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Natural Gas versus Coal: Is Natural Gas Better for the Climate?

This article analyzes the level of greenhouse gas emissions attributable to electricity from natural-gas-fired power plants and coal-fired power plants, then compares the two. An analytical framework is employed that considers the key greenhouse gases released during the production and combustion of coal and natural gas: carbon dioxide and methane.

Chris Busch and Eric Gimon

I. Introduction

There has been great debate about the environmental merits of greater use of natural gas in the United States. Is natural gas a lower-carbon bridge to a very-low-carbon future, or is it a ''gangplank to a warmer future?'' Cornell Professor Anthony Ingraffea, who has been an important contributor to the literature, coined the ''gangplank'' term in an Op-Ed published in *The New York Times*, ''Gangplank to a Warm Future,'' published on July 28, 2013. The concept of natural gas as a lower carbon bridge fuel has been frequently discussed, see, e.g., Levi's (2012), an article entitled, ''Climate Consequences of natural gas as a bridge fuel'' (Levi, 2013).

The first order of business to answer this question is to set out the basic facts and dependencies that determine greenhouse gas (GHG) emissions over the fuel-cycle – i.e., from extraction of a fuel

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to its combustion – for electricity generated from coal and natural gas in the United States. In this paper, results show that the impact of substituting gas for coal largely depends on the timeframe being considered and the extent of leakage from the natural gas system. We define leakage to cover both intentional venting and unintended releases from leaks or equipment malfunctions releases of natural gas. For short time frames and if natural gas leakage rates are high, natural gas may offer little benefit compared to coal or could even exacerbate warming. Over a longer period, such as 100 years or more, natural gas from electricity provides greenhouse gas reductions compared to coal even if leakage rates are relatively high.

Our results are consistent with other recent research. We extend the literature by considering a wider range of technological configuration of coal and natural gas plants. While data and assumptions are rooted in the U.S. context, the broad contours of the conclusions are applicable to other countries. The power plant technologies available will be largely the same across countries and methane emissions from the natural gas system will be important to deciding the relative impact of natural gas compared to other technologies.

To answer the initial question about the cost and effectiveness of using natural gas combustion as a bridge to a zero-carbon future, we not only need the basic results calculated in this article but also an overall strategy for how a coal to gas conversion will take place. To estimate global warming impact for such systemic change, it is necessary to define when coal plants will be retired, what existing natural gas plants will be used, what new natural gas plants will be installed, what new gas delivery and storage infrastructure needs to be built, as well as how and when each natural gas plant gets retired or converted to make way for energy sources without carbon emissions. It is also important to understand whether gas is actually displacing coal, or energy efficiency and renewable energy. Our results demonstrate that the environmental value of switching from coal to gas is contingent on gas system leakage and the time horizon studied, but the larger question of emissions benefits from a system-wide shift from coal to gas requires an assessment of these other factors, and that is beyond the scope of this article.

The impact of substituting gas for coal largely depends on the timeframe being considered and the extent of leakage from the natural gas system.

II. Context

Hydraulic fracturing and directional drilling have changed the dynamics of the natural gas industry. Natural gas extracted this way is still often called ''unconventional,'' though these techniques have become standard practice. The unconventional label serves as convenient shorthand to distinguish the extraction of gas from shale rock and other previously inaccessible sources through hydraulic fracturing and horizontal drilling, as contrasted with previous conventional approaches to tapping reservoirs through vertical drilling.

Unconventional production has dramatically increased the supply and reserves of natural gas in the United States. In 2012, shale gas accounted for 40 percent of domestic production, roughly 27 billion cubic feet per day and up from 1.2 bcf in just 10 years (Energy Information Administration, 2012). Henry Hub natural gas spot prices went from 2008 highs around $13/mmBtus (million British thermal units) to lows around $2.0/mmBtus in 2012 (Energy Information Administration, 2014a). As a result, electricity from natural gas has increased 34 percent from 2009 to 2012 (Energy Information Administration, 2013a), although coal generation has recovered a little as natural gas prices have more than doubled since recent lows experienced in 2012 (Energy Information Administration,

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2014b). Natural gas is also directly burned for residential use, e.g., for water heating or cooking, and as an input in industrial processes, and as a feedstock for chemicals and fertilizer. We do not consider these uses in this article.

The U.S. has reduced carbon dioxide emissions from their peak in 2008, and natural gas has received some credit for the reduction. How much is debatable. Trevor Houser finds the recession and increased use of renewable energy deserve more credit, but that increased use of gas caused about 17 percent of the reductions in carbon dioxide (Houser and Mohan, 2013). This analysis does not consider changes in methane emissions.

III. Methodology

Our unit of analysis is 1 megawatt-hour (MWh) of electricity produced by either type of power plant, coal or natural gas. To enable summation with a single metric, methane emissions are converted to carbon dioxide equivalent for three timeframes: time zero (immediately after the release of the gas), a 20-year time horizon, and a 100-year horizon. In addition to the time dimension, the methodology explores variations in power plant technology and rate of methane leakage from the natural gas system. Fuel cycle GHG emissions for different technologies at different levels of leakage are calculated and compared. We calculate the impact of natural gas on the margin and the threshold levels of methane leakage that would be required for natural gas and coal parity for four different natural gas and coal power plant technology couplets representing real-world situations.

The U.S. has reduced carbon dioxide emissions from their peak in 2008, and natural gas has received some credit for the reduction. How much is debatable.

A. GHG emissions

The analysis focuses on the three largest sources of GHG emissions from the coal and natural gas fuel cycles: (1) upstream methane, (2) upstream CO_2, and (3) smokestack CO_2. Upstream methane refers to the methane emissions that occur for both coal and natural gas as they are extracted and delivered to power plants. The term upstream indicates that these emissions occur before combustion occurs at the power plant. Though the natural gas system is a larger source of methane emissions, coal is a source too. Methane is commingled to some extent with coal deposits, and escapes during the mining process. Upstream CO_2 emissions are also part of the pre-combustion inventory. In the case of coal, these are attributable to transportation fuel combustion. For gas, upstream CO_2 is a combination of flaring, removal of CO_2 that is mixed with underground natural gas and is extracted during processing, and natural gas combustion for energy during the whole well to plant delivery process – for example for pipeline compressors. Smokestack CO_2 emissions are the principal emissions, which are released out the power plant smokestack when coal or natural gas is burned.

We do not consider nitrous oxide emissions associated with power generation. These emissions do contribute to climate change and are part of the fuel cycle, but they are small and do not play a large effect in determining the overall GHG emissions.

This is a not a lifecycle study. As such, we do not estimate emissions associated with producing the required hardware. For fossil fuel power plants, these tend to be relatively small compared to fuel cycle emissions. For example, Spath and Mann (2010) estimate the emissions associated with manufacturing and constructing a natural gas plant to be 0.4 percent of lifecycle emissions.

Global warming potential (GWP) is a way to compare the

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relative effects of different GHGs over time. We use GWP values to aggregate the effects of carbon dioxide (CO_2) and methane emissions over the fuel cycle. Methane is a potent greenhouse gas. Pound-for-pound, methane traps heat approximately 120 times more effectively than CO_2 when it is first released into the atmosphere, according to the Intergovernmental Panel on Climate Change (Intergovernmental Panel on Climate Change, 2013). This difference decreases over time because methane gradually breaks down into CO_2. Methane's relative impact is estimated to be 84 times larger than an equivalent mass of CO_2 over a 20-year time period and 28 times larger over a 100-year time period feedback (Intergovernmental Panel on Climate Change, 2013). These scaling factors are known as the GWP values for methane. The GWP of carbon dioxide on this scale is always one. When GHG emissions are scaled by GWP values, the resulting value is called carbon dioxide equivalent. The carbon dioxide equivalent measure of a gas indicates the amount of carbon dioxide that would have to be released to produce the same amount of radiative forcing.

In the latest Intergovernmental Panel on Climate Change report, the notion of GWP was modified to include carbon-cycle feedback effects from short-term forcers. For example, taking into account some follow-on effects from early radiative forcing due to methane increases its 100-year GWP from 28 to 34. The Intergovernmental Panel on Climate Change lists both GWP values both with and without feedbacks. In the interest of brevity, we have chosen to present results using only one set of GWP values. In an abundance of caution, to avoid any appearance of inflating damages from methane, we use the lower GWP values, those absent feedback effects.

Pound-for-pound, methane traps heat approximately 120 times more effectively than CO_2 when it is first released into the atmosphere.

B. Technology

To estimate fuel cycle emissions from electricity generation, a power plant technology must be specified. To compare two different types of power plants, their duty cycles would have to be considered. This complication is not relevant to this analysis since we are comparing energy produced (1 MWh). A given technology is represented by a power plant's heat rate, which is the amount of energy used by a power plant to generate 1 kilowatt-hour (kWh) of electricity. As plants become more efficient, the heat rate declines. Cathles et al. (2011) takes issue with Howarth et al. (2011) for not taking into account the greater efficiency of natural gas power plants: ''Howarth et al. treat the end use of electricity almost as a footnote,'' page 6. In addition to representing typical plants, Cathles considers one variation, an advanced coal plant. We agree that it is important to include a more nuanced representation of technology efficiency, and extend the literature by considering a wider range of heat rates to better characterize the actual range of efficiencies across the existing stock of generators and new plants. The framework analyzes three plant technologies for each fuel type.

Coal test cases:

i. **New coal** (heat rate = 8,687 Btu/kWh): super-critical pulverized coal plant (National Energy Technology Laboratory, 2010). This is the same plant type used in the analysis by Alvarez et al. (2012). It is more efficient than the sub-critical pulverized coal plant that makes up the bulk of the U.S. fleet. Sub-critical coal heat rates average 9,370 Btu/kWh (Black and Veatch Corporation, 2012).

ii. **System average** (heat rate = 10,444 Btu/kWh): This is not a specific type of power plant but the system average, weighted by production, for coal plants operating in 2011, the most recent

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annual data from the EIA (Energy Information Administration, 2013b).

iii. **Retired coal** (heat rate = 11,665 Btu/kWh): The heat rate of the average of coal plants retired over the 2009–2011 period, according to EIA data (Energy Information Administration, 2013).

Natural gas test cases:

i. **Combined-cycle H-class** (heat rate = 6,093 Btu/kWh): The most efficient natural gas turbine widely commercially available is a combined-cycle (CC) H-class plant (Steele, 2012). These are not the convention today, but could be in the future. It is often the case that it takes some time for innovations to fall in cost and enter into widespread use. Note that the gross efficiency level and implicit heat rate reported in the Electric Power Research Institute work was adjusted to account for the difference between Higher Heating Value and Lower Heating Value.

ii. **New combined-cycle** (heat rate = 6,798 Btu/kWh): When a new gas plant is built today, it is typically a combined-cycle plant. These plants achieve greater efficiency through a combination of direct use of gas to drive a turbine and secondary use of steam to turn another turbine. We use a heat rate of 6,798, following Alvarez et al. (2012), who in turn rely on NETL (National Energy Technology Laboratory, 2010).

iii. **System average** (heat rate = 8,152 Btu/kWh): This is not a specific type of power plant but the system average, weighted by production, for natural gas plants operating in 2011, the most recent annual data from the EIA (Energy Information Administration, 2013a).

C. Leakage scenarios

We define leakage on a mass basis, though it is also possible to

measure it as the volumetric percentage of methane leakage as a percentage of gross withdrawals. To reflect the continuing uncertainty over the rate of leakage from the natural gas system, we model leakage rates an order of magnitude apart, 1 percent and 10 percent. Recent work by Brandt et al. (2014) has helped to clarify the state of the science regarding methane emissions. The 1 percent and 10-percent values are both outside the range of system-wide leakage that is likely based on this new work. Using these values serves to highlight for policymakers the continued uncertainty around methane leakage. These extreme scenarios serve to illustrate the importance of methane leakage, and highlight the implications of ''what if?'' scenarios. At the lower end of the range, a 1-percent leakage rate is an attainable near-term goal for system-wide leakage. At the upper end of the range, a 10-percent leakage range could represent the highest emitting parts of the system. Alternatively, it could be that 1 percent represents an emission level that would be found in better-run operations and 10 percent represents emissions at poorly performing operators.

The Brandt et al. (2014) work defines its findings in relation to the EPA's National Inventory of Greenhouse Gas Emissions and Sinks (''EPA inventory''). The EPA released a new draft inventory with a longer time series of data, through the year 2012, in February 2014. However, the Brandt et al. paper was working with the 2013 EPA inventory covering 1990 through 2011 (US Environmental Protection Agency, 2013). The 2013 inventory estimates natural gas system leakage at 1.4 percent on a volumetric basis (as a percentage of gas produced; this is the more commonly referenced value) and 1.5 percent on a mass basis. (These leakage values are calculated as detailed in the supporting materials spreadsheet published along with Brandt et al. See the ''Natural Gas Flows'' worksheet for details.)

The EPA's inventory uses bottom-up studies to estimate

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methane emissions from the natural gas system. Bottom-up studies involve direct measurement of the rate of emissions for different components of the natural gas system. The result is emission factors for different components. Then, the EPA combines population data (the number of such components) and activity data (on the intensity or duration of use) with these emission factors to estimate the system-wide level of emissions.

The other approach to estimating methane emissions is called top-down and involves atmospheric samples from aircraft or tall towers, both upstream and downstream of gas fields, to see the difference. Top-down methods are better at estimating total levels of methane emissions, but have only begun to attempt to link atmospherically sampled methane to ground level sources. They are not able to separately distinguish leaks from pipelines, compressor stations, distribution systems, and end uses. Doing this involves the complicated parsing of atmospheric chemistry markers. Bottom-up methods do not have to engage in such analytical complications in order to tie measured emissions to a source. On the other hand, bottom-up studies are costly to carry out and researchers have found it difficult to secure the voluntary permission from natural gas operators needed for such research to go forward. This means that bottom-up studies have collected relatively small samples, raising questions about how representative they are – and this concern over selection bias is reinforced by the fact that it is the most responsible operators with the lowest leakage levels that would have an incentive to voluntarily open themselves up to such investigation.

The Brandt et al. work surveys all the major top-down studies, and concludes that the EPA inventory is significantly undercounting methane emissions. They conclude that actual emissions are 14 Tg higher in the aggregate (plus or minus 7 Tg). This means that the EPA is most likely underestimating methane emissions by 50 percent. This is an overall undercounting in reference to the entire EPA inventory, not the portion attributed to the natural gas system.

The natural gas system is not the only possible source for these emissions, though it is one likely source. Brandt et al. did not translate the unaccounted for methane into an estimated rate of emissions from the natural gas system in order to emphasize the continued uncertainty. While recognizing this uncertainty, it is also illustrative to extrapolate the implied rate of leakage under different assumptions. If emissions from the natural gas system are 3.5 Tg higher, equal to one-fourth of the central estimate of 14 Tg in unaccounted for methane that would imply a system wide leakage rate of 2.1 percent. If the natural gas system's methane emissions are 7 Tg higher in reality, equal to half of the best estimate of unaccounted for methane, that would mean the real system-wide average is 2.8 percent. At the upper end of what seems possible, if all of the 14 Tg in unaccounted for methane is due to natural gas that would imply a system-wide average of 4.2 percent. In our analysis of the thresholds at which methane leakage rises to a level to make natural gas as greenhouse gas intensive as coal, we will refer to a rounded version of this range 2.1–4.2 percent as the likely range. To highlight continued uncertainty, we round to one significant figure, meaning we present the likely range as 2–4 percent.

D. Smokestack CO_2

Each technology's heat rate implies a certain amount of primary energy required to produce 1 MWh. The EIA (Energy

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Information Administration, 2013b) offers statistics on the heat content of pipeline gas for electricity and different types of coal. These in combination with EPA emission factors for coal and gas enable estimation of smokestack emissions (Environmental Protection Agency, 2004). The analysis assumes new coal plants run on bituminous coal. The system average and retired coal cases are assigned an average emission factor that is a weighted average of the different types of coal mined in the U.S., weighted according to market share and energy content.

E. Upstream CO_2

For coal, following Alvarez et al. (2012) we use the value from the National Energy Technology Laboratory's analysis of supercritical pulverized coal (National Energy Technology Laboratory, 2010), and scale this value according to the higher heat rates for the system average and recently retired coal plants. For natural gas, we source data from two main places. First, total natural gas system CO_2 from non-combustion sources (EPA terminology for upstream CO_2) is listed in the national GHG inventory (US Environmental Protection Agency, 2014) (EPA 2014). About a third of this CO_2 from gas is from field production (flaring) while most of the remainder is from processing (when first extracted, natural gas often contains some carbon dioxide, which is removed during processing). Second, we look at CO_2 emitted when natural gas is combusted for energy during the well to power plant production and delivery process. We use natural gas listed in the 2012 EIA Annual Natural Gas Summary as

combusted for: lease fuel (used in well, field, and lease operations, such as gas used in drilling operations, heaters, dehydrators, and field compressors), plant fuel (used as fuel in natural gas processing plants), and transmission and distribution use. Following Alvarez et al. (2012) we assume that only half of the natural gas used in transmission and distribution is used in the infrastructure that feed natural gas power plants, i.e., the pipelines that make up the high volume transmission portion of the system.

A fraction of all upstream CO_2 emissions can be attributed to the electricity sector, based on end use: in this case 39 percent of natural gas was used for electricity generation in 2012 (Energy Information Administration, 2013a). This amount is divided by the number of MWh of electricity generated by natural gas in that same year. The result is a value of 60 kg CO_2/MWh for the system on average. For new CC and CC H-class plants, this value is scaled down according to the ratio of their heat value over the system average. These more efficient plants burn less natural gas, so there are fewer associated upstream CO_2 emissions.

F. Upstream methane

The upstream methane emission factor for coal is a straightforward derivation based on methane emissions from coal mining reported for 2012, the most recent year available in the national inventory 2012 (US Environmental Protection Agency, 2014) and the amount of coal produced in that year. This yields an estimate of the amount of methane emitted per Btu of coal mined in the United States. There is significant variability in upstream methane for coal, an issue not explored in this work, though Alvarez et al. (2012) do some sensitivity analysis in this regard. Upstream methane from coal is a less important contributor to total GHG emissions than smokestack emissions or upstream methane

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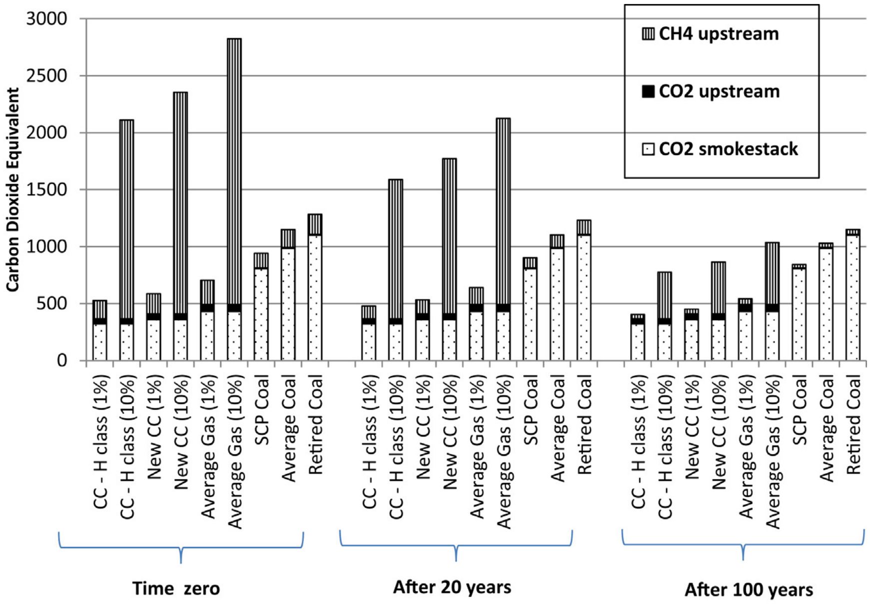

Figure 1: Fuel-Cycle GHG Emissions (kg) From 1 MWh of Electricity

from gas, so we focus sensitivity analysis on this factor.

Upstream methane emissions from natural gas are calculated by defining a mass balance equation (Eq. (1)) that accounts for methane from extraction to combustion at a natural gas power plant, recognizing that the amount of gas produced must equal the amount of gas combusted – either at the power plant or upstream – plus the amount of gas leaked.

The heat rates associated with each technology scenario are used to calculate how much gas must be combusted to generate 1 MWh of electricity. We calculate upstream combustion of methane (flaring during the field production phase along with natural gas combusted to produce and deliver) using the relevant fraction of upstream CO_2 figure above (about 83 percent of all upstream CO_2, all but the CO_2 directly extracted in the processing phase) multiplied by the fraction of CH_4 molecular weight to CO_2 molecular weight to impute the mass of CH_4 flared upstream per MWh.

Variable definitions for mass balance equation:

P	**Production**	Amount of gas that must be produced to support 1 MWh of combustion given U, C and *r*
r	**Rate of leakage**	The rate of leakage from the natural gas system that occurs before gas is burned at an electricity generator
U	**Upstream combustion**	Amount of gas flared or combusted upstream
C	**Combustion**	Amount of gas burned at generator to produce 1 MWh

The resulting mass balance equation consists of four variables, one unknown and three known (one of these is the leakage rate assumed for the scenario) as evident in Eq. (1).

$$P = P*r + U + C \tag{1}$$

Algebraic manipulation yields

$$P = \frac{U + C}{(1 - r)} \tag{2}$$

Thus, with U, C, being calculated quantities as explained above and r being an assumed value, production can be calculated. Using these elements, we can find net leakage (L) = $P * r$, the product of the rate of leakage and the amount of gas produced.

$$L = r*\left(\frac{U + C}{I - r}\right) \tag{3}$$

IV. Results

Figure 1 presents an overview of fuel cycle GHG emissions for 1 MWh of electricity produced from coal versus natural gas under different assumptions about leakage and power plant technologies over different periods of time.

Figure 1 and **Table 1** illustrate the importance of the time frame being considered and the leakage rate. The first bar in Figure 1 shows the greenhouse gas emissions associated with an advanced natural gas power plant, a ‘‘combined-cycle H-class’’ plant. CO_2 released out the smokestack when gas is combusted, 322 kg, is the first segment. The much smaller second segment is CO_2 released from the natural gas system

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Table 1: Fuel-Cycle GHG Emissions (kg) From 1 MWh of Electricity Produced.

Fuel	Natural Gas Power Plants						Coal Power Plants		
Technology (Leakage)	CC-H Class (1 percent)	CC-H Class (10 Percent)	Combined Cycle (1 Percent)	Combined Cycle (10 Percent)	System Gas (1 Percent)	System Gas (10 Percent)	New Coal	System Coal	Retired Coal
CH_4 upstream (kg)	1.3	15	1.5	16	1.8	19	1.1	1.3	1.5
CH_4 in time zero CO_2e	159	1744	147	1946	212	2334	130	156	174
CH_4 in 20-year CO_2e	111	1221	124	1362	149	1634	91	109	122
CH_4 in 100-year CO_2e	37	407	41	454	50	545	30	36	41
CO_2 upstream (kg)	45	45	50	50	60	60	6.5	7.8	8.7
CO_2 smokestack (kg)	322	322	360	360	431	431	805	985	1101
Totals									
Time zero CO_2e	526	2122	587	2356	704	2825	942	1149	1284
20-year CO_2e	479	1588	534	1772	640	2125	903	1102	1231
100-year CO_2e	405	774	451	864	541	1036	842	1030	1150

before the power plant, 45 kg, from the flaring of natural gas and on-site use of gas to fuel the natural gas system. The top segment represents the carbon dioxide equivalent of methane emission at 1-percent leakage. The corresponding segment of the next bar to the right provides the contrasting quantity at 10-percent leakage. To produce 1 MWh of electricity from a combined-cycle H-class natural gas plant, a 1-percent leakage would imply that 1.2 kg of methane have leaked while a 10-percent leakage rate would imply that 13 kg have leaked (equivalent to carbon dioxide equivalent emissions of 122 kg at a 1-percent leakage rate and 1340 kg at a 10-percent leakage rate).

At time zero and after 20 years with a methane leakage rate of 10 percent, then, natural gas would have higher carbon dioxide equivalent emissions than coal under the entire range of technological assumptions. After 100 years, even at 10-percent methane leakage, natural gas has lower carbon dioxide equivalent emissions than coal for most technological comparisons, though there are two cases at the 100-year time scale in which coal slightly betters natural gas. These two cases are when the most efficient coal plant (SPCP) is compared to the two less efficient natural gas plants, the system average and current conventional combined-cycle.

These results illustrate the importance of technological assumptions when evaluating GHG emissions from fossil-fuel-fired electricity generation as they have an importance similar in magnitude to methane leakage. For example, retired coal has emissions 36 percent higher than new coal. For gas, H-class gas is 33 percent better than system gas. Over the likely range 2–4 percent in methane leakage, the magnitude of the impact is similar to differences due to technology. The difference in fuel cycle GHG emissions due to leakage at 4 percent versus 2 percent is 18 percent over 100 years, 39 percent over 20 years, and 49 percent at time zero.

Smokestack CO_2 emissions from natural gas are often presented as 50 percent of those from coal plants. Looking at the data in Table 1, it is evident that stack emissions due to natural gas are sometimes substantially less than 50 percent of those from coal. For example, comparison of advanced gas and system coal shows that H-class gas has only 32.7 percent of the emissions, more than 73 percent less than system coal. These very low smokestack CO_2 rates serve to raise the threshold amount of leakage needed for gas-fired power plant fuel cycle GHG emissions to equal those of coal-fired plants.

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We develop various pairings of the different plant types to give insight into the tradeoffs that would result in different specific situations. The following scenarios suggest some pairings with an explanation of the situations under which these circumstances and the associated marginal impacts might hold.

1. ***System average gas versus retired coal.*** Recent increases in the share of U.S. electricity generated by gas happened mainly through greater use of the existing fleet rather than through new capacity additions. We calculate the system average based production, not capacity, providing a weighted average of the mix of vintages scattered throughout the electricity sector today. Coal units that were switched on in the past during periods of higher demand were replaced by power generated from existing gas units, which system operators moved up the stacking order due to lower natural gas prices. In light of this, recently retired coals plants can serve as a proxy for coal plants at the operating margin. The impacts of any particular tradeoff will depend on whether the natural gas plant being utilized to produce the 1 MWh of electricity that is substituting for coal is a single or combined-cycle plant. Nonetheless, this weighted system average broadly represents the gas – coal tradeoff on the margin that has been a dominant recent electricity sector dynamic.

2. ***Combined cycle versus system average coal.*** This pairing provides a forward-looking perspective. The system average for coal serves as a proxy for the type of coal plant that newer natural gas plants are likely to back down (cause to be idle a larger percentage of the time) going forward. Combined-cycle technology represents the typical natural gas plant installed today, which would comply with the EPA's proposed new source performance standards for power plants. So, to the extent that newer gas plants are substituting on the margin for coal, this pairing provides insights into the marginal emission effects.

3. ***Combined cycle versus super-critical pulverized coal***. This pairing explores the marginal impact of natural gas where the 1 MWh substitution involves a newer, more efficient coal plant. The conventional coal plant being built today is more advanced than the sub-critical pulverized coal plants that were commonly built in the 20th century. Thus, the new coal plant scenario assumes super-critical pulverized coal technology. However, the U.S. has been closing old coal plants and not building many new ones. Companies built just three new coal plants in 2013. Newer coal plants are more common in the developing world. Thus, we expect this circumstance to be most relevant outside of the U.S.

4. ***Combined-cycle H-class versus super-critical pulverized coal***. Going forward, as emerging H-class or other more advanced gas plants become the standard, what would the impacts be if these advanced gas plants are substituting for new coal on the margin? For the same reasons given above, this circumstance is more likely to occur in countries other than the United States.

Next we present the effect on GHG emissions due to a 1 MWh substitution of gas for coal under the technological specifications implied in the four different pairings described above. A negative value indicates that the substitution of natural gas for coal would reduce CO_2-equivalent emissions. A positive value indicates that CO_2-equivalent emissions would be higher with natural gas as compared to coal. As before, we take three different temporal perspectives on the question. The results are summarized in **Table 2**.

Table 2 further drives home the point that leakage rates strongly affect the impact of natural gas susbstitutions. At 1-percent

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Table 2: Percentage Change in GHG Emissions Due to a 1 MWh Substitution of Natural Gas for Coal.

	Time Zero	20 Years	100 Years
Results with 1 percent (1 percent) methane leakage			
Average gas vs. retired coal	−45	−48	−53
Combined cycle gas vs. system average coal	−49	−52	−56
Combined cycle gas vs. supercritical coal	−38	−41	−47
H-class gas vs. supercritical coal	−44	−47	−52
Results with 10 percent (10 percent) methane leakage			
Average gas vs. retired coal	120	73	−10
Combined cycle gas vs. system average coal	105	61	−16
Combined cycle vs. supercritical coal	150	96	3
H-class gas vs. supercritical coal	124	76	−8

leakage, natural gas provides some GHG gains over coal in every comparison. At 10-percent leakage, the short-term potency of methane is evident in that natural gas substitution result in higher emissions over the lifecyle in every case at time zero and over the 20-year period. At the 100-year timescale and with 10-percent leakage, the results are split. In three cases, natural gas emissions are higher and in one instance coal emissions are higher.

It is also instructive to evaluate the level of methane leakage that would make natural gas fuel cycle emissions equivalent to those of coal. These are the breakeven points for natural gas or threshold levels of methane leakage that need to be added in order for natural gas to have fuel cycle GHG emissions as large as coal. The value is calculated as follows. For each pairing, for the given natural gas power plant technology, we calculate the amount of emissions from upstream combustion and combustion at the power plant. The amount of leakage that defines the leakage threshold is the amount equal to the difference of total coal emissions (for the technology assumed in this comparison) less upstream and combustion emissions from the natural gas plant ''($U + C$).'' We then get a leakage rate by inverting Eq. (3) to get the rate ''r'' from the leakage ''L,'' which works out to L divided by the total coal plant emissions. **Table 3** presents these threshold values under the various technology pairings and timeframes.

The largest amount of leakage required for natural gas fuel cycle GHG emissions to meet the level emitted by a coal plant is in the new combined-cycle versus system average coal pairing. In that case, the leakage thresholds for parity between coal and gas are 4.0 percent, 5.3 percent, and 13.2 percent respectively over the three increasingly longer periods of time. The lowest thresholds occur in the new combined cycle versus super-critical pulverized coal pairing. In that case, the breakeven values for leakage are 2.9 percent, 3.9 percent, and 9.6 percent over the three periods.

The results of this modeling work are consistent with other similar work, for example Alvarez et al. (2012) and Larson (2013). Alvarez et al. (2012) finds a threshold at time zero of 3.2 percent. That analysis highlights results for coal plants burning ''low gassy coal,'' that is coal from mines that leak less methane gas than average. The framework developed here uses the U.S. average for methane emissions from coal mining. As well, Alvarez et al. attribute a portion of petroleum sector methane emissions to natural gas to reflect the fact that some natural gas is produced as a byproduct of oil production (associated gas). These factors serve to increase somewhat the threshold levels of leakage needed for natural gas to be as polluting as coal in terms of greenhouse gas emissions.

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Table 3: Leakage Thresholds for Natural Gas Emissions to Equal Coal.

Leakage Threshold	System Gas vs. Retired Coal (Percent)	New CC vs. System Coal (Percent)	New CC vs. New Coal (Percent)	CC H-Class vs. New Coal (Percent)
Time zero	3.6	4.0	2.9	3.5
20 years	4.8	5.3	3.6	4.6
100 years	11.8	13.2	9.6	11.5

V. Implications

In light of the Brandt et al. work, which indicates that leakage from the natural gas system is likely in the 2–4-percent range, our results imply that substituting natural gas for coal-fired electricity offer benefits in the long run. Better information about the rate of leakage is needed to offer a definitive judgment of short run effects. Over the 20-year time period, one of the four leakage thresholds for our technology pairings falls within the feasible range of natural gas system leakage, but three of the thresholds are above the highest value that seems likely given the Brandt et al. work. At time zero, thresholds are in the 2.9–4.0-percent range. The uncertainty range around emissions from the natural gas sector will have to be reduced before conclusions that are more definitive can be reached about the GHG emission impacts of a substitution of 1 MWh from natural gas for coal over shorter periods, such as 20 years or less.

The present analysis highlights the role of time in the consideration of relative GHG impacts and methane's particular strong radiative effect in the short term. Some researchers, such as Cathles et al. (2011), have argued that a 100-year timeframe or longer is the right time for climate policy analysis. Climate change is certainly a long-term problem, and thus the 100-year timeframe is important. Carbon dioxide, the most important single greenhouse gas, accumulates in the atmosphere over time. The atmosphere offers the capacity to absorb roughly 1 trillion tons of carbon dioxide without dangerous destabilization of the climate (Harvey et al., 2013). About 50 percent of a given quantity of carbon dioxide emitted remains in the atmosphere after 100 years and approximately 20 percent remains for thousands of years (Meehl, 2007).

Nonetheless, the impacts of climate change in the near term are also of interest to policymakers. The impacts of climate change are being experienced today. Wildfires are intensifying; sea level rise is accelerating; glaciers are melting. As ice melts, the reflectivity of the earth's surface is decreased. This leads to more heat being absorbed and less reflecting back and escaping the earth's atmosphere, in what is known as a positive feedback loop. Reducing short-lived GHGs such as methane decreases the current and near-term damages from global warming. This is valuable in its own right, and creates time for greater technological innovation to occur and to prepare for necessary adaptations. Increasingly, reductions in emissions of short-lived GHGs are being emphasized as a way to manage the peak warming. Tamping down the peak warming that humanity will be forced to endure is a valuable function. It makes sense to reduce carbon dioxide emissions and emissions of methane and other ''short lived'' pollutants as illustrated by Shoemaker et al. (2013).

The 1 MWh substitution of natural gas for coal that is at the heart of this analysis is appropriate for consideration of substitutions made on the margin. Put differently, the results are applicable to operating decisions about what existing units to run. A different calculation is needed for the question of investment of a new plant and then again for the question of systemic change. At the plant level, it would be necessary to consider the lifetime and duty cycle (how the plant is operated). For example, using a 20-year GWP for methane

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impacts from a plant running for 30 years stretches the relevance of that GWP to a 50-year period (see Alvarez et al. for relevant discussion). At the system level, it is necessary to factor in the pace of turnover: how fast coal plants are retired and replaced with natural gas.

An important concern is the issue of technological lock-in. Generators and infrastructure last for many decades. Looking at the historical experience for retired natural gas plants, Davis et al. (2010) find the average lifetime of natural gas plants to be 36 years. There is little reason to believe that plants built will operate for shorter timeframes, especially given expectations of lower future gas prices. Recently closed coal plants have been over 50 years old on average (Energy Information Administration, 2014c). Trembath et al. (2013) point out that the capital cost of natural gas is lower than coal, and argues that this makes natural gas less subject to inducing technological lock it. It is true that sunk costs create a political force that works against shut down. Plant owners assert to policymakers that ''it is only fair that we be allowed to keep running because we still have to recoup our investment.'' While there is a political element of how lock-in can occur, the economic decision to shut down is based on the variable cost and revenue on the margin, not the level of fixed capital costs. As long as revenue exceeds variable cost, with variable cost including the cost of fuel and other operation and maintenance cost, then plant owners have an incentive to continue operating.

While this work analyzes the relative impacts of coal as compared to natural gas, a broader perspective is needed to analyze the optimal path for the U.S. electricity sector. In some

instances, new investment in natural gas will be diverting investment from renewable energy or energy efficiency projects. There are also issues that need to be considered for natural gas plants that are used to balance renewable electricity. The frequent starts and stops, with part-loading and fast ramps, of such peaker plants results in higher effective heat rates (National Renewable Energy Laboratory, 2013), which in turn increase the relative importance of methane emissions in their fuel cycle emissions. To evaluate the optimal role for natural gas plants in renewables integration, alternative very-low-carbon options, such as storage, advanced demand-response, and wider balancing areas, must be considered.

The role for natural gas in national and international GHG emission scenarios is another important perspective for judging the relative value of natural gas for climate change mitigation. In advance of the Copenhagen meeting of the UN Framework Convention on Climate Change, President Obama set GHG emission reduction goals for the United States. These call for the reductions, relative to 2005 emission levels, of 17 percent by 2020, 42 percent by 2030, and 80 percent by 2050. Banks and Taraska (2013) conclude that natural gas for electricity generation in the U.S. must peak by 2030 in order to meet these reduction targets. Building on this work, James (2013) points out that 70 percent of U.S. natural gas electricity generators are less than 12 years old and calculates what type of scenario would enable such a peak by 2030. He concludes that this is achievable if the only new plants built are currently planned additions to the fleet, and if there is enforced retirement for plants over 45 years old.

Scientists and international negotiations have identified 450 parts per million of carbon dioxide equivalent (ppmCO_2e) as a target stabilization level for GHG concentrations in the atmosphere that provides a good chance of avoiding dangerous

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damages due to climate change. Using a suite of three different energy–economy–climate models, Levi (2013) analyzes the issue of whether natural gas can help achieve such a target. Levi finds that natural gas does not provide much assistance in achieving stabilization at 450 ppmCO_2e. The reason is that to achieve such a target, both coal and gas must be quickly phased out. Levi does find evidence that natural gas could have a useful role in stabilization at 550 ppmCO_2e.

Davis et al. (2010) use a more bottom-up approach to analyze the same question. They analyze global datasets on power plants and motor vehicles as well as household combustion to estimate the future emissions expected from the world's existing energy infrastructure. They find that emissions from the current existing infrastructure alone will not push global emissions above the 450 ppmCO_2e stabilization target. They estimate that current energy infrastructure, if not prematurely retired, would lead to stabilization of emissions at less than 430 ppmCO_2e. This leads them to conclude that there is little scope for adding new fossil fuel-fired infrastructure to the global mix.

VI. Conclusion

Natural gas proponents present it as the logical next step down the staircase of environmentally destructive energy. As the preceding discussion shows, more than incremental progress is needed when thinking about the future of the U.S. electricity system. Moreover, while natural gas is often hailed as a cleaner alternative, the reality is more complex. The research described in this article illustrates that when

there are opportunities to substitute for coal power on the margin, looking at GHG emissions alone, it likely makes sense under a wide range of circumstances. This is even before the criteria pollutant advantage of natural gas is considered. Nonetheless, it is important to emphasize the difference between running current plants more intensively and building out further infrastructure. If the case for new investment in natural gas is motivated in part by GHG mitigation then it is necessary to calculate cost per ton abated and to compare this to other alternative mitigation investments. Significant leakage in the methane system may not completely eliminate the GHG benefit of new gas over coal, but it will erode the relative climate benefit of natural gas as a GHG mitigation option.

Moreover, there is an urgent need to reduce both short-term and long-term GHGs. It is not enough that gas substitution for coal does no harm in the very long run. We need to be minimizing methane emissions including leakage from the natural gas supply in order to make short-term progress in averting increasingly severe impacts from climate change. Measurable impacts and economic damage are already occurring.

Though policymakers would benefit from less uncertainty about the rate of methane leakage from the natural gas system, enough is known to move forward with more regulations to drive emissions down. The federal government has put in place a ''green completion'' regulation for new wells, and Colorado has enacted the most wide-ranging rules targeting methane leaks. The Colorado regulation requires the use of infrared cameras to help with leak detection. Other emerging low cost-detection monitors and mobile fence line sampling technologies offer promise for more quickly identifying leaks, their source and magnitude. ARPA-e is aiming for low cost stationary methane detectors that would help identify leaks through

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continuous monitoring. Proven technologies and practices are available to plug natural gas pipeline and storage leaks and put an end to unnecessary venting of methane. In many cases, adopting such practices will provide financial benefits to the industry, as operators can capture gas for use on site or for sale. The newly announced White House strategy on methane emissions and five white papers on the topic from the EPA offer some indication that further federal efforts to staunch the leaks are on the way.■

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