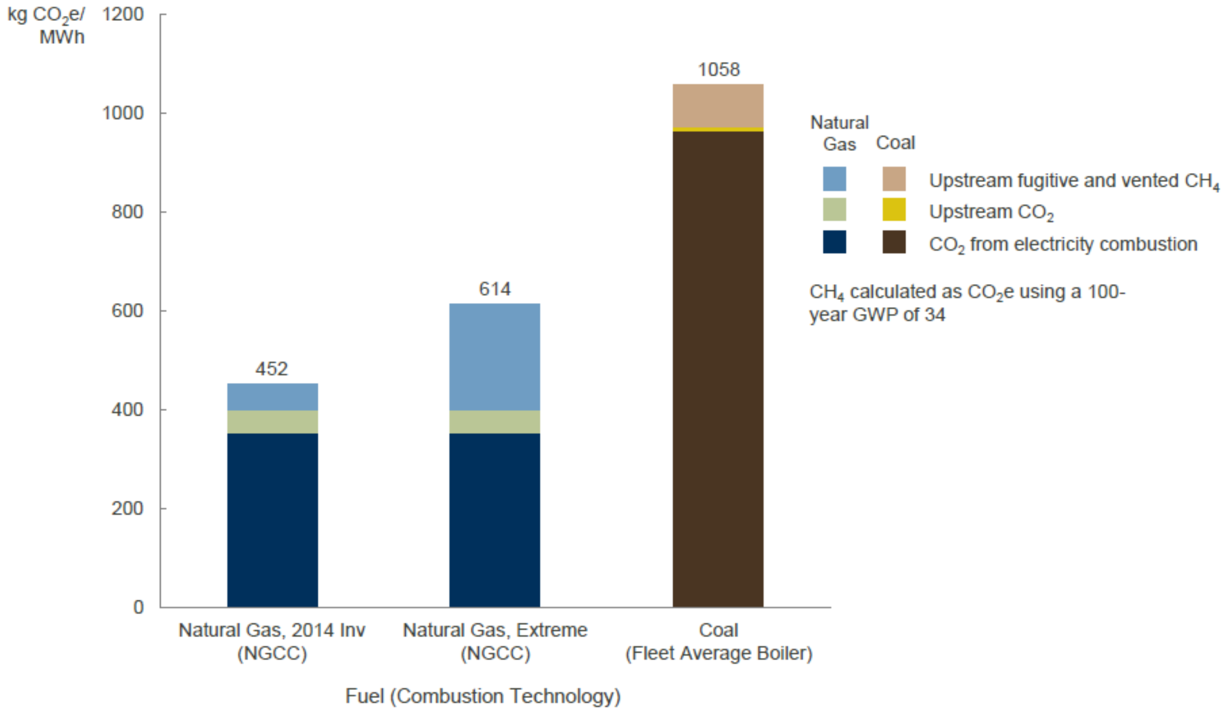

Figure 14. MJB&A Estimated Life Cycle Emissions for Natural Gas- and Coal-based Electricity Generation

Exploring the role of power plant efficiency, Figure 15 shows the 100-year GWP crossover point for a range of natural gas power plant efficiencies as compared to an average coal-fired boiler with an efficiency of 34 percent and a supercritical coal-fired boiler with an efficiency of 39 percent. As shown, less efficient natural gas power plants have a lower vented and fugitive emissions crossover point.

[xxix] We calculate the emissions associated with average U.S. natural gas as the total estimated emissions from the GHG Inventory divided by total U.S. natural gas production. We assume an NGCC efficiency of 51 percent and a coal boiler efficiency of 34 percent.

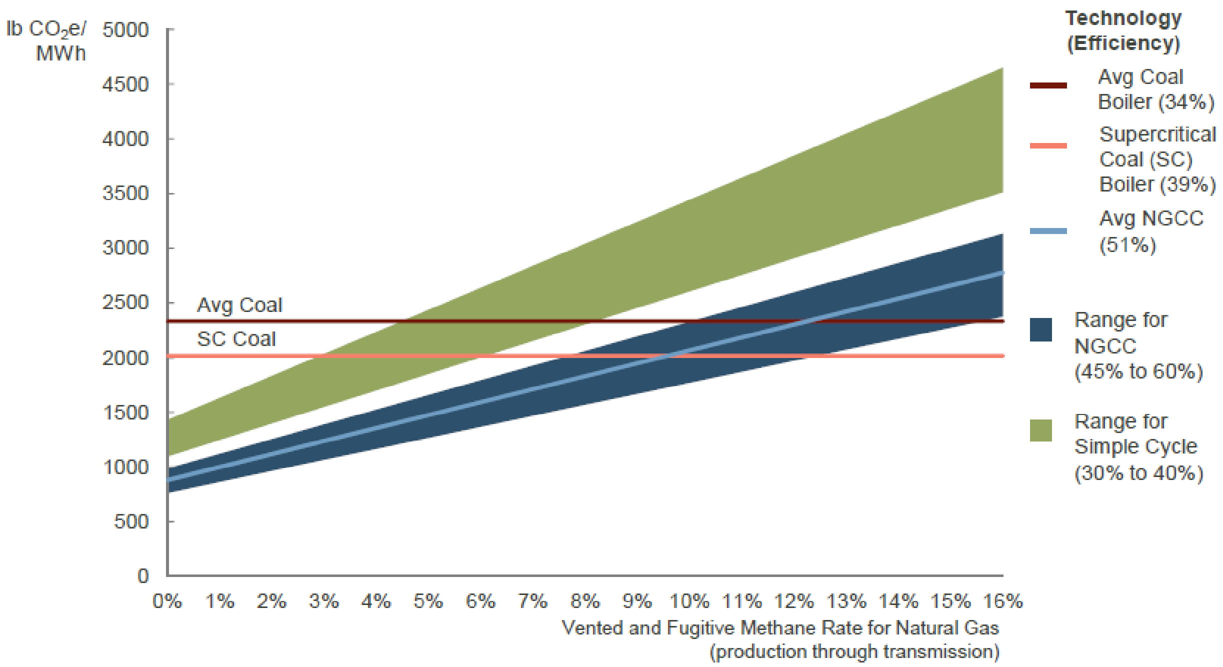

Figure 15. Life Cycle Emissions at Different Power Plant Efficiencies, 100-year GWP

As state and regional policymakers are making decisions about the resource mix, it seems clear that there are GHG benefits of NGCC relative to coal boilers. However, it is important to remember that power plant efficiency is a key variable in shaping life cycle emissions. For the average natural gas combined cycle and subcritical coal boilers we reviewed, power plant CO_2 emissions contribute 80 and 90 percent of life cycle GHG emissions, respectively. Regional generating fleets consist of EGUs with varying efficiencies and capacity factors, resulting in unique combustion CO_2 profiles. While our analysis compares generic combined cycle and coal plants, power plants are not directly interchangeable. Policymakers may want to evaluate how changes to distinct generating fleets will impact GHG emissions. The most relevant comparison may not be a coal boiler versus an NGCC unit but the existing fossil fleet versus a portfolio of alternative options. For example, system planners may evaluate different types of dispatchable resources to provide system flexibility as more variable resources, such as wind or solar projects, are added to the grid. Different types of flexible resource including lower efficiency gas turbines, such as simple cycle turbines, or NGCC power plants designed to cycle, will have different GHG emissions profiles. It would be informative to review the life cycle emissions of individual power plants and implications of different resource decisions for the entire system.

Emerging Understanding of "Super Emitters"

Research suggests that vented and fugitive emissions are not normally distributed across emission source categories. This has implications for understanding significant emission sources as well as identifying the most cost-effective control strategies.

From the perspective of understanding emission potential, the uneven distribution of emissions contributes to the differences between top-down and bottom-up studies of emissions. By relying on average emission factors, bottom-up studies may underestimate actual emissions if high-emitters were not part of the sampling conducted to develop the emission factor. On the other hand, top-down studies that are based on observed emissions at a particular place at a particular time may overestimate emissions if their observations are extrapolated across a broad geographic area and across an entire year. At the same time, top-down studies may be particularly useful at identifying specific areas with elevated methane emissions. However, pin-pointing the source of emissions and attributing them to current natural gas systems, as opposed to other geologic sources of methane such as coal seams or abandoned wells, remains a challenge. Further, although most studies that directly measured emissions identified the presence of super emitters, more data is needed to understand if the observed frequency and magnitude of these sources is equally distributed across a specific region or the U.S.

Ongoing research should help to reconcile the differences between top-down and bottom-up studies of emissions and contribute to understanding of the potential super emitter issue. Research to date suggests that it may be appropriate to develop regional emissions inventories using region- or basin-specific emission factors that are informed by both equipment sampling (as in bottom-up studies) and atmospheric methane measurements (as in top-down studies). Such an approach has the potential to provide more accurate emissions estimates than national inventories developed with generic emissions factors.

From a control strategy perspective, unevenly distributed emissions create a challenge for regulators or firms trying to identify emission sources and controls. While there will continue to be normally distributed sources of emissions where traditional regulatory approaches may be appropriate, there may also be a need to develop approaches where a range of potential emission sources are monitored or evaluated on a regular basis to identify unexpected leaks. As an example, the recent Colorado regulations included revised emission control requirements for storage vessels but also included a requirement for regular review of the storage vessels to ensure the ongoing integrity of the system.

Regional Context

Although the main focus of this report is a comparison of average U.S. life cycle GHG emissions of natural gas-fired generation versus coal-fired generation, implications for regional system planning are dependent on regional gas supplies and electric generation infrastructure. While we have found that natural gas combusted at a combined cycle unit generates roughly half the life cycle GHG emissions of coal burned at the average boiler, the relative benefit of natural gas will vary from region to region.

Many regions source their natural gas from specific production areas and top-down studies suggest some areas may have higher emissions than others. With the majority of gas supplies in regions coming from specific basins, consideration of national emissions rates may not be as informative in the development of regional GHG policies. Regional policy planners may want to consider the unique upstream GHG characteristics of their gas supply.

Emissions Allocation

A key emerging issue is how to properly allocate methane emissions to natural gas and petroleum systems. Across U.S. production fields, there are oil wells that also produce gas and gas wells that also produce oil and other liquid hydrocarbons. EPA's GHG Inventory does not currently allocate methane emissions associated with these co-produced commodities proportionately across natural gas and petroleum systems. As such, all methane from wells defined as oil wells is attributed to petroleum systems and all methane from wells defined as gas wells is attributed to natural gas systems, regardless of their co-production. In our calculation of life cycle emissions from natural gas, we followed the methodology of Alvarez et al. in assigning

35 percent of methane emissions from petroleum systems to natural gas to account for co-produced gas. A more recent study by researchers at the University of Texas at Austin suggests that only 85 percent of methane emissions from gas wells should be attributed to natural gas systems, with the remaining 15 percent assigned to liquid hydrocarbons.[39] While we did not factor this consideration into our life cycle analysis, it would have the effect of reducing life cycle GHG emissions from natural gas.

In addition to more direct measurement of methane emissions from oil and gas sources, efforts to reconcile differences between top-down and bottom-up emissions estimates will improve understanding of emissions allocation. Included in this is more data on emissions from abandoned oil and gas wells, which are not well understood. While existing literature has suggested specific percentages for allocating methane across natural gas and petroleum systems, there is significant regional variation in co-production at oil and gas wells across the U.S. Using a national average to assign methane emissions across both value chains may therefore be inappropriate, especially in the context of regional planning. Regardless of which value-chain methane emissions are ultimately associated with, oil and gas production are closely interrelated from a GHG mitigation perspective.

Recent Actions to Address Natural Gas Value Chain Emissions

EPA's most significant regulatory action to date related to upstream methane emissions from natural gas systems was the 2012 Oil and Gas NSPS which regulated VOC emissions from a range of upstream sources. At the time the rule was proposed and finalized, EPA touted the methane co-benefits of the rule. EPA estimated that when fully implemented, the NSPS will reduce annual methane emissions from affected sources by 1 to 1.7 million tons.[40] A key aspect of the 2012 Oil and Gas NSPS is that it applies to new and modified sources, not existing sources. With the exception of well completions, which occur at the beginning of the life of a well and are considered "new" emission sources, control technologies and strategies required as part of the rule have not had a dramatic impact on the annual emission estimates from the industry.

In addition to the federal rulemaking, states have taken action to control emissions from sources in the natural gas sector. One of the leading states is Colorado, which has a history of regulating emissions from the oil and gas sector as part of its strategy to reduce emissions of ozone precursors. In 2014, Colorado finalized regulations that implemented the 2012 Oil and Gas NSPS regulations and expanded the coverage to include first-in-the-country methane regulations. The methane regulations include LDAR requirements for natural gas well production facilities and compressor stations. The Colorado regulations apply to both new and existing sources and require RECs on hydraulically fractured gas and oil wells. Together, Colorado estimates that these regulations will reduce methane emissions by 65,000 tons per year.[41]

In addition to regulatory action, EPA's long-standing voluntary partnership program, Natural Gas STAR, has resulted in significant reported emission reductions from the industry. These emission reductions are accounted for in the GHG Inventory. According to the 2014 GHG Inventory, Natural Gas STAR resulted in 2,211 Gg (2.4 million tons) of CH_4 reductions from natural gas systems (including distribution) in 2012.[42] Without these reductions, methane emissions from natural gas systems would have been 36 percent higher. These reductions are across a range of sources, both new and existing.

Certification of production companies by third parties to recognize industry leading best management practices has also emerged with the development of the CSSD standards in the Appalachian region. This voluntary certification process allows industry companies to demonstrate environmental stewardship and commitment to operations that meet or exceed regulatory requirements.

Future Actions to Address Natural Gas Value Chain Emissions

In January 2015, the Obama Administration provided an update to its Methane Strategy describing specific actions focused on emission reductions from the oil and gas sector. The Administration's expressed goal is to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025. As summarized in Table 19, the strategy involves a range of agencies pursuing both regulatory and voluntary efforts.

Table 19. Summary of Administration Oil & Gas Methane Strategy

Agency	Rule/Program	Action	Likely Affected Segment (s)	Timeline
EPA	111(b) regulations for methane and VOC emissions	Regulatory (New Sources)	Production & Gathering, Processing, Transmission & Storage	Propose Summer 2015 Final Summer 2016
	Control Technology Guidelines	Regulatory (Existing Sources)	Production	Propose Summer 2015 Final 2016
	GHG Reporting Program	Regulatory (All Sources)	All Segments	Proposed December 9, 2014 Final 2015
	Enhanced Natural Gas STAR	Voluntary (All Sources)	All Segments	Stakeholder Outreach Summer 2015 Program Launch Fall 2015 Implementation January 2016
DOI (BLM)	Onshore Order 9	Regulatory	Production & Gathering	Propose late spring 2015
DOT	PHMSA Monitoring	Regulatory	Transmission	2015
DOE	Methane Roundtables	Pre-Regulatory	All segments	Spring 2014
	Natural Gas Modernization Initiative	Information Sharing	Transmission & Distribution	FOA to be issued with 2015 Appropriations

Most notably, the Administration directed EPA to promulgate new VOC and methane regulations. The VOC portion of these regulations would follow up on the 2012 Oil and Gas NSPS. Sources likely to be targeted by the new standards include those discussed in EPA's 2014 Methane White Papers:[xxx] hydraulically fractured oil well completions, pneumatic devices, compressors, liquids unloading, and equipment leaks. The proposed regulations are scheduled to be released in summer 2015, with a final rule in summer 2016.

[xxx] The white papers are available at: http://www.epa.gov/airquality/oilandgas/whitepapers.html.

While requirements for new and modified sources will reduce emissions over time as the system is expanded and upgraded, the majority of emissions come from existing sources. A 2014 study by ICF International projected that despite recent growth in oil and gas production, existing sources (existing in 2011) will be responsible for nearly 90 percent of methane emissions in 2018.[43] Reductions from existing sources are therefore a key component of reducing overall emissions from the oil and gas industry. However, there is no comprehensive federal regulatory program to address these emissions. While the regulation of GHGs from new sources triggers an obligation to review the need for state guidance to establish emission performance standards for existing sources, EPA has not established a timeframe for developing such guidance for existing sources of methane emissions from the oil and gas industry.

To begin to address emissions from existing sources, the Methane Strategy announced by the Administration includes an evaluation of emission control technologies for existing sources through the development of CTGs. CTGs provide states with strategies to reduce VOC emissions in areas that do not attain ozone NAAQS. States with areas designated as having moderate or higher nonattainment areas must implement EPA CTGs or alternative measures as part of their strategies to achieve attainment. Implementation of the CTGs to reduce VOCs will result in methane co-benefit reductions from existing oil and gas sources. Under the 2008 ozone standard, Texas and California are the only states with oil and gas production to have areas designated as moderate or higher nonattainment. However, EPA has proposed more stringent ozone standards which are scheduled to be finalized in October 2015. Under the revised standard, it is likely that more states will have nonattainment areas and will have to implement CTGs or alternative measures for oil and gas sources. The process of designating areas in nonattainment and developing state plans will take a number of years.

While broad federal regulation of existing sources does not appear to be imminent, most states have significant regulatory discretion. States often lead the federal government in terms of regulatory programs. In the oil and gas sector, this has been the case with Wyoming and Colorado.[xxxi] In states with less experience with oil and gas production, rules are also likely to evolve as regulation catches up with the initial rush of unconventional hydrocarbon development. For example, Ohio recently incorporated LDAR requirements for production facilities into its permitting process.[xxxii]

Voluntary emission reduction activities may also expand in the future. This includes action under both EPA's revamped Gas STAR program and certification programs such as CSSD. More companies may take voluntary action as reduction technologies evolve and become more cost effective. Industry executives may also see advantages in voluntarily reducing emissions as a response to increased public and investor scrutiny of potential environmental impacts.

[xxxi] Wyoming has proposed new rules that would regulate certain existing sources, available at: http://sgirt.webfactional.com/filesearch/content/Air%20Quality%20Division/Programs/Rule%20Development/Proposed%20Rules%20and%20Regulations/AQD_Rule-Development_Chapter-8-NAA-Existing-Source-IBR-draft_02-02-15-Strike-and-Underline.pdf

[xxxii] Model general permits for oil and gas well-site production operations in Ohio are available here: http://www.epa.ohio.gov/dapc/genpermit/oilandgaswellsiteproduction.aspx

Appendix A: Glossary of Natural Gas and Life Cycle Analysis Terms

Allocation of Co-product Emissions: Crude oil and natural gas liquids (NGLs) are also produced at some natural gas wells. These co-products and their subsequent treatment and processing result in additional GHG emissions. LCAs that do not account for emissions from co-products may assign these emissions to the natural gas produced by the well, resulting in higher life cycle emissions rate estimates. Similarly, certain oil wells co-produce natural gas. As such, a percentage of methane emissions from oil production may be assigned to the natural gas sector.

Estimated Ultimate Recovery (EUR): EUR is the lifetime natural gas production of a well, usually expressed in billions of cubic feet (bcf). This has a major impact on life cycle GHG emissions, with high-EUR wells having lower life cycle emissions and low-EUR wells having higher life cycle emissions. Certain well preproduction and production activities such as pad development, drilling, and completion are one-time events. Emissions associated with these activities are the same regardless of how much gas the well produces over its lifetime. For wells that produce less gas, these fixed emissions increase life cycle emissions per volume gas or MWh electricity produced. In contrast, a well that produces more gas "dilutes" these fixed emissions with higher lifetime production, resulting in lower life cycle emissions per unit of produced gas.

Flaring Rate: Flaring natural gas converts most methane to CO_2 and reduces GHG emissions compared to direct venting. Higher flaring rates compared to direct venting therefore result in lower life cycle GHG emissions. Flaring is generally assumed to destroy 98 percent of all methane passing the flare. It is important to note that the Oil & Gas NSPS require the use of reduced emission completions (RECs) for almost all completions and workovers after January 1, 2015, and required flowback emissions to be flared starting in October 2012. Assumptions on flaring rates used in the reviewed LCAs (some as low as 15 percent) are therefore significantly lower than current industry practices.

Global Warming Potential (GWP) of Methane: Methane is a more potent GHG than CO_2. Methane emissions must therefore be multiplied by a GWP to determine their carbon dioxide equivalent (CO_2e). Methane breaks down in the atmosphere over time, so methane has a higher GWP in the short term. Twenty and 100 year GWPs have been developed to account for the decline in methane's CO_2e over time. All LCAs examined in this report used a 100 year methane GWP of 25 with the exception of Howarth, which used 33. Higher GWPs lead to higher life cycle emissions. GWP assumptions can be normalized to allow for direct comparison of life cycle emissions. The most recent IPCC 100-year and 20-year GWPs for methane are 34 and 86, respectively, including climate feedback mechanisms (28 and 84 without climate feedback mechanisms). Per WIEB's request, all methane to CO_2e conversions this report use GWPs of 34 or 86.

Liquids Unloading: Liquids unloading refers to the removal of water and condensates that build up inside producing natural gas wells, slowing the flow of gas to the well head. Removing these liquids allows gas to flow freely and increases production. Methane can also be released during this process, contributing to life cycle GHG emissions (widely used technologies such as plunger lifts can significantly reduce these emissions). Many of the LCAs examined in this report were written in 2011 and relied on older data that suggested that shale gas wells did not require liquids unloading. As such, LCAs that assume shale wells do not undergo liquids unloading may be missing a component of life cycle emissions. Conversely, LCAs that include liquids unloading may not assume use of plunger lifts and therefore overestimate emissions from this activity.

Methane Leakage Rate: LCAs have different assumptions on the amount of methane that leaks along the natural gas fuel cycle. Higher leak rates contribute to higher life cycle emissions estimates. Leakage rates can be defined as methane mass emitted per unit mass of methane produced (CH_4/CH_4) or as methane mass emitted per unit mass of natural gas produced (CH_4/NG). Because natural gas is not 100% methane the later leakage rate definition will always result in lower numerical values for leak rate.

Natural Gas Distribution Systems: Some natural gas power plants receive gas directly from transmission systems while others have gas delivered through distribution systems. Emissions from leaks in distribution systems contribute to life cycle emissions for plants that receive gas via distribution systems. It is important to note that some LCAs assume gas delivery via transmission while others assume delivery through distribution. The natural gas distribution system is generally defined as those elements of the natural gas system that include and are downstream of the city gate (i.e., metering and regulating stations).

Natural Gas Methane Content: Assumptions about the methane content of natural gas can influence life cycle GHG emissions estimates. While methane content can vary from basin to basin and well to well, LCAs typically apply set methane content percentages to calculate methane-related emissions. Methane content increases after processing when other components of natural gas are removed, and some LCAs account for this with separate methane content assumptions for production gas and pipeline gas. Higher methane content assumptions naturally result in higher methane emissions estimates.

Power Plant Efficiency: The combustion efficiency of natural gas power plants has a significant impact on life cycle GHG emission estimates; plants with lower efficiencies have higher emission rates (kg/MWh) due to greater fuel use (and consequent CO_2 emissions) per unit of power output. LCA comparison tables in this report show life cycle emissions based on combustion at natural gas combined cycle (NGCC) power plants (if available). Assumptions on power plant efficiency can be normalized to allow for more direct comparison of LCA emission estimates.

Recompletion Rate: Recompletion refers to the re-fracturing of a well to increase production. Completion events can result in additional emissions, so assumptions on the number of times a well is re-fractured over its life directly influences life cycle emissions. In its 2014 GHG Inventory, EPA assumes a recompletion rate of one percent, whereas many of the reviewed LCAs use EPA's previous assumption of ten percent. Some reviewed LCAs do not account for recompletions and therefore do not include emissions from this part of the natural gas life cycle.

Reduced Emission Completion (REC): A REC or green completion is a process that reduces methane and VOC emissions during the flowback period. As defined by the 2012 Oil and Gas NSPS, a REC "means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere."[44]

Appendix B: Review of Bottom-up Studies

Authors	**Jiang et al.** (Mohan Jiang, W Michael Griffin, Chris Hendrickson, Paulina Jaramillo, Jeanne VanBriesen, Aranya Venkatesh)
Lead Author Affiliation	Carnegie Mellon University
Title	Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas (2011)
Basin/Type of Gas	Marcellus shale
Leakage Rate (CH_4/NG produced)	2.2% (conventional, does not include pre-production)
Life Cycle NGCC Emissions Rate	488 kg CO_2e/MWh (shale, as listed in JISEA/NREL report) 473 kg CO_2e/MWh (U.S. domestic, as listed in JISEA/NREL report)
Overview	Jiang found that natural gas from the Marcellus has life cycle GHG emissions of 68g CO_2e/MJ gas produced. Of this, 50g CO_2e/MJ is the result of combustion at a power plant. The report captures the full range of emissions related to shale gas development, including well pad development, fracturing fluid production, and water transport. Emissions from these activities are not included in a number of other LCAs. Power plant efficiency (50%), GWP (25, 100 years) and EUR (2.7 bcf) are comparable to other LCAs. The report did not include any information on assumptions of how many times workovers were performed at a well. The analysis assumes a methane leakage rate of 2.2% for conventional gas, based on the 2010 petroleum and natural gas systems Subpart W TSD and the 1996 GRI/EPA study. However, the study's assumptions for methane emissions may in some cases overestimate emissions. Methane emissions per completion or workover, with a range of 26-1,000 tons and a mean of 400 tons, is significantly higher than contemporary estimates (2014 GHG Inventory emission factor for uncontrolled completions/workovers is 41 MT). The assumed methane content of production gas is high at 97.2%, higher than even the pipeline gas content assumptions used by other LCAs. The analysis also assumes gas is delivered to power plants through distribution systems as opposed to transmission lines.
Citation	Jiang M, et al. (2011) "Life cycle greenhouse gas emissions of Marcellus shale gas". Environ Research Letters 6:034014. Available at: http://iopscience.iop.org/1748-9326/6/3/034014/pdf/1748-9326_6_3_034014.pdf

Authors	**Heath et al.** (Jeffery Logan, Garvin Heath (Heath was the lead author of the report's chapter on shale gas life cycle emissions), Jordan Macknick, Elizabeth Paranhos, William Boyd, Ken Carlson)
Lead Author Affiliation	National Renewable Energy Laboratory (Logan, Heath, Macknick), University of Colorado Law School (Paranhos, Boyd), Colorado State University (Carlson)
Title	Natural Gas and the Transformation of the U.S. Energy Sector: Electricity (2012)
Basin/Type of Gas	2009 Barnett Shale gas
Leakage Rate (CH_4/NG produced)	1.3% (shale)
Life Cycle NGCC Emissions Rate	440 kg CO_2e/MWh (shale) 450 kg CO_2e/MWh (conventional) as reported in O'Donoughue et al.
Overview	The JISEA report estimated life cycle emissions from shale gas wells in the Barnett to be 440 kg CO_2e/MWh. Of this, 363 kg CO_2e/MWh was the result of gas combustion at a power plant. This study did not factor in nitrogen oxide emissions from any stage of the fuel cycle, non-CO_2 emissions from power plants, or GHG emissions related to purchased fuels or the transport of water. Emissions from these sources are included in some other LCAs. This study used the lowest EUR of all LCAs examined (lower EURs result in higher life cycle emissions), and assumed that one percent of all wells underwent workovers each year. It was similar to other studies with its use of 25 as the 100 year GWP for methane and assumption of 51% for power plant efficiency. JISEA used a novel approach to estimate methane emissions. While most other studies relied on EPA for source data, JISEA took VOC emissions data collected by the Texas Commission on Environmental Quality from over 16,000 sources and used it to estimate methane and CO_2 emissions from those sources. A number of assumptions regarding methane leakage may have resulted in lower estimates compared to other studies. The overall leakage rate, at 1.3 percent, is lower than all other LCAs. The methane content of natural gas is also low at 66.2 percent. Finally, the study assumed that wells did not require liquids unloading. The report notes that if it had accounted for liquids unloading, total life cycle emissions would have increased by between 6 and 28 kg CO_2e/MWh (and even more under scenarios with lower EUR). While these factors may have lowered total life cycle emissions, JISEA's assumption that 9,175 Mcf of methane is released per completion or workover is significantly higher than current emissions factors.
Citation	Joint Institute for Strategic Energy Analysis (JISEA). (2012) "Natural Gas and the Transformation of the U.S. Energy Sector: Electricity". Logan, J., Heath, G., Paranhos, E., Boyd, W., Carlson, K., Macknick, J. NREL/TP-6A50-55538. Golden, CO, USA: National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy13osti/55538.pdf

Authors	**Howarth et al.** (Robert Howarth, Renee Santoro, Anthony Ingraffea)
Lead Author Affiliation	Cornell University
Title	Methane and the Greenhouse-gas Footprint of Natural Gas from Shale Formations (2011)
Basin/Type of Gas	Shale (Haynesville, Barnett), tight (Piceance, Uinta) and conventional
Leakage Rate (fugitive CH_4/ CH_4 produced)	3.6-7.9% (shale) 1.7-6% (conventional)
Life Cycle NGCC Emissions Rate	554-758 kg CO_2e/MWh (shale, as listed in JISEA/NREL report) 471-671 kg CO_2e/MWh (conventional, as listed in JISEA/NREL report)
Overview	The Howarth study estimated methane emissions from well to gate, but did not calculate life cycle GHG emissions through power generation. Average methane emissions were found to be about 20.2g CO_2e/MJ gas produced for conventional natural gas and 30.6g CO_2e/MJ for shale gas. The study focuses solely on methane emissions, and does not include detailed information on CO_2 emissions across the value chain or any information on N_2O emissions. While assumptions on the methane content of natural gas (78.8%) are comparable to other studies, Howarth uses a 100-year GWP of 33, while all others use 25. The EUR of 3 bcf per well is similar to that used by other LCAs. There is no discussion on the rate of flaring. Howarth's estimates of methane leakage (as percentage of total production) are significantly higher compared to other studies, with average shale gas leakage at 5.75% and average conventional gas at 3.85%. While the higher leak rate is a major factor in the study's overall higher life cycle emissions numbers, other assumptions also contribute. The study's use of a 100-year methane GWP of 33 is more in line with the current IPCC GWP for methane. This assumption raises the impact of GHG leakage estimates compared to other studies. The range of 95 to 4,608 tons of methane released per completion or workover is higher than the EPA estimate of 177 tons used by other studies. Howarth also includes emissions from distribution systems in his estimate of life cycle emissions. While emissions from these systems are included in some other LCAs (Jiang, Hultman), power plants frequently receive natural gas directly from transmission pipelines. Howarth does include emissions from liquids unloading at shale gas wells, which are not included in some LCAs due to earlier assumptions that shale wells did not require liquids unloading.
Citation	Howarth, R. et al. (2011) "Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations." Climatic Change 106(4): 679–690. Available at: http://www.acsf.cornell.edu/Assets/ACSF/docs/attachments/Howarth-EtAl-2011.pdf

Authors	**Burnham et al.** Andrew Burnham, Jeongwoo Han, Corrie Clark, Michael Wang, Jennifer Dunn, Ignasi Palou Rivera)
Lead Author Affiliation	Argonne National Laboratory
Title	Life Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum (2012)
Basin/Type of Gas	Shale (Barnett, Marcellus, Fayetteville, Haynesville) and conventional
Leakage Rate	2.01% (shale) 2.75% (conventional)
Life Cycle NGCC Emissions Rate	602 kg CO_2e/MWh (shale) 639 kg CO_2e/MWh (conventional)
Overview	The Argonne National Laboratory study estimated life cycle GHG emissions to be 602 kg CO_2e/MWh from shale gas and 639 kg CO_2e/MWh from conventional gas when burned in NGCC. When fired in a boiler, shale gas life cycle emissions are 855 kg CO_2e/MWh and conventional gas emissions are 880 kg CO_2e/MWh. Although the study focuses on emissions related to fugitive methane leaks, the life cycle estimates factor in emissions related to pre-end-use combustion, well pad development, drilling, and wastewater management. This report used the highest assumption for EUR at 3.5 bcf. Power plant efficiency (47% for NGCC, 33.1% for boiler) is comparable to other studies. Burnham assumes each well has two workovers per year. This is higher than most LCAs, some of which do not include information on workovers. The assumed 100-year GWP of methane is 25. The study uses average methane leakage rates of 2.01% for shale gas and 2.75% for conventional gas. Assumptions on the methane content of gas are slightly above the LCA average at 85% for conventional wells and 80% for shale wells. The flare rate used is 41%, which is in the mid-range of all the LCAs but lower than current industry practices. Emissions per completion / workover (177 tons) is the emissions factor from the 2011 GHG Inventory and is the same as most other studies. The study assumes that liquids unloading does not occur at shale wells, which may lower overall emissions estimates. The study also includes methane emissions from distribution systems in its life cycle analysis.
Citation	Burnham et al. (2011) "Life cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum." Environ Sci Technol. doi: 10.1021/es201942m. Available at: http://pubs.acs.org/doi/pdfplus/10.1021/es201942m

Authors	**Skone et al.** (Timothy Skone, James Littlefield, Robert Eckard, Greg Cooney, Joe Marriott)
Lead Author Affiliation	National Energy Technology Laboratory (NETL)
Title	Role of Alternative Energy Sources: Natural Gas Technology Assessment (2012)
Basin/Type of Gas	2009 Shale (Barnett and Marcellus) and conventional
Leakage Rate (fugitive NG/ produced gas)	4.8% (shale) 5.6% (conventional)
Life Cycle NGCC Emissions Rate	488 kg CO_2e/MWh (shale) 469 kg CO_2e/MWh (conventional)
Overview	This NETL LCA found life cycle emissions of 469 kg CO_2e/MWh for conventional gas and 488 kg CO_2e/MWh for unconventional gas. Conventional gas includes onshore, offshore and associated gas. The NETL LCA includes methane, CO_2, and N_2O emissions beginning with well construction through combustion at a power plant. The study did not factor in emissions related to the production of fracturing fluid, but did include GHG emissions from water sourcing and transport, land use, and management of wastewater. Its assumptions on GWP (100 year – 25) and power plant efficiency (NGCC – 50.2%) are similar to those used in other LCAs. This LCA also factored electricity transmission and distribution losses into its final emission rate. The study's analysis of methane leakage was slightly different from that of other LCAs in that it does not entirely differentiate the percentage of methane emitted to the atmosphere. Instead, it estimates that 3 percent of total production is either vented or flared and 1.8 percent is lost to fugitive leaks. Overall, these emissions are equal to 210.61lb CO_2e/MWh for average gas, with higher emissions for unconventional gas and lower for conventional. Although it is not clear how much gas is vented or leaked, a leakage rate of 4.8% is assumed for this study. NETL does not include emissions from distribution systems and assumes that gas is delivered directly to power plants from transmission systems. As with most other LCAs, it uses EPA's 2011 emission factor of 177 tons per completion or workover. Workovers are assumed to occur an average of 1.11 times per lifetime at conventional wells and 3.5 times per lifetime at unconventional wells. Methane content assumptions are also similar to other LCAs, although NETL uses a content of 92.8% for pipeline gas (78.3% for well gas). The report uses a flaring rate of 51 percent for conventional wells and 15 percent for unconventional wells, both of which are below current industry practices. NETL has completed subsequent studies that have updated a number of these assumptions.
Citation	Skone et al. (2012) "Role of Alternative Energy Sources: Natural Gas Technology Assessment" (US DOE National Energy Technology Laboratory, Washington, DC), DOE/NETL-2012/1539. Available at: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2012-1539-NGTechAssess.pdf

Authors	**Hultman et al.** (Nathan Hultman, Dylan Rebois, Michael Scholten, Christopher Ramig)
Lead Author Affiliation	University of Maryland
Title	The Greenhouse Gas Impact of Unconventional Gas for Electricity Production (2011)
Basin/Type of Gas	National average of unconventional (shale, tight, CBM) and conventional
Leakage Rate (CH_4/ consumed gas)	2.4% (unconventional) 3.8% (conventional)
Life Cycle NGCC Emissions Rate	529 kg CO_2e/MWh (unconventional) 476 kg CO_2e/MWh (conventional)
Overview	The Hultman study differs from other LCAs in that it focuses only on GHG from methane emissions and power plant combustion. The study does not include emissions from pre-end-use combustion, well pad development, water transport and treatment, and other emissions-generating activities captured in other LCAs. Despite this, the study's findings were similar to those of other LCAs: life cycle emissions of 476 kg CO_2e/MWh for conventional gas and 529 kg CO_2e/MWh for unconventional gas (both assume NGCC). Assumptions on power plant efficiency were slightly lower than the average of all LCAs at 45.9 percent (NGCC). The study uses EPA emissions factors to calculate total methane emissions and develop life cycle emissions. Many of the study's assumptions related to methane leakage are similar to those in other studies: 177 tons methane release per completion/workover, one workover per lifetime, and a 100-year GWP of 25. The report's flaring rate is low at 15 percent. Assumptions on the methane content of natural gas are consistent with other studies at 78.8 percent. Hultman's life cycle emissions include methane leaks from distribution systems, but assume that there is no liquids unloading at unconventional wells.
Citation	Hultman et al. (2011) "The greenhouse impact of unconventional gas for electricity generation". Environ Res Lett 6(4):044048. Available at: http://iopscience.iop.org/1748-9326/6/4/044008/pdf/1748-9326_6_4_044008.pdf

Authors	**Alvarez et al.** (Ramon Alvarez, Stephen Pacala, James Winebrake, William Chameides, Steven Hamburg)
Lead Author Affiliation	Environmental Defense Fund
Title	Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure (2012)
Basin/Type of Gas	U.S. production
Leakage Rate	2.1%
Life Cycle NGCC Emissions Rate	474.5 kg CO_2e/MWh
Overview	The Alvarez study calculates life cycle natural gas GHG emissions to be 474.5 kg CO_2e/MWh. The study does not account for any emissions related to pre-production activities. All assumptions on methane leakage and upstream CO_2 emissions are taken from the 2011 GHG Inventory. The assumed average gas power plant efficiency is lower than most other LCAs at approximately 43 percent. For electric systems, the study uses a methane leakage rate of 2.1 percent, which does not include distribution systems. The methane content of natural gas used by this study is higher than that used in other LCAs at 90 percent. The report also differs from others in that it includes methane emissions from oil wells, based on the energy content of gas produced at oil wells.
Citation	Alvarez et al. (2012) "Greater focus needed on methane leakage from natural gas infrastructure." PNAS. Available at: http://www.pnas.org/content/early/2012/04/02/1202407109.abstract.

Authors	**Laurenzi et al.** (Ian Laurenzi, Gilbert Jersey)
Lead Author Affiliation	ExxonMobil
Title	Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas (2013)
Basin/Type of Gas	Marcellus shale
Leakage Rate (fugitive CH_4/gross CH_4 produced)	1.7% (shale)
Life Cycle NGCC Emissions Rate	466 kg CO_2e/MWh (shale) 450 kg CO_2e/MWh (conventional)
Overview	This study estimated life cycle GHG emissions from Marcellus shale gas to be 466kg CO_2e/MWh. This estimate accounts for methane, CO_2, and N_2O emissions from pre-production through power plant combustion. It does not include emissions from wellpad development or natural gas distribution systems. This study was unique in that it used ExxonMobil data to estimate emissions from drilling, completion and production. For some production phases and emissions from processing and transmission, the study used EPA and EIA data. While the EUR used was slightly lower (1.8) than other LCAs, assumptions on GWP and power plant efficiency were similar to most other studies. The assumed leak rate of 1.7% was slightly lower than that of other LCAs. Also, this analysis accounted for emissions from natural gas co-products, which leads to a lower total GHG emissions rate. The study's flare rate of 99% is the highest of all LCAs examined.
Citation	Laurenzi et al. (2013) "Life cycle greenhouse gas emissions and freshwater consumption of Marcellus shale gas". Environ Sci Technol 47(9):4896–4903. Available at: http://www.fraw.org.uk/files/extreme/laurenzi_2013.pdf

Authors	**Stevenson et al.** (Trevor Stephenson, Jose Eduardo Valle, Xavier Riera-Palou)
Lead Author Affiliation	Shell
Title	Modeling the Relative GHG Emissions of Conventional and Shale Gas Production (2011)
Basin/Type of Gas	U.S. shale gas
Leakage Rate (mixed units)	0.65% (shale) 0.51% (conventional)
Life Cycle NGCC Emissions Rate	499 kg CO_2e/MWh (shale) 489 kg CO_2e/MWh (conventional)
Overview	This study estimated life cycle emissions from both conventional and shale gas. It concluded that shale gas emissions (499 kg CO_2e/MWh) were only slightly higher than those from conventional gas (489 kg CO_2e/MWh). GHGs included in the analysis include CO_2, methane, and N_2O. It does not include emissions from well pad development, fracturing fluid production, liquids unloading, or distribution systems. The study used EPA data to estimate emissions from most sources, but API data was used to calculate fugitive emissions. The study used a EUR of 2 bcf, which is in the mid-range of all the LCAs examined. The study had the lowest shale gas leakage rate of all LCAs, at 0.65%. The power plant efficiency used (43%) was also lower than that used by most other studies. One factor that lowered life cycle emissions was the allocation of emissions associated with natural gas production co-products. The study's assumption that natural gas has a methane content of 85% is slightly higher compared to other LCAs.
Citation	Stephenson et al. (2011) "Modeling the relative GHG emissions of conventional and shale gas production". Environ Sci Technol 45(24):10757–10764. Available at: http://pubs.acs.org/doi/pdf/10.1021/es2024115

Authors	**Allen et al.** (David T. Allen, Vincent M. Torres, James Thomas, David W. Sullivaa, Matthew Harrison, Al Hendler, Scott C. Herndon, Charles E. Kolb, Matthew P. Fraser, A. Daniel Hill, Brian K. Lamb, Jennifer Miskimins, Robert F. Sawyer, and John H. Seinfeld)
Lead Author Affiliation	University of Texas at Austin
Title	Measurements of Methane Emissions at Natural Gas Production Sites in the United States (2013)
Basin/Type of Gas	U.S. shale gas
Leakage Rate	0.42% (production only)
Life Cycle NGCC Emissions Rate	N/A
Overview	The UT Austin study involved the direct measurement of emissions from production-stage natural gas system components and activities located at various locations across the U.S. Unlike the other bottom-up studies discussed in this report, the UT Austin study does not provide estimates of life cycle GHG emissions, but instead develops emissions rates and annual emissions estimates, similar to EPA's GHG Inventory. The study is unique in that the emissions rates used are based on actual measurements of modern natural gas systems, whereas many of the emissions rates used by EPA for the same equipment are over 20 years old. For a number of emission sources, UT Austin applied the new emissions factors derived from their direct measurements across national activity data to estimate national emissions. The study concluded that EPA may be overestimating emissions from hydraulically fractured well completions. Conversely, the study found that methane emissions from pneumatic devices and equipment leaks may be higher than reported by EPA.
Participating Industry Companies	Anadarko Petroleum Corporation, BG Group plc, Chevron, Encana Oil & Gas (USA) Inc., Pioneer Natural Resources Company, SWEPI LP (Shell), Southwestern Energy, Talisman Energy USA, and XTO Energy
Citation	Allen DT, et al. (2013) "Measurements of methane emissions at natural gas production sites in the United States". PNAS. Available at: http://www.pnas.org/content/early/2013/09/10/1304880110.full.pdf+html

Authors	**Allen et al.** (David T. Allen, David W. Sullivan, Daniel Zavala-Araiza, Adam P. Pacsi, Matthew Harrison, Kindal Keen, Matthew P. Fraser, A. Daniel Hill, Brian K. Lamb, Robert F. Sawyer, and John H. Seinfeld)
Lead Author Affiliation	University of Texas at Austin
Title	Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquids Unloading (2014)
Basin/Type of Gas	U.S. production
Leakage Rate	0.38% (production only)
Life Cycle NGCC Emissions Rate	N/A
Overview	This UT Austin study involved the direct measurement of emissions from 107 liquids unloadings at sites across the U.S. As with the other UT Austin studies, this study does not provide estimates of life cycle GHG emissions, but instead develops emissions rates and annual emissions estimates, similar to EPA's GHG Inventory. While liquids unloading can be performed without emissions, this study focused on events that result in emissions (blowdown venting or venting after incomplete unloading with plunger lifts). The study found that wells without plunger lifts that unload less than ten times per year average 21,000 to 35,000 scf CH_4/event. Wells with plunger lifts averaged 1,000 to 10,000 scf CH_4/event. Wells with automated plunger lifts that unload thousands of times per year are responsible for the majority of emissions from liquids unloading. For all three well types (no lifts, manual lifts, auto lifts), a minority of wells were responsible for the majority of emissions. When the study's findings are scaled nationally, total U.S. methane emissions from liquids unloading are estimated to be 270 Gg, similar to the 2014 GHG Inventory's estimate of 274 Gg. However Allen et al. show EPA to be overestimating emissions from unloadings without plunger lifts and underestimating emissions from unloadings with plunger lifts.
Participating Industry Companies	Anadarko Petroleum Corporation, BG Group plc, Chevron, ConocoPhillips, Encana Oil & Gas (USA) Inc., Pioneer Natural Resources Company, SWEPI LP (Shell), Southwestern Energy, Statoil, and XTO Energy
Citation	Allen DT, et al. (2014) "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquids Unloading". Environmental Science & Technology. Available at: http://pubs.acs.org/doi/pdf/10.1021/es504016r

Authors	**Allen et al.** (David T. Allen, Adam P. Pacsi, David W. Sullivan, Daniel Zavala-Araiza, Matthew Harrison, Kindal Keen, Matthew P. Fraser, A. Daniel Hill, Robert F. Sawyer, and John H. Seinfeld)
Lead Author Affiliation	University of Texas at Austin
Title	Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers (2014)
Basin/Type of Gas	U.S. production, oil wells
Leakage Rate	0.38% (production only)
Life Cycle NGCC Emissions Rate	N/A
Overview	This UT Austin study took direct measurements of methane emissions from pneumatic controllers at natural gas (351 controllers) and oil (26 controllers) production sites across the U.S. While the UT Austin Phase I study also measured emissions from pneumatic devices, that study only evaluated recently fractured shale gas wells (newly completed shale wells tend to produce large amounts of fluids and thus may have higher device actuation rates and higher emissions). This study looked at different types of wells (conventional gas, shale gas, and oil) to measure emissions across all U.S. production. Average methane emissions from pneumatic controllers were found to be 4.7 scf/hour. Emissions varied widely depending on device application, type (continuous or intermittent bleed), and region. While only 19 percent of devices had emissions rates above 6 scf/hour, these sources accounted for 95 percent of total emissions. When applied nationally, measured methane emissions from this study are 17 percent higher than estimates in the 2014 GHG Inventory (394 Gg/year compared to 334 Gg/year). Allen et al. also observed an average of 2.7 controllers per well compared to the GHG Inventory assumption of one controller per well. However, Allen et al. observed many devices with very low or no emissions, including emergency shut-down controllers. These types of controllers may not be included in controller counts in the GHG Inventory. When assumptions (75 percent of wells have average of 2.7 pneumatic controllers and 75 percent of controllers have emissions) are applied to account for the study's findings and inclusion of non-emitting devices, national methane emissions are approximately 600 Gg/year.
Participating Industry Companies	Anadarko Petroleum Corporation, BG Group plc, Chevron, ConocoPhillips, Encana Oil & Gas (USA) Inc., Pioneer Natural Resources Company, SWEPI LP (Shell), Southwestern Energy, Statoil, and XTO Energy
Citation	Allen DT, et al. (2014) "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers". Environmental Science & Technology. Available at: http://pubs.acs.org/doi/pdf/10.1021/es5040156

Authors	**Zavala-Araiza et al.** (Daniel Zavala-Araiza, David T. Allen, Matthew Harrison, Fiji C. George, and Gilbert R. Jersey)
Lead Author Affiliation	University of Texas at Austin
Title	Allocating Methane Emissions to Natural Gas and Oil Production from Shale Formations (2015)
Basin/Type of Gas	U.S. shale gas
Leakage Rate	N/A
Life Cycle NGCC Emissions Rate	N/A
Overview	This UT Austin study used data from the UT Austin Phase I (2013) production study to allocate methane emissions to natural gas, oil, and NGLs. While the report found significant regional variability (some plays with wet gas and others with very dry gas), nationally natural gas is estimated to account for 85 percent of production-phase methane emissions. The remaining ten and five percent of emissions are allocated to oil and NGLs, respectively.
Citation	Zavala-Araiza D, Allen DT, Harrison M, George FC, Jersey GR (2015) "Allocating Methane Emissions to Natural Gas and Oil Production from Shale Formations". ACS Sustainable Chemistry & Engineering. Available at: http://pubs.acs.org/doi/pdf/10.1021/sc500730x

Authors	**Subramanian et al.** (R. Subramanian, Laurie L. Williams, Timothy L. Vaughn, Daniel Zimmerle, Joseph R. Roscioli, Scott C. Herndon, Tara I. Yacovitch, Cody Floerchinger, Daniel S. Tkacik, Austin L. Mitchell, Melissa R. Sullivan, Timothy R. Dallmann, and Allen L. Robinson)
Lead Author Affiliation	Carnegie Mellon University
Title	Measurements of Methane Emissions from Natural Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol (2015)
Basin/Type of Gas	N/A
Leakage Rate	N/A
Life Cycle NGCC Emissions Rate	N/A
Overview	This EDF-sponsored study measured equipment- and site-level methane emissions at 45 compressor stations in the transmission and storage sector. Overall, the highest emitting 10 percent of sources were responsible for 50 percent of total emissions. The site surveys detected two super emitter sources which skewed the average study-wide emissions rate. Excluding the two super emitter sources, average emissions were comparable to or lower than the corresponding emissions factors in the GHG Inventory. However, if the two outlier emissions sources are factored in, the study-wide emissions factors would exceed those used by EPA. A companion study that uses this report's results to estimate national emissions is expected to be published in 2015. Additionally, the report found that only 38 percent of emissions from the observed sources would have been reported under current GHGRP rules. This gap is due to GHGRP rules, the reporting thresholds, and the fact that the GHGRP emission measurement requirements would not have resulted in identification of the two super emitters. More specifically, the emissions factors used by the GHGRP underestimate methane emissions from engine exhaust, and reporting of emissions from standby pressurized reciprocating compressors, a major emissions source, is not required. The authors note the while the GHG Inventory could be improved by using GHGRP data, the GHGRP itself should also be updated. According to the authors, key steps to improve the GHGRP include requiring more direct measurements of emissions, eliminating certain reporting exclusions, and updating of emissions factors.
Participating Industry Companies	Dominion, Dow Chemical, Enable Gas Transmission LLC, Kinder Morgan, Columbia Pipeline Group, TransCanada, and The Williams Companies Inc.
Citation	Subramanian et al. (2015) "Measurements of Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons to the EPA Greenhouse Gas Reporting Program Protocol". Environmental Science & Technology. Available at: http://pubs.acs.org/doi/pdf/10.1021/es5060258.

Authors	**Mitchell et al.** (Austin L. Mitchell, Daniel S. Tkacik, Joseph R. Roscioli, Scott C. Herndon, Tara I. Yacovitch, David M. Martinez, Timothy L. Vaughn, Laurie L Williams, Melissa R. Sullivan, Cody Floerchinger, Mark Omara, R. Subramanian, Daniel Zimmerle, Anthony J. Marchese, and Allen L. Robinson)
Lead Author Affiliation	Carnegie Mellon University
Title	Measurements of Methane Emissions from Natural Gathering Facilities and Processing Plants: Measurement Results (2015)
Basin/Type of Gas	N/A
Leakage Rate	N/A
Life Cycle NGCC Emissions Rate	N/A
Overview	This EDF-sponsored study measured methane emissions at 114 gathering facilities and 16 processing plants at sites across the U.S. At 85 of the gathering facilities, methane emissions were less than one percent of total facility throughput. The majority of emissions from gathering stations came from a minority of sources – 30 percent of facilities contributed 80 percent of total emissions. Gathering facilities with venting storage tanks generally had emissions rates four time higher than similar facilities without substantial tank venting. The report also found a negative correlation between methane throughput and leakage rate, with facilities with larger methane throughput having lower emissions rates. Overall, processing plants were found to have emissions rates less than one percent. Emissions from processing plants were much more evenly distributed across the facilities surveyed. The authors suggest that LDAR programs and the fact that most processing plants were staffed at all times contributed to lower emissions rates at these facilities. A companion study that uses this report's results to estimate national emissions from gathering and processing is expected to be published in 2015.
Participating Industry Companies	Access Midstream, Anadarko Petroleum Corporation, Hess Corporation, Southwest Energy, Williams Corporation, and DCP Midstream
Citation	Mitchell et al. (2015) "Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results". Environmental Science & Technology. Available at: http://pubs.acs.org/doi/pdf/10.1021/es5052809

Table 20. Review of Key Emission Sources Included in Each Reviewed Life Cycle Analysis

Emissions Activity	**Alvarez (2012)**	**Burnham (Argonne NL, 2011)**	**Howarth (Cornell, 2011)**	**Hultman (UMD, 2011)**	**Jiang (CMU, 2011)**	**JISEA (2012)**	**Laurenzi (ExxonMobil, 2013)**	**Skone (NETL, 2011)**	**Stephenson (Shell, 2011)**
Well Pad Development	**o**	**X**	**o**	**o**	**X**	**X**	**o**	**X**	**o**
Drilling	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Fracturing Fluid Production	**o**	**X**	**o**	**o**	**X**	**o**	**X**	**o**	**o**
Completion	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Liquids Unloading	**X**	**o**	**X**	**o**	**o**	**o**	**X**	**o**	**o**
Imported Fuels	**o**	**X**	**o**	**o**	**X**	**o**	**X**	**X**	**X**
Upstream Combustion	**X**	**X**	**X**	**o**	**X**	**X**	**X**	**X**	**X**
Wastewater Transport & Treatment	**o**	**X**	**o**	**o**	**X**	**X** (disposal only)	**X**	**o**	**X**
Distribution Systems	**o**	**X**	**X**	**X**	**X**	**o**	**o**	**o**	**o**
N_2O Emissions	**o**	**X**	**o**		**X**	**o**	**X**	**X**	**X**
Power Plant Combustion	**X**	**X**	**o**	**X**	**X**	**X**	**X**	**X**	**X**

X = Emission source included as part of study
o = Emission source not included as part of study

Table 21. Summary of Reported Values from Life Cycle Analyses

Emissions Activity	**Alvarez (EDF,2012)**	**Burnham (Argonne NL, 2011)**	**Howarth (Cornell, 2011)**	**Hultman (UMD, 2011)**	**Jiang (CMU, 2011)**	**Heath (JISEA, 2012)**	**Laurenzi (ExxonMobil, 2013)**	**Skone (NETL, 2012)**	**Stephenson (Shell, 2011)**
Life Cycle Emissions (kg CO_2e/MWh)	474.5	Shale: 602 Con: 639	Shale: 554-758 Con: 471-671	Uncon: 529 Con: 476	Shale: 488 U.S. Domestic: 473	Shale: 440 Con: 450	Shale: 466 Con: 450	Shale: 486-488 Con: 469	Shale: 499 Con: 489
Methane Leakage	U.S. production: 2.1%	Shale: 2.01% Con: 2.75% (CH_4/NG produced)	Shale: 3.6-7.9% Con: 1.7-6% (fugitive CH_4/CH_4 produced)	Uncon: 2.4% Con: 3.8% (CH_4/consumed gas)	U.S. Domestic: 2.2% (CH_4/NG produced)	Shale: 1.3% (CH_4/NG produced)	Shale: 1.7% (fugitive CH_4/CH_4 produced)	Shale: 4.8% Con: 5.6% (fugitive NG/produced gas)	Shale:0.65% Con: 0.51% (mixed units)
EUR (unconventional, bcf)	NR	3.5	3	NR	2.7	1.42	1.8	3	2
100 Year GWP	NR	25	33	25	25	25	25	25	25
Flare Rate	NR	41%	NR	15%	76%	NR	99%	Uncon: 15% Con: 51%	51%
Emissions/ completion or workover	177 tons	177 tons	95-4,608 tons	177 tons	400 tons	177 tons	73 tons	177 tons	177 tons
Natural Gas Methane Content	90%	Shale: 80% Con: 85%	78.8%	78.8%	97.2%	66.2%	Well: 79.4% Pipeline: 89.9%	Well: 78.3% Pipeline: 93.4%	85%
Power Plant Efficiency (NGCC)	43%	47%	NA	45.9%	50%	51%	50.2%	50.2%	43%

NR = Not Reported
NA = Not Applicable

Appendix C: Top-down Summaries

Authors	**Anna Karion et al.** (Anna Karion, Colm Sweeney, Gabrielle Pétron, Gregory Frost, R. Michael Hardesty, Jonathan Kofler, Ben R. Miller, Tim Newberger, Sonja Wolter, Robert Banta, Alan Brewer, Ed Dlugokencky, Patricia Lang, Stephen A. Montzka, Russell Schnell, Pieter Tans, Michael Trainer, Robert Zamora, Stephen Conley)
Lead Author Affiliation	NOAA
Title	Methane Emissions Estimate from Airborne Measurements Over a Western United States Natural Gas Field (2013)
Basin/Type of Gas	Uinta County, UT
Leakage Rate	8.8±2.6%
Life Cycle NGCC Emissions Rate	N/A
Overview	This study uses measurements taken from an airplane to calculate methane flux from the Uinta County oil and gas field using a mass balance approach. Measurements were taken during flights in February 2012, with results based on methane flux levels recorded on two days. The study only measures methane emissions from a natural gas and oil production field, it does not include estimates of emissions from other segments of the natural gas value chain or estimate the life cycle emissions of natural gas. The study determined methane emissions to be 8.8±2.6% of natural gas production in Uinta County. At the time of publication, this estimate was 1.8 to 38 times inventory-based estimates from the region and five times the leakage rate from production and processing estimated in EPA's GHG Inventory (2011). The leakage rate from the study area is estimated at 54.6±15.4x10^3 kg methane/hour.
Citation	Karion, A., et al. (2013), "Methane emissions estimate from airborne measurements over a western United States natural gas field", Geophys. Res. Lett., 40, 4393–4397, doi: 10.1002/grl.50811 Available at: http://www.fraw.org.uk/files/extreme/karion_2013.pdf

Authors	**Pétron et al.** (Gabrielle Pétron, Gregory Frost, Benjamin R. Miller, Adam I. Hirsch, Stephen A. Montzka, Anna Karion, Michael Trainer, Colm Sweeney, Arlyn E. Andrews, Lloyd Miller, Jonathan Kofler, Amnon Bar-Ilan, Ed J. Dlugokencky, Laura Patrick, Charles T. Moore Jr., Thomas B. Ryerson, Carolina Siso, William Kolodzey, Patricia M. Lang, Thomas Conway, Paul Novelli, Kenneth Masarie, Bradley Hall, Douglas Guenther, Duane Kitzis, John Miller, David Welsh, Dan Wolfe, William Neff, and Pieter Tans)
Lead Author Affiliation	NOAA
Title	Hydrocarbon Emissions Characterization in the Colorado Front Range: A Pilot Study (2012)
Basin/Type of Gas	Denver Julesburg/tight, shale and associated gas
Leakage Rate	2.3%-7.7% (average 4%)
Life Cycle NGCC Emissions Rate	N/A
Overview	This study provides top-down estimates of methane emissions from the Denver-Julesburg Basin based on atmospheric samples taken from a 300 meter tower from 2007-2010 and a vehicle in the summer of 2008. These data were then applied to bottom-up information (WRAP Phase III, Colorado Oil and Gas Conservation Commission and Colorado Department of Public Health and the Environment) to create three emission scenarios. In these scenarios, vented gas ranged from 2.3-2.7 percent of annual production. All of these top-down emissions scenarios showed higher methane leakage than a bottom-up estimate based on WRAP Phase III data, which estimated 1.68 percent of annual production was vented.
Citation	Pétron, G., et al. (2012), "Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study", J. Geophys. Res., 117, D04304, doi:10.1029/2011JD016360. Available at: http://onlinelibrary.wiley.com/doi/10.1029/2011JD016360/pdf

Authors	**Pétron et al.** (Gabrielle Pétron, Anna Karion, Colm Sweeney, Benjamin R. Miller, Stephen A. Montzka, Gregory Frost, Michael Trainer, Pieter Tans, Arlyn Andrews, Jonathan Kofler, Detlev Helmig, Douglas Guenther, Ed Dlugokencky, Patricia Lang, Tim Newberger, Sonja Wolter, Bradley Hall, Paul Novelli, Alan Brewer, Stephen Conley, Mike Hardesty, Robert Banta, Allen White, David Noone, Dan Wolfe, and Russ Schnell)
Lead Author Affiliation	NOAA
Title	A New Look at Methane and Non-methane Hydrocarbon Emissions from Oil and Natural Gas Operations in the Colorado Denver-Julesburg Basin (2014)
Basin/Type of Gas	Denver Julesburg/tight, shale and associated gas
Leakage Rate	4.1±1.5%
Life Cycle NGCC Emissions Rate	N/A
Overview	This study analyzes methane emissions in May 2012 from the Denver-Julesburg Basin in Weld County, Colorado using airborne measurements. Airplane based methane measurements were combined with ground based wind speed and direction measurements to calculate methane flux in and out of the study area. Total oil and gas related methane emissions were estimated to be 19.3±6.9 tons/hour, which is equal to a leak rate of 4.1±1.5 percent of natural gas produced. These estimates account for non-oil and gas sources such as agriculture, landfills and water treatment plants, whose methane emissions were estimated using state and EPA data. This study does not distinguish between methane from oil and gas production. This is significant because nearly 50 percent of the natural gas produced in the region is co-produced at oil wells, and the area has a large number of oil and liquid condensate storage tanks and other non-gas infrastructure that emit methane.
Citation	Pétron, G., et al. (2014). "A new look at methane and nonmethane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin". J. Geophys. Res. Atmos., 119, 6836–6852. Available at: http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/abstract

Authors	**Caulton et al.** (Dana Caulton, Paul B. Shepson, Renee L. Santoro, Jed P. Sparks, Robert W. Howarth, Anthony R. Ingraffea, Maria O. L. Cambaliza, Colm Sweeney, Anna Karion, Kenneth J. Davis, Brian H. Stirm, Stephen A. Montzka, and Ben R. Miller)
Lead Author Affiliation	Purdue University
Title	Toward a better understanding and quantification of methane emissions from shale gas development (2014)
Basin/Type of Gas	Marcellus shale
Leakage Rate	2.8-17.3%
Life Cycle NGCC Emissions Rate	N/A
Overview	This study used airborne methane flux measurements to estimate methane emissions from the Marcellus formation in southwestern Pennsylvania in June 2012. Using measurements from flights taken on two separate days, the study estimates that the area sampled had a fugitive methane emission rate of 2.8-17.3 percent of total production. This estimate accounts for methane emissions from other sources, such as agriculture and landfills. The data collected allowed the authors to identify methane emissions from individual well pads and pad clusters that exhibited high leak rates. Significantly, all these wells were determined to be in the drilling stage, an activity previously thought to have relatively low methane emissions. The emissions detected by airplane during drilling were two to three orders of magnitude larger than estimates from bottom-up inventories. Study data suggests that these high emission rates may be the result of underbalanced drilling through shallow coal beds, which could allow coal bed methane to escape through the wellbore. While the authors emphasized that the data only reflected emissions from two days and was not representative of all Marcellus or other shale formation wells, it did identify drilling as a potential source of large methane emissions. The possibility that a small number of wells have significant emissions during drilling is in line with the theory that throughout the natural gas life cycle, a small number of super emitters are responsible for the majority of emissions.
Citation	Caulton, D., et al. (2014). "Toward a better understanding and quantification of methane emissions from shale gas development". PNAS. Available at: http://www.pnas.org/content/early/2014/04/10/1316546111

Authors	**Peischl et al.** (J. Peischl, T. B. Ryerson, K. C. Aikin, J. A. de Gouw, J. B. Gilman, J. S. Holloway, B. M. Lerner, R. Nadkarni, J. A Neuman, J. B. Nowak, M. Trainer, C. Warneke, and D. D. Parrish)
Lead Author Affiliation	University of Colorado Boulder, NOAA
Title	Quantifying Atmospheric Methane Emissions from the Haynesville, Fayetteville, and Northeastern Marcellus Shale Gas Production Regions (2015)
Basin/Type of Gas	Haynesville, Fayetteville, and Marcellus shale
Leakage Rate	1.1% (three region average)
Life Cycle NGCC Emissions Rate	N/A
Overview	This report used plane-based instruments to calculate methane flux across the Haynesville, Fayetteville, and northeastern Marcellus shale regions. Emissions estimates are based on single flights for each region, which took place in June/July 2013. Using EIA and state production data from the time of the measurement flights, total methane leakage across all three areas is estimated to be 1.1 percent of natural gas production. Leakage rates varied across the three regions: Haynesville 1.0-2.1 percent; Fayetteville 1.0-2.8 percent; and Marcellus 0.18-0.41 percent. At the time of measurement, these regions accounted for 20 percent of total U.S. gas production and over 50 percent of total U.S. unconventional production. The majority of methane emissions were determined to be from oil and gas activities, with non-oil and gas sources accounting for approximately ten percent of total methane in each region. Non-oil and gas emissions were estimated using bottom-up inventories. Unquantifiable non-oil and gas emissions were factored into the study's uncertainty analysis. Methane to ethane and other propane ratios were also used to confirm that detected methane was from natural gas activities. Leakage from this report is lower than earlier estimates from western production areas (Petron and Karion reports). The authors suggest that their estimates may be lower, especially in the Marcellus, because production in the observed areas is more recent and the use of newer and more efficient technologies may reduce leakage. Differences in gas composition and regulations also contribute to regional variability. Despite lower leakage rates, Peischl et al. note that the magnitude of methane emissions from the observed regions are equal to those of western regions with lower leakage rates due to higher production levels in the Haynesville, Fayetteville, and Marcellus shale plays. The authors emphasize the importance of regional studies to accurately estimate methane emissions and the need for additional measurements to determine if their one-day findings are fully representative of each region.
Citation	Peischl et al. (2015). "Quantifying Atmospheric Methane Emissions from the Haynesville, Fayetteville, and Northeastern Marcellus Shale Gas Production Regions". Journal of Geophysical Research: Atmospheres. Available at: http://onlinelibrary.wiley.com/doi/10.1002/2014JD022697/pdf

Appendix D: Meta-analysis Summaries

Authors	**Heath et al.** (Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian)
Lead Author Affiliation	JISEA/NREL
Title	Harmonization of Initial Estimates of Shale Gas Life Cycle Greenhouse Gas Emissions for Electric Power Generation (2014)
Basin/Type of Gas	U.S. shale and conventional
Leakage Rate	0.66-6.2% (range of LCA leak rates adjusted with consistent units)
Life Cycle NGCC Emissions Rate	465 kg CO_2e/MWh (unconventional) 461 kg CO_2e/MWh (conventional)
Overview	NREL's harmonization study analyzed eight previously released natural gas life cycle assessments. The harmonization process involves assigning consistent assumptions across the LCAs wherever possible. In this case, power plant efficiency, GWP and well recompletion rate were standardized across all eight LCAs. Emissions from liquids unloading, recompletions, well pre-production, and power plant construction and decommissioning were added to the LCAs that did not account for these activities. These added emissions were developed in a consistent manner but were influenced by each reports' unique assumptions, such as EUR. Methane leak rate and allocation of emissions from natural gas co-products were not harmonized. After harmonization, NREL found median shale gas life cycle GHG emissions from the eight studies to be slightly higher than life cycle emissions from conventional gas. Both types of gas had approximately half the life cycle emissions of coal.
Citation	Heath, G.A. et al., (2014) "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation". PNAS. Available at: http://www.pnas.org/content/early/2014/07/16/1309334111.full.pdf+html.

Authors	**Brandt et al. (**A. R. Brandt, G. A. Heath, E. A. Kort, F. O'Sullivan, G. Pétron, S. M. Jordaan, P. Tans, J. Wilcox, A. M. Gopstein, D. Arent, S. Wofsy, N. J. Brown, R. Bradley, G. D. Stucky, D. Eardley and R. Harriss)
Lead Author Affiliation	Stanford University
Title	Methane Leaks from North American Natural Gas Systems (2014)
Basin/Type of Gas	U.S. and Canadian production
Leakage Rate	3.6-7.1% (Includes non-natural gas sources. Authors acknowledge the natural gas systems are not responsible for all methane represented by this leak rate range)
Life Cycle NGCC Emissions Rate	N/A
Overview	This analysis reviewed over 200 bottom-up and top-down methane leakage estimates that have been published over the past 20 years. To enable comparison between the bottom-up and top-down studies, Brandt et al. normalized the atmospheric studies to baselines derived from EPA's 2013 GHG Inventory. After normalization, national-scale atmospheric measurements typically estimated total national methane emissions to be about one and a half times greater than those in EPA's Inventory. However, the report cautioned that natural gas systems were not responsible for all of these excess emissions and that a better understanding of all methane sources is essential to accurately distinguishing and measuring methane emissions from natural gas systems. Brandt et al. also found that replacing coal with natural gas in the power sector provides climate benefits even when the lower emission estimates from the GHG Inventory are updated with higher numbers that the authors believe more likely represent actual emissions.
Citation	Brandt AR, et al. (2014) Energy and Environment. "Methane leaks from North American natural gas systems". Science 343(6172):733–735. Available at: http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf.

Authors	**Zhang et al.** (Xiaochun Zhang, Nathan P. Myhrvold, and Ken Caldeira)
Lead Author Affiliation	Carnegie Institution for Science
Title	Key Factors for Assessing Climate Benefits of Natural Gas versus Coal Electricity Generation (2014)
Basin/Type of Gas	U.S. production
Leakage Rate	N/A
Life Cycle NGCC Emissions Rate	N/A
Overview	This report compared the climate impacts of natural gas- and coal-fired electricity generation by modeling the global mean temperature change attributed to both fuels across a range of upstream methane leakage and power plant efficiency scenarios. Overall, the report found that while natural gas almost always provides long term climate benefits over coal, coal can be better in the short term if upstream methane leakage from natural gas systems is high. Because methane breaks down in the atmosphere relatively quickly, the impact of upstream emissions diminishes after power plants have stopped operating. As a result, power plant efficiency is the most important factor in overall climate impact. Despite the near term climate benefits of high-efficiency gas plants in low leakage scenarios, Zhang et al. concluded that without carbon capture and storage, natural gas plants cannot achieve the GHG reductions required to avoid additional global warming.
Citation	Zhang X. et al. (2014) “Key Factors for Assessing Climate Benefits of Natural Gas versus Coal Electricity Generation”. Environmental Research Letters. Available at: http://iopscience.iop.org/1748-9326/9/11/114022/pdf/1748-9326_9_11_114022.pdf

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