Using Common Boundaries to Assess Methane Emissions
A Life Cycle Evaluation of Natural Gas and Coal Power Systems
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Summary
There is consensus on the importance of upstream methane (CH$_4$) emissions to the life cycle greenhouse gas (GHG) footprint of natural gas systems, but inconsistencies among recent studies explain why some researchers calculate a CH$_4$ emission rate of less than 1% whereas others calculate a CH$_4$ emission rate as high as 10%. These inconsistencies arise from differences in data collection methods, data collection time frames, and system boundaries. This analysis focuses on system boundary inconsistencies. Our results show that the calculated CH$_4$ emission rate can increase nearly fourfold not by changing the magnitude of any particular emission source, but by merely changing the portions of the supply chain that are included within the system boundary. Our calculated CH$_4$ emission rate for extraction through pipeline transmission is 1.2% for current practices. Our model allows us to identify GHG contributors in the upstream supply chain, but also allows us to tie upstream findings to complete life cycle scenarios. If applied to the life cycles of power systems and assessed in terms of cumulative radiative forcing, the upstream CH$_4$ emission rate can be as high as 3.2% before the GHG impacts from natural gas power exceed those from coal power at any point during a 100-year time frame.

Keywords: GHG, GWP, industrial ecology, LCA, methane, natural gas emissions

Introduction
As a gaseous fuel, natural gas is more difficult to contain than liquid or solid fuels. Aging wells and delivery infrastructure, poor practices, and costly capture and control measures can all result in increased emissions from portions of the natural gas supply chain. One-time or periodic events (completions, workovers, and liquids unloading) at natural gas wells are emission sources that, although occasional, represent significant contributions to the total emissions from the supply chain. Further, natural gas is unique in that the key component, methane (CH$_4$), is a potent greenhouse gas (GHG) and a significant driver of the total GHG emissions from natural gas systems.

Despite the challenges associated with CH$_4$ emissions, the use of natural gas in the United States has increased significantly, nearly 18% in the 5-year span from 2007 to 2012. The use of this fuel specifically for power generation has increased at an even faster rate—a 33% increase in the same time period. The growth of natural gas use in power generation is forecasted to continue at an annual rate of 0.8%, making it important to focus on natural gas in the context of electricity generation (US EIA 2013). Compared to coal-fired power, natural gas–fired power has lower GHG emissions per unit of electricity because of the relatively low carbon-to-energy intensity of natural gas, and the relatively high efficiency of natural gas power plants. However, upstream CH$_4$ emissions (which we define as the emissions from extraction, processing, and delivery of natural gas to the end user) could offset the life cycle GHG advantage of natural gas–fired power plants (Alvarez et al. 2012; Wigley 2011; Zhang et al. 2014). Reducing the uncertainty in CH$_4$
emission rates for upstream natural gas is crucial in evaluating the overall environmental performance of natural gas power systems. To understand and then reduce that uncertainty, researchers should be clear on how they are measuring, describing, and calculating CH₄ emissions.

The variability in reported CH₄ emissions is demonstrated by Brandt and colleagues (2014), who compiled CH₄ emission rates from 20 years of literature and show that reported CH₄ emissions vary by 10 orders of magnitude. These extremes are bounded on the low end by device-level measurements at the exact point of emission, and on the high end by continental measurements after atmospheric mixing. Brandt and colleagues conclude that two data collection approaches, bottom-up and top-down measurements, are key drivers of the variability observed in reported CH₄ emission rates. We assert that boundary differences account for a large portion of this variability.

Two recent studies by Pétron and colleagues (2012) and Allen and colleagues (2013) exemplify how boundaries can affect results. Pétron and colleagues measured atmospheric volatile organic compounds (VOCs) in northeast Colorado and concluded that 4% of extracted natural gas (a combination of CH₄ and VOCs) is released to the atmosphere. Allen and colleagues measured emissions from activities at conventional and unconventional natural gas production sites across the United States and calculated that natural gas production sites release 0.42% of extracted CH₄ to the atmosphere, ostensibly 10 times less than Pétron and colleagues. The boundaries of the two studies are very different, to the point where the results are not directly comparable without significant reconciliation. Pétron and colleagues’ data are representative of tight gas extraction, processing, and transport in the Denver–Julesburg Basin, whereas Allen and colleagues’ data represent production activities at hundreds of conventional and unconventional wells across the United States. Unfortunately, these types of boundary differences are not considered by third parties who compare CH₄ emission rates and draw false conclusions (Romm 2014).

The large range of reported upstream CH₄ emission rates has introduced confusion to the widely documented conclusion that natural gas power systems, fed with either conventional or unconventional gas, have lower life cycle GHG emissions than coal power, regardless of whether the emissions are considered on a 20- or 100-year time frame (NETL 2012; Jiang et al. 2011; Burnham et al. 2011; Logan et al. 2013; Laurenzi and Jersey 2013; Bradbury et al. 2013). This analysis shows how clearer boundary definitions can reduce the confusion surrounding upstream CH₄ emission rates and strengthen the life cycle conclusions about natural gas power systems.

**Method**

We use a flexible, detailed model that allows us to calculate the GHG emissions from an unlimited number of natural gas supply chain scenarios. Detailed documentation of the model and data are provided in our latest report on natural gas extraction and power generation (NETL 2014). As summarized below, this method involves the definition of emission pathways, development of unit processes, parameterization of variables, and application of impact assessment.

**Greenhouse Gas Emission Pathways**

CH₄ is lost at many points throughout the natural gas supply chain; however, not all losses are leaks. Consumptive losses are the use of natural gas for heat or energy generation by processing equipment or compressors. Nonconsumptive losses include controllable, intentional, and fugitive emissions. Controllable emissions are from sources that are augmented with vapor recovery equipment that send captured gas to flares (flares combust CH₄ to carbon dioxide [CO₂], reducing its climate impact, but a small amount of uncombusted CH₄ passes through flares). Intentional emissions arise from one-time or periodic events, such as well completions or liquids unloading, for which vapor recovery and flaring equipment are often not available; pneumatic devices are also intentional emission sources because they must vent gas as part of normal operation. Fugitive emissions are released through valve stems, flanges, and other connections or storage tanks and are the only type of loss that can be accurately described as “leaks.” Figure 1 shows the natural gas pathways that result in CH₄ emissions.

There are also processes in the supply chain that emit GHGs, but are not natural gas losses. For example, the construction and installation of wells and pipelines, transport of hydrofracking water, treatment of flowback water before it is discharged, and production of electricity for electrically powered compressors all combust fuels and emit GHGs, but do not result in natural gas losses.

**Unit Processes**

We use a unit process approach to calculate the life cycle burdens of energy systems. This approach first identifies the activities in a supply chain; develops a unit process that uses engineering relationships or measured data to account for the energy consumption, material requirements, emissions, and products of each activity; and combines all unit processes into an interconnected network that scales all resource requirements.
and emissions to a common basis. Our approach also includes unit processes that account for energy and material flows of ancillary processes that are not directly related to the supply chain, but contribute to the life cycle burdens. A flow diagram of the primary unit process network of our natural gas model is provided in the Supporting Information available on the Journal’s website. As an example of the type of math implemented by unit processes, consider the translation of the natural gas in flowback water to GHG emissions. There are two unit processes involved in this calculation: (1) a completion unit process that holds information on the volume of natural gas entrained in flowback water and (2) a venting and flaring unit process that models the percent split between gas that is vented to the atmosphere and gas that is combusted by a flare. Given 9,000 million cubic feet (Mcf) of natural gas in flowback water (US EPA 2011), a natural gas density of 19 kg/Mcf (Shires et al. 2009), a 15% flaring rate (US EPA 2011), and an emission factor of 2.67 kilograms of carbon dioxide per kilogram (kg CO₂/kg) of flared natural gas (US EPA 2011; US EPA 1998), the resulting CO₂ emissions are given by equation (1).

\[
\frac{9,000 \text{ Mcf}}{\text{episode}} \times 19 \frac{\text{kg}}{\text{Mcf}} \times 15\% \times 2.67 \frac{\text{kg CO}_2}{\text{flared gas}} = 68,500 \frac{\text{kg CO}_2}{\text{episode}} \quad (1)
\]

If natural gas is not flared, it is vented directly to the atmosphere without being combusted. Unprocessed natural gas has an average CH₄ composition of 78.8% (US EPA 2011). Applying this composition to the portion of unflared natural gas from well completion allows the calculation of CH₄ emissions as shown in equation (2).

\[
\frac{9,000 \text{ Mcf}}{\text{episode}} \times 19 \frac{\text{kg}}{\text{Mcf}} \times (100\% - 15\%) \times 78.8\% = 115,000 \frac{\text{kg CH}_4}{\text{episode}} \quad (2)
\]

The emissions calculated in equations (1) and (2) are pulses of CO₂ and CH₄ that occur during a single event during a well’s life. To apply a life cycle perspective, they must be apportioned per unit of natural gas produced. The CO₂ and CH₄ emissions from the venting and flaring of potential completion emissions are divided by lifetime well production to convert them to a basis of a unit of natural gas extracted. We report lifetime well production in terms of estimated ultimate recovery (EUR) and use units of billion cubic feet (Bcf) of natural gas. This translation of emissions from an episodic basis to a life cycle basis is shown by equations (3) and (4):

\[
\frac{68,500 \frac{\text{kg CO}_2}{\text{episode}}}{\text{well}} \times \frac{1 \text{ episode}}{\text{well}} \times 1,000 \frac{\text{g}}{\text{kg}} \times \frac{\text{well}}{3.25 \text{ Bcf}} \quad (3)
\]

\[
\frac{115,000 \frac{\text{kg CH}_4}{\text{episode}}}{\text{well}} \times \frac{1 \text{ episode}}{\text{well}} \times \frac{1,000 \text{ g}}{\text{kg}} \times \frac{\text{well}}{3.25 \text{ Bcf}} \quad (4)
\]

The above calculations are a simplified example of how the flows of a particular wellhead activity—the venting and flaring of natural gas from a well completion—are translated to a life cycle basis. However, the CO₂ and CH₄ emissions shown in equations (3) and (4) are not the final modeling results for the venting and flaring of completion emissions. The life cycle model performs an additional step by scaling these emissions—and the emissions from all other unit processes in the model—to the basis of a common functional unit. In this analysis, and other natural gas analyses conducted by the National Energy Technology Laboratory (NETL), the functional units are either 1 megajoule (MJ) of delivered natural gas or 1 megawatt-hour of delivered electricity, depending on what questions are being asked.

### Parameters

The life cycle model comprises a network of interconnected unit processes. By using parameters, we can tune the unit processes so they represent specific conditions. The use of parameters is possible because most of our unit processes use a bottom-up approach. The bottom-up approach uses engineering principles to calculate the energy or material flows of an activity. In contrast, the top-down approach uses data from outside the boundaries of a process and calculates the energy materials of flows that occur within the system. For example, a bottom-up calculation of the CO₂ emissions from pipeline compressors would factor variables for the thermodynamic properties of fluid compression, compressor efficiency, spacing between compressors, pipeline pressure drop, the split between natural gas and electricity use by pipeline compressors, the combustion chemistry for natural gas, and the flow rate of natural gas through the pipeline. But a top-down calculation of CO₂ emissions from pipeline compressors could use national pipeline CO₂ inventories calculated by the U.S. Environmental Protection Agency (US EPA) or corporate CO₂ emissions reported by pipeline operators, divided by the corresponding natural gas throughput, to arrive at the same emission.

Table 1 shows key parameters used by our natural gas extraction unit processes and the corresponding values for three scenarios. Note that the Marcellus Shale scenario has a completion factor of 9,000 Mcf natural gas/episode (NG/episode) and an expected flaring rate of 15%; these are the parameters that were used to demonstrate the unit process math in equations (1) through (4) above.

The above parameters are a small sample of the parameters used by our model. Other extraction parameters include well depth and natural gas composition; a similar level of parameterization is also used for natural gas processing and pipeline transmission. Only two natural gas source scenarios
(onshore conventional and Marcellus Shale) and a reduced CH₄ scenario are shown in Table 1. A complete list of parameters for seven sources of natural gas is provided in the Supporting Information on the Web.

In addition to defining scenarios, parameters are also used to assess uncertainty. In this analysis, three parameters (EUR, flaring rate, and pipeline distance) are modeled with low and high values in addition to their expected values. The uncertainty ranges around EUR and flaring rate are shown in Table 1; the expected transmission distance is 971 kilometers (km) (bounded by low and high distances of 777 and 1,170 km, respectively). The reduced CH₄ scenario is based on potential emission reductions mandated by the New Source Performance Standards (NSPS) for the Oil and Gas Sector (US EPA 2012). The NSPS rules are applicable to new or modified wells and will be fully implemented by 2015. The NSPS sets standards for emission reductions, but does not offer explicit guidance on how to reduce CH₄ emissions at the equipment level. Because the exact mechanisms for NSPS implementation are open to interpretation, the remainder of this analysis uses “reduced CH₄” to refer to the emission reductions that NSPS could bring for new or modified wells. In the reduced CH₄ scenario, four modifications are made to the parameters for the Marcellus Shale gas scenario. First, the loss of natural gas in flowback water from hydraulic fracturing was reduced by 95%. So, in the reduced CH₄ scenario, the flowback from hydraulic fracturing sends 450 Mcf, instead of 9,000 Mcf, of natural gas to venting or flaring. Second, the reduced CH₄ scenario flares a larger portion of potential emissions, which is represented in our model by increasing flaring activity from 15% to 51%. Third, in the reduced CH₄ scenario, pneumatic venting for onshore conventional and unconventional wells is reduced by a factor of 1,000, making the bleed rates from pneumatically controlled equipment used by onshore wells similar to those for offshore wells. The fourth and final parameter change for the reduced CH₄ scenario is a 95% reduction in the emissions through wet seals on centrifugal compressors and rod packing on reciprocating compressors. The NSPS does not apply to pipeline compressors, so the reduced CH₄ scenario does not model any emission reductions for natural gas transport.

### Impact Assessment

Compared to other energy systems, the GHG emissions from natural gas systems have high proportions of CH₄. The climate impact of CH₄ is significantly higher than that of CO₂, so this analysis uses two climate impact assessment methods, global warming potential (GWP) and technology warming potential (TWP), to interpret GHG results.

GWP is based on the heat trapping capacities of GHGs relative to CO₂ and is the de facto climate impact assessment method used by life cycle practitioners. The use of GWP requires the selection of a 100- or 20-year time frame. Because of the high decay rate of CH₄ relative to CO₂, the scaling factors to convert CH₄ to carbon dioxide equivalents (CO₂eq) are significantly different between the two time frames. The GWPs from the Intergovernmental Panel on Climate Change’s (IPCC) fifth assessment report (IPCC 2013) are 36 and 87 for 100- and 20-year time frames, respectively. The 100-year GWP for methane with climate carbon feedback, as specified in the IPCC’s fifth assessment report, is 34 for nonfossil sources and 36 for fossil sources; for fossil sources, the value is increased by 2 (from 34 to 36) to account for the decomposition of CH₄ to CO₂. Another aspect of GWP is that it assumes that all emissions take place in a single pulse at the very beginning of the study period (Smith and Wigley 2000a, 2000b; Fuglestvedt et al. 2003) and thus does not account for the pattern of GHG emission over the life of a system.

We use TWP in a way similar to Alvarez and colleagues’ (2012) implementation. TWP does not require the selection of a 20- or 100-year time frame because it directly calculates the forcing that has occurred up to each year in a time series. For instance, given a 10-year timeframe, TWP shows that the cumulative radiative forcing (CRF) of 1 unit of CH₄ released in

### Table 1: Key natural gas extraction parameters used by the natural gas model

| Parameter                          | Units | Onshore conventional | Marcellus Shale | Reduced CH₄ scenario |
|------------------------------------|-------|----------------------|----------------|----------------------|
| Estimated ultimate recovery        | Bcf   | Low 0.50             | 2.2            | 2.2                  |
|                                    |       | Expected 0.72        | 3.3            | 3.3                  |
|                                    |       | High 0.94            | 4.9            | 4.9                  |
| Controllable flows                 |       |                      |                |                      |
| Completions                        | Mcf NG/episode | 47 | 9,000 | 450 |
| Workovers                          | Mcf NG/episode | 2.4 | 9,000 | 450 |
| Workover frequency                 | episodes/well-life | 1.1 | 0.3 | 0.3 |
| Liquid unloading flow              | Mcf NG/episode | 3.6 | n/a | n/a |
| Unloading frequency                | episodes/well-life | 9.0 | n/a | n/a |
| Other controllable flows           | lb CH₄/Mcf NG | 0.003 | 0.003 | 0.003 |
| Flaring rate                       | %     | Low 41               | 12             | 41                   |
|                                    |       | Expected 51          | 15             | 51                   |
|                                    |       | High 61              | 18             | 61                   |
| Fugitive emissions                 |       |                      |                |                      |
| Pneumatic devices                  | lb CH₄/Mcf NG | 0.11 | 0.11 | 0.0011 |
| Fugitives                          | lb CH₄/Mcf NG | 0.043 | 0.043 | 0.043 |

Sources: US EPA (2011, 2012) and US EIA (2011).

Bcf = billion cubic feet; Mcf = million cubic feet; NG = natural gas; lb = pound; CH₄ = methane; n/a = not applicable.
the first year is higher than the CRF of 0.1 units of CH₄ released each year. Considering the timeline of emissions is important because the differences in radiative efficiency and decay rates of CH₄ and CO₂ can lead to inaccurate GWP results for emissions that take place over decades. TWP was first applied to natural gas and coal power systems by Alvarez and colleagues (2012). TWP calculates the ratio of CRF between two technologies over time. In their analysis, the TWP breakeven is the point at which the CRF caused by the natural gas-fired power is equal to that of coal-fired power. Their analysis concluded that if the CH₄ emission rate is less than 3.2%, then new natural gas power plants will always have a lower climate impact than new coal-fired power plants that burn low-methane coal—the CRF ratio will be less than 1 at all points in the timeframe of the emission impacts (Alvarez et al. 2012). Zhang et al. (2014) also use radiative forcing as a metric for comparing the life cycle GHG emissions for natural gas- and coal-fired power plants, and for evaluating the importance of CH₄ emission rate. Our conclusions are similar to Alvarez and colleagues (2012) and Zhang and colleagues (2014); however, our results are unique because they are based on a complex model of upstream natural gas emissions that accounts for key sources of variability and uncertainty.

The only changes that we have applied in the TWP calculation method are the use of updated impulse response functions (IRFs) and radiative efficiencies from the IPCC Fifth Annual Report (2013), and the addition of climate carbon feedbacks for CH₄ emissions. The adjusted lifetime of CH₄ used is 12.4 years, and the radiative efficiency is 120 times that of CO₂. Climate carbon feedbacks, which account for additional CO₂ emissions from the ocean and biosphere to the atmosphere from higher temperatures, are included in the IRF for CO₂ but must be added separately for CH₄. These calculations are performed using methods and data from Collins and colleagues (2013) and Arora and colleagues (2013).

**Methane Emission Rate and Upstream Greenhouse Gas Emissions**

Table 2 shows the CH₄ emission rates for various boundaries and denominators, as calculated by the model. The values in table 2 are based on a single inventory (the life cycle of 1,000 grams [g] of distributed natural gas) that is parsed into different cradle-to-gate and gate-to-gate boundaries and demonstrates how denominators (the amount of gas exiting a boundary) and CH₄ emission rates are sensitive to the chosen boundary. If the boundaries of this single inventory are restricted to extraction only, the upstream emissions are 4.7 g CH₄ and the extracted natural gas is 1,086 g, which translates to a CH₄ emission rate of 0.43%. If the boundaries are expanded from extraction to distribution, the total CH₄ emissions are 17 g CH₄ and the distributed natural gas is 1,000 g, which translates to a CH₄ emission rate of 1.70%. The CH₄ emission rate of the cradle-to-extraction boundary (0.43%) is only one quarter of the full upstream boundary, from extraction through distribution (1.7%).

The rest of this article expresses CH₄ emission rates using a denominator of natural gas delivered by the transmission network, which is representative of natural gas delivery scenarios for large-scale end users such as power plants. Some studies express CH₄ emission rates using a denominator of extracted, not delivered, natural gas. We have chosen to express the CH₄ emission rate in terms of delivered natural gas to avoid boundary confusion in the interpretation of our life cycle results for power systems.

The majority of upstream GHG emissions from natural gas are from CH₄. The balance of GHG emissions is CO₂ from combustion, negligible amounts of naturally occurring CO₂ in vented natural gas, and negligible amounts of nitrous oxides from combustion. The upstream GHG emissions from Marcellus Shale natural gas under current and reduced CH₄ scenarios are shown in figure 2. The potential GHG emission reductions caused by improved practices are also shown in figure 2.

For current practices, the completion and workovers of unconventional wells (in this case, Marcellus Shale wells) are one-time or periodic activities that account for 11.0% and 3.3% of upstream GHG emissions, respectively. This is an unusually large contribution from periodic activities; one would expect the contributions from steady-state operations and the long service lives (used as the denominator for apportioning periodic activities) of natural gas wells to dilute the contributions from periodic activities to a point of insignificance.

A reduced CH₄ scenario could reduce the upstream GHG emissions from new or modified Marcellus Shale wells by 31%, from 11.8 to 8.0 g CO₂-eq/MJ of delivered natural gas (using a 100-year time frame for GWP). CH₄ is 74% of the upstream GHG emissions from Marcellus Shale natural gas using current practices. In the reduced CH₄ scenario, CH₄ accounts for 62% of the upstream GHG emissions from Marcellus Shale natural gas.

Reducing natural gas venting and fugitive emissions should be the top priority when tackling GHG reductions of upstream natural gas, but GHG reductions could also be realized by increasing the efficiencies of compressors and other equipment that combust natural gas and emit CO₂. For instance, a 10% increase in pipeline compressor efficiency would reduce the upstream GHG emissions from current Marcellus Shale natural gas by 2.4%. This includes a reduction in CO₂ emissions from compressors, but also a reduction in all natural gas flows before the pipeline. Given a fixed quantity of delivered natural gas, a reduction in the amount of natural gas used by pipeline compressors reduces the amount of natural gas that needs to be extracted and processed before pipeline transport.

The results (figure 2) for upstream natural gas from Marcellus Shale are representative of CH₄ emission rates of 1.4% and 0.79%, for current and reduced CH₄ scenarios, respectively. When modeling the 2010 domestic supply mix, as shown by the U.S. Energy Information Administration’s (EIA) Annual Energy Outlook (US EIA 2011), the CH₄ emission rate from the current natural gas supply chain is 1.2%. When modeling upstream natural gas with the reduced CH₄ scenario, the CH₄...
Table 2  CH4 emission rates for various boundaries in the natural gas supply chain (U.S. domestic supply mix), with shading denoting the extent of each boundary

| Boundary          | Numerator Upstream emissions (g CH4) | Denominator NG exiting boundary (g NG) | Loss rate (%) | Emission rate (%) |
|-------------------|--------------------------------------|----------------------------------------|---------------|-------------------|
|                   | Extraction — Processing — Transmission — Distribution |                                     |               |                   |
| Cradle to extraction | 4.7                                   | 1,286                                  | 0.5           | 0.43              |
| Cradle to processing | 4.7 + 2.6                            | 1,020                                  | 6.6           | 0.71              |
| Cradle to transmission | 4.7 + 2.6 + 5.2                      | 1,005                                  | 7.9           | 1.24              |
| Cradle to distribution | 4.7 + 2.6 + 5.2 + 4.5               | 1,000                                  | 8.4           | 1.70              |
| Processing only   | 2.6                                   | 1,020                                  | 6.1           | 0.25              |
| Transmission only | 5.2                                   | 1,005                                  | 1.5           | 0.52              |
| Distribution only | 4.5                                   | 1,000                                  | 0.5           | 0.45              |

Note: CH4 = methane; g = grams; NG = natural gas.

Figure 2  Detailed upstream GHG results for delivered Marcellus Shale natural gas (error bars represent variability in EUR and flaring rates, as shown in table 1, as well as the variability in natural gas transmission distance). GHG = greenhouse gas; EUR = euro.

emission rate from the domestic natural gas supply is reduced to 0.80%.

The CH4 emission rates for all natural gas sources in our model range from 0.60% to 1.6%. The variability in upstream GWPs across seven unique sources of natural gas and the 2012 domestic supply mix, as well as the range of CH4 emission rates for each natural gas source, are shown in figure S1 and S2 in the supporting information on the Web. Parameter variability and different methane GWPs for 20- and 100-year time frames cause variability in upstream GWPs, but CH4 emission rates are not affected by choice of impact assessment method or time frame.

Life Cycle Greenhouse Gas Emissions

An understanding of the upstream natural gas supply chain is valuable because it helps identify opportunities for GHG reductions, but a life cycle perspective includes other GHG emissions and allows comparisons between technologies. For
large-scale energy conversion systems, the combustion of fuel is usually the biggest contributor to life cycle GHG emissions. Natural gas–fired power plants are not an exception to this rule.

The new natural gas power plant in this analysis is a state-of-the-art combined-cycle natural gas power plant used for baseload electricity generation with a net efficiency of 50.2% and an emission rate of 365 g CO₂ per kilowatt-hour (kWh) of electricity generated (NETL 2010). Our model also accounts for the small amount of CH₄ that is emitted by natural gas power plants. From a life cycle perspective, which accounts for natural gas extraction and transmission upstream from the power plant and electricity transmission downstream from the power plant, power plant emissions compose 80.5% of the life cycle GHG emissions from natural gas power, using our CH₄ emission rate of 1.2% and a 100-year GWP of 36 for CH₄ (IPCC 2013). The CO₂ emissions from power plant operations are the largest contributor to the life cycle GHG emissions from natural gas–fired power. There are few near-term opportunities for reducing power plant emissions; work continues on improving power plant efficiencies, and carbon capture and sequestration is a long-term goal with policy and implementation barriers. There are few barriers to immediate reductions in CH₄ emissions from upstream natural gas. Upstream CH₄ emission reductions are the best near-term opportunity for reducing the GHG emissions from natural gas power systems.

An existing fleet coal-fired power plant has an efficiency of 32% and emits approximately 1,000 g CO₂/kWh (NETL 2012). From a life cycle perspective, which accounts for coal extraction and transport upstream from the power plant and electricity transmission downstream from the power plant, power plant emissions are 96% of the GHG emissions from baseload coal–fired power. The new coal power plant in this analysis is a state-of-the-art supercritical pulverized coal power plant that is fired with sub-bituminous coal and has an efficiency of 39% (NETL 2011). The direct power plant combustion emissions of 860 g CO₂/kWh of electricity generated account for nearly 96.4% of all GHG emissions in the life cycle. Our coal scenarios include CH₄ emissions from coal mine CH₄ as well as the small amounts of CH₄ that are emitted by coal-fired power plants. Sub-bituminous coal has low CH₄ emissions and thus lower upstream burdens than gassy bituminous coal, providing for a conservative comparison between natural gas and coal systems.

The power plant efficiencies used herein are within the ranges used by other analyses (Alvarez et al. 2012; Heath et al. 2014; Zhang et al. 2014). However, we use our detailed upstream natural gas model to account for key sources of variability and uncertainty in the natural gas supply chain. Using our upstream natural gas model in combination with our models of natural gas– and coal-fired power plants, it is possible to calculate the CH₄ emission rates that make the GHG emissions from natural gas–fired power match, or break even with, those from coal-fired power. These break-even points are shown in figure 3 and include comparisons between combined-cycle natural gas with the fleet and new coal power plant technologies described above. The break-even points are shown for both 20- and 100-year GWPs, which are 87 and 36 for CH₄ (IPCC 2013). Also shown are the corresponding points for the current (1.2% CH₄ emission rate) and reduced CH₄ (0.8% CH₄ emission rate) scenarios for 2010 U.S. average gas through the combined-cycle natural gas plant described above. This evaluation shows that the cradle-to-delivered CH₄ emission rate would have to be greater than 4.4% or 10.0% for new natural gas power to be worse than new coal power on 20- or 100-year GWPs, respectively. The break-even CH₄ emission rates are higher for the comparison to fleet coal because of the reduced plant efficiency.

The CH₄ emission rates for all domestic natural gas sources range from 0.6% to 1.6% (figure SI and S2 in the supporting information on the Web) and are below any of the break-even points shown in figure 3; our choice to compare natural gas and coal power plants using a mix of domestic natural gas sources instead of a single natural gas source does not affect our conclusions.

As illustrated by figure 3, when comparing systems that are a mix of CO₂ and CH₄, GWP results are sensitive to the choice between 20- and 100-year time frames. Because GWP assumes that all emissions take place in a single pulse at the very beginning of the study period, it has limitations when modeling the GHG impacts of energy systems that operate for decades. To provide clarity to our interpretation of GHG results, we applied TWP to the life cycle GHG inventories of coal and natural gas systems. Our application of TWP compares new natural gas power to new coal power and models uniform emissions over a 30-year operating life. After 30 years, no new emissions are generated, but radiative forcing persists whereas the GHG emissions from the 30-year period are removed from the atmosphere. This emission schedule contrasts that for the GWP result, which models all life cycle emissions as a pulse in the first year. Our results for TWP are shown in figure 4 and include curves for four scenarios: CH₄ emission rates for current and reduced CH₄ scenarios, as well as CH₄ emission rates that correspond to two of the break-even points in figure 3.

As long as CH₄ emission rates are lower than 3.3%, advanced natural gas power has a lower climate impact (in terms of CRF) than advanced coal power at all points in a time series. (This 3.3% rate is not shown in figure 3, but we calculated it by solving for the natural gas power scenario at which the CRF ratio is always less than 1.) At a CH₄ emission rate of 4.4% (the breakeven when using a 20-year GWP) it takes 30 years before the cumulative forcing of the natural gas option is equal to the CRF of the coal option. The time period for natural gas to achieve equivalency with coal significantly increases as the CH₄ emission rate increases. At a CH₄ emission rate of 10.0% (the breakeven when using a 100-year GWP), it takes 108 years for natural gas power to achieve the same radiative forcing as coal power. As discussed, the CH₄ emission rate calculated by our model is 1.2% and could be reduced below 1% if improved extraction and processing practices are used to reduce CH₄ emissions. Owing to the short lifetime of CH₄ emissions in the atmosphere and the higher emissions of long-lived CO₂ from coal power, at long enough time frames TWP will always be less than 1 for natural gas systems, regardless of CH₄ emission rate.
Conclusions and Recommendations

Initial studies on the life cycle GHGs of natural gas systems called for better data on upstream emissions (NETL 2012; Jiang et al. 2011; Burnham et al. 2011; Bradbury et al. 2013; Weber and Clavin 2012). Responses to that call have been slow, but steady, and at much smaller scales than are necessary to produce a full, or even statistically significant, inventory. Each new study has unique scope and boundaries, and there is an instinct to put the results in the context of all other studies without performing the reconciliation exercise that is critical for allowing accurate comparisons. Boundary reconciliation alone will help reconcile the seemingly disparate results of different studies. As shown by our model, the CH₄ emission rate can be interpreted as 0.43% if based on a narrow boundary (extraction only) and 1.7% if expanded to a wider boundary (cradle-to-distribution).
Much of the current discussion surrounding the preference for natural gas over coal comes down to the idea of uncertainty and variability in CH₄ emission rate. Our results show that life cycle GHGs for natural gas–fired power are lower than those for coal–fired power across a wide range of potential CH₄ emission rates. Using 100-year GWPs, if natural gas emissions are lower than 11.9%, new natural gas power is preferable to new coal power; when using 20-year GWPs, this breakeven is reduced to 4.5%. If TWP is used instead of GWP, new natural gas power will have a lower climate impact than new coal power over its entire operating life if the CH₄ emission rate is lower than 3.3%, and over longer periods will always result in lower cumulative forcing.

Implementing best practices (whether owing to state or federal regulations such as the NSPS for the oil and gas sector or because of safety or economic concerns) can significantly reduce upstream natural gas emissions. For example, best practices for CH₄ management can reduce the upstream GHG emissions from new shale gas wells by 31% compared to existing wells. Shale gas and other unconventional technologies are a growing contribution to the U.S. natural gas supply, making reductions to unconventional extraction emissions a wide-reaching strategy for reducing GHG emissions.

This analysis, and many others on the subject, examine the GHG implications of a choice between producing electricity with coal or natural gas, and quantify potential reductions of choosing natural gas. This comparison ignores other potential options for reducing GHGs from power generation, many of which would likely have larger overall reductions, such as post-combustion carbon capture and sequestration, nuclear power, or renewables, such as wind and solar. Whereas a coal–gas comparison may be useful for some policy scenarios, a more comprehensive GHG reduction strategy should take into account a broader range of options. That being said, only in highly unusual or isolated circumstances will the climate impact from natural gas power be higher than that from coal power during power plant operation; further, over long periods the cumulative radiative forcing from natural gas systems will never be higher than the CRF from coal systems, because CH₄ has a much shorter atmospheric lifetime than CO₂.

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Supporting Information

Additional Supporting Information may be found in the online version of this article at the publisher’s web site:

Supporting Information S1: This supporting information includes key parameters for modeling upstream natural gas flows under current practices. It also contains a diagram depicting the unit process network for the life cycle of natural gas power, and a graph depicting the variability in upstream GHG emissions for different natural gas extraction sources.