The Carbon Footprint of Shale Gas Development and the Remedial Measures Necessary to Address it.

Anthony R. Ingraffea, PhD, PE

June 26, 2013

Prepared for Ontario Energy Board Proceedings:

EB-2012-0451: Enbridge Gas Distribution Inc.; and

EB-2012-0433 and EB-2013-0074: Union Gas Limited

I have prepared this report at the request of the Council of Canadians for the purpose of introducing certain articles I have co-authored, and follow-up related articles by others, which evaluate the greenhouse gas footprint of natural gas derived from high-volume fracturing from shale formations. In my opinion this work bears upon projections about the cost and availability of natural gas from this source, as well as the priority that should be given to investments in renewable energy and conservation measures.

I currently hold the Dwight C. Baum Professorship in Engineering and serve on the faculty of the School of Civil and Environmental Engineering at Cornell University. My research concentrates on computer simulation and physical testing of complex fracturing processes including hydraulic fracturing. A copy of my Curriculum Vitae is attached as Schedule “A” to this report.

I have not reviewed the record of these proceedings, but have been advised by Counsel of the following matters:

> The applications[1] before the Ontario Energy Board (the “Board”) seek approvals, *inter alia*, for the expansion and restructuring of the natural gas pipeline infrastructure in the Greater Toronto area (the “GTA”). The proponents have identified various benefits they predict to follow from proceeding with their projects, including improving supply chain diversity, reducing upstream supply risks and reducing gas supply costs over the period 2015 to 2025.
>
> To a significant extent the projects may be seen as a response to what the applicants describe as unprecedented changes to the North American natural gas market which include declines in Western Canadian supplies and substantial increases in new basins in

[1] Ontario Energy Board: Enbridge Gas Distribution Inc. – GTA Project (EB-2012-0451); Union Gas Limited – Parkway West Project (EB-2012-0433) & Brantford- Kirkwall/Parkway D (EB-2013-0074)

close proximity to the GTA. The most important and proximate of these is the Marcellus shale gas reserve.

The companies recite the projections of the Annual Energy Outlook 2012, the [US Energy Information Administration] EIA which indicate that the largest contributor to natural gas production growth in the United States will be shale gas for the next two and a half decades. Specifically, the EIA expects gas production in the US Northeast to increase from about 1.5 tcf (4.2 bcf/d) in 2010 to approximately 5.4 tcf (14.7 bcf/d) in 2035. Marcellus production is expected to account for roughly 3.0 tcf (8.2 bcf/d) of this projected production increase. Furthermore the EIA is projecting production growth, relative to other natural gas production regions in the US, to be greatest for the Northeast region.

Enbridge states that while supply of conventional gas from western Canada is declining, "shale gas production in the U.S. Northeast is projected to grow from approximately 1.8 PJ/d to 7.3 PJ/d between 2010 to 2021[2]. It notes that as of November 2012, approximately 0.4 PJ/d of Marcellus supply is flowing into Ontario." It goes on relate that "The increasing availability from emerging supply basins also provides the opportunity to procure gas supply more economically than western Canadian supply."

Union Gas has acknowledged however that certain supply risks are associated with Shale Basin Supply sources, including that changes to legislation or regulation might limit the available supply from shale basins.

I have also been advised that in exercising its authority in these proceedings Board is to be guided by particular objectives, including the following:

To protect the interests of consumers with respect to prices and the reliability and quality of gas service.

To facilitate rational expansion of transmission and distribution systems.

To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

To promote communication within the gas industry and the education of consumers consumers.[3]

[2] Enbridge: EB- 2012-0451, Exhibit A, Tab 3, Schedule 3, Page 23 of 24

[3] Ontario Energy Board Act, S.O. 1998, CHAPTER 15, section 2.

I have reviewed a draft copy of a report prepared by Ms. Lisa Sumi which describes risks to the supply and/or cost of shale gas, which may arise from policy and regulatory responses by governments to the environmental impacts associated with shale gas development.

I have reviewed the response[4] by Union Gas to an interrogatory from the Council of Canadians concerning the nature of the supply and price risks foreseen as potentially arising from public policy and law as it relates to shale gas exploration and development.

It is for the purpose of shedding light on one particular aspect of those environmental impacts, namely greenhouse gas emissions from shale gas development, that this report has been prepared. It is intended to provide perspective on evidence before the Board concerning the upstream supply risks and supply costs associated with the shale gas described as an important future source of natural gas supply for consumers in the Greater Toronto Area.

In June 2011, the journal, Climatic Change, devoted to publication and discussion of peer-reviewed climate science, published a paper written with two co-authors which represented the first comprehensive analysis of the GHG emissions from shale gas. That paper titled “Methane and the greenhouse-gas footprint of natural gas from shale formations” is attached as Schedule “B” to this report. We subsequently published further research and analysis concerning these emissions, and these peer reviewed papers are attached as Schedule “C” to this report.

The essential findings of our research work are as follows:

> Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from the shale-gas life-cycle escapes to the atmosphere in purposeful venting and leaks over the lifetime of a well. This predicted range is being validated recently by actual measurements reported in the peer-reviewed literature.[5] These methane emissions are at least 30% more than, and perhaps more than twice as great as, those from conventional gas.
>
> The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Shale gas wells are fractured with 50 to 100 times the volume of fluid used in non-shale wells, making the flowback period much longer.
>
> Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of

[4] Filed: 2013-06-07,EB-2012-0451/EB-2012-0433/EB-2013-0074, Exhibit I.A1.UGL.COC.1

[5] See, Petron G, et al., 2012. *Hydrocarbon emissions characterization in the Colorado front range*: a pilot study. J Geophys. Res.,117,D04304, http://dx. doi.org/10.1029/2011JD016360; Townsend-Small A, et al., 2012. *Isotopic measurement of atmospheric methane in Los Angeles, California, USA*: *Influence of “fugitive fossil fuel emissions*, J. Geophys. Res., 117, D07308, doi:10.1029/2011JD016826; Wennberg PO, et al., 2013, *On the sources of methane to the Los Angeles atmosphere*, Environ. Sci. Technol., doi:10.1021/es301138y; and Wunch D, et al. 2009. *Emissions of greenhouse gases from an American megacity*, Geophys. Res. Lett., 36, L15810, doi:10.1029/2009GL039825.

> shale gas on shorter time scales than traditionally mentioned, dominating it on a 20-year time horizon where its global warming potential is greater than 72 times that of carbon dioxide.
>
> The footprint for shale gas is greater than that for conventional gas or oil and for coal used for electricity generation when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.
>
> The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. This does not justify the continued use of either oil or coal, but rather demonstrates that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Remedial Measures to Address CH_4 Emissions from Shale Gas Development

Some recent papers have suggested that there are remedial measures available to address life-cycle methane emissions from shale gas development. Some of these measures are technical, some economic. None, in my opinion are currently effective.

As an example of an ineffective economic measure, carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change

As an example of an effective, but certainly not yet universal technical measure, better regulation and enforcement can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

Can shale-gas methane emissions be reduced? Clearly yes, and proposed EPA regulations to require capture of gas at the time of well completions are an important step. Regulations and enforcement are necessary to accomplish emission reductions, as economic considerations alone have not driven such reductions (EPA 2011b). And it may be extremely expensive to reduce leakage associated with aging infrastructure, particularly distribution pipelines in cities[8] but also long distance transmission pipelines, which are on average more than 50 years old in the U.S.

Meanwhile, shale gas competes for investment with green energy technologies, slowing their development and distracting politicians and the public from developing a long-term sustainable energy policy.

With time, perhaps engineers can develop more appropriate ways to handle fracking-fluid return wastes, and perhaps the technology can be made more sustainable and less polluting in other ways. Meanwhile, the gas should remain safely in the shale, while society uses energy more efficiently and develops renewable energy sources more aggressively.

The related and important question is this: given present risks, should society invest massive capital in such improvements for a so-called “bridge fuel” that is to be used for only 20 to 30 years, or would the capital and fuel expenditures be better spent on conservation and efficiency improvements, and switching end uses to more sustainable, efficient energy sources? I think not. A “ bridge” in time is not necessary as all of these sustainable measures are available now.

However, if we proceed further down the present path, the imperative to reduce shale-gas methane emissions will add significantly to the costs of natural gas from this source. These costs, when considered together with those of remedial measures needed to address other environmental impacts of shale-gas development (Sumi), call into question the economic viability of shale-gas development and hence present projections for future supply expansion.

June 26, 2013.

A. R. Ingraffea, Ph.D., P.E.
Dwight C. Baum Professor of Engineering
Weiss Presidential Teaching Fellow
Cornell University
www.cfg.cornell.edu
President: Physicians, Scientists, and Engineers for Healthy Energy, Inc.
www.psehealthyenergy.org
607-351-0043

SCHEDULE “B”

Climatic Change
DOI 10.1007/s10584-011-0061-5

LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

Robert W. Howarth · Renee Santoro · Anthony Ingraffea

Received: 12 November 2010 / Accepted: 13 March 2011
© The Author(s) 2011. This article is published with open access at Springerlink.com

Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

Electronic supplementary material The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material, which is available to authorized users.

R. W. Howarth (✉) · R. Santoro
Department of Ecology and Evolutionary Biology, Cornell University, Ithaca, NY 14853, USA
e-mail: rwh2@cornell.edu

A. Ingraffea
School of Civil and Environmental Engineering, Cornell University, Ithaca, NY 14853, USA

Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a] Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b] Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c] Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d] Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e] Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during "liquid unloading." Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in

EB 2012-0451/2012-0433/2013-0074
Exhibit L.EGD.COC.1

temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

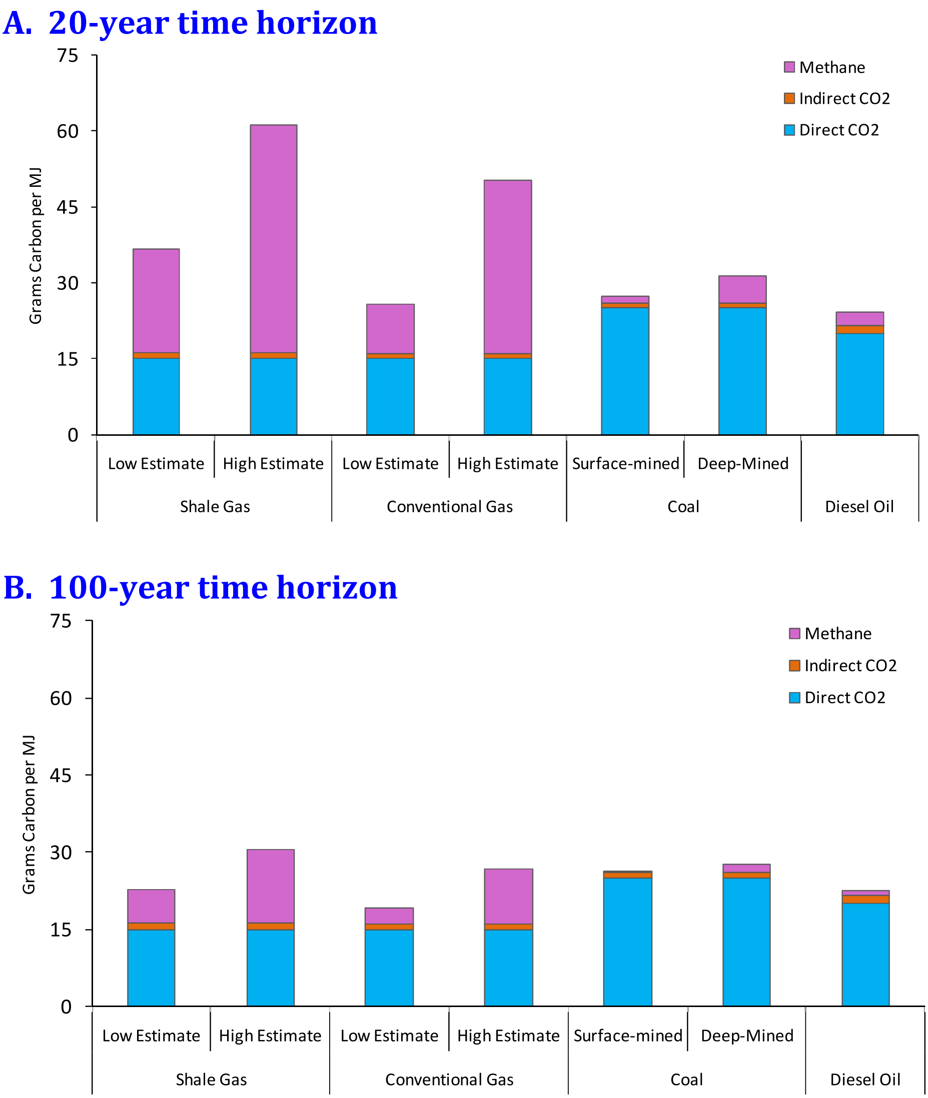


Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

Acknowledgements Preparation of this paper was supported by a grant from the Park Foundation and by an endowment funds of the David R. Atkinson Professorship in Ecology & Environmental Biology at Cornell University. We thank R. Alvarez, C. Arnold, P. Artaxo, A. Chambers, D. Farnham, P. Jamarillo, N. Mahowald, R. Marino, R. McCoy, J. Northrup, S. Porder, M. Robertson, B. Sell, D. Shrag, L. Spaeth, and D. Strahan for information, encouragement, advice, and feedback on our analysis and manuscript. We thank M. Hayn for assistance with the figures. Two anonymous reviewers and Michael Oppenheimer provided very useful comments on an earlier version of this paper.

Open Access This article is distributed under the terms of the Creative Commons Attribution Noncommercial License which permits any noncommercial use, distribution, and reproduction in any medium, provided the original author(s) and source are credited.

References

Armendariz A (2009) Emissions from natural gas production in the Barnett shale area and opportunities for cost-effective improvements. Report prepared for Environmental Defense Fund, Austin TX

Bracken K (2008) Reduced emission completions in DJ basin and natural buttes. Presentation given at EPA/GasSTAR Producers Technology Transfer Workshop. Rock Springs Wyoming, 1 May 2008. http://www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/rocksprings5.pdf

Chambers AK (2004) Optical measurement technology for fugitive emissions from upstream oil and gas facilities. Report prepared for Petroleum Technology Alliance Canada by Carbon and Energy Management, Alberta Research Council, Edmonton, Alberta

Cicerone RJ, Oremland R (1988) Biogeochemical aspects of atmospheric methane. Global Biogeochem. Cycles 2:299–327

Council of Scientific Society Presidents (2010) Letter from the council to President Obama and senior administration officials, dated May 4, 2010. Council of Scientific Society Presidents, 1155 16th Avenue NW, Washington, DC 20036. Available at http://www.eeb.cornell.edu/howarth/CCSP%20letter%20on%20energy%20&%20environment.pdf

Crutzen PJ (1987) Role of the tropics in atmospheric chemistry. In: Dickinson R (ed) Geophysiology of Amazonia. Wiley, NY, pp 107–129

Eckhardt M, Knowles B, Maker E, Stork P (2009) IHS U.S. Industry Highlights. (IHS) Houston, TX, Feb–Mar 2009. http://www.gecionline.com/2009-prt-7-final-reviews

EIA (2010a) Annual energy outlook 2011 early release overview. DOE/EIA-0383ER(2011). Energy Information Agency, U.S. Department of Energy. http://www.eia.gov/forecasts/aeo/pdf/0383er(2011).pdf. Accessed 3 January 2011

EIA (2010b) Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm

EPA (2004) Green completions. Natural Gas STAR Producer's Technology Transfer Workshop, 21 September 2004. http://epa.gov/gasstar/workshops/techtransfer/2004/houston-02.html

EPA (2006) Lessons learned: options for reducing methane emissions from pneumatic devices in the natural gas industry. U.S. EPA/ Gas STAR. http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf

EPA (2007) Reducing methane emissions during completion operations. Natural Gas STAR Producer's Technology Transfer Workshop, 11 September 2007. http://epa.gov/gasstar/documents/workshops/glenwood-2007/04_recs.pdf

EPA (2010) Greenhouse gas emissions reporting from the petroleum and natural gas industry. Background Technical Support Document. http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf. Accessed 3 January 2011

Fernandez R, Petrusak R, Robinson D, Zavadil D (2005) Cost-Effective methane emissions reductions for small and midsize natural gas producers. Reprinted from the June 2005 issue of Journal of Petroleum Technology. http://www.icfi.com/Markets/Environment/doc_files/methane-emissions.pdf

GAO (2010) Federal oil and gas leases: opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases. GAO-11–34 U.S. General Accountability Office Washington DC. http://www.gao.gov/new.items/d1134.pdf

Harrison MR, Shires TM, Wessels JK, Cowgill RM (1996) Methane emissions from the natural gas industry. Executive summary, vol 1. EPA-600/R-96-080a. U.S. Environmental Protection Agency, Office of Research and Development, Washington, DC

Hayhoe K, Kheshgi HS, Jain AK, Wuebbles DJ (2002) Substitution of natural gas for coal: climatic effects of utility sector emissions. Climatic Change 54:107–139

Henke D (2010) Encana, USA division overview. Encana Natural Gas, investors presentation. http://www.encana.com/investors/presentations/investorday/pdfs/usa-division-overview.pdf

Intergovernmental Panel on Climate Change (1995) IPCC second assessment. Climate Change, 1995. http://www.ipcc.ch/pdf/climate-changes-1995/ipcc-2nd-assessment/2nd-assessment-en.pdf

Intergovernmental Panel on Climate Change (2007) IPCC fourth assessment report (AR4). Working Group 1, The Physical Science Basis. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html

Jamarillo P, Griffin WM, Mathews HS (2007) Comparative life-cycle air emissions of coal, domestic natural gas, LNG, and SNG for electricity generation. Environ Sci Technol 41:6290–6296

Kirchgessner DA, Lott RA, Cowgill RM, Harrison MR, Shires TM (1997) Estimate of methane emissions from the US natural gas industry. Chemosphere 35: 1365–1390

Kruuskraa VA (2004) Tight gas sands development—How to dramatically improve recovery efficiency. GasTIPS, Winter 2004. http://media.godashboard.com/gti/4ReportsPubs/4_7GasTips/Winter04/TightGasSandsDEvelopment-HowToDramaticallyImproveRecoveryEfficiency.pdf

Lassey KR, Lowe DC, Smith AM (2007) The atmospheric cycling of radiomethane and the “fossil fraction” of the methane source. Atmos Chem Phys 7:2141–2149

Lelieveld J, Lechtenbohmer S, Assonov SS, Brenninkmeijer CAM, Dinest C, Fischedick M, Hanke T (2005) Low methane leakage from gas pipelines. Nature 434:841–842

Liu AE (2008) Overview: pipeline accounting and leak detection by mass balance, theory and hardware implementation. Quantum Dynamics, Woodland Hills. Available at http://www.pstrust.org/library/docs/massbalance_ld.pdf

National Research Council (2009) Hidden costs of energy: unpriced consequences of energy production and use. National Academy of Sciences Press, Washington

New York Department of Environmental Conservation (2009) Draft supplemental generic environmental impact statement on the oil, gas and solution mining regulatory program. http://www.dec.ny.gov/energy/58440.html

Nisbet EG, Manning MR, Lowry D, Lassey KR (2000) Methane and the framework convention on climate change, A61F-10, Eos Trans. AGU 81(48), Fall Meet. Suppl

Pacala S, Socolow R (2004) Stablization wedges: solving the climate problem for the next 50 years with current technologies. Science 305:968–972

Percival P (2010) Update on “lost and unaccounted for” natural gas in Texas. Basin Oil and Gas. Issue 32. http://fwbog.com/index.php?page=article&article=248

Reshetnikov AI, Paramonova NN, Shashkov AA (2000) An evaluation of historical methane emissions from the Soviet gas industry. JGR 105:3517–3529

Revkin A, Krauss C (2009) By degrees: curbing emissions by sealing gas leaks. New York Times, 14 October 2009. Available at http://www.nytimes.com/2009/10/15/business/energy-environment/15degrees.html

Samuels J (2010) Emission reduction strategies in the greater natural buttes. Anadarko Petroleum Corporation. EPA Gas STAR, Producers Technology Transfer Workshop Vernal, Utah, 23 March 2010. http://www.epa.gov/gasstar/documents/workshops/vernal-2010/03_anadarko.pdf

Santoro R, Howarth RW, Ingraffea T (2011) Life cycle greenhouse gas emissions inventory of Marcellus shale gas. Technical report of the Agriculture, Energy, & Environment Program, Cornell University, Ithaca, NY. To be archived and made available on-line

Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716–718

Shires TM, Loughran, CJ, Jones S, Hopkins E (2009) Compendium of greenhouse gas emissions methodologies for the oil and natural gas industry. Prepared by URS Corporation for the American Petroleum Institute (API). API, Washington DC

Wood R, Gilbert P, Sharmina M, Anderson K, Fottitt A, Glynn S, Nicholls F (2011) Shale gas: a provisional assessment of climate change and environmental impacts. Tyndall Center, University of Manchester, Manchester, England. http://www.tyndall.ac.uk/sites/default/files/tyndall-coop_shale_gas_report_final.pdf

SCHEDULE "C-I"

EB 2012-0451/2012-0433/2013-0074
Exhibit L.EGD.COC.1

Climatic Change
DOI 10.1007/s10584-012-0401-0

Venting and leaking of methane from shale gas development: response to Cathles et al.

Robert W. Howarth · Renee Santoro · Anthony Ingraffea

Received: 10 December 2011 / Accepted: 10 January 2012
© The Author(s) 2012. This article is published with open access at Springerlink.com

Abstract In April 2011, we published the first comprehensive analysis of greenhouse gas (GHG) emissions from shale gas obtained by hydraulic fracturing, with a focus on methane emissions. Our analysis was challenged by Cathles et al. (2012). Here, we respond to those criticisms. We stand by our approach and findings. The latest EPA estimate for methane emissions from shale gas falls within the range of our estimates but not those of Cathles et al. which are substantially lower. Cathles et al. believe the focus should be just on electricity generation, and the global warming potential of methane should be considered only on a 100-year time scale. Our analysis covered both electricity (30% of US usage) and heat generation (the largest usage), and we evaluated both 20- and 100-year integrated time frames for methane. Both time frames are important, but the decadal scale is critical, given the urgent need to avoid climate-system tipping points. Using all available information and the latest climate science, we conclude that for most uses, the GHG footprint of shale gas is greater than that of other fossil fuels on time scales of up to 100 years. When used to generate electricity, the shale-gas footprint is still significantly greater than that of coal at decadal time scales but is less at the century scale. We reiterate our conclusion from our April 2011 paper that shale gas is not a suitable bridge fuel for the 21st Century.

1 Introduction

Promoters view shale gas as a bridge fuel that allows continued reliance on fossil fuels while reducing greenhouse gas (GHG) emissions. Our April 2011 paper in *Climatic Change* challenged this view (Howarth et al. 2011). In the first comprehensive analysis of the GHG emissions from shale gas, we concluded that methane emissions lead to a large

Electronic supplementary material The online version of this article (doi:10.1007/s10584-012-0401-0) contains supplementary material, which is available to authorized users.

R. W. Howarth (✉) · R. Santoro
Department of Ecology & Evolutionary Biology, Cornell University, Ithaca, NY 14853, USA
e-mail: rwh2@cornell.edu

A. Ingraffea
School of Civil and Environmental Engineering, Cornell University, Ithaca, NY 14853, USA

GHG footprint, particularly at decadal time scales. Cathles et al. (2012) challenged our work. Here, we respond to the criticisms of Cathles et al. (2012), and show that most have little merit. Further, we compare and contrast our assumptions and approach with other studies and with new information made available since our paper was published. After carefully considering all of these, we stand by the analysis and conclusions we published in Howarth et al. (2011).

2 Methane emissions during entire life cycle for shale gas and conventional gas

Cathles et al. (2012) state our methane emissions are too high and are "at odds with previous studies." We strongly disagree. Table 1 compares our estimates for both conventional gas and shale gas (Howarth et al. 2011) with 9 other studies, including 7 that have only become available since our paper was published in April 2011, listed chronologically by time of publication. See Electronic Supplementary Materials for details on conversions and calculations. Prior to our study, published estimates existed only for conventional gas. As we discussed in Howarth et al. (2011), the estimate of Hayhoe et al. (2002) is very close to our mean value for conventional gas, while the estimate from Jamarillo et al. (2007) is lower and should probably be considered too low because of their reliance on emission factors from a 1996 EPA report (Harrison et al. 1996). Increasing evidence over the past 15 years has suggested the 1996 factors were low (Howarth et al. 2011). In November 2010, EPA (2010) released parts of their first re-assessment of the 1996 methane emission factors, increasing some emissions factors by orders of magnitude. EPA (2011a), released just after our paper was published in April, used these new factors to re-assess and update the U.S. national GHG inventory, leading to a 2-fold increase in total methane emissions from the natural gas industry.

Table 1 Comparison of published estimates for full life-cycle methane emissions from conventional gas and shale gas, expressed per unit of Lower Heating Value (gC MJ^{-1}). Studies are listed by chronology of publication date

	Conventional gas	Shale gas
Hayhoe et al. (2002)	0.57	*
Jamarillo et al. (2007)	0.15	*
Howarth et al. (2011)	0.26–0.96	0.55–1.2
EPA (2011a)	0.38	0.60^{+}
Jiang et al. (2011)	*	0.30
Fulton et al.(2011)	0.38^{++}	*
Hultman et al. (2011)	0.35	0.57
Skone et al. (2011)	0.27	0.37
Burnham et al. (2011)	0.39	0.29
Cathles et al. (2012)	0.14–0.36	0.14–0.36

See Electronic Supplemental Materials for details on conversions

* Estimates not provided in these reports

+ Includes emissions from coal-bed methane, and therefore may under-estimate shale gas emissions

++ Based on average for all gas production in the US, not just conventional gas, and so somewhat over-estimates conventional gas emissions

The new estimate for methane emissions from conventional gas in the EPA (2011a) inventory, 0.38 g C MJ^{-1}, is within the range of our estimates: 0.26 to 0.96 g C MJ^{-1} (Table 1). As discussed below, we believe the new EPA estimate may still be too low, due to a low estimate for emissions during gas transmission, storage, and distribution. Several of the other recent estimates for conventional gas are very close to the new EPA estimate (Fulton et al. 2011; Hultman et al. 2011; Burnham et al. 2011). The Skone et al. (2011) value is 29% lower than the EPA estimate and is very similar to our lower-end number. Cathles et al. (2012) present a range of values, with their high end estimate of 0.36 g C MJ^{-1} being similar to the EPA estimate but their low end estimate (0.14 g C MJ^{-1}) far lower than any other estimate, except for the Jamarillo et al. (2007) estimate based on the old 1996 EPA emission factors.

For shale gas, the estimate derived from EPA (2011a) of 0.60 g C MJ^{-1} is within our estimated range of 0.55 to 1.2 g C MJ^{-1} (Table 1); as with conventional gas, we feel the EPA estimate may not adequately reflect methane emissions from transmission, storage, and distribution. Hultman et al. (2011) provide an estimate only slightly less than the EPA number. In contrast, several other studies present shale gas emission estimates that are 38% (Skone et al. 2011) to 50% lower (Jiang et al. 2011; Burnham et al. 2011) than the EPA estimate. The Cathles et al. (2012) emission estimates are 40% to 77% lower than the EPA values, and represent the lowest estimates given in any study.

In an analysis of a PowerPoint presentation by Skone that provided the basis for Skone et al. (2011), Hughes (2011a) concludes that a major difference between our work and that of Skone and colleagues was the estimated lifetime gas production from a well, an important factor since emissions are normalized to production. Hughes (2011a) suggests that Skone significantly overestimated this lifetime production, and thereby underestimated the emissions per unit of energy available from gas production (see Electronic Supplemental Materials). We agree, and believe this criticism also applies to Jiang et al. (2011). The lifetime production of shale-gas wells remains uncertain, since the shale-gas technology is so new (Howarth and Ingraffea 2011). Some industry sources estimate a 30-year lifetime, but the oldest shale-gas wells from high-volume hydraulic fracturing are only a decade old, and production of shale-gas wells falls off much more rapidly than for conventional gas wells. Further, increasing evidence suggests that shale-gas production often has been exaggerated (Berman 2010; Hughes 2011a, 2011b; Urbina 2011a, 2011b).

Our high-end methane estimates for both conventional gas and shale gas are substantially higher than EPA (2011a) (Table 1), due to higher emission estimates for gas storage, transmission, and distribution ("downstream" emissions). Note that our estimated range for emissions at the shale-gas wells ("upstream" emissions of 0.34 to 0.58 g C MJ^{-1}) agree very well with the EPA estimate (0.43 g C MJ^{-1}; see Electronic Supplementary Materials). While EPA has updated many emission factors for natural gas systems since 2010 (EPA 2010, 2011a, 2011b), they continue to rely on the 1996 EPA study for downstream emissions. Updates to this assumption currently are under consideration (EPA 2011a). In the meanwhile, we believe the EPA estimates are too low (Howarth et al. 2011). Note that the downstream emission estimates of Hultman et al. (2011) are similar to EPA (2011a), while those of Jiang et al. (2011) are 43% less, Skone et al. (2011) 38% less, and Burnham et al. (2011) 31% less (Electronic Supplemental Materials). One problem with the 1996 emission factors is that they were not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed emissions from model facilities run by companies that voluntarily participated (Kirchgessner et al. 1997). The average long-distance gas transmission pipeline in the U.S. is more than 50 years old, and many cities rely on gas distribution systems that are 80 to 100 years old, but these older systems were not part of the 1996 EPA assessment. Our range of estimates for methane emissions during gas storage, transmission, and distribution falls well within the range given by Hayhoe et al. (2002), and our mean estimate is virtually identical to their "best estimate" (Howarth et al. 2011). Nonetheless, we readily admit that these estimates are highly uncertain. There is an urgent need for better measurement of methane fluxes from all parts of the natural gas industry, but particularly during completion of unconventional wells and from storage, transmission, and distribution sectors (Howarth et al. 2011).

EPA proposed new regulations in October 2009 that would require regular reporting on GHG emissions, including methane, from natural gas systems (EPA 2011c). Chesapeake Energy Corporation, the American Gas Association, and others filed legal challenges to these regulations (Nelson 2011). Nonetheless, final implementation of the regulations seems likely. As of November 2011, EPA has extended the deadline for the first reporting to September 2012 (EPA 2011c). These regulations should help evaluate methane pollution, although actual measurements of venting and leakage rates will not be required, and the reporting requirement as proposed could be met using EPA emission factors. Field measurements across a range of well types, pipeline and storage systems, and geographic locations are important for better characterizing methane emissions.

3 How much methane is vented during completion of shale-gas wells?

During the weeks following hydraulic fracturing, frac-return liquids flow back to the surface, accompanied by large volumes of natural gas. We estimated substantial methane venting to the atmosphere at this time, leading to a higher GHG footprint for shale gas than for conventional gas (Howarth et al. 2011). Cathles et al. (2012) claim we are wrong and assert that methane emissions from shale-gas and conventional gas wells should be equivalent. They provide four arguments: 1) a physical argument that large flows of gas are not possible while frac fluids fill the well; 2) an assertion that venting of methane to the atmosphere would be unsafe; 3) a statement that we incorrectly used data on methane capture during flowback to estimate venting; and 4) an assertion that venting of methane is not in the economic interests of industry. We disagree with each point, and note our methane emission estimates during well completion and flowback are quite consistent with both those of EPA (2010, 2011a, b) and Hultman et al. (2011).

Cathles et al. state that gas venting during flowback is low, since the liquids in the well interfere with the free flow of gas, and imply that this condition continues until the well goes into production. While it is true that liquids can restrict gas flow early in the flow-back period, gas is freely vented in the latter stages. According to EPA (2011d), during well cleanup following hydraulic fracturing "backflow emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate backflow, with intermittent slugs of water and sand along with free gas, is typically directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels." The methane emissions are "vented as the backflow enters the impoundment or vessels" (EPA 2011d). Initial flowback is 100% liquid, but this quickly becomes a two-phase flow of liquid and gas as backpressure within the fractures declines (Soliman & Hunt 1985; Willberg et al. 1998; Yang et al. 2010; EPA 2011a, d). The gas produced is not in solution, but rather is free-flowing with the liquid in this frothy mix. The gas cannot be put into production and sent to sales until flowback rates are sufficiently decreased to impose pipeline pressure.

Is it unsafe for industry to vent gas during flowback, as Cathles et al. assert? Perhaps, but venting appears to be common industry practice, and the latest estimates from EPA (2011b, page 3–12) are that 85% of flowback gas from unconventional wells is vented and less than 15% flared or captured. While visiting Cornell, a Shell engineer stated Shell never flares gas during well completion in its Pennsylvania Marcellus operations (Bill Langin, pers. comm.). Venting of flow-back methane is clearly not as unsafe as Cathles et al. (2012) believe, since methane has a density that is only 58% that of air and so would be expected to be extremely buoyant when vented. Under sufficiently high wind conditions, vented gas may be mixed and advected laterally rather than rising buoyantly, but we can envision no atmospheric conditions under which methane would sink into a layer over the ground. Buoyantly rising methane is clearly seen in Forward Looking Infra Red (FLIR) video of a Pennsylvania well during flowback (Fig. 1). Note that we are not using this video information to infer any information on the rate of venting, but simply to illustrate that venting occurred in the summer of 2011 in Pennsylvania and that the gas rose rapidly into the atmosphere. Despite the assertion by Cathles et al. that venting is illegal in Pennyslvania, the only legal restriction is that "excess gas encountered during drilling, completion or stimulation shall be flared, captured, or diverted away from the drilling rig in a manner than does not create a hazard to the public health or safety" (PA § 78.73. *General provision for well construction and operation*).

Cathles et al. state with regard to our paper: "The data they cite to support their contention that fugitive methane emissions from unconventional gas production is [sic] 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." We did indeed use data on captured gas as a surrogate for vented emissions, similar to such interpretation by EPA (2010). Although most flowback gas appears to be vented and not captured (EPA 2011b), we are aware of no data on the rate of venting, and industry apparently does not usually measure or estimate the gas that is vented during flowback. Our assumption (and that of EPA 2010) is that the rate of gas flow is the same during flowback, whether vented or captured. Most of the data we used were reported to the EPA as part of their "green completions" program, and they provide some of the very few publicly available quantitative estimates of methane flows at the time of flowback. Note that the estimates we published in Howarth et al. (2011) for emissions at the time of well completion for shale gas could be reduced by 15%, to account for the estimated average percentage of gas that is not vented but

Fig. 1 Venting of natural gas into the atmosphere at the time of well completion and flowback following hydraulic fracturing of a well in Susquehanna County, PA, on June 22, 2011. Note that this gas is being vented, not flared or burned, and the color of the image is to enhance the IR image of this methane-tuned FLIR imagery. The full video of this event is available at http://www.psehealthyenergy.org/resources/view/198782. Video provided courtesy of Frank Finan

rather is flared or captured and sold (EPA 2011b). Given the other uncertainty in these estimates, though, our conclusions would remain the same.

Cathles et al. also assert that we used initial production rates for gas wells, and that in doing so over-estimated flowback venting. Our estimates of flowback emissions for the Barnett, Piceance, Uinta, and Denver-Jules basins were not based on initial production rates, but rather solely on industry-reported volumes of gas captured, assuming. We estimated emissions for the Haynesville basin as the median of data given in Eckhardt et al. (2009), who reported daily rates ranging from 400,000 m^3 (14 MMcf) to 960,000 m^3 (38 MMcf). We assumed a 10-day period for the latter part of the flowback in which gases freely flow, the mean for the other basin studies we used. The use of initial production rates applied to the latter portion of flowback duration as an estimate of venting is commonly accepted (Jiang et al. 2011; NYS DEC 2011).

Finally, Cathles et al. state that economic self-interest would make venting of gas unlikely. Rather, they assert industry would capture the gas and sell it to market. According to EPA (2011b), the break-even price at which the cost of capturing flowback gas equals the market value of the captured gas is slightly under \$4 per thousand cubic feet. This is roughly the well-head price of gas over the past two years, suggesting that indeed industry would turn a profit by capturing the gas, albeit a small one. Nonetheless, EPA (2011b) states that industry is not commonly capturing the gas, probably because the rate of economic return on investment for doing so is much lower than the normal expectation for the industry. That is, industry is more likely to use their funds for more profitable ventures than capturing and selling vented gas (EPA 2011b). There also is substantial uncertainty in the cost of capturing the gas. At least for low-energy wells, a BP presentation put the cost of "green" cleanouts as 30% higher than for normal well completions (Smith 2008). The value of the captured gas would roughly pay for the process, according to BP, at the price of gas as of 2008, or approximately \$6.50 per thousand cubic feet (EIA 2011a). At this cost, industry would lose money by capturing and selling gas not only at the current price of gas but also at the price forecast for the next 2 decades (EPA 2011b).

In July 2011, EPA (2011b, e) proposed new regulations to reduce emissions during flowback. The proposed regulation is aimed at reducing ozone and other local air pollution, but would also reduce methane emissions. EPA (2011b, e) estimates the regulation would reduce flowback methane emissions from shale gas wells by up to 95%, although gas capture would only be required for wells where collector pipelines are already in place, which is often not the case when new sites are developed. Nonetheless, this is a very important step, and if the regulation is adopted and can be adequately enforced, will reduce greatly the difference in emissions between shale gas and conventional gas in the U.S. We urge universal adoption of gas-capture policies.

To summarize, most studies conclude that methane emissions from shale gas are far higher than from conventional gas: approximately 40% higher, according to Skone et al. (2011) and using the mean values from Howarth et al. (2011), and approximately 60% higher using the estimates from EPA (2011a) and Hultman et al. (2011). Cathles et al. assertion that shale gas emissions are no higher seems implausible to us. The suggestion by Burnham et al. (2011) that shale gas methane emissions are less than for conventional gas seems even less plausible (see Electronic Supplementary Materials).

4 Time frame and global warming potential of methane

Methane is a far more powerful GHG than carbon dioxide, although the residence time for methane in the atmosphere is much shorter. Consequently, the time frame for comparing methane and carbon dioxide is critical. In Howarth et al. (2011), we equally presented two time frames, the 20 and 100 years integrated time after emission, using the global warming potential (GWP) approach. Note that GWPs for methane have only been estimated at time scales of 20, 100, and 500 years, and so GHG analyses that compare methane and carbon dioxide on other time scales require a more complicated atmospheric modeling approach, such as that used by Hayhoe et al. (2002) and Wigley (2011). The GWP approach we follow is quite commonly used in GHG lifecycle analyses, sometimes considering both 20-year and 100-year time frames as we did (Lelieveld et al. 2005; Hultman et al. 2011), but quite commonly using only the 100-year time frame (Jamarillo et al. 2007; Jiang et al. 2011; Fulton et al. 2011; Skone et al. 2011; Burnham et al. 2011). Cathles et al. state that a comparison based on the 20-year GWP is inappropriate, and criticize us for having done so. We very strongly disagree.

Considering methane's global-warming effects at the decadal time scale is critical (Fig. 2). Hansen et al. (2007) stressed the need for immediate control of methane to avoid critical tipping points in the Earth's climate system, particularly since methane release from permafrost becomes increasingly likely as global temperature exceeds 1.8°C above the

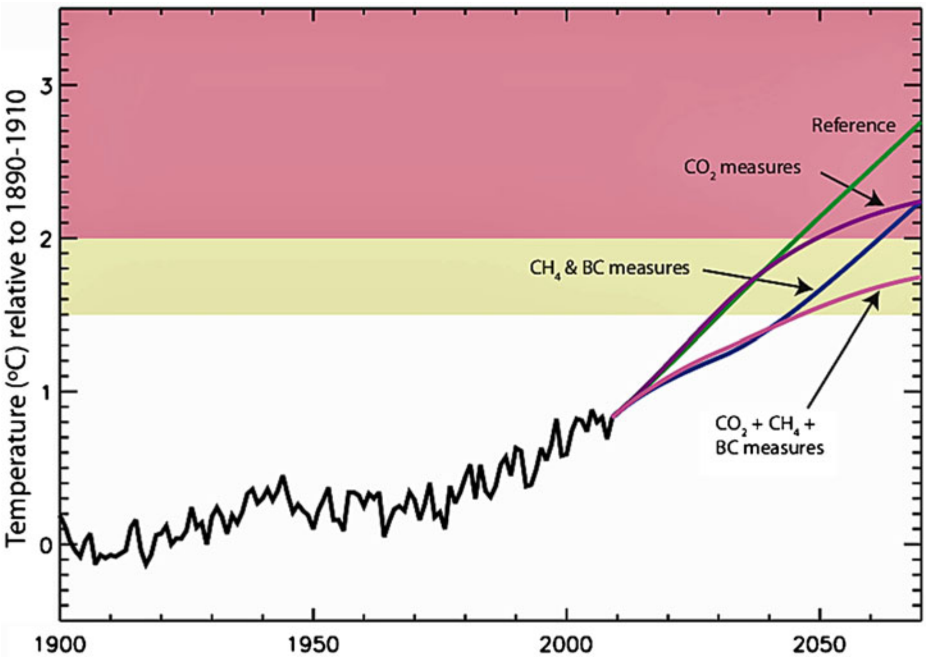


Fig. 2 Observed global mean temperature from 1900 to 2009 and projected future temperature under four scenarios, relative to the mean temperature from 1890–1910. The scenarios include the IPCC (2007) reference, reducing carbon dioxide emissions but not other greenhouse gases ("CO_2 measures"), controlling methane and black carbon emissions but not carbon dioxide ("CH_4 + BC measures"), and reducing emissions of carbon dioxide, methane, and black carbon ("CO_2 + CH_4 + BC measures"). An increase in the temperature 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. The lower bound of this danger zone, 1.5° warming, is predicted to occur by 2030 unless stringent controls on methane and black carbon emissions are initiated immediately. Controlling methane and black carbon shows more immediate results than controlling carbon dioxide emissions, although controlling all greenhouse gas emissions is essential to keeping the planet in a safe operating space for humanity. Reprinted from UNEP/WMO (2011)

baseline average temperature between 1890 and 1910 (Hansen and Sato 2004; Hansen et al. 2007). This could lead to a rapidly accelerating positive feedback of further global warming (Zimov et al. 2006; Walter et al. 2007). Shindell et al. (2012) and a recent United Nations study both conclude that this 1.8°C threshold may be reached within 30 years unless societies take urgent action to reduce the emissions of methane and other short-lived greenhouse gases now (UNEP/WMO 2011). The reports predict that the lower bound for the danger zone for a temperature increase leading to climate tipping points – a 1.5°C increase – will occur within the next 18 years or even less if emissions of methane and other short-lived radiatively active substances such as black carbon are not better controlled, beginning immediately (Fig. 2) (Shindell et al. 2012; UNEP/WMO 2011).

In addition to different time frames, studies have used a variety of GWP values. We used values of 105 and 33 for the 20- and 100-year integrated time frames, respectively (Howarth et al. 2011), based on the latest information on methane interactions with other radiatively active materials in the atmosphere (Shindell et al. 2009). Surprisingly, EPA (2011a) uses a value of 21 based on IPCC (1995) rather than higher values from more recent science (IPCC 2007; Shindell et al. 2009). Jiang et al. (2011), Fulton et al. (2011), Skone et al. (2011), and Burnham et al. (2011) all used the 100-year GWP value of 25 from IPCC (2007), which underestimates methane's warming at the century time scale by 33% compared to the more recent GWP value of 33 from Shindell et al. (2009). We stand by our use of the higher GWP values published by Shindell et al. (2009), believing it appropriate to use the best and most recent science. While there are considerable uncertainties in GWP estimates, inclusion of the suppression of photosynthetic carbon uptake due to methane-induced ozone (Sitch et al. 2007) would further increase methane's GWP over all the values discussed here.

In Fig. 3, we present the importance of methane to the total GHG inventory for the US, considered at both the 20- and 100-year time periods, and using the Shindell et al. (2009) GWP values. Figure 3 uses the most recently available information on methane fluxes for the 2009 base year, reflecting the new methane emission factors and updates through July 2011 (EPA 2010; 2011a, b); see Electronic Supplemental Materials. Natural gas systems dominate the methane flux for the US, according to these EPA estimates, contributing 39% of the nation's total. And methane contributes 19% of the entire GHG inventory of the US at the century time scale and 44% at the 20-year scale, including all gases and all human activities. The methane emissions from natural gas systems make up 17% of the entire anthropogenic GHG inventory of the US, when viewed through the lens of the 20-year integrated time frame. If our high-end estimate for downstream methane emissions during gas storage, transmission, and distribution is correct (Howarth et al. 2011), the importance of methane from natural gas systems would be even greater.

5 Electricity vs. other uses

Howarth et al. (2011) focused on the GHG footprint of shale gas and other fuels normalized to heat from the fuels, following Lelieveld et al. (2005) for conventional gas. We noted that for electricity generation – as opposed to other uses of natural gas – the greater efficiency for gas shifts the comparison somewhat, towards the footprint of gas being less unfavorable. Nonetheless, we concluded shale gas has a larger GHG footprint than coal even when used to generate electricity, at the 20-year time horizon (Howarth et al. 2011). Hughes (2011b) further explored the use of shale gas for electricity generation, and supported our conclusion. Cathles et al. criticize us for not focusing exclusively on electricity.

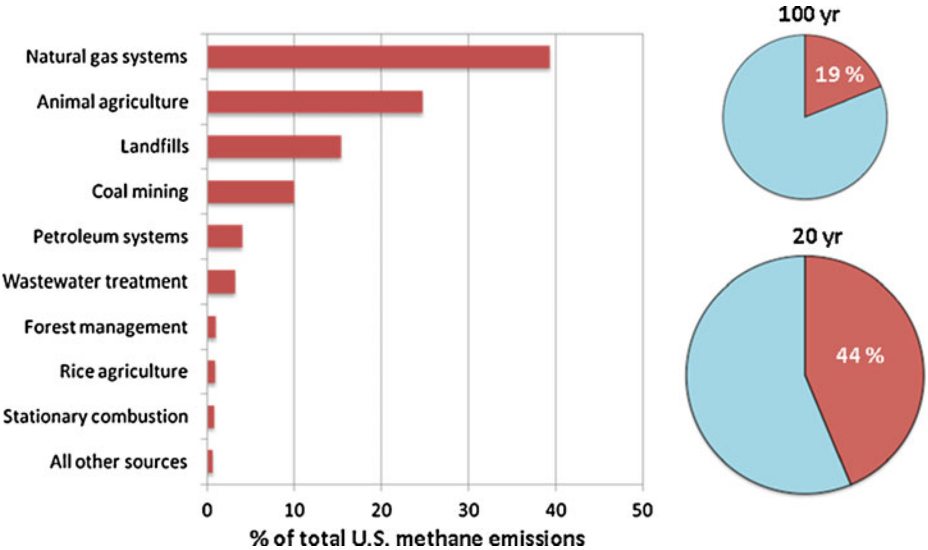


Fig. 3 Environmental Protection Agency estimates for human-controlled sources of methane emission from the U.S. in 2009 (bar graph) and percent contribution of methane to the entire greenhouse gas inventory for the U.S. (shown in red on the pie charts) for the 100-year and 20-year integrated time scales. The sizes of the pie charts are proportional to the total greenhouse gas emission for the U.S. in 2009. The methane emissions represent a greater portion of the warming potential when converted to equivalents of mass of carbon dioxide at the shorter time scale, which increases both the magnitude of the total warming potential and the percentage attributed to methane. Data are from EPA (2011a, b), as discussed in Electronic Supplemental Material, and reflect an increase over the April 2011 national inventory estimates due to new information on methane emissions from Marcellus shale gas and tight-sand gas production for 2009 (EPA 2011b). Animal agriculture estimate combines enteric fermentation with manure management. Coal mining combines active mines and abandoned mines. The time-frame comparisons are made using the most recent data on global warming potentials from Shindell et al. (2009)

We stand by our focus on GHG emissions normalized to heat content. Only 30% of natural gas in the U.S. is used to generate electricity, while most is used for heat for domestic, commercial, and industrial needs, and this pattern is predicted to hold over coming decades (EIA 2011b; Hughes 2011b). Globally, demand for heat is the largest use of energy, at 47% of use (International Energy Agency 2011). And natural gas is the largest source of heat globally, providing over half of all heat needs in developed countries (International Energy Agency 2011). While generating electricity from natural gas has some efficiency gains over using coal, we are aware of no such advantage for natural gas over other fossil fuels for providing heat.

Many view use of natural gas for transportation as an important part of an energy future. The "Natural Gas Act" (H.R.1380) introduced in Congress in 2011 with bipartisan support and the support of President Obama would provide tax subsidies to encourage long-distance trucks to switch from diesel to natural gas (Weiss and Boss 2011). And in Quebec, industry claims converting trucks from diesel to shale gas could reduce GHG emissions by 25 to 30% (Beaudine 2010). Our study suggests this claim is wrong and indicates shale gas has a larger GHG footprint than diesel oil, particularly over the 20-year time frame (Howarth et al. 2011). In fact, using natural gas for long-distance trucks may be worse than our analysis suggested, since it would likely depend on liquefied natural gas, LNG. GHG emissions from LNG are far higher than for non-liquified gas (Jamarillo et al. 2007). See Electronic Supplemental Materials for more information on future use of natural gas in the U.S.

6 Conclusions

We stand by our conclusions in Howarth et al. (2011) and see nothing in Cathles et al. and other reports since April 2011 that would fundamentally change our analyses. Our methane emission estimates compare well with EPA (2011a), although our high-end estimates for emissions from downstream sources (storage, transmission, distribution) are higher. Our estimates also agree well with earlier papers for conventional gas (Hayhoe et al. 2002; Lelieveld et al. 2005), including downstream emissions. Several other analyses published since April of 2011 have presented significantly lower emissions than EPA estimates for shale gas, including Cathles et al. but also Jiang et al. (2011), Skone et al. (2011), and Burnham et al. (2011). We believe these other estimates are too low, in part due to over-estimation of the lifetime production of shale-gas wells.

We reiterate that all methane emission estimates, including ours, are highly uncertain. As we concluded in Howarth et al. (2011), "the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas." The new GHG reporting requirements by EPA will provide better information, but much more is needed. Governments should encourage and fund independent measurements of methane venting and leakage. The paucity of such independent information is shocking, given the global significance of methane emissions and the potential scale of shale gas development.

We stress the importance of methane emissions on decadal time scales, and not focusing exclusively on the century scale. The need for controlling methane is simply too urgent, if society is to avoid tipping points in the planetary climate system (Hansen et al. 2007; UNEP/WMO 2011; Shindell et al. 2012). Our analysis shows shale gas to have a much larger GHG footprint than conventional natural gas, oil, or coal when used to generate heat and viewed over the time scale of 20 years (Howarth et al. 2011). This is true even using our low-end methane emission estimates, which are somewhat lower than the new EPA (2011a) values and comparable to those of Hultman et al. (2011). At this 20-year time scale, the emissions data from EPA (2011a, b) show methane makes up 44% of the entire GHG inventory for the U.S., and methane from natural gas systems make up 17% of the entire GHG inventory (39% of the methane component of the inventory).

We also stress the need to analyze the shale-gas GHG footprint for all major uses of natural gas, and not focus on the generation of electricity alone. Of the reports published since our study, only Hughes (2011b) seriously considered heat as well as electricity. Cathles et al. (2012), Jiang et al. (2011), Fulton et al. (2011), Hultman et al. (2011), Skone et al. (2011), and Wigley (2011) all focus just on the generation of electricity. We find this surprising, since only 30% of natural gas in the U.S. is used to generate electricity. Other uses such as transportation should not be undertaken without fully understanding the consequences on GHG emissions, and none of the electricity-based studies provide an adequate basis for such evaluation.

Can shale-gas methane emissions be reduced? Clearly yes, and proposed EPA regulations to require capture of gas at the time of well completions are an important step. Regulations are necessary to accomplish emission reductions, as economic considerations alone have not driven such reductions (EPA 2011b). And it may be extremely expensive to reduce leakage associated with aging infrastructure, particularly distribution pipelines in cities but also long-distance transmission pipelines, which are on average more than 50 years old in the U.S. Should society invest massive capital in such improvements for a bridge fuel that is to be used for only 20 to 30 years, or would the capital be better spent on constructing a smart electric grid and other technologies that move towards a truly green energy future?

We believe the preponderance of evidence indicates shale gas has a larger GHG footprint than conventional gas, considered over any time scale. The GHG footprint of shale gas also exceeds that of oil or coal when considered at decadal time scales, no matter how the gas is used (Howarth et al. 2011; Hughes 2011a, b; Wigley et al. 2011). Considered over the century scale, and when used to generate electricity, many studies conclude that shale gas has a smaller GHG footprint than coal (Wigley 2011; Hughes 2011b; Hultman et al. 2011), although some of these studies biased their result by using a low estimate for GWP and/or low estimates for methane emission (Jiang et al. 2011; Skone et al. 2011; Burnham et al. 2011). However, the GHG footprint of shale gas is similar to that of oil or coal at the century time scale, when used for other than electricity generation. We stand by the conclusion of Howarth et al. (2011): "The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming."

Acknowledgements We thank Terry Chapin, Chris Costello, Jon Foley, David Hughes, Amy Mall, Roxanne Marino, Nathan Phillips, and Drew Shindell for comments and advice. Funding was provided by the Park Foundation and endowments given by David. R. Atkinson and Dwight C. Baum to Cornell University. The authors have no financial conflict of interests.

Open Access This article is distributed under the terms of the Creative Commons Attribution License which permits any use, distribution, and reproduction in any medium, provided the original author(s) and the source are credited.

References

Beaudine M (2010) In depth: shale gas exploration in Quebec. The Gazette, November 15, 2010

Berman A (2010) Shale gas—Abundance or mirage? Why the Marcellus shale will disappoint expectations. The Oil Drum, Drumbeat, October 29, 2010. http://www.theoildrum.com/node/7079

Burnham A, Han J, Clark CE, Wang M, Dunn JB, and Rivera IP (2011) Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum. Environ Sci Technol. doi:10.1021/es201942m

Cathles LM, Brown L, Taam M, Hunter A (2012) this volume

Eckhardt M, Knowles B, Maker E, Stork P (2009) IHS U.S Industry Highlights. (IHS) Houston TX. Feb-Mar 2009. http://www.gecionline.com/2009-prt-7-final-reviews

EIA (2011a) U.S. Natural Gas Wellhead Price (Dollars per Thousand Cubic Feet). U.S. Department of Energy, Energy Information Agency http://www.eia.gov/dnav/ng/hist/n9190us3m.htm

EIA (2011b) Annual Energy Outlook 2011. U.S. Department of Energy, Energy Information Agency (released April 2011)

EPA (2010) Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry. Background Technical Support Document. U.S. Environmental Protection Agency, Washington DC. http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf

EPA (2011a) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009. April 14, 2011. U.S. Environmental Protection Agency, Washington DC. http://epa.gov/climatechange/emissions/usinventoryreport.html

EPA (2011b) Regulatory Impact Analysis: Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Gas Industry. July 2011. U.S. Environmental Protection Agency, Office of Air and Radiation. Washington DC

EPA (2011c) Climate Change – Regulatory Initiatives. U.S. Environmental Protection Agency, Washington DC. http://www.epa.gov/climatechange/emissions/ghgrulemaking.html (downloaded Nov. 22, 2011)

EPA (2011d) Oil and natural gas sector: standards of performance for crude oil and natural gas production, transmission, and distribution. EPA-453/R-11-002. Prepared for U.S. EPA Office of Air Quality Planning and Standards by EC/R Incorporated. U.S. Environmental Protection Agency, Washington DC

EPA (2011e) Proposed Amendments to Air Regulations for the Oil and Gas Industry Fact Sheet. U.S. Environmental Protection Agency, Washington DC. http://www.epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf

Fulton M, Mellquist N, Kitasei S, and Bluestein J (2011) Comparing greenhouse gas emissions from natural gas and coal. 25 Aug 2011. Worldwatch Institute/Deutsche Bank

Hansen J, Sato M (2004) Greenhouse gas growth rates. Proc Natl Acad Sci USA 101:16 109–16 114

Hansen J, Sato M, Kharecha P, Russell G, Lea DW, Siddall M (2007) Climate change and trace gases. Phil Trans R Soc A 365:1925–1954

Harrison MR, Shires TM, Wessels JK, Cowgill RM (1996) Methane emissions from the natural gas industry. Volume 1: executive summary. EPA-600/R-96-080a. U.S. Environmental Protection Agency, Office of Research and Development, Washington, DC

Hayhoe K, Kheshgi HS, Jain AK, Wuebbles DJ (2002) Substitution of natural gas for coal: climatic effects of utility sector emissions. Clim Chang 54:107–139

Howarth RW, Ingraffea A (2011) Should fracking stop? Yes, it is too high risk. Nature 477:271–273

Howarth RW, Santoro R, Ingraffea A (2011) Methane and the greenhouse gas footprint of natural gas from shale formations. Climatic Chang Lett. doi:10.1007/s10584-011-0061-5

Hughes D (2011a) Lifecycle greenhouse gas emissions from shale gas compared to coal: an analysis of two conflicting studies. Post Carbon Institute, Santa Rosa, http://www.postcarbon.org/reports/PCI-Hughes-NETL-Cornell-Comparison.pdf

Hughes D (2011b) Will Natural Gas Fuel America in the 21st Century? Post Carbon Institute, Santa Rosa, CA. http://www.postcarbon.org/report/331901-will-natural-gas-fuel-america-in

Hultman N, Rebois D, Scholten M, Ramig C (2011) The greenhouse impact of unconventional gas for electricity generation. Environ Res Lett 6:044008. doi:10.1088/1748-9326/6/4/044008

International Energy Agency (2011) Cogeneration and renewables: solutions for a low-carbon energy future. International Energy Agency, Paris

IPCC (1995) IPCC Second Assessment, Climate Change, 1995. http://www.ipcc.ch/pdf/climate-changes-1995/ipcc-2nd-assessment/2nd-assessment-en.pdf

IPCC (2007) IPCC Fourth Assessment Report (AR4), Working Group 1, The Physical Science Basis. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html

Jamarillo P, Griffin WM, Mathews HS (2007) Comparative life-cycle air emissions of coal, domestic natural gas, LNG, and SNG for electricity generation. Environ Sci Technol 41:6290–6296

Jiang M, Griffin WM, Hendrickson C, Jaramillo P, vanBriesen J, Benkatesh A (2011) Life cycle greenhouse gas emissions of Marcellus shale gas. Environ Res Lett 6:034014. doi:10.1088/1748-9326/6/3/034014

Kirchgessner DA, Lott RA, Cowgill RM, Harrison MR, Shires TM (1997) Estimate of methane emissions from the US natural gas industry. Chemosphere 35:1365–1390

Lelieveld J, Lechtenbohmer S, Assonov SS, Brenninkmeijer CAM, Dinest C, Fischedick M, Hanke T (2005) Low methane leakage from gas pipelines. Nature 434:841–842

Nelson G (2011) Natural gas, electronics groups sue EPA. Energy Tribune. Feb. 2, 2011. http://www.energytribune.com/articles.cfm/6480/Natural-Gas-Electronics-Groups-Sue-EPA

NYS DEC (2011) SGEIS on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. Revised draft, Sept 2011. New York State Dept. of Environmental Conservation, Albany, NY

Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716–718

Shindell D, Kuylenstierna JCI, Vignati E, van Dingenen R, Amann M, Klimont Z, Anenberg SC, Muller N, Janssens-Maenhout G, Raes F, Schwartz J, Faluvegi G, Pozzoli L, Kupiainen K, Höglund-Isaksson L, Emberson L, Streets D, Ramanathan V, Hicks K, Oanh NTK, Milly G, Williams M, Demkine V, Fowler D (2012) Simultaneously mitigating near-term climate change and improving human health and food security. Science 335:183–189. doi:10.1126/science.1210026

Sitch S, Cox PM, Collins WJ, Huntingford C (2007) Indirect radiative forcing of climate change through ozone effects on the land-carbon sink. Nature 448:791–794

Skone TJ, Littlefield J, Marriott J (2011) Life cycle greenhouse gas inventory of natural gas extraction, delivery and electricity production. Final report 24 Oct 2011 (DOE/NETL-2011/1522). U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA

Smith GR (2008) Reduced Emission (Green) Completion in Low Energy Reserves. BP America Production Company. 15th Annual Natural Gas STAR Implementation Workshop, San Antonio TX, Nov. 11–13, 2008. http://www.epa.gov/gasstar/workshops/annualimplementation/2008.html

Soliman MY Hunt JL (1985) Effect of fracturing fluid and its cleanup on well performance. SPE 14514. Presented paper. SPE Regional Meeting, Morgantown WV, 6–8 Nov 1985

UNEP/WMO (2011) Integrated assessment of black carbon and tropospheric ozone: summary for decision makers. United Nations Environment Programme and the World Meteorological Organization, Nairobi

Urbina I (2011a) Insiders sound an alarm amid a natural gas rush. New York Times, June 26, 2011. http://www.nytimes.com/2011/06/26/us/26gas.html?_r=1&ref=ianurbina

Urbina I (2011b) Behind veneer, doubts on natural gas. New York Times, June 26, 2011. http://www.nytimes.com/2011/06/27/us/27gas.html?ref=ianurbina

Walter KM, Smith LC, Chapin FS (2007) Methane bubbling from northern lakes: present and future contributions to the methane budget. Phil Trans R Soc A 365:1657–1676

Weis DJ, Boss S (2011) Conservatives Power Big Oil, Stall Cleaner Natural Gas Vehicles. Center for American Progress, June 6, 2011. http://www.americanprogress.org/issues/2011/06/nat_gas_statements.html

Wigley TML (2011) Coal to gas: the influence of methane leakage. Climatic Chang Lett. doi:10.1007/s10584-011-0217-3

Willberg DM, Steinsberger N, Hoover R, Card RJ, Queen J (1998) Optimization of fracture cleanup using flowback analysis. SPE 39920. Presented paper. SPE Rocky Mountain Regional/ Low-permeability Reservoirs Symposium and Exhibition, Denver CO, 5–8 April 1998

Yang JY, Holditch SA, McVay DA (2010) Modeling fracture-fluid cleanup in tight-gas wells. Paper SPE 119624, SPE Journal 15(3)

Zimov SA, Schuur EAG, Chapin FS (2006) Permafrost and the global carbon budget. Science 312:1612–1613

SCHEDULE "C-II"

EB 2012-0451/2012-0433/2013-0074
Exhibit L.EGD.COC.1

COMMENT

D. ACKER/BLOOMBERG VIA GETTY

A drilling operation in Bradford County, Pennsylvania: one of the many places where shale rocks are fractured to release oil and gas.

Should fracking stop?

Extracting gas from shale increases the availability of this resource, but the health and environmental risks may be too high.

POINT
Yes, it's too high risk

Natural gas extracted from shale comes at too great a cost to the environment, say Robert W. Howarth *and* Anthony Ingraffea.

Natural gas from shale is widely promoted as clean compared with oil and coal, a 'win–win' fuel that can lessen emissions while still supplying abundant fossil energy over coming decades until a switch to renewable energy sources is made. But shale gas isn't clean, and shouldn't be used as a bridge fuel.

Shale rock formations can contain vast amounts of natural gas (which is mostly methane). Until quite recently, most of **PAGE 272 ▶**

COUNTERPOINT
No, it's too valuable

Fracking is crucial to global economic stability; the economic benefits outweigh the environmental risks, says Terry Engelder.

After a career in geological research on one of the world's largest gas supplies, I am a born-again 'cornucopian'. I believe that there is enough domestic gas to meet our needs for the foreseeable future thanks to technological advances in hydraulic fracturing. According to IHS, a business-information company in Douglas County, Colorado, the estimated recoverable gas from US shale source rocks using fracking is about 42 trillion cubic metres, almost **PAGE 274 ▶**

© 2011 Macmillan Publishers Limited. All rights reserved

POINT: FRACKING: TOO HIGH RISK ▶ this gas was not economically obtainable, because shale is far less permeable than the rock formations exploited for conventional gas. Over the past decade or so, two new technologies have combined to allow extraction of shale gas: 'high-volume, slick-water hydraulic fracturing' (also known as 'fracking'), in which high-pressure water with additives is used to increase fissures in the rock; and precision drilling of wells that can follow the contour of a shale layer closely for 3 kilometres or more at depths of more than 2 kilometres (see 'Fracking for fuel'). Industry first experimented with these two technologies in Texas about 15 years ago. Significant shale-gas production in other states, including Arkansas, Pennsylvania and Louisiana, began only in 2007–09. Outside North America, only a handful of shale-gas wells have been drilled.

Industry sources claim that they have used fracking to produce more than 1 million oil and natural gas wells since the late 1940s. However, less than 2% of the well fractures since the 1940s have used the high-volume technology necessary to get gas from shale, almost all of these in the past ten years. This approach is far bigger and riskier than the conventional fracking of earlier years. An average of 20 million litres of water are forced under pressure into each well, combined with large volumes of sand or other materials to help keep the fissures open, and 200,000 litres of acids, biocides, scale inhibitors, friction reducers and surfactants. The fracking of a conventional well uses at most 1–2% of the volume of water used to extract shale gas[1].

Many of the fracking additives are toxic, carcinogenic or mutagenic. Many are kept secret. In the United States, such secrecy has been abetted by the 2005 'Halliburton loophole' (named after an energy company headquartered in Houston, Texas), which exempts fracking from many of the nation's major federal environmental-protection laws, including the Safe Drinking Water Act. In a 2-hectare site, up to 16 wells can be drilled, cumulatively servicing an area of up to 1.5 square kilometres, and using 300 million litres or more of water and additives. Around one-fifth of the fracking fluid flows back up the well to the surface in the first two weeks, with more continuing to flow out over the lifetime of the well. Fracking also extracts natural salts, heavy metals, hydrocarbons and radioactive materials from the shale, posing risks to ecosystems and public health when these return to the surface. This flowback is collected in open pits or large tanks until treated, recycled or disposed of.

Because shale-gas development is so new, scientific information on the environmental costs is scarce. Only this year have studies begun to appear in peer-reviewed journals, and these give reason for pause. We call for a moratorium on shale-gas development to allow for better study of the cumulative risks to water quality, air quality and global climate. Only with such comprehensive knowledge can appropriate regulatory frameworks be developed.

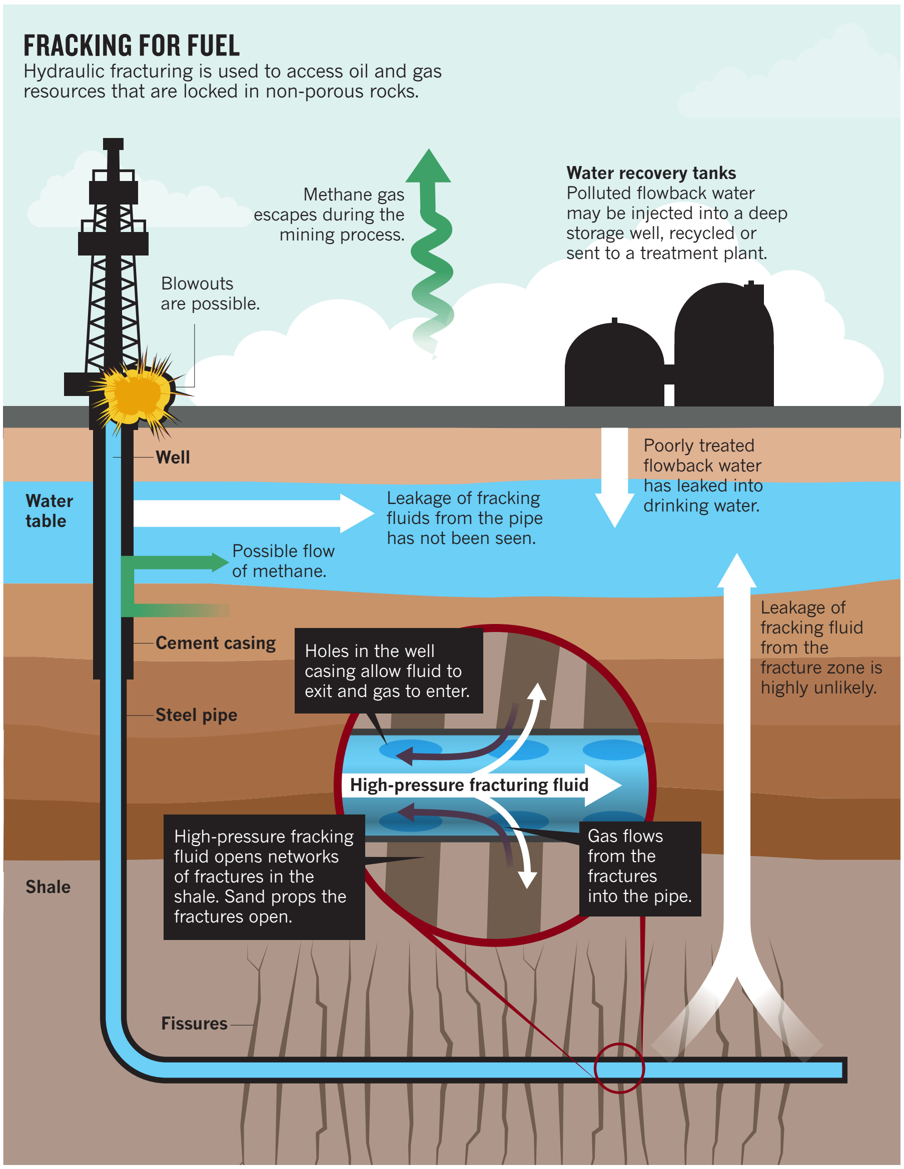
We have analysed the well-to-consumer lifecycle greenhouse-gas footprint of shale gas when used for heat generation (its main use), compared with conventional gas and other fossil fuels — the first estimate in the peer-reviewed literature[2]. Methane is a major component of this footprint, and we estimate that 3.6–7.9% of the lifetime production of a shale gas well (compared with 1.7–6% for conventional gas wells) is vented or leaked to the atmosphere from the well head, pipelines and storage facilities. In addition, carbon dioxide is released both directly through the burning of the gas for heat, and to a lesser extent indirectly through the process of developing the resource.

Methane is a potent greenhouse gas, so even small emissions matter. Over a 20-year time period, the greenhouse-gas footprint of shale gas is worse than that for coal or oil (see 'A daunting climate footprint'). The influence of methane is lessened over longer time scales, because methane does not stay in the atmosphere as long as carbon dioxide. Still, over 100 years, the footprint of shale gas remains comparable to that of oil or coal.

When used to produce electricity rather than heat, the greater efficiency of gas plants compared with coal plants slightly lessens the footprint of shale gas[3]. Even then, the total greenhouse-gas footprint from shale gas exceed those of coal at timescales of less than about 50 years.

Methane venting and leakage can be decreased by upgrading old pipelines and storage systems, and by applying better technology for capturing gas in the 2-week flowback period after fracking. But current economic incentives are not sufficient to drive such improvements; stringent regulation will be required. In July, the US Environmental Protection Agency released a draft rule that would push industry to reduce at least some methane emissions, in part focusing on post-fracking flowback. Nonetheless, our analysis[2] indicates that the greenhouse-gas footprint of shale gas is likely to remain large.

Another peer-reviewed study looked at



© 2011 Macmillan Publishers Limited. All rights reserved

private water wells near fracking sites[4]. It found that about 75% of wells sampled within 1 kilometre of gas drilling in the Marcellus shale in Pennsylvania were contaminated with methane from the deep shale formations. Isotopic fingerprinting of the methane indicated that deep shale was the source of contamination, rather than biologically derived methane, which was present at much lower concentrations in water wells at greater distances from gas wells. The study found no fracking fluids in any of the drinking-water wells examined. This is good news, because these fluids contain hazardous materials, and methane itself is not toxic. However, methane poses a high risk of explosion at the levels found, and it suggests a potential for other gaseous substances in the shale to migrate with the methane and contaminate water wells over time.

Have fracking-return fluids contaminated drinking water? Yes, although the evidence is not as strong as for methane contamination, and none of the data has yet appeared in the peer-reviewed literature (although a series of articles in *The New York Times* documents the problem, for example go.nature.com/58hxot and go.nature.com/58koj3). Contamination can happen through blowouts, surface spills from storage facilities, or improper disposal of fracking fluids. In Texas, flowback fluids are disposed of through deep injection into abandoned gas or oil wells. But such wells are not available everywhere. In New York and Pennsylvania, some of the waste is treated in municipal sewage plants that weren't designed to handle these toxic and radioactive wastes. Subsequently, there has been contamination of tributaries of the Ohio River with barium, strontium and bromides from municipal wastewater treatment plants receiving fracking wastes[5]. This contamination apparently led to the formation of dangerous brominated hydrocarbons in municipal drinking-water supplies that relied on these surface waters, owing to interaction of the contaminants with organic matter during the chlorination process.

Shale-gas development — which uses huge diesel pumps to inject the water — also creates local air pollution, often at dangerous levels. Volatile hydrocarbons such as benzene (which occurs naturally in shale, and is a commonly used fracking additive) are one major concern. The state of Texas reports benzene concentrations in air in the Barnett shale area that sometimes exceed acute toxicity standards[6], and although the concentrations observed in the Marcellus shale area in Pennsylvania are lower[7] (with only 2,349 wells drilled at the time these air contaminants were reported, out of an expected total of 100,000), they are high enough to pose a risk of cancer from chronic exposure[8]. Emissions from drills, compressors, trucks and other machinery can lead to very high levels of ground-level ozone, as documented in parts of Colorado that had not experienced severe air pollution before shale-gas development[9].

"Have fracking-return fluids contaminated drinking water? Yes."

UNPROFITABLE PROGRESS

The argument for continuing shale-gas exploitation often hinges on the presumed gigantic size of the resource. But this may be exaggerated. The Energy Information Administration of the US Department of Energy estimates that 45% of US gas supply will come from shale gas by 2035 (with the vast majority of this replacing conventional gas, which has a lower greenhouse-gas footprint). Other gas industry observers are even more bullish. However, David Hughes, a geoscientist with more than 30 years experience with the Canadian Geological Survey, concludes in his report for the Post Carbon Institute, a non-profit group headquartered in Santa Rosa, California, that forecasts are likely to be overstated, perhaps greatly so[3]. Last month, the US Geological Survey released a new estimate of the amount of gas in the Marcellus shale formation (the largest shale-gas formation in the United States), concluding that the Department of Energy has overestimated the resource by some five-fold[10].

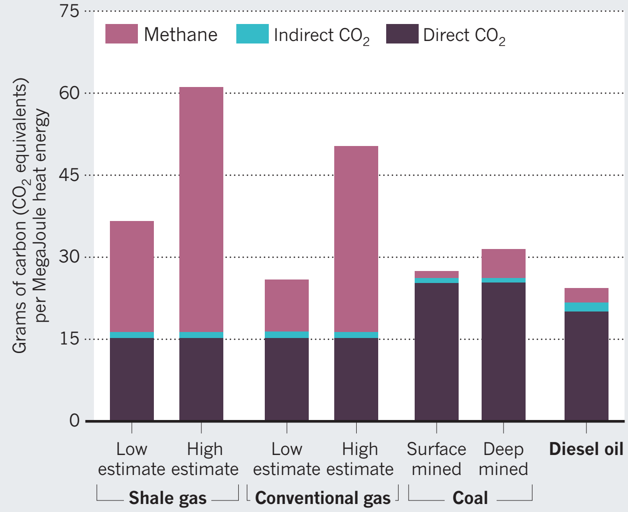
Shale gas may not be profitable at current prices, in part because production rates for shale-gas wells decline far more quickly than for conventional wells. Although very large resources undoubtedly exist in shale reservoirs, an unprecedented rate of well drilling and fracking would be required to meet the Department of Energy's projections, which might not be economic[3]. If so, the recent enthusiasm over shale gas could soon collapse, like the dot-com bubble.

Meanwhile, shale gas competes for investment with green energy technologies, slowing their development and distracting politicians and the public from developing a long-term sustainable energy policy.

With time, perhaps engineers can develop more appropriate ways to handle fracking-fluid return wastes, and perhaps the technology can be made more sustainable and less polluting in other ways. Meanwhile, the gas should remain safely in the shale, while society uses energy more efficiently and develops renewable energy sources more aggressively. ■

A DAUNTING CLIMATE FOOTPRINT

Over 20 years, shale gas is likely to have a greater greenhouse effect than conventional gas or other fossil fuels.



SOURCE: REF. 2

Robert W. Howarth *is in the Department of Ecology and Evolutionary Biology, Cornell University, Ithaca, New York, New York 14853, USA.* **Anthony Ingraffea** *is in the School of Civil and Environmental Engineering at Cornell University, Ithaca, New York, New York 14853, USA.*
e-mail: rwh2@cornell.edu

1. New York State Department of Environmental Conservation *Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program (Sept. 2011)*; available at: http://go.nature.com/yzponk
2. Howarth, R. W., Santoro, R. & Ingraffea, A. *Clim. Change* **106,** 679–690 (2011).
3. Hughes, D. *Will Natural Gas Fuel America in the 21st Century?* (Post Carbon Institute, 2011); available at: http://go.nature.com/gkboqm
4. Osborn, S. G., Vengosh, A., Warner, N. R. & Jackson, R. B. *Proc. Natl Acad. Sci. USA* **108,** 8172–8176 (2011).
5. Volz, C. D. *et al. Contaminant Characterization of Effluent from Pennsylvania Brine Treatment Inc., Josephine Facility Being Released into Blacklick Creek, Indiana County, Pennsylvania* (2011); available at: http://go.nature.com/5otd59
6. Texas Commission on Environmental Quality. *Barnett Shale Formation Area Monitoring Projects* (2010); available at: http://go.nature.com/v7k4re
7. Pennsylvania Department of Environmental Protection. *Northeastern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report* (2011); available at: http://go.nature.com/tjscnt
8. Talbott, E. O. *et al. Environ. Res.* **111,** 597–602 (2011).
9. Colorado Department of Public Health and Environment. *Public Health Implications of Ambient Air Exposures as Measured in Rural and Urban Oil & Gas Development Areas — an Analysis of 2008 Air Sampling Data* (2010); available at: http://go.nature.com/5tttna
10. Coleman, J. L. *et al. Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011.* US Geological Survey Fact Sheet 2011–3092 (2011); available at http://go.nature.com/8kejhm

© 2011 Macmillan Publishers Limited. All rights reserved

EB 2012-0451/2012-0433/2013-0074
Exhibit L.EGD.COC.1

COUNTERPOINT: FRACKING: TOO VALUABLE ▶ equal to the total conventional gas discovered in the United States over the past 150 years, and equivalent to about 65 times the current US annual consumption. During the past three years, about 50 billion barrels of additional recoverable oil have been found in shale oil deposits — more than 20% of the total conventional recoverable US oil resource. These 'tight' oil resources, which also require fracking to access, could generate 3 million barrels a day by 2020, offsetting one-third of current oil imports. International data aren't as well known, but the effect of fracking on global energy production will be huge (see 'Global gas reserves').

Global warming is a serious issue that fracking-related gas production can help to alleviate. In a world in which productivity is closely linked to energy expenditure, fracking will be vital to global economic stability until renewable or nuclear energy carry more of the workload. But these technologies face persistent problems of intermittency and lack of power density or waste disposal. Mankind's inexorable march towards 9 billion people will require a broad portfolio of energy resources, which can be gained only with breakthroughs such as fracking. Such breakthroughs should be promoted by policy that benefits the economy yet reduces overall greenhouse-gas emissions. Replacing coal with natural gas in power plants, for example, reduces the plants' greenhouse emissions by up to 50% (ref. 1).

At present, fracking accounts for 50% of locally produced natural gas (see 'US natural-gas production set to explode') and 33% of local petroleum. The gas industry in America accounts for US$385 billion in direct economic activity and nearly 3 million jobs. Because gas wells have notoriously steep production declines, stable supplies depend on a steady rate of new well completions. A moratorium on new wells would have an immediate and harsh effect on the US economy that would trigger a global ripple.

Global warming aside, there is no compelling environmental reason to ban hydraulic fracturing. There are environmental risks, but these can be managed through existing, and rapidly improving, technologies and regulations. It might be nice to have moratoria after each breakthrough to study the consequences (including the disposal of old batteries or radioactive waste), but because energy expenditure and economic health are so closely linked, global moratoria are not practical.

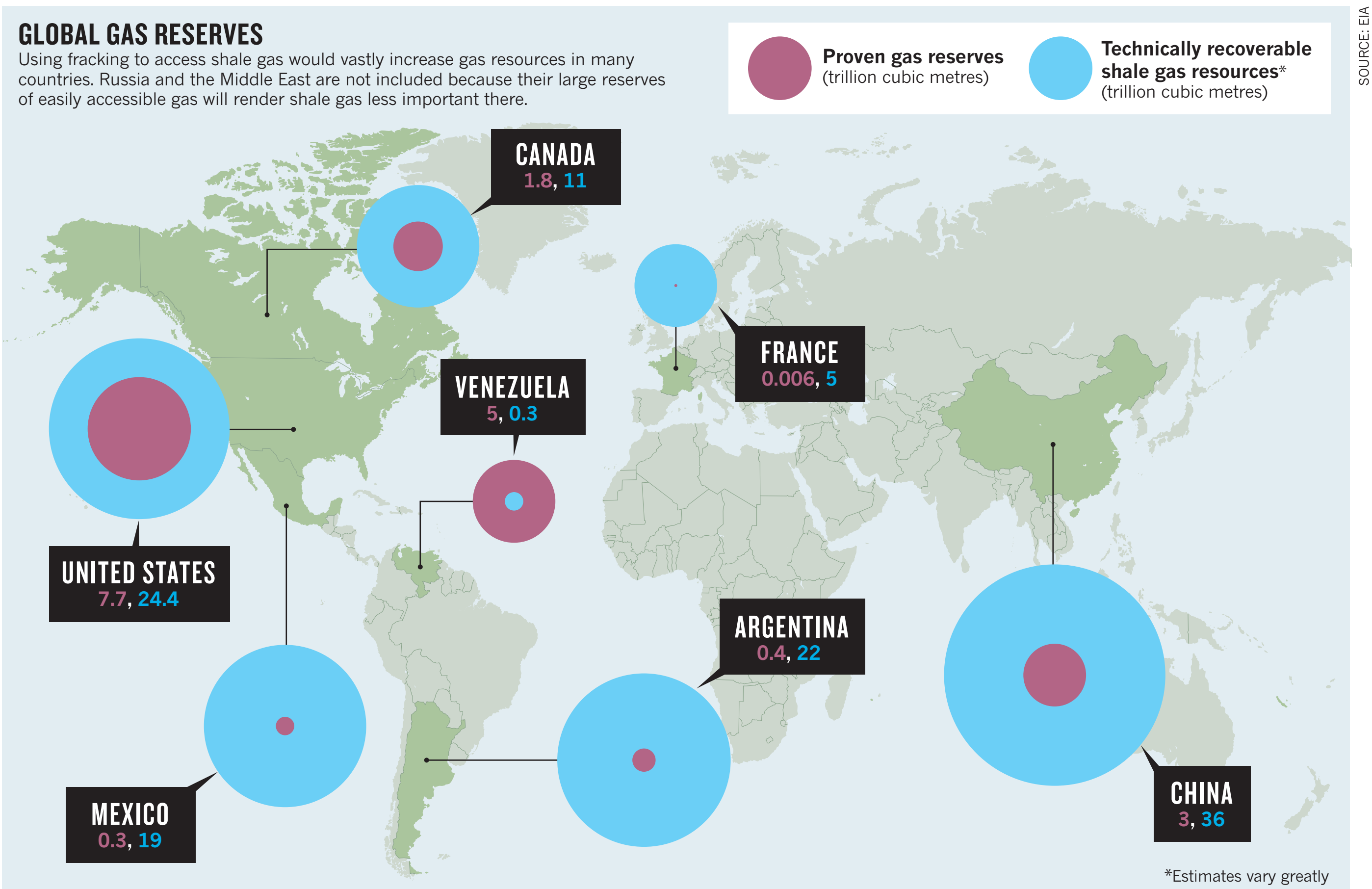
The gains in employment, economics and national security, combined with the potential to reduce global greenhouse-gas emissions if natural gas is managed properly, make a compelling case.

NO NEED FOR PANIC

I grew up with the sights, sounds and smells of the Bradford oil fields in New York state. My parents' small farm was over a small oil pool, with fumes from unplugged wells in the air and small oil seeps coating still waters. Before college, I worked these oil fields as a roustabout, mainly cleaning pipes and casings. Like me, most people living in such areas are not opposed to drilling, it seems. In my experience, such as during the recent hearings for the Pennsylvania Governor's Marcellus Shale Advisory Commission, activists from non-drilling regions outnumber those from drilling regions by approximately two to one.

Modern, massive hydraulic fracturing is very different from that used decades ago. Larger pads are required to accommodate larger drill rigs, pumps and water supplies. People usually infer from this that modern techniques have a greater impact on the environment. This isn't necessarily true. Although more water is used per well, there are far fewer wells per unit area. In the Bradford oil fields in the 1950s, a 640-acre parcel of land might have held more than 100 wells, requiring some 18 kilometres of roads, and with a lattice of surface pipelines. During the Marcellus development today, that same parcel of land is served by a single pad of five acres, with a 0.8-kilometre right-of-way for roads and pipelines.

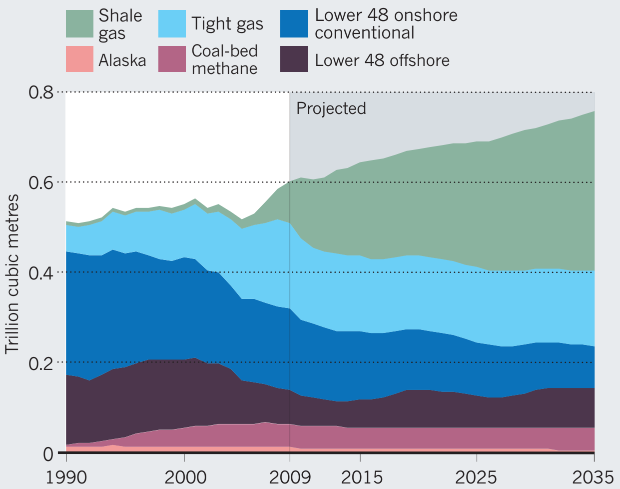
Although 'fracking' has emerged as a scare term in the press,



© 2011 Macmillan Publishers Limited. All rights reserved

US NATURAL-GAS PRODUCTION SET TO EXPLODE

Shale-gas output already matches production from offshore wells in the lower 48 states (mainland US states excluding Alaska). Gas (shale and tight) extracted by fracking is set to overtake all other sources.



SOURCE: US EIA *ANNUAL ENERGY OUTLOOK 2011*

hydraulic fracturing is not so strange or frightening. The process happens naturally: high-pressure magma, water, petroleum and gases deep inside Earth can crack rock, helping to drive plate tectonics, rock metamorphism and the recycling of carbon dioxide between the mantle and the atmosphere.

Oil and gas have their origins in muds rich with organic matter in low-oxygen water bodies. Over millions of years, some of these deposits were buried and 'cooked' in the deep Earth, turning the organic matter into fossil fuel and the mud to shale rocks. In many areas, natural hydraulic fracturing allowed a large portion of oil and gas to escape from the dense, impermeable shale and migrate into neighbouring, more porous rocks. Some of this fossil fuel was trapped by cap rock, creating the conventional reserves that mankind has long tapped. The groundwater above areas that host such conventional deposits naturally contains methane, thanks to natural hydraulic fracturing of the rock and the upward seeping of gas into the water table over long time periods.

More than 96% of all oil and gas has been released from its original source rocks; industrial hydraulic fracturing aims to mimic nature to access the rest. As in nature, industrial fracking can be done with a wide variety of gases and liquids. Nitrogen can be used to open cracks in the shale, for example. But this is inefficient, because of the energy lost by natural decompression of the nitrogen gas. Water is more efficient, because very little energy is wasted in decompression. Sand is added to prop open the cracks, and compounds such as surface-tension reducers are added to improve gas recovery.

UNDER CONTROL

Two main environmental concerns are water use and water contamination. Millions of gallons of water are required to stimulate a well. In Pennsylvania, high rainfall means that water is abundant, and regulations ensure that operators stockpile rainwater during the wet season to use during drier months (thus the injection of massive volumes of water in the Bradford oil fields for secondary recovery of oil, once the well pressure has fallen, flew under the radar of environmentalists for half a century). Obtaining adequate water for industrial fracking in dry regions such as the Middle East and western China is a local concern, but is no reason for a global moratorium.

Press reports often repeat strident concerns about the chemicals added to fracking fluids. But many of these compounds are relatively benign. One commonly used additive is similar to simethicone, which is also used in antacids to reduce surface tension and turn small bubbles in the stomach into larger ones that can move along more easily. Many of the industrial additives are common in household products. Material safety data sheets for these additives are required by US regulation. Industry discloses additives on a website called FracFocus.org, run by state regulators.

Some people have expressed worries that fracking fluids might migrate more than 2 kilometres upwards from the cracked shale into groundwater. The Ground Water Protection Council, a non-profit national association of state groundwater and underground-injection control agencies headquartered in Oklahoma City, has found no instance in which injected fluid contaminated groundwater from below[2]. This makes sense: water cannot flow this distance uphill in timescales that matter. This is the premise by which deep disposal wells, used to hold toxic waste worldwide, are considered safe. During gas production, the pressure of methane is reduced: this promotes downward, not upward flow of these fluids.

Gas shale contains a number of materials that are carried back up the pipe to the surface in flowback water, including salts of barium and radioactive isotopes, that might be harmful in concentrated form. According to a recent *New York Times* analysis, these elements can be above the US Environmental Protection Agency's sanctioned background concentrations in some flowback tanks. Industry is moving towards complete recycling of these fluids so this should be of less concern to the public. However, production water will continue to flow to the surface in modest volumes throughout the life of a well; this water needs to be, and currently is, treated to ensure safe disposal.

The real risk of water contamination comes from these flowback fluids leaking into streams or seeping down into groundwater after reaching the surface. This can be caused by leaky wellheads, holding tanks or blowouts. Wellheads are made sufficiently safe to prevent this eventuality; holding tanks can be made secure; and blowouts, while problematic, are like all accidents caused by human error — an unpredictable risk with which society lives.

> ***"With hydraulic fracturing, as in many cases, fear levels exceed the evidence."***

Although methane coming up to the surface within the steel well pipe cannot escape into the surrounding rocks or groundwater, it is possible that the cement seal between the well and the bedrock might allow methane from shallow sandstone layers (rather than the reservoir deep below) to seep up into groundwater. Methane is a tasteless and odourless component of groundwater that can be consumed without ill effect when dissolved. It is not a poison. Long before gas-shale drilling, regulators warned that enclosed spaces, such as houses, should be properly ventilated in areas with naturally occurring methane in groundwater.

An alarm has been sounded too about the effect of escaped methane on global warming. The good news is that methane has a very short half-life in the atmosphere: carbon dioxide emitted during the building of the first Sumerian cities is still affecting our climate, whereas escaped methane from the fracturing of the Barnett shale in 1997 is more than half gone. Industry can and should take steps to reduce air emissions, by capturing or flaring methane and converting motors and compressors from diesel to natural gas.

Risk perception is ultimately subjective: facts are all too easily combined with emotional responses. With hydraulic fracturing, as in many cases, fear levels exceed the evidence. ■

Terry Engelder *is in the department of geosciences at Pennsylvania State University, University Park, Pennsylvania 16802, USA.*
e-mail: jte2@psu.edu

1. Jiang, M. *Environ. Res. Lett.* **6,** 034014 (2011).
2. Statement of Scot Kell, on behalf of the Ground Water Protection Council, to the House Commitiee on Natural Resources Subcommitee on Energy and Mineral Resources (4 June 2009); available at: http://go.nature.com/5jl2bp

The author declares competing financial interests: details accompany this article online at go.nature.com/pjenyw.

© 2011 Macmillan Publishers Limited. All rights reserved