Council of Canadians
Response to
Union Gas Limited Interrogatory # 1
(Dr. Ingraffea)

1. *Reference:* Exhibit L.EGD.COC.1

Preamble: The Environmental Research Letters journal published an article written by Nathan Hultman et al., titled "The greenhouse impact of unconventional gas for electricity generation" on December 15, 2011. This paper is referenced in Exhibit L.EGD.COC.1.

Request:

1a) Please provide this paper.

Response:

a) The paper is attached as Appendix "A". Please note that I am co-author of a review (Reference number 2011-0003) requested by the White House's National Climate Assessment program. That review is attached as Appendix "B", and provides an evaluation of the paper by Hultman et al., see Tables 1, 2 and 3.

2. *Reference:* Exhibit L.EGD.COC.1

Preamble: Environmental Science & Technology Journal published a paper written by Christopher L. Weber and Christopher Clavin, titled "Life-Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications" on April 30, 2012. This paper compares the results of various studies completed on upstream carbon footprint estimates from shale gas and the methodologies used to estimate these emissions. One of the studies discussed is the information provided in the referenced exhibit.

Request:

2a) Is Dr. Ingraffea aware of this paper? Please provide this paper.

Response:

This paper is attached as Appendix "C". Yes, I am well aware of this paper, which appeared after our review for the White House's National Climate Assessment program. In its analysis, this paper uses only the 100-year GWP of methane:

> *"We utilize 100-year GWP values from the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, as standardized by recent carbon footprint protocols." [Page 5689]*

and claims that this is "standardized". It is not. The IPCC-4 also uses a 20-year GWP, and assigns it a value of 72, nearly three times the 100-year GWP, 25, used by Weber and Clavin.

3. *Reference:* Exhibit L.EGD.COC.1

Preamble: The World Resources Institute developed a Working Paper entitled "Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems," in April of 2013. This paper compares various studies completed on emissions from shale gas at each of the life cycle stages of the well. One of the studies discussed is the information provided in the referenced exhibit.

Request:

3a) Is Dr. Ingraffea aware of this paper? Please provide this paper.

Response:

This report, not paper, is attached as Appendix "D". Yes, I am well aware of this non-peer-reviewed report, which appeared after our review for the White House's National Climate Assessment program. This report is over-optimistic in expecting technology changes needed to support its policy assertions:

> *"Through these and other steps, governments will have the tools they need to achieve continuous air quality improvements over time and slow the rate of climate change by reducing methane emissions to below 1 percent of total natural gas production."*

Reducing methane emissions to below 1 percent of total natural gas production is entirely unrealistic in any time frame at any cost. This report criticizes the actual field measurement findings of Petron et al. of NOAA, which found upstream/midstream only (not including transmission and distribution losses) emissions in a region of Colorado between 2.3 and 7 percent of production. Other NOAA peer-reviewed papers since this WRI report have measured (not estimated) upstream/midstream emissions only up to 9 percent in Utah, and upstream/midstream/downstream emissions up to 17 percent in the Los Angeles CA basin.

4. *Reference:* Exhibit L.EGD.COC.1

Preamble: Environmental Science & Technology Journal published a peer-reviewed paper written by Andrew Burnham et al., titled "Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal and Petroleum" on November 22, 2011. This paper is referenced in Exhibit L.EGD.COC.1.

Request:

4a) Please provide this paper.

Response:

This paper is attached as Appendix "E" See response to UGL-COC IR 1(a)

5. *Reference:* Exhibit L.EGD.COC.1, Schedule C-I Page 1

Preamble: The Abstract of Schedule C-I in Exhibit L.EGD.COC.1 identifies that the April 2011 paper prepared by Robert W. Howarth, Renee Santoro and Anthony Ingraffea was challenged by Cathles et al. (2012).

Request:

5a) Please provide a copy of the Cathles et al. (2012) challenge to the April 2011 report.

Response:

This paper is attached as Appendix "F".

Request:

5b) Did Cathles et al. produce a review/challenge of Schedule C-I? If so please provide this document.

Response:

No, Cathles et al. did not respond to our rebuttal in R. Howarth, R. Santoro, A. Ingraffea. Venting and leaking of methane from shale gas development: response to Cathles et al., Climatic Change (2012) 113:537–549, DOI 10.1007/s10584-012-0401-0.

Appendix “A”

APPENDIX A

IOP PUBLISHING ENVIRONMENTAL RESEARCH LETTERS

Environ. Res. Lett. 6 (2011) 049504 (1pp) doi:10.1088/1748-9326/6/4/049504

Corrigendum

The greenhouse impact of unconventional gas for electricity generation

Nathan Hultman, Dylan Rebois, Michael Scholten and Christopher Ramig 2011 *Environ. Res. Lett.* **6** 044008

Received 15 November 2011
Published 15 December 2011

In our discussion of the use of global warming potential (GWP) values in the Howarth *et al* (2011) paper, our text implies that the GISS group's 2009 and 2010 papers (Shindell *et al* 2009 and Unger *et al* 2010) were contradictory. Such an interpretation does not reflect the conclusions of those papers and was not our intention. First, the 2009 and 2010 papers address GWP and radiative forcing, respectively. Our intentions in that paragraph were (a) to illustrate the possible ways that the GWP and radiative forcing discussions in the scientific community were misapplied to lifecycle analysis of greenhouse gas emissions from unconventional gas extraction, and (b) to underscore that the reasonable questions about GWP raised by Shindell *et al* (2009) are a justification for retaining a broader, rather than narrower, range of GWP possibilities for this calculation.

References

Howarth R W, Santoro R and Ingraffea A 2011 Methane and the greenhouse-gas footprint of natural gas from shale formations *Clim. Change Lett.* **106** 679–90

Shindell D T, Faluvegi G, Koch D M, Schmidt G A, Unger N and Bauer S E 2009 Improved attribution of climate forcing to emissions *Science* **326** 716–8

Unger N, Bond T C, Wang J S, Koch D M, Menon S, Shindell D T and Bauer S E 2010 Attribution of climate forcing to economic sectors *Proc. Natl Acad. Sci.* **107** 3382–7

IOP Publishing Environmental Research Letters

Environ. Res. Lett. 6 (2011) 044008 (9pp) doi:10.1088/1748-9326/6/4/044008

The greenhouse impact of unconventional gas for electricity generation

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Abstract

New techniques to extract natural gas from unconventional resources have become economically competitive over the past several years, leading to a rapid and largely unanticipated expansion in natural gas production. The US Energy Information Administration projects that unconventional gas will supply nearly half of US gas production by 2035. In addition, by significantly expanding and diversifying the gas supply internationally, the exploitation of new unconventional gas resources has the potential to reshape energy policy at national and international levels—altering geopolitics and energy security, recasting the economics of energy technology investment decisions, and shifting trends in greenhouse gas (GHG) emissions. In anticipation of this expansion, one of the perceived core advantages of unconventional gas—its relatively moderate GHG impact compared to coal—has recently come under scrutiny. In this paper, we compare the GHG footprints of conventional natural gas, unconventional natural gas (i.e. shale gas that has been produced using the process of hydraulic fracturing, or 'fracking'), and coal in a transparent and consistent way, focusing primarily on the electricity generation sector. We show that for electricity generation the GHG impacts of shale gas are 11% higher than those of conventional gas, and only 56% that of coal for standard assumptions.

Keywords: unconventional gas, fracking, hydraulic fracturing, greenhouse gases, shale gas, energy policy

1. Introduction

New techniques to extract natural gas from unconventional resources—such as shales or tight sands—have become economically competitive over the past several years, leading to a rapid and unanticipated expansion in natural gas production. These techniques led to an increase in US production of unconventional gas at an average annual rate of 17% between 2000 and 2006. Production further increased by 45% from 2006 to 2010 (Energy Information Administration 2011a). The US Energy Information Administration (EIA) projects that unconventional gas will supply nearly half of US gas production by 2035, up from 16% in 2009 (figure 1). In addition, unconventional gas reserves are found in many places worldwide and exploration continues. This widespread geographic distribution, combined with new production techniques, implies a substantial potential for global deployment of unconventional gas extraction (Energy Information Administration 2011c).

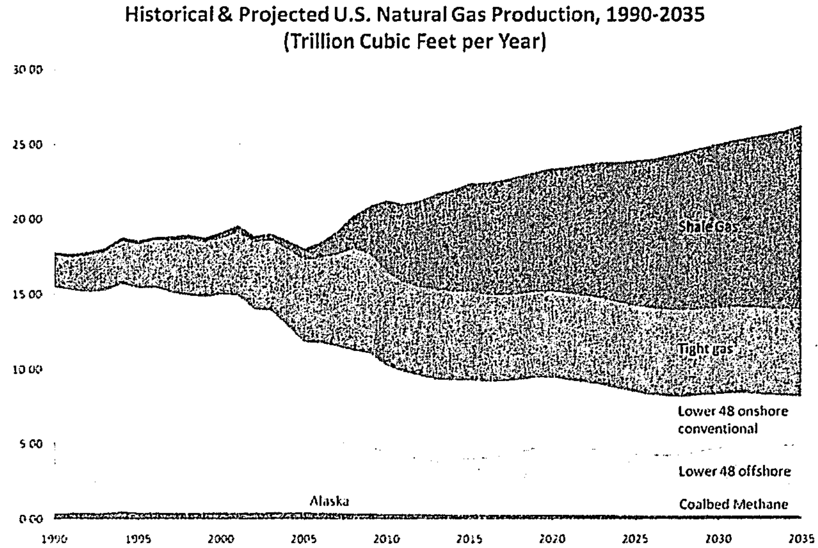

Figure 1. US natural gas production 1990–2035, showing recent and projected increases in unconventional (shale and tight) gas production. Data from EIA (Energy Information Administration 2011a).

By significantly expanding and diversifying the gas supply, the exploitation of new unconventional gas resources has the potential to reshape energy policy at national and international levels—altering geopolitics and energy security, recasting the economics of energy technology investment decisions, and shifting trends in greenhouse gas (GHG) emissions. Absent a carbon price, electricity generation from gas could constitute a highly competitive option relative to nuclear, many renewables, and even coal. Nevertheless, in the wake of the recent rapid expansion of this technology, and in anticipation of continued rapid growth, reasonable questions have been raised about the environmental and health impacts of shale gas extraction, particularly the possibility of contamination of water from proprietary chemicals used in the fracturing process. In addition, more recently, one of the perceived core advantages of unconventional gas—its relatively moderate GHG impact compared to coal—has come under scrutiny. One recent and visible study has estimated that, per gigajoule of fuel, unconventional gas has a higher greenhouse gas footprint than coal (Howarth *et al* 2011). A forthcoming study by the National Energy Technology Laboratory (Skone 2011) sets out a comprehensive life-cycle-assessment (LCA) framework and finds a relatively minor GHG difference between conventional and unconventional gas. In this paper, we compare the GHG footprints of conventional natural gas, unconventional natural gas (i.e. shale gas that has been produced using the process of hydraulic fracturing, or 'fracking'), and coal in a transparent and consistent way, focusing primarily on the electricity generation sector. We show that for electricity generation the GHG impacts of shale gas are only marginally higher than those of conventional gas, and both remain substantially lower than those of coal under standard assumptions.

2. The greenhouse footprint of conventional and unconventional gas

Gas produced from unconventional wells has roughly the same methane content as that produced from conventional wells (Rojey 1997)[5] and therefore combustion can be assumed to yield the same climate effect. However, extraction techniques for unconventional gas differ from those used for conventional gas, and figures on well-lifecycle methane emissions have not been comprehensively established. Unlike other unconventional fossil fuel production, such as the extraction of petroleum from oil sands, these new gas extraction methods do not require substantial amounts of energy to process the resource. They rely instead on a technique called hydraulic fracturing that injects a fluid under high pressure into the geological formation, creating fractures in the rock. The fluid is then withdrawn, a well is established, and the gas embedded in the rock diffuses to the surface. While the data are still uncertain, the fracturing process may release substantial amounts of methane directly into the atmosphere (called fugitive methane emissions). Methane is a potent GHG, so the emissions from this process could substantially increase the greenhouse footprint of unconventional gas compared to conventional gas.

Calculating the GHG footprint of unconventional gas requires three steps and associated assumptions. First, emissions of GHG from the production process, leaked methane and CO_2, must be estimated. Second, these numbers

[5] Typically, the composition of associated gas (that generated in tandem with crude oil) is distinct from non-associated gas, but even that generalization is blurry. The line between conventional and unconventional gas cuts across the division between associated and non-associated gas; therefore there is no easy way to establish a correlation between the conventionality of gas production and its methane content. For the purposes of this paper, we assume the mean methane content of conventional and unconventional gas is equivalent.

must be converted to a common GHG metric such as CO_2-equivalent (CO_2e). Third, because electricity generation technologies vary greatly in their combustion efficiencies, the emissions attributable to a kilogram or GJ of fuel are more appropriately compared on the basis of electricity delivered to the end-user—i.e. on a per kWh basis. In this section, we explain our approach to each of these steps and present results comparing the greenhouse footprint of electricity generated from conventional natural gas, unconventional natural gas, and coal.

2.1. Fugitive emissions from natural gas production

Despite the use of either flaring or control and capture technologies, natural gas routinely leaks or is vented during well drilling and operation. These fugitive emissions contain a heavy concentration of methane, which, because of its high radiative forcing, can contribute significantly to the global warming impact of natural gas mining operations. We consider fugitive emissions from nine distinct segments of the production process: well drilling and completion, periodic well workovers, routine production activities, processing, transmission, storage, liquefied natural gas (LNG) storage, LNG processing terminals, and distribution[6]. Calculations are based on an aggregated data set provided by the United States Environmental Protection Agency (US Environmental Protection Agency 2010). Each statistic is presented for both conventional and unconventional natural gas wells, with the latter comprised of shale and tight sands formations, and coal bed methane[7]. Calculations are presented on a per well basis and multiplied by the total number of unconventional wells (including tight sands) to yield an aggregate value. The omission of tight sands data does not skew these results[8]. Estimating total production from an 'average' well is not straightforward. Natural gas wells exhibit considerable variability in production lifetime, and the mean half-life of US domestic wells has shifted over time. EIA data indicate that the half-life of wells that first produced in 1990 was roughly 40 months, whereas that for wells that first produced in 1999 was 25 months (Energy Information Administration 2001). A well half-life of 30 months is used here as a reasonable estimate of productivity, and we assume that gas wells will remain active until 85%–95% of the original reserves have been depleted (Energy Information Administration 2001). After ten years, roughly 95% of the natural gas reserves will have been depleted[9]. We use this as our mean well lifetime; one-time emission events like well completion are spread over that lifetime to calculate average annual emissions. The coal fugitive emissions were taken directly from EIA data (Energy Information Administration 2009c)[10] on emissions of greenhouse gases DOE/EIA-0573. Conventional gas data were taken from the same report cited in calculating fugitive emissions from unconventional sources. The original datasets were comparable, but the publicly available coal data were more limited than those for gas. There is no *a priori* reason to suspect the coal data are less accurate.

2.1.1. Flowback from well completion and workover. Fugitive emissions escape in two ways: first, during well completion activities as fracturing fluids are expelled in a process called flowback; and second, as geological leaks occur before equipment is installed and sealed. Additionally, during the production lifetime, wells often require major overhauls called workovers, yielding additional emissions. The EPA data estimate emissions factors for natural gas wells assuming 'high rate, extended flowback to expel fracture fluids and sand proppant', which leads to higher natural gas emissions. Estimates of 36.65 Mcf/completion and 2.454 Mcf/workover are used for conventional natural gas wells. For unconventional natural gas wells, 9175 Mcf/completion and 9175 Mcf/workover are used (US Environmental Protection Agency 2010).

It is worth noting that this difference in flowback emissions will account for most of the GHG difference between conventional and unconventional gas. At the time of writing, the publicly available estimates for flowback emissions from unconventional gas were based on preliminary EPA figures and are therefore highly uncertain (see annexe 3 in US Environmental Protection Agency (2011a) and MIT appendix 1A in Moniz *et al* (2011)). The numbers are derived from non-peer-reviewed presentations at EPA workshops that do not document their sources. It is moreover possible that, since the workshops that designed to identify sources of potential GHG reduction, there might have been incentives to present inflated numbers. Even if there is no inherent bias, the numbers are likely to be revised as further information becomes available. It is possible that the numbers are off by a factor of two, or even ten. Unfortunately, just as the data are uncertain, so too are the uncertainties. As such, we have decided not to make an estimate of how far off these numbers are. We will return to this point in the discussion of our results.

While assuming the same emissions factor for flowback as for completion may overestimate the former, it is used here as a conservative figure. Workovers take place about once per decade. Assuming the above lifetime of 10 years, this results in an average of one completion event and one workover event per well. Calculations for the CO_2 equivalent emissions from completion and workover activities for conventional and unconventional natural gas wells are shown in table 1.

To estimate the fraction of leaked gas that is flared during well operations, we use the conservative estimate of 15% combustion and 85% direct venting. This is

[6] Emissions for LNG are small with respect to the other terms.

[7] While the source data do not consider tight sand formations, it is assumed that all unconventional gas sources have a similar emissions profile.

[8] This claim is made based on the assumption that fugitive emissions from tight sands formations are comparable to those from other unconventional sources. We did not have explicit emissions data from tight sands, but we know the number of tight sands wells that exist. By using emissions data from the other unconventional sources, we can calculate the annual emissions per well (which applies to all unconventional sources including tight sands, per our assumption that they have similar emissions profiles). We then multiply that number by the total number of unconventional wells to get an approximation of all fugitive emissions from unconventional sources.

[9] Ten years represents about four half-lives for the depletion of a well.

[10] Table 17 (www.eia.gov/oiaf/1605/ggrpt/methane.html) specifies US methane emissions from energy sources and gives numbers for surface and underground coal mining.

Table 1. Fugitive methane emissions from well completion and workover for both conventional and unconventional gas production. Source: US Environmental Protection Agency (2010).

		Conventional gas		Unconventional gas	
		Completion	Workover	Completion	Workover
Aspect of production process		per well			
Emissions factor	$m^3\ y^{-1}$	1037.8	69.5	259 807	259 807
Natural gas vented	$m^3\ y^{-1}$	882.1	59.1	220 836	220 836
Methane vented	$m^3\ y^{-1}$	695.1	46.5	174 018	174 018
Natural gas flared	$m^3\ y^{-1}$	152.6	10.2	38 192	38 192
Methane flared	$m^3\ y^{-1}$	120.2	8.0	30 095	30 095
Methane flared	$kg\ y^{-1}$	81.8	5.5	20 488	20 488
CO_2 from flaring	$kg\ y^{-1}$	224.5	15.0	56 208	56 208
CH_4 vented form flaring pipes	$m^3\ y^{-1}$	3.1	0.2	779	779
Total methane vented	$m^3\ y^{-1}$	698.2	46.8	174 798	174 798
Total methane vented	kg	475.4	31.8	119 000	119 000
Total methane vented, annualized	$kg\ y^{-1}$	47.5	3.2	11 900	11 900
CO_2e from vented methane	$t\ y^{-1}$	11.9	0.8	2974 998	2974 998
Total CO_2e	t	12.1	0.8	3031	3031
CO_2e, annualized	$t\ y^{-1}$	1.2	0.1	303	303
CO_2 from flaring	$t\ y^{-1}$	22.5	1.5	5621	5621

Table 2. Fugitive emissions from production, aggregated for the United States (US Environmental Protection Agency 2010).

Segment	Methane emissions (kg)
Onshore production	2.376×10^9
Processing	6.984×10^8
Transmission	1.869×10^9
Storage	3.456×10^8
LNG storage	7.383×10^7
LNG terminals	1.455×10^7
Distribution	1.300×10^9
Total	6.678×10^9

consistent with the EPA's estimate for flaring assuming all unconventional wells (including tight sands) are accounted for (US Environmental Protection Agency 2010). We assume a natural gas composition of 78.8% CH_4. The global warming impact contribution from other constituent gases is considered to be negligible (US Environmental Protection Agency 2010). Of the flared gas, 98% undergoes perfect stoichiometric combustion (US Environmental Protection Agency 2010). Given the atomic weights of 1.008, 12.01, and 16.00 for H, C, and O respectively, every pound of CH_4 that is combusted yields 2.743 pounds of CO_2. We use a density of 0.0425 lb/ft^3 for methane (Air Liquide 2011). Results show that completion and workover events for conventional natural gas wells release 475 and 32 kg of methane respectively. Completion and workover events for unconventional gas wells release 119 000 kg of methane each.

2.1.2. Emissions from other aspects of production. Data from the EPA on other aspects of natural gas systems include aggregated national annual totals (table 2). Production, which includes fugitive emissions from equipment leaks as well as venting and flaring activities, emits $2.376 \cdot 10^9$ kg of methane. This is shown in table 2, along with other major segments of the gas cycle.

We total the emissions for 431 035 gas wells, both conventional and unconventional. We assume that, after drilling and with the exception of workover, both well types contribute equally to emissions in the natural gas system. The natural gas industry emits $6.678 \cdot 10^9$ kg of methane each year through these processes.

EPA estimates show that in 2007 liquid unloading from conventional wells released 223 billion cubic feet (Bcf) of natural gas. While only 41.5% of conventional wells require unloading, this number can be distributed over the entire population of conventional wells to illustrate the sector average. Following industry convention, we assume that unconventional wells do not require unloading: conventional wells are hampered by liquid loading, in which the build up of fluids eventually plugs wells and prevents gas from flowing freely. Unconventional wells are not hindered by the same effect, and do not require regular unloading. The annual total, considering 389 245 conventional wells, is $3.388 \cdot 10^9$ kg of methane.

2.2. Selection of global warming potentials

Estimates of the conventional and unconventional gas GHG footprint are sensitive to the scaling factor used to convert emissions of methane from well completion into equivalent emissions of CO_2. Methane is a 'high-leverage' GHG; 1 kg of methane produces a radiative forcing that is many times that from a kilogram of CO_2. Normally, the conversion to CO_2e is performed using an accepted if imperfect indicator called the global warming potential (GWP). GWP accounts for several factors, including the strength of radiative forcing in the atmosphere as well as the expected decay of the gas in the atmosphere. Because of these multiple components (magnitude and time), GWP is conventionally calculated on one of three timescales—a 20 y, 100 y, or 500 y scale, where the baseline for each is that the GWP for CO_2 is defined as exactly 1. Methane has the ability to trap large amounts of infrared radiation relative to CO_2, but it also has a comparatively shorter lifetime in the atmosphere. As a result, methane's 100 y GWP is much lower than its 20 y GWP. The IPCC estimates the GWP of methane to be 72 times that of CO_2 over a 20 y time horizon and 25 times CO_2 over a 100 y horizon (Solomon *et al* 2007). By comparison, Howarth *et al* cite figures of 105 and 33 over the 20- and 100 y time horizons respectively, based largely on a recent assessment by Shindell *et al* (2009). Shindell *et al* argue that the standard numbers, as reported in the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (AR4), do not adequately account for the interaction of methane with both direct and indirect aerosols (Shindell *et al* 2009). Modeling results from the Goddard Institute for Space Studies (GISS) Model for Physical Understanding of Composition-Climate Interactions and Impacts (G-PUCCINI) indicate that the GWP of methane may be significantly higher when its impact on aerosols is included (Shindell *et al* 2009). However, the GISS research group that wrote the Shindell *et al* paper published a follow-up study in 2010. In this letter, they estimated the radiative forcing of methane to be 0.41 W m^{-2}, not significantly different from the IPCC AR4 figure of 0.48(+/ − 0.05) W m^{-2} (Unger *et al* 2010). Significantly, the confidence interval for Shindell *et al*'s estimate of the 100 y GWP of methane ranges from 25 to 42, with 33 as the median best estimate. Howarth *et al* report only the median from this interval, without considering the error band around it. Selection of a GWP time horizon is a major factor in this calculation. While it is true that 20 y effects are important for the climate, it is also conventional to use a 100 y time horizon when comparing different greenhouse gas policies. Howarth *et al* emphasize the GWP of methane emissions over the 20 y time horizon, and also use a relatively high 20 y GWP, which greatly amplifies the apparent greenhouse footprint (Howarth *et al* 2011). Methane has an atmospheric lifetime of approximately 12 y, so its impacts are concentrated within the first 20 y (Solomon *et al* 2007). However, CO_2 has a considerably longer lifetime and its effects are therefore distributed over a much longer period. In considering the central question, which is how to trade off different fuels or energy options in a portfolio, there is no obviously correct choice of time horizon, and there are certainly robust arguments to support reducing long-lived gases preferentially since the momentum of radiative forcing will be substantially higher several decades in the future. Given reasonable alternative perspectives, it is appropriate to evaluate emissions using 20, 100, and 500 y GWPs, the values of which we present in table 3. Using these values allows us to combine the carbon embodied in the fuel (kg CO_2 per GJ fuel) described earlier with the GWP-weighted fugitive emissions described in section 2.1 to arrive at a total GHG equivalent per GJ fuel (table 4).

2.3. *Emissions from electricity generation*

Any comparison of the GHG emissions of fuel alternatives must consider the pathway by which each fuel creates useful energy services for the user. In this paper, we consider

Table 3. Global warming potential ranges for methane for 20, 100, and 500 y time horizons. The low and middle case values are those currently accepted by IPCC in AR4 (Solomon *et al* 2007). The high 20 and 100 y values are those based on Shindell *et al* as quoted in Howarth *et al* (see text for discussion).

GWP methane	Low	Mid	High
20 y	72.0	72.0	105.0
100 y	25.0	25.0	42.0
500 y	7.6	7.6	7.6

Table 4. Total emissions factor for conventional gas, unconventional gas, and coal (kg CO_2 equivalent per GJ fuel). Figures are equal to the carbon content of fuel per unit of energy plus the GWP-weighted fugitive emissions as described earlier.

	Total emissions factor for fuel (kg CO_2e/GJ fuel)								
	Gas-conventional			Gas-unconventional			Coal		
	Low	Best	High	Low	Best	High	Low	Best	High
20 y	80.4	80.4	94.2	99.3	99.3	121.7	89.2	89.2	89.2
100 y	60.7	60.7	67.8	67.4	67.4	78.9	89.2	89.2	89.2
500 y	53.4	53.4	53.4	55.6	55.6	55.6	89.2	89.2	89.2

emissions from electricity generation, and so we present results not only for GHG emissions per GJ fuel but also for emissions per kWh of electricity generated. The per GJ emissions are useful primarily for comparing direct combustion for heat, such as for home heating or in cogeneration plants—two applications that are confined almost exclusively to gas, and therefore confound easy comparison with coal. In the US, by nameplate capacity, 11% of gas plants and 3% of coal plants feature cogeneration (US Environmental Protection Agency 2006). Our concern in this paper is primarily a direct comparison of emissions from the three fuels for electricity generation. However, we note that, in the US, substantial amounts of gas are used for other applications. Only 30% of gas is used for electricity production and the rest primarily for heating applications. In contrast, roughly 90% of coal energy is used for generation (Energy Information Administration 2011b, 2009b).

The remainder of the paper focuses on emissions from electricity production. Two factors lead to an overall carbon intensity advantage for gas during the combustion stage. First, gas releases more energy per unit of carbon emitted. Second, the technology used for combustion of gas is more thermodynamically efficient than that used for coal, enabling a larger amount of chemical potential energy in the fuel to be converted to electricity. Calculating the greenhouse footprint therefore requires estimates of both factors (Bellman *et al* 2007). In the absence of an assessment of fugitive emissions, a basic energy balance calculation shows that coal embodies about 75% more CO_2 per GJ than gas; if the difference in generation efficiency is included, coal produces about 100% more CO_2 per kWh of electricity generated.

We estimated the carbon intensity of these fuels using reported US CO_2 emissions weighted by reported MWh generated (US Environmental Protection Agency 2006). This resulted in estimates for average US carbon intensity of energy of approximately 50 kg CO_2 GJ^{-1} for gas and 89 kg CO_2 GJ^{-1}

for coal. These results are similar to other published values (Quick 2010, Hong and Slatick 1994).

Generation efficiency for this purpose can be estimated in several ways. The most straightforward approach to comparing US gas and US coal efficiency is simply to take the average fleet efficiencies for each fuel, which are readily calculable from EIA data. Such an estimate implies the premise that any new supply of coal or gas would be distributed to generation assets in roughly the same proportion they are today—a reasonable assumption since national markets with moderately efficient transportation exist for both fuels (rail for coal and pipelines for gas). Using this assumption, overall US coal and gas efficiencies are 33% and 38%, respectively. However, this premise of uniform fuel deployment may not hold if the marginal supply of fuel goes to certain generation assets preferentially—perhaps geographically or perhaps favoring one type of technology. It also may not hold if generation assets are operating near an upper limit for capacity factor.

This latter question has significant implications for the overall GHG calculation. In the US, the average fleet gas generation efficiency is still fairly low compared to the best new technologies that are being installed. This is in part because the overall fleet is a combination of older plants, some of which are simple boiler-type designs ($\eta \sim 30\%$) or simple turbines ($\eta \sim 33\%$), and newer combined cycle turbines ($\eta \sim 45\%$). In addition, much of the US gas capacity, including newer and older plants, is currently idle. In 2008, the US coal capacity factor was over 70% while the factor for conventional gas turbines was less than 30%, and the more advanced combined cycle gas turbines (CCGT) were running at approximately a 35% capacity factor. This implies substantial high-efficiency generation capacity that can be easily brought online with new gas supplies. Moreover, for longer-term energy policy and planning, the central question is not what current efficiencies are but what efficiencies are expected to be in 10 or 20 y. It is likely that the addition of new gas capacity will significantly increase the average fleet efficiency. New coal capacity is unlikely to increase average fleet efficiency to the same degree. For example, today's best coal technology is in the range of 40% (for IGCC and supercritical coal) whereas the best gas technology is in the range of 55% for CCGT (Energy Information Administration 2011d); at the upper end, the GE H-System combined cycle turbine runs at 58.4% efficiency (Bellman *et al* 2007). This imbalance in generation efficiency for individual generators is projected to increase fleet efficiency via new capital additions and replacement of old assets. The average efficiency of coal electricity generation is projected to increase to roughly 34% by 2030. Natural gas is projected to reach 40.1% efficiency by 2023 (Bellman *et al* 2007).

Table 5 shows generation efficiencies used in the calculations presented in this paper. We calculated the current fleet average emissions in both CO_2 kWh^{-1} and kg CO_2 GJ^{-1} from data reported in the EPA's CEMS 2009 GDM Report. These numbers are in close agreement with EIA estimates.

In order to ensure the national average was representative of power plants closest to shale gas production, we also calculated the regional emissions distribution for gas (Energy Information Administration 2011d). Regional emissions intensities varied by less than 4% for all regions with greater than 1% of national emissions from each fuel.

Table 5. Efficiency for coal and gas-fired electricity generation assets in the United States used for calculation of greenhouse gas emissions. See text for sources and discussion.

Current generation efficiencies in US	
Coal	
US average	33.95%
Median of most efficient 20	36.30%
Gas	
US average	38.94%
Average for current CCGT	45.90%
Average for Conv GT	33.70%
Future (2030) generation efficiency scenarios	
Coal	
High	38.93%
Mid	37.80%
Low	36.30%
Gas	
High	50.53%
Mid	47.41%
Low	43.08%

2.4. Calculating total GHG equivalent emissions

The per kWh total greenhouse footprint for each fuel was calculated as the sum of the GWP-weighted fugitive emissions (CH_4 and CO_2) and the CO_2 emitted from combustion. Fugitive emissions of methane and CO_2 from unconventional and conventional gas were estimated as described in section 2.1. Methane production from coal was calculated using national emissions information reported by the 2008 EIA report on GHG emissions in the US (US Environmental Protection Agency 2010). GWP selection and weighting was described in section 2.2. The resulting per GJ GHG figures for each fuel (conventional gas—CG, unconventional gas—UG, coal) were assumed to feed into generation assets with efficiencies that varied as described in section 2.3 (Energy Information Administration 2009a). Table 6 shows the results across different assumptions for GWP and technology. Across almost all assumptions, unconventional gas results in lower greenhouse gas emissions from electricity than does coal (figure 2). One must assume relatively inefficient gas combustion technology and a high-end 20 y GWP to realize gas emissions in excess of coal, which is similar to what Howarth *et al* found. In most cases, even under relatively high assumptions about fugitive emissions, the greenhouse footprint of unconventional gas is substantially below that of coal, and relatively close to conventional gas, for most other assumptions about technology and GWP. This result is presented in figure 3, which expresses the greenhouse footprint of CG and UG as a percentage of the emissions from coal, under these varying assumptions.

3. Mitigation and learning

Even if one assumes that fugitive methane emissions from well drilling and production are very high, it may be possible

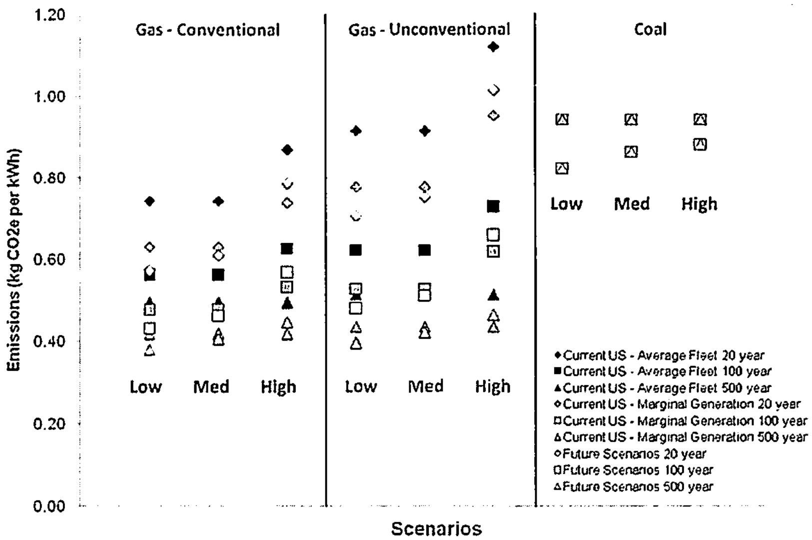

Figure 2. Comparison of combustion emissions intensity (kg CO_2 equivalent per kWh electricity generated) ranges under different technology and GWP assumptions.

Table 6. Combustion emissions intensity (kg CO_2 equivalent per kWh electric generated) for conventional gas, unconventional gas, and coal in the United States. 'Current US—average fleet' assumes new gas goes to generation with average fleet efficiency; 'Current US—marginal generation' assumes new gas goes to efficient existing generation capacity (CCGT); 'future scenarios' assumes alternative efficient technologies as described in the text.

	Combustion emissions intensity (kg CO_2e kWh^{-1})								
	Gas-conventional			Gas-unconventional			Coal		
	Low	Best	High	Low	Best	High	Low	Best	High
Current US—average fleet									
20 y	0.743	0.743	0.871	0.918	0.918	1.125	0.946	0.946	0.946
100 y	0.561	0.561	0.627	0.623	0.623	0.730	0.945	0.945	0.945
500 y	0.494	0.494	0.494	0.514	0.514	0.514	0.945	0.945	0.945
Current US—marginal generation									
20 y	0.631	0.631	0.739	0.779	0.779	0.954	0.946	0.946	0.946
100 y	0.476	0.476	0.532	0.529	0.529	0.619	0.945	0.945	0.945
500 y	0.419	0.419	0.419	0.436	0.436	0.436	0.945	0.945	0.945
Future scenarios									
20 y	0.573	0.610	0.787	0.707	0.754	1.017	0.825	0.866	0.885
100 y	0.433	0.461	0.567	0.480	0.512	0.660	0.825	0.866	0.884
500 y	0.381	0.406	0.447	0.396	0.422	0.465	0.825	0.866	0.884

to reduce these emissions significantly by using better leak mitigation technologies and practices. The Environmental Protection Agency's Natural Gas STAR (NG STAR) Program lists over 30 recommended technologies and practices that natural gas producers can use to reduce their emissions during the well production stage alone (US Environmental Protection Agency 2011b). For example, one NG STAR industry partner reduced their fugitive emissions by more than 72 000 Mcf y^{-1} by redesigning their blowdown systems and altering their emergency shutdown systems (Natural Gas Star 2004). Like many of NG STAR's other recommended technologies and practices, these measures are extremely cost effective. Based on reports from industry, NG STAR estimates that changing these systems has a capital cost of less than $1000 and a payback period of less than one year (Natural Gas Star 2004). This makes it extremely likely that unconventional gas drillers would adopt these practices over time (Seto 2011).

However, without knowing the magnitude and exact sources of fugitive emissions from unconventional natural gas, it is difficult to state with authority what effects better mitigation technology and practices might have, or whether these practices will further the advantage of unconventional gas over coal in lifecycle GHG emissions. We were unable to find good data on fugitive emissions from unconventional gas production in general, much less data documenting the equipment and practices most commonly used by these wells. This is at least partially because NG STAR and EPA do not currently track fugitive emissions from unconventional wells separately from overall figures.

4. Discussion

There can remain little doubt that, by increasing the availability of low-cost natural gas across many geographical regions, the

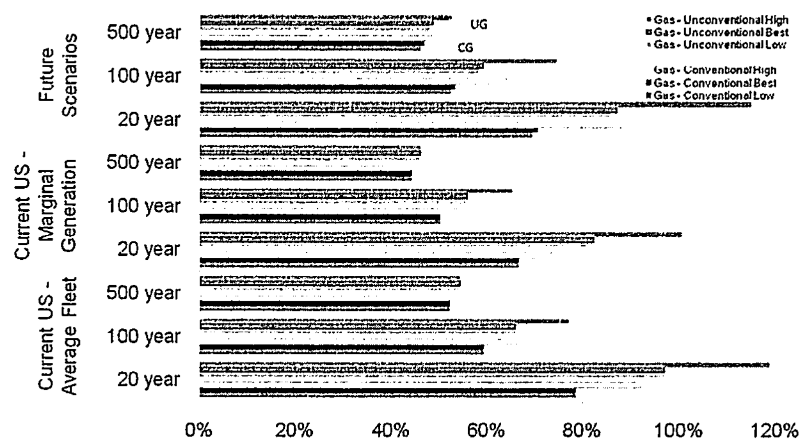

Figure 3. Greenhouse gas footprint of electricity from conventional and unconventional gas, relative to that of coal (defined as 100%). Results are expressed as a percentage of coal emissions and are derived from combustion emissions intensities in table 6 (kg CO_2e kWh^{-1} for gas normalized to kg CO_2e kWh^{-1} for coal). Results shown for GWP timescales of 20, 100, and 500 y. Reference coal emissions are taken from parallel assumptions (GWP, technology, etc).

Table 7. Summary of greenhouse gas emissions from unconventional gas, conventional gas, and coal for the US, assuming mid-range scenarios and 100 y GWP.

	Summary; mid-range scenarios, 100 y GWP		
	CG	UG	Coal
Current US—average fleet			
Combustion emissions intensity (kg CO_2e kWh^{-1})	0.561	0.623	0.945
Combustion emissions intensity (per cent of coal)	59.4	65.9	100.0
Combustion emissions intensity (increase versus CG) (%)	0.0	11.0	68.4
Current US—CGT generation			
Combustion emissions intensity (kg CO_2e kWh^{-1})	0.476	0.529	0.945
Combustion emissions intensity (per cent of coal)	50.4	55.9	100.0
Combustion emissions intensity (increase versus CG) (%)	0.0	11.0	98.5
Future technology			
Combustion emissions intensity (kg CO_2e kWh^{-1})	0.461	0.512	0.866
Combustion emissions intensity (per cent of coal)	53.3	59.1	100.0
Combustion emissions intensity (increase versus CG) (%)	0.0	11.0	87.7

advent of hydraulic fracturing techniques may fundamentally reorient national energy policies globally. As such, understanding the consequences of expanded unconventional gas production is an essential step to ensuring that this transition is managed rationally. While shale gas presents a number of questions and challenges, we have demonstrated that the fugitive emissions from the drilling process are very likely not substantially higher than for conventional gas. Table 7 presents the results of our mid-range assumptions for a 100 y GWP. In our calculations, a robust conclusion seems to be that even with high existing uncertainties in fugitive emissions from the hydraulic fracturing process, the greenhouse footprint of shale gas and other unconventional gas resources is about 11% higher than that of conventional gas for electricity generation, and still 56% that of coal. Moreover, if the spread in future fleet efficiencies between gas and coal increases over the coming decades, this differential from coal will continue to increase.

It is extremely important to note that this study's results derive from uncertain estimates of fugitive emissions from unconventional gas well development. We have reason to believe that better data collection and improved technology could substantially lower the estimates of emissions from a standard unconventional gas well, which would reduce (possibly substantially) the difference in GHG emissions between unconventional and conventional gas. However, without solid data it is impossible to say with certainty. Therefore, because the quality of publicly available data on fugitive emissions remains extremely poor, any sensible policy to evaluate the future of unconventional gas should include a transparent data collection program. This should cover a diverse set of geological situations, be conducted over the lifetime of sampled wells, and be published systematically and regularly.

Evaluated solely on the criterion of GHG emissions from electricity generation, shale gas is not likely to be substantially more polluting than conventional gas. Additional technologies to ensure reasonable capture of fugitive emissions may be able to reduce the disparity between the two resources further. Any regulatory standard that classifies conventional gas as a source of 'clean energy' should therefore consider shale gas in this context; arguments that shale gas is more polluting than coal are largely unjustified. On the other hand, despite the promises of inexpensive, abundant, and relatively low GHG fossil fuel, unconventional gas technology poses other challenges if it is to become a truly 'clean' bridge fuel. As a new technology, its deployment has arguably outpaced the ability of the policy and scientific communities to understand and regulate the possible environmental and health consequences of the fracking process. These issues require serious attention but, should they be solvable, new generation from unconventional gas could deliver benefits similar to those of conventional gas.

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Appendix “B”

Methane Emissions from Natural Gas Systems

Background Paper Prepared for the National Climate Assessment
Reference number 2011-0003

Robert Howarth (Cornell University), Drew Shindell (NASA Goddard Space Institute), Renee Santoro (Cornell University), Anthony Ingraffea (Cornell University), Nathan Phillips (Boston University), and Amy Townsend-Small (University of Cincinnati)

February 25, 2012

The past few years have seen major changes both in our understanding of the importance of methane as a driver of global climate change and in the importance of natural gas systems as a source of atmospheric methane. Here, we summarize the current state of knowledge, relying on peer-reviewed literature.

Methane is the second largest contributor to human-caused global warming after carbon dioxide. Hansen and Sato (2004) and Hansen et al. (2007) suggested that a warming of the Earth to 1.8° C above the 1890-1910 baseline may trigger a large and rapid increase in the release of methane from the arctic due to melting of permafrost. While there is a wide range in both the magnitude and timing of projected carbon release from thawing permafrost in the literature (e.g. Schaefer et al., 2011), warming consistently leads to greater release. This release will therefore in turn cause a positive feedback of accelerated global warming (Zimov et al. 2006).

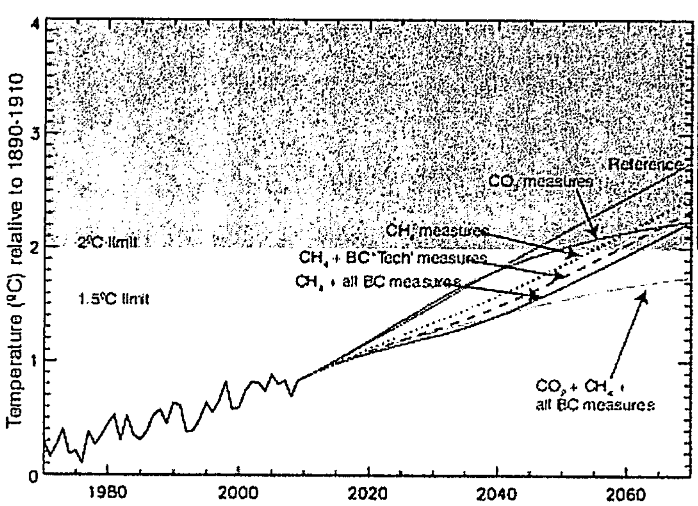

Fig. 1. Observed global mean temperature from 1900 to 2009 and projected future temperature under various scenarios of controlling methane + black carbon (BC) and carbon dioxide, alone and in combination. An increase to 1.5° to 2.0 ° C above the 1890-1910 baseline (illustrated by the yellow bar) poses high risk of passing a tipping point and moving the Earth into an alternate state for the climate system. Reprinted from Shindell et al. (2012).

Shindell et al. (2012) noted that the climate system is more immediately responsive to changes in methane (and black carbon) emissions than carbon dioxide emissions (Fig. 1). They predicted that unless emissions of methane and black carbon are reduced immediately, the Earth will warm to 1.5° C by 2030 and to 2.0° C by 2045 to 2050 whether or not carbon dioxide emissions are reduced. Reducing methane and black carbon emissions, even if carbon dioxide is not controlled, would significantly slow the rate of global warming and postpone reaching the 1.5° C and 2.0° C marks by 12 to 15 years. Controlling carbon dioxide as well as methane and black carbon emissions further slows the rate of global warming after 2045, through at least 2070.

Natural gas systems are the single largest source of anthropogenic methane emissions in the United States (Fig. 2), representing almost 40% of the total flux according to the most recent estimates from the U.S. Environmental Protection Agency (EPA) as compiled by Howarth et al. (2012). Note that through the summer of 2010, the EPA used emission factors from a 1996 study to estimate the contribution of natural gas systems to the U.S. greenhouse gas (GHG) inventory. Increasing evidence over the past 16 years has indicated these emission factors were probably too low, and in November 2010 EPA began to release updated factors. The estimates for natural gas systems in Fig. 2 are based on these updated emission factors and information released through 2011 in two additional EPA reports, as presented in Howarth et al. (2012). Note that the use of these new methane emission factors resulted in a doubling in the estimate of methane emissions from the natural gas industry. Note also that, to date, EPA has only increased emission factors for "upstream" and "midstream" portions of the natural gas industry (leaks and emissions at the well site and in processing gas). Factors for "downstream" emissions (storage systems and transmission and distribution pipelines) are still from the 1996 report, although EPA is considering also modifying these (Howarth et al. 2012).

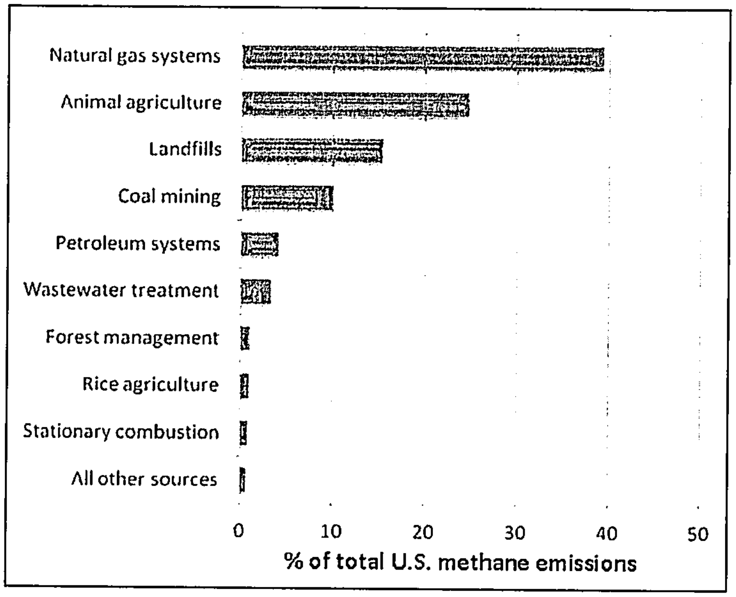

Fig. 2. Human-controlled sources of atmospheric methane from the United States for 2009, based on emission estimates from the U.S. Environmental Protection Agency in 2011. Reprinted from Howarth et al. (2012).

The natural-gas-system emissions in Fig. 2 are based on an average emission of 2.6% of the methane produced from natural gas wells over their production lifetime, with 1.7% from upstream and midstream emissions (for the national mix of conventional and unconventional gas in 2009) and 0.9% from downstream emissions (Howarth et al. 2012). As discussed below, these methane emission estimates from natural gas systems are based on limited data and remain uncertain.

Recent estimates in the peer-reviewed literature for downstream emissions of methane from natural gas systems range from 0.07% to 10% of the methane produced over the lifetime of a well (Table 1). It is important to note that only Lelieveld et al. (2005) presented actual data on emissions, in their case leakage from high-pressure transmission pipelines. Other estimates are based on emission factors from the 1996 EPA study, on emission factors from a more recent report from the American Petroleum Institute, or on reports of "lost and unaccounted for gas" to governmental agencies, leading to high uncertainty. Lelieveld et al. reported a leakage rate from high-pressure transmission pipelines of 0.4% to 1.6%, with a "best estimate" of 0.7%; they used the 1996 EPA emission factors to estimate emissions from storage and distribution systems, yielding an estimate for total downstream emissions of 1.4% (or twice their measured value for just transmission). Howarth et al. (2011) took the "best estimate" of 1.4% from Lelieveld et al. (2005) as their low-end estimate, arguing that the 1996 EPA emission factors were probably low. For their high-end estimate, Howarth et

Table 1. Estimates of methane emission from downstream emissions (transmission pipelines and storage and distribution systems) expressed as the percentage of methane produced over the lifecycle of a well. Studies are listed chronologically by date of publication. Modified from Howarth et al. (2012).

Hayhoe et al. (2002)	2.5 %	("best estimate;" range = 0.2% - 10%)
Lelieveld et al. (2005)	1.4 %	("best estimate;" range = 1.0% - 2.5%)
Howarth et al. (2011)	2.5 %	(mean; range = 1.4% - 3.6%)
EPA (2011)*	0.9 %	
Jiang et al. (2011)	0.4 %	
Hultman et al. (2011)	0.9 %	
Ventakesh et al. (2011)	0.4 %	
Burnham et al. (2011)	0.6 %	
Stephenson et al. (2011)	0.07 %	
Cathles et al. (2012)	0.7 %	

* The EPA (2011) estimate is as calculated in Howarth et al. (2012), using national emissions from EPA reports and national gas production data from US Department of Energy reports.

al. (2011) used data on "missing and unaccounted for gas" from Texas. Their mean estimate of 2.5% is identical to the "best estimate" from Hayhoe et al.

(2002). The estimates of Jiang et al. (2011), Hultman et al. (2011), Ventakesh et al. (2011), Burnham et al. (2011), and Cathles et al. (2012) are all based on various permutations of the 1996 EPA emission factors, factors that were developed before the measurements of Lelieveld et al. (2005). The "best estimate" of measured emissions from transmission pipelines of 0.7% by Lelieveld et al. (2005) is similar to or greater than the estimates for all downstream emissions (including storage and distribution) from these studies that used the 1996 EPA emission factors. The estimate of Stephenson et al. (2011) includes only transmission pipelines, is based on emission factors reported by the American Petroleum Institute in 2009 (which in turn are derived from the EPA 1996 emission factors), and is far lower than any other estimate. Comparisons of predicted and observed methane concentrations in Los Angeles have indicated that emissions factors for leakage from natural gas systems may be underestimated (Wunch et al. 2009; Hsu et al. 2010). A new study using stable isotopic and radiocarbon signatures of methane confirms that emission from natural gas systems is likely the dominant source of methane in Los Angeles (Townsend-Small et al. 2012).

Most recent estimates for upstream emissions (those that occur during well completion and production at the well site) and midstream emissions (those that occur during gas processing) for conventional natural

Table 2. Conventional natural gas, estimates of methane emissions from upstream (at the well site) plus midstream (at gas processing plants), expressed as the percentage of methane produced over the lifecycle of a well. Studies are listed chronologically by date of publication. Modified from Howarth et al. (2012).

Hayhoe et al. (2002)	1.2 %	("best estimate")
Howarth et al. (2011)	1.4 %	(mean; range = 0.2% to 2.4%)
EPA (2011)*	1.6 %	
Hultman et al. (2011)	1.3 %	
Venkatesh et al. (2011)	1.8 %	
Burnham et al. (2011)	2.0 %	
Stephenson et al. (2011)	0.4 %	
Cathles et al. (2012)	0.9 %	

* The EPA (2011) estimate is as calculated in Howarth et al. (2012), using national emissions from EPA reports and national gas production data from US Department of Energy reports.

gas cluster fairly closely to the new EPA estimate of 1.6% (Table 2). The mean estimate from Howarth et al. (2011) is 1.4%; the Howarth et al. (2011) low-end value of 0.2% is an estimate of what is possible using best technologies, while 2.4% reflects emissions using poor technologies. Other estimates range from 0.4% to 2.0% (Table 2). As for the downstream emissions, the lowest number (0.4%) comes from Stephenson et al. (2011).

Table 3. Unconventional gas (shale gas and gas from tight sands), estimates of methane emissions from upstream (at the well site) plus midstream (at gas processing plants), expressed as the percentage of methane produced over the lifecycle of a well. Studies are listed chronologically by date of publication. Modified from Howarth et al. (2012).

Howarth et al. (2011)	3.3 %	(mean; range = 2.2% to 4.3%)
EPA (2011)*	3.0 %	
Jiang et al. (2011)	2.0 %	
Hultman et al. (2011)	2.8 %	
Burnham et al. (2011)	1.3 %	
Stephenson et al. (2011)	0.6 %	
Cathles et al. (2012)	0.9 %	
Petron et al. (2012)	4.0 %	("best estimate;" range = 2.3 to 7.7%)

* The EPA (2011) estimate is as calculated in Howarth et al. (2012), using national emissions from EPA reports and national gas production data from US Department of Energy reports.

Estimates for upstream plus midstream methane emissions from unconventional gas (obtained from shales and tight-sands) vary from 0.6% to 4.0% for mean or "best" estimates (Table 3). The US EPA 2011 data indicate an estimated loss of 3.0% for upstream plus midstream emissions from unconventional gas (Howarth et al. 2012).

With the exception of the estimate by Petron et al. (2012), all of these upstream emissions for unconventional gas are based on sparse and poorly documented data (Howarth et al. 2011, 2012). The study by Petron et al. (2012) measured fluxes from an unconventional gas field – at the landscape scale – over the course of a year, and is a robust estimate. Although it represents only one field (the Piceance tight-sands basin in Colorado), emissions during the flowback period following hydraulic fracturing for unconventional gas are similar in this basin to other unconventional gas basins for which data are available (Howarth et al. 2011).

The Petron et al. (2012) study should be repeated in other unconventional gas fields, but it nonetheless suggests that most of the estimates in Table 3 are likely to be too low.

The methane emissions during flowback of fracking fluids, which occur during a 1-2 week period following hydraulic fracturing, are the major difference in emissions between unconventional and conventional gas. Flowback emissions are estimated as 1.9% of the lifetime production of an unconventional gas well according to Howarth et al. (2011), although the data of Petron et al. (2012) suggest the flux may in fact be greater. Flowback does not occur when a conventional gas well is completed, and the methane emissions at the time of well completion are far less (Howarth et al. 2011, 2012). Howarth et al. (2012), which was published before the Petron et al. (2012) study was released, concluded that shale gas emissions are 40% to 60% greater than emissions from conventional natural gas, when both upstream and downstream emissions are considered.

The US Department of Energy predicts that the major use of shale gas over the next 23 years will be to replace conventional reserves of natural gas as these become depleted. To the extent that methane emissions associated with shale gas and other unconventional gas are greater than for conventional gas, this will increase the methane emissions from the US from the natural gas industry beyond those indicated in Fig. 2. An increase of 40% to 60% in methane emissions is likely, based on the majority of studies summarized in Howarth et al. (2012), possibly more in light of the new field-based measurements by Petron et al. (2012). Note further that to the extent the US EPA is underestimating emissions from downstream sources (storage, transmission, and distribution), methane emissions from natural gas systems may already be substantially greater than shown in Fig. 2.

Global warming potentials provide a relatively simple approach for comparing the influence of methane and carbon dioxide on climate change. In the national GHG inventory, the US EPA uses a global warming potential of 21 over an integrated 100-year time frame, based on the 1995 report from the Intergovernmental Panel on Climate Change (IPCC) and the Kyoto protocol. However, the latest IPCC Assessment from 2007 used a value of 25, while more recent research that better accounts for the interaction of methane with other radiatively active materials in the atmosphere suggests a mean value for the global warming potential of 33 for the 100-year integrated time frame (Shindell et al. 2009). Using this value and the methane emission estimates based on EPA data shown in Fig. 2, Howarth et al. (2012) calculated that methane contributes 19% of the entire GHG inventory of the U.S., including carbon dioxide and all other gases from all human activities. The methane from natural gas systems alone contributes over 7% of the entire GHG inventory of the U.S. Note that the variation in the global warming potential estimates between 21 and 33 is substantially less than the variation among the methane emission estimates.

The global warming potentials of 21, 25 and 33 are all for an integrated 100-year time frame following emission of methane to the atmosphere. The choice of 100 years is arbitrary, and one can also consider the global warming potentials at longer or shorter time scales. To date, estimates have typically been provided at time scales of 20 years and 500 years, in addition to the 100-year time frame. An emphasis on the 20-year time frame in addition to the widely-used 100-year timeframe is important, given the urgency of reducing methane emissions and the evidence that if measures are not taken to rapidly reduce the rate of warming, the Earth will continue to warm so quickly that risk of dangerous consequences will grow markedly. We may reach critical tipping points in the climate system, on the time scale of 18 to 38 years (Figure 1).

For the 20-year time frame, Shindell et al. (2009) provide a mean estimate of 105 for the global warming potential. Using this value, Howarth et al. (2012) calculated that methane contributes 44% of the entire GHG inventory of the U.S., including carbon dioxide and all other gases from all human activities. Hence while methane is only causing about 1/5 of the century-scale warming due to US emissions, it is responsible for nearly half the warming impact of current US emissions over the next 20 years. At this time scale, the methane emissions from natural gas systems contribute 17% of the entire GHG inventory of the U.S., for all gases from all sources. We repeat that these estimates may be low, and that the gradual replacement of conventional natural gas by shale gas is predicted to increase these methane fluxes by 40% to 60% or more (Howarth et al. 2012).

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Appendix “C”

Environmental Science & Technology

Policy Analysis

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Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications

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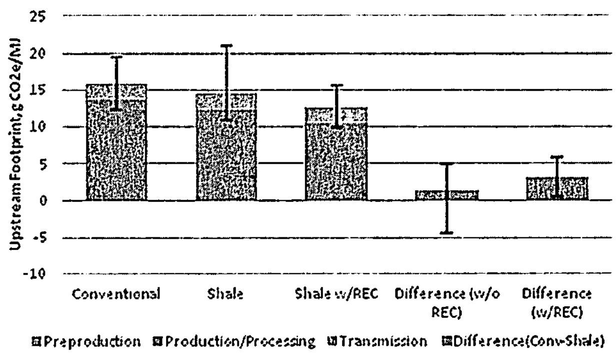
Supporting Information



ABSTRACT: The recent increase in the production of natural gas from shale deposits has significantly changed energy outlooks in both the US and world. Shale gas may have important climate benefits if it displaces more carbon-intensive oil or coal, but recent attention has discussed the potential for upstream methane emissions to counteract this reduced combustion greenhouse gas emissions. We examine six recent studies to produce a Monte Carlo uncertainty analysis of the carbon footprint of both shale and conventional natural gas production. The results show that the most likely upstream carbon footprints of these types of natural gas production are largely similar, with overlapping 95% uncertainty ranges of 11.0–21.0 g CO_2e/MJ_{LHV} for shale gas and 12.4–19.5 g CO_2e/MJ_{LHV} for conventional gas. However, because this upstream footprint represents less than 25% of the total carbon footprint of gas, the efficiency of producing heat, electricity, transportation services, or other function is of equal or greater importance when identifying emission reduction opportunities. Better data are needed to reduce the uncertainty in natural gas's carbon footprint, but understanding system-level climate impacts of shale gas, through shifts in national and global energy markets, may be more important and requires more detailed energy and economic systems assessments.

1. INTRODUCTION

Recent advances in horizontal drilling and hydraulic fracturing technology have made it technically and economically possible to access vast deposits of natural gas in shale deposits located across the U.S. and elsewhere.[1,2] Shale gas production has grown 48% per year from 2006 to 2010 in the U.S., and growing estimates of recoverable resources have altered US and world energy outlooks for the foreseeable future.[3] Many authors have praised the industry's growth as leading to significant job growth, further decoupled gas and oil prices, and the potential for displacing more carbon-intensive oil in transportation or coal in electricity.[4,5]

Despite the potentially positive impacts of shale gas development, it has been criticized for several reasons, including its impacts on water quality, air quality, and climate change.[6−10] Current federal initiatives to identify and assess shale gas impacts have focused across a range of these issues.[10] For example, in August 2011, EPA issued proposed rulemaking to establish New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for specific processes and equipment associated with unconventional oil and gas recovery.[11] Although not necessarily the greatest potential environmental issue with shale gas, one recent concern identified in the literature is the potentially high life cycle greenhouse gas emissions (i.e., carbon footprint[12]) associated with shale gas production due to fugitive methane emissions in the production phase. A study by Howarth, Santoro, and Ingraffea[13] suggested that fugitive methane emissions from shale gas yielded a higher overall carbon footprint for shale gas compared to coal, though the methods and modeling choices have been criticized by other authors.[14−16] Since the publication of this study, several authors have performed similar life cycle carbon footprint studies using different data and assumptions.[8,15−19]

The goal of this research was 2-fold: first, to compare the original study to five subsequent studies with consistent system boundaries and assumptions; and second, to compare these current estimates of the life cycle carbon footprint of shale gas to conventional onshore natural gas production. We present our results broken down by process in significant detail in the Supporting Information so researchers and policymakers can perform comparative analysis of this important policy issue.

After reconciling assumptions and boundaries, we utilize the data and assumptions in these studies to construct a best estimate of the carbon footprint of both shale gas and onshore

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conventional gas production, including both of their associated uncertainties. Additionally we utilize our analysis of the current estimates and model the impacts of EPA's proposed NSPS rule requiring reduced emission completions (RECs) on nearly all unconventional natural gas drilling activity.[11] We limit our discussion to onshore conventional production because only one study discussed offshore production in detail.[18] We further discuss the policy implications of these studies and their uncertainties and the suitability and limitations of life cycle carbon footprint assessment for analyzing large-scale energy system changes such as shale gas development.

2. METHODS

This section examines differences between the six cited studies across several different categories: differences in the goal and scope of each study and differences in the assumptions; data for one large and uncertain emissions categories, well completion; and data and assumptions related to the combustion phase of the life cycle. Additional categories of importance, including workovers, liquids unloading, lease and plant fuel usage, fugitive emissions in production, and fugitive emissions in transmission, are discussed in detail in the SI. Emissions categories were chosen for detailed analysis based on an initial comparison of the major emissions sources in the upstream life cycle of shale and conventional gas (see Table SI-5 for a detailed comparison). Each of these categories represents a significant portion (greater than 10% in at least one study) of the upstream carbon footprint of either shale or conventional gas (or both) and displays disagreement (greater than 20% difference) between the different authors' results. For simplicity, we refer to the authors by first author (or institutional author in the case of the National Energy Technology Laboratory, NETL[18]). Jiang[8] covers only the preproduction phase of the shale gas life cycle and cites Venkatesh[19] for the remainder of the life cycle, though we refer to the two studies collectively as Jiang[8] here. All studies were process-based assessments, though Jiang[8] utilizes some input-output data for infrastructure construction.

We conducted a Monte Carlo simulation (sample size 10,000) using a selected combination of the inputs taken from across the six studies, summed together to create category subtotal (preproduction, production, and transmission) and total carbon footprint estimates for both conventional and shale gas production. As is common in life cycle assessment and carbon footprint studies, data scarcity did not allow us to fully determine the functional form of the underlying uncertainty distributions.[20] Instead we chose flexible triangular distributions with a most likely value equal to either the average of the various study estimates (using only the subset of studies that estimated each process) or a single value judged to be of high quality and minimum/maximum values equal to the minimum and maximum study estimates for each emissions subcategory (see Table SI-4). Given no further information on correlations between the different model parameter uncertainties, we assume statistical independence. We note that this may lead to an underestimate of total uncertainty, though we have no reason to believe a priori that such correlations exist except in the potential case of workovers and ultimate well production (further details on workovers provided in the Supporting Information).

Our best judgment was used to determine whether an individual study's subcategory estimate was an outlier, based on the method and data used to produce the estimate. If we judged the value to be an outlier it was not included in the construction of the best estimate distribution. Where individual studies provided uncertainty ranges at the subcategory level, we again utilized judgment based on the underlying data and methodology in question (and a comparison to other study estimates) to determine whether the maximum/minimum values of our distributions should include the uncertainty range from the study in question. Generally the uncertainty range was kept to ensure the worst-case (i.e., highest carbon footprint) and best-case scenarios were captured by our analysis. For the case of Howarth,[13] who presented only low and high emissions estimates without a mean, we averaged the low and high estimates for the base case (thus assuming a symmetric uncertainty distribution) and included the low and high estimates in our distributions where they were not judged to be outliers. Except where judged to be an outlier, we did not attempt to correct for any errors or omissions in the reported studies.

2.1. Goal, Scope, and Functional Unit. The first stage of a life cycle assessment is identifying study goal and scope and the functional unit.[21] The six studies all attempted to study the carbon footprint of shale gas (and conventional gas as well for all but Hultman et al.[17]), but each had different specific inclusions or exclusions within its scope. In terms of functional unit, we follow the convention of all studies except Howarth[13] and present results in terms of an upstream carbon footprint at the power plant gate (in g CO_2e/MJ_{LHV}) and a downstream "well-to-wire" estimate of the total carbon footprint for each type of gas to produce 1 kWh of electricity (g CO_2e/kWh). We utilize 100-year GWP values from the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, as standardized by recent carbon footprint protocols.[22,23]

The studies had different specific scopes. First, the studies analyzed different geographies: NETL[18] examined only the Barnett shale basin, Jiang[8] examined only the Marcellus shale basin, Stephenson[16] and Burnham[15] averaged over North American basins, and Hultman[17] and Howarth[13] averaged over all unconventional gas including tight gas. The basin choice affects both the estimated ultimate recovery of wells as well as the methane content of produced natural gas-- cited as 97% in Jiang,[8] 87% in Stephenson,[16] 80% in Burnham,[15] and 78% in NETL,[18] Howarth,[13] and Hultman.[17] Here we attempt to describe U.S. average practices wherever possible though recognize that data limitations do not allow a full description of geographic variability.

Second, several modeling choices resulted in differences across studies that were quantified where possible. Each study used different time periods of analysis, ranging from 3 years[16] to 30 years.[18] These differences show the immense uncertainty in estimated gas recoveries. All of the studies used different system boundaries, as shown in Table SI-5 by notations where an individual study did not estimate a certain emissions category. We attempted to draw as broad a system boundary as possible to include all potential sources identified in any of the studies. We also made adjustments where necessary to make system boundaries as similar as possible, such as removing liquid unloading emissions associated with shale gas in Jiang[8] and Howarth[13] to parallel the other studies (further details on liquids unloading provided in the Supporting Information).

Third, in several emissions categories, certain studies used a top-down estimate from a governmental source (such as EIA or EPA), whereas others use the bottom-up estimate using process-specific calculations, potentially producing system

Table 1. Assumed Parameters by Study for Estimating Completion and Workover Emissions Factors

	total vent/flare (t CH_4)	flaring rate	estimated ultimate recovery (EUR), BCF	CH_4 mass fraction	workovers per EUR	completion emissions factor (g CO2e/ MJ_{LHV})	workovers emissions factor (g CO2e/ MJ_{LHV})
Jiang[8]	400 (26–1000)	76% (51%–100%)	2.85 (0.5–91)	97.2	0	1.2 (0.1–9.2)	0
NETL[18]	177[a]	15% (12%–18%)	3 (2.1–3.9)	78.3	3.5	1.3 (1.0–1.9)	4.5 (3.4–6.7)
Hultman[17]	139[a]	15%	0.54	78.8	1	5.2	5.2
Stephenson[16]	177[a] (52–385)	51% (0%–100%)	2 (1–3)	87	0–1	1.6	0.0–1.2
Burnham[15]	177[a] (13.5–385)	41% (37–70%)	3.5 (1.6–5.3)	80 (40–97)	2	0.75	1.5
Howarth[13]	74–3610	0%	1.2–7.4	78	0	8.6	0

[a]NETL,[18] Stephenson,[16] Burnham,[15] and Hultman[17] all use the EPA TSD to estimate total vented or flared gas, but Hultman[17] assumes that EPA factors represented gas, rather than methane (177 tons gas contains 139 tons CH_4 due to 78.8% CH_4 mass fraction assumed).

boundary differences when comparing between the studies. These were controlled for where possible but taken as uncertainty in the emissions category where not possible.

Fourth, natural gas statistics can be shown in terms of low heating values (LHVs) or high heating values (HHVs), which differ by around 10%.[16] Two of the studies utilized HHV (Jiang[8] and Hultman[17]) and were converted to LHV basis using values from Stephenson[16] and NETL[18] (resulting in an average of 10% difference between LHV and HHV).[16,18] All values reported here have been converted to a common unit (g CO_2e/ MJ_{LHV}).

Finally, two studies specifically noted that natural gas often is produced with other coproducts like condensate, ethane, and LPG.[16,18] Both authors applied an energy content-based allocation factor (88% in Stephenson[16]) to all processes involving both natural gas and its coproducts. We adjusted for Stephenson's coproduct allocation in the following emission categories: well drilling, water management, and well completion.[16] We only attempted to adjust for NETL[18] allocation in the vented plant CO_2 due to AGR unit coproduct allocation. We did not attempt to adjust for other NETL[18] process categories as it was difficult to determine which processes were allocated and which were not.

2.2. Upstream Emissions Sources. *2.2.1. Well Completion.* The first large emissions category is well completion. While well completion emissions apply to both conventional and shale wells, most authors focused more on shale completions given the much higher values reported by EPA for shale completions as compared to conventional completions.[24] One author (Stephenson[16]) rightfully noted that the EPA values for conventional completions are relatively old estimates that are significantly lower than comparable estimates from the API Compendium.[16] We thus utilize Stephenson's[16] values for conventional completions as an alternative value to the EPA values cited by most of the other authors (see Table SI-5).

In terms of shale completions, Table SI-5 shows relatively good agreement between four of the studies with two outliers (Hultman[17] and Howarth[13]). It is difficult to know the underlying uncertainty in these estimates without more fully documenting their assumptions, and thus our analysis focused on the relevant parameters used to calculate well completion emissions, as shown in Table 1. Most of the studies utilize US EPA's Greenhouse Gas Emissions Reporting Background Technical Support Document (TSD) for their assumptions regarding the amount of gas released per completion and the flaring rate for completions, the two critical parameters that describe the amount of greenhouse gases released per completion. The TSD lists two alternative minimum flaring rates derived from state requirements for flaring, one that includes the production of tight gas (15%) and the other that includes shale gas only (51%). Despite the possibility for the emissions from completion and workover to be captured and sold using RECs, it is important to note these percentages are *absolute minimums* of the extent of flaring as required by law, despite flaring's added safety benefits over cold venting.[25] Most of the studies used one of these percentages as their base case. Howarth[13] instead assumes zero flaring, and Burnham[15] instead utilized data from the EPA NG STAR program, which produced the base case estimate of 41%.

In terms of total gas vented or flared, four studies utilized the TSD value of 177 tons CH_4, while Jiang[8] modeled the process directly using an extremely large range for illustrative sensitivity analysis. Howarth[13] cites several data for different basins, but their average is increased considerably by data from the Haynesville basin, which has been criticized by the original report's author as misrepresenting its findings.[25] Further, as several authors have pointed out, Howarth's[13] data are based on initial production rates, during which time gas concentrations in flowback water are very small, another factor that may lead to Howarth's high estimates.[13,15,25] While it is difficult to know exactly where to draw the line of the upper uncertainty range for this parameter, we chose Burnham's[15] upper estimate (385 tons CH_4) as a reasonable upper bound expected to be highly conservative considering safety and economics.[15,25]

These two parameters are combined with the estimated ultimate recovery (EUR) from each well to allocate the one-time emissions from completion and workovers to the functional unit of MJ. The studies used different sources for EUR, but most used a range given that the parameter is highly uncertain and varies by well and by basin. Tables A-15 in NETL[18] and Table S-4 of Stephenson[16] examine different data on production rates and EUR's in different types of wells, showing that such rates can vary over several orders of magnitude.[8,16,18,26] Hultman's[17] value was considerably lower due to a top down method that allocates total natural gas consumed in the US to conventional and unconventional wells based on number of wells, thus assuming that production rates for conventional and unconventional wells are similar.[27] Jiang's[8] range could be considered illustrative of EURs of individual wells, but the national average is expected to be a much tighter range based on data provided by NETL[18] and Stephenson.[16]

When combined, the total emissions factor for well completions varied surprisingly little between four of the

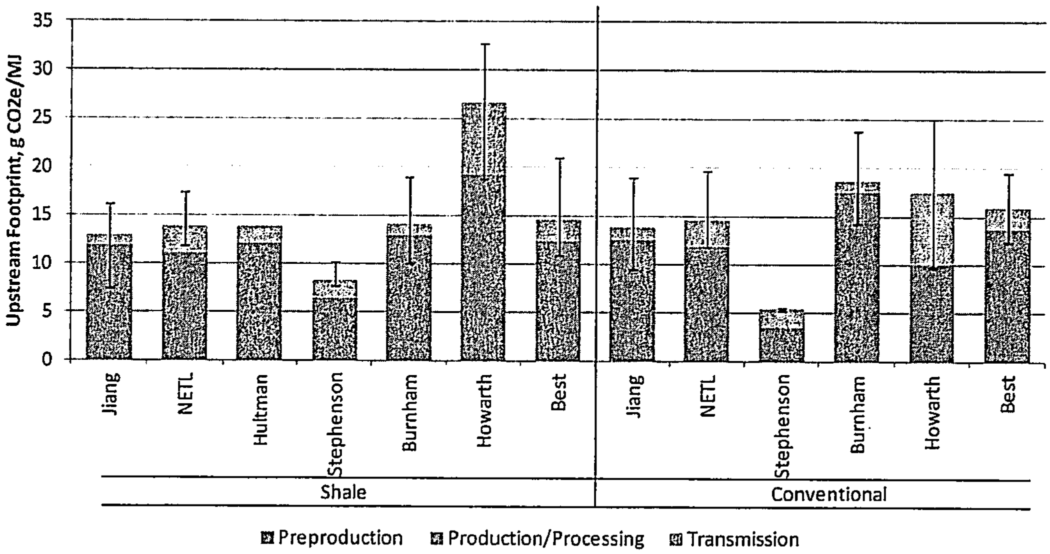

Figure 1. Summary of upstream carbon footprint estimates and uncertainty ranges for each study, including authors' best estimates. Note that different studies have different system boundaries. See Table SI-5 for more details.

studies given that it combines three uncertain parameters (total CH_4 vented and flared, flaring rate, and EUR) with large differences. As shown in Table 1, the base case factors were fairly similar with the exception of Hultman,[17] whose low EUR inflated the estimate, and Howarth,[13] who used a 0% flaring rate and extremely high CH_4 emissions factor from one basin. The ranges found in the different studies were much larger, however, showing the inherent uncertainty and variability in this emissions factor. All of the studies reported that estimates were sensitive to assumed quantity vented and flared and flaring rate. We created a Monte Carlo simulation using distributions for EUR (0.5, 2, 3.5), flaring rate (15%, 41%, 100%), and total emitted gas (13.5, 177, 385), yielding a best estimate range of 0.2–3.4 with a mean of 1.2 g CO_2e/MJ_{LHV}. The value could range as high as 4–5 g/MJ_{LHV} with very low flaring rates and EURs.

We take our analysis on completions and workovers one step further to generate an alternative scenario where reduced emission completion equipment (REC) are used on unconventional natural gas drilling activity, reflecting the REC requirement of EPA's proposed NSPS and NESHAPs rule.[11] We expect that the other sources of emissions covered by the rule will apply approximately equally to components present in both the conventional and shale production processes. Thus, to account for the differential impact between shale and unconventional processes, the alternative scenario assumes all completions use reduce emission completion (REC) equipment, and we adopt EPA's assumption that REC equipment is 90% effective capturing flowback.[28]

2.2.2. Other Significant Upstream Emissions Sources. As shown in Table SI-5, several other categories of important upstream emissions exist for shale and conventional gas production, including workovers, liquids unloading, lease and plant fuel usage, fugitive emissions in production, and fugitive emissions in transmission. These sources are explored in more detail in the Supporting Information.

2.3. Combustion Emissions. The Supporting Information discusses assumptions regarding combustion emissions in detail. Emissions resulting from the combustion of natural gas in power plants are relatively certain compared to upstream sources given the high (99%) levels of combustion achieved in large boilers and turbines.[29] The main uncertainty in combustion emissions, thus, is due only to uncertainty and variability in energy content of gas. We averaged the cited combustion emissions (56.3 g CO_2e/MJ_{LHV}) in five of the studies where the information was easily attainable, as shown in Table SI-1. To present values in well-to-wire terms, the life cycle emissions including combustion were converted to g CO_2e/kWh using several different types of generation technologies: the average US natural gas fleet over the past 10 years (an analysis of EIA data provides NG fleet efficiency averages of 40% in 2001 rising to 48% in 2010 on a LHV basis[30]), a relatively inefficient conventional gas turbine (average 37% efficiency LHV based on EIA data[30]), and a highly efficient combined cycle turbine (assumed efficiency 50% LHV). These values were taken from several of the reviewed studies and EIA data, as shown in Table SI-2 and SI-3.

3. RESULTS AND DISCUSSION

3.1. Upstream Carbon Footprint Results. Figure 1 shows the results of the upstream comparison at the category level (preproduction, production, and transmission) for each study and the best estimate simulated through Monte Carlo analysis. Detailed results at the process level are shown in the Supporting Information in Table SI-5. Shale gas estimates are shown to the left of the vertical line and conventional gas to the right.

It should be noted that the uncertainty bounds in Figure 1 represent different methods of uncertainty quantification: none (Hultman[17]), simple high-low ranges (Howarth,[13] Stephenson,[16] and NETL[18]), and Monte Carlo simulations with an 80% probability interval (Burnham[15]) and 90% probability interval (Jiang[8]). Our best estimate values show a 95% probability interval using Monte Carlo analysis with probability distributions constructed using the estimates in all six studies (see Table SI-5 of the SI for more details). We chose a 95% interval to capture best- and worst-case scenarios exhibited in the tails of the various input parameters' distributions.

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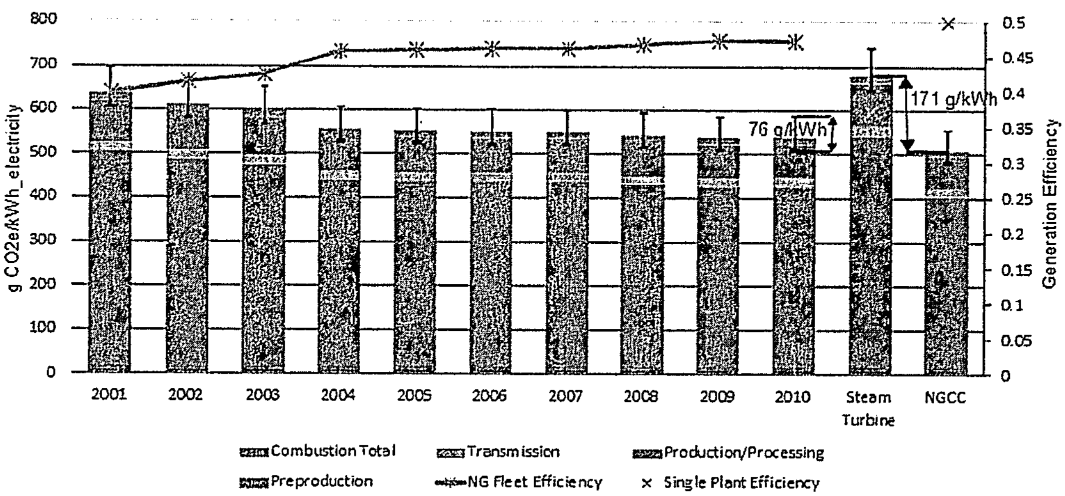

Figure 2. Well-to-wire carbon footprint for shale gas across the range of power generation efficiencies assumed in the studies and reported by EIA Electric Power Monthly data.[30,32]

Several important conclusions can be drawn from Table SI-5 and Figure 1. First, with respect to shale gas, the majority of the studies' best estimates for shale gas carbon footprint fall within a narrow range of 13 to 15 g CO_2e/MJ_{LHV}. The exceptions are Stephenson (low)[16] and Howarth (high).[13] The differences between the remaining studies are well within the typical estimated uncertainty ranges, despite the use of different approaches, data sources, and assumptions. Stephenson's[16] total is considerably lower than the other studies totals, due to low assumed energy use and fugitive methane emissions in both the production field and the natural gas processing plant. Howarth's[13] total for shale gas, which both Figure 1 and Table SI-5 show as the midpoint of a low and a high estimate, is well outside the range of uncertainty estimated by the other authors due to two extremely high estimates for well completion and fugitive emissions in transmission, as discussed above and by several authors.[15,16,25]

An equally important observation, however, is the relative difference in upstream carbon footprint between conventional gas production and shale gas production. As Figure 1 shows, this difference is considerably smaller than the uncertainty in either estimate. Our modeled mean estimate place the upstream carbon footprint for shale gas at approximately 14.6 g CO_2e/MJ_{LHV} and for conventional gas at 16.0 g CO_2e/MJ_{LHV}, though with relatively similar uncertainty ranges, 11.0−21.0 g CO_2e/MJ_{LHV} for shale gas and 12.4−19.5 g CO_2e/MJ_{LHV} for conventional gas, respectively. Our alternative scenario with NSPS required RECs estimates the carbon footprint at 12.7 g CO_2e/MJ_{LHV} with an uncertainty range of 9.9−15.6 g CO_2e/MJ_{LHV}. Of the studies that compare the two gas sources, NETL,[18] Jiang[8]/Venkatesh,[19] and Burnham[15] estimated a higher total for conventional gas than shale gas, whereas Howarth[13] and Stephenson[16] estimated a higher total for shale gas. (The Jiang[8] and Venkatesh[19] studies do not explicitly make this comparison. The numbers shown in Table 1 were calculated using numbers supplied by these authors through personal communication after removing emissions associated with liquid unloading from the shale gas carbon footprint for consistency with the other studies.) The balance between the two depends on the assumptions associated with liquids unloading, which most authors assume applies only to conventional wells, and the higher one-time emissions associated with well completion and workovers for shale gas. We estimated the importance of each individual parameter to the overall shale gas or conventional gas carbon footprint (see section 3.B of the SI for details) and found that the most important parameters to the uncertainty in the carbon footprints are as follows: 1. the number of well workovers per well lifetime (primarily shale gas), 2. the fugitive emissions rate at the wellhead (conventional and shale gas), 3. the estimated ultimate recovery (i.e., total produced gas) of the well (primarily shale gas), 4. the completion and workover emissions factor (primarily shale gas), 5. the liquid unloading emissions factor (conventional gas), and 6. the fugitive emissions at the gas processing plant (conventional and shale gas).

We also simulated the difference between conventional and shale gas (see SI section 3.A) and found that the conventional gas averaged 1.3 g CO_2e/MJ_{LHV} greater than shale gas, with 23% of simulations produced a higher footprint for shale gas, whereas 77% of simulations produced a higher footprint for conventional gas. Given the high uncertainty in one-time emissions sources like completion and workovers, however, there is a small chance that the footprint of shale is considerably greater than conventional gas, as shown by the large left tail in Figure SI-1. This scenario occurs only when completion emissions factors are high, average workovers per well lifetime are high, and flaring rates are low.

Interestingly, when considering the emissions profile associated with implementing the proposed EPA rule for RECs on shale wells, our modeled mean estimate is reduced to 12.7 g CO_2e/MJ_{LHV} with a substantially reduced uncertainty range of 9.9−15.6 g CO_2e/MJ_{LHV} (95% interval of ~6 g CO_2e/MJ_{LHV} vs 10 g CO_2e/MJ_{LHV} for the default scenario). Thus, substantially reducing the emissions associated with completions and workovers from shale wells reduces both the mean and the uncertainty range associated with shale gas carbon footprint. The scenario also changes the most important parameters associated with uncertainty, as shown by comparing Figures SI-3 and SI-5. It follows that the reduced emissions from completions and workovers also increases the average difference between conventional and shale gas, which changes from 1.3 to 3.3 g CO_2e/MJ_{LHV} (conventional emissions are greater than shale emissions). Without the large uncertainty associated with completion and workover events, we find that less than 1% of simulations produced an upstream shale gas footprint higher than the conventional footprint. See the Supporting Information for more details.

3.2. Well-to-Wire Comparison. While emissions from the upstream component of the natural gas supply chain may be significant, they must be placed into context of the overall life cycle of natural gas, which in most cases ends in combustion for one of many purposes—natural gas-fired electricity, commercial or home heating, industrial energy use, and so on. The well-to-wire analysis conducted by all studies reviewed here other than Howarth[13] places these emissions in the context of the overall life cycle for natural gas-fired versus coal-fired electricity with various assumptions regarding the efficiency of converting coal and gas to electricity. It is important to note that this is not the only relevant comparison for natural gas; various policy proposals have espoused increasing the proportion of natural gas used for electricity generation, transportation, and export to other markets.[15,19,31]

Figure 2 shows well-to-wire carbon footprints (including the best estimate upstream values for shale gas reported in the previous section) across the range of power generation efficiencies in the studies, including typical single cycle power plants, high-efficiency combined-cycle plants, and the average mix of gas plants in 2001–2010 (see Section 1 of the SI and Table SI-2 and SI-3 for details).[30] As Figure 2 shows, regardless of the assumed conversion efficiency, upstream greenhouse gas emissions accounted for approximately 20–22% (95% uncertainty) of the natural gas footprint, with the remainder associated with combustion. Importantly, despite the somewhat high uncertainty in upstream emission estimates (representing 96 g CO_2e/kWh at 37% efficiency), the difference between different types of natural gas power plants (less-efficient steam turbine vs highly efficient combined cycle plants, 171 g CO_2e/kWh) accounts for a much greater difference. Overall well-to-wire uncertainty estimates reported in Figure 2 are assumed to be based upon modeled 95% uncertainty in the studied literature and do not represent shifts in this uncertainty estimate over time. Over the past decade, the increase in fleet average efficiency, in part due to increased combined cycle plant capacity factors, has already pushed down the life cycle carbon footprint of shale gas down by over 97 g CO_2e/kWh from 2001 to 2010. This life cycle emission decrease is significant because it exceeds the magnitude of total upstream uncertainty by over 25% (76 g CO_2e/kWh in 2010) and is nearly as large as the upstream emissions altogether (111 g CO_2e/kWh in 2010).

3.3. Uncertainties and Limitations. As is often the case when conducting life cycle assessments, data limitations constrained our analysis in several ways. While 6 similar studies worth of data are significantly more than is frequently encountered in LCAs, many of the data utilized by different authors were either from the same source or from different basins, leading to high geographic uncertainty.[20] Given the relatively new technology associated with shale gas production, it is possible many of the data will also change with technological progress. Another large limitation relates to the inability to accurately know the distributional form in the Monte Carlo assessment or whether any parameters are correlated. We chose triangular distributions for simplicity and their ability to shift probability mass toward subjectively more accurate values.[33] However, the true uncertainty in the data may be poorly modeled by this distribution form or the choice of most likely values. Further data collection on the most important model parameters described above could help future analyses more accurately describe such uncertainties. Finally, the studies we analyzed represented a variety of different geological basins and areas, but impacts are expected to differ substantially in different areas due to different gas chemistries, basin pressures, and coproduct production. Future work should focus on more regionally explicit analyses.

4. DISCUSSION AND POLICY IMPLICATIONS

Our review of several studies published since Howarth's[13] initial shale gas carbon footprint study shows that although the carbon footprint of shale gas is highly uncertain, it is also difficult to distinguish from conventional onshore gas production. Thus, while reducing life cycle emissions associated with both conventional and unconventional gas should be a policy goal, the evidence to date suggests that the carbon footprint of shale gas is not of considerably greater concern than previously discussed issues with the natural gas system.[34] Of course, it is important to note that shale gas development presents large economic possibilities and several types of potential environmental issues that are outside of the scope of the current analysis.

Despite the large recent interest in the issue, data are extremely scarce for several sources of greenhouse gas emissions associated with shale gas production. Nearly all of the studies examined here used two sources[24,35] for at least some of the emissions data, and the uncertainty in these underlying API and EPA data is unknown. Further, the carbon footprint of shale gas is dependent on not only the amount of one-time emissions but also the ultimate production of each type of well, which varies considerably between individual wells and basins.[16,18,26] These data will naturally increase in quality with time as wells are refurbished or expire, providing key information on ultimate recovery potential. However, if the uncertainty in natural gas carbon footprint is to be reduced, further data collection and research is also needed for well completion events, ultimate gas recoveries, in-field flaring rates, and both the extent of, and the emissions associated with, well workovers and liquids unloading.

One of the traditional uses of life cycle assessments has been to identify "hot spots" where the environmental impacts of a product can be reduced.[36] Many of the upstream greenhouse gas emissions associated with both sources of natural gas can be controlled effectively and economically through flaring (thus converting high-GWP methane to CO_2) or capture of fugitive emissions in completion and workover through best practices (such as RECs). EPA's Natural Gas STAR program compiles cost-effective opportunities (many with paybacks below 3 years) reported by gas producers that increase production while reducing methane emissions.[37] The studies analyzed here provide significant guidance on where to focus to effectively reduce emissions from both upstream and the full-life cycle of project-scale shale gas production.

Nevertheless, despite these uncertainties, the upstream emissions associated with both types of gas are made less significant by the fact that they represent less than a quarter of total life cycle emissions when combustion is included. When examining the entire life cycle, it becomes clear that the uncertainty in upstream emissions is less significant than using the resulting gas in the most efficient manner possible. This is

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true both within a certain sector (such as electricity) as well as across sectors.

Within the electricity sector, the average gas power generation fleet is expected to further its recent efficiency increases in the short run given the relatively low capacity factors of advanced combined-cycle gas plants today. Two primary factors have influenced the increased US utilization of natural gas generation capacity in the past decade: 1. an overwhelming majority of generation-capacity additions in the past decade (81% of additional rated capacity) have been natural gas-generating units and a majority of these units were combined-cycle units, and 2. combined-cycle power plants have been increasingly contributing to US baseload generation.[38] Projections of increasing levels of domestic natural gas production due to higher levels of shale gas production and increased environmental regulations on coal electricity generation will continue to influence the projected growth of higher efficiency natural gas generation in the US electricity generation portfolio.[3]

However, different energy pathways for the future could lead to different productive uses for the large quantities of shale gas expected to be extracted in the coming years, including power generation, transportation (through compressed natural gas or electricity pathways), industrial usage, and exports.[1,15,19] These uses are not necessarily mutually exclusive but not all can simultaneously be expanded—any natural gas used to displace coal will not be available to potentially displace oil in the transportation sector. It is within this broader scope of systems issues that the real impacts of such a large energy shift must be analyzed. These system-level issues are not adequately answered using tools such as life cycle assessment—despite efforts to move toward more policy-relevant "consequential" LCAs[39]—due to the need to define a single functional unit of a multifunctional energy commodity.

Unexpected large additions of natural gas into the US and global energy profile may have beneficial impacts for climate change, such as reducing the utilization of coal generation facilities or the utilization of oil for transportation, as well as negative impacts, such as on the rate of renewable energy technology deployment. Such questions can only be answered through the use of energy systems and climate models taking into account both the results of life cycle assessments along with economics and technological development pathways.[40−42] Linking the results of LCAs to more complex models of policies and economic markets represents a fruitful avenue for future research.[43] Before such models can be linked, of course, there is a need to understand the life cycle impacts of different energy options fuels with greater confidence.

■ ASSOCIATED CONTENT

Supporting Information

Additional information on calculations and detailed results. This material is available free of charge via the Internet at http://pubs.acs.org.

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Appendix “D”

CLEARING THE AIR: REDUCING UPSTREAM GREENHOUSE GAS EMISSIONS FROM U.S. NATURAL GAS SYSTEMS

JAMES BRADBURY, MICHAEL OBEITER, LAURA DRAUCKER, WEN WANG, AND AMANDA STEVENS

SUMMARY FOR POLICYMAKERS

Natural gas production in the United States has increased rapidly in recent years, growing by 23 percent from 2007 to 2012. This development has significantly changed projections of the future energy mix in the U.S. Advances combining horizontal drilling and hydraulic fracturing have enabled producers to access vast supplies of natural gas deposits in shale rock formations. This shale gas phenomenon has helped to reduce energy prices, directly and indirectly supporting growth for many sectors of the U.S. economy, including manufacturing.

This paper seeks to clarify what is known about methane emissions from the natural gas sector, what progress has been made to reduce those emissions, and what more can be done. Box S-1 lists the paper's key findings. Box S-2 describes the scope of this study.

Shale gas development has triggered divisive debates over the near- and long-term environmental implications of developing and using these resources, including concerns over air quality, water resources, and community impacts. One point of controversy concerns the climate change implications of shale gas development, in part due to uncertainty about emissions of methane, a potent greenhouse gas (GHG) that is the primary component of natural gas. Fugitive methane emissions reduce the net climate benefits of using lower-carbon natural gas as a substitute for coal and oil for electricity generation and transportation, respectively.

CONTENTS

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Box S-1 | Key Findings from the Working Paper

1. Fugitive methane emissions from natural gas systems represent a significant source of global warming pollution in the U.S. Reductions in methane emissions are urgently needed as part of the broader effort to slow the rate of global temperature rise.

2. Cutting methane leakage rates from natural gas systems to less than 1 percent of total production would ensure that the climate impacts of natural gas are lower than coal or diesel fuel over any time horizon. This goal can be achieved by reducing emissions by one-half to two-thirds below current levels through the widespread use of proven, cost-effective technologies.

3. Fugitive methane emissions occur at every stage of the natural gas life cycle; however, the total amount of leakage is unclear. More comprehensive and current direct emissions measurements are needed from this regionally diverse and rapidly expanding energy sector.

4. Recent standards from the Environmental Protection Agency (EPA) will substantially reduce leakage from natural gas systems, but to help slow the rate of global warming and improve air quality, further action by states and EPA should directly address fugitive methane from new and existing wells and equipment.

5. Federal rules building on existing Clean Air Act (CAA) authorities could provide an appropriate framework for reducing upstream methane emissions. This approach accounts for input by affected industries, while allowing flexibility for states to implement rules according to unique local circumstances.

While a shift in electric generation to natural gas from coal has played a significant role in recent reductions in U.S. carbon dioxide (CO_2) emissions, more will need to be done for the U.S. to meet its goal of reducing GHG emissions by 17 percent below 2005 levels by 2020. A related WRI report found that cost-effective cuts in methane leakage from natural gas systems are among the most important steps the U.S. can take toward meeting that goal.[1] To achieve climate stabilization in the longer term, policies are needed to address combustion emissions through carbon capture and storage or by other means.

In addition to methane emissions, natural gas sector operations and infrastructure represent a significant source of CO_2; volatile organic compounds (VOCs), which are chemicals that contribute to ground-level ozone and smog; and hazardous air pollutants (HAPs). In 2012, EPA finalized air pollution standards for VOCs and HAPs from the oil and natural gas sector. These rules will improve air quality and have the co-benefit of reducing methane emissions. As discussed below, these standards can be complemented by additional actions to further reduce methane emissions, which will help to slow the rate of global temperature rise in the coming decades.

Fortunately, most strategies for reducing venting and leaks from U.S. natural gas systems are cost-effective, with payback periods of three years or less. The case for policy action is particularly strong considering that recent research shows that climate change is happening faster than expected. In addition, the projected expansion in domestic oil and natural gas production increases the risk of higher emissions if proper protections are not in place.

Box S-2 | The Scope of this Study

This study focuses primarily on evaluating and reducing upstream methane emissions in the natural gas sector. This has two important implications. First, this paper in no way aims to diminish the urgent need to achieve GHG emissions reductions from other segments of the economy. For example, significant cost-effective opportunities also exist to reduce carbon dioxide emissions from both upstream and downstream stages of the natural gas life cycle, and to reduce methane emissions from coal mines, landfills, and other sources. Longer term, addressing combustion emissions will be increasingly important, whether through carbon capture and storage or by other means. Second, this paper does not address other aspects of natural gas development that pose significant risks for public health and the environment, including potential effects on drinking water and other community impacts. We focus on actions to reduce methane emissions, and generally do not consider additional policies that may be necessary to protect the public interest from these other risks. The one exception is that toxic and VOC emissions are frequently discussed—because the technologies and practices that effectively reduce those emissions typically also achieve reductions in methane emissions.

LIFE CYCLE ASSESSMENTS

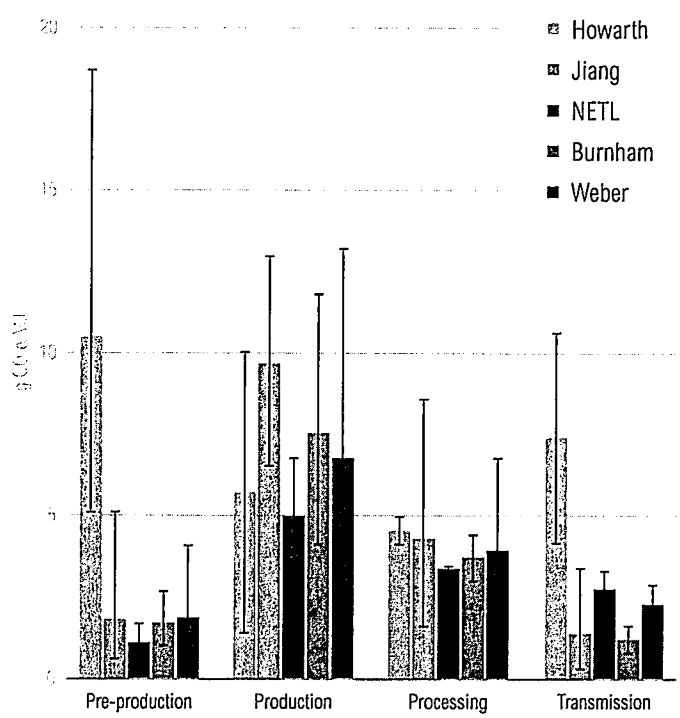
While natural gas emits about half as much carbon dioxide as coal at the point of combustion, the picture is more complicated from a life cycle perspective. There is considerable uncertainty about the scale of upstream methane emissions from natural gas systems due to variations between production basins and a scarcity of recent, direct emissions measurements from several key processes. Ultimately, the question of whether or not gas has a lower climate impact than coal depends on the life cycle methane leakage rates, plus other factors that include subjective policy considerations. Section 2 includes more extensive discussion of this and related questions.

Most life cycle studies agree, based primarily on data from EPA's U.S. GHG Inventory, that carbon dioxide (CO_2) emissions from end-use combustion of natural gas represents roughly 70 to 80 percent of total life cycle GHG emissions.[2] Most studies also agree that upstream GHG emissions associated with shale gas and conventional gas production are roughly comparable to one another, within the margin of error. EPA's GHG inventory data imply a methane leakage rate of less than 3 percent of total natural gas production.[3] At this leakage rate, natural gas produces fewer GHG emissions than coal over any time horizon and regardless of how the fuels are used. Additionally, according to a 2012 study published in the Proceedings of the National Academy of Sciences, reducing the methane leakage rate to below 1 percent would ensure that heavy-duty vehicles, like buses and long-haul trucks, fueled by natural gas would have an immediate climate benefit over similar vehicles fueled by diesel. Thus, reducing total methane leakage to less than 1 percent of natural gas production is a sensible performance goal for the sector to achieve.

Accurate life cycle emissions estimates from the natural gas sector require reliable data for a broad range of industry activities and emissions factors associated with those activities. Regarding the quality of available data, there are uncertainties at all life cycle stages. With the exception of one study published by researchers at Cornell University, findings from life cycle assessments of methane emissions from unconventional wells have varied the most on production stage emissions (see Figure S-1). This is because of differing assumptions regarding how frequently the average well requires hydraulic fracturing and liquids unloading[4], and the extent to which control technologies are used when these activities are performed. Hydraulic fracturing is often an emissions-intensive process used to initiate production at both conventional and unconventional wells (i.e., "well completions"; Figure S-2). It may be repeated to re-stimulate production multiple times over a well's estimated 20-to-30-year lifetime (during "workovers"; Figure S-2). Liquids unloading is a practice used to clean up all types of onshore wells, removing liquids to increase the flow of gas, and potentially causing significant emissions.

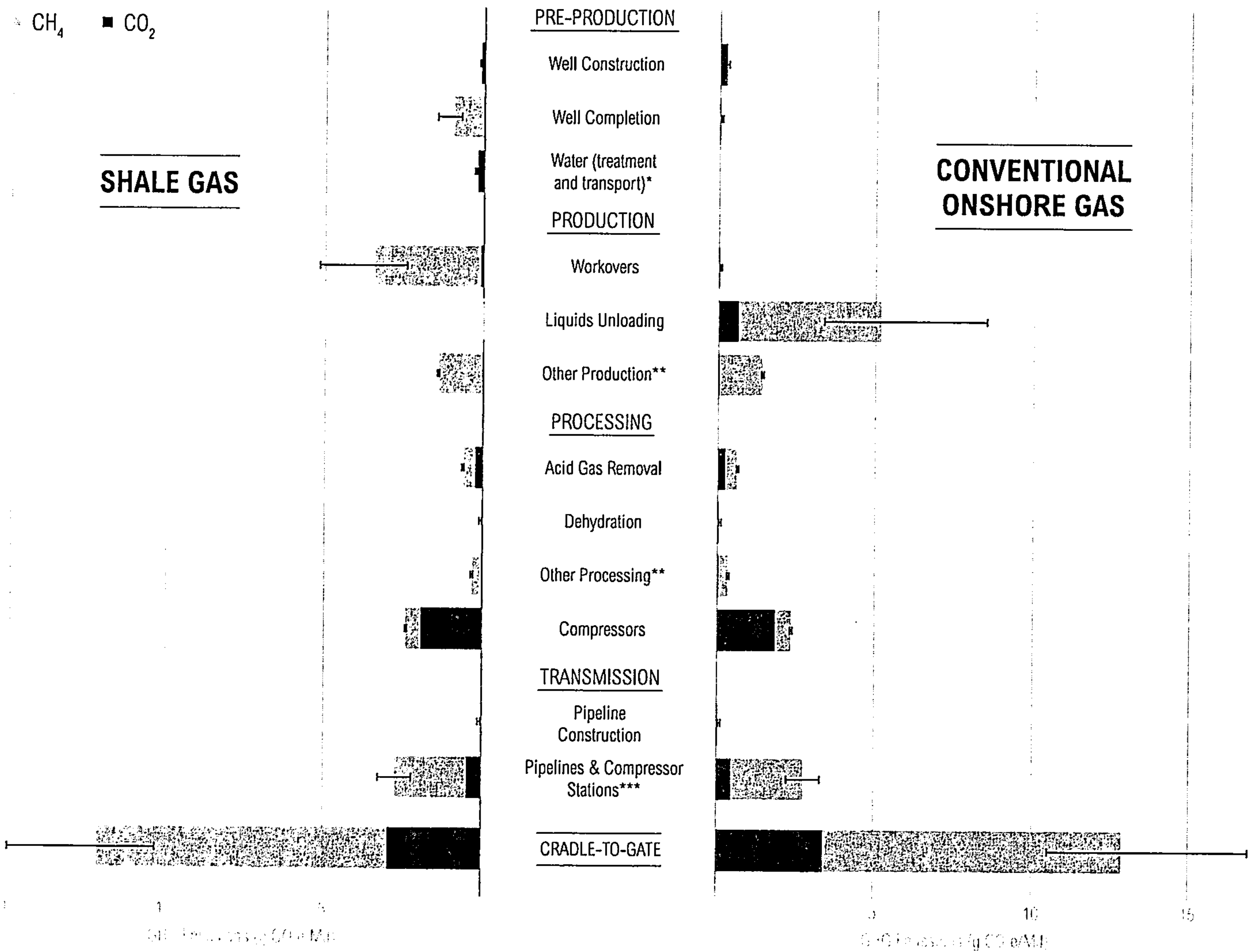
Since 2009, EPA's annual GHG inventory has dramatically adjusted their emissions factors associated with these production-stage activities. In EPA's draft 2013 GHG inventory, there is a 90 percent reduction in their estimates of emissions associated with liquids unloading in response to self-reported industry data showing that unloading events are less emissions-intensive than previously thought; that is, industry reported more frequent use of control technologies than EPA had assumed in earlier inventories.

Figure S-1 | Upstream GHG Emissions from Shale Gas, by Life Cycle Stage



Sources: All data presented in this figure are derived from the referenced studies, with only unit conversions and minor adjustments for heating rates. See Figure 4 for complete study references and more detailed discussion.

Figure S-2 | Comparing Detailed Estimates of Life Cycle GHG Emissions from Shale Gas and Conventional Onshore Natural Gas Sources



* Data available from Marcellus only
** "Other Production" and "Other Processing" each include point source and fugitive emissions (mostly from valves)
*** Includes all combustion and fugitive emissions throughout the entire transmission system (mostly from compressor stations)

Notes: Recent evidence suggests that liquids unloading is a common practice for both shale gas and onshore conventional gas wells (Shires and Lev-On 2012). Therefore, contrary to data originally published by NETL, showing zero emissions, liquids unloading during shale gas development may result in GHG emissions that are comparable to those associated with conventional onshore natural gas development. GWP for methane is 25 over a 100-year time frame.
Source: National Energy Technology Laboratory.

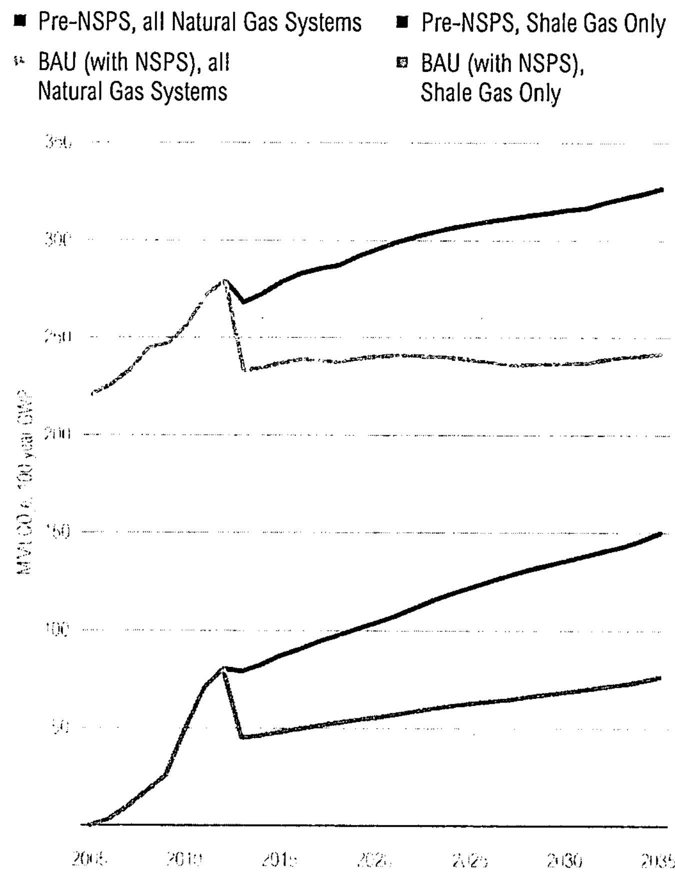
Meanwhile, recent research based on field measurements of ambient air near natural gas well-fields in Colorado and Utah suggest that more than 4 percent of well production may be leaking into the atmosphere at some production-stage operations.[5] With hundreds of thousands of wells and thousands of natural gas producers operating in the U.S., this will likely remain an active debate, even as forthcoming data from EPA and other sources aims to clarify these questions in the coming months. For example, independent researchers at the University of Texas at Austin are teaming up with the Environmental Defense Fund and several industry partners to directly measure methane emissions from several key sources. When results are published in 2013 and 2014, these data will provide valuable points of reference to help inform this important discussion.

While uncertainties remain regarding exact methane leakage rates, the weight of evidence suggests that significant leakage occurs during every life cycle stage of U.S. natural gas systems, not just the production stage (Figures S-1 and S-2). A recent expert survey by Resources for the Future identified methane emissions as a consensus environmental risk that should be addressed through government and industry actions.

THE IMPACT OF EPA'S NEW SOURCE PERFORMANCE STANDARDS

In April 2012 EPA finalized regulations for New Source Performance Standard (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that primarily target VOC and air toxics emissions but will have the co-benefit of reducing methane emissions. The new EPA rules require "green completions," which reduce emissions during the flow-back stage of all hydraulic fracturing operations at new and re-stimulated natural gas wells. The rules will also reduce leakage rates for compressors, controllers, and storage tanks. We estimate that this will reduce methane emissions enough to cut all upstream GHG emissions from shale gas operations between 40 to 46 percent below their projected trajectory in the absence of the rules (Figure S-3; bottom two lines). For all natural gas systems (including shale gas), methane emissions reductions resulting from the NSPS/NESHAP rules are projected to lower upstream GHG emissions by 13 percent in 2015 and 25 percent by 2035 (Figure S-3; top two lines). These rules will have a greater impact over time as the proportion of domestic gas production coming from shale formations—the source of the greatest emissions reductions resulting from the new rules—rises from one-third to one-half during the next twenty years, and as old equipment is gradually replaced with new equipment that is covered by the rules.

Figure S-3 | GHG Emissions from Shale Gas Systems and All Natural Gas Systems



Notes: Upstream GHG emissions before and after application of the EPA NSPS rule, for all natural gas systems (top two lines) and for shale gas systems (bottom two lines).

FURTHER POTENTIAL TO REDUCE METHANE EMISSIONS

With the implementation of just three technologies that capture or avoid fugitive methane emissions, we estimate that upstream methane emissions across all natural gas systems could be cost-effectively cut by up to an additional 30 percent (Figure S-4). The technologies include (a) the use of plunger lift systems at new and existing wells during liquids unloading operations; (b) fugitive methane leak monitoring and repair at new and existing well sites, processing plants, and compressor stations; and (c) replacing existing high-bleed pneumatic devices with low-bleed equivalents throughout natural gas systems. By our estimation, these three steps would bring down the total life cycle leakage rate across all natural gas systems to just above 1 percent of total production. Through the adoption of five additional abatement measures that each address smaller emissions sources, the 1 percent goal would be readily achieved.

NEXT STEPS TO REDUCE METHANE EMISSIONS

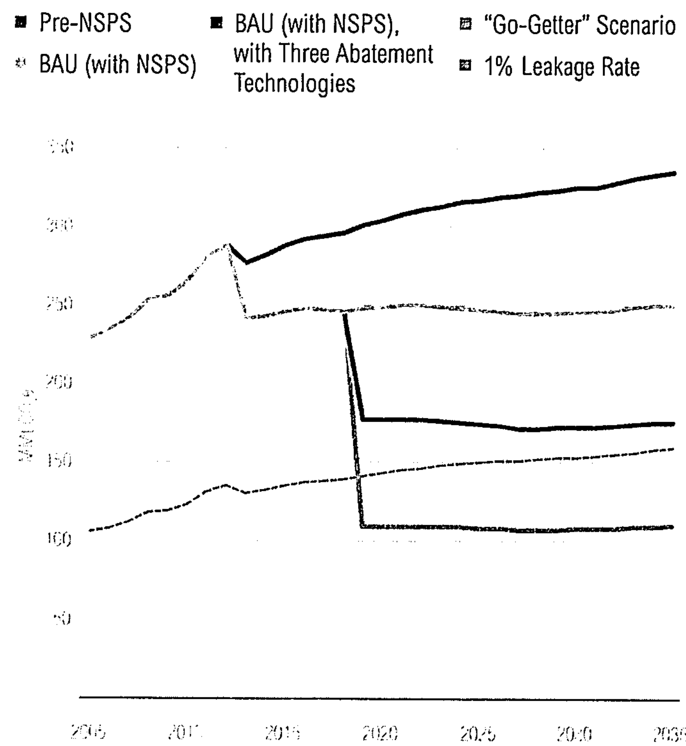
New public policies will be needed to reduce methane emissions from both new and existing equipment throughout U.S. natural gas systems because market conditions alone are not sufficient to compel industry to adequately or quickly adopt best practices. Minimum federal standards for environmental performance are a necessary and appropriate framework for addressing cross-boundary pollution issues like air emissions. Federal CAA regulations are generally developed in close consultation with industry and state regulators and are often implemented by states. This framework allows adequate flexibility to enable state policy leadership and continuous improvement in environmental protection over time.

We have identified a range of actions that can be taken to reduce methane emissions.[6] These tools are listed in this summary, and discussed in more detail in section 5.

Federal Approaches to Address Emissions

In addition to the recently enacted NSPS/NESHAP rules, EPA has a number of additional tools to either directly or indirectly reduce methane emissions from U.S. natural gas systems, most of which would also support more protective actions at the state level. For example, EPA could do the following:

Figure S-4 | Projections of GHG Emissions from All Natural Gas Systems after Additional Abatement



Source: Baseline GHG data are based on Weber and Clavin (2012), EPA (2012a), and EIA (2012).

Notes: Potential for additional upstream methane emissions reductions for all natural gas systems based on implementation of a hypothetical rule in 2019 requiring plunger lift systems, leak detection and repair, and replacing existing high-bleed pneumatic devices with low-bleed equivalents (purple line); or a rule requiring those technologies and five additional abatement measures (green line). The light blue dashed line shows the total amount of GHG emissions (MMt CO_2e) that would result from 1 percent fugitive methane emissions relative to total dry gas production in each year, plus estimated annual CO_2.

- *Direct regulation of GHG emissions.* EPA could directly regulate GHG emissions under section 111 of the CAA, which could achieve greater reductions in methane and CO_2 emissions from new and existing sources than would otherwise be achieved indirectly through standards for VOCs or HAPs.

- *Emissions standards for air toxics.* Under section 112 of the CAA, EPA could set emissions standards for HAPs from production-stage infrastructure and operations in urban areas.

- *Supporting best practices.* EPA could do more through Natural Gas STAR and other programs to recognize companies that demonstrate a commitment to best practices. They could further encourage voluntary actions by maintaining a clearinghouse for technologies and practices that reduce all types of air emissions from the oil and natural gas sector.

Enabling State Policy Leadership

State governments play an important role in developing new approaches to reducing air emissions, and they are largely responsible for implementing many federal rules under the CAA. However, they are often short on resources and could benefit from additional policy and technical assistance, particularly given the current rate of expanding U.S. oil and natural gas development and expectations for additional growth in the future. As a first step, state governments could raise new revenues through fees, royalty payments, and severance taxes levied on oil and gas industry activities to secure adequate funding for emissions monitoring and associated regulatory actions. In addition, state governments and EPA could:

- *Provide technical assistance.* Recognizing the central role of state governments in achieving federal National Ambient Air Quality Standards, EPA could provide targeted technical and regulatory assistance to states with expanding oil and natural gas development.

- *Address smog and other air quality problems.* States concerned about smog and other air quality problems associated with unconventional oil and gas development can voluntarily engage with EPA's Ozone Advance Program. Addressing local air quality problems related to this sector will likely have co-benefits, including reduced methane emissions.

- *Develop a policy database.* States with limited recent experience managing oil and natural gas sector development would benefit from a comprehensive and current database of existing state policies and regulatory practices that have been used by others to address environmental risks, including air emissions. This resource, which could be developed and maintained by any credible research organization, would serve as a practical resource for policymakers. It could also be used to help recognize policy gaps or to identify and promulgate model rules or model legislation, as needed.

- *Assistance with environmental regulations.* With more funding, the organization STRONGER (State Review of Oil and Natural Gas Environmental Regulations) could provide more states with timely assistance with the development and evaluation of environmental regulations.

Improve Understanding of Emissions

Basic information on actual air emissions from the oil and natural gas sector is difficult to come by. As noted in Appendix 1, current emissions estimates are based on assumed emissions factors—as opposed to direct measurements—because there are hundreds of thousands of natural gas wells in the U.S. and direct emissions measurements are expensive. As a result of these data uncertainties, persistent questions remain about the effectiveness of commonly used emissions control technologies. This both raises compliance concerns and reduces the likelihood that a company would invest in pollution control, since the resulting level of product recovery is in question. To improve understanding of emissions, the following actions could be taken by EPA, states, or non-governmental organizations:

- *Analyze emissions data.* EPA and independent researchers should analyze recently published emissions data from the GHG Reporting Rule to better understand regional variability in methane leakage, support regulatory development, and track industry performance over time.

- *Add oil and gas emissions to the TRI.* To better determine which cities and surrounding communities face the greatest risk of exposure to HAPs from oil and natural gas operations, EPA could add oil and natural gas sector emissions to the Toxic Release Inventory (TRI).

- *Estimate production-stage emissions from tight oil wells.* Associated natural gas production is increasing as unconventional oil and gas development shifts toward more oil-rich shale plays (such as North Dakota). Research by EPA and other federal agencies could better understand the climate implications of this trend, including a detailed assessment of production-stage methane emissions from tight-oil well completions.

- *Update emissions factors for key processes.* To help resolve questions regarding the scale of methane emissions from U.S. natural gas infrastructure and operations, EPA or non-governmental organizations could convene a working group of industry experts to develop updated emissions factors for key processes such as liquids unloading operations. Findings of this research could be used to improve subsequent emissions estimates reported under the GHG Reporting Program.

- *Establish a database for voluntary air emissions reporting.* To encourage greater transparency regarding emissions from oil and natural gas sector companies, EPA or states could establish a database for voluntary reporting of all types of air emissions from the sector.

Research to Improve Technology and Policy Options

While this paper has identified a suite of technology and policy options for reducing methane emissions from natural gas systems, the expected expansion of natural gas production means continued improvement will be necessary to keep pace.

- Efforts to reduce upstream GHG emissions from natural gas systems could be aided by applied technology research and development to improve emissions measurements, and to develop new and lower cost methane emission reduction strategies.

- Further policy research is needed to identify policy solutions to regulatory barriers and market failures that prevent companies from investing in cost-effective projects that reduce methane emissions and more efficiently use fossil fuels throughout the natural gas life cycle.

Through these and other steps, governments will have the tools they need to achieve continuous air quality improvements over time and slow the rate of climate change by reducing methane emissions to below 1 percent of total natural gas production.

SUMMARY ENDNOTES

1. For more details on how the Obama administration can achieve this goal using existing authorities, see the recent WRI report "Can the U.S. Get There from Here? Using Existing Federal Laws and State Actions to Reduce Greenhouse Gas Emissions," available at: http://www.wri.org/publication/can-us-get-there-from-here.

2. This assumes a 100 year time-horizon for integrating the global warming potential (GWP) of methane. Over a 20-year time horizon, end-use combustion represents 60 to 70 percent of most life cycle estimates of total GHG emissions from natural gas.

3. Throughout this report we refer repeatedly to EPA's final 2012 GHG inventory published in April 2012. An updated draft inventory was released by EPA in February 2013, but has not yet been finalized at this writing (see Appendix 1). EPA's draft 2013 GHG inventory revises downward their estimates of methane emissions from U.S. natural gas systems, with an equivalent reduction in the implied methane leakage rate to approximately 1.54 percent of total production.

4. Note: Definitions of these and other terms can be found in the glossary.

5. This 4 percent methane leakage rate estimate, published by Gabriele Petron and colleagues in the Journal of Geophysical Research, was subsequently challenged in a peer-reviewed article published in the same journal by Michael Levi, who estimated a lower methane leakage rate based on Petron's data.

6. We gratefully acknowledge the experts who attended an all-day workshop that WRI co-hosted with the Environmental Defense Fund, on October 16, 2012. The policy options in this paper were developed based on WRI research. While these options draw heavily from input provided at the workshop, they are not necessarily endorsed by the workshop participants.

SECTION 1. INTRODUCTION

The rapid development of shale gas resources in the last few years has significantly changed projections of the future energy mix in the U.S. (EIA 2012) and internationally (IEA 2012). Advances combining horizontal drilling and hydraulic fracturing have enabled access to vast supplies of natural gas deposits in shale rock formations. According to the EIA, in 2012 over 25 trillion cubic feet (Tcf) of natural gas was produced in the U.S., an expansion of over 20% in just 5 years. While the shale gas phenomenon has contributed to a reduction in U.S. natural gas prices (EIA 2012) and created economic opportunity for some sectors such as manufacturing (ACC 2011), it has also triggered divisive debates over the near- and long-term environmental implications of the development and use of natural gas resources.

The climate change implications of shale gas development have been a point of particular controversy, in part due to uncertainty about the methane emissions associated with natural gas development, particularly from shale formations. These associated upstream methane emissions—that is, emissions that occur prior to fuel combustion[1]—reduce the net climate benefits of switching end-use fuel consumption from coal and oil to lower-carbon natural gas (Wigley et al. 2011). In the last two years, a number of recent studies have looked at this issue, coming at times to very different conclusions. In section 2 we examine these studies and explain their differences. One common feature is that most recent studies have found that carbon dioxide (CO_2) emissions from the end-use combustion of natural gas represents roughly 70 to 80 percent of its total life cycle GHG emissions (when integrated over a 100-year time frame; see Boxes 1 and 2).

Another related point of active debate is the long-term role of natural gas in the economy. On the one hand, it could potentially serve as a "bridge fuel," displacing coal while complementing renewable energy sources during a low-carbon transition. On the other hand, abundant and inexpensive natural gas could undercut the economics of energy efficiency and put all other energy sources—including coal, nuclear and renewable energy—at a competitive disadvantage.

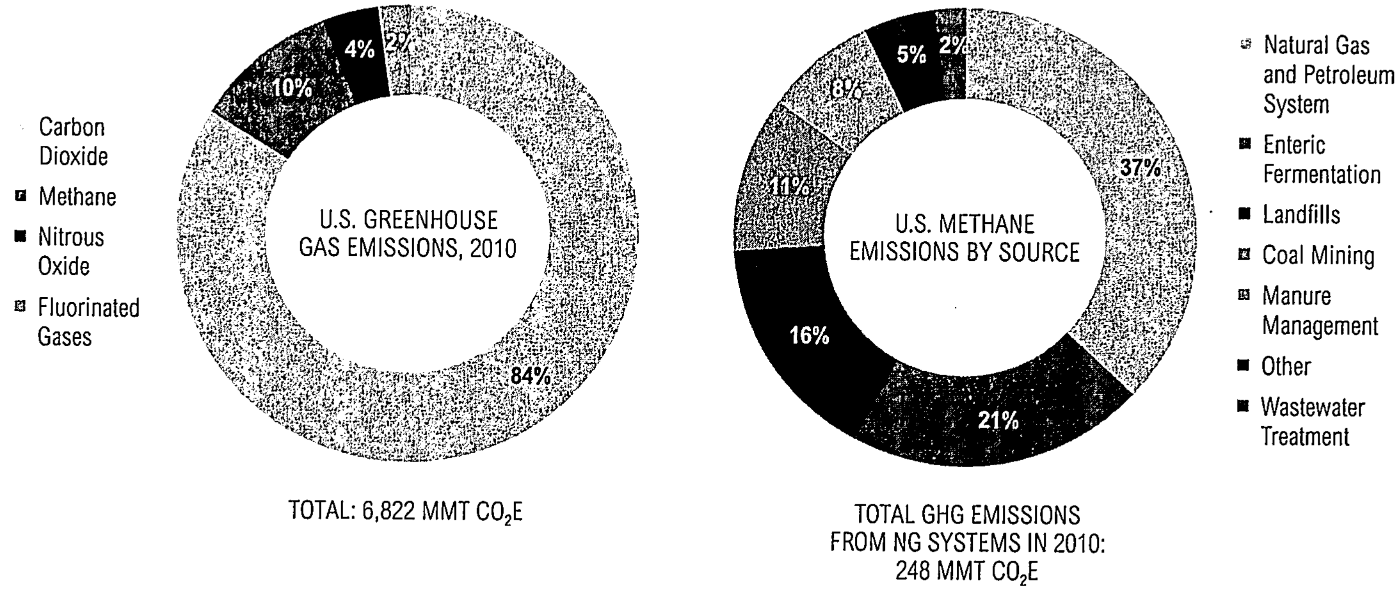
Economic modeling studies have consistently found that climate and energy policies would be needed to reduce carbon dioxide emissions by 80 percent in the U.S. (Brown et al. 2009; Jacoby et al., 2012), which is necessary to achieve climate stabilization at relatively safe levels (NRC 2011). The International Energy Agency (2012) reached the same conclusion, finding that a significant increase in the use of natural gas over the coming decades could have some climate benefits (compared to a scenario in which oil and coal played more prominent roles). However, the IEA's "Golden Rules" scenario would result in climate stabilization at 650 parts per million (ppm) CO_2 concentrations in the atmosphere and a global temperature rise of 3.5° Celsius, almost twice the internationally accepted 2° Celsius target.

A recent modeling study by Levi (2013) found that several years of heightened natural gas use —for example, from 2010 through 2030— displacing coal and delaying investment in zero-carbon energy sources could be consistent with climate stabilization at relatively safe levels (e.g., 450 and 550 ppm). However, a 2° Celsius scenario involves a short-lived natural gas "bridge," with significant reductions in natural gas use by mid-century unless there is broad adoption of carbon capture and storage (CCS) technologies at power plants and other facilities with industrial-scale natural gas combustion (Levi 2013).

According to the U.S. Environmental Protection Agency (EPA), upstream natural gas infrastructure is a leading source of methane emissions in the U.S. Methane emissions from natural gas systems now account for about one-third of all U.S. methane emissions (Figure 1) and more than 3 percent[2] of the total U.S. GHG inventory (EPA 2012a), though significant uncertainty remains concerning the extent of these emissions. EPA also recently published new GHG emissions data from U.S. natural gas systems. These data were reported for the first time to the Greenhouse Gas Reporting Program (GHGRP) (see Appendix 1 for more details). They show that natural gas and petroleum systems were the second largest stationary source of greenhouse gases in the U.S. in 2011, after power plants.[3] This newly reported data has not yet been analyzed and factored into EPA's emissions inventory.

Meanwhile, the U.S. Energy Information Administration (EIA) projects that total U.S. production of natural gas will increase by 55 percent above 2010 levels by 2040, primarily as a result of increased onshore production from shale gas resources (EIA 2012). Despite the uncertainties regarding aspects of methane emissions from U.S. natural gas systems (EPA 2013a),[4] the growing role of natural gas in U.S. energy systems underscores the urgency of identifying and seizing cost-effective opportunities for reducing methane emissions.

Figure 1 | U.S. Greenhouse Gas Emissions by Source, 2010



Source: EPA 2012a.
Notes: Emissions data presented in million metric tons of carbon dioxide equivalent (MMt CO_2e). This assumes a 100-year time frame, and a methane GWP of 21.

Reducing methane emissions slows the rate of warming

Though methane accounted for only 10 percent of the U.S. greenhouse gas (GHG) emissions inventory in 2010 (Figure 1),[5] it represents one of the most important opportunities for reducing GHG emissions in the U.S. (Bianco et al. 2013). In addition to the scale and cost-effectiveness of the reduction opportunities, climate research scientists have concluded that cutting methane emissions in the near term could slow the rate of global temperature rise over the next several decades (NRC 2011).

Scientists at the National Research Council of the U.S. National Academy of Sciences have concluded that global carbon dioxide (CO_2) emissions need to be reduced in the coming decades by at least 80 percent below current levels to stabilize atmospheric CO_2 concentrations and thus avoid the worst impacts of global warming (NRC 2011).[6] However, given the slow pace of progress in the U.S. toward enacting policies that would achieve the necessary CO_2 emissions reductions, it is valuable and important for policymakers to consider cost-effective mitigation strategies—such as cutting methane emissions—that would have a disproportionate impact in the short-term (Box 1).

Objectives: Identify the largest GHG emissions sources from natural gas systems and develop targeted reduction strategies

This paper summarizes the state of knowledge about methane emissions from U.S. natural gas systems, highlights emissions reduction potential, and discusses the role of current and future policies in helping to reduce these emissions.

Section 2 introduces the concept of life cycle assessment (LCA) as a policy-relevant tool for measuring greenhouse gas emissions and summarizes the findings from LCA studies published in 2011 and 2012. This section explains key differences among these studies, which were completed in the context of evolving emissions estimates from EPA and others. These studies emphasized shale-gas-related emissions, due to heightened public attention and the rapidly expanding development of this resource base.

Box 1 | Time Horizons for Global Warming Potential (GWP)—a Policy Question

Rising methane concentrations in the atmosphere have a potent, near-term warming effect because this greenhouse gas has a relatively high global warming potential and short atmospheric lifetime (IPCC 2007). As a result, policies that effectively reduce methane emissions from all sources could slow the rate of global temperature rise in the coming decades, reducing the risks associated with a rapidly warming planet (NRC 2011; Howarth et al. 2012a).

Global warming potential (GWP) is a measure of the total energy that a gas absorbs over a particular period of time (usually 100 years), compared to carbon dioxide. Key factors affecting the GWP of any given gas include its average atmospheric lifetime and the ability of that molecule to trap heat. By mass, the same amount of methane emissions is 25 times more potent than carbon dioxide emissions over a 100-year time horizon (IPCC 2007). Methane chemically reacts in the atmosphere to produce other climate warming gases, for example, ozone in the troposphere and water in the stratosphere. An estimate of the warming effects of these product gases is included in the GWP of 25 cited above. However, these reactions also indirectly affect aerosols in the atmosphere, likely further enhancing the warming effect of methane. Shindell et al. (2009) found that aerosol-related indirect effects result in a GWP value of 33 over a 100-year time horizon. In the 20-year time frame, IPCC (2007) estimates that methane's GWP is 72 times greater than that of carbon dioxide, while Shindell et al. (2009) put this number at 105.

The life cycle assessment (LCA) studies discussed in Section 2 of this paper have helped to fuel a public debate over the climatic implications of methane emissions from natural gas systems. All of these studies have looked at the 100-year time horizon for GWP. However, to better inform policy discussions, some of these studies also consider a 20-year time horizon (for example, Howarth et al. 2011; NETL 2012; and Burnham et al. 2011). In the context of IPCC science assessment reports, the 500-year time horizon—also occasionally considered—highlights the necessity of reducing CO_2 for achieving long-term climate stabilization. From a policy perspective, the downside to using a 500-year time horizon for GWP is that it heavily discounts the importance of short-lived pollutants like methane, thus diminishing the apparent importance of mitigation efforts that could effectively slow the rate of global warming in the near term.

Another approach to understanding the climatic implications of technology and fuel choices was recently discussed by Alvarez et al. (2012). This study used the concept of technology warming potential (TWP) to better enable straightforward comparisons of fuel-technology options. Rather than focusing on the 20-year, 100-year, or 500-year time horizon for GWP, their results were presented over a 200-year continuum to help illustrate the time-dependent relative climatic implications of emissions scenarios resulting from various policy outcomes. They found that methane leakage rates are very important for determining to what extent fuel switching by any given technology—for example, from diesel to natural gas for heavy duty trucks—would yield a net benefit to the climate. They also show how many years it would take for any such benefit to be realized. This is a helpful frame of reference, showing that the appropriate time horizon for considering the climatic implications of different technologies and fuel types is as much a policy question as anything else, one that is informed by scientific study but not determined by it.

Given mounting evidence that climate change is occurring faster than expected (Rahmstorf et al. 2012), policymakers should recognize that upstream methane emissions reductions are an urgent priority to help slow the rate of warming (NRC 2011)—regardless of how natural gas is ultimately used (for example, as a feedstock or fuel). Nevertheless, it is clearly important to conduct full life cycle assessments and to examine GWPs and TWPs over multiple time horizons, particularly when considering the climate implications of fuel switching. For convenience, consistency with previous studies, and because of this study's limited scope, this paper defaults to the conventional 100-year time horizon for GWP. We also found that our consideration of policy options was largely unaffected when using either the 20-year or 100-year time frame for GWP, in large part because methane is a significant portion of upstream GHG emissions from U.S. natural gas systems—more than half by most estimates (EPA 2012a; NETL 2012; Burnham et al. 2011; Fulton et al. 2011)—with the remainder consisting primarily of CO_2.

Section 3 describes the specific processes most responsible for upstream GHG emissions, within the preproduction, production, processing, and transmission life cycle stages. This highlights the relative contributions of methane vs CO_2 emissions within each of these life cycle stages. Available abatement technologies are also described.

Section 4 includes original analysis that estimates the emissions reductions that will result from an EPA combined rule that was finalized in April 2012, including new source performance standards (NSPS) for volatile organic compounds (VOCs) and national emissions standards for hazardous air pollutants (NESHAP) for oil and natural gas production (EPA 2012b). This section also includes estimates of the potential for new technologies and practices to achieve additional methane emissions reductions from natural gas systems through 2035.

The final two sections provide an overview of the current landscape for relevant federal and state environmental policies that regulate upstream air emissions from U.S. natural gas systems. Voluntary measures to reduce air emissions, such as efforts to define and propagate best practices, are also highlighted. Finally, a range of policies are presented for consideration by state and federal lawmakers, air agencies, and industry.

SECTION 2: WHAT HAVE WE LEARNED FROM PREVIOUS LIFE CYCLE ASSESSMENTS?

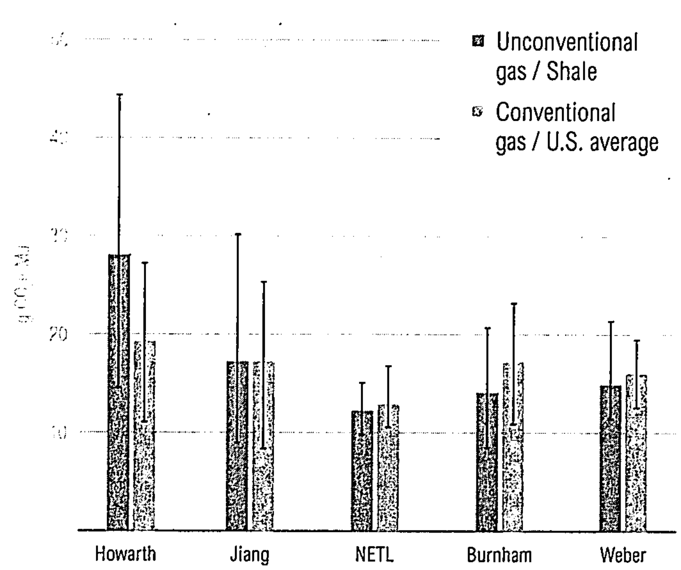
Several researchers have recently conducted life cycle assessments of GHG emissions from U.S. natural gas systems, with a particular focus on emissions from shale gas development (Box 2). As discussed below, differing results across these studies reflect differences in their underlying assumptions, scope, and primary data sources. Agreement across several of these studies often reflects the fact that most studies are based on common underlying data, including EPA's GHG inventory and other EPA data sources (Appendix 1).

Though results and conclusions have varied and consensus results have been elusive, most LCA studies to date have reached three primary conclusions.

First, upstream GHG emissions associated with shale gas and conventional gas production are roughly comparable to one another (Figure 2), within the margin of error in most cases (Logan et al. 2012; Weber and Clavin 2012). One reason for this is that most studies rely heavily on EPA's inventory. The primary exception to this is Howarth et al. (2011). This study estimated exceptionally high leakage rates from the flow-back stage of hydraulic fracturing operations and also from transmission pipelines and distribution infrastructure. (see Section 2 for more discussion). While there are significant uncertainties regarding upstream emissions from both conventional and unconventional sources of natural gas (particularly during the preproduction and production stage), ongoing efforts to directly measure upstream emissions will likely help resolve this question (see Appendix 1).

Below we discuss in greater detail the key factors that drive the uncertainties and differences between previous study estimates of life cycle GHGs from shale gas. This is an important question, given that shale gas production is expected to grow to 50 percent of total U.S. natural gas production by 2040 (with unconventional gas rising to almost 80 percent of total production).

Figure 2 | Comparing Upstream GHG Emissions from Conventional vs. Shale Gas



Sources: Howarth et al. 2011; Jiang et al. 2011; NETL 2012; Burnham et al 2011; Weber and Clavin 2012.

Notes: Howarth's estimate for shale gas represents a midpoint between their high and low range; Jiang's estimate for emissions from conventional natural gas represents a U.S. average, originally published by Venkatesh et al. (2011).

Box 2 | Key Findings from Five Previous Life Cycle Studies

Burnham et al. (2011). This study, prepared by researchers from Argonne National Laboratory, produces a GHG comparison of shale gas, conventional natural gas, coal, and petroleum through life cycle modeling. The life cycle was developed for the greenhouse gases, regulated emissions, and energy use in transportation (GREET) modeling program. The study concluded that the life cycle emissions of shale gas are 6 percent lower than conventional natural gas, but within the range of statistical uncertainty. Taking into account end-use energy conversion efficiencies, the study also concluded that: (a) life cycle GHG emissions from natural gas-fired electric power generation is roughly 30 to 50 percent lower than from coal (depending on power plant efficiency); and (b) life cycle emissions from compressed natural gas (CNG) vehicles are comparable to gasoline cars and diesel buses at the 100-year time horizon, but CNG is roughly 20 to 30 percent more GHG-intensive than conventional cars and buses over a 20-year time horizon.

Howarth et al. (2011). This study is a life cycle assessment by Cornell University researchers that compares methane emissions from shale gas to those from coal and petroleum, focusing considerably on fugitive emissions. The study concluded that the total life cycle emissions from shale gas are at least 20 percent higher than emissions from conventional gas and up to 100 percent higher than coal when considering a 20-year time frame, using the Shindell et al. (2009) GWP (global warming potential; see Box 1). The study also concluded that shale gas emissions are 60 percent higher than emissions from diesel or gasoline.

Jiang et al. (2011). This study, by authors from Carnegie Mellon University, conducts a GHG life cycle assessment of natural gas recovered from Marcellus shale, comparing results to average emissions associated with U.S. domestic natural gas, and also to life cycle emissions associated with electricity production from coal. The study concluded that shale gas results in a slight increase in life cycle emissions from U.S. natural gas and that electricity production from Marcellus shale gas results in 20 to 50 percent lower life cycle GHG emissions than from conventional coal.

NETL (2012). This assessment from the National Energy Technology Laboratory compares life cycle GHG emissions from different processes to recover natural gas and extract coal. The study, which singles out shale gas to account for the unique activities included in its life cycle, concluded that natural gas has 39 percent lower GHG emissions than coal when considering a 20-year global warming potential (GWP). Conventional natural gas sources have life cycle GHG emissions 42 to 53 percent lower than those of coal, when used for baseload electricity generation.

Weber and Clavin (2012). This review study by authors at the IDA Science and Technology Policy Institute, is based on a Monte Carlo uncertainty analysis of six recent studies to compare the life cycle carbon footprint of both shale and conventional natural gas production. System boundaries and assumptions were normalized across all previous studies and "best estimates" were derived for both production types. The study concluded that the upstream carbon footprints of shale and conventional natural gas production are largely similar, well within the margin of error and uncertainty.

Since market expansion means investments in new equipment and infrastructure, it is appropriate for government to focus attention on ensuring that new development is done as cleanly and responsibly as possible.

Second, when used as a vehicle fuel, compressed natural gas (CNG) is more GHG-intensive than conventional cars and buses over a 20-year time horizon (See Box 2, Burnham et al. 2011). However, when this comparison is made at the 100-year time horizon, Burnham et al. find there is no statistically significant difference among these fuels.[9] Alvarez et al. (2012) conclude that a 1 percent methane leakage rate is needed for CNG vehicles to provide immediate GHG reductions compared to vehicles powered by conventional fuels, with benefits to the climate increasing over time.

Third, when used for the purpose of baseload electric power generation, natural gas is likely a less GHG-intensive fuel than coal (see Box 2; Logan et al. 2012; Fulton et al. 2011), in part because of the higher energy conversion efficiency of natural gas combined cycle power plants. This is an important benchmark for a number of reasons, including the fact that just over 30 percent of U.S. natural gas is used for power generation and more than 90 percent of all U.S. coal consumption is used for this purpose. The question has also received heightened attention as many older, inefficient coal-fired power plants retire and natural gas-fired plants provide a growing share of total electric power generation (EIA 2012).

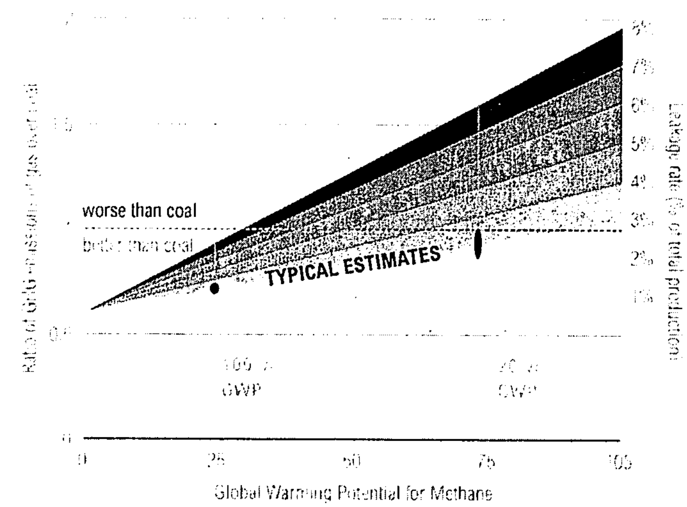
While these three conclusions are based on reasonable assumptions and are generally well-supported by available published data, others disagree (Howarth et al. 2012b; Hughes 2011), or at least withhold judgment until more complete and current data become available (Hamburg 2013). These differences are discussed in more detail below.

Simple question: "From a climate perspective, is gas better than coal?"

While this question has garnered significant attention in recent years, coal is not an ideal benchmark for measuring the relative environmental merits of alternative energy sources. By any measure, every other energy source has a lower environmental footprint than coal (NRC 2010). With that said, it is worth considering why consensus has been so elusive with regard to this apparently simple question. The answer is influenced by three key considerations: (1) GWP for methane, (2) energy conversion efficiency, and (3) methane leakage rate.

- *GWP for methane.* As discussed in Box 1, the choice of GWP is largely a policy question that is informed by science. The "correct" GWP to use for methane depends partly on the time scale over which you expect your policy—and affected energy infrastructure investments—to be relevant. As evident in Figure 3, the choice of time scale has profound implications: when integrated over a 100-year time horizon, natural gas has a lower GHG impact than coal, even with

Figure 3 | Methane Leakage Rates and Choice of Methane GWP



Sources: Adapted from IEA (2012), Figure 1.5.

Notes: Methane leakage rates and choice of methane GWP are key factors affecting whether natural gas is better than coal, from a life cycle GHG emissions standpoint without consideration of end-use efficiency. Typical estimates are shown for natural gas from conventional sources, at the 100-year and 20-year time horizons, using the GWP estimates from the IPCC (2007); see Table 1 for estimates and uncertainty ranges.

Table 1 | Life Cycle Methane Leakage Rate Estimates for Natural Gas from Onshore Conventional and Shale Gas Sources

	CONVENTIONAL ONSHORE	RANGE		SHALE / UNCONVENTIONAL	RANGE	
		LOW	HIGH		LOW	HIGH
Burnham	2.75	0.97	5.47	2.01	0.71	5.23
Howarth	3.85	1.70	6.00	5.75	3.60	7.90
Weber	2.80	1.20	4.70	2.42	0.90	5.20
Logan	–	–	–	1.30	0.80	2.80

Sources: Burnham et al. 2011; Howarth et al. 2011; Weber and Clavin 2012; Logan et al. 2012.

Notes: Weber and Clavin (2012) estimates are based on WRI calculations (derived from data presented in Table SI-5; assuming EUR of 2 Bcf). Logan et al. (2012) estimate is based on data from the Barnett basin. Leakage rate estimates are highly sensitive to choice of EUR.

leakage rates as high as 8 percent. However, at the 20-year time horizon, gas is less GHG-intensive than coal only when total leakage rates are kept below 3.2 percent of total production (Alvarez et al. 2012). To complicate matters, the most recent research of the indirect warming effects caused by methane emissions (Shindell et al. 2009) suggests that methane's GWP has been consistently underestimated by previous studies (for example, IPCC 2007).

- *Energy conversion efficiency.* Natural gas-fired power plants tend to have much higher energy conversion efficiency (U.S. average 41.8 percent) than coal-fired units (U.S. average 32.7 percent),[10] which significantly increases the advantage of natural gas vs. coal from the perspective of life cycle GHG emissions from electric power production.[11] However, recognizing that there are many end uses for natural gas, Figure 3 plots the ratio of life cycle GHG emissions of gas over coal without taking end-use efficiency into account (that is, only considering the heat content of the fuels).

- *Methane leakage rate.* Calculated as a percent of total methane production, the methane leakage rate is the most important consideration (see estimates in Table 1), one that relies primarily on accurate emissions data. As points of reference, we calculated two total annual methane leakage rate estimates for U.S. natural gas systems in 2010. These leakage rates were 2.27 percent (using 2012 EPA GHG inventory data) and 1.54 percent (using 2013 draft inventory data). The discrepancy reflects EPA's annual recalculation of emissions factors for equipment and processes related to natural gas development.[12]

All LCAs that we reviewed for this paper emphasized the need for more comprehensive and up-to-date data on methane leakage to be more confident in their conclusions (see Appendix 1). Because the leakage rate is often evaluated relative to the amount of natural gas produced over the life of the well, a key assumption when calculating the leakage rate is the estimated ultimate recovery (EUR) for that well. EUR for U.S. shale gas production remains uncertain, and EUR can vary substantially from well to well, even within the same basin. Shale gas EUR numbers used by the EIA were revised substantially downward in the 2012 Annual Energy Outlook, compared to the 2011 AEO.[13] Recent estimates by the U.S. Geological Survey (USGS 2012) suggest that the 2012 AEO's EUR numbers were still too high for several of the most significant shale basins, including the Marcellus (see Appendix 2 for more details).

Box 3 | Evaluating Environmental Risk through Life Cycle Assessment (LCA)

Life cycle assessment (LCA) is a valuable tool for evaluating the environmental impacts throughout a product's life cycle, from raw material acquisition through production, use, and end-of-life waste management.

LCA, officially standardized by the International Organization for Standards (ISO) in 2006, is used to systematically calculate and summarize environmental risks, as well as opportunities to reduce those risks throughout the product's life cycle (ISO 2006). This holistic approach to environmental assessment of a good or service is a unique feature of LCA, and avoids the problem-shifting or leakage of environmental impacts to other life cycle stages, regions, sectors, or products (Finnvedena et al. 2009). Natural gas is an excellent example of the importance of the life cycle approach. Looking only at the combustion stage of natural gas, there is no difference between gases extracted in a conventional manner (including offshore), gas from shale rock formations, or imported liquefied natural gas. The differences between GHG intensities of natural gas sources only come to light using LCA to evaluate impacts along the full life cycle from material acquisition through distribution.

Assessments following ISO 14044 (ISO 2006) or the GHG Protocol Product Lifecycle Standard (WRI and WBCSD, 2011), the international standard for GHG life cycle assessments, both start with setting the goal and scope of a study. The goal identifies the reasons for carrying out the study and the study audience, while the scope identifies, among other things, the life cycle boundary (ISO 2006). For example, a particular study may have a goal of identifying all GHG risks along the shale gas life cycle; therefore the scope would include all processes that occur along that life cycle from cradle (material acquisition) to grave (end-of-life). While LCA by definition considers all potential environmental impacts, this study focuses only on GHG emissions and their related climate change impacts (Box 4).

For LCA studies to be comparable to one another, their scopes—including life cycle boundaries—must be equivalent (ISO 2006). Even if two studies are done on the same product, these studies may not be comparable if the scope and boundary are different. This is especially true for emissions from natural gas systems, where many of the recently published studies have differed in terms of their scopes and boundaries (Branosky et al. 2012).

Why do life cycle GHG emissions estimates for shale gas differ so much?

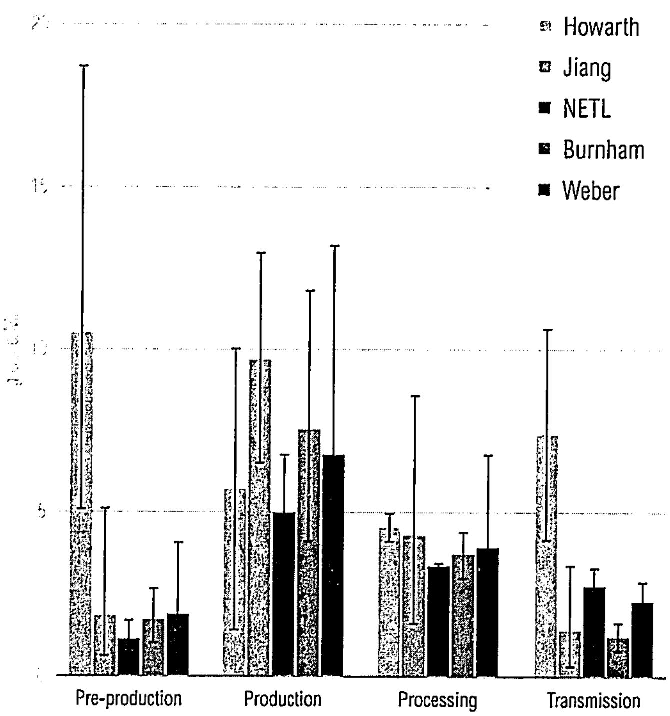
For the remainder of this section we discuss in some detail why previous life cycle assessments of GHG emissions from shale gas have reached different conclusions. We do this by comparing the quantitative results of five studies across four common life cycle stages.[15] The focus on shale gas is motivated by the rising significance of this resource base (EIA 2012) and to help inform ongoing public policy discussions regarding its environmental implications.[16]

Specifically, we focus on the five studies summarized in Box 2, including four bottom-up LCA studies (NETL 2012, Jiang et al. 2011, Howarth et al. 2011, and Burnham et al. 2011) and one LCA review study by Weber and Clavin (2012). The work by Weber derives "best estimates" for each life cycle stage based on the four other studies reviewed here, plus one by Stephenson et al. (2011) and one by Hultman et al. (2011).[17] More detailed discussions of similarities and differences between these studies can be found in Appendix 2 and Table A1. Figure 4 shows GHG emission estimates (including high and low ranges) for four life cycle stages of shale gas development, as estimated by five previous studies.[18]

The largest potential source for methane emissions during preproduction occurs during the flow-back stage of well completion. While flaring (or capture) rate has been a significant area of uncertainty and a contributing factor to varying study results (Weber and Clavin 2012), most studies reach similar conclusions regarding life cycle GHG emissions from the preproduction stage. Howarth's relatively high emissions estimates during this stage (Figure 4) are likely most affected by his choice of emissions data sources. Howarth et al.'s flow-back emissions estimate is an average of estimates from five different basins, yielding a significantly higher estimate than other studies. In particular, Howarth's average is boosted by an estimate for methane leakage at Haynesville, which is an order of magnitude larger than for the other four basins.[19] While O'Sullivan and Paltsev (2012) confirmed that the highly productive Haynesville shale yields relatively higher potential[20] methane emissions during flow back, they still concluded that Howarth's estimate of methane venting from Haynesville was at least 700 percent too high.[21]

Several authors—such as Weber and Clavin 2012, Burnham et al. 2011, and Cathles et al. 2012—have attributed Howarth et al.'s high emissions estimate for Haynesville to their assumption that methane concentrations leaving the well during the flow-back stage are the same as that during the initial production stage, when liquids and debris are free from the wellbore. However, it is typical for methane concentrations to be much lower during the flow-back stage, because of non-gaseous material periodically obstructing the wellbore (O'Sullivan and Paltsev 2012; Cathles et al. 2012; EPA 2012c).

Figure 4 | Upstream GHG Emissions from Shale Gas, by Life Cycle Stage



Sources: NETL (2012), Jiang et al. (2011), Howarth et al. (2011), Burnham et al. (2011), and Weber and Clavin (2012).

Notes: All data presented in this figure are derived from the referenced studies (in some cases through personal communication with the authors), with only unit conversions and minor adjustments for heating rates. However, not all studies calculate emissions for each of the four life cycle stages shown here, so, the authors of this study occasionally allocated a single emissions estimate over more than one life cycle stage. Since Howarth et al. generally do not calculate a central, or base case, life cycle emissions estimate, the top of each gold bar on the chart represents a mid-point between their high and low range estimates (the exception to this is in the preproduction stage, for which Howarth et al. present an average value for the methane emissions from well completions in five separate basins). Howarth et al. is the only study that does not use the IPCC (2007) GWP numbers for converting methane emissions to CO_2e. They instead rely on Shindell et al. (2009). This partially explains why Howarth has larger upstream emission estimates than the rest of the studies shown here. Uncertainty ranges for each study have different meanings; for some studies, the range represents a range of scenarios explored by authors (e.g., Jiang et al.), while others only represent emissions data uncertainties (e.g., NETL).

In the production stage, GHG emissions come primarily from venting and flaring of emissions during workovers and liquids unloading, plus methane leakage and routine venting from equipment. Figure 4 shows that the greatest disagreement among the study results occurs for this life cycle stage. Variations between studies are mostly driven by discrepancies in assumptions regarding the frequency of liquids unloading and well refracturing during workovers over the lifetime of the average well. For example, Jiang et al. (2011) and Howarth et al. (2011)[22] both include liquids unloading as one of the integral steps to shale gas development, while others do not. Additionally, differences stem from disagreements regarding the extent to which pollution controls—such as green completions and other technologies to avoid venting of gas—are used in practice during these episodic events.

During the processing stage, the studies show relatively very good agreement between life cycle GHG emissions estimates, with base-case estimates ranging from 3.4 to 4.5 g CO_2e/MJ. CO_2 emissions associated with energy consumption by compressors are the biggest GHG emissions category in this stage, with base-case estimates ranging from 2.06-3.3 g CO_2e/MJ. These calculations are generally based on engineering requirements for different natural gas compression technologies, and are less affected by uncertainty regarding methane leakage rates during this life cycle stage.

Most studies also generally agree on the magnitude of life cycle GHG emissions from the transmission stage. The estimates of Jiang and Burnham are both based on the EPA GHG inventory (EPA 2011a), while NETL estimates methane loss as a function of pipeline distance, yielding slightly higher fugitive methane estimates. For this life cycle stage, Howarth et al. bound their estimates[23] using a variety of data sources, including Russian pipeline data in which "lost and unaccounted for gas" is treated as 100 percent vented. Howarth et al. (2012) acknowledge potential shortcomings to their approach and recognize that the high end of their estimates are well above those of other studies; however, they question the EPA inventory data on which other researchers have relied, arguing that it is more than a decade out-of-date (see Appendix 1; EPA/GRI 1996) and overly reliant on voluntary industry reporting. Clearly, further data collection efforts are needed to resolve lingering questions about the scale of methane emissions from U.S. natural gas transmission systems.

SECTION 3. PRIMARY UPSTREAM GHG EMISSIONS SOURCES FROM NATURAL GAS SYSTEMS

This section builds a baseline understanding of life cycle greenhouse gas emissions from conventional and unconventional onshore natural gas production, highlighting key processes that are responsible for the bulk of upstream methane emissions and technologies for reducing emissions at each stage.

WRI has taken the first step in comparing the boundaries of several different shale gas studies in a 2012 working paper entitled "Defining the Shale Gas Life Cycle: A Framework for Identifying and Mitigating Environmental Impacts" (Branosky et al. 2012). This section builds on that framework, taking a life cycle approach that concentrates on four upstream life cycle stages—preproduction, production, processing, and transmission[24]—to more clearly illustrate how and why five previous assessments of methane emissions from shale gas systems have differed in their conclusions (see Box 2). This approach also presents emissions data in a way that informs subsequent sections of this paper, which assess the scale of the potential for methane emissions reductions and policy options for more effectively measuring and curbing those emissions.

Conventional and unconventional onshore production processes and related upstream emissions

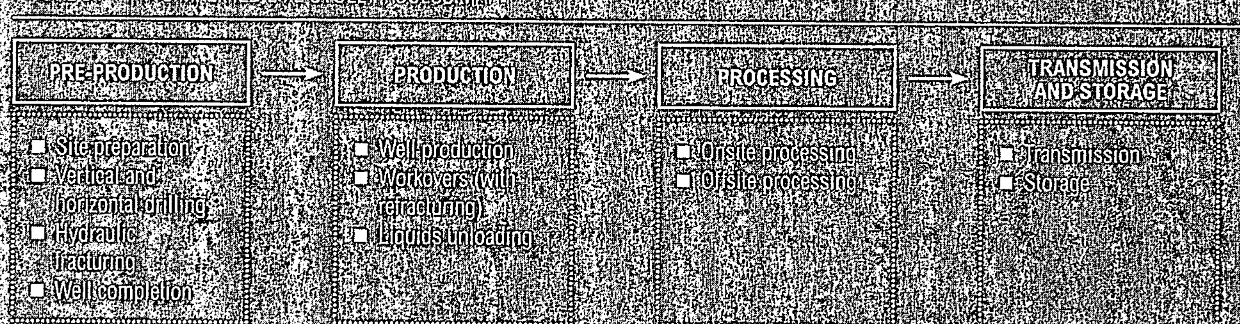
Unconventional natural gas production represents over half—and a growing share—of all U.S. natural gas production (EIA 2013) and related upstream GHG emissions (NETL 2012). Figure 5 shows common classifications for natural gas production sources. It also illustrates how conventional versus unconventional sources are distinguished for the purposes of this working paper (consistent with EIA 2012 and IEA 2012). Unconventional sources—shale gas, coal-bed methane, and tight gas—rely on horizontal drilling and hydraulic fracturing for economic gas production. In contrast, onshore conventional wells are either vertical or slanted, and although many also use hydraulic fracturing to stimulate natural gas production, preproduction processes at conventional wells involves much lower water volumes[26] and fewer associated emissions.

Box 4 |

Methodological approaches to LCA depend largely on the goal(s) and scope of each assessment. While the availability of quality data may limit the scope of any particular study, the methods underlying each LCA generally take the following key factors into consideration (see Appendix 2 for additional discussion):

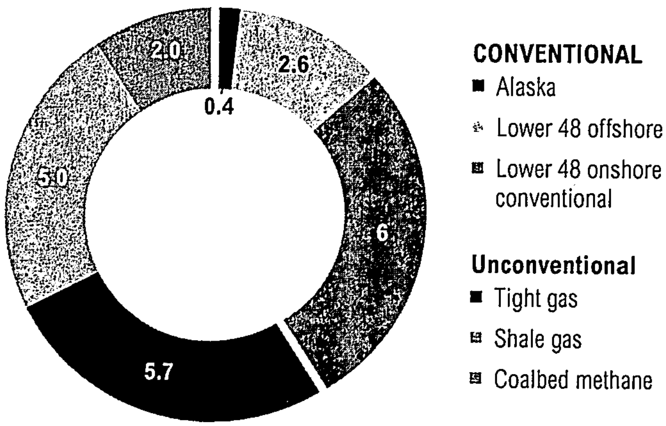
- *Boundary setting.* System boundary setting determines which processes, or life cycle stages, are included in the life cycle assessment. These are the three boundaries typically considered in a natural gas LCA:
  - A "cradle-to-gate" boundary includes all emissions prior to the "use" life cycle stage upstream of the "city-gate" or power plant gate. Figure B4-1 below illustrates the primary attributable processes of the cradle-to-gate shale gas life cycle. Attributable processes are defined as service, material, and energy flows that become the product, make the product, and carry the product through its life cycle (WRI and WBCSD 2011). For this paper, we normalize cradle-to-gate emissions to grams of CO_2 equivalent per Megajoule of natural gas (g CO_2e/MJ) for all upstream estimates.
  - A "well-to-wire" boundary includes all emissions upstream of the electric transmission system but does not account for downstream electric transmission and distribution line losses or efficiencies associated with the use of electricity. A well-to-wire assessment presents results in terms of emissions per unit of electricity generated. For example, well-to-wire emissions are typically normalized to grams CO_2e per kilowatt-hour of electricity (g CO_2e/kWh). This is useful for considering the climate implications of fuel switching in the power sector, because coal-fired and gas-fired power plants typically have significantly different combustion efficiencies.
  - A third boundary—used by Jiang et al. (2011), Burnham et al. (2011) and this study—measures all upstream emissions plus the emissions from the combustion of natural gas without specifying end-use and efficiency (i.e., based on heat input or delivered energy), also reported in g CO_2e/MJ. This measurement is equivalent to having natural gas for heat generation as end-use (for example, Howarth et al. 2011).
- *Calculation methods and data sources.* As discussed in Appendix 1, lingering questions remain regarding the quality of available data for estimating GHG emissions from various stages of U.S. natural gas systems. Depending on data sources and study goals, top-down (e.g., average global data) or bottom-up (e.g., process specific data) methods may be used to calculate emissions estimates for each life cycle stage. Adding further complexity, shale gas technologies, production practices, and emission controls are rapidly evolving; therefore, different data sources may reflect different and potentially antiquated operational methods.
- *Geographic scope.* Studies also differ in geographic scope, which means that differing results may reflect parameters that are unique to each geologic context (e.g., estimated ultimate recovery (EUR), well lifetime, methane content). For example, Jiang et al. (2011) and NETL (2012) each focus on individual shale basins, as opposed to U.S. nationwide averages (see Table A1 for more details).

FIGURE B4-1 | A SIMPLIFIED LIFE CYCLE PROCESS MAP



Notes: The four life cycle stages are listed across the top of this figure, while attributable processes are listed below each associated life cycle stage. Since this working paper includes a review of previous life cycle assessments of GHG emissions, our boundary setting is inherently limited to include attributable processes considered by previous studies.

Figure 5 | U.S. Natural Gas Production From Conventional and Unconventional Sources, 2010



Source: EIA 2012.

Note: Figure shows dry gas production in trillion cubic feet (Tcf).

Do we know where the methane leaks are?

Despite the uncertainties (Appendix 1), available public data suggest that there are significant intentional and unintentional leaks throughout the natural gas value chain. As discussed below, we also have good information regarding a suite of proven technologies for cost-effectively reducing those leaks (e.g., EPA Gas STAR; Harvey et al. 2012). As a point of reference for the following discussion, Figure 6 illustrates with some detail the relative contributions of CO_2 versus methane emissions within each of the four upstream life cycle stages, for both shale gas and onshore conventional wells.[27]

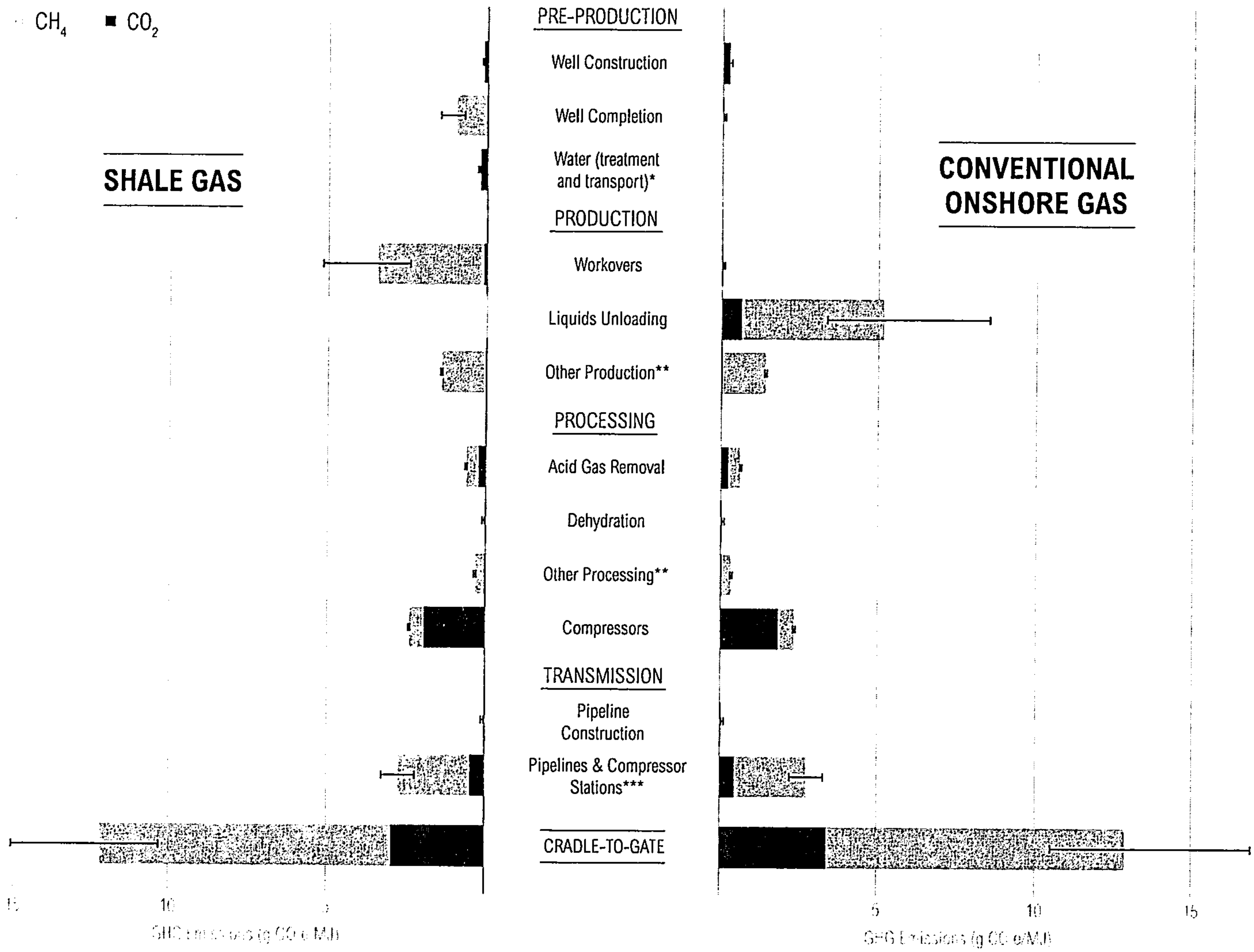
- *Pre-production Stage.* In the pre-production stage—including exploration, site preparation, drilling, and well completion, which includes hydraulic fracturing—GHG emissions come predominantly from venting (methane) and flaring (CO_2) during well completion.[28] CO_2 emissions during this stage come largely from diesel fuel combustion associated with well construction, and also from material acquisition. Well completion occurs after well construction and it may include hydraulic fracturing, after which fluids (also known as flowback fluids) and debris flow back through the wellbore to the surface. During the three- to ten-day flowback period,[29] unconventional wells have the potential to produce a large amount of fugitive methane emissions. Relatively fewer methane emissions are believed to be associated with the final stages of well completion at conventional wells (Figure 6). O'Sullivan and Paltsev (2012) conducted an extensive review of pre-production stage emissions,[30] finding that net emissions during this stage depend significantly on whether the gas is managed through (a) cold venting directly to the atmosphere, (b) flaring, or (c) reduced emission completions ("RECs" or "green completions"), which captures methane for sale.

As noted above, the extent to which green completions have been used in practice is a matter of dispute. New EPA rules will require RECs or flaring at all new wells starting in 2013, and RECs at all new wells starting in 2015 (Box 5).

- *Production Stage.* During the production stage, natural gas flows from the well into gathering lines (and associated natural gas liquids, flow back, and water are diverted to storage tanks). Liquids unloading and well workovers are occasionally performed at the well site to maintain production rates. Liquids unloading is a practice used to increase the flow of natural gas by removing water and other liquids that clog the wellbore. This practice has the potential to result in significant emissions, although operators may employ control technologies such as plungers[31] or artificial lifts to minimize the release of natural gas to the atmosphere. Though Figure 6 is based on an analysis that holds to a common assumption—consistent with GHG inventories published by EPA (EPA 2011a; 2012a)—that liquids unloading is only necessary for onshore conventional wells, a recent oil and gas industry survey suggests that this is actually a common practice for conventional and unconventional wells alike (Shires and Lev-On 2012).

Similarly, well workovers with hydraulic fracturing are occasionally necessary to restimulate production at unconventional wells and the flowback process is similar to that associated with preproduction stage well completions. While both conventional and unconventional wells may require workovers, the high volumes of water associated with refracturing unconventional wells leads to a more prolonged flowback period and greater potential emissions (Figure 6).

Figure 6 | Comparing Detailed Estimates of Life Cycle GHG Emissions from Shale Gas and Conventional Onshore Natural Gas Sources



* Data available from Marcellus only

** "Other Production" and "Other Processing" each include point source and fugitive emissions (mostly from valves)

*** Includes all combustion and fugitive emissions throughout the entire transmission system (mostly from compressor stations)

Notes: Recent evidence suggests that liquids unloading is a common practice for both shale gas and onshore conventional gas wells (Shires and Lev-On 2012). Therefore, contrary to data originally published by NETL, showing zero emissions, liquids unloading during shale gas development may result in GHG emissions that are comparable to those associated with conventional onshore natural gas development. GWP for methane is 25 over a 100-year time frame.

Source: NETL 2012, adapted from Figures 4-5, 4-6 and 4-7.

Regarding abatement opportunities, the level of venting that occurs during liquids unloading could be substantially reduced through the greater use of plunger lifts and other equipment (Harvey et al. 2012), though this is not required by the recently finalized NSPS rule. With some exceptions, the new NSPS does require that green completion technologies be used during well refracturing, which will substantially reduce future methane emissions during these episodic events. Further emissions reductions could be achieved through the replacement of high-bleed pneumatic devices with low-bleed equivalents (see Section 4), or through the utilization of vapor recovery units.[32]

Processing and Transmission Stages. After the production stage, life cycle emissions for natural gas from conventional versus unconventional sources are not inherently different.[33] The natural gas is processed (on-site and off-site) and transmitted through pipelines and stored in the same manner no matter where the gas originated. Though there are significant regional differences, before it is processed the average composition of natural gas includes 83 percent methane;[34] after processing, methane makes up 93 percent[35] of the average natural gas composition.

During the processing stage, GHG emissions come from energy consumption for acid gas removal, dehydration, compression, as well as methane and CO_2 from the plant. CO_2 emissions associated with energy consumption by compressors are the biggest GHG emissions source in this stage (Figure 6). In the transmission stage, most leaked and vented methane emissions occur at pipeline compressor stations. CO_2 emissions result from fuel combustion by compressors, and indirect GHG emissions are associated with pipeline materials manufacturing and construction and the consumption of electricity by pumps and other equipment.

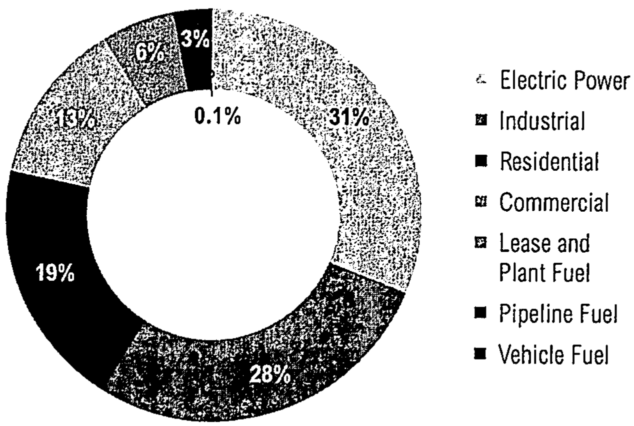
Regarding abatement opportunities, the NSPS requires leak detection and repair (LDAR) at compressors located between the wellhead and the point in which the gas enters the transmission and storage life cycle segment. Glycol dehydrators, valves, and other processing equipment are sources of methane leaks and vents not addressed by the NSPS, but for which cost-effective abatement technologies exist.

Industry can undertake numerous measures to reduce emissions from the transmission and storage of natural gas. From compressor stations to storage tanks to pipelines themselves, the transmission life cycle stage is home to many significant and unabated sources of fugitive methane. Section 4 goes into more detail on pneumatic controllers and LDAR regimens—which address two of the greatest sources of GHG emissions in the transmission stage—but there are many smaller sources of GHG emissions that can be reduced cost-effectively.

End-Use Combustion. The combustion of natural gas for electricity production directly emits large quantities of CO_2 emissions, producing the greatest GHG emissions among the five stages described here. From a total life cycle emission of 71.1 g CO_2e/MJ (per Weber), combustion itself produces GHG emissions at the rate of 56g CO_2e /MJ, which is almost 80 percent of the total GHG emissions over a 100-year time frame. In general, GHG emissions during combustion are relatively certain. The biggest differences between electricity-sector LCAs often relate to the type of end use combustion technology. For example, some studies assume combustion efficiencies based on the U.S. fleet average or for a particular type of power plant (e.g., Jiang et al. 2011) while others present results based on a range of end-use efficiencies (e.g., NETL 2012, Burnham et al. 2011). Another factor is that different studies assume different heating values for the fuel (see Appendix 2).

During the final life cycle stage, natural gas is consumed for a variety of end uses, including electricity generation, heating for buildings and industrial processes, vehicle fuel, and chemical feedstock (Figure 7). While this paper focuses on upstream GHG emissions, a fuel's end use (or mix of end uses) has important implications for its life cycle emissions. When assessing the net GHG impacts of natural gas use, key considerations include the energy conversion efficiency of the end-use technology and the carbon content of alternative fuels. For example, in the electric power sector, where just over 30 percent of U.S. natural gas is consumed, gas-fired plants are significantly more efficient than the average coal-fired plant. On the other hand, in the transport sector—which is presently less than 1 percent of total consumption—passenger cars fueled by compressed natural gas (CNG) are up to 10 percent less efficient than gasoline cars, and CNG buses are up to 20 percent less efficient than diesel-fueled buses.[36]

Figure 7 | [illegible]



Source: EIA 2012.

SECTION 4: GHG IMPLICATIONS OF RECENT EPA RULES AND FURTHER ABATEMENT POTENTIAL

As domestic natural gas production continues to ramp up, methane has the potential to play an increasing role in short-term climate forcing, and therefore presents important near-term opportunities for GHG emissions reduction. Near-term reductions in methane emissions would help slow the rise of global temperatures over the next several decades (Box 1), even as market conditions and existing regulations accelerate the shift from coal to natural gas for electricity generation. In the long-term, it is critical for climate policies to achieve significant reductions in economy-wide carbon dioxide emissions, which represents over 80 percent of the total life cycle GHG footprint of natural gas (when integrated over a 100-year time frame). The analysis below offers strategies for achieving substantial near-term reductions in upstream methane emissions, which would have the greatest impact in the short term.

Data and methods

In this section, we expand our discussion beyond the life cycle emissions of a single well (Section 3) to quantify economy-wide emissions from shale gas and natural gas systems to illustrate the magnitude of the GHG emissions from this sector. We then estimate the impact of the recent EPA rules on those emissions, and examine the abatement potential of hypothetical future rules addressing the largest remaining emissions sources after full implementation of the NSPS (see Box 5 for a detailed description of these EPA rules). All of our modeling focuses only on additional methane emissions reductions, although cost-effective reductions in upstream CO_2 emissions are likely also achievable. Due to the recent growth in natural gas production and the attendant uncertainty in projecting gas production over the coming decades,[37] we modeled three different scenarios—a reference case, a high-shale estimated ultimate recovery (EUR) case, and a low-shale EUR case. The reference case is built on the shale and natural gas production estimates from the EIA's Annual Energy Outlook (2012) reference case; more information on the high- and low-shale cases can be found in Box 6.

We built our model from the bottom up, using data from GHG life cycle analyses to project emissions at the national level. Primary GHG data sources were Weber and Clavin (2012), which synthesizes the findings of multiple life cycle studies of emissions from natural gas systems, and EPA's 2010 Inventory of Greenhouse Gas Emissions and Sinks (GHG Inventory) published on April 15, 2012.[38] We have developed our own methodologies for projecting total emissions for all natural gas and shale gas systems, emissions reductions expected from EPA's recent NSPS rule (Box 5), and the remaining potential for emissions abatement (see Appendix 3 for a more detailed description of our methods, assumptions, and data sources).

While other data sources are available, including a report[39] from the American Petroleum Institute and America's Natural Gas Alliance (two industry associations), we use EPA inventory data—and analysis from Weber and Clavin (2012), which also relies on EPA Inventory data—because of its continual refinement over several decades of peer review. We believe they represent the most definitive source for GHG emissions from U.S. natural gas systems. In Box 7 , we have included modeling results using emissions factors from the API/ANGA study, some of which EPA adopted for its draft 2013 GHG inventory, to illustrate the continuing uncertainty surrounding methane emissions from natural gas systems. EPA is continuously reviewing its assumptions

Box 5 | Recent EPA Rules Affecting Natural Gas Systems

In April 2012, in its first move to establish federal standards for emissions at natural gas production wells, EPA released the final versions (EPA 2012b) of two rules that impact various equipment or processes throughout the natural gas lifecycle— New Source Performance Standards (NSPS) for volatile organic compounds (VOCs) and a National Emissions Standard for Hazardous Air Pollutants (NESHAP) for oil and natural gas production. These rules are designed to limit the release of VOCs and other air toxics that contribute to smog and are associated with a wide range of adverse health effects, and do not directly address GHG emissions. However, by requiring the mitigation or capture of some of the gas that is leaked, vented or flared, the rules will have the cobenefit of reducing GHG emissions, primarily methane, at the pre-production, production, and processing lifecycle stages.

The most significant requirement contained in the new rules from the perspective of GHG mitigation concerns the process of well completion at newly fractured and refractured wells. The NSPS requires a 95 percent reduction in VOCs from well completions, which can be achieved through the use of green completions to capture gas that would otherwise be vented or flared at the wellhead. While the water-to-gas ratio is relatively high during the initial flowback stage (and therefore less economical to capture for sale), the EPA and O'Sullivan and Paltsev (2012) have concluded that the use of green completion technologies is likely profitable in most cases.

While the NSPS for well completions and workovers will have the greatest impact on GHG and VOC emissions, the other standards recently finalized by EPA will result in further reductions of GHGs and VOCs. New high-bleed pneumatic controllers, employed during the processing stage of the natural gas life cycle to maintain gas pressure, may not exceed a new leakage rate threshold of six cubic feet of gas per hour, initially resulting in small reductions in methane emissions according to emissions data from the EPA GHG inventory. Similar reductions will come from compressors used in gas production and processing which will need to reduce VOC emissions by 95 percent. The new rule should reduce methane emissions from compressors by a similar amount, and can be achieved by converting wet seal compressors to dry seals and properly maintaining reciprocating compressors. The new performance standard for storage tanks at well sites will primarily address VOC emissions, with limited GHG cobenefits, as storage tanks are not a major source of GHG emissions, according to the GHG inventory.

Projections of the GHG reductions resulting from these new requirements can be found below.

and methodologies for a wide range of emissions factors that could impact the results of this study. Significant new information and analysis will be coming out over the next year, including the publication in April of EPA's 2013 inventory, the recently released emissions data provided by industry under Subpart W of EPA's Greenhouse Gas Reporting Rule (EPA 2011c), and the results of several independent studies that will directly measure methane leakage rates from natural gas systems (See Appendix 1; Hamburg 2013). As new data on methane emissions from natural gas systems are published, WRI anticipates updating the analysis in this working paper.

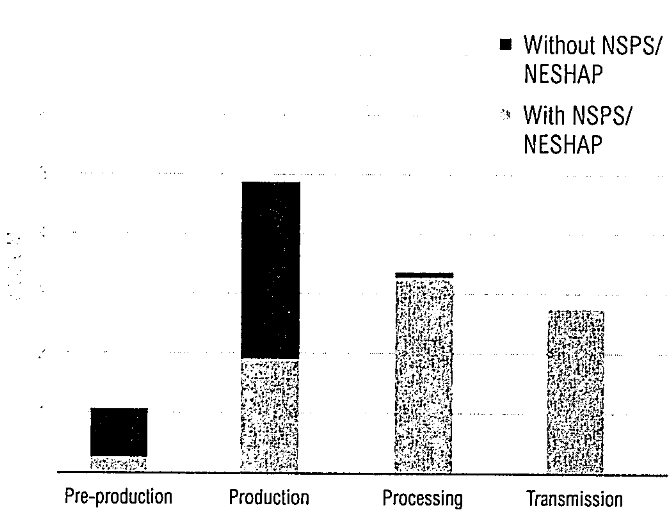
Shale gas systems

Because EPA's recent NSPS primarily impacts emissions from shale and other unconventional gas systems, we begin our discussion with shale gas before turning to all natural gas systems. Our analysis shows the significant impact of EPA's recent NSPS for oil and gas systems on reducing GHG emissions from gas processing equipment and shale gas production, and illuminates the areas where there is still much work left to do. By focusing on three of the largest sources of upstream emissions in the shale life cycle—well completions (pre-production), workovers (production), and pneumatics—EPA rules will ensure substantial reductions below the pre-NSPS emissions trajectory from 2013 through 2035 and beyond.[41] Figures 8 and 9 represent static "snapshots" of the effect of the rule on emission rates for the four upstream stages of the shale gas lifecycle—preproduction, production, processing, and storage, transmission and distribution (ST&D)—in 2015, the first year in which the NSPS is fully implemented, as well as in 2035, when the existing stock of high-bleed pneumatic controllers and compressors should be nearly completely retired or replaced with low-bleed equipment, as the rule requires a low bleed rate from new—but not existing—equipment. Using a 100-year GWP, the NSPS reduces upstream shale gas emissions from 12.11 g CO_2e/MJ to 8.24 g CO_2e/MJ in 2015 and 7.57 g CO_2e/MJ in 2035, a reduction of 32 percent and 37 percent, respectively.[42]

Over the next several decades, we project (Figure 10) that total upstream shale gas emissions would steadily increase in the absence of the NSPS rules ("pre-NSPS"), from 89 MMt CO_2e in 2012 to 159 MMt in 2035.[43]

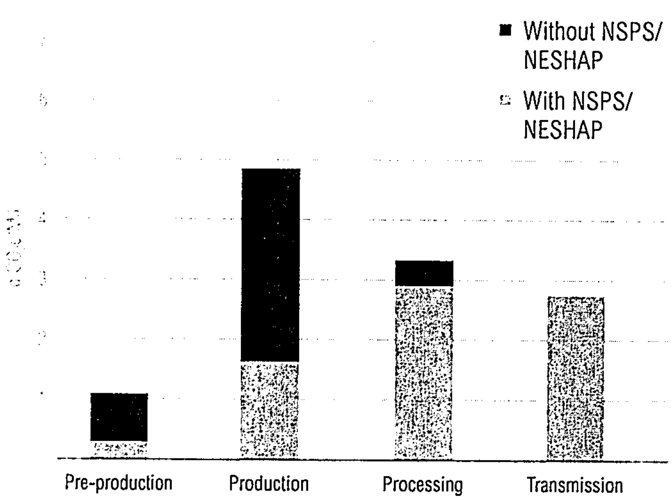
When the reductions from the NSPS rules are included ("BAU (with NSPS)"), one can see the significant effect they have on upstream emissions of GHGs (primarily methane) from shale gas. Beginning in 2013, as companies begin to capture and flare gas leaked during well comple-

Figure 8 | Snapshot of Projected GHG Emissions from Shale Wells, 2015



Source: Baseline GHG data were provided by NETL (2012).

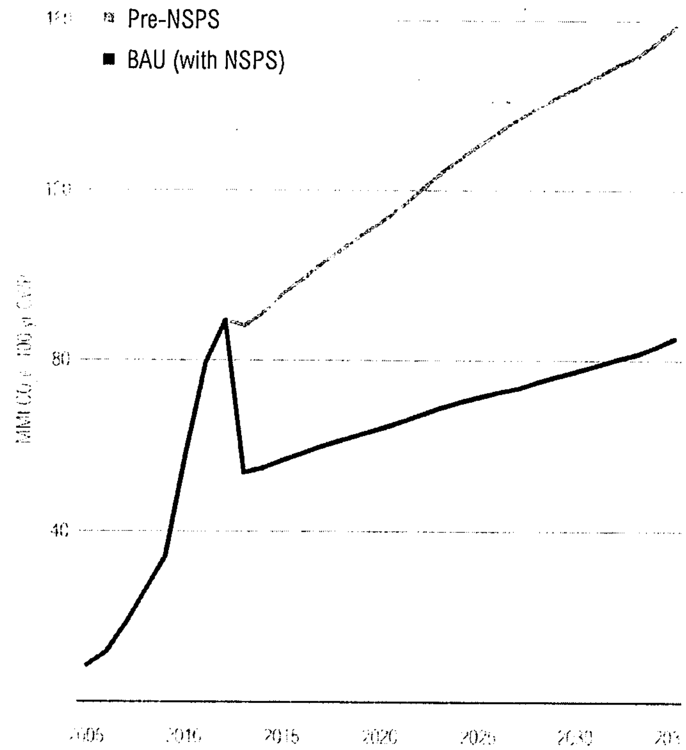
Figure 9 | Snapshot of Projected GHG Emissions from Shale Wells, 2035



Source: Baseline GHG data were provided by NETL (2012).

tions and workovers (and begin to replace high-bleed pneumatic devices and compressors with lower-bleed equipment, which has a smaller but still notable impact),

Figure 10 | Upstream Emissions from Shale Gas Systems



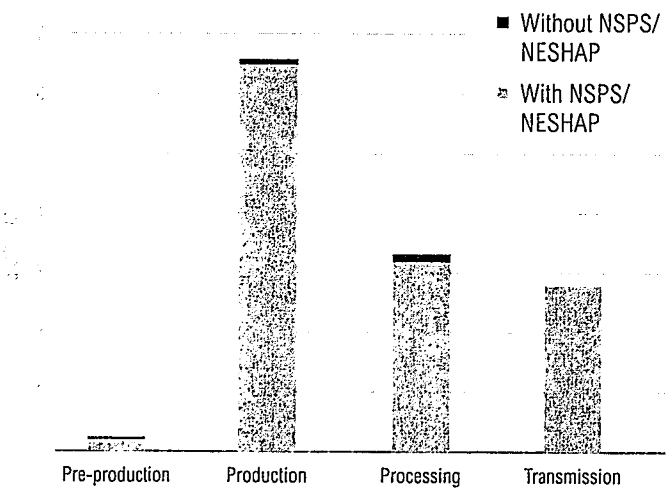
Sources: Baseline GHG data are based on Weber and Clavin (2012), EPA (2012a), and EIA (2012).

shale gas emissions fall by roughly 39 percent relative to projections without the NSPS. By 2035, emissions reductions below baseline increase to 46 percent. Even as shale gas production increases in both absolute terms and as a percentage of all natural gas production, upstream shale gas emissions under the NSPS rules will still not have returned to their current levels.

Conventional gas systems

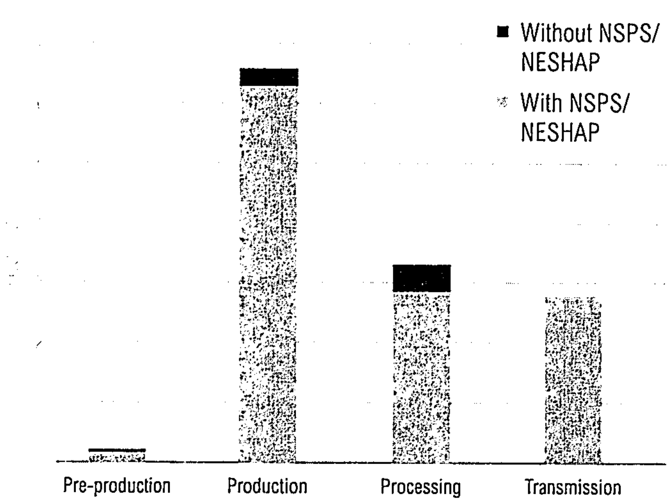
As mentioned above, the recent EPA rules, which primarily focus on well completions and workovers, disproportionately affect emissions from shale and other unconventional gas systems. However, the standards for compressors and controllers will affect conventional gas systems as well. These rules went into effect in October 2012, and will have an increasing effect over time as high-bleed equipment is replaced, as shown in Figures 11 and 12. The rules result in a 1 percent overall reduction in GHG emissions from conventional gas systems in 2015, from 12.87 g CO2e/MJ to 12.68 g CO2e/MJ, and a 7 percent reduction to 11.99 g CO2e/MJ in 2035, using a 100-year GWP.

Figure 11 | Snapshot of Projected GHG Emissions from Conventional Wells, 2015



Source: Baseline GHG data were provided by NETL (2012).

Figure 12 | Snapshot of Projected GHG Emissions from Conventional Wells, 2035



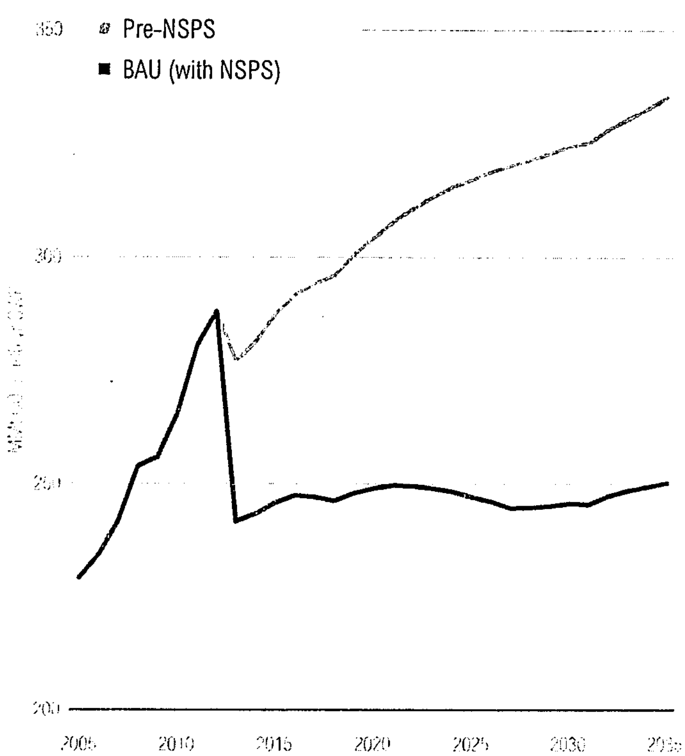
Source: Baseline GHG data were provided by NETL (2012).

All natural gas systems

Beginning in October 2012, when the recent EPA rules went into effect, we estimate that emissions will be nearly 13 percent lower than they would have been without the NSPS; similarly, by 2035, emissions will be 25 percent lower than they would have been (compare 335 MMt CO_2e to 250 MMt CO_2e). The upstream emissions in 2035 remain below current levels, even as shale gas production increases from one-third of total domestic gas production in 2013 to one half in 2035, according to the AEO 2012 reference case.

As a point of comparison, EPA projects its rules will result in a reduction of 1–1.7 million short tons of methane per year in 2015.[44] Our analysis projects methane reductions of 1.3 million short tons in 2015, a figure which increases to 2.85 million short tons by 2035 as shale gas production increases and older, higher-emissions equipment is phased out.

Figure 13 | Emissions from All Natural Gas Systems, 100-year GWP



Source: Baseline GHG data are based on Weber and Clavin (2012), EPA (2012a), and EIA (2012).

Box 6 | [illegible] Scenarios

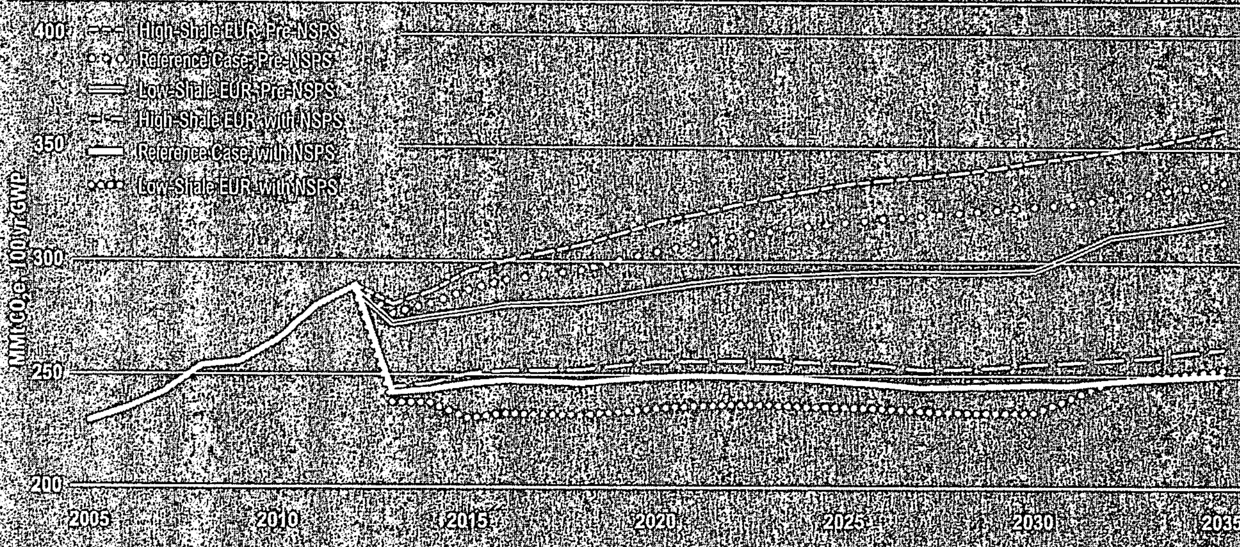
In addition to a reference case scenario, we modeled the impact of EPA rules in both a high-shale EUR and low-shale EUR scenario. These scenarios are based on the corresponding scenarios from AEO 2012. For a comparison of shale and non-shale gas production levels in these scenarios, see Table B6-1.

On a percentage basis, the effects of the recent EPA rules in the high-shale EUR and low-shale EUR scenarios are similar to the reference case scenario, with slightly higher percentage reductions in the high-shale EUR scenario and slightly lower percentage reductions in the low-shale EUR scenario. In the high-shale EUR scenario, upstream emissions reductions across all natural gas systems in 2035 due to the new rules were 27 percent below the high-shale baseline using a 100-year GWP (Figure B6-1); in the low-shale scenario, the corresponding emissions reduction was 21 percent. Absolute emissions reductions were higher in the high-shale EUR scenario, as would be expected due to the greater absolute emissions in the high-shale EUR scenario as well as the greater proportion of natural gas production from shale formations. And even though total production in 2035 is lower in the low-shale EUR scenario than in the reference case, increased production of relatively higher emissions conventional gas in the low-shale EUR scenario means that emissions will converge with the reference case, as seen in Figure B6-1.

TABLE B6-1 | PRODUCTION OF SHALE AND CONVENTIONAL GAS IN 2020 AND 2035, IN TRILLION CUBIC FEET PER YEAR

SCENARIO	SHALE GAS PRODUCTION IN 2020	OTHER UNCONVENTIONAL GAS PRODUCTION IN 2020	CONVENTIONAL GAS PRODUCTION IN 2020	TOTAL PRODUCTION IN 2020	SHALE GAS PRODUCTION IN 2035	OTHER UNCONVENTIONAL GAS PRODUCTION IN 2035	CONVENTIONAL GAS PRODUCTION IN 2035	TOTAL PRODUCTION IN 2035
Reference Case	9.69	7.85	7.55	25.09	13.63	7.90	6.39	27.92
High-Shale EUR	10.93	7.70	7.63	26.26	16.01	7.63	6.43	30.07
Low-Shale	8.03	8.06	7.52	23.61	9.74	8.10	8.27	26.11

FIGURE B6-1 | REFERENCE CASE, HIGH-SHALE EUR, AND LOW-SHALE EUR EMISSIONS SCENARIOS, 100-YEAR GWP, ALL GAS SYSTEMS



Source: Baseline GHG data are based on Weber and Clavin (2012), EPA (2012a), and EIA (2012).

Box 7 | Modeling Results Using API/ANGA Data

The API/ANGA study entitled "Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production" has considerably lower emissions factors and emissions estimates for well completions, workovers and liquids unloading. Emissions from completions and workovers are largely addressed by the NSPS, but liquids unloading is the largest source of methane emissions from conventional-gas systems in EPA's 2010 inventory (EPA 2012a). The API/ANGA study therefore implies a considerably lower quantity of methane emissions from natural gas systems overall, and it is instructive to illustrate how the results of this survey would impact our projections of natural gas systems emissions and the reductions associated with the recent EPA rules.

TABLE B7-1 | EMISSIONS PROJECTIONS ASSUMING AN ALTERNATIVE METHANE EMISSIONS BASELINE (API/ANGA)

SCENARIO	EMISSIONS IN 2015 (MMT CO_2E)	EMISSIONS IN 2035 (MMT CO_2E)
Pre-NSPS Projections, EPA Inventory Data	288	335
Pre-NSPS Projections, API/ANGA Data	236	281
BAU (includes NSPS) EPA Inventory Data	246	250
BAU (includes NSPS) API/ANGA Data	207	217

Emissions reduction potential

Even with the EPA rules in place, upstream emissions are projected to be nearly 250 MMt CO_2e per year in every year through 2035 in the reference case scenario, and even higher under the high-shale EUR scenario (using the 100-year GWP). However, there are many cost-effective opportunities to reduce upstream GHG emissions from natural gas systems. WRI calculations show that many, including the three technologies described below, turn a profit after several months or just a few years as leaking gas is captured and sold (see Appendix 2 for more details).

The uncertainty about the magnitude of emissions from natural gas systems has led some (such as Howarth et al. 2011) to claim that gas may be worse than coal on a life cycle emissions basis (including combustion). However, through the adoption of a range of policies (see Section 5) and cleaner production practices, the upstream methane leakage rate for all U.S. natural gas systems could be reduced to below 1 percent, ensuring that natural gas has a significant advantage over coal from a climate impact perspective. As natural gas production is expected to increase dramatically over the coming decades, it is critical to reduce emissions from natural gas systems as much as is economically and technologically feasible.

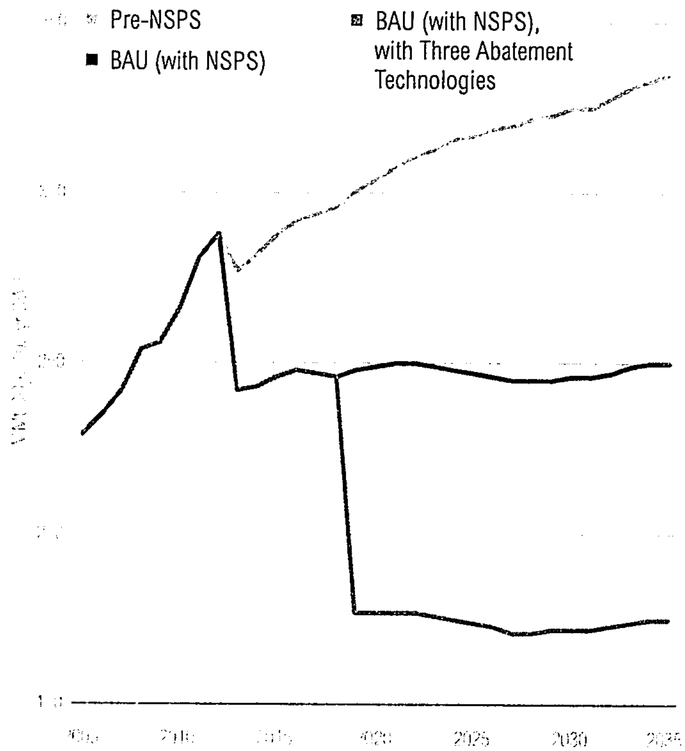
The three technologies discussed below are cost-effective even without a price on carbon, with payback periods ranging from several months to several years. This analysis is based on projected gas prices from the EIA's Annual Energy Outlook (2012) reference case, and conservative estimates for the voluntary adoption rate and amount of emissions captured by each process. An interagency working group has assessed the social cost of carbon to allow agencies to incorporate the benefits of reducing greenhouse gas emissions into the cost-benefit analyses of proposed regulatory actions.[47] The working group settled on a social cost of carbon of $19 per ton of CO_2, though we believe this figure should be higher.[48] Yet even without a price on carbon,[49] our analysis demonstrates that the technologies and practices discussed here are cost-effective and would be excellent candidates for future state or federal air emissions standards.[50]

Total abatement potential

Taken together, the three processes listed below could have a substantial impact on GHG emissions across all upstream life cycle stages of natural gas.[51] Assuming full implementation in 2019, these measures could reduce upstream emissions by 30 percent relative to the BAU (with NSPS) scenario (using the 100-year GWP for methane). In absolute terms, this is a reduction of 71 MMt CO_2e in 2019, and 75 MMt CO_2e in 2035. Such a requirement would mitigate any growth in upstream emissions over this period, as can be seen in Figure 14.

Detailed descriptions of the three abatement processes included in these composite graphs are below.

Figure 14 | Projections of GHG Emissions from All Natural Gas Systems After Additional Abatement



Source: Baseline GHG data are based on Weber and Clavin (2012), EPA (2012a), and EIA (2012).

Reducing emissions from well blowdowns with plunger lift systems[52]

Over time, liquids building up inside a well can impede the flow of gas. As noted above, when these liquids are removed, in a process known as a well blowdown (or liquids unloading), gas is often vented into the atmosphere. A plunger lift system, which is typically installed in a well while it is producing, regularly removes liquids as they build up, obviating the need for blowdowns. The otherwise vented gas can be captured, treated, and sold.

After the implementation of recent EPA rules, emissions from liquids unloading would account for nearly one-third of all upstream methane emissions from natural gas systems, a figure that remains roughly constant through 2035 in our BAU (with NSPS) scenario.[53] In fact, liquids unloading represents the greatest remaining source of upstream GHG emissions in the natural gas industry after implementation of the recent EPA rules.[54]

Based on conversations with experts, we estimate that half of all conventional wells are currently using this technology voluntarily. We estimate that a rule requiring plunger lifts at all new and existing wells would result in a total reduction of approximately 24 MMt CO_2e per year each year through 2035. This would pay for itself in around one year, as the gas that the plunger lifts and prevents from being leaked is then sold in the market (see Appendix 3 for more details).

Replacing existing high-bleed pneumatic controllers with low-bleed devices

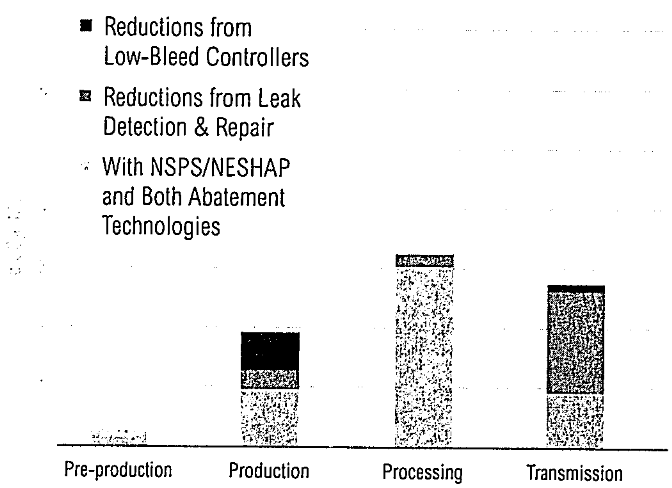
Controllers used to regulate gas flow and pressure are often powered by gas, and are designed to continuously bleed gas into the atmosphere as part of their normal operations. The EPA rule addresses methane emissions from new and modified controllers during processing. Opportunities remain, though, to capture gas and reduce emissions through the replacement of existing pneumatic controllers with low-bleed or instrument air (no-bleed) devices (Harvey et al. 2012).

Venting from pneumatic controllers in the course of normal operations represented 29 MMt CO_2e in 2010 (100 year GWP), per the EPA's 2012 GHG Inventory. Because controllers are used in both shale gas and conventional gas systems, we project this figure to increase to 37 MMt CO_2e in 2035. Low-bleed or no-bleed devices can eliminate a high percentage of emissions from controllers in the production and transmission stages,[55] but are not extensively utilized voluntarily. Assuming a 25 percent voluntary adoption rate, a rule that requires the reduction of 75 percent of emissions from pneumatic controllers beginning in 2019 would result in a reduction of GHG emissions of nearly 19 MMt CO_2e in the first year, increasing to 21 MMt CO_2e in 2035, with a payback period of approximately three years.

Leak detection and repair (LDAR)

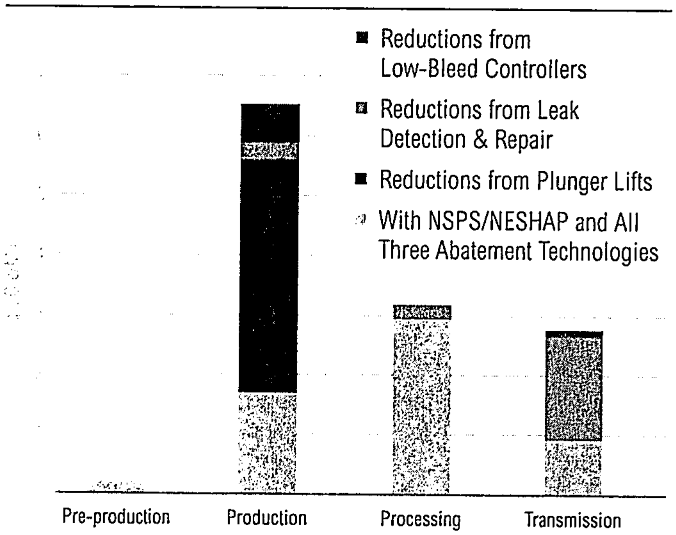
Fugitive gas leaks from field equipment at the well site at processing plants and compressor stations is a significant source of GHG emissions during the production, processing, and transmission life cycle stages. Detecting these fugitive emissions can be quick and easy, but inaccessible locations require special equipment, such as infrared cameras, due to the fact that methane is both colorless and odorless.[56] Our analysis shows that investing in this equipment and the training to use it will quickly turn a profit in most instances.

Figure 15 | Effect on Shale Gas Emissions of Replacing High-bleed Pneumatic Controllers and Utilizing LDAR



Source: Baseline GHG data were provided by NETL (2012).

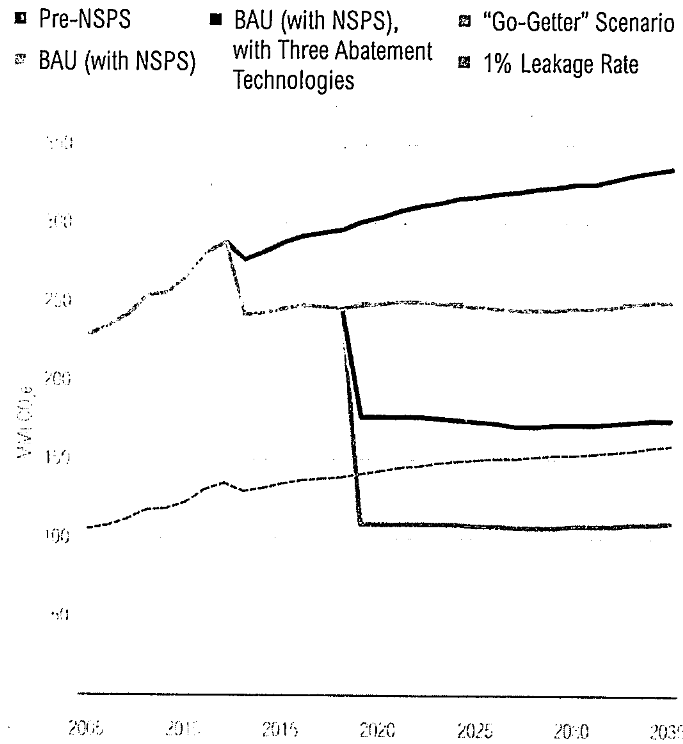
Figure 16 | Effect on Conventional Gas Emissions of All Three Abatement Technologies



Source: Baseline GHG data were provided by NETL (2012).

A 1 percent methane leakage rate is almost achievable, according to our analysis of the implications of the recent EPA rule and with additional reductions through the adoption of three additional cost-effective technologies (Figure 17).[57] However, we also know that more cost-

Figure 17 | Projections of GHG Emissions from All Natural Gas Systems after Additional Abatement



Source: Baseline GHG data are based on Weber and Clavin (2012), EPA (2012a), and EIA (2012).

Notes: Potential for additional upstream methane emissions reductions for all natural gas systems based on implementation of a hypothetical rule in 2019 requiring plunger lift systems, leak detection and repair, and replacing existing high-bleed pneumatic devices with low-bleed equivalents (purple line); or a rule requiring those technologies and five additional abatement measures (green line). The light blue dashed line shows the total amount of GHG emissions (MMt CO_2e) that would result from 1 percent fugitive methane emissions relative to total dry gas production in each year, plus estimated annual CO_2.

effective reduction opportunities are available, so more could be done to further reduce emissions throughout the natural gas life cycle. For example, Harvey et al. (2012) identified a total of ten measures—two of which are now required by the 2012 NSPS. Broad implementation of all of these technologies was the basis for the most ambitious (or "go-getter") scenario included in a report, recently published by WRI (Bianco et al. 2013).[58] Figure 17 illustrates that a more comprehensive set of federal rules, entering into force in 2019, would reduce upstream methane emissions to well below 1 percent of total production. This ambitious scenario would keep upstream natural gas systems emissions flat even as production increases over the coming decades.

Table 2 | [illegible] of Annual GHG Emissions from U.S. Natural Gas Systems Under Various Scenarios, through 2035

SCENARIO	EMISSIONS IN 2015 (MMT CO_2E)	EMISSIONS IN 2020	EMISSIONS IN 2035
Pre-NSPS Projections	288	304	335
BAU, Reference Case	246	249	250
BAU, Reference Case with Additional Abatement	246	177	175
Pre-NSPS Projections, High-Shale EUR Case	296	317	359
BAU, High-Shale EUR Case	251	256	262
BAU, High-Shale EUR Case with Additional Abatement	251	182	183
Pre-NSPS Projections, Low-Shale EUR Case	278	288	318
BAU, Low-Shale EUR Case	231	235	253
BAU, Low-Shale EUR Case with Additional Abatement	231	159	167
"Go-getter" Scenario	246	109	110
1% Leakage Rate	135	143	159

SECTION 5 POLICY APPROACHES TO REDUCING METHANE EMISSIONS

Policymakers, industry, and investors have compelling reasons to focus on reducing air emissions from natural gas systems. Natural gas sector operations and infrastructure represent a significant source of several harmful air emissions.[59] These include volatile organic compounds (VOCs), which are chemicals that contribute to ground-level ozone (i.e., smog); nitrogen oxide (NOx) which also contributes to smog formation;[60] air toxics; carbon dioxide and methane. Exposure to ozone is linked to asthma, increased hospital admissions, and premature death.[61] Air toxics, such as benzene and toluene, are suspected or known causes of cancer and many other serious health effects.[62] Though short-lived in the atmosphere, methane is a relatively potent greenhouse gas (Box 1) and it also contributes to ground-level ozone (West et al. 2006).[63]

Public debates over the rapid development of unconventional natural gas resources are ongoing, and vocal opposition to hydraulic fracturing has received widespread media attention. Furthermore, a recent expert survey (Krupnick et al. 2013) identified venting of methane as a consensus environmental risk[64] associated with shale gas development.

These concerns are leading to a growing trend toward more environmental regulation of oil and gas development. EPA recently updated federal standards for emissions from segments of the oil and gas sector. Policy has progressed at varying speeds at the state level, resulting in a policy patchwork (Logan et al. 2012). Natural gas development presents a wide range of risk factors (Krupnick et al. 2013), and no state can boast a comprehensive model of policies to address air pollution, water quality, water usage, and other community impacts (GAO 2012). Experience has shown that state policy leadership has been critical for reducing pollution from this sector; however, a strong case remains for federal rules to overcome barriers and to more effectively improve air quality.

Air emissions from natural gas systems has received heightened attention in recent years. However, most studies have focused on "unconventional" natural gas development, especially on production-stage methane emissions from shale gas production. This includes recent reports characterizing the shale gas regulatory landscape (e.g., Logan et al. 2012; Wiseman and Gradijan 2012), offering policy recommendations (e.g., SEAB 2011a; SEAB 2011b; IEA 2012), and suggesting guidance to the investment community (Liroff 2011; Williams 2012). However, since upstream air emissions extend beyond the shale gas production stage (Section 2), this section considers all onshore operations. The discussion begins with an overview of the current policy landscape, describing the relevant federal and state environmental rules that broadly apply to "upstream[65]" air emissions from U.S. natural gas systems.[66] The section concludes with a discussion of specific policy actions that state and federal policymakers, plus environmental leaders in industry, could take to help reduce methane emissions.

The federal policy landscape

EPA—Clean Air Act

National Ambient Air Quality Standards (NAAQS). Section 109 of the Clean Air Act (CAA) requires EPA to set ambient air quality standards for pollutants that originate from a variety of new and existing sources and are harmful to public health and welfare. EPA has established NAAQS for "six criteria" air pollutants, including ground-level ozone (O_3)[67] which is formed through chemical reactions between VOCs, NO_x, and sunlight. Current NAAQS for ozone were finalized in 2008 and EPA is required to periodically review the standards to ensure that they are adequately protective of public health and the environment.

A central goal of the CAA is to achieve NAAQS through a variety of well-known provisions, including NSPS (described below). NAAQS are not directly enforceable by the EPA; rather, the states are responsible for achieving NAAQS within their jurisdiction, with oversight and back-up enforcement by EPA (Ayres and Olson 2011). Section 110 of the CAA requires states to develop and submit to EPA state implementation plans (SIPs), specifying how each state will attain the federal standards through regulations, permitting, or other policies. Areas where pollution levels exceed the NAAQS for any criteria pollutants are designated "nonattainment." States with nonattainment areas are generally required to submit an updated SIP[68] and are subject to more stringent permitting requirements for a wide range of new and existing pollution sources across the state. Sources determined to be significant contributors to air quality problems are more likely to be subject to targeted regulations under updated SIPs. The NAAQS process can be used to address both new and existing emissions sources, an important distinguishing feature that enables state leadership in air quality improvement.

Elevated ground-level ozone levels in rural parts of Colorado and Utah have been attributed to natural gas development in those states (Logan et al. 2012; Fruedenthal 2009). Ozone pollution in the Dallas Fort-Worth metropolitan area also has been attributed to nearby natural gas development (Armendariz 2009). Of course, these trends toward rising ground-level ozone in areas with expanding oil and gas development have regulatory implications. In 2012, Wyoming's rural Upper Green River Basin was classified for the first time by EPA as in nonattainment with the 8-hour NAAQS for ozone.[69] Finally, the EPA recently finalized an integrated science assessment for ozone (EPA 2013b), which forms the scientific foundation for the periodic review of NAAQS standards and could provide the basis for more stringent standards in the future.

New Source Performance Standards. Section 111 of the CAA requires EPA to set new source performance standards for industrial categories that cause, or significantly contribute to, air pollution that may "endanger public health or welfare." NSPS are nationally uniform technology-based emissions standards for industrial source categories (Martineau and Stagg 2011). NSPS sets a federal floor for emissions performance by covered facilities and can apply to both new and existing emissions sources. The standard is set according to emission levels achieved by the best "adequately demonstrated" control technology, taking costs into consideration. NSPS is designed as a complement to NAAQS, with the purpose of avoiding new pollution problems (Martineau and Stagg 2011). States may choose to implement and enforce NSPS[70] based on more stringent standards than those established by the EPA, but state NSPS rules may not be less stringent.

In April of 2012, EPA finalized rules for oil and gas facilities and updated the NESHAP rules to reduce VOCs and air toxics from the oil and gas sector (see Box 5, above, for details). The rule targets VOC emissions from gas wells, storage tanks, and other equipment with the benefit of reducing ground-level ozone at oil and gas production fields, and to a lesser extent at processing plants and transmission facilities. The CAA requires EPA to update these standards within eight years, although EPA has discretion to do so earlier, if it is warranted. These rules target VOCs and air toxics, but will have the cobenefit of reducing methane emissions from new and modified wells.[71] However, many impurities are removed from natural gas during the processing stage, so pipeline grade natural gas is composed primarily of methane. For this reason, any rule that targets air toxics and VOC pollutants will be less effective at indirectly achieving methane emissions reductions during the transmission stage.

New Source Performance Standards for Methane? Since EPA's 2009 "endangerment finding" that rising atmospheric concentrations of greenhouse gases endanger public health and welfare,[72] the Clean Air Act has been used to regulate major sources of GHG emissions.[73] In 2012 the EPA used section 111(b) of the Clean Air Act as the basis for a proposed NSPS for greenhouse gas emissions from new power plants, suggesting that this is the preferred approach for stationary source regulations. CAA sections 111(b) and 111(d) give the EPA a mechanism to directly regulate methane emissions from new and existing methane emissions sources (Bianco et al. 2013).

On December 11, 2012, attorneys general from seven Northeast states—New York, Connecticut, Delaware, Maryland, Massachusetts, Rhode Island, and Vermont—announced their plans to sue EPA for its failure to use section 111(b) of the Clean Air Act to directly regulate methane emissions from the oil and gas industry.[74] In their letter to EPA Administrator Lisa Jackson, the coalition, led by New York attorney general Eric Schneiderman, concluded that "control measures are available and cost-effective, and that methane standards therefore are appropriate and legally required."[75]

Hazardous Air Pollutants (HAPs). Section 112 of the CAA requires EPA to protect public health and the environment through reduced exposure to certain toxic, or hazardous, air pollutants.[76] For major sources of toxics listed in the Act, EPA is required to set technology-based standards that achieve "the maximum degree of reduction in emissions." Standards for new sources are set based on emissions levels that are achieved "in practice by the best controlled similar source," while existing sources have slightly less stringent standards to meet (i.e., as good as or better than the best performing 12 percent of existing sources). Relatively small emissions sources—that is, those below the "major source" threshold—regulated under section 112 are called "area sources" and held to separate standards.

However, section 112 includes special exemptions for the oil and gas sector that make it more difficult to control toxic pollution from these sources. Specifically, section 112(n)(4) explicitly prevents EPA from treating oil and gas infrastructure as "area sources" or from aggregating multiple oil and gas emissions sources into a single facility that could be subject to "major source" regulation. While this still makes refineries and other major facilities subject to emissions standards under this CAA section, it excludes wells, gathering lines, storage tanks, and other individually small sources that may add up to significant emissions when aggregated with all of the other infrastructure from a large natural gas development. Given that natural gas leaking from preproduction and production stage infrastructure is not-yet refined or processed, it emits relatively high concentrations of toxics and VOCs.

However, EPA has the ability to waive this exception in "metropolitan statistical areas" such as Dallas Fort-Worth, Texas, and Denver, Colorado. In light of rapid expansion of natural gas development into urban and suburban areas and recent evidence of health effects linked to toxic air emission exposure (McKenzie et al. 2012), EPA should consider revisiting this section of the CAA. To better understand which densely populated suburban and urban areas of the country are most exposed to HAPs from oil and gas operations, EPA should consider expanding the scope of the Toxic Release Inventory to require reporting of toxic air emissions from natural gas systems (see further discussion, below).

Greenhouse Gas Reporting Program (GHGRP). In February 2013, EPA's GHGRP published for the first time GHG emissions data from petroleum and natural gas facilities—for the year 2011. The authorizing legislation[77] for the GHGRP directed EPA to use its existing authority under section 114 of the CAA to set up this GHG registry. In the final rulemaking,[78] EPA noted that these GHG data would enable states, the public, and EPA "to track emission trends from industries and facilities within industries over time, particularly in response to policies and potential regulations."

The rule requires GHG reporting by all facilities that emit 25,000 metric tons or more of CO_2e per year. To enable broader coverage, the EPA defines "facility" for the oil and gas sector to include all emissions associated with wells owned or operated by a single company in a specific hydrocarbon producing basin.[79] However, the EPA has not estimated what percentage of total actual emissions is covered by the rule.[80] The GHG Inventory is designed to estimate total emissions from the sector[81], including from small and dispersed sources (see Appendix 1, for more details).

EPA – Toxic Release Inventory

Toxic Release Inventory (TRI). The TRI was established by Congress in 1986, as part of the Emergency Planning and Community Right-to-Know Act, and provides one of the most comprehensive public sources of information on release of toxic materials into the environment. Although the oil and gas extraction sector is a significant source of toxic air emissions, it is not required to report in the TRI because individual sources within this sector are generally small and dispersed. However, for Subpart W of the GHGRP, EPA aggregated multiple sources into a broader definition of "facility." On October 24, 2012, seventeen public interest groups filed a petition[82] for the U.S. EPA to initiate a rulemaking to similarly redefine "facility" for the purposes of the TRI, which would require the oil and natural gas extraction industry to publicly report their releases of toxic chemicals.

Department of Interior—Public Lands

The U.S. Department of Interior (DOI) has jurisdiction over oil and gas leasing agreements on federal and Indian lands, which currently supply 11 percent of all U.S. natural gas production. This gives DOI the authority to limit the environmental impacts of oil and gas development in several ways, including through the promulgation of regulations and Onshore oil and gas orders, through negotiated lease agreements and through the collection and dissemination of information regarding best management practices (BMP).[83]

While DOI rules only apply to activities on public and Indian lands, the agency can develop model policies for other federal agencies—notably EPA—or state regulators[84] to apply more broadly to oil and gas operations in other jurisdictions. For example, one of the mitigation measures required for approval of an oil and gas project in Wyoming was the construction of pipelines to handle drilling liquids in order to reduce truck traffic to well sites.[85] Below are two other examples of steps that the Bureau of Land Management (BLM) has recently taken to reduce the environmental impact of oil and gas operations.

In May 2012, DOI signed a Record of Decision[86] approving Anadarko Petroleum Corp.'s Greater Natural Buttes Area Gas Development Project in northeast Utah. The project, including plans for drilling more than 3,000 natural gas wells over a 10-year period, went forward with support from environmental groups after developers committed to a so-called Resource Protection Alternative with pollution control measures to reduce air emissions that contribute to ground-level ozone in the region (Streater 2012).

In May 2012, BLM proposed a rule[87] to increase transparency and to protect water supplies from risks associated with hydraulic fracturing on public and Indian lands. The rule would require disclosure of the chemicals used in hydraulic fracturing, protect groundwater through updated standards for wellbore integrity, and ensure proper management of flowback water. While this proposed rule would not address air emissions, external pressure is growing on the BLM to update regulations, notices, and orders to reduce air emissions from oil and gas operations.[88]

State policy landscape

State governments and commissions have historically played a prominent role in regulating oil and gas development (NPC 2011; Wiseman and Gradijan 2012). Most state-level oil and gas regulations deal with issues pertaining to safety and local air and water quality (GAO 2012). In general, states often write and enforce their own regulations and permitting requirements. In addition, they have responsibility for implementing federal environmental rules, in cases where EPA has delegated such authorities at the request of states (see the discussion on NSPS and NESHAP above). Through these processes, many states have developed a record of leadership that ultimately forms the basis for federal pollution control regulations.

With the exception of Colorado and Wyoming, few states have chosen to set air emissions standards for preproduction and production-stage oil and gas operations that are more stringent than federal rules (GAO 2012; Gribovicz, 2011). Many state regulators defer to EPA's standards, especially in cases where state legislatures have explicitly prohibited regulators from exceeding federal requirements (Hecht 2004) (see "barriers to state leadership," discussed below). For example, while states may establish minimum safety requirements for workers or nearby residents, most toxic air pollution from oil and gas production sites has been unregulated (GAO 2012). This is true in part because individual sources in the upstream value chain are often relatively small, and thus fail to trigger some size thresholds under the federal Clean Air Act (Wiseman and Gradijan 2012; GAO 2012).

Nevertheless, states with poor air quality that exceeds NAAQS for one or more criteria air pollutants (e.g., ground-level ozone) have the authority and impetus to include controls on VOCs or NOx from oil and gas facilities in their state implementation plans. Many states have also adopted NSPS for processing plants, which are larger stationary sources (Gribovicz 2011). While this has created benefits for local air quality, one result has also been a regulatory patchwork and incomplete air regulation for some regions—with individual states advancing different rules on different timelines.

State policy leadership

Most states with significant shale gas development—or resource potential, in the case of New York—have been actively working to update their regulations to address growing concerns about air and water-related impacts of hydraulic fracturing (Logan et al. 2012; Wiseman and Gradijan 2012; GAO 2012). In the context of air emissions, the most notable examples are the regulation of VOCs from oil and gas operations in Colorado and Wyoming, which provide a model for EPA's recently finalized NSPS (Wiseman and Gradijan 2012; GAO 2012).

- Colorado requires green completions or other emissions abatement strategies during well completions and recompletions to the extent feasible (GAO 2012; Gribovicz, 2011). In addition, Colorado requires no or low-bleed pneumatic devices for all new and existing applications, but only in ozone nonattainment areas. In addition, 90 to 95 percent of VOC reductions are required for most liquids condensate and crude oil tanks, and also at dehydrator units (Gribovicz 2011). Colorado conducted an open process with extensive public outreach and stakeholder engagement,[89] which contributed to the successful development and implementation of these oil and gas sector regulations.

- Wyoming's oil and gas permitting requires reporting during episodic releases of regulated emissions, and the state's BMPs require that VOC and HAP emissions be "minimized to the extent practicable" during liquids unloading and from other sources.[90] The permitting requires controls for dehydration units, condensate tanks, pneumatics, and green completions, with different tiers of control level based on geographic location (Gribovicz 2011).[91]

- Another example under consideration is the "Illinois Hydraulic Fracturing Regulatory Act," which was recently introduced in the Illinois General Assembly.[92] Like the NSPS/NESHAP rules, the bill would require green completions during well completions and workovers, but would go beyond the scope of federal regulations in two important regards. First, the bill would impose green completion requirements on oil wells (not just natural gas wells). Second, it would require operators to annually report the quantity of natural gas flared or vented from each hydraulically fractured well.[93]

This experience demonstrates the value of state policy innovation for establishing model rules based on local expertise and experience with emerging industry practices and technologies. Meanwhile, many states with limited recent experience or those facing the prospect of expansion in oil and gas development within their jurisdiction are taking steps to add more comprehensive regulations, including measures to mitigate air emissions. For example, New York continues to have a moratorium in place as they work to complete a new regulatory framework for air, water, and other impacts of shale gas development.

In many cases, government and industry are working together to identify and promulgate best practice regulations. For example, STRONGER (State Review of Oil and Natural Gas Environmental Regulations; www.strongerinc.org) is a state-federal-industry partnership that documents and reviews state regulations on natural gas production in order to help improve their efficacy. One major challenge with this model is that its effectiveness depends on states volunteering time and resources to invite external scrutiny of their regulatory processes. With more funding (SEAB 2011b; NPC 2011) and more state-level participation, it could become a more effective model in support of state policy leadership.

Barriers to state leadership; legal, fiscal, and political limitations

The net benefits of federal environmental laws such as the Clean Air Act have been well-documented in both human health and economic terms (NRC 2009; EPA 2011b). However, debates continue regarding the appropriate roles for state versus federal government in regulating industry. The oil and gas industry typically argues that state governments are best suited to regulate the sector because state personnel are uniquely well-versed in local geology, hydrology, and other relevant considerations (NPC 2011). The alternative view, which underpins most federal environmental laws, is that consistent, national minimum protections for public health and the environment are appropriate, especially for air pollutants, which can also cause air quality problems in downwind neighboring states or have implications for the global climate (in the case of GHGs).

The result of our federalist system is a patchwork of rules, which has both positive and negative features. On the plus side, the public benefits when states can innovate and be the laboratories for new policies that can be more protective than minimum standards required by federal law and that the federal government may later adopt. On the down side, some state legislatures have enacted so-called "no-more-stringent" rules (NMSRs), which explicitly prevent state environmental agencies from developing or enforcing regulations that are more protective than those set by the federal government (Hermans 2011). Though NMSR policies may be designed to encourage investment by industry, they also have a tendency to promote a "race-to-the-bottom," resulting in relatively poor environmental quality and fewer protections for public health in states that adopt them (Hecht 2004). Ironically, the policy dynamic created by NMSRs can be detrimental to economic development. As noted above, allowing ambient ozone levels to deteriorate beyond allowable federal standards causes states and counties to be classified as nonattainment areas (for example, counties in Colorado, Wyoming, and Utah), which complicates federal permitting for prospective new industrial development.

As of 2004, NMSRs were on the books in roughly half of all states in the U.S. Among the states with NMSRs applying to some or all environmental regulations, those that also have ongoing or potential development of shale gas or oil resources include Arkansas, Colorado, Kentucky, Montana, North Dakota, Ohio, Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming (Hecht 2004). The practical implication of NMSRs is that they constrain what state executive branch agencies may do. None of these rules are written into state constitutions, so state legislatures can always pass new environmental laws that are not subject to such rules. In addition, some NMSRs have limited applicability, while others may include exemptions that merely require hearings or economic impact assessments (for example, in Colorado) before regulations may be developed. Having NMSRs on the books does not necessarily prevent state air agencies from curbing air emissions beyond the federal requirements, but they can serve as practical and political barriers to state policy leadership.

A challenging issue for air quality management at the state level is that actions taken by most state clean air authorities are primarily driven by achieving attainment with respect to six criteria pollutant thresholds; that is, NAAQS. As a result, unless poor air quality has triggered (or threatens to trigger) nonattainment, few state air agencies have taken steps to regulate air emissions from the oil and gas sector. However, section 110 of the CAA requires states to develop regulations not just to correct nonattainment, but also to maintain attainment of NAAQS in their own jurisdictions and in neighboring states. If the current trend of expanding oil and gas development makes it increasingly difficult for states to maintain NAAQS compliance, states thus have the authority to proactively address this issue.

Finally, all states have limited resources dedicated to the inspection of oil and gas operations and the enforcement of rules and regulations. While some states, like Pennsylvania and Colorado, have recently increased staffing in these areas, others retain limited staff capacity despite increasing levels of development in their states (Logan et al. 2012; WORC 2013).

Regulatory and market structure barriers

While broad authorities exist for federal and state governments to improve air quality, until very recently most of the preproduction and production-stage oil and gas activities remained largely unregulated from an air emissions standpoint. Furthermore, while natural gas companies may have an incentive to minimize gas leaks throughout the life cycle, oil and gas market structures are not always directly aligned to enable this outcome, despite the economic and/or environmental benefits.

The reasons for this are varied within each life cycle stage because of numerous potential "principal-agent" problems. The economic benefits of investments may accrue to companies operating elsewhere in the supply chain, which reduce the incentive for businesses to make apparently cost-effective capital investments in low-emissions equipment. For example, while production companies typically own the gas as it leaves the wellhead, they will hire a service company to drill the well and conduct well completions. Unless a service company is contractually obligated to use green completions or take other measures to reduce methane leakage, it is not necessarily in their interest to minimize unmeasured, invisible losses of a product that they do not own. Fortunately, the new NSPS/NESHAP rule will help to address this particular problem by requiring green completions for all hydraulically fractured natural gas wells.

Another, related concern occurs when production companies sign leases from landowners or mineral rights owners that require well development by a date certain. A firm deadline like this can drive companies to drill and hydraulically fracture wells before gathering lines are available, requiring extensive venting or flaring during the flowback stage of well completion. In North Dakota, short-term lease agreements are contributing to the same dynamic with respect to tight oil wells. These wells are producing significant amounts of associated natural gas, 30 percent of which is being vented or flared.[94] Associated gas already makes up 9 percent of U.S. natural gas production,[95] and the market is shifting further in this direction because natural gas is cheap and oil is expensive and profitable. Unfortunately, these oil wells are not covered by the new NSPS/NESHAP rule.

From a policy perspective, the pipeline stage is of particular interest because tariffs and contracts between pipeline companies and their shippers are subject to oversight and approval by the Federal Energy Regulatory Commission (FERC). Pipeline companies often require shippers to make in-kind payments (tariffs) for natural gas used by pipeline companies and for lost and unaccounted for fuel (LAUF), both of which contribute to upstream CO_2 and methane emissions from natural gas pipeline systems. While a competitive market for natural gas transmission creates an incentive for pipeline companies to keep their tariff rates down, some tariff structures guarantee cost recovery for fuel usage and LAUF regardless of the services rendered. FERC recognized this problem in its 2007 Notice of Inquiry,[96] which sought public comment on ways to increase the incentive for pipeline companies to reduce their fuel use and LAUF gas (given that fuel gas charges had been rising as a portion of total interstate transmission rates). The commission has since received a handful of related filings from pipeline companies. For example, the El Paso Natural Gas Company proposed to establish an incentive mechanism whereby customers would share capital project costs and savings that result from efficiency improvements and reduced LAUF.[97] So far, FERC has not approved any such proposals, suggesting that more work is needed by FERC, pipelines, shippers, and perhaps state utility commissions to establish appropriate rewards for these investments and to properly account for achieved natural gas savings.[98]

Finally, over 6,300 natural gas producers operate in the U.S. and thousands more companies are involved with natural gas processing, pipelines, storage, marketing, and distribution.[99] As a result, even the best intentioned and well-coordinated efforts by large companies to develop, promulgate, and adopt best practices for reducing methane emissions will not be adequate to ensure that all businesses have the technical or financial capacity to voluntarily hold themselves to high standards. Even with the general trend toward greater consolidation within this sector (NPC 2011), the existence of thousands of market players is a good reason for policymakers to support a more active government role in terms of regulatory oversight, to protect the public interest through the establishment and enforcement of minimum standards for responsible oil and gas development.

Private sector leadership and initiatives

Despite the barriers listed above, oil and gas companies have a number of reasons to act proactively and voluntarily to identify and adopt best practices (for example, the Shell Shale Gas Operating Principles[100]). A business case for reducing air emissions includes the following considerations:

- Many emissions reduction options are cost-effective, such that reducing methane loss can improve a company's competitive advantage.
- The extraction of remaining oil and gas reserves often requires new (i.e., "unconventional") technologies and practices; investors and customers are increasingly concerned about their exposure to the risks associated with such practices. This puts added pressure on oil and gas companies to demonstrate a commitment to environmentally and socially responsible practices.
- Being proactive about worker safety and environmental protection is good for corporate image and generally beneficial for preserving the industry's social license to operate, enabling access to oil and gas resources.
- It is beneficial for companies to avoid noncompliance situations that can potentially have significant commercial and legal implications.

The American Petroleum Institute (API) publishes model standards and offers technical guidance for companies to improve their environmental performance across a wide range of operations and activities (API 2009). API has not yet identified or agreed to standards for cost-effectively minimizing air emissions throughout the U.S. natural gas life cycle. However, industry leaders are taking proactive steps by following recommendations made by SEAB

Box 8 | Policy Recommendations in Previous Studies

This working paper builds on earlier efforts by several influential and well-positioned groups. Three studies stand out. These studies were broader in scope but generally less detailed than this paper, which is narrowly focused on air emissions. We summarize here the key air emissions-related policy recommendations from the following reports:

1. In 2011, the secretary of energy's Advisory Board Natural Gas Subcommittee issued two reports (SEAB 2011a; SEAB 2011b) in response to the request from Secretary Steven Chu to develop consensus recommendations for government agencies on practices for shale extraction to ensure the protection of public health and the environment.

2. In 2011, the National Petroleum Council, an oil and natural gas advisory committee to the U.S. secretary of energy, issued a report (2011)—entitled Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources—that details the changing landscape for oil and natural gas development and includes several emissions-related policy recommendations.

3. The Golden Rules for a Golden Age of Gas (IEA 2012) was a special report of the International Energy Agency's annual World Energy Outlook. This publication included several valuable air emissions-related policy recommendations, some of which echoed suggestions made previously by SEAB and NPC.

All three studies recognized the need for better public information on many aspects of shale gas development. SEAB specifically recommended a federal interagency planning process to collect emissions data and assess the life-cycle greenhouse gas footprint of natural gas used in the U.S.

SEAB also encouraged operating companies to more actively and systematically collect air emissions data from production sites in a variety of shale gas basins, using common methodologies for measuring, analyzing, and disclosing emissions data. An effort to partially implement this recommendation is under way in the form of a collaborative research project led by the University of Texas at Austin and the Environmental Defense Fund (see Appendix 1).

SEAB and IEA both recommended that oil and gas companies focus more attention on actively managing the full spectrum of short-term, long-term, and cumulative impacts of industrial activities that accompany large-scale oil and gas development. All three reports encouraged companies to more actively build public trust through increased transparency, along with better and more active engagement with local communities. Specifically, SEAB and NPC both recommended the establishment of regional "centers of excellence" to develop and promulgate best practices in cooperation with public interest groups, state and local regulatory agencies, and local academic institutions. Some leadership companies have already taken steps to implement this recommendation (see "Private Sector Partnerships and Initiatives" above).

Though all three groups support voluntary industry efforts to improve environmental performance, IEA and SEAB also envisioned a greater role for government in developing regulations. They also encouraged independent evaluation and verification. There was agreement that regulations should (a) be developed through transparent and inclusive processes, (b) avoid redundancies with existing laws, and (c) be structured to enable continuous improvement in environmental performance over time.

These reports also highlighted the need for new revenues to support new regulations and other policy efforts. The rapid increase in U.S. natural gas development demands urgent, more proactive actions by air and environmental agencies, with greater financial support than state and federal governments have been willing or able to provide. For example, SEAB (2011b) called for state governments to raise new revenues through fees, royalty payments, and severance taxes levied on oil and gas industry activities to finance a range of activities, including emissions monitoring and associated regulatory actions. Many oil and gas companies have expressed public support for such fees (NPC 2011), provided that new revenues are applied directly for the purpose of achieving efficient and effective regulations (as opposed to being funneled into general funds and subject to annual appropriations). While the establishment of such dedicated revenue streams through a legislative process could be useful for ensuring consistent and adequate levels of much-needed funding, protections must also be in place to avoid conflicts of interest between industry and direct funding recipients.

(2011b) and NPC (2011). Eleven oil and gas companies recently formed a regional council of excellence called the Appalachia Shale Recommended Practices Group (ASRPG), which has issued consensus recommendations. Another example is the Center for Sustainable Shale Development, which recently agreed to 15 initial performance standards for protecting air quality, water resources and climate.[101]

Though not directly related to air emissions, FracFocus[102] serves as a high-profile, somewhat controversial example of an industry-state government partnership, designed to increase public awareness of hydraulic fracturing operations. FracFocus is a national registry through which industry voluntarily discloses the chemicals they use for hydraulic fracturing operations. The FracFocus registry is managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission, though it has been widely criticized for being predominantly funded and founded with support from industry (Elgin et al. 2012). With ten states now using FracFocus as the central database for official state chemical disclosure (no longer voluntary in these cases), it has drawn heightened scrutiny for not being subject to third-party verification, for not being sufficiently comprehensive (Elgin et al. 2012), and for not making raw data publicly accessible in a way that would more readily allow for robust analysis by independent researchers.[103]

SECTION 6. CONCLUSION: NEXT STEPS TO REDUCE METHANE EMISSIONS

Reducing methane emissions from natural gas systems is critical for minimizing the contribution to climate change from natural gas development and use. New public policies will be needed because market conditions alone are not sufficient to compel industry to adequately or quickly adopt best practices, particularly when the cost-saving benefits of investments accrue to other entities down the supply chain.

Minimum federal standards for environmental performance are a necessary and appropriate framework for addressing cross-boundary pollution issues like air emissions. The federal Clean Air Act regulations are generally developed in close consultation with industry and state regulators and are implemented by states. This framework allows adequate flexibility to enable state policy leadership and continuous improvement in environmental protection over time.

Any new regulations should be developed with the following considerations in mind:

- Policies and regulatory programs should be environmentally effective and designed to be as protective as authorizing statutes allow.

- New and updated regulations should be developed in coordination or consultation with relevant federal and state agencies and commissions to avoid redundancies, inconsistencies or other potentially costly inefficiencies.

- When evaluating the cost-effectiveness of proposed regulations, the full scope of cobenefits associated with pollution reductions should be taken into account whenever possible. For example, the many benefits of reducing emissions from oil and gas systems include cutting air toxics, reducing smog-forming pollutants, and slowing the rate of climate change.

New regulations must always be developed based on the most current and accurate data and information available. Fortunately, new facility-level GHG emissions data for 2011 were recently published by GHGRP (and 2012 GHG emissions data are due to be published in the fall of 2013). This provides sufficient information for state and federal governments to initiate the rulemaking processes described below.[104] Finally, any new rulemaking would necessarily involve the collection of additional data, as needed, to ensure that emissions standards are appropriately designed to minimize potential emissions from new, modified, and existing sources.

The remainder of this section describes the range of actions that can be taken to reduce methane emissions.[105] Through these and related efforts, policies can be put in place to reduce total methane leakage rates to below 1 percent of total production.

Federal approaches to address emissions

The recently enacted federal VOC and air toxics standards for oil and gas systems will result in significant reductions in methane emissions from shale gas development, as discussed in section 4 above. A number of additional tools remain available that can either directly or indirectly reduce methane emissions and support stronger and smarter action at the state level.

- *Directly regulate GHG emissions under section 111 of the Clean Air Act.* As noted above, section 111 of the Clean Air Act authorizes EPA to set performance standards for GHG emissions, including methane, from new and existing oil and natural gas systems. These authorities could be used to achieve emissions reductions from any number of significant sources, including through measures described in section 4 of this working paper: (a) the use of plunger lift systems at new and existing systems during liquids unloading operations; (b) fugitive methane leak monitoring and repair at new and existing well sites, processing plants, and compressor stations; and (c) replacing existing high-bleed pneumatic devices with low-bleed equivalents throughout natural gas systems.

  This approach would enable the regulation of methane emissions from new and existing pollution sources. By regulating methane directly rather than as a cobenefit of addressing VOCs or HAPs, such rules would more effectively achieve GHG emissions reductions from all segments of the supply chain, including those with relatively low concentrations of non-methane pollutants (for example, after processing). This approach would also allow EPA to address upstream sources of CO_2 emissions. While these emission are not a focus of this study, they do represent significant sources of GHG emissions (see Figure 7).

- *Regulate HAPs in urban areas.* EPA has the authority under section 112 of the CAA to regulate hazardous air pollution in densely populated areas, and it could use that authority in urban areas with expanding oil and gas development. This would be a prudent action, given the findings of McKenzie et al. (2012) that living in near proximity to natural gas development increases the risk of cancer and other health effects caused by air toxics. Expanding the scope of the Toxic Release Inventory to require emissions reporting from oil and gas preproduction and production-stage operations (as discussed below) would help policymakers and the public better understand current levels of exposure to HAPs, as well as help EPA determine the extent to which it would be appropriate to pursue this regulatory route.

- *Recognize and promulgate best practices.* The federal government could do more to recognize and reward companies that voluntarily demonstrate a commitment to advancing best practices with the sector. For example, with more funding, Natural Gas Star could be expanded and more regularly updated to serve as a clearinghouse for technologies and practices that enable companies to meet compliance with the new NSPS/NESHAPs rules and other air regulations. This could be similar to what EPA does for the so-called "RBLC",[106] which is a clearinghouse for emissions control technologies that are used by companies to meet compliance under various Clean Air Act programs. Companies that are actively engaged in this program and who achieve verified emissions reductions beyond a certain benchmark could be publicly recognized (similar to EPA Energy Star programs).

Enabling state policy leadership

State governments play an important role in developing new approaches to reducing air emissions, and they are largely responsible for implementing many federal rules under the Clean Air Act. However, they are often short on resources and could benefit from additional policy and technical assistance, particularly given the rate of current oil and gas development, plus expectations for further expansion.

- *Provide assistance to states with expanding oil and gas sector development.* State air regulators are responsible for developing SIPs to ensure compliance with the NAAQS established under the CAA. EPA could target technical assistance to states with expanding oil and gas production and assist with the development of SIPs that address emissions from new and existing sources within this sector.

  EPA recently finalized its Integrated Science Assessment for Ozone (EPA 2013b), which forms the scientific foundation for the periodic review of NAAQS standards. This review may provide the basis for more stringent standards in the future. A more stringent, updated NAAQS for ozone would likely bring more areas of the country into nonattainment, compelling greater action by states to identify and reduce pollution sources that significantly contribute to smog formation, including VOCs from oil and gas operations. This process may provide an opportunity for EPA to work with the states on these issues.

- *EPA's Ozone Advance program.* As a service to states with strong interests in avoiding nonattainment, EPA provides technical and policy assistance through the voluntary "Ozone Advance" program.[107] States and counties with rising levels of oil and gas operations within their jurisdiction should consider joining the Ozone Advance program, particularly given the expectation that new standards will likely be more stringent when EPA updates NAAQS for ozone. Participating states should work with EPA to specifically evaluate whether current (or expanded) levels of natural gas operations could significantly exacerbate ground-level ozone within their air shed.

- *Third party review of state regulations (e.g., STRONGER).* Third-party reviews can help states improve current regulations and help other states learn from previous efforts. As an example, although STRONGER had previously focused most of its review on oil and gas commissions (such as Colorado), the organization is shifting its focus toward air emissions and beginning to work more closely with state air agencies. Additional, independent funding for groups like STRONGER would enable them to build their capacity and credibility (SEAB 2011a; NPC 2011). This would make their regulatory reviews less of a burden on participating agencies. Such review findings could provide a credible basis for model rules that other states could adopt.

- *Develop model rules and legislation and support implementation.* With an increasing number of states (and foreign governments) looking to mitigate the air emissions associated with expanding oil and gas operations, many will be seeking model rules for effective pollution abatement efforts that build on rules developed by EPA and some states. Developing and publishing sound model rules can be a valuable service to government agencies, but it can also be a time and resource-intensive exercise. This suggests that model rule development efforts should prioritize addressing challenges that are likely to have solutions with broad technical and legal applicability. For example, the Environmental Defense Fund has been working with leadership service companies to develop model rules for safe well construction and operations.[108] To be effective, supportive NGOs, federal agency staff, and industry groups may need to work with state governments and legislatures to adapt rules for individual circumstances and help ensure proper implementation. The sort of technical support that goes into developing and implementing model rules can be especially helpful to rural, low-population states with scant budgets. Model legislation also may be needed in some cases, depending on existing regulatory authorities of state agencies.

- *Provide regulatory guidance; develop and publish a menu of policy options.* The tools and approaches listed in this report provide a good starting point for moving forward, but more detailed support will be needed to build state policy leadership. Building on information published by EPA's Natural Gas Star program, such a menu could include technology and policy options for state governments to pursue in addressing emissions from new and existing sources. For example, to help with NSPS implementation, states with oversight of natural gas wells split between two or more agencies could learn from Colorado's experience implementing air emissions requirements under similar circumstances.

  This approach could be useful for any state with air quality concerns to better understand how other states may have addressed such issues amid the rapid growth and expansion of oil and gas development within their jurisdictions. Finally, as a complement to a policy menu, and to help foster friendly competition among states, an independent research organization could create a scorecard for state regulations of oil and gas sector emissions, based on clear and transparent standards for assessing policy performance.

Improve understanding of emissions

Basic information on actual air emissions from the oil and gas sector is difficult to come by. As noted in Appendix 1, current emissions estimates are based on assumed emissions factors as opposed to direct measurements, largely because direct measurements are so expensive to record. These emissions data uncertainties result in questions about the effectiveness of commonly used emissions control technologies. This both raises compliance concerns[109] and reduces the likelihood that a company would invest in pollution control, since the resulting level of product recovery is in question.

- *Analyze GHG emissions reporting data from the sector and track industry performance over time.* With the initial public release of facility-level GHGRP data for the oil and gas sector in February, researchers are just beginning to evaluate the strengths and limitations of this new dataset. Some of its limitations are already known; for example, emissions factors are not based on direct measurements. Nonetheless, it will undoubtedly help policymakers better understand the geographic, sectoral, and other factors that are the most important determinants of GHG-intensity within the U.S. oil and gas sector. As data quality and coverage improves over time, this data set will likely prove invaluable to developing new regulatory regimes and for tracking regional and national methane leakage rates and other important GHG benchmarks.

- *Add oil and gas sector emissions to the Toxic Release Inventory (TRI).* Despite being a significant source of toxic air emissions, the oil and gas extraction sector is not required to report in the TRI[110] because individual sources within this sector are generally small and dispersed. However, for subpart W of the GHGRP, EPA aggregated multiple sources into a broader definition of "facility." A similar approach could be used for the TRI. On October 24, 2012, seventeen public interest groups filed a petition for the U.S. EPA to initiate a rulemaking that would require the oil and gas extraction industry to report releases of toxic chemicals to the TRI.[111]

- *Assess the production-stage emissions at tight oil wells.* The recently finalized NSPS/NESHAP rules apply to hydraulic fracturing operations at new and restimulated natural gas wells, but not to hydraulic fracturing operations at oil wells that produce associated natural gas. Additional information on the extent to which production-stage emissions at tight oil wells are comparable to emissions from natural gas wells would help determine whether the recently finalized NSPS/NESHAP rule should be extended to cover oil wells that produce associated natural gas.

- *Convene a broad range of experts to develop updated emissions factors.* Updated emissions factors for oil and natural gas equipment and activities that are significant sources of upstream GHG emissions could improve life cycle emission estimates. This is necessary because, as discussed in Appendix 1, EPA is currently deferring to industry on emissions factors used for the purpose of reporting emissions to the GHGPR. Per the final subpart W rule, industry will not be required to report to EPA key inputs to emissions equations such as production and fuel use until after 2015, and only then after such data are determined to be nonconfidential.

Among the tasks for this group could be to improve estimates for emissions from gathering lines and other equipment not covered under subpart W of the GHGRP, which would better enable comprehensive life cycle assessments, including all significant upstream emissions sources.

- *Establish a FracFocus-like database for voluntary reporting of air emissions.* FracFocus has been proposed as a possible model for industry to publicly disclose releases of toxic, VOC, and methane air emissions from oil and gas operations. However, to address criticisms that have been lodged against FracFocus (see above), states interested in adopting a similar model for air emissions disclosure should consider meeting the following criteria. First, a FracFocus for air emissions should be funded through public sources that are independent of industry. Second, submissions to the registry should be subject to third-party verification. Finally, raw data submitted to the registry should be readily accessible in a way that allows for aggregation, ready analysis, and cross-referencing by independent researchers.

Promote research to improve technology and policy options

While this paper has identified a suite of technology and policy options for reducing methane emissions from natural gas systems, the expected expansion of natural gas production means that continued improvements will be necessary to keep pace.

- *Research emissions monitoring and control technologies.* With additional funding, the Department of Energy could conduct applied research designed to develop and improve oil and gas sector emissions measurement and control technologies, and to reduce the cost of those technologies.[112] With less expensive monitoring equipment and more cost-effective control technologies, it would be easier for oil and gas service companies to identify leaks and repair them.

- *Identify public and private sector policy options for removing barriers to energy efficiency and fugitive emissions reductions.* Research is needed to identify policy solutions to regulatory barriers and market failures that prevent companies from investing in cost-effective projects that reduce methane emissions and more efficiently use fossil fuels throughout the natural gas life cycle. For example, pipeline contracts are not always structured in a way that provides incentives for pipeline companies to minimize fugitive emissions from their compressor stations. Research that includes interviews with industry and legal experts—

plus veteran staff at state and federal air agencies, natural resource agencies, oil and gas commissions and public service commissions—could help identify additional barriers and develop appropriate governmental and industry solutions.

Conclusion

Upstream emissions of greenhouse gases—particularly methane—contribute significantly to the climate impacts of U.S. natural gas production. While there remain significant uncertainties regarding the exact level of methane emissions throughout the U.S. natural gas life cycle, studies generally agree that life cycle GHG emissions from natural gas are lower than coal, particularly when considering a longer, 100-year time horizon. Previous studies also agree that upstream methane emissions from natural gas can and should be reduced with new policy action and investment. Uncertainty is no reason for delayed action, particularly given that aspects of climate change (e.g. sea level rise) are happening faster than expected and that there are cost-effective opportunities to significantly reduce upstream methane emissions.

Our analysis is not meant to be exhaustive, but rather an illustration of the magnitude of emissions reductions that can be achieved in a cost-effective manner through the development of new rules regulating methane emissions from natural gas systems. We find that the 2012 NSPS/NESHAP rules regulating VOCs and air toxics will reduce projected upstream GHG emissions by up to 25 percent by the year 2035. With further policy actions, we project that regulations requiring just three methane abatement measures could achieve an additional 30 percent reduction in upstream GHG emissions. The total of 72 MMt CO_2e in annual emission reductions by 2020 represent nearly 2 percent of all projected energy-related emissions in that year[113]—the equivalent of taking roughly 14 million passenger cars off the road. All three of these proposed measures are economically viable under a wide range of natural gas prices and implied costs of carbon. With more ambitious policy actions, the widespread adoption of five additional control technologies would cut projected upstream GHG emissions from U.S. natural gas systems by 56 percent below the projected 2035 emissions levels that will result from full implementation of the 2012 NSPS/NESHAP rules.

Additional policy actions are needed to achieve these and other cost-effective methane reduction opportunities. Natural gas markets and related regulatory structures are not well-configured to ensure the best economic or environmental outcomes, which helps to explain why so many cost-effective methane reduction projects remain untapped. While states have played a leadership role in advancing policies that help reduce the environmental impacts of oil and gas development, minimum federal standards are critically important for ensuring continuous improvements in air quality and climate protection.

We have identified a range of actions that could further reduce GHG emissions from the oil and gas sector. First among these is use of section 111 of the Clean Air Act to set GHG emissions performance standards for new and existing natural gas infrastructure and equipment. This approach is likely the most effective means of achieving methane emissions reductions throughout the natural gas life cycle. EPA has the ability under the existing CAA and with the newly available GHGRP data to begin a rulemaking process today. Absent a GHG rule for natural gas systems, additional methane emissions reductions could be achieved as a result of updated National Ambient Air Quality Standards for Ozone, especially if EPA targets related technical assistance to states with expanding oil and gas production.

Continued state leadership and voluntary industry actions are also important to advance policies and practices that will further reduce methane emissions over time. We list a number of actions that could enable or directly require emissions control technologies from all life cycle stages of natural gas development. We estimate that implementation of these actions would enable emissions reductions to the point where fuel-switching to natural gas from coal or diesel fuels could result in unquestionable relative benefits for the climate.

This appendix provides detailed descriptions of data published by EPA, including discussion of their limitations and applications that are most relevant to this paper. EPA methodologies for estimating emissions are developed through transparent processes that include expert reviews and public input. As a result, despite their imperfections, we consider EPA emissions data to be more reliable and comprehensive than alternative data sources.

Where do available methane emission data come from?

U.S. GREENHOUSE GAS INVENTORY REPORT[114]

Each year, EPA publishes a complete U.S. GHG inventory, accounting for all emissions and sinks by source, economic sector, and greenhouse gas. The annual report is developed based on national-level data on energy use and sector-specific economic activity, with results reported to the United Nations' Framework Convention on Climate Change (UNFCCC).[115] EPA is responsible for estimating and reporting annual U.S. GHG emissions trends, from 1990 through the most recent full year for which comprehensive data are available.

EPA's GHG inventory is developed using a specific methodology, which is constrained in part by UNFCCC protocols. For example, methane emissions estimates in the GHG inventory reflect all potential emissions, less voluntary emissions reductions that are officially registered—through EPA's Gas STAR program—and less natural gas recovery that results from emissions controls that are required by state laws. EPA (2013a) acknowledges that many of the emissions factors used to calculate potential emissions for the natural gas sector are based on dated information, developed through a comprehensive 1996 study by EPA and the Gas Research Institute (EPA/GRI 1996). Inherent shortcomings associated with this underlying methodology coupled with dated methane emissions factors may result in an overestimate of methane emissions to the extent that published GHG inventory estimates do not reflect technology improvements or additional voluntary measures not required by law (e.g., practices that are conducted for economic reasons). On the other hand, the GHG inventory may underestimate methane emissions, to the extent that EPA's dated emissions factors do not accurately reflect new emissions-intensive processes, leakage from accidents, poorly maintained equipment, and/or operators not following best practices.

While many emissions factors may be dated, EPA regularly updates other aspects of their methodologies (EPA 2013a) to ensure that emissions estimates in their inventories are based on the best available data and information (including control technologies registered with Natural Gas STAR) . To ensure comparability, these updates are always applied retroactively for all previous years. For example, the 2011 inventory included methodological changes in how EPA estimates methane emissions from the preproduction and processing stages of natural gas development (EPA 2011a), resulting in a near doubling in estimated methane emissions from U.S. natural gas systems. In the 2013 GHG Inventory (EPA 2013a), the public draft of which was released on February 22, total natural gas sector methane emissions were adjusted downward, based on industry survey data provided by API/ANGA (Shires and Lev-On 2012) showing that liquids unloading episodes were shorter in duration and emissions control technologies were more widely used than EPA had previously assumed. Figure A1-1 illustrates how changes in the 2011 inventory and the 2013 draft inventory retroactively affected EPA's estimate of methane emissions in the year 2007[116].

As discussed below, future GHG inventories will continue to be adjusted based on information submitted by industry to the Greenhouse Gas Reporting Program, as well as direct measurements and other data published by independent research efforts (EPA 2013a).

GREENHOUSE GAS REPORTING PROGRAM (GHGRP).

In 2012, EPA published for the first time facility-level GHG emissions data (for power plants and other major sources, but not for the oil and natural gas sector), based on 2010 data reported to the agency. Per the mandatory reporting of greenhouse gases rule,[117] EPA has taken a phased approach to implementing this program. Subpart W[118] details procedures for the oil and gas sector to begin submitting data on their 2011 emissions and related activities, which they did for the first time in the fall of 2012. All facilities with annual emissions greater than 25,000 metric tons of CO_2e are covered under the rule. For the onshore production segment of the sector, the "facility" includes all emissions associated with wells owned or operated by a single company in a specific hydrocarbon producing basin.[119] While this approach will result in data collection from most upstream life cycle stages of oil and gas development, smaller facilities will not be covered, and it excludes gathering lines and boosting segments, which link wellheads to processing facilities.[120]

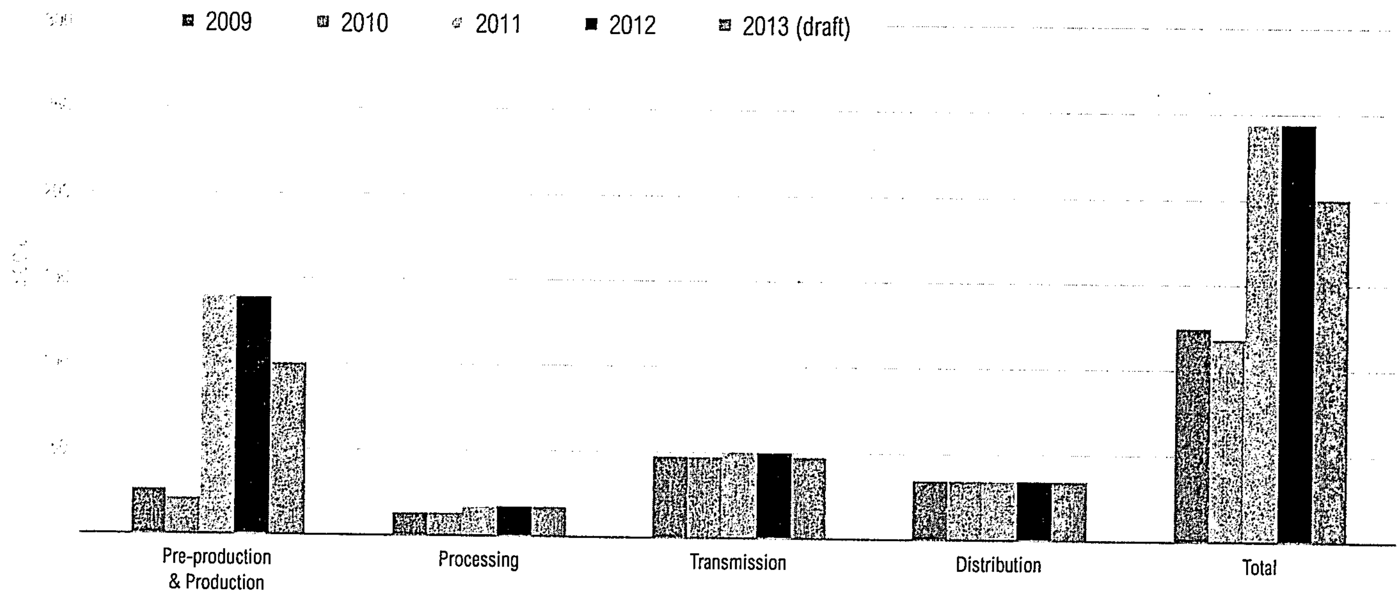
Another important caveat is that this rule does not yet require industry or EPA to conduct direct measurements of emissions from affected sources. Rather, industry is given discretion in terms of the emissions factors that they assign to reported emissions-related activities. Unfortunately, there is little transparency regarding the basis on which reporting entities derive their chosen emissions factors. On this point, SEAB (2011b) was critical of the final rule for including a "deferral that prevents the agency from collecting inputs to emissions equations data until 2015 for Subpart W sources. These inputs are critical to verify emissions information calculated using emission equations." In the meantime, EPA will make a determination as to whether or not such data should remain confidential business information, after which nonconfidential data would be subject to public disclosure in subsequent reporting years.

OTHER EPA SOURCES:

- *Technical support documents (TSDs).* TSDs are developed in association with EPA regulations to ensure that rules are based on the best available data and information (e.g. EPA 2012c). In addition to inventory data, LCAs often also consider information in TSDs, which includes additional industry activity data that may be relevant to developing life cycle emission estimates.

- *Natural Gas STAR.* EPA's Natural Gas STAR is a voluntary program that promotes the adoption of technologies and practices that reduce methane emissions from natural gas systems (EPA 2013c). The Natural Gas STAR website includes economic and technical information on dozens of methane emissions control technologies, many of which are highly cost-effective. Voluntary data submissions by industry are used by EPA in developing their annual emissions inventory (as discussed above), and related fact sheets published on the website provide useful input for economic modeling of cost-effective emissions control options and opportunities (Harvey et al. 2012; also see section 4 of this paper)

Figure A1-1 | 2007 Methane Emissions from U.S. Natural Gas Systems, by Life Cycle Stage



Source: As reported by five consecutive EPA inventory reports published between 2009 and 2013.

Note: Data from the 2013 GHG inventory are undergoing public review and are subject to change; final data will be published after this working paper goes to press. The fact that methodological changes can lead to such significant changes in inventory estimates from one year to the next illustrates a high level of uncertainty with regard to U.S. natural gas sector emissions, particularly during the pre-production and production life cycle stages.

What about the quality and completeness of EPA emissions data?

A February 2013 report by the EPA's Office of Inspector General (EPA/OIG 2013) found that "EPA has limited directly measured air emissions data for air toxics and criteria pollutants for several important oil and gas production processes and sources," further concluding that this "hampers EPA's ability to accurately assess risks and air quality impacts from oil and gas production activities." The OIG report included several recommendations for actions that EPA should take to ensure better data quality, citing recent and projected growth in the oil and gas sectors as reasons for urgency in addressing shortcomings in available data.

Until recently, the oil and gas industry was not required to publicly report their upstream emissions. As noted above, much of the available data published by EPA are based on limited direct observations; emissions are typically calculated indirectly, based on natural gas production, fuel use and other measures of industry activity. As a result, the quality of EPA's data have been questioned for both overestimating (ANGA 2011) and underestimating (Howarth et al., 2011) emissions associated with natural gas development and production.

To get a more accurate and complete picture of methane emissions, the Environmental Defense Fund is engaged in an extensive field campaign,[121] working in partnership with several companies and scientists at the University of Texas, Austin.[122] Their study—which includes five modules,[123] and will be summarized in a series of scientific papers published in 2013 and 2014—will directly measure fugitive methane emissions from several basins and at critical points across the entire U.S. natural gas supply chain. As these data are published and cross-referenced with the EPA inventory and GHGRP data, there is a broad expectation that we will have more accurate and complete data moving forward.

Have any previous studies independently measured methane emissions?

Of course, all previous studies are inherently limited by a paucity of direct observations that are both comprehensive and current. In addition, some studies are based on data reported by industry, data collected during limited periods of time, or the studies are incomplete because they only use information from individual shale basins or discrete stages of the natural gas life cycle. The ongoing collaborative study with EDF and the University of Texas (mentioned above) is designed to address many of these shortcomings (Hamburg 2013).

The first is a study conducted by researchers at the National Renewable Energy Lab, who developed a high-resolution GHG inventory for the preproduction, production, and processing life cycle stages for natural gas production in the Texas Barnett shale basin. Specifically, Logan et al. (2012) used a highly detailed public data set of VOC emissions and industry activity data to independently derive GHG emissions estimates for natural gas wells in this basin. They used this inventory to estimate life cycle GHG emissions from Barnett shale gas and compare this result with harmonized[124] results from published estimates of life cycle emissions of natural gas from unconventional (e.g., NETL 2012; Burnham et al. 2011; Jiang et al. 2011) and conventional sources. Logan et al. (2012) found that the average life cycle GHG emissions from electricity generated by Barnett shale gas is 8 percent lower than conventional gas, and roughly 9 percent lower than other unconventional gas, well within the margins of error.

A pilot study led by scientists at the University of Colorado, Boulder (Petron et al. 2012) estimated a 4 percent "best estimate[125]" methane leakage rate from a well field in Colorado; a very high leak rate that is roughly twice as large as EPA inventory-derived estimates, even without accounting for processing and transmission system losses. The methods used to derive this somewhat alarming finding have been challenged in a recent comment by Levi (2012). Levi's peer-reviewed response countered with his own estimate (based on data published in Petron et al. 2012) finding a lower methane leakage rate that is consistent with EPA inventory estimates. More recently, preliminary (i.e., not-yet peer-reviewed) research—presented at the annual meeting of the American Geophysical Union in December 2012—estimated up to a 9 percent methane leakage rate from one natural gas production field in the Uinta basin in Utah (Tollefson 2013).

APPENDIX 2: KEY ASSUMPTIONS AND PARAMETERS OF LIFE CYCLE STUDIES

In addition to the basic methodological questions described in Box 4, differing results among previous studies are significantly influenced by each author's assumptions regarding certain key parameters, including GWP (see Box 1), estimated ultimate recovery (EUR), and flaring rates. This appendix highlights some of those important assumptions and their implications.

Estimated ultimate recovery (EUR)

EUR is defined as the total amount of gas expected to be economically recovered from a reservoir or field during each well's production lifetime. LCA studies frequently highlight EUR as a significant area of uncertainty for shale gas wells. While shale wells are expected to have up to a 30-year lifespan (NETL), they only started to be developed in significant numbers in the last decade, so their full lifespan is not yet well-understood. LCA results are highly sensitive to EUR (Weber and Clavin 2012; Logan et al. 2012; Burnham et al. 2011) because life cycle emissions are typically calculated as emissions per unit of energy output (See boundary setting, Box 4).

As shown in Table A2-1, EUR estimates used by previous studies have a wide range, from 2 to 3.5 Bcf (billion cubic feet) per well. Energy output is a direct function of the total volume of natural gas produced by each well over its lifetime; therefore, if a shale gas well turns out to be less productive than expected, the life cycle emissions estimates will be higher in nearly equal proportions. Meanwhile, most upstream methane emissions appear to occur disproportionately during the early stages of each well's lifetime (for example, during well completions, workovers, and liquids unloading) rather than evenly over the life of the well.

Significant uncertainty remains regarding the total recoverable quantity of natural gas in the U.S., and the average EUR at wells in each producing basin. For example, at the national level, the National Petroleum Council cites various assessments that have estimated the remaining recoverable resource of all natural gas in the U.S. at between 1,000 and 4,500 Tcf (NPC 2011). EIA significantly reduced its estimate of technically recoverable shale gas from 827 Tcf in the 2011 Annual Energy Outlook to 482 Tcf in the 2012 edition.[126] This uncertainty flows down to the level of an individual well; for example, the most recent assessment by the U.S. Geological Survey (USGS 2012) finds that most U.S. shale plays have EURs in the range of 0.7 to 1.3 Bcf per well, which is less than industry estimates (Rogers 2012) and less than half the estimates used by previous LCA authors (Table A2-1). This would suggest that LCAs are generally underestimating average well life cycle emissions; on the other hand, today's EUR estimates are based on current information, while unexpected future technology improvements could result in better economics and higher EURs.

Flaring rates

Venting and flaring occurs during the processes of well completion, workovers, and processing, in circumstances in which it is not practical or economically viable to recover vented gas. Flaring rate refers to the percentage of vented methane gas that is flared and thus converted to CO_2 (assuming complete combustion), with the remaining gas vented into the atmosphere. Because methane has a much higher GWP than CO_2, higher flaring rates lower the overall life cycle emissions, and vice versa.

During well completions, Howarth et al. (2012) assumes zero flaring; NETL (2012) assumes a 15 percent flaring rate (citing EPA's 2011 technical support document for subpart W). A recent study by O'Sullivan and Paltsev (2012) assumed 70 percent of potential fugitive emissions were captured, 15 percent vented, and 15 percent flared. The authors argued that this was a "reasonable representation of current gas handling practices in the major shale plays." Industry representatives have claimed as high as 97 percent of 2011 well completions were either flared or captured using green completion technologies (ANGA 2011).

Production stage workovers and liquids unloading

A recent oil and gas industry report (Shires and Lev-On 2012) concluded that 16 percent of their surveyed unconventional (including shale gas) wells vented methane in the process of liquids unloading (versus 11 percent for surveyed conventional wells).[127] While these are fairly high activity rates, the report assigns much lower emissions to each liquids unloading event, yielding emissions estimates roughly 80 percent lower than 2012 GHG inventory estimates (EPA 2012a). EPA's draft 2013 GHG inventory cites this industry survey as the basis for changing assumptions previously held in the 2011 and 2012 GHG Inventories—now assuming that liquids unloading occurs at both conventional and unconventional wells, but with significantly reduced associated emissions (EPA 2013a).

There is also uncertainty regarding the frequency in which workovers with refracturing will be required to stimulate production at the typical unconventional natural gas well. In the TSD for the proposed NSPS, EPA assumed that refracturing would occur 3.5 times, on average, over the lifetime of unconventional natural gas wells.[128] However, in the TSD accompanying the final NSPS rule (EPA 2012c), EPA assumed that only 30 percent of all unconventional wells would be refractured during their lifetimes. Of course, these projections are fraught with uncertainties and based on only a few years of limited data and experience.

Nevertheless, based on the TSD for the proposed rule,[129] NETL (2012) and Burnham et al. (2011) assumed multiple well workovers with refracturing during the production stage, while others assumed zero workovers (see Table A1). It is common to assume that refracturing during workovers results in roughly the same GHG emissions as well completions. For example, NETL and Burnham et al. (2011) calculate emissions associated with well workovers by multiplying the number of workovers per well life-time by the level of emissions associated with well completion. However, this likely overestimates emissions associated with workovers, since offtake pipes and gathering lines are always in place when workovers occur (though they may not be in place when the well is initially developed) and this increases the chances that operators will use green completions during refracturing operations.

Table A2-1 | Summary of Parameters in Different Shale / Unconventional Gas Studies

PARAMETER	HOWARTH	JIANG	NETL	BURNHAM
Geographic area	Barnett, Haynesville, Piceance tight sand, Uinta tight sand, Den-Jules	Marcellus	Barnett & Marcellus	Barnett, Marcellus, Fayetteville, Haynesville
EUR, BCF (with range)		2.7	3.13*	3.5 (1.6–5.3)
GWP (integrated time frame)	20-year = 105 100-year = 33	100-year = 25	20-year = 72 100-year = 25	20-year = 72 100-year = 25
GWP (source)	Shindell et al., 2009	IPCC, 2007	IPCC, 2007	IPCC, 2007
Flaring rate for well completions	0	76%	15%	41%
Number of workovers (or refracture) per well lifetime	0	0	3.5	2
Methane emissions per well completion (or workover)	95 to 4,608 tons	26 to 1000 tons	177 tons	177 tons
Primary methane emissions data sources	EPA, GAO, and others	EPA	EPA	EPA

Sources: Howarth et al. 2011; Jiang et al. 2011; NETL 2012; Burnham et al 2011.

Notes: *NETL's EUR value is a simple average of EURs for Marcellus Shale and Barnett Shale, based on data provided in NETL's Table 4-6.

Boundary setting

System boundary setting determines which processes are included in the life cycle assessment (see Box 3). The most comprehensive greenhouse gas LCA study would include all the life cycle stages that have greenhouse gas emissions. However, not all life cycle stages are considered in every LCA study, in part because some stages have significantly fewer GHG emissions associated with them. Ultimately, each study delineates its boundaries differently depending on the study's research objectives (see Branosky et al. 2012 for further discussion).

Calculation Methods

Methane emissions data (including deliberately vented and leaked gases) are usually adapted from top-down or bottom-up estimates published in government or trade association reports.[130] For example, the EPA GHG inventory lists annual methane emissions from specific activities and devices. LCA studies then convert EPA's annual data to a unit production basis by dividing the annual methane emissions by the annual natural gas production (e.g., NETL) or a similar unit of energy output basis.

Indirect CO_2 emissions from energy consumption and material usage can also be calculated using top-down estimates from sources like the Energy Information Administration (EIA), but more commonly indirect CO_2 emissions are estimated using process engineering calculations—by multiplying the amount of energy or material needed for a specific process by the emission intensity per unit of energy (depending on fuel type) or the emission intensity for per unit of material (depending on material type), respectively.

Other important assumptions and parameters

HEATING VALUES

Higher heating value (HHV) is calculated with the product of water being in liquid form while lower heating value (LHV) is calculated with the product of water being in vapor form. NETL (2012) and Jiang et al. (2011) use HHV (1.086 MJ /cf), while others use LHV (1.018 MJ/ cubic feet). The choice of heating value affects every stage of upstream/cradle-to-gate emission estimates because the functional unit used by this paper requires dividing total GHG emissions by the total energy content of natural gas produced. Therefore, the energy content could reflect either the total amount of heat released during combustion (HHV) or the portion of heat that is usable(LHV). Essentially, the latter excludes heat that is lost to water vapor. The choice of heating value does not affect well-to-wire emission estimates because when a higher heating value is used, the efficiency of electricity generation would be correspondingly lower to account for the part of energy that's lost in water vapor.

CO-PRODUCTS

NETL (2012) and Stephenson (2011) assumes co-products like LPG and ethane are produced along with natural gas in the life cycle. Total GHG emissions are apportioned to all the products including natural gas according to their energy contents (87.6 percent in Stephenson and 88.1 percent in NETL). NETL allocates 88.1 percent of the energy requirements and environmental emissions of acid gas removal to the natural gas product.

METHANE CONTENT

Methane content is used when converting gas loss percentage to g CO_2e/MJ or g CO_2e/KWh. Usually methane content changes after it is processed. The number used in conversion is the methane content of produced natural gas; that is, gas that just comes out of a well.

APPENDIX E. METHODOLOGY FOR EMISSIONS PROJECTIONS AND ABATEMENT CALCULATIONS

Developing emissions projections for this working paper necessitated many assumptions, which are outlined below. Modeling the abatement potential of conventional gas and shale gas systems followed a three-step process:

1. Develop a baseline of past emissions and projections of future emissions for both shale gas systems and all natural gas systems in a business-as-usual scenario, as well as high-shale and low-shale production scenarios to establish upper and lower bounds.

2. Calculate emissions reductions due to EPA's recent New Source Performance Standard[131] (NSPS) for the oil and gas industries to determine the impact of that rule on future emissions from natural gas systems, and especially on emissions from shale gas production.

3. Using available data from EPA's GHG inventory and other sources, estimate the amount of emissions mitigation potential from processes and equipment not covered by the NSPS, and provide examples of future rules that could help reduce emissions beyond what is achieved in the NSPS.

The primary data sources for this analysis were EPA's Inventory of Greenhouse Gas Emissions and Sinks[132] (EPA 2012a) and EIA's Annual Energy Outlook[133] (EIA 2012).

Step 1: Develop baseline, high-shale, and low-shale scenarios

The GHG inventory contains data on carbon dioxide (CO_2) and methane (CH_4) emissions from all natural gas systems for 2005–10. EPA activity data from the inventory was used for total emissions for those years, though our model estimates slightly different emissions totals than are presented in the inventory. To project business-as-usual emissions (which do not take into account the recent NSPS but do include reductions from voluntary actions) for the years 2011–35, we began by breaking down emissions by greenhouse gas. For methane, we used emissions data from Weber and Clavin (2012)—broken down by life cycle stage—to calculate emissions factors for both shale gas and conventional gas, expressed as the percentage of total well production that was vented or leaked. We then multiplied these emissions factors by the AEO projections of shale and conventional production through 2035. Because this only captures CH_4 and not CO_2, we had to account for non-combustion CO_2 emissions as well. By using historical CO_2 emissions from natural gas (NG) systems from the GHG inventory, and because CO_2 emissions are relatively constant across NG systems from all formations,[134] we calculated an average rate of million metric tons CO_2 emitted per Tcf of NG production. We then used this emissions factor to project the amount of CO_2 emissions in each year through 2035, and added them to the CH_4 emissions calculated as described above.

The GHG inventory does not break the NG systems summary data down by formation type (e.g., shale gas, tight sands, conventional, etc.), and so emissions from shale gas in all years had to be modeled. For all scenarios, the methane leakage rate for shale gas systems that we used in our calculations was derived from data in Weber and Clavin (2012) as described above. For the business-as-usual scenario for shale gas emissions, this leakage rate was multiplied by the shale gas production in each year, per AEO. Because the leakage rates listed in the studies include only CH_4 and not CO_2, we accounted for CO_2 emissions from shale gas (SG) systems by multiplying the fraction of production from SG in each year (derived from EIA 2012) by the total actual or projected CO_2 emissions in that year, as described above.

To calculate the emissions resulting from a high-shale estimated ultimate recovery (EUR) scenario, excluding the NSPS rule, we substituted the high-shale EUR case from EIA (2012) for the reference case, and assumed that the percentage of SG wells voluntarily performing green completions remains constant. In the high-shale EUR case, SG production grows at a faster rate than conventional NG production, so that by 2035 SG production is 18 percent greater in the high EUR case than in the reference case. Emissions from SG are concomitantly greater as well.

For the low-shale EUR scenario, we substituted the low-shale EUR case from EIA (2012) for the reference case, and assumed that the percentage of SG wells voluntarily performing green completions remains constant. In this scenario, production from shale formations is lower than in the reference scenario, while non-shale production is higher, so shale and non-shale emissions are lower and higher, respectively, than in the reference scenario.

Step 2: Calculate emissions reductions due to the NSPS

To determine how much abatement potential remained after the implementation of EPA's NSPS for oil and gas systems, it was first necessary to calculate the emissions reductions that would result from the NSPS. Because the final rule was announced in April 2012 and enters into force in January 2013, our model first captures reductions in 2013. And because EPA, after listening to concerns from industry about the availability of equipment required to perform green completions, allows for the flaring of natural gas leaked during well completions until full compliance in 2015, our model phases in the reductions expected from the rule over 2013–14. We therefore assume that two-thirds of methane from completions and workovers is flared and one-third is captured in 2013; one-third is flared and two-thirds is captured in 2014; and all gas is captured in 2015 and each year thereafter.

To quantify the amount of methane released during completions of fractured and refractured wells, we used the number of completions and workovers performed (from the GHG inventory) and SG production data from AEO to calculate the average amount of gas produced per completion and workover in 2005–10. We then multiplied this number by projected SG production from AEO to estimate the number of new completions and workovers that would be performed in each year in the business-as-usual, high-shale EUR, and low-shale scenarios. Using EPA's emissions factor of 9,000 Mcf of natural gas per completion,[135] we converted the emissions factor to MMt CH_4,[136] multiplied this by the number of completions and workovers performed in each year, and multiplied that total by the amount of VOC emissions required to be captured by EPA (95 percent), by the percentage of wells with enough pressure to perform green completions (90 percent), and by the percentage of wells not already performing voluntary green completions to derive the total of methane emissions from completions and workovers that would be reduced in each year due to the new rule.[137] Beginning in 2013, because all of these emissions are either captured or flared, this number was subtracted from the total SG emissions figure. However, because we assume that two-thirds of gas leaked during well completion is flared in 2013, and one-third in 2014, CO_2 emissions from flaring were added back in.[138]

Furthermore, the NSPS includes emissions standards for some new production and processing equipment as well. The GHG inventory provides data for the emissions from each type of covered equipment[139] from 2006–10 for all NG systems. Because emissions from these processes do not differ greatly between shale gas and conventional gas, we used the data from these five years to create an average rate of methane emissions per Tcf of production. We then multiplied this by the projected total NG production in each year, and by the production from SG in each year, and subtracted the resulting quantity of emissions from covered equipment from the total respective NG and SG emissions in that year. Because the NSPS only applies to new (and not existing) equipment, emissions reductions from this part of the rule are phased in over the average lifetime of this equipment, which we have estimated to be 15 years.

To calculate the effect of the NSPS rule on all NG emissions (not just SG), we subtracted the SG emissions reductions from the business-as-usual scenario. However, because the production and processing equipment covered by the rule is not specific to SG systems, we had to account for those emissions reductions as well. To do so, we subtracted the emissions from covered equipment from all NG production, not including SG. In summary, we took business-as-usual emissions and then subtracted emissions from well completions and workovers, emissions from covered SG processing equipment, and emissions from all other covered processing equipment.

Step 3: Estimate remaining abatement potential and ways to further mitigate emissions

After emissions reductions due to the EPA rules were accounted for, we investigated ways to further reduce the remaining emissions from NG systems. We calculated which processes, of those not addressed by EPA rules, had the greatest emissions, and researched methods and equipment that could capture leaked or vented gas, or prevent or preclude the leaking or venting altogether.

For each additional abatement measure, we calculated costs and savings in each year to gauge cost-effectiveness, and projected quantities of emissions reductions that could be achieved through future EPA rules.

COST-EFFECTIVENESS

We first calculated the initial and annual costs of the equipment required for each abatement process, using cost estimates from EPA's Natural Gas Star Program,[140] NRDC's Leaking Profits report (Harvey et al. 2012), and industry experts, updated to 2012 dollars and using the high end of the range of possible costs, when available. We then calculated, in each year, the cumulative cost of purchasing and operating that equipment to date.

To calculate the savings achieved, we first projected the quantity of leaked or vented gas that could be captured or avoided through the implementation of each process, using data from EPA Natural Gas STAR, NRDC, and industry experts. To calculate a dollar value for the avoided emissions of natural gas, we multiplied the quantity of fugitive emissions captured or mitigated by the projected price of gas in each year, taken from the EIA (2012) reference case.

We subtracted the cumulative costs from the cumulative savings in each year, calculated the net present value of the difference using a 7 percent discount rate, and evaluated the breakeven point. Of the three abatement processes listed in this paper, the replacement of high-bleed pneumatic devices with low-bleed equivalents was the slowest to turn a profit, in just over three years.[141]

We did not independently estimate the cost-effectiveness of emissions control technologies used in the "Go-Getter" scenario. However, Harvey et al. (2012) estimated that all of these proposed technologies and measures would turn a profit in less than three years.

Table A3-1 | Cost Effectiveness Calculations for Three Abatement Processes

TECHNOLOGY	INITIAL COST	ANNUAL COST	GAS CAPTURED, PER FACILITY (MCF)	PAYBACK PERIOD (YEARS)
Plunger Lifts	$11,813	$1,482	2,670	1.1
Replacing High-Bleed Pneumatics	$3,420	$0	255	3.1
Leak Detection and Repair	$59,000	$59,000	29,400	0.9

Sources: EPA Natural Gas STAR (2013c); Harvey at al. 2012.

Notes: Initial and annual costs are presented in 2012 dollars. For plunger lifts, we assumed initial cost based on the high-end of the range provided by Natural Gas STAR; annual costs were based on Harvey et al., while gas captured per facility was based on the average of low end of range from Harvey, et al. and low end of range from EPA Gas STAR (this accounts for fact that production levels at older wells is lower than new wells, so amount of gas that can be captured by plunger lifts declines over time). For replacements of high-bleed pneumatics, estimates of initial cost and gas captured per facility were taken from Natural Gas STAR. For LDAR, estimates of initial cost and gas captured per facility were taken from Harvey at al.

EMISSIONS REDUCTIONS

After a process was deemed to be cost-effective under our assumptions, we calculated the emissions reductions that would result from a future EPA rule requiring its implementation. We had already calculated the methane emissions reductions per facility, above. To calculate the number of facilities that would be implementing each process in each year, we used emissions and facilities data from the GHG inventory data from 2006–10 and historical gas production figures from EIA (2012) to calculate a constant emissions factor of MMt CH_4 per Tcf gas produced. We then used this emissions factor as a proxy to scale up projected emissions from each process in each year as production increased. This gave us an upper bound for the total potential quantity of emissions that could be addressed with an EPA rule targeting that process.

To calculate the expected emissions reductions in each year, we multiplied this upper bound by a conservative estimate of the percent of emissions that could be captured or avoided through the use of currently available technology, and by the percentage of facilities not already utilizing that technology voluntarily. To ensure our numbers were conservative, we used the low end of the range provided by industry experts for the percentage of emissions that could be reduced with the use of each technology, and the high end of the range of percentage of voluntary adoption. We performed these calculations for the reference case, high-shale EUR, and low-shale scenarios with a 20-year GWP.

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ENDNOTES

1. "Upstream" refers to life cycle stages beginning with exploration, up to and including natural gas transmission and storage. It does not include end-use combustion or distribution systems (that is, past the city gate). Fugitive methane emissions from natural gas distribution systems represent a significant source of emissions, but these are beyond the scope of this working paper.
2. Methane emissions from natural gas systems represent 4 percent of economy-wide emissions when assuming the more current (IPCC 2007) global warming potential (GWP) of 25 for methane (see Box 1). The 3 percent estimate by EPA is based on an out-of-date GWP of 21 (IPCC, 1995), for the sake of consistency with UNFCCC reporting guidelines. In EPA's draft GHG inventory for 2013, methane emissions from natural gas systems represent 2.6 percent of total U.S. GHG emissions (3 percent when using the updated GWP of 25), due to a change in methodology. These are draft estimates; the final GHG inventory for 2013 will be released after this paper goes to press.
3. Eighty-six percent of natural gas and petroleum systems emissions are from natural gas systems, according to data from EPA's 2012 GHG inventory. Note that data published under the GHG reporting rule (EPA 2011c) are not complete; only facilities with emissions greater than 25,000 metric tons of CO_2e are required to report emissions data to EPA. See: <http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=189038685>.
4. EPA's 2012 GHG inventory estimated that methane emissions from U.S. natural gas systems grew by roughly 14 percent between 1990 and 2010 as a result of increased domestic consumption of natural gas (EPA 2012a). However, according to EPA's draft 2013 GHG inventory, methane emissions have fallen by 11 percent during this same time period (EPA 2013a), even as total gas production has grown by 20 percent (EIA 2013).
5. Again, this estimate by EPA is based on an out-of-date GWP of 21, based on IPCC's SAR (1995), for the sake of consistency with UNFCCC reporting guidelines.
6. This conclusion is also consistent with Levi (2013), who finds that higher methane leakage rates would lead to more rapid increases in global temperatures and greater peak warming in a climate stabilization scenario.
7. See IPCC 2007, available at: <http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2.html>.
8. The 100-year time horizon for GHG accounting is the standard international convention; however, this perspective also gives an incomplete picture of atmospheric warming effects caused by non-CO_2 gases, each of which have different radiative properties and different residence times in the atmosphere.
9. These findings account for life cycle GHG emissions from oil and natural gas systems, upstream CO_2 emissions associated with petroleum refining (which is energy-intensive), and the fact that gasoline cars and diesel-fueled heavy-duty vehicles are relatively more energy efficient than comparable CNG vehicles.
10. Conversion efficiency estimates are based on heat rates published by EIA (and assuming the equivalent Btu content of a kWh of electricity is 3,412 Btu). Available at: <http://www.eia.gov/totalenergy/data/monthly/pdf/sec13_6.pdf>.
11. Because it does not take energy conversion efficiency into account, Figure 3 presents a conservative estimate of the relative advantage that natural gas has over coal when used for electric power generation (assuming low methane leakage rates).
12. These calculations are derived using EPA inventory numbers (total methane emissions in 2010) plus methane emissions from associated natural

gas production (from the GHGRP; source: http://www.epa.gov/ghgreporting/ghgdata/reported/index.html) in the numerator and total gross withdrawals in the denominator (source: <http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm>).The difference in these estimates is driven entirely by the significant change in the methodology used to calculate production emissions—and in particular, emissions from liquids unloading—in the draft 2013 GHG inventory. A longer discussion of the changes between the 2012 and draft 2013 inventories can be found in Appendix 1. To ensure comparability between the numerator and denominator, we assume a 90 percent average methane content of gas. These leakage rates were calculated based on total annual emissions and production data from the year 2010, as presented in the 2012 and draft 2013 inventories. Meanwhile, published leakage rate estimates (Table 1) were calculated assuming different estimated ultimate recovery (EUR) values, which apply over the lifetime of the average well.

13. See: <http://www.eia.gov/forecasts/archive/aeo12/source_natural_gas_all.cfm#uscrude>.
14. Life cycle stages are a useful categorization of the interconnected steps in a product's life cycle for the purposes of organizing processes, data collection, and inventory results (WRI & WBCSD, 2011). In this paper we refer to the following life cycle stages: exploration, site preparation, vertical and horizontal drilling, hydraulic fracturing, well completion, well production, processing, transmission, and end-use combustion.
15. The purpose of this discussion is to highlight differences between the findings of previous studies, both graphically and through discussion. Unlike Weber and Clavin (2012) or Logan et al. (2012), this study deliberately takes minimal steps to harmonize results from previous studies; functional units and heating rates are converted, but other assumptions are not adjusted.
16. Recognizing significant uncertainties regarding the quality of currently available data and to avoid replicating the work of others, the goal of this section is not to produce our own "best estimate" of life cycle GHG emissions from shale or conventional natural gas resources. For such an assessment, readers are referred to Weber and Clavin (2012) and Logan et al. (2012).
17. Though useful and informative to our assessment, Stephenson et al. (2012) was not included because it was intended more as a modeling exercise than as a realistic assessment of upstream emissions from U.S. natural gas systems; and Hultman (2011) was not included because its LCA was relatively limited in scope to shale gas only (e.g., not directly comparable to life cycle emissions from other energy sources).
18. It should be reiterated that most previous LCA studies rely heavily on EPA data when calculating life cycle emissions, which helps to explain why they often reach similar conclusions. As discussed below, Howarth et al. (2011) estimate much higher leakage rates, which is largely attributable to their choice of alternative data sources.
19. Authors of the industry report that was used as the source for Howarth et al.'s (2011) Haynesville emission factor have been sharply critical of Howarth's study, charging misuse of their data (IHS/CERA 2011). Cathles et al. (2012) echo the main criticisms raised by IHS CERA. These criticisms are disputed in Howarth et al. (2012b).
20. Potential emissions are the emissions that could have occurred in absence of the appropriate emissions control technologies. Actual emissions are emissions from the emitting source or activity after application of emission controls.
21. The 700 percent estimate used here is derived by comparing Howarth et al.'s (2011) 4638 Mg CH_4/well estimate (converted from Howarth's Table 1) with O'Sullivan and Paltsev's (2012) "all-vented" estimate of 632.7 Mg CH_4/well (O'Sullivan and Paltsev's Table 4). Note, the "all vented" scenario assumes zero flaring or capture.
22. In calculating the high end of his range of life cycle emissions, Howarth et al. (2011) assumes that liquids unloading emissions of shale gas are equal to that of conventional gas.
23. Note that Howarth et al. (2011) presented transmission and distribution-stage emissions together; however, Figure 4 shows our estimates of transmission-only emissions, based on Weber and Clavin's (2012) analysis of the Howarth study (See Table SI-5, Weber).
24. For the purpose of this paper (and with reference to attributable processes outlined in the figure in Box 4), "pre-production" includes exploration, site preparation, vertical and horizontal drilling, hydraulic fracturing, and well completion; "production" only includes well production; "processing" includes onsite processing and offsite processing; and "transmission" includes transmission and storage (but not distribution). "End-use combustion" is discussed throughout this working paper; however, our analysis typically avoids assigning end uses and, rather, presents end use in terms of heat input, or delivered energy, not accounting for end-use efficiency (see functional unit, in Box 4). While the four upstream life cycle stages used by this study include many of the attributable processes defined by Branosky et al (2012), these stages and some of the processes included in this paper do not directly align with processes in Branosky et al.
25. The average efficiency for natural-gas-fired power plants is 41.8 percent, while coal-fired plants only have an average efficiency of 32.7 percent. See: endnote 10.
26. Hydraulic fracturing of conventional wells will typically use less than 80,000 gallons of water per well. Meanwhile, unconventional hydraulic fracturing may use between 3 and 7 million gallons of water per well. See: <http://www.oilandgasbmps.org/resources/fracing.php>.
27. For this discussion, we rely on National Energy Technology Laboratory (NETL) data because they have usefully published detailed life cycle results for methane and carbon dioxide separately.The same data are also used as the basis for static emissions scenarios, presented in section 4 of this working paper. We reiterate that reasonable assumptions used in different life cycle assessments lead to different emissions estimates. For example, Logan et al. (2012) find that CO_2 emissions represented more than half of all upstream GHG emissions for the Barnett Shale basin, when integrated over a 100-year time frame (find more discussion of uncertainties in section 2).
28. Though not all studies are consistent in their use of terminology for describing fugitive emissions, we use the following conventions, which are consistent with the EPA inventory and the IPCC. The difference between leaked and vented emissions is that leaked emissions refer to unintentional emissions, while vented emissions refer to those intentionally emitted. Vented emissions also include those inevitable routine releases from valves and other pneumatic devices. Fugitive emissions refer to both intentional and unintentional emissions from systems that extract, process, and deliver fossil fuels.
29. U.S. EPA, 49518 Federal Register / Vol. 77, No. 159 / Thursday, August 16, 2012.
30. O'Sullivan and Paltsev (2012)conducted a detailed analysis of methane emissions from well completions at nearly 4,000 hydraulically fractured horizontal wells across multiple natural gas basins in the U.S.
31. See: <http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf>.
32. For more information on vapor recovery units and other abatement technologies mentioned in this paper, see EPA Gas STAR's list of recommended technologies and practices at: <http://www.epa.gov/gasstar/tools/recommended.html>.
33. Note, however, that the extent of natural gas processing is regionally variable; e.g., some wells produce natural gas containing fewer impurities, thus requiring little or no processing.

34. See: <http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf>.
35. See: <http://www.eia.gov/oiaf/1605/ggrpt/documentation/pdf/0638%282008%29.pdf>.
36. In addition to Alvarez et al. (2012), Moniz et al. (2011, chapter 5) explore end-use efficiencies, emissions and other demand-side aspects of the natural gas value chain.
37. For example, the Energy Information Administration's Annual Energy Outlook 2012 reference case projects an annual growth rate in shale gas production of 4.1 percent, up from 3.8 percent in the AEO 2011. This leads to a difference of over 11 percent in EIA's projection of the proportion of natural gas production from shale in 2035. See: http://www.eia.gov/forecasts/aeo/source_natural_gas.cfm, Table 14.
38. EPA's draft GHG inventory for 2013 was released for public comment on February 22. The final version of the report is slated for release on April 15, after this working paper goes to press. A discussion of how the draft 2013 inventory compares to the 2012 inventory can be found in Appendix 1.
39. Available at: <http://www.api.org/news-and-media/news/news-items/2012/oct-2012/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf>.
40. See, for example, EPA's analysis of emissions reductions from the new rules in Table 3-3 of the agency's regulatory impact analysis, available at: <http://www.epa.gov/ttnecas1/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf>.
41. The NSPS requires that gas released during well completions be captured or flared beginning in 2013, and captured beginning in 2015. Because flaring increases CO_2 emissions but reduces methane emissions, the NSPS will result in significant emissions reductions beginning in 2013, and slightly greater reductions in 2015 and beyond.
42. Due to data limitations, the static emissions scenarios for shale gas and conventional gas (below) were calculated using methane and carbon dioxide emissions data provided by NETL, while longer-term emissions projections were calculated with CO_2e emissions data from Weber (which derives a best estimate based on results from several LCA assessments, including NETL). Differences between the two studies in the estimates of methane emissions, primarily from the production and processing stages, account for the slight discrepancy in calculated emissions reductions in 2015, when comparing the static emissions scenarios and the long-term emissions projections.
43. These emissions figures were calculated using the 100-year global warming potential (GWP) of methane, 25.
44. See: <http://epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf>.
45. As a simplifying assumption, our analysis does not assume any correlation between EUR and leakage rate.
46. EPA's draft 2013 inventory adopts the emissions factors for liquids unloading from the API/ANGA study. Therefore, modeling results for the post-NSPS emissions projections were comparable between the two data sources.
47. See: <http://www.epa.gov/otaq/climate/regulations/scc-tsd.pdf>.
48. For example, previous WRI analysis has highlighted the weaknesses of the working group's approach (see http://www.wri.org/publication/more-than-meets-the-eye-social-cost-of-carbon), and the IPCC Fourth Assessment Report notes that, of the more than 100 peer-reviewed estimates of the social cost of carbon completed by 2007, the mean value was $43 per metric ton (in 2007 dollars). See: <http://www.ipcc.ch/publications_and_data/ar4/wg2/en/ch20s20-es.html>.
49. This figure is consistent with the low-ambition, "lackluster" scenario in other WRI publications, including Bianco et al. (2013). Each technology is cost-effective even in the absence of a price on carbon emissions, though with a slightly longer pay-back period.
50. There are many processes beyond those listed here that are cost-effective means of reducing emissions (EPA 2013c). EPA also demonstrates the cost savings potential of the technologies on their Gas STAR website, but due to assumptions that are often less conservative than our own and our use of updated natural gas price projections, the pay-back periods listed by EPA may be different from ours.
51. EPA could develop a single rule addressing all three emission mitigation opportunities listed in this section, in much the same way that their recent NSPS and NESHAP included standards for gas wells, compressors, controllers, and storage tanks.
52. The API/ANGA survey, and the draft EPA GHG inventory for 2013, conclude that emissions from liquids unloading are only a small fraction of what EPA estimated in the 2012 GHG inventory. We base our estimates on the final, peer-reviewed 2012 EPA inventory, but if future studies determine that liquids unloading does not represent a significant source of methane emissions, then cost-effective abatement potential will necessarily be reduced from what we present here.
53. As discussed in section 2, the practice of liquids unloading is more prevalent in conventional gas wells than shale gas wells, much as well completions and workovers are a more significant source of emissions from shale gas wells than conventional gas wells. Even as gas production increases in the coming decades—because much of that increase is likely to come from shale gas (even at the expense of conventional gas production)—GHG emissions from liquids unloading do not increase over time.
54. Understanding the prevalence of liquids unloading and the emissions associated with it is still evolving. For example, in the API/ANGA study, industry estimates that emissions from liquids unloading accounted for only 8 million metric tons CO_2e in 2010, compared to 85.7 million metric tons in the EPA inventory. See: <http://www.epa.gov/climatechange/Downloads/ghgemissions/2012Workshop/EPA-Liquids_Unloading.pdf>. Forthcoming studies that will include measurement data should bring some clarity to this issue.
55. According to the Global Methane Initiative, 84 percent of pneumatic device emissions come from the production stage, and most of the remainder is from compressor stations in the transmission stage. See <http://www.globalmethane.org/documents/events_oilgas_20051006_methanerec_pd_vru_dehy.pdf>.
56. See descriptions of various leak screening techniques at: <http://www.epa.gov/gasstar/documents/ll_dimgatestat.pdf>.
57. The 1 percent methane leakage rate shown in Figure 17 is calculated relative to total observed and projected (EIA 2012) dry gas production of natural gas in the U.S. Since total dry gas production is a lower number than gross withdrawals (a more typical basis used for calculating leakage rate, Alvarez et al. 2012) this approach results in a relatively ambitious performance benchmark. Still, given uncertainties regarding EUR from future wells, we feel that this approach offers a reasonable approximation.
58. In addition to green completions and reducing emissions from centrifugal compressors with wet seals, as required by the NSPS, the technologies included in the "go-getter" scenario are plunger lifts, TEG dehydrators, dessicant dehydrators, improved compressor maintenance, low-bleed pneumatic controllers, pipeline maintenance and repair, vapor recovery units, and leak detection and repair. For more details on the "go-getter" scenario for natural gas systems, see <http://pdf.wri.org/can_us_get_there_from_here_full_report.pdf>.
59. See <http://www.epa.gov/airquality/oilandgas/basic.html>.
60. Ground-level ozone is sometimes NOx-limited and sometimes VOC-limited, depending on the part of the country and the time of year.
61. See: <http://www.epa.gov/glo/health.html>. McKenzie et al. (2012)

found that residents living within ½ mile of natural gas development in Colorado were at greater risk of health effects caused by exposure to air toxics, including benzene.

62. See: <http://www.epa.gov/oar/toxicair/newtoxics.html>.
63. Methane is a relatively stable organic compound and therefore not regulated by EPA with other VOCs.
64. The RFF study defined "consensus risks" as those that survey respondents from all four expert groups most frequently identified as needing further regulatory or voluntary action.
65. As with previous sections of this working paper, "upstream" refers to life cycle stages beginning with exploration, up to and including natural gas transmission and storage, and not including end-use combustion or distribution systems (i.e., past the city gate). Fugitive methane emissions from natural gas distribution systems may be a significant source of emissions and therefore additional policies to address these emissions are likely worth pursuing; however, these are beyond the scope of this working paper.
66. While natural gas systems are the focus of this paper, many of the underlying regulatory authorities and frameworks—at the federal and state levels—apply equally to the oil and gas industry, more broadly.
67. These are referred to as "criteria" pollutants because EPA regulates them by setting permissible levels based on human health and environmental criteria.The other five "criteria" air pollutants are lead, sulfur dioxide (SO_2), particulate matter (PM2.5 and PM10), nitrogen dioxide (NO_2), and carbon monoxide (CO).
68. An updated SIP is not required for areas in marginal nonattainment areas (only in moderate, serious, severe and extreme nonattainment areas). See Environmental Protection Agency, Federal Register /Vol. 77, No. 30 / Tuesday, February 14, 2012, 40 CFR Parts 50 and 51.
69. See: <http://www.epa.gov/oaqps001/greenbk/hnca.html#8600>.
70. EPA may delegate authority to states to implement and enforce NSPS regulations, to the extent that states request such authorities within their state implementation plans.
71. See: <http://www.epa.gov/airquality/oilandgas/actions.html>.
72. See: <http://www.epa.gov/climatechange/endangerment/>.
73. A 2007 U.S. Supreme Court decision required the EPA to make this scientific determination.The finding was challenged and upheld in a June 2012 decision by the U.S. Court of Appeals for the D.C. Circuit, which also affirmed the EPA's authority to regulate GHGs under the Clean Air Act.
74. Several environmental groups—including the NRDC, EDF, Sierra Club, and Earth Justice—filed a similar notice of intent to sue EPA in August 2012.
75. See: <http://www.ag.ny.gov/pdfs/ltr_NSPS_Methane_Notice.pdf>.
76. EPA may delegate authority to states to implement and enforce regulations under section 112, to the extent that states request such authorities within their state implementation plans.
77. FY2008 Consolidated Appropriations Act (H.R. 2764).
78. See: <http://www.gpo.gov/fdsys/pkg/FR-2009-10-30/pdf/E9-23315.pdf>.
79. See: <http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=189038685>.
80. See: <http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=189038686>.
81. See the EPA fact sheet describing the difference between the GHGRP and the GHG inventory: <http://www.epa.gov/climatechange/Downloads/ghgemissions/inventory-factsheet.pdf>.
82. For more information, see: <http://www.environmentalintegrity.org/news_reports/documents/2012_10_24TRIPetitionFINALSIGNED.pdf>.
83. For more information on the statutory authority granted to DOI and BLM to regulate oil and gas production on Federal and Indian lands, see: <http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/Energy_Facts_Enforcement.html>.
84. For example, BLM's Onshore Oil and Gas Order Number 6 from 1990 (available at: <http://www.blm.gov/pgdata/etc/medialib/blm/nm/programs/0/og_docs/onshore_orders.Par.54461.File.dat/ord6.pdf>) requires gas drillers to submit a drilling operations plan with their application for permit to drill if hydrogen sulfide levels in the gas stream are expected to be 100 parts per million or greater. Many states eventually followed suit with hydrogen sulfide rules of their own (see Table 19 of GAO's report on Unconventional Oil and Gas Development, available at: <http://www.gao.gov/assets/650/647782.pdf>). Colorado's rule in particular is very similar to BLM's Onshore Oil and Gas Order Number 6.
85. For more information, see: <http://www.blm.gov/wy/st/en/info/NEPA/documents/pfo/anticline/seis.html>.
86. See: <http://www.blm.gov/pgdata/etc/medialib/blm/ut/vernal_fo/planning/greater_natural_buttes/record_of_decision.Par.86388.File.dat/Cover_ROD.pdf>.
87. See: <https://www.federalregister.gov/articles/2012/05/11/2012-11304/oil-and-gas-well-stimulation-including-hydraulic-fracturing-on-federal-and-indian-lands>.
88. In September 2012, a petition was filed for the secretary of the Department of Interior to expand agency efforts to reduce air emissions from oil and gas operations: <http://www.biologicaldiversity.org/programs/public_lands/energy/dirty_energy_development/oil_and_gas/pdfs/12_9_11__BLM_Nonwaste_Petition.pdf>.
89. See: <http://www.colorado.gov/cs/Satellite/CDPHE-AP/CBON/1251594423029>.
90. Wyoming DEQ. 2010, "Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance."Available at: <http://deq.state.wy.us/aqd/oilgas.asp>.
91. Find other examples and further discussion of western states with air regulations of the oil and gas sector that predate or go further than the NSPS/NESHAP rule in Gribovicz (2011).
92. Full text of the bill is available at: <http://ilga.gov/legislation/98/HB/PDF/09800HB2615lv.pdf>.
93. For a summary of the bill and its provisions, see <http://elpc.org/illinoisfrackingbill>.
94. See: <http://www.eia.gov/todayinenergy/detail.cfm?id=4030>.
95. See: <http://www.eia.gov/forecasts/aeo/er/executive_summary.cfm>.
96. Fuel Retention Practices of Natural Gas Companies, FERC Stats.&Regs.¶ 35,556 (2007) (Notice of Inquiry). Available at: <http://www.ferc.gov/whats-new/comm-meet/2007/092007/G-1.pdf>.
97. See: <http://www.ferc.gov/whats-new/comm-meet/2009/031909/G-2.pdf>.
98. For example, since 2009, FERC has been leading an initiative to assess the economic viability of installing waste heat recovery systems at compressor stations to increase their energy efficiency. See: <http://www.ferc.gov/about/strat-docs/FY-09-14-strat-plan-print.pdf>.
99. See: <http://www.naturalgas.org/business/industry.asp>.
100. See: <http://www.shell.us/aboutshell/shell-businesses/onshore/principles.html>.
101. See: <http://037186e.netsolhost.com/site/performance-standards/>.
102. See: <http://fracfocus.org/>.
103. See: <http://www.ewg.org/release/california-issues-early-draft-fracking-regulations>.
104. A lack of high-quality, comprehensive data has hindered the development of such rules in the past. For example, data limitations with respect to VOC emissions from oil production operations was cited by EPA as a primary reason why the NSPS/NESHAP rules did not apply to oil wells with associated natural gas.

105. We gratefully acknowledge the experts who attended an all-day workshop that WRI co-hosted with the Environmental Defense Fund on October 16, 2012. The policy options in this study were developed based on WRI research. While these options draw heavily from input provided at the workshop, they are not necessarily endorsed by the workshop participants.
106. RBLC stands for "RACT/BACT/LAER Clearinghouse." Reasonably achievable control technology (RACT), best available control technology (BACT), and lowest achievable emission rate (LAER) are all terms for different program requirements under the Clean Air Act. For information on the clearinghouse, see: <http://cfpub.epa.gov/RBLC/>.
107. See: <http://www.epa.gov/ozoneadvance/>.
108. See: <http://www.edf.org/energy/natural-gas-policy>.
109. See: <http://www.tceq.state.tx.us/permitting/air/announcements/nsr_announce_9_30_09.html>.
110. The TRI was established by Congress in 1986, as part of the Emergency Planning and Community Right-to-Know Act.
111. For more information, see: <http://www.environmentalintegrity.org/news_reports/documents/2012_10_24TRIPetitionFINALSIGNED.pdf>.
112. This could be conducted by the National Energy Technology Laboratory, which is already engaged in research designed to reduce the environmental risks associated with developing unconventional natural gas resources. See: <http://www.netl.doe.gov/technologies/oil-gas/ngres/index.html>.
113. Per AEO
114. See: <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.
115. As a party to the convention, the U.S. has agreed to annually submit an official GHG inventory. The U.S. has also committed to the convention's objective to achieve "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."
116. The year 2007 is chosen as a benchmark for illustrative purposes only.
117. Find basic information on the rule here: <http://www.epa.gov/ghgreporting/basic-info/index.html>.
118. Find specifics of Subpart W here: <http://www.epa.gov/ghgreporting/reporters/subpart/w.html>.
119. See: <http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=189038685>.
120. See: <http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=189038685>.
121. See: <http://www.edf.org/news/2012/10/11/study-will-measure-methane-leakage-during-natural-gas-operations>.
122. See: <http://www.engr.utexas.edu/news/7416-allenemissionsstudy>.
123. See: <http://www.epa.gov/climatechange/Downloads/ghgemissions/2012Workshop/EDF_Alvarez.pdf>.
124. Harmonization is a form of meta-analysis, through which results from previous studies are systematically adjusted to enable more direct comparisons.
125. This best estimate is bound by a large range of uncertainty, with possible leakage rates from 2.3 percent to 7.7 percent of total annual production.
126. See: <http://www.eia.gov/forecasts/archive/aeo12/table_14.cfm>.
127. Since Shires and Lev-On (2012) was not a peer-reviewed study, its findings may remain an issue of dispute.
128. EPA had estimated that 0.118 workovers (i.e., refractures) occur per well-year. This translates to 3.5 refractures during the average 30-year well lifetime (NETL).
129. Since the final rule had not yet been published.
130. For the same process, GHG emissions may be calculated using top-down or bottom-up approaches (Weber and Clavin 2012). Top-down methods are typically based on aggregated data that are representative of national or basin-wide emissions. Bottom-up methods rely more on site-specific emissions measurements and process engineering calculations that are specific to emission pathways.
131. Text of the final rule available at: <http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf>.
132. See: <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.
133. See: <http://www.eia.gov/forecasts/archive/aeo11/>.
134. Emissions of CO_2 in natural gas systems are primarily due to flaring at the wellhead and the use of electricity or natural gas to power equipment at each stage in the gas life cycle.
135. See Technical Support Document (TSD) for NSPS rule, pp. 1-14. Available at: <http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf>.
136. Using an average methane content of unprocessed shale gas of 83 percent, as listed in TSD (EPA 2012c).
137. The 95 percent and 90 percent figures are both taken from the TSD (EPA 2012c).
138. To convert CH_4 to CO_2, we referred to the chemical formula ($CH_4 + 2O_2 \rightarrow 2H_2O + CO_2$) and used the atomic weights of each molecule to convert 1 metric ton of CH_4 to 2.8 metric tons of CO_2.
139. Equipment covered by the NSPS includes reciprocating compressors, wet seal centrifugal compressors and pneumatic devices during the processing stage, and compressor and pipeline leaks during the preproduction and production lifecycle stages.
140. For descriptions of these technologies as well as their costs, see: <http://www.epa.gov/gasstar/tools/recommended.html>.
141. Some of our payback periods are longer than those calculated by EPA, due to differing methodologies, updated projections of gas prices, and our more conservative approach.

Bleed rate: The rate at which natural gas is released from pneumatic devices during normal operations.

Blowdown: The removal of undesirable gas from a well or production system through venting or flaring. Wells that have been shut in for a period frequently develop a gas cap caused by gas percolating through the fluid column in the wellbore that needs to be removed before work can commence on the well (adapted from Schlumberger 2012).

Combustion: The process of igniting a fuel (typically in a boiler, incinerator, or engine) to release energy in the form of heat.

Compressors: Mechanical devices that pressurize a gas to reduce its volume.

Distribution: The conveyance of natural gas and associated products to the end user through local pipeline systems (adapted from API 2012). Distribution pipelines are smaller in diameter than transmission pipelines.

Equipment leaks: Emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

Expected ultimate recovery: The amount of gas expected to be economically recovered from a reservoir or field by the end of its producing life (adapted from Schlumberger 2012).

Exploration: Generally, the act of searching for potential subsurface reservoirs of gas or oil. Methods include the use of magnetometers, gravity meters, seismic exploration, surface mapping, exploratory drillings, and other such methods (AGA 2012).

Flaring: Deliberate burning of natural gas and waste gas/vapor streams, without energy recovery (IPCC 2006).

Flowback: Used treatment fluid, natural gas and debris that returns to the surface upon release of pressure on the wellbore in the hydraulic fracturing attributable process (adapted from Branosky et al. 2012).

Fugitive emissions: Both intentional and unintentional emissions from systems that extract, process, and deliver fossil fuels (IPCC 2006).

Global Warming Potential (GWP): Calculated as the ratio of the radiative forcing of one kilogram of greenhouse gas emitted to the atmosphere to that from one kilogram of CO_2 over a period of time (e.g., 100 years) (IPCC 2006).

Heating value: The amount of heat produced by the complete combustion of a unit quantity of fuel. The gross of higher heating value is obtained when all of the products of combustion are cooled to the temperature existing before combustion, the water vapor formed during combustion is condensed, and all the necessary corrections have been made. The net or lower heating value is obtained by subtracting the latent heat of vaporization of the water vapor, formed by the combustion of the hydrogen in the fuel, from the gross or higher heating value (AGA 2012).

Hydraulic fracturing: A stimulation treatment in which specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing vertical fractures to open. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid to keep the fractures open once the treatment is complete (adapted from Schlumberger 2012).

Liquids unloading: The process of removing liquid from the wellbore that would otherwise slow production in a mature well. Some approaches include using a down-hole pump or reducing the wellhead pressure (Branosky et al. 2012).

Processing (onsite and offsite): The act of removing assorted hydrocarbons or impurities such as sulfur and water from recovered natural gas. Initial settling could occur in onsite storage pipes or tanks. Natural gas is then transported offsite through gathering lines, where further processing occurs.

Shale gas systems: All of the processes, equipment, and associated emissions from the upstream (i.e., up to, but not including, combustion) stages of the shale gas life cycle.

Site preparation: The act of priming a location for natural gas activities, including securing permits, procuring water and materials, constructing the well pad, preparing access roads, laying gathering lines, and building other necessary infrastructure.

Storage: Process of containing natural gas, either locally in high pressure pipes and tanks or underground in natural geologic reservoirs (e.g., salt domes, depleted oil and gas fields) over the short- or long-term (adapted from AGA 2012 and SOG 2012).

Transmission: Gas physically transferred and delivered from a source or sources of supply to one or more delivery points (EIA 2011).Transmission lines are larger in diameter than distribution lines.

Vented emissions: Intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

Vertical and horizontal drilling: The directional deviation of a wellbore from vertical to horizontal so that the borehole penetrates a productive shale formation in a manner parallel to the formation (adapted from OSHA 2012). WRI assumes that the vertical and horizontal drilling attributable process includes disposal of mud (i.e., liquid circulating the wellbore during drilling) and placement and cementing of the well casing.

Volatile organic compound (VOC): Organic chemicals, either manmade or naturally occurring, that can be dangerous to human health or the environment. Though most are not acutely toxic, they can have negative long-term health effects.

Well closure/site remediation: At the end of a well's working life, the process of ending production by plugging the wellbore, removing equipment, and returning the site to pre-drilling conditions.

Well completion: A generic term used to describe the events and equipment necessary to bring a wellbore into production once drilling operations have been concluded, including but not limited to the assembly of equipment required to enable safe and efficient production from a gas well (adapted from Schlumberger 2012). The attributable process of well completion primarily includes the flowback of fluids and gases to the surface through the well borehole. WRI does not consider placement and cementing of the well casing as an activity in well completion (see vertical and horizontal drilling).

Well production: The process that occurs after successfully completing attributable processes in the material acquisition and pre-processing stage during which hydrocarbons are drained from a gas field (adapted from Schlumberger 2012). Recovered hydrocarbons may return produced water to the surface that requires treatment before disposal.

Workover: The performance of one or more of a variety of remedial operations on a producing well to try to increase production (OSHA 2012).

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Appendix “E”

Environmental Science & Technology

APPENDIX E

POLICY ANALYSIS

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Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum

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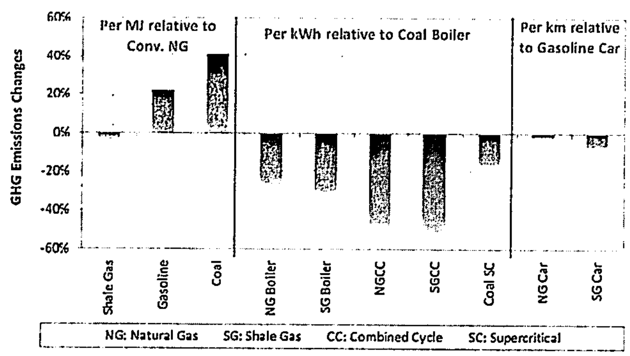
Supporting Information



ABSTRACT: The technologies and practices that have enabled the recent boom in shale gas production have also brought attention to the environmental impacts of its use. It has been debated whether the fugitive methane emissions during natural gas production and transmission outweigh the lower carbon dioxide emissions during combustion when compared to coal and petroleum. Using the current state of knowledge of methane emissions from shale gas, conventional natural gas, coal, and petroleum, we estimated up-to-date life-cycle greenhouse gas emissions. In addition, we developed distribution functions for key parameters in each pathway to examine uncertainty and identify data gaps such as methane emissions from shale gas well completions and conventional natural gas liquid unloadings that need to be further addressed. Our base case results show that shale gas life-cycle emissions are 6% lower than conventional natural gas, 23% lower than gasoline, and 33% lower than coal. However, the range in values for shale and conventional gas overlap, so there is a statistical uncertainty whether shale gas emissions are indeed lower than conventional gas. Moreover, this life-cycle analysis, among other work in this area, provides insight on critical stages that the natural gas industry and government agencies can work together on to reduce the greenhouse gas footprint of natural gas.

1. INTRODUCTION

In the United States, there has been a rapid increase in natural gas (NG) production from shale formations due to recent advancements in drilling technologies, such as horizontal drilling and hydraulic fracturing. In horizontal drilling, a well is drilled down to the depth of the play and turned approximately 90 degrees to run laterally through the formation. This allows for greater access to the play and can increase production on a per-well basis. Due to the low permeability of shale, producers hydraulically fracture the formation to enable better flow of NG. The fracture fluid is typically water-based and contains proppants to maintain fracture openings once pumping of the fluid has ceased. The development of this resource has generated interest in expanding NG usage in areas such as electricity generation and transportation. However, the environmental impacts (e.g., water quality, air quality, global climate change) of shale gas (SG) production and use are currently being debated as the impacts of these new technologies have just started to be examined.[1−5]

Only a few studies have examined the greenhouse gas (GHG) impacts of shale gas production, and there is a wide variation in the potential emissions due to differences in methodology and data assumptions. A study by Howarth et al.[4] used a functional unit of per-megajoule (MJ) of fuel burned to compare the emissions of SG, conventional NG, coal, and petroleum. In addition, this study argued that a global warming potential (GWP) for a 20-year time horizon should be used when comparing the impacts of these fuels. Jiang et al.[5] used an economic input-output (EIO) model as well as process specific data to estimate the emissions of Marcellus SG. U.S. average domestic natural gas emissions from Jiang et al.[5] were based on Venkatesh et al.[6] which updated an earlier analysis[7] that used methane leakage estimates from a joint NG industry and U.S. Environmental Protection Agency (EPA) study[8] that has since been modified.[9] Venkatesh et al.[6] assume the GHG emissions from the production, processing, transmission, and distribution stages of conventional and unconventional NG sources are similar and do not include NG infrastructure establishment in their system boundary.

In this analysis we examined the current state of knowledge regarding the key CH_4 emission sources from shale gas, conventional NG, coal, and petroleum to estimate up-to-date GHG emissions and to understand the uncertainties involved in calculating their life-cycle GHG impacts. We used the GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) model, which can analyze more than 100 fuel pathways, to perform our simulations.[10] We updated the latest version, GREET 1.8d, to include shale gas production and have revised the existing pathways for NG, coal, and petroleum. Through this effort we

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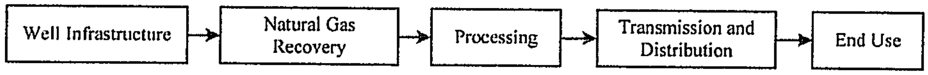

Figure 1. System Boundary for Shale and Conventional NG Pathways.

have also identified data gaps that need to be addressed in future GHG assessments of the natural gas life cycle.

2. LIFE-CYCLE ANALYSIS APPROACH AND DATA SOURCES

2.1. Life-Cycle Analysis Approach. Argonne National Laboratory has been developing and using the GREET model to examine life-cycle energy and emission effects of different transportation fuels and advanced vehicle technologies. In our life-cycle analysis (LCA) of SG, conventional NG, coal, and petroleum, we use GREET to estimate the GHG emissions from feedstock recovery, fuel production, and fuel use as well as from transportation and distribution of feedstocks and fuels. The GREET LCA methodology for these pathways has been well documented.[11−14] In this study, the system boundary was expanded to include infrastructure establishment, including gas well drilling and completion. For each stage in the system boundary, the GREET model calculates CO_2, CH_4, and N_2O emissions from both fuel combustion and noncombustion sources such as leaks. This article documents the fugitive emissions from leaks and venting for each pathway, however combustion emissions are included as part of the results to examine the life-cycle emissions. Figure 1 shows the particular stages included in our study for both shale gas and NG life cycles. Similar system boundaries were used for coal and petroleum life cycles (see Figures S2−S3 in the Supporting Information).

Functional units for LCA directly affect the meaning of LCA results. For example, Howarth et al.[4] used the unit of a MJ of fuel produced and burned. However, directly burning fuels is typically not the purpose of energy use. Useful energy products or services provided by fuel use are more relevant. In our study, we included three functional units: per-MJ of fuel burned, per-kWh of electricity produced, and per-kilometer driven for transportation services. The latter two functional units take into account efficiencies of energy conversion into energy services as well as efficiencies and emissions of energy production. For electricity generation, we included various power plant types fueled by SG, NG, and coal. For transportation services, we included a passenger car fueled with petroleum gasoline and compressed natural gas (CNG) and a bus fueled with petroleum diesel and CNG.

There are large variations and uncertainties in data for critical LCA stages in each of the four energy pathways in our study. Therefore, to systematically address uncertainties, we developed statistical distribution functions for the key parameters in each pathway in order to conduct stochastic modeling. The methodology for developing the distribution functions for this analysis was to estimate at least upper and lower bounds for each key parameter in the study. In this paper, we discuss the key parameters along with their uncertainty; for complete details on each parameter and the distribution values and function used, see the Supporting Information. For example, Table 1 presents our assumptions for key parameters and data sources for SG and NG, while Supporting Information Table S1 provides the complete list of our parametric assumptions for both pathways.

2.2. Data Sources and Key Parametric Assumptions. The EPA has been developing an annual U.S. GHG emission inventory for more than 10 years. This effort has helped accumulate large amounts of GHG data, as EPA has developed methodologies to estimate emissions for different sectors including oil, coal, and NG. In its most recent inventory estimation, EPA made major methodological changes for analyzing the total CH_4 emissions of the U.S. NG system.[15] EPA's current CH_4 emission factors (and previous GREET results) are based on a 1996 joint study[8] by the gas industry and EPA; however, the EPA has annually updated some activity factors such as length of the U.S. pipeline network and number of gas wells. EPA has also made minor adjustments to emission factors and included additional CH_4 sources as data became available. In its 2011 inventory estimation, EPA made a significant upward adjustment of CH_4 emissions from the U.S. NG system as total CH_4 emissions more than doubled from the previous inventory, primarily due to revisions in assumptions regarding SG well completions and conventional NG liquid unloadings, see Supporting Information Figure S1.

2.2.1. Shale Gas and Conventional Natural Gas. A major focus of our analysis was to examine the fugitive and vented methane emissions at NG wells as much of the debate on the benefits of NG versus other fossil fuels centers on activities during NG recovery. Since GHG emissions from SG and NG well completions, workovers, and liquid unloadings are periodic and estimated on a per-well basis, it was necessary to determine the estimated ultimate recovery (EUR) for both SG and NG wells. For SG wells, a range was developed according to the per-well average of four major plays: Marcellus, Barnett, Haynesville, and Fayetteville. The high estimate, 150 million m^3, was based upon industry reported average EURs.[16] The low estimate, 45 million m^3, was based upon a review developed for the U.S. Energy Information Administration (EIA) of emerging shale resources.[17] As seen by the widespread in values, there is significant uncertainty regarding SG well EUR, due to the industry being in its early stages. For conventional NG EUR, we assumed an average production rate over the lifetime of the well according to EIA production data and EPA well compositional makeup, recognizing that production rates typically decline over time, to estimate a 45 million m^3 base-case EUR.[15,18] Our estimate is comparable to an analysis of Texas wells prior to large-scale shale gas production.[19]

Well Completions and Workovers. Our shale gas well completion emissions are based on several EPA sources.[9,15,21] The estimate of CH_4 vented during completions, which involve removing hydraulic fracture fluids and debris from the well, was significantly adjusted by EPA in its 2011 inventory. EPA's previous inventories only had data for conventional wells and all completion emissions were assumed to be flared. EPA now includes separate emission factors for SG wells to account for the additional time that venting occurs, after hydraulic fracturing, when flowback water is collected prior to commencement of gas production. These "unmitigated" emission factors, along with those for liquid unloadings and well equipment, do not account for technologies or practices (e.g., flaring) in industry to reduce or capture these emissions. The emission factors (see Supporting Information Table S1) currently used by EPA (and in our analysis) are based on data from the Natural Gas STAR program on the CH_4 saved through the practices called reduced emission completions

Table 1. Key Parameters for Shale and Natural Gas Pathways (mean values with ranges presented in parentheses)

	units	conventional NG	shale gas	key sources
well completion and workovers (venting)	CH_4: % of NG produced	0.003 (0.002–0.005)	0.46 (0.006–2.75)	EPA[9,15]
liquid unloadings (venting)	CH_4: % of NG produced	1.20 (0.27–2.98)	NONE	EPA[9,15]
well equipment (leakage and venting)	CH_4: % of NG produced	0.73 (0.35–1.20)	0.73 (0.35–1.20)	GAO,[20] EPA[15]
processing (leakage and venting)	CH_4: % of NG produced	0.15 (0.06–0.23)	0.15 (0.06–0.23)	EPA[15]
transmission and distribution (leakage and venting)	CH_4: % of NG produced	0.67 (0.29–1.05)	0.67 (0.29–1.05)	EPA[15]
total	CH_4: % of NG produced	2.75 (0.97–5.47)	2.01 (0.71–5.23)	
well equipment (CO_2 from flaring and venting)	g CO_2 per MJ NG	0.469 (0.389–0.549)	0.469 (0.389–0.549)	GAO,[20] EPA[15]
processing (CO_2 venting)	g CO_2 per MJ NG	0.832 (0.583–1.081)	0.832 (0.583–1.081)	EPA[15]
total	g CO_2 per MJ NG	1.301 (0.972–1.629)	1.301 (0.972–1.629)	

(RECs).[22,23] From these data, EPA calculated unmitigated completion emissions ranging from 20 000 to 570 000 m^3 with an average of 260 000 m^3 or 177 t of CH_4 per unconventional (which includes tight sands as well as shale plays) completion. EPA applied the same emission factor to workovers, which involves additional hydraulic fracturing to improve gas flow and is assumed to take place every 10 years.[9,15]

However, EPA might be overestimating completion emissions because REC equipment allows operators to flowback for a longer period of time, as they are not losing gas to the atmosphere, which is desirable as this improves debris removal and well flow. Wells without REC equipment flowback for a shorter time period than REC wells and thus will potentially have lower emissions. Another issue with these estimates can be demonstrated by examining Howarth et al.[4] which included some of the data from the NG STAR program.[22−25] Several of these estimates based their flowback emissions on initial production (IP) rates, which are calculated following hydraulic fracturing and flowback. In practice, the flowback initially brings up mostly sand and frac fluids, and as the sand and water are removed from the well, the gas concentration increases. When the well builds to a high enough pressure, the operators stop venting and send the gas to the gathering lines. Therefore using IP for the entire flowback period will overestimate completion emissions. With these methodological issues, it is clear that the emission factors require further development to help reduce the uncertainties involved with shale well completions.

Liquid Unloadings. The amount of CH_4 vented during liquid unloadings, which involves removing (or blowing down) liquids that gradually build up and block flow in wet gas wells, was also adjusted significantly by the EPA.[9] The unmitigated emission factor is based upon fluid equilibrium calculations and NG STAR program data for two basins.[26,27] EPA estimated this by calculating the amount of gas needed to blow out the liquid, which is a function of well depth, casing diameter, and shut-in pressure and the amount of gas vented after the liquid has been blown out by using annual recovery data reported by operators utilizing automated plunger lift systems to remove liquids and capture gas. The number of unloadings for the two basins were 11 and 51, respectively, with an average of 31 unloadings per well per year; we created a distribution function using these values to examine the frequency of unloadings.[9] The emission factor, 11 t of CH_4 per year per well, reported by EPA,[9] incorporates the assumption that only 41.3% of conventional wells require liquid unloading, which was based on the findings from Harrison et al.[8] This factor suggests that 26.7 t of CH_4 are released per year per well that requires liquid unloadings. Our unloading estimates are significantly higher than studies[4,7] that are based on EPA estimates prior to their methodological change.

These emission factors should be examined further as the frequency of liquid unloadings will depend on the age of the well and will vary both between and within basins. In addition, like well completion emission factors, uncertainty stems from limited testing, the applicability of NG STAR program activities to calculate industry baseline emissions, and a lack of details for reduction estimates. Blowdowns account for 50% of the unmitigated emissions from the NG production sector according to EPA[15] and therefore the absence of reliable data on the frequency of these blowdowns and their emissions creates a large degree of uncertainty for the conventional NG pathway. While the EPA assumption that liquid unloadings only occur at conventional gas wells is reasonable since SG is typically a dry gas, some shale formations such as the Antrim and New Albany do produce water and may require liquid unloadings.

Well Equipment Leakage and Venting. For both SG and NG wells, methane emissions can occur from various equipment (and practices) on-site such as pneumatic devices, condensate tanks, and gathering compressors. We assumed that equipment would perform similarly for SG and NG, so identical emissions were assumed per amount of NG produced. We estimated the unmitigated emissions from these sources as 0.108 g of methane per MJ (lower heating value) of NG, using EPA[15] emissions for 2005 through 2009 and normalizing according to gross NG production data for the same time period.[18] We also examined a U.S. Government Accountability Office (GAO) study[20] which included EPA 2008 emission data for federal onshore activities and the Bureau of Land Management's 2008 estimate for federal onshore production of 88 billion m^3 and derived an emission factor of 0.287 g of CH_4 per MJ of NG.[28] We used these two data points as the range for our distribution, while using the mean value as our base case.

Further we examined another source of GHG emissions from well equipment and practices, CO_2 flaring and venting. With EPA data,[15] we estimated that flaring would emit 0.350 g of CO_2 per MJ of NG; while with GAO data,[20] we estimated that flaring would emit 0.510 g of CO_2 per MJ of NG. As NG also contains CO_2, vented emissions were estimated to be roughly 0.039 g of CO_2 per MJ of NG.[15]

Methane Reductions from Natural Gas Recovery. The EPA updated emission factors for SG well completions and NG liquid unloadings because the methane reductions reported by the NG STAR program were larger than the total emissions for each activity calculated using its previous methodology. In our analysis, which is primarily based on EPA data, the unmitigated emission factors for each activity in the NG recovery sector were

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adjusted to represent real world conditions. However, EPA only provided aggregated emissions reductions from both the NG STAR program and the National Emission Standards and Hazardous Air Pollutants (NESHAP) regulations, and as a result, the reduction estimates do not provide details on which activity's emissions are reduced in the real world.[15] As the focus of this analysis is to not only determine total emissions from shale and conventional NG pathways but also to examine the key issues and uncertainties, we needed to separate the recovery reductions based on our key parameters. Therefore, we examined data from the NG STAR program[21] and EPA assumptions on NESHAP regulations[15] to estimate emissions reductions for each activity.

We grouped the recovery sector technologies listed by NG STAR into three categories based on the key parameters in our analysis: (1) SG well completions, (2) NG liquid unloadings, and (3) well equipment fugitives.[21] For shale completions, most of the uncertainty was due to flaring assumptions so our low-reduction scenario assumed only reductions from the NG STAR program (38%), while our base case assumed a small amount of flaring, based on NESHAP regulations, along with the NG STAR reductions (41%), and finally our high-reduction scenario assumed the same amount of flaring as EPA[9] along with NG STAR reductions (70%). For liquid unloadings, uncertainty results from NG STAR accounting practices as NG STAR does not report emission reduction projects that exceed an agency-prescribed sunsetting period (projects after a certain amount of years are excluded in order to motivate the industry to find new reductions), even though those emissions are still being reduced in practice. Therefore, we developed a low-reduction scenario for liquid unloadings based on reported NG STAR reductions (8%) and a high-reduction scenario where we adjusted for the sunsetting period (15%), while our base case is the average of those two. For well equipment, we developed a low-reduction scenario based on NG STAR and NESHAP reductions (18%) and a high-reduction scenario where we adjusted for the sunsetting period (37%), while our base case is the average of those two. Further information on CH_4 reductions is available in Supporting Information Section S3.3.

Processing, Transmission and Storage, and Distribution. After recovery, NG is typically processed to separate valuable liquids and undesirable components from the gas, then transmitted long distances via high-pressure pipelines, and finally distributed to customers through low-pressure pipelines. In our analysis we calculated emission factors for the NG processing, transmission and storage (T&S), and distribution sectors, using the total average CH_4 emissions for these sectors (excluding liquefied natural gas-related emissions for the T&S sector) between 2005 and 2009 after subtracting emissions reductions resulting from NG STAR and NESHAP activities in the processing, T&S, and distribution sectors.[15] We divided these average emissions by the average production of NG for this same time period.[18] We also examined vented CO_2 emissions from acid gas removal (AGR) in the processing sector, which account for about 50% of total GHG emissions from that sector.[15] The results for these sectors, shown in Table 1, include CH_4 emission factor distributions based on the uncertainties provided in Harrison et al.[8] For the low and high AGR vent emission factors, we assumed an uncertainty of plus or minus 30% based on EPA's discussion.[15]

Other researchers have estimated significantly higher emissions for these activities.[4,29] Specifically, Howarth et al.[4] developed a range of leakage factors for the T&S and distribution sectors using emissions from the Russian NG transmission and distribution network[29] and estimates of lost and unaccounted for gas (LUG) in Texas.[30] The estimate of leakage in the Russian T&S and distribution sectors is likely an overestimate of emissions for these sectors in the U.S. as the two systems have significant differences. In addition, LUG is an accounting term for the difference between the volume of gas produced and sold. Percival points out drawbacks to using LUG as an estimate of leaked NG and that it will consistently overestimate leakage.[30,31] For further details on these issues see Supporting Information Section S3.4.

2.2.2. Coal Recovery. Coal mining releases the methane generated through anaerobic digestion of plant material during the process of coal formation. In order to update the emission factors for coal mining, we determined the total average CH_4 emissions for underground mining, underground postmining operations, surface mining, surface postmining operations, and abandoned underground mines between 2005 and 2009.[15] We divided the average emissions by the average production of underground and surface coal for this same time period.[15] Supporting Information Table S7 lists the emission factors developed for each coal activity.

We estimated the average methane emissions to be 0.340 g CH_4 per MJ of underground mine coal and 0.046 g CH_4 per MJ of surface mine coal. When developing average coal cases, we weighted these values by the ratio of surface mining production (69%) to underground mining production (31%) to estimate the average coal mining emissions of 0.138 g CH_4 per MJ of coal.[15]

2.2.3. Petroleum Recovery. Associated gas is a byproduct of conventional crude oil recovery, which contains large amounts of methane, so its disposal has important GHG consequences. A portion of produced associated gas is flared or vented, usually for commercial or infrastructural reasons.[32] Crude oil production is an international endeavor, and therefore the GHG emissions produced in their countries of origin should be charged to an average U.S.-market barrel of crude with the appropriate weights.

The World Bank has sponsored the *Global Gas Flaring Reduction Partnership* (GGFR) with the explicit mission of reducing gas flaring and venting in oil producing countries and has collected flaring data through surveys until 2005 and from satellite data afterward. In this analysis, we use volumes of flaring emissions for each country (2008 reference year) estimated by satellite data and combine it with EIA oil production data for the same countries to calculate a ratio of gas flared to crude oil produced.[33,34] We then compiled a list of U.S. oil imports from EIA, and after adding the U.S. crude oil production, we calculated the proportional contribution of each country to the average barrel of crude oil used in U.S. refineries.[35] Supporting Information Table S9 provides the list of oil production and flaring data by region.

Associated gas venting data from crude oil production is not widely available, as it cannot be estimated from satellite images. Therefore, we need to rely on surveyed data to estimate vented volumes. We modeled gas venting volumes using the ratio of vented to flared gas from several references that provided gas flaring and venting quantities.[36−38] For U.S.-bound crude we estimate an average venting to flaring ratio of 0.2, with a distribution between 0.1 and 0.3.

We estimated the average flaring emissions to be 1.008 g CO_2 per MJ of crude oil and the vented emissions to be 0.057 g CH_4 per MJ of crude oil. We also updated the methane emissions from surface mined oil sands as emissions from tailing ponds were roughly 0.104 g CH_4 per MJ of oil sands.[39]

2.2.4. End Use Efficiency. We included the end-use efficiencies for both power plants and vehicles to estimate the life-cycle GHG

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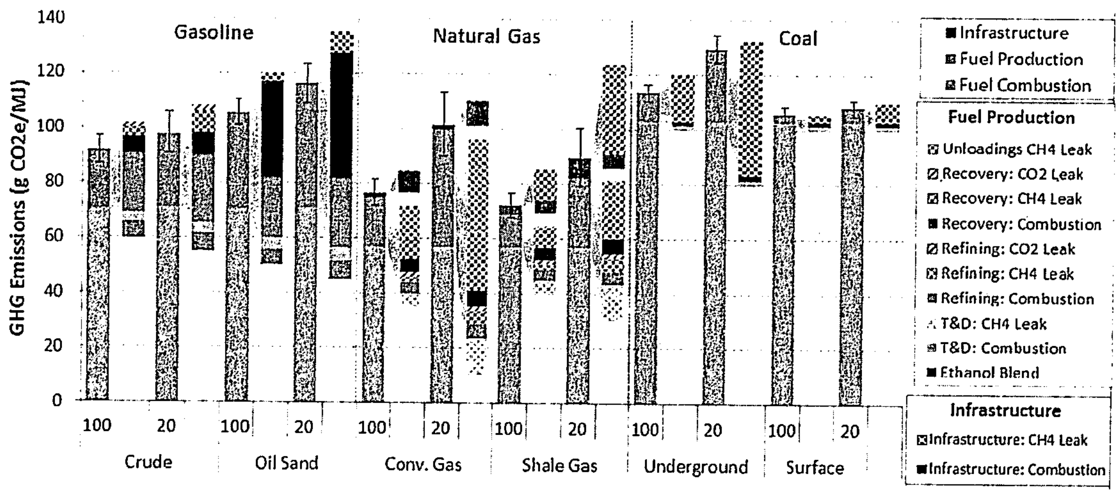

Figure 2. Life-cycle GHG emissions per MJ of fuel produced and combusted for both 100-year and 20-year time horizons.

impacts of the fuels in specific applications. For NG power plants, we estimated the base-case efficiency for a conventional NG boiler to be 33.1%, with a range from 33.0 to 33.5%,[13] while a NG combined cycle (NGCC) power plant would have an efficiency of 47%, with a range from 39 to 55%.[40] For coal power plants, we estimated the efficiency for a conventional pulverized coal boiler to be 34.1%, with a range from 33.5 to 34.4%,[13] while a supercritical boiler would have an efficiency of 41.5%, with a range from 39.0 to 44.0%.[41]

For a passenger car, we assumed a fuel economy of 29 miles per gallon gasoline-equivalent (mpgge) or 8.11 L per 100 km and that a CNG car with similar performance would have a fuel economy penalty of 5% (on an mpgge-basis) primarily because of the weight penalty of on-board CNG storage cylinders. We developed a distribution function for the relative fuel economy of the CNG car as compared to the gasoline car around this value, with the high estimate that the CNG car will have the same fuel economy, while the low estimate that it will have a 10% reduction as compared to the gasoline car.

Several studies have examined the fuel consumption of NG and diesel transit buses and have found that CNG-fueled transit buses on average have a fuel economy 20% lower than diesel-fueled buses.[42−44] These results are due to the low thermal efficiency of a spark-ignited engine (when compared with a compression-ignition diesel engine) operating at low speed and load.[43] However, it has been argued that the fuel efficiency benefit of diesel buses has been reduced due to the emission control equipment and strategies used to meet the EPA 2010 heavy-duty engine emission standards. According to Cummins-Westport, its 8.1-L ISL G NG engine achieves fuel efficiencies much closer to a diesel engine and depending on the duty cycle, the engine can either match an equivalent diesel fuel economy or have a fuel economy that is 10% lower.[44] For our analysis, we assumed that for our low estimate CNG transit buses would have a 20% reduction in fuel economy and for our high estimate a 10% reduction, while using the mean value as our base case. A summary of our end use efficiency assumptions is shown in Supporting Information Table S12.

2.2.5. Global Warming Potentials of Greenhouse Gases. GWP is an attempt to provide a simple measure to compare the relative radiative effects of various GHG emissions. The index is defined as the cumulative radiative forcing between the time a unit of gas is emitted and a given time horizon, expressed relative to CO_2. When comparing the emission impacts of different fuels one must choose a time frame for comparison, as the IPCC calculates GWPs for multiple time horizons such as 20-, 100-, and 500-year timeframes. The IPCC recommends using GWPs for a 100-year time horizon when calculating GHG emissions for evaluating various climate change mitigation policies. When using a 20-year time frame the effects of methane are amplified as it has a relatively short perturbation lifetime (12 years). Howarth et al.[4] use results from a recent study by Shindell et al.[45] that suggest a higher GWP for methane due to direct and indirect aerosol effects. We have chosen to use the current IPCC published results.[46] Supporting Information Table S13 presents GWPs that we used in comparison to those Howarth et al.[4] used.

3. RESULTS

With the parametric assumptions incorporated into the GREET model, we produced life-cycle GHG emissions for the four energy pathways with three functional units. With the distribution functions developed in this study and those from previous studies[13,14] for other key activities such as recovery and refining efficiencies, we used GREET stochastic modeling capability to generate results with distributions.

3.1. GHG Emissions for Fuel Pathways per MJ of Fuel Produced and Burned. Figure 2 presents life-cycle CO_2 equivalent (CO_2e) emissions of CO_2, CH_4, and N_2O (which is primarily from fuel combustion) of gasoline from conventional crude and oil sands, natural gas from conventional and shale gas, and coal from underground and surface mining. In addition, detailed breakdowns of GHG emissions from the fuel production and infrastructure stages are provided to show the relative importance of CH_4 and CO_2 venting and flaring emissions. Each bar represents the estimate for our base case, the error line on each bar represents the range for the probability of 10% and 90% (P10 and P90) values. Results for GWPs with both 100- and 20-year time horizon are presented, though the 20-year horizon is intended for comparison with Howarth et al.[4]

Fuel combustion accounts for a large portion of total GHG emissions for all pathways, while the fuel production stage has a significant amount of GHG emissions for all pathways except for surface mined coal. The second largest GHG emission source for

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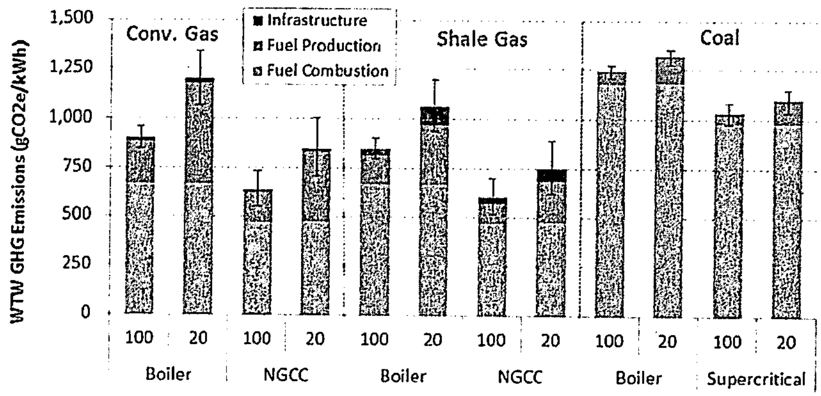

Figure 3. Life-cycle GHG emissions per kWh of electricity produced for both 100-year and 20-year time horizons.

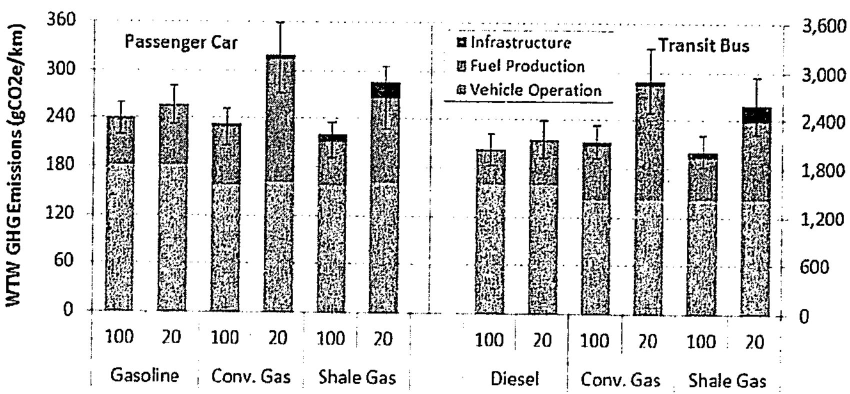

Figure 4. Life-cycle GHG emissions per vehicle kilometer traveled – passenger car and transit bus for both 100-year and 20-year time horizons.

gasoline is combustion from the refining stage for conventional crude and the recovery stage for oil sands. For NG pathways, CH_4 venting and leakage during NG recovery operations are the largest upstream GHG emission source. Again, liquid unloadings are a key factor for conventional NG, while completion and workover emissions are significant for shale gas. GHG emissions associated with materials and fuel combustion for infrastructure are almost negligible to the life-cycle emissions; a detailed discussion of this topic is in the Supporting Information.

On the per-MJ basis, our results show that when using GWPs for the 100-year time horizon, oil and coal GHG emissions are significantly higher, 22% and 41%, whereas SG is 6% lower as compared to conventional NG. However, the ranges for SG and NG overlap, so there is statistical uncertainty whether SG emissions are indeed lower than NG. In contrast, Howarth et al.[4] show 17% higher emissions for SG, while oil emissions are 3% lower and coal is 21% higher than conventional NG. With GWPs for the 20-year time horizon, our results show that oil is 2% lower and coal is 13% higher, while shale gas is 12% lower than conventional NG. Meanwhile Howarth et al.[4] show 33% higher emissions for SG while oil is 36% lower and coal is 24% lower than NG.

3.2. GHG Emissions by End Use of Energy. Figure 3 illustrates that taking into account power plant efficiencies, electricity from NG shows significant life-cycle GHG benefits over coal power plants. When compared to a coal boiler under a 100-year time horizon, a SG boiler has 31% fewer emissions while a SG NGCC plant has 52% fewer emissions. Only for the case of a NG boiler under a 20-year time horizon do the emissions approach (in the case of SG) or exceed (in the case of conventional NG) a supercritical coal power plant. Our relative differences between NG and coal power plants are very similar to Jiang et al.,[5] though our absolute emissions are about 20% higher for both NGCC and advanced coal plants. In addition, Jiang et al.[5] found that the shale gas emissions were 3% higher than conventional NG.

Figure 4 illustrates that, considering a 100-year time horizon, no statistically significant difference in well-to-wheel (WTW) GHG emissions is evident among fuels on a vehicle kilometer traveled basis. With a 20-year time horizon, however, conventional NG has a 25% greater GHG impact than gasoline. The figure also shows the GHG emissions per vehicle kilometer traveled for CNG transit buses are not statistically different from diesel buses with a 100-year time horizon. However, with a 20-year time horizon, CNG buses show significantly larger GHG emissions (34% for NG and 20% for SG) than their diesel-fueled counterparts. For CNG vehicles to reduce GHG emissions, they will need to exceed our base-case fuel economy assumptions.

3.3. Sensitivity Analysis of Key Parameters. We conducted a sensitivity analysis of key parameters for the life-cycle GHG emissions of the two NG pathways. The following tornado chart (Figure 5) presents our results for the 100-year time horizon, whereas Supporting Information Figure S4 has the results for the 20-year time horizon.

From the conventional NG tornado charts, it is clear that CH_4 venting during liquid unloadings contributes the most uncertainty to

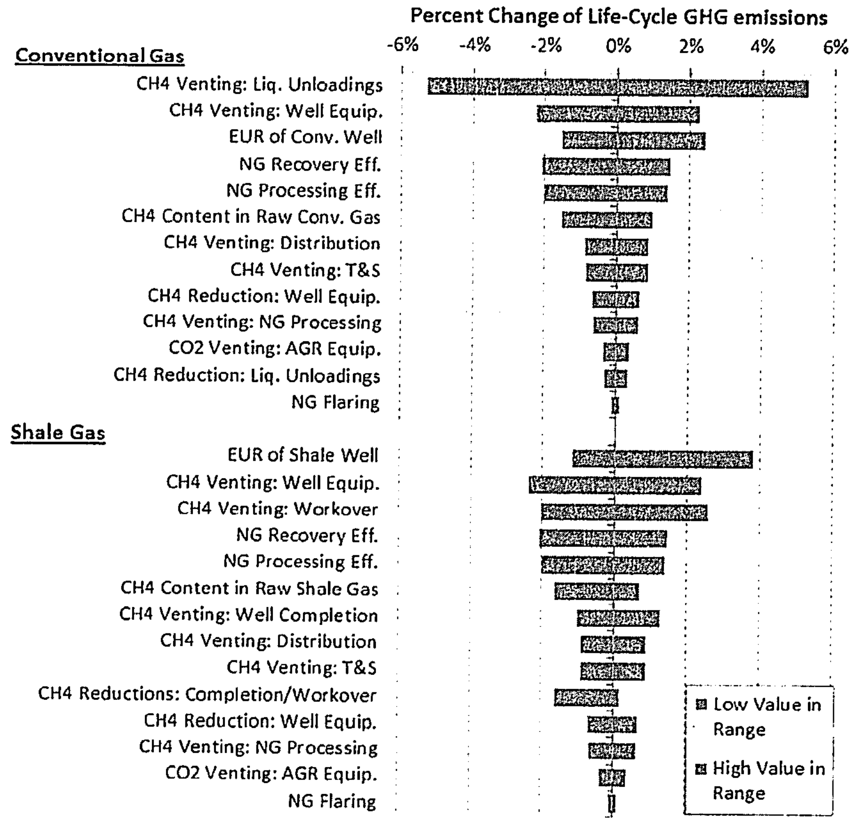

Figure 5. Sensitivity analysis results for shale and NG pathways (100-year time horizon).

our results. The large uncertainty is due to a wide range of the number of unloadings required for these wells and emissions resulting from this activity. The shale gas tornado chart shows a similar trend to conventional NG, except that the EUR of the SG well replaces liquid unloadings, which are not assumed to be required for SG, as the greatest source of uncertainty. The other major difference between the two pathways is that SG completion and workover emissions are a much more significant factor as compared to conventional NG. However, they only have a moderate impact on the uncertainty of life-cycle emissions. CH_4 venting from well equipment shows the second largest impact for both pathways as difference between estimates from EPA and GAO are significant.[15,20]

4. DISCUSSION

Inherently, natural gas combustion produces significantly less GHG emissions as compared to coal and oil. However, upstream fuel production impacts can result in different conclusions. Our analysis demonstrates that upstream CH_4 leakage and venting is a key contributor to the total upstream emissions of NG pathways, and can significantly reduce the life-cycle benefit of NG compared to coal or petroleum. Limited data for several key areas have been used to make significant changes in EPA's GHG inventory and could potentially support erroneous conclusions. Reliable data will help spur a healthy debate of the role of natural gas in the U.S. energy supply.

Specifically, for shale gas wells the volume of gas vented during completions and workovers needs to be examined with and without technologies and practices that can reduce emissions. This will require a better understanding of the volumes of both fraccing fluids and natural gas being released during the flowback and how those volumes vary during the process. In addition, the number of workovers typically performed during the lifetime of shale gas wells needs further examination as the decision to do a workover will be based on the economics of the well, likely depending on factors such as the age of the well, expected improvement in production after workover, and the wellhead price of NG. Moreover, greater transparency is needed on the percentage of completions and workovers implementing REC technologies. A survey of flaring practices for wells with and without RECs by examining state regulations and industry practices would provide greater certainty of the emissions from shale gas. Finally, as the NG industry gains more experience with SG production through the well lifetime, the accuracy of EUR projections will hopefully improve.

Likewise for conventional wells, the volume of gas vented during liquid unloadings needs to be calculated for the various technologies implemented to remove liquids, along with a survey of the prevalence of each technology in practice would provide much greater certainty to these emissions. This survey should also examine the percentage of conventional NG and shale wells requiring liquid unloadings as not all wells undergo this process. In addition, the number of unloadings required over the lifetime of a well is a factor that causes significant uncertainty and should be examined in detail. This data should differentiate the unloadings required in different basins/geologic formations as well as in different wells within the same basin. The number of unloadings required as

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function of the age of the well would also provide relevant information when trying to create an inventory of these emissions. Finally, flaring practices should also be examined for liquid unloading operations by examining state regulations and industry practices.

Large-scale shale gas production is a relatively new phenomenon. Environmental management in general and GHG emission reduction in particular need to be exercised in order for shale gas (and conventional NG) to be produced sustainably. The partnership of the natural gas industry and EPA under the NG STAR program has helped reduce CH_4 emissions but further efforts could be taken to address remaining environmental issues of natural gas production and transmission. With this context, our analysis, among other analyses, provides some insight on critical stages that industry and government agencies could work together on to reduce the environmental footprint of natural gas.

■ ASSOCIATED CONTENT

Supporting Information. Further methodological details and results. This material is available free of charge via the Internet at http://pubs.acs.org.

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A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea

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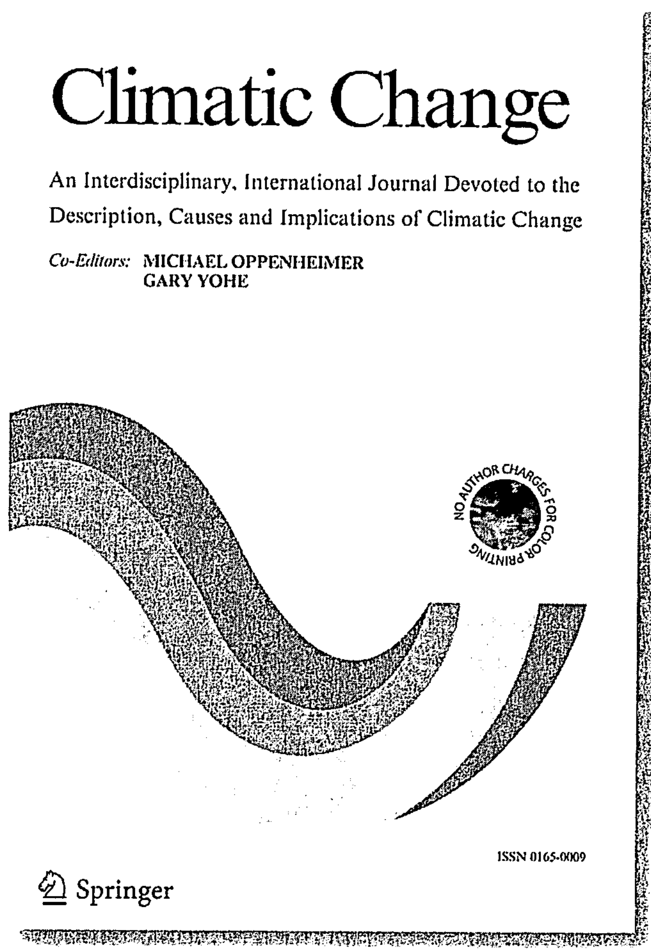

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Appendix “F”

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APPENDIX F

COMMENTARY

A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea

Lawrence M. Cathles III · Larry Brown · Milton Taam · Andrew Hunter

Received: 20 June 2011 / Accepted: 21 October 2011

Abstract Natural gas is widely considered to be an environmentally cleaner fuel than coal because it does not produce detrimental by-products such as sulfur, mercury, ash and particulates and because it provides twice the energy per unit of weight with half the carbon footprint during combustion. These points are not in dispute. However, in their recent publication in Climatic Change Letters, Howarth et al. (2011) report that their life-cycle evaluation of shale gas drilling suggests that shale gas has a larger GHG footprint than coal and that this larger footprint "undercuts the logic of its use as a bridging fuel over the coming decades". We argue here that their analysis is seriously flawed in that they significantly overestimate the fugitive emissions associated with unconventional gas extraction, undervalue the contribution of "green technologies" to reducing those emissions to a level approaching that of conventional gas, base their comparison between gas and coal on heat rather than electricity generation (almost the sole use of coal), and assume a time interval over which to compute the relative climate impact of gas compared to coal that does not capture the contrast between the long residence time of CO_2 and the short residence time of methane in the atmosphere. High leakage rates, a short methane GWP, and comparison in terms of heat content are the inappropriate bases upon which Howarth et al. ground their claim that gas could be twice as bad as coal in its greenhouse impact. Using more reasonable leakage rates and bases of comparison, shale gas has a GHG footprint that is half and perhaps a third that of coal.

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Natural gas is widely considered to be an environmentally cleaner fuel than coal because it does not produce detrimental by-products such as sulfur, mercury, ash and particulates and because it provides twice the energy per unit of weight with half the carbon footprint during combustion. These points are not in dispute.

However, in their recent letter to Climatic Change, Howarth et al. (2011) report that their life-cycle evaluation of shale gas drilling suggests that shale gas has a larger GHG footprint than coal. They conclude that:

- During the drilling, fracturing, and delivery processes, 3.6–7.9% of the methane from a shale gas well ends up, unburned, in the atmosphere. They claim that this is at least 30% and perhaps more than twice the methane emissions from a conventional gas well.
- The greenhouse gas footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon. In fact, they state that compared with the greenhouse gas (GHG) emissions from coal, it is 20–100% greater on the 20-year horizon and is comparable over 100 years.

They close with the assertion that: "The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over the coming decades, if the goal is to reduce global warming."

We argue here that the assumptions used by Howarth et al. are inappropriate and that their data, which the authors themselves characterize as "limited", do not support their conclusions.

In particular, we believe Howarth et al.'s arguments fail on four critical points:

1. Howarth et al.'s high end (7.9%) estimate of methane leakage from well drilling to gas delivery exceeds a reasonable estimate by about a factor of three and they document nothing that indicates that shale wells vent significantly more gas than conventional wells.

   The data they cite to support their contention that fugitive methane emissions from unconventional gas production is significantly greater than that from conventional gas production are actually estimates of gas emissions that were captured for sale. The authors implicitly assume that capture (or even flaring) is rare, and that the gas captured in the references they cite is normally vented directly into the atmosphere. There is nothing in their sources to support this assumption.

   The largest leakage rate they cite (for the Haynesville Shale) assumes, in addition, that flow tests and initial production rates provide a measure of the rate of gas release during well completion, drill out and flowback. In other words they assume that initial production statistics can be extrapolated back to the gas venting rates during the earlier periods of well completion and drill out. This is incompatible with the physics of shale gas production, the safety of drilling operations, and the fate of the gas that is actually indicated in their references.

   While their low-end estimate of total leakages from well drilling through delivery (3.6%) is consistent with the EPA (2011) methane leakage rate of ~2.2% of production, and consistent with previous estimates in peer reviewed studies, their high end estimate of 7.9% is unreasonably large and misleading.

   We discuss these issues at length below.
2. Even though the authors allow that technical solutions exist to substantially reduce any leakage, many of which are rapidly being or have already been adopted by industry (EPA 2007, 2009), they seem to dismiss the importance of such technical improvements on the GHG footprint of shale gas. While the low end estimates they provide

incorporate the potential impact of technical advances in reducing emissions from the sources common to both conventional and unconventional gas, they do not include the potential impact of "green technologies" on reducing losses from shale gas production. The references they cite document that the methane loss rate during completion of unconventional gas wells by modern techniques is, or could be, at least 10 times lower than the 1.9% they use for both their high end and low end estimates. Downplaying ongoing efforts and the opportunity to further reduce fugitive gas emissions in the natural gas industry, while at the same time citing technical improvements in the coal industry, gives a slanted assessment which minimizes the positive greenhouse potential of natural gas. Although the Howarth et al. agree "Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies or REC", they qualify this possibility by saying: "However, REC technologies require that pipelines to the well are in place prior to completion." This suggests that if the pipeline is not in place the methane would be vented to the atmosphere, which is misleading. If a sales pipeline is not available, the gas captured by REC technologies could be easily be (and are) flared and the GHG footprint thereby minimized.

3. Howarth et al. justify the 20-year time horizon for their GHG comparison by simply stating that "we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades". But the point Nisbet et al. make in their meeting abstract is that "adoption of 20-year GWPs would substantially increase incentives for reducing methane from tropical deforestation and biomass burning". Their concern is that the 100-year timeframe would not discourage such methane emissions enough. Everyone would agree that discouraging methane as well as CO_2 emissions is desirable, but the Nisbet et al. abstract offers no support whatever for the adoption of a 20-year GWP timeframe when considering replacing CO_2 emissions with CH_4 emission by swapping coal for gas, and we strongly disagree that the 20 year horizon is the appropriate choice in this context. As Pierrehumbert (2011) explains, "Over the long term, CO_2 accumulates in the atmosphere, like mercury in the body of a fish, whereas methane does not. For this reason, it is the CO_2 emissions, and the CO_2 emissions alone, that determine the climate that humanity will need to live with." In the context of a discussion of the benefits of swapping gas for coal, a 20 year horizon hides the critical fact that the lifetime of CO_2 in the atmosphere is far longer than that of methane. Any timeframe is artificial and imperfect in at least some contexts, but a 100 year timeframe at least captures some of the implications of the shorter lifetime of methane in the atmosphere that are important when considering swapping gas for coal. One could argue (although Howarth et al. do not) that the 20-year horizon is "critical" because of concern over triggering an irreversible tipping point such as glacial meltdown. However, if substituting gas for coal reduces (or could reduce) the GHG impact on a 20-year horizon as well as on a 100-year horizon, as we argue below is the case, substitution of gas for coal minimizes the tipping point risk as well. Most workers choose the 100 year timeframe. Hayhoe et al. (2002), for example, show that in the long, 100 year, timeframe but not on the short timeframe of 20 years or so, substitution of gas for coal reduces greenhouse warming. They consider the warming effects of decreasing SO_2 and black carbon emissions as coal burning is reduced as well as the warming effects of CO_2 and CH_4 emissions, and they calculate greenhouse impact of various substitution scenarios over the next 100 years using a coupled atmosphere-ocean energy balance climate model. Their analysis avoids the arbitrariness of GWP factors. Although there are many considerations regarding the

transition in the short term, their analysis shows the long term benefits of swapping gas for coal are completely missed by the 20 year GWP factor.

4. Howarth et al. choose an end use for comparing GHG footprints that is inappropriate in the context of evaluating shale gas as a bridging fuel. Coal is used almost entirely to generate electricity, so comparison on the basis of heat content is irrelevant. Gas that is substituted for coal will of necessity be used to generate electricity since that is coal's almost sole use. The appropriate comparison of gas to coal is thus in terms of electricity generation. The "bridge" is from coal-generated electricity to a low-carbon future source of electricity such as renewables or nuclear (EIA AEO 2011). Howarth et al. treat the end use of electricity almost as a footnote. They acknowledge in their electronic supplemental material that, if the final use is considered, "the ability to increase efficiency is probably greater for natural gas than for coal (Hayhoe et al. 2002), and this suggests an additional penalty for using coal over natural gas for the generation of electricity not included in our analysis". They address the electrical comparison in an electronic supplement table, however they do so there on the basis of a 20 year GWP and they minimize the efficiency differential between gas and coal by citing a broad range for each rather than emphasizing the likelihood that efficient gas plants will replace inefficient coal plants. Had they used a 100 year GWP and their low-end 3.6% methane leakage rate, shale gas would have about half the impact of surface coal when used to generate electricity (assuming an electricity conversion efficiency of 60% for gas and their high 37% conversion efficiency for coal). The electric industry has a large stock of old, inefficient coal-fired electric generating plants that could be considered for replacement by natural gas (Table 1 in EIA AEO 2011). The much lower construction costs associated with gas power plants (e.g. Kaplan 2008) means modern gas technology will likely replace this old coal technology as it is retired. If total (well drilling to delivery) leakage is limited to less than 2% (which may be the current situation and, in any case, seems well within the capabilities of modern technology; EPA 2007, 2009), switching from coal to natural gas would dramatically reduce the greenhouse impact of electricity generation. Minimizing this point by stressing extreme rather than likely scenarios is perhaps the most misleading aspect of the Howarth et al. analysis.

Figure 1 depicts what we suggest is a more representative comparison of the likely impact on greenhouse gas emissions when natural gas replaces coal in older coal-burning electric power plants. In our analysis, we assume 60% efficiency for natural gas generation of electricity, 30% efficiency for coal generation of electricity in older plants, and a total methane leakage rate of 2.2%. Relatively low-cost 60% efficient generators using natural gas are commonly available (Siemens). When both fuels are used to produce electricity (MJe), the greenhouse impact of natural gas is only as bad as coal if a very high methane leakage rate of 7.9% and a short global warming impact period of 20 years are selected (column labeled Howarth et al. in Fig. 1). If the comparison is based on the heat content of the fuels, the top (green) portion of the Howarth et al. column is doubled in length, and gas becomes twice as bad as coal from a greenhouse perspective. This is the basis of Howarth et al.'s suggestion that gas could be as bad or twice as bad as coal from a greenhouse perspective. Assuming more realistic estimates of gas leakage rates and using the 100 year global warming potential factor (of 33 g of GHG-equivalent CO_2 per gram of methane released to the atmosphere), which captures the contrast in atmospheric lifetimes of CO_2 and natural gas, we show in Fig. 1 that gas has a much smaller global warming impact than coal. For leakage rates less than 2%, the impact of natural gas approaches one third that of coal, and methane leakage (top green bar) is an insignificant part of the greenhouse forcing compared to the CO_2 released during combustion (bottom blue part of bar). For the 100y GWP of 33, gas exceeds the global warming impact of deep coal only when its leakage rate exceeds 18.2% of production, and exceeds the global warming impact of surface coal only when its leakage exceeds 17.1% of production. These natural gas leakage rates are well beyond any known estimates. If the fuels are compared just on the basis of heat (i.e. disregarding efficiency of use), gas has a lower greenhouse impact than coal if the leakage is <5.5% for a 100 year GWP, and if the leakage is <2% for a 20 year GWP.

Column 4 in Fig. 1 makes more favorable assumptions regarding the use of coal. Here we compute the greenhouse impact of producing electricity in an ultra-supercritical pulverized coal unit without CO_2 capture (which would reduce its conversion efficiency) of 62 gC/MJe. A 2007 interdisciplinary MIT study found that a plant of this nature might achieve a 43.3% conversion efficiency when burning low impurity coal (MIT 2007). Although no plant of this kind has yet been constructed, the 4th column in the gas category of Fig. 1 shows that the greenhouse impact of a gas plant with 50% conversion efficiency would have about half the GHG impact of this high-end coal plant.

Sixty percent conversion efficiency is not the limit for gas. Combined heat and power (CHP) generation can utilize 90% of the chemical energy in gas. Heat could be likewise used from coal facilities, but small gas units are more cost effective and gas facilities could be built closer to populated user markets that could utilize the heat. Thus gas has a greater CHP potential than coal.

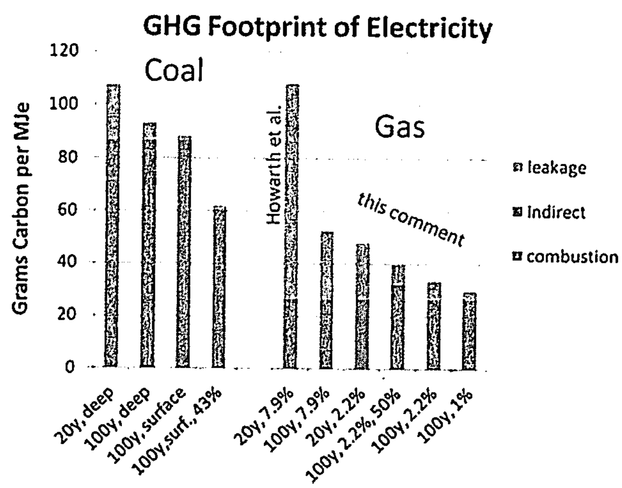

Fig. 1 Comparison of the greenhouse impact of burning natural gas to coal when the fuels are used to produce electricity, expressed as the grams of GHG-equivalent CO_2 carbon per megajoule of electricity generated. The conversion efficiency to electricity of coal and gas are assumed to be 30 and 60% respectively in all columns except the 4th and 8th columns, which compare a very efficient coal plant to a less efficient gas plant. As in Howarth et al. (2011) we use 20 and 100 year GWP factors of 105 and 33 g of GHG-equivalent CO_2 per gram of methane released, and assume deep and shallow coal mining releases 8.4 m^3 and 2.3 m^3 methane per ton, respectively. Indicated below each column are the GWP factors, the percent methane leakage (1, 2.2 and 7.9%), whether the coal burned is from deep or shallow mines, and where different from 60%, the gas conversions efficiency used in the calculation. No allowance is made for the transport/ transmission of either fuel, which effectively assumes electricity generation at the well/mine head. Shale gas is generally closer to power markets than coal, however

1 Methane venting during well completion and drill out of unconventional gas wells

A critical part of Howarth et al.'s paper's contention that shale gas has a larger greenhouse impact than conventional gas is the contention that an unconventional gas well vents 1.9% of its lifetime gas production during well completion. (Unconventional gas wells include those producing from tight sands, shales, and coal bed methane wells—the Howarth et al. figures assume that emissions from these are all similar.) This is dramatically more than the 0.01% they cite as vented by a conventional gas well. Their 1.9% number is a large component in their high-end leakage rates, which are themselves central to their contention that the global warming impact of gas could be twice as bad as coal on a heat content basis.

We agree with Howarth et al. that the available data are extremely limited, that their analysis relies heavily on powerpoint presentations rather than values published in reviewed literature, and that there is an obvious need for better estimates. However, given the lack of quality data, we feel that the authors have a responsibility to make explicit the nature and limitations of such sources, and to be especially clear on the assumptions made in their interpretation of such data. We feel that was not done, and offer the following to put their estimates in context.

There are fundamental problems with key numbers that they use in their Table 1 to support their 1.9% contention:

(1) The numbers they use to represent fugitive emissions for the Haynesville Shale cannot be found in the references they cite. That the daily methane loss estimates shown in their Table 1 are close to the initial production (IP) values cited in their references suggests that the authors assume that the latter is somehow an estimate of the former. As argued below and in the electronic supplement, this is incompatible with (a) the basic physics of gas production, (b) the economic incentives of gas production, and (c) the only early production data related to shale gas that can be found amongst any of their references.

(2) The only discussion of methane losses during well completion is found in the citations for tight gas sands, and those values are presented to illustrate how currently used technologies can capture most (up to 99%; Bracken 2008) of those "losses" for sale.

(3) Their estimate of methane loss from drill out is based on two numbers from the Piceance Basin reported in a powerpoint slide presented to an EPA Gas STAR conference (EPA 2007). They assume that 10 million cubic feet of gas is typically vented during well drill out rather than being captured or flared, although their source makes no such claim. For reasons discussed below and in the electronic supplement, gas production is rare during drill out and if significant gas were produced during drill out it would not be emitted into the atmosphere for economic and safety reasons.

(4) The magnitude of the releases they suggest are not credible when placed in the context of well completion and well pad operating procedures, safety, and economic factors.

The high releases of methane Howarth et al. suggest for the Haynesville data in their Table 1 are the most problematic because they skew the average for the suite of locations listed, and because the numbers are not based on documented releases to the atmosphere but rather on initial production rates that may well have been captured and sold or flared.

The value shown in their Table 1 for methane emitted during flowback in the Haynesville does not exist in any of their citations. The reference linked to this number (Eckhardt et al. 2009) is an online industry scout report on various values of flow tests and initial production (IP). To the extent that this reference deals with the fate of the gas associated with those flow tests it indicates that the production was captured and sold. The estimate for IP for the Haynesville is based on another informal, unvetted, web posting by a gas producer that is no longer available. However that estimate of IP is consistent with the values cited in Eckhardt et al. and the known characteristics of Haynesville wells. The fact their values for the daily rate of "lost" emissions for the Haynesville are virtually identical to the IP values for the wells indicates that the authors believe or assume that: (a) a well produces gas during completion at a rate that is equal to the highest rate reported for the well (the IP rate), and (b) that this gas is vented directly to the atmosphere. They provide no documentation for either of these beliefs/assumptions, which are on multiple grounds illogical. Because initial production is the highest flow achievable, and flowback occurs when the well still contains substantial water, flowback gas recoveries cannot exceed initial production recoveries, although Howarth et al. imply this is the case for all the areas listed in their Table 1. The problem is this: High gas flow rates are not possible when the well is substantially full of water, as it usually is during the flowback period. Gas cannot move up a wellbore filled with water other than in isolated packets, and it can flow optimally only when enough water is removed for the gas to have a connected pathway of gas up the well to the surface. Unless otherwise explicitly noted, initial production figures are published to show the highest recorded production rate for each well. They are a benchmark that characterizes what optimal production rate can be achieved by a well (and for which there is every incentive for producers to exaggerate in order to attract investors: http://www.oilempire.us/shalegas.html). These initial production tests are seldom run until after any substantial water has been removed from the well because substantial water impedes the outflow of gas.

The only sources which explicitly provide estimates of gas production during completion are for the Barnett (EPA 2004; although the Barnett is not named in this reference), the Piceance (EPA 2007), the Uinta (Samuels 2010), and the Den Jules (Bracken 2008) gas sands. These references report how gas production was recovered for sales and imply that this has been the case (at least for these companies) for several years! They emphasize the strong economic incentives for gas producers to capture and sell completion gases rather than flare or vent them. Only one (EPA 2007) provides explicit measurements of both captured (with "green technology") and lost emissions, and these numbers indicate a loss rate of 0.1% of total production. Howarth et al. cite the gas capture numbers in these references as representative of the gas leakage into the atmosphere that would occur if the gas was neither captured nor flared. They assume that this is the common situation, but do not make it clear that they have made this assumption. Rather they buttress their leakage estimates with the citations as if the latter explicitly documented methane leakage into the atmosphere, which they do not.

Based on Howarth et al's own references, as confirmed by conversations we have had with people experienced in well completions, we believe the losses during drill out and well completion for unconventional shale gas wells are not significantly greater than those cited by Howarth et al. for conventional gas wells. Certainly this could be made to be the case. This is supported by some of the examples cited by the EPA and Howarth et al. The Williams Corp (EPA 2007, p 14) shows, for example, that >90% of the flowback gas is captured and some of the remainder flared (George 2011, p14). If this were generally the case Howarth et al.'s 1.9% leakage would be reduced to 0.2%. An alternative life cycle analysis of a natural gas combined cycle power plant shows the total methane release from unconventional Barnett Shale hydrofractured gas wells is within a few percent of that from conventional onshore gas wells (DOE/NETL 2010, Table 5.1 and Figure 5.1). The leakage during drill out and well completion could be legislated to near zero by legally requiring flaring.

It is also worth pointing out that much of the oil produced in the United States at present is either from hydrofractured wells or shale formations, and thus is unconventional oil. Almost every conventional and unconventional oil well also produces natural gas. A clean distinction between "conventional" and "unconventional" gas production, and between "oil" and "gas" wells, thus may be very difficult to make, as there is an enormous amount of overlap between these categories.

Additional material supporting the statements made above is provided in an electronic supplement to this commentary. We describe there what happens when a well is completed and brought into production, and explain why a well cannot vent at its IP rate during the early drill out and completion phases, and (with discussion and a figure) why Howarth et al.'s projection of the IP rate to the flowback stage (these early stages) of well development is inappropriate. We discuss the purpose and nature of a scout report and show that the scout report cited by Howarth et al. states that the reported gas production was captured and diverted to sales (not vented into the atmosphere as Howarth et al. imply). We discuss the safety implications of Howarth et al.'s contention that 3.2% of the total eventual production of a shale gas well is vented into the atmosphere over a period of ~10 days, and show that this represents $1,000,000 worth of gas and presents a fire/explosion hazard that no company would countenance. And we show that the EPA's suggestion of release rates 50% of Howarth et al.'s is based on the assumption that, where capture or flaring is not required by law, methane is released to the atmosphere—an assumption that is not warranted on current practice, economic, or safety grounds. Those not familiar with well completion and production or economic and safety well procedures may find this additional material useful.

2 Methane leakage from the well site to the customer

The leakage that occurs between an operating well and consumers as the result of gas handling, processing, storage, and distribution is the same whether the well is producing from tight shale or conventional source rock. These losses are very hard to measure as they rely on a variety of sources that cannot be controlled in a scientific fashion. As well as true leakage you have to deal with questions of metering accuracy, shrinkage due to removal of higher order hydrocarbons, fuel use by compressors along the pipeline, etc. Trying to reach an estimate is important because various parties have a financial interest in the gas as it travels to the consumer, but scientific assessments are also encumbered by accounting conventions that relate to how gas transmission is charged to pipeline users. The results of most studies should not be considered accurate estimates that can be used for climate studies.

With well completion and drill out losses from both sources negligibly small (see above), the range of methane emissions that Howarth et al. identify is from 1.7 to 6% of total production. Leaking 6% of the gas that will ultimately be produced into the atmosphere during on-site handling, transmission through pipelines, and delivery appears to be far too high and at odds with previous studies. The most recent comprehensive study (EPA 2011, Table 3–37, assuming a 2009 U.S. production of natural gas of 24 TCF) shows the emission of methane between source and user is ~2.2% of production. Breaking this down, 1.3% occurs at the well site, 0.73% during transmission, storage, and distribution, and 0.17% during processing. The EPA Natural Gas STAR program (EPA 2009), a voluntary partnership to encourage oil and natural gas companies to adopt best practices, reports methane emissions of 308 BCF in 2008 This represents an emission of ~1.3% of total production. A life cycle analysis of combined cycle natural gas power pollutants suggests leakage can be much smaller. This report estimates ~0.9 wt.% leakage of methane between source and consumer (DOE/NETL 2010, Table 5.1), and suggests what best practices might achieve. A reasonable range for methane emissions to the atmosphere between source and consumer in the U.S. (the proper subject of the current discussion) would thus appear to be between 0.9 and 2.2% of production.

Excepting completion and drill out losses, the losses during transmission, storage and distribution, which Howarth et al. claim are conservatively 1.4–3.6% of production, constitute the largest fraction of their range of total gas losses of 1.7–6%. Howarth et al.'s transmission, storage and distribution losses are 2–5 time higher than the EPA (2011) estimate of 0.73%. Even their low end estimate seems far too high. Furthermore, many organizations have addressed these leakages, and many are striving to reduce them. Even if a 6% leakage rate were true in the US, the obvious policy implication would surely be to "fix the leaks". For example, Russian leakage was huge in the 1980s but with recent investments and improvements their leakage rate now is comparable to and perhaps less than ours. Of all the possibilities one could think of, reducing methane leakage should be the easiest, most accessible, and least costly way to reduce greenhouse gas emissions, and something that should be done regardless of how a comparison of gas and coal turns out.

3 Conclusions

We have highlighted key aspects of the recent letter from Howarth et al. that we believe are misleading.

The first aspect is the question of just how much methane gets released directly into the atmosphere during drilling, production, and transmission from unconventional gas wells. We show that the authors base their leakage rates heavily on two assumptions: (1) that drillers vent gas to the atmosphere during the drill out and pre-IP stages of development rather than capture and divert it to sales or flare it, and (2) that the discharge rate during these periods is comparable to the maximum production rate the well will experience—the IP rate. Absent very specific documentation, which Howarth et al do not offer, we can find no reasons to suspect that it is current industry practice to vent gas during these periods at the extreme rates and quantities Howarth et al. suggest, and we find obvious economic and safety reasons that this would not be industry practice. Howarth et al.'s assessment of the leakage from shale gas production appears to be too large by a factor of ~10 (0.2% of lifetime production rather than the 1.9% Howarth et al. assume). Even if we were to accept their estimate as representative of current practice (which we believe it is not), it is clear from Howarth et al.'s own citations that there are existing technological options that can greatly reduce such losses, and future technological improvements are sure to further reduce losses venting from both conventional and unconventional wells.

The second aspect of the Howarth et al. paper that we question is the effect of methane leakage from gas drilling on greenhouse gases and the future climate. Howarth et al. compute the GHG impacts using the most unfavorable time period (20 years vs 100 years) and basis (heat vs electricity) for comparing gas with coal. Considering that coal is used almost exclusively for generating electricity, gas must replace electricity generation by coal and the fuels should be compared on this basis. When considering the impact of swapping methane for CO_2 it is important to take into account the very short lifetime of methane in the atmosphere compared to the very long lifetime of the CO_2. The 100 year GWP for methane does this, the 20 year GWP does not. Focusing on electricity generation and using a 100 year GWP we show, using the same methods as Howarth et al., that gas has less than half and perhaps a third the greenhouse impact as coal. Since gas also possesses other important emission advantages such as no particulates, SO_2, NO_2, or ash, it is clearly the "cleaner" option in comparison to coal. Howarth et al. arrive at their conclusion that gas could have twice the greenhouse impact as coal only by using fugitive gas emissions 3.6 times larger than is reasonable (e.g. 2.2%), selecting a 20 year Global Warming Potential period for methane (which confers an impact 3.2 times bigger than a 100 year GWP), and failing to consider that a modern gas plant can generate electricity nearly twice as efficiently (and therefore with half the GHG input) as old coal plants.

It is of course possible, although we consider it highly unlikely and find no evidence to that effect, that methane emissions from wells and pipelines might be as large as Howarth et al. aver. But, as they acknowledge, these leaks could be economically and relatively easily fixed. Addressing whatever deficits natural gas might have at present so that it realizes the potential GHG benefits that are indicated in our Fig. 1 seems to us a goal eminently more achievable with current technology, and should be far more economic and less risky than relying on undeveloped and unproven new technologies to achieve the same degree of GHG reduction through other methods. Surely we need to consider how to reduce GHG emissions for all fuels, and should do the best we can with all the fuels we are using and are likely to continue using for some time. But in the short term, our energy needs should be satisfied mainly by those fuels having the fewest inherent environmental disadvantages, and we believe those preferred fuels include natural gas.

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Electronic Supplementary Material

Gas production is a specialized topic that is unfamiliar to most people, including most scientists. Best practice descriptions cover many aspects of gas drilling and hydrofracturing (e.g., API HF1, 2009), but we have found very few descriptions of well completion and flowback procedures (e.g., Lavelle, 2010), and these are quite general. We therefore describe below what we have discerned from conversations with those experienced with drilling and completion that makes it seem unlikely that fugitive methane emissions are occurring at anything like the rates Howarth et al. suggest.

Completing and Bringing a Well Into Production

Consider what happens in completing a well and bringing it into production: The well is drilled, logged, and then hydrofractured. When the hydrofracturing is finished, the wellbore and producing formations are full of water. Drilling out the plugs which divide the well into hydrofracture intervals occurs at this stage. Because the well is filled with water, only water is typically produced from the well during this process, and only gas dissolved in this water is brought to the surface, at least initially. Generally this condition persists during the full drill out period, but sometimes gas enters the well during drill out and must be dealt with at this stage. When the drill out is under water-filled-wellbore conditions, the gas leakage rate is comparatively small because, compared to a freely venting gas well, very little gas can be brought to the surface dissolved in water since gas solubility in water is low. The water produced at this stage is usually (and could always be) put into a capped tank where the gas exsolves from the water and is flared or captured. When the drill out occurs with substantial gas in the wellbore, more and perhaps very much more gas can be produced, but for safety and economic reasons (see below) it is not vented, but captured and either flared of diverted to sales through a pipeline. After drill out is completed, the operator begins to flow water from the well and the flowback stage begins. Normally no gas (or very minimal dissolved gas) is produced initially, but after a period ranging from hours to multiple days, the well starts to produce slugs of gas, and shortly thereafter enough gas that the well effluent can be diverted to a separator. The gas flow from the separator is generally either flared or put into a pipeline for sale. The first well on a pad may be flared (the methane is not released), but after this the gas is generally diverted to a pipeline and delivered to sales once enough gas pressure is obtained (or a skid-mounted compressor is utilized).

Figure S1 shows gas well production curves for the Haynesville Shale that include the pre-IP production (that portion of a well's production that took place before the flowback was completed and the production peaked). It shows clearly that production rates during the pre-IP production period are much lower than the monthly maximum production rates of the wells (which are themselves less than their reported IP rates). Production of gas is essentially non-existent in the early flow-back period (when only frac water is being produced). Significant gas flow starts only when enough frac water has been removed to let the gas begin to flow. The duration of the flowback period is poorly defined and there is no firm correlation between how a well will perform and the volume of gas that is produced during the flowback period. Gas production rates peak days to months later when frac water has been recovered from every producing frac stage and the well is operating optimally. From this maximum the production steadily declines. Most published production curves shown for unconventional gas production do not include the initial start up of gas production but begin when the well is considered to be done flowing back and in regular production and declining from its peak production.

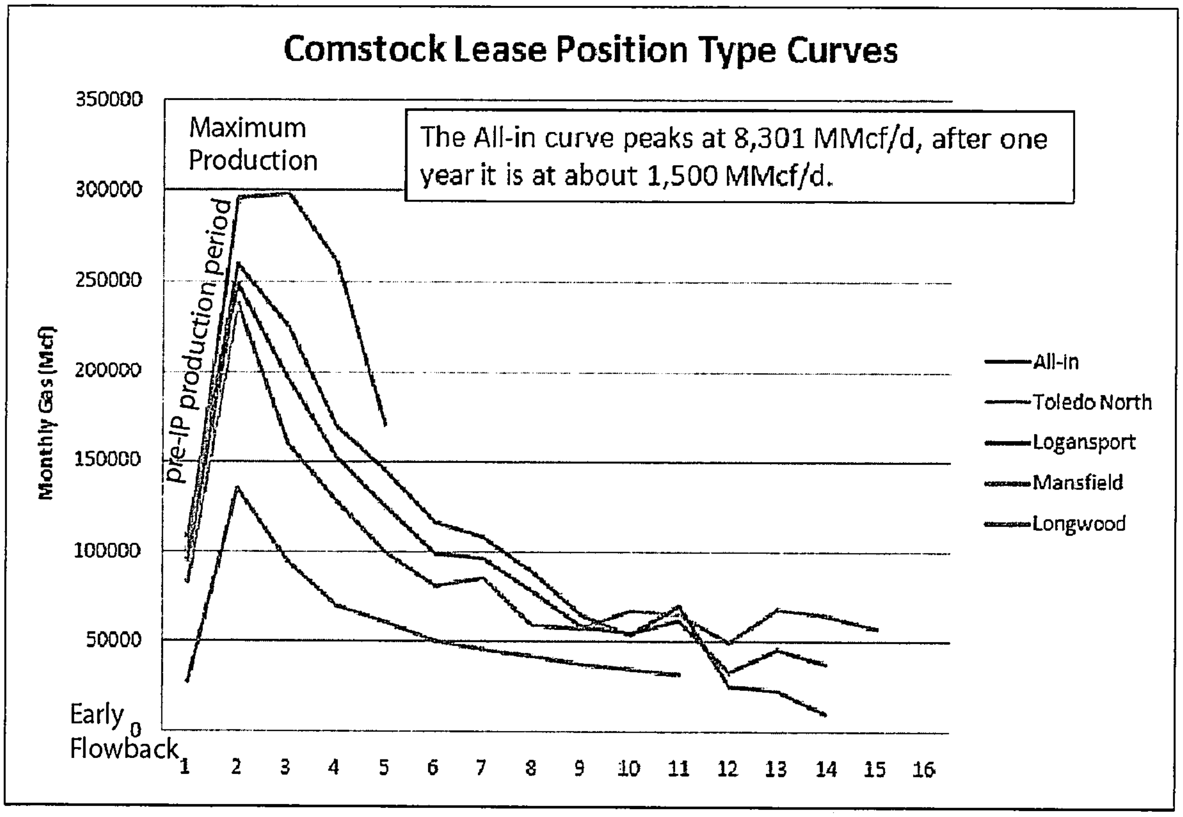

Figure S1. Production curves for Haynesville shale gas production. Figure is modified from DI ESP (2010) by the addition of text. The horizontal axis is time in months.

Scout Reports

A scout report, such as the one cited by Howarth et al. for their initial Haynesville leakage and production numbers, rarely indicates what the operator actually does with their gas during the initial testing of a well. Initial production figures therefore generally can't be used to estimate methane emissions because these reports are intended to convey how the well produces at its peak, not what the operator does with the production. The only entry in the source document Howarth et al. reference that gives any information related to emissions (Eckhardt et al., 2009) suggests that the gas flow noted was captured: *"The 1 Moseley was reported producing to sales at the daily rate of 14 million cu ft of gas equivalent through perforations at 12,800-15,260 ft while the operator was still cleaning up frac load."* In other words, at the time the gas flow rate was measured, the flowback was still ongoing and gas was *producing to sales.* This is the exact opposite of the venting of the gas to the atmosphere that Howarth et al. suggest.

One of the authors of this scout report (Philip H. Stark) recently published a statement regarding the use of their data by Howarth et al. (Appendix 1 in Barcella et al., 2011). His conclusion matched the one we made independently here - that their (eg., Stark and others) report did not contain "any evidence of such methane emissions".

Economic and Safety Considerations

The large values for methane lost during completion that Howarth et al. suggest is routine industry practice is incompatible with elementary safety and economic considerations. Consider again the Haynesville Shale case. Howarth et al. indicate that 6.8 million cubic meters of Haynesville natural gas (3.2% of a typical well's lifetime production) is released during an assumed flowback period of 10 days. Releasing 6.8 million cubic meters of gas into the atmosphere is equivalent to venting roughly $1,000,000 worth of natural gas (wholesale) from a single well. This leakage rate is equal to the consumption rate of 100,000 households, a city the size of Buffalo, NY (assuming 2.6 people per household) (EIA 2010). It's also a volume of potentially explosive gas so large that no driller (let alone their employees, contractors and regulators) would willfully release it. The volume of this gas can be appreciated from the fact that it could cover a square mile of land to a height of 176 feet with a combustible 5% mix of methane. It is equivalent to the gas transmission in a small gas pipeline (e.g., Smith, 2010). Of course, during venting much of this methane would be injected at pressure and at some height above the platform, and pure methane would buoyantly rise from the well. However, methane that is mixed with 95% air is still explosive and its distribution would be governed by air currents (convection) as well as buoyancy. Any spark could trigger an explosion that would be followed by a controlled burn (similar to flaring). Think how a homeowner worries what a very small emission from a gas stove might do to their house if not properly turned off before they leave for the theatre. The concern is not the small burning flame, but the explosion that could result from accumulated methane if the burner were blown out. The idea that methane is released in a routine fashion at the rates and volumes suggested by Howarth et al. is simply not credible on safety considerations alone.

If an operator could find a way to safely vent such a high volume of shale gas, and preferred to do that over flaring or selling the gas, they could theoretically do so. It's illegal on this scale in most states (see 25 PA Code Sec. 78.74, for instance), and would clearly violate the terms of their liability insurance, but it could *physically* happen during initial production testing. As a practical matter, however, we have seen no evidence that it happens on any such scale except in very rare circumstances, such as a well blow-out, and it cannot happen during the periods when there is still substantial frac water in the well (generally the case during the drill out and early flow back periods) which is the period when Howarth et al. suggest the methane is released.

EPA's Venting Analysis

Howarth et al. support their very high leakage estimate in general terms by citing the EPA's (2010) conclusion that large quantities of methane accompany the flow back of water and are vented in the first few days or weeks after hydrofracture injection. The basis for the EPA's (2010, p. 84 ff) conclusion is their observation that 51% of the U.S. unconventional production (coal bed methane and shale gas only - no tight sands gas data was available) in 2007 was in Wyoming (of which none was from shale), where flaring is required by law, and 49% was in Texas, Oklahoma, and Louisiana, where it is not required, but isn't banned either. The EPA then assumed that where regulations did not require the methane to be flared, it was all released directly into the atmosphere (not flared or sold), and they generalized this to be universally true. The EPA thus concludes that 4.6 million cubic feet of methane (50% of the typical 9.2 million cubic feet that they estimate is produced from an unconventional gas well during flowback) is released into the atmosphere. For all the reasons discussed above, we believe that this is a highly questionable assumption, and certainly one that is clearly stated by the EPA to be speculative. They did not document the venting, and are very clear that their basis is the assumption that when not required by law to flare or sell gas, unconventional wells are vented (into the atmosphere) during initial production. At least the EPA acknowledges that a significant portion of the methane emissions may be flared, rather than vented, in contrast to Howarth et al, who appear to assume 100% venting, the least likely scenario for real world operations.

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