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Benchmarking Natural Gas and Coal-Fired Electricity Generation in the United States

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Abstract: This study answers a critical question facing the energy sector in the United States: how does natural gas compare to coal as a climate change mitigation technique? Although natural gas burns cleaner than coal, methane leakage potentially undermines the climate benefits of fuel switching. This study investigates the impact of methane leakage using a novel plant-level lifecycle emissions inventory of greenhouse gas emissions associated with coal mining, transportation, and combustion at 337 existing coal power plants in the United States. Individual plant emissions rates ranged from 901 to more than 2,200 kgCO2e/MWh (100-yr GWP); generation-weighted average was 1,046 kgCO2e/MWh. Our study finds that the "breakeven" leakage rates for natural gas to have short and long term climate benefits over coal range from 4.4-20.9%, depending on the timeframe, plant efficiency, and upstream coal emissions. Emissions benefits can be maximized by replacing highest emitting coal plants with new natural gas plants. Finally, we find fugitive methane emissions can limit carbon reductions from natural gas carbon capture; above 2% leakage, methane leakage reduces CCS benefits by up to half for 20-yr GWP.

Keywords: upstream emissions, methane leakage, emissions intensity

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1. Introduction

In the United States, surging natural gas production from the shale revolution has led to a dramatic increase in the use of natural gas to create electricity. Between 2008 and 2014, the amount of natural gas delivered to power plants grew 22.2%, displacing significant amounts of coal. [1] As natural gas is less carbon intensive when combusted than coal, this increase has major potential greenhouse gas ramifications for the United States and globally. In recent years, however, multiple studies have found that methane leakage from natural gas infrastructure could jeopardize these climate benefits. [2,3,4] Methane is a more potent greenhouse gas than carbon dioxide, meaning even small leaks can greatly impact the climate attractiveness of the use of natural gas compared to coal in the power sector.

To examine the attractiveness of natural gas, it is critical to identify how methane leakage and other potential factors influence lifecycle greenhouse gas emissions. Alvzarez et.al. found that the time frame over which climate impacts occur is critically important, with shorter time frames less favorable to natural gas. [2] Zhang et. al. similarly found that time frames are important, but also determined that plant efficiency is a critical factor shaping potential benefits of coal to natural gas fuel switching scenarios. [5] In examining emissions at coal power plants specifically, Whitaker et. al. found that variations in combustion emissions and coal mine methane emissions influence the lifecycle greenhouse gas profiles of coal generating units, with large potential variations between individual power plants. [6] Heath et. al., found that harmonizing natural gas lifecycle emissions estimates reveals that natural gas leakage is similar from both conventional and unconventional (shale) wells in the United States. [7]

Multiple studies have found that the key variables influencing the coal versus gas question are plant efficiency and leakage rate. Hausfather found that, with a 100-yr GWP, leakage rates for natural gas plants to equal plants were between 5.2%-9.9%; these values were calculated with a range of assumed electricity generation efficiency. [8] Meanwhile, Lueken et. al. found that replacing all US coal plants with natural gas plants could impact net power sector emissions by -50 to +5% depending on methane leakage rates and the efficiency of replacement natural gas. [9] In finding US LNG exports could reduce emissions by replacing foreign coal generation, Abrahams et. al. conducted an uncertainty analysis further highlighting that variations in plant efficiency plays a large role in shaping ultimate lifecycle benefits. [10]

These studies have identified the variables that might impact the lifecycle emissions of natural gas compared to coal. However, they have not examined how characteristics of the existing fleet impact breakeven leakage rates. More precisely, their results only examine either hypothetical coal plants with assumed efficiencies or real life coal plants taken at an aggregate, not individual, level. They do not examine the climatic ramifications of replacing specific existing coal-fired power plants with likely natural gas options.

The actual climate dynamics associated with fuel switching the existing generating fleet in a specific country are considerably more complex than the results of these studies imply. The United States provides a good example. Almost the entire U.S. coal-fired generation fleet was built decades ago, and low natural gas prices and environmental regulations have virtually halted the construction of new coal fired power plants. While most coal comes from surface mining, a substantial portion comes from underground mining, leading to major potential ramifications for lifecycle methane emissions for an individual coal units depending on their direct coal source.

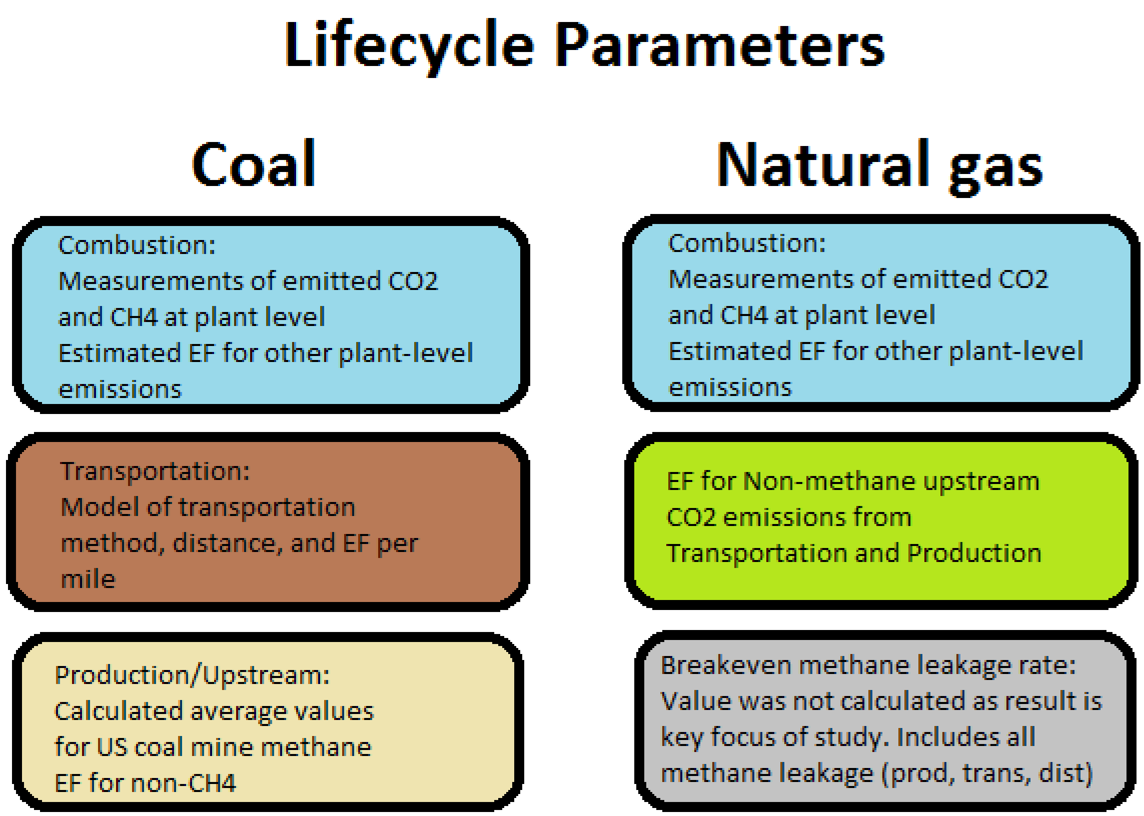
Meanwhile, most natural gas electric generating capacity in the U.S. has been built in the last fifteen years. New capacity is also being added constantly. As these plants were built recently they have benefited from recent efficiency gains in generating technology, leading to a relatively efficient natural gas fleet overall. The emissions associated with both the existing coal fleet and natural gas fleets in the United States could thus vary considerably. Existing studies do not explicitly account for how this variation impacts fuel switching scenarios when assessing the implications of methane leakage. This variation, however, is critical for determining how methane leakage in a specific country will impact the climate benefits of switching from coal to natural gas. In particular, understanding how fuel switching within a specific generating fleet provides better insight into the temporal nature of fuel switching.

To develop a more rigorous framework for analyzing the climatic benefits (if any) of coal to gas fuel switching, this study asks: how does natural gas compare to coal when actual emissions at existing or proposed plants in both sectors are accounted for? To answer this question, we develop a first-of-a-kind plant level lifecycle emissions inventory of existing coal fired generation for 2009 in the United States. Emissions from plants in this inventory are compared to three types of natural gas plants: the average existing plant, a new combined cycle plant, and a combined cycle plant using carbon capture and storage (CCS). We find that the relative inefficiency of the existing coal fleet and upstream emissions associated with coal mining indicate that climate mitigation benefits from switching to natural gas may be greater than previously realized. Further we find that the use of an inventory analysis reveals a striking temporal implication: coal-fired power plants with the lifecycle greenhouse gas emission rates are likely to be replaced first. Accordingly, the effect of a specific level of methane leakage from natural gas infrastructure on the climate advantages of natural gas over coal vary over time.

2. Materials and Methods

This section of the study briefly justifies our selection and compilation of data, our temporal focus on 2009, and our use of 20-yr and 100-yr GWP values.

Each coal plant in our inventory includes emissions from generation, coal mining, and transportation, using data developed from individual plant statistics and information from the U.S. Environmental Protection Agency and Energy Information Administration. [11,12] Natural gas combustion emissions are also taken from the EPA and EIA. [11,12] This means that this study only compares upstream methane, transportation, and combustion emissions for coal-fired power plants with upstream methane and combustion emissions at natural gas-fired power plants. Our primary criteria for including a coal power plant was if it was represented in both EPA and EIA data sets, leading to coverage of the vast majority of the U.S. coal fleet.



These are generally the largest contributors to annual emissions. However, there are many emissions not considered, including those associated with: carbon dioxide venting in natural gas infrastructure, pollution control equipment at coal plants, energy used for extracting coal and natural gas, construction or demolition, and maintenance activities, among others. The magnitude of these factors is much smaller than upstream methane and combustion emissions, and is harder to calculate on a plant-by-plant basis. Therefore, considering these data limitations, we have excluded these factors from our analysis. Excluding these factors is consistent with the conclusions in Whitaker et. al. that indicated that first order LCA GHG emissions can be calculated for an individual coal-fired power plant based on knowledge of thermal efficiency and coal mine source. [4] While including all factors would provide a more precise accounting of complete lifecycle emissions, they would at least partially offset each other and are not likely to impact this study's conclusions.

While combustion emissions at each plant are based on reported data, upstream and transmission emissions are estimates based on a model of historical deliveries and estimated transport distances for each coal plant.

We derived emissions from coal mining by determining the average emissions for underground and surface mines based on EPA's inventory of greenhouse gas emissions and EIA's coal production. [13] In particular, EIA data indicates from which specific coal mines each coal-fired power plant in the United States received its coal from during 2009, and whether that coal was from surface or underground mines. Notably, coal can be stored on site for several months, making exact attribution of coal mine source difficult. Nevertheless, annual deliveries provide an appropriate proxy with which to assess the relative contribution of emissions at different upstream stages. Our calculations determined that coal mined at underground mines had an average emission of 7.9 kgs of methane per ton while coal mined at surface mines had an average emission of 1.0 kgs of methane per ton. If a plant's coal source was uncertain, a production-weighted average was used.

Transportation emissions were estimated through a model that combined transport method with estimated distances between the state where the coal was mined and where it was burned. Both the mine location and coal plant location were determined using EIA data. Distance between the states was calculated using "as the crow flies" distance between the two states (thus, transportation emissions are likely somewhat under counted as direct paths were likely longer). Distances were multiplied by EPA transportation emissions factors for specific transportation technologies (rail, barge, truck) to develop transportation related emissions for each coal plant.

For coal produced and consumed in the same state a small, nominal value was used to estimate emissions.

In developing our plant level lifecycle analysis of the U.S. coal fleet, we decided to only focus on 2009. Although the U.S. generation mix has since shifted away from coal, 2009 provides a good benchmark year to examine climate benefits as it was when the existing coal fleet began to be replaced by natural gas rapidly.

As previously mentioned, the short-term high radiative forcing of methane makes the time selection critical to assessing the greenhouse gasses associated with fuel switching. This study uses 20-yr and 100-yr GWP values for three greenhouse gases (carbon dioxide, methane, and nitrous oxide), as these values provide an accepted method to compare both short and long term climate impacts. [14] Using two sets of GWPs more accurately captures methane's impacts over different timeframes. Our GWP values are from the most recent 5th IPCC Assessment.

When comparing coal and natural gas emissions at specific power plants, we calculate breakeven leakage rates. The breakeven leakage rate is the specific amount of methane leakage that would have to occur to make lifecycle emissions from the natural gas plant equal to the lifecycle emissions from the coal plant over a specified time interval. After we have calculated breakeven leakage rates for individual plants, we need an estimate for upstream leakage to assess potential climate benefits. However, considerable uncertainty remains about what leakage rates actually are in the United States. Although various studies have looked at leakage in individual basins, Brandt et. al. has comprehensively examined national methane emissions. [4] While Brandt et. al. did find that methane emissions from all sources exceeded EPA's inventory, the authors were unable to determine how much of this was due to natural gas leakage. In order to assess potential climate benefits, Brandt et. al. developed a worst case scenario estimate of methane leakage at

3.6-7.2% of natural gas production, which we use to judge the benefits of fuel switching individual plants. The actual methane leakage rate remains unknown and subject to significant uncertainty and variability. Using this worst case scenario range estimates allows a bounding of the potential climatic downsides from switching to natural gas. Importantly, this 3.6-7.2% range represents emissions from all natural gas infrastructure – many natural gas power plants connect directly to interstate pipelines and thus do not have experience methane leakage from distribution infrastructure.

3. Results and Discussion

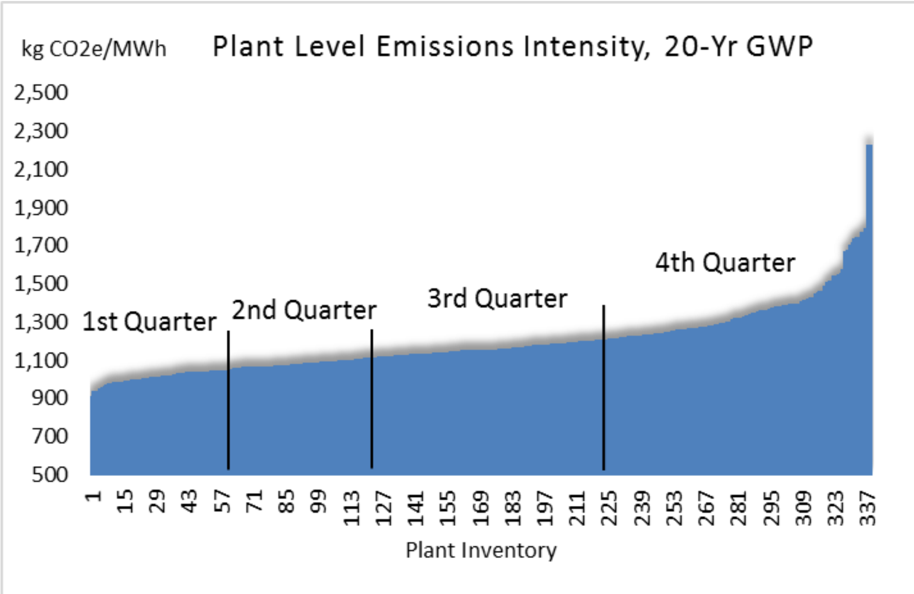
3.1. Estimating Emissions from the Existing Coal Fleet

Combining plant level combustion emissions with our upstream and transport models documented lifecycle carbon dioxide, methane, and nitrous oxide emissions per MWh at 321,078 MW of coal-fired facilities, responsible for 91.5% of coal generation in the United States in 2009. The generation-weighted average intensity for coal-fired plants in the inventory was 1,114 kg CO2e/MWh for a 20-yr GWP and 1,046 kg CO2e/MWh for a 100-yr GWP.

As Figure 1 reveals, there was considerable variations between plants; on a 20-year basis, the best plant produced 901 kg CO2e/MWh while the worst plant was almost double that at 2,213 kg CO2e/MWh. Generation was heavily weighted towards the less carbon intensive plants, largely a reflection of better heat rates. There was a particular drop off in generation from individual coal plants that had the highest lifecycle carbon intensities (of above 1,270 kg CO2e/MWh).

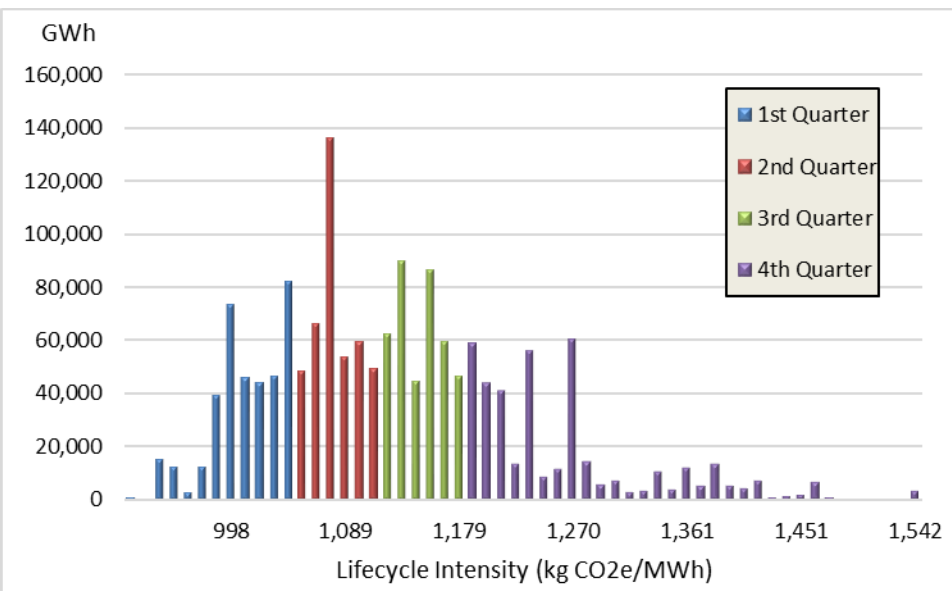
Figure 1. Partial Lifecycle Emissions Intensity Inventory for U.S. Coal Fleet, 20-Yr GWP

A. Plant Level Inventory Weighted by Emissions Intensity



Note: The generated-weighted average intensity for the top quarter, 2nd best, 2nd worst, and worst quarter of coal plants are indicated.

B. Generation by Emissions Intensity Level, by Plant Quarters



In aggregate, the coal-fired power plants in our inventory were responsible for a total of 1,866.7 million metric tons of CO2e in 2009, on a 100-year basis. While not an exact comparison, this represents around 27.5% of US emissions in 2009 (the comparison is not exact as it compares emissions calculated using GWP values from IPCC's 5th Assessment with EPA's national greenhouse gas inventory, which uses GWP values from a previous IPCC report. Nevertheless, the comparison provides a good indicator).

Our analysis revealed that two major factors affect the variations in lifecycle emissions at individual plants: plant efficiency and coal source. This is consistent with Whitaker et. al.'s previously mentioned conclusions. [6] Transport method and distance were relatively small contributors to emissions at most plants but were notably large factors at a select few power plants.

Combustion emissions constituted the majority of emissions at all plants in this study's inventory. Most of the U.S. coal fleet was built decades ago and are much less efficient than newly built units. The average plant produced 987 kgCO2e/MWh of combustion related emissions, responsible for 88% of total lifecycle emissions (using a 20-year GWP basis). Plant efficiency was the major cause for variation in combustion-related emissions, with more efficient plants having better heat rates and a lower carbon dioxide emission intensity. Variations in efficiency were also responsible for most of the differences in overall GHG emissions between individual plants. Combustion emissions constituted 90% or more of short-term emissions at more than 57% of plants in the inventory. Even at the worst plant, combustion was still responsible for 69% of short-term emissions, indicating its dominant role across the whole fleet.

EPA estimates indicate that coal mining and preparation led to the emission of 3.3 million metric tons of methane nationally in 2009, a substantial portion of US energy-related methane emissions. [10] There are two major types of coal mining: underground and surface (which includes mountaintop removal and valley fill operations, strip, and open pit mining).

Underground mining is very emission intensive when it comes to methane – despite being the source of only 31% of U.S. coal, underground mines are estimated to be responsible for 83% of methane from coal mining in the United States. [33] Emissions from underground mines have a high level of certainty as methane at individual mines is tracked by the Mine Safety and Health Administration, due to safety concerns. [13] Surface emissions have more uncertainty as they are based on basin specific emissions factors and not measurements at individual mines. [13]

Our analysis documented that upstream emissions in this inventory were responsible for 10.6% of emissions on a 20-year basis and 4.5% of long term emissions on a 100-year basis. Upstream methane emissions were responsible for virtually all of the difference between 20-yr GWP and 100-yr GWP total emissions at the average power plant. The plants with the largest share of upstream emissions used predominantly coal from underground mines. As underground coal is less prevalent than surface coal, this led to a skewed distribution of the share of upstream emissions towards a smaller number of plants. These results clearly indicate that switching an individual coal plant in the United States from underground to surface coal will significantly reduce its associated lifecycle 20-year GWP emissions. Further research could explore how the recent shifts towards using PRB coal (mined from the surface in Wyoming) in place of Appalachian coal (the primary source of underground coal in the United States) has impacted changing emissions at individual coal plants.

Our final emissions source was transportation. In order to be burned to produce electricity, coal must be transported from where it was mined to coal-fired generators. There were two major factors that influence transportation related emissions at a plant: transportation method and distance. In the United States, coal is transported by many sources, including railroads, boats, trucks, and conveyor belts. Railroads and barges are the most common and transport coal the farthest. Trucks usually transport coal short distances while conveyor belts are used to transport coal from the mine mouth to proximate coal plants.

Transportation-related greenhouse gas emissions were the least important factor in emissions intensity at the average coal plant in our inventory, at only 1.3% of short-term and 1.4% of long-term emissions. However, transport emissions were particularly high at a small number of power plants located far away from distribution centers. For nineteen plants in our inventory, transportation emissions were responsible for more than 5% of total lifecycle greenhouse gas emissions.

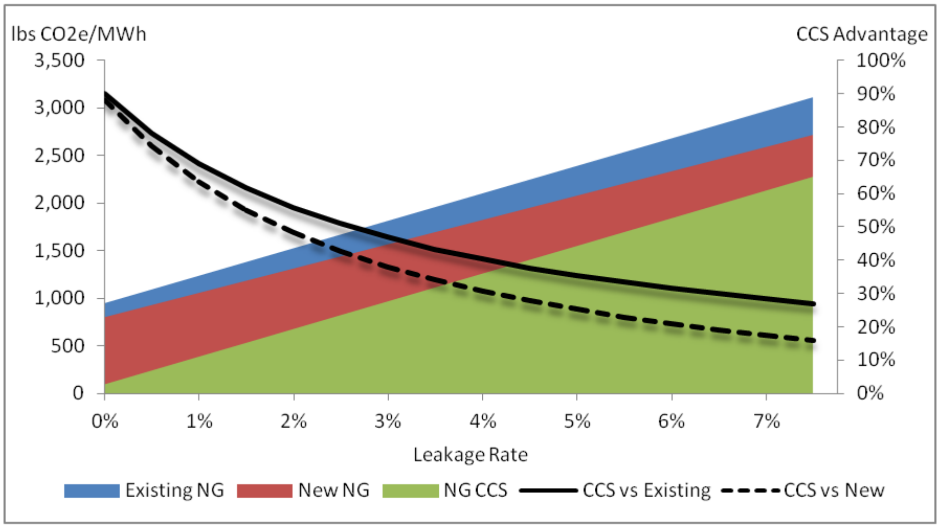
3.2. Estimating Emissions from Natural Gas Substitution

Assessing the benefits of fuel switching from coal to gas depends on the heat rate efficiency of natural gas-fired generation. As the existing coal fleet would be replaced over many years in a fuel switching scenario, there are several types of natural gas plant that could substitute for coal. Most of the existing natural gas generation fleet in the U.S. has been built in the last fifteen years. As such, due to technological development, the average existing natural gas power plant is relatively efficient, with an emissions intensity of 427 kg CO_2/MWh. [8] New natural gas plants are also likely to be built and are even more efficient; a modern natural gas combined cycle (NGCC) emits only 362 kg CO_2/MWh. [15] Notably, further improvements are already reducing the combustion emissions rates from new natural gas combined cycle power plants – this means that the efficiency at an individual plant in the future will likely be even higher, though this study does not account for this. Finally, although not currently feasible, natural gas combined cycle power plants could eventually employ carbon capture and sequestration (CCS) to limit carbon dioxide emissions. At a 90% capture rate, a natural gas combined cycle with CCS directly emits only 42 kg CO2/MWh. [15]

The use of carbon capture and storage (CCS) at natural gas power plants has received less research and attention compared to coal. However, natural gas with CCS has significant potential to reduce emissions and has several advantages compared to coal. The major barrier to coal with CCS is significant efficiency penalties of 38-40% for coal boilers, leading to higher fuel and operating costs. [15] Due to reduced carbon volume and cleaner flue gas emissions, CCS for natural gas only has an efficiency penalty of 17%, with associated lower capital and operating costs. [15] While not immediately likely to be built, natural gas combined cycles with CCS have the potential to replace coal generation in the United States in the longer term, and are thus included in our analysis.

To fully test the emissions associated with replacing coal with different types of natural gas generators in the United States, we compared emissions from existing natural gas plants, new NGCCs, and new NGCCs with CCS at different methane leakage rates. As demonstrated in Figure 2, the lifecycle emissions advantage of CCS for natural gas compared to non-CCS natural gas plants is very sensitive to the rate of methane leakage. This advantage shrinks rapidly at low rates of leakage. For example, at a 1% leakage rate and with a 20-Yr GWP, a NGCC using CCS emits 70% less lifecycle emissions than a new NGCC. At a 3% leakage rate, however, using CCS only reduces short term lifecycle emissions by 50%. Notably, Figure 2 examines short term impacts (20-Yr GWP); the CCS advantage is more pronounced and less sensitive to leakage rates when using 100-Yr GWPs, but is still significant. This point is critical as it indicates that natural gas employing carbon capture is only likely to drive major climatic benefits when methane leakage rates are minimized.

Figure 2. Emissions Profiles of Natural Gas Plants at Different Leakage Rates, 20-Yr GWP



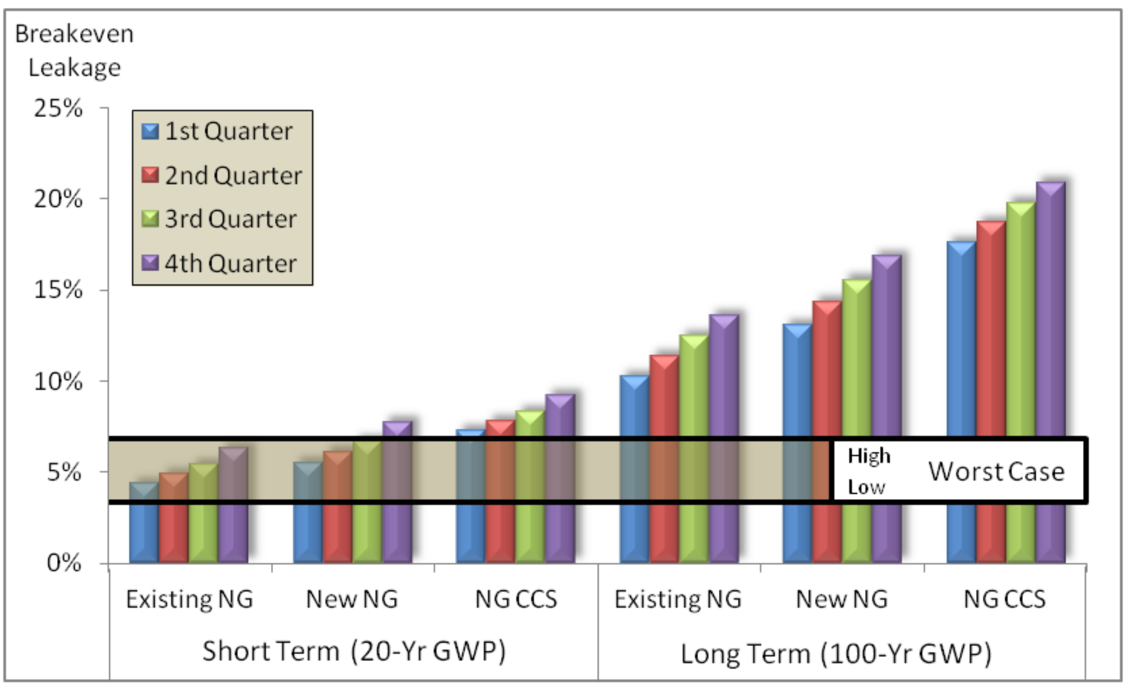
Note: CCS Advantage refers to the emissions reductions from using a NGCC CCS plant compared to an existing NG plant (solid line) and a new NGCC (dashed line). The lines "CCS vs Existing" and "CCS vs New" are plotted on the right axis.

3.3. Estimating Methane Leakage and Replacement Scenarios

Comparing emissions intensities at existing coal fired power plants with the suite of natural gas replacement options yields a large range of breakeven leakage rates (i.e. the leakage rate at which the emissions from natural gas equals that of coal over a specific time frame). Breakeven rates over all time frames range from 4.4%, for replacing the best quarter of coal plants with the average existing gas plant, to 20.9%, for replacing the worst quarter of coal plants with a natural gas CCS plant. The most indicative metric for current fuel switching in the United States in the short term is likely replacing the average existing coal fired power plant with a new natural gas plant; the breakeven rate for this replacement when using a 20-Yr GWP was 6.5% while the rate using a 100-Yr GWP was 15%.

The breakeven leakage rate depends on three primary factors: the emissions efficiency of the replaced coal plant, the type of natural gas plant, and the timeframe (See Figure 3). To assess the climate impacts of plants with different emissions intensities, we divided the existing coal fleet into generation-weighted quarters – the best quarter, the 2nd best quarter, the 2nd worst quarter, and the worst quarter. The breakeven leakage rate associated with each quarter varied meaningfully among different replacement scenarios. Over the short-term (20-Yr GWP), the breakeven rate for the worst quarter was 2.0-2.2% higher than the best quarter, regardless of the replacement natural gas. Over the long term (100-Yr GWP), the range was higher, at 3.3-3.8%. This variation clearly illustrates the importance of plant level lifecycle inventories in a specific country and examining coal plants with multiple emissions profiles.

Figure 3. Breakeven Leakage Rates for Replacing Existing Coal Plants with Natural Gas



Note: Breakeven leakage rates for each type of natural gas plant are compared against the existing coal fleet, divided into quarters based on their emissions intensity. The Worst Case box identifies the range of the worst case leakage scenario from Brandt et. al. Actual leakage rates are almost certainly lower, as explained in the text.

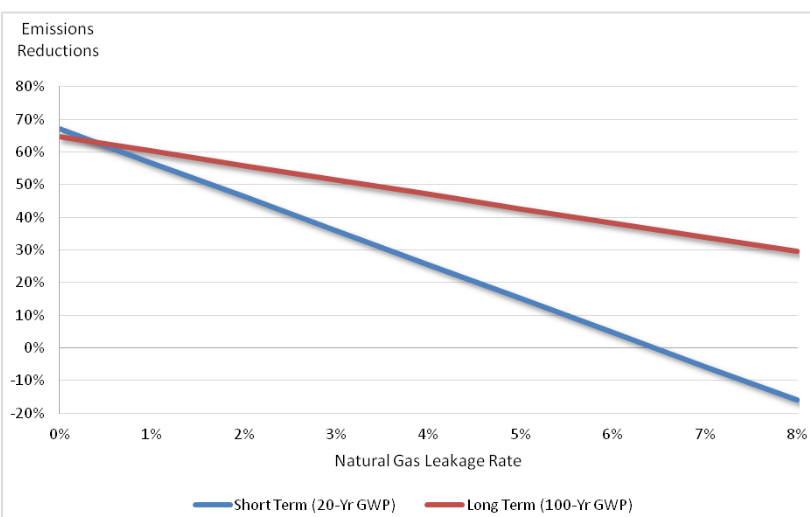
Breakeven leakage rates varied tremendously depending on the type of gas plant. The average existing natural gas plant consistently had the lowest rates, indicative of their higher carbon intensity relative to new NGCCs and NGCCs with CCS. Similarly, leakage rates for replacement with a CCS plant were the highest, due to very low emissions from the combustion process – notably, the breakeven leakage rates for CCS replacement were greater in longer term scenarios compared to other NG sources.

A coal plant's emission intensity is correlated with the cost of running the plant. Less efficient plants consume more coal, cost more to run, and have higher combustion emissions. Underground coal generally costs more than surface mined coal, in addition to having higher methane emissions. Plants where transportation was a large emission factor moved the coal a very long distance, leading to higher transport costs. Higher costs for more emission intense coal plants will likely lead to these plants being replaced first. Notably, plants in the worst half of the inventory were more likely to have retired or announced retirements for one or more units than plants in the best half of the inventory. Therefore, the initial breakeven leakage rate for replacement with a new natural gas plant is likely to be closer to the worst half of coal plants, at 7.2% in the short term and 16.2% over the long term. Replacing these plants will likely take some time; it could be many years before the breakeven leakage rate for the replaced fleet actually approaches the average.

To compare this study's breakeven leakage rate against leakage estimates, this study uses the worst case scenario developed by Brandt et. al. [4] At the low end of the range, 3.6%, we find that all coal to gas replacement scenarios have climate benefits using both a 20-year and 100-year GWP. The situation is less clear at the upper end of the range, 7.2%. Over the long term (100-yr GWP) at a 7.2% leakage rate, natural gas is better than coal in all scenarios. Over the short term (20-yr GWP) at a 7.2% leakage rate, natural gas is better than coal when using CCS and when replacing the worst quarter of existing coal plants with a new natural gas plant. However, this does not indicate that coal is better than natural gas for the other scenarios or for use in other sectors, such as industrial use or heating. This last point is important: as our study is limited to coal and natural gas competition in the electricity sector, the implications of coal to natural gas fuel switching in other sectors is not examined.

While there may be climatic benefits at current real world leakage rates, reducing leakage will still lead to much larger climate benefits. As demonstrated in Figure 4, decreasing leakage rates by 1% will increase emissions reductions from a fuel switch in an indicative scenario (existing coal with new gas) by 10% when looking at a 20-Yr GWP and by 4% when looking at 100-Yr GWP.

Figure 4. Emissions Reductions for Fuel Switching at Different Leakage Rates



Note: Short and long term reductions are displayed for a new natural gas plant replacing the average existing coal power plant. Reductions would generally be lower for an existing natural gas plant and higher for a natural gas CCS plant.

4. Conclusions and Policy Implications

Our analysis of the fuel switching implications of natural gas and coal in the United States results in three primary conclusions.

First, in examining fuel switching scenarios, the use of a plant-level lifecycle emissions inventory for individual countries offers a new and insightful approach to lifecycle analysis. Segmenting the plants to be replaced and replacement options provides a greater understanding of fleet dynamics and better guides policy decisions. For the purposes of this study, we specifically found that replacing the worst half of coal has noticeably higher climate benefits and breakeven leakage rates.

This has major temporal ramifications as the worst half of coal plants in the United States are likely to be replaced first; methane leakage for natural gas infrastructure could thus be higher in the short term and there could be notable climate benefits if natural gas is replacing coal. Notably, these potential short term benefits are a result of the high number of natural gas combined cycle power plants in the United States, which increase the average efficiency of natural gas units. As such, the benefits of natural gas replacement in other countries could vary significantly – further studies in other countries could identify how the lifecycle emissions for specific coal and natural gas fleets vary and impact environmental outcomes. Similarly, further study of fleet emissions profiles after 2009 could provide improved insights into temporal tradeoffs, changing utilization rates at individual power plants, and other developments in nationwide lifecycle emissions.

Our second conclusion is that replacing existing coal plants in the United States with new and existing natural gas plants has significant short (20-yr GWP) and long term (100-yr GWP) climate benefits. This study determines that natural gas is better over the long term in all scenarios and better over the short term in most scenarios. Only under very extreme, unlikely assumptions does methane leakage impact the emissions benefits of fuel switching in the short term. As leakage rates still retain a high degree of uncertainty and variability, balancing replacement of coal with different types of natural gas power plants reduces the risks of transitioning to gas. The least risky pathway involves replacing the worst coal plants with existing natural gas, followed by new natural gas combined cycles, and eventually natural gas with CCS. Plant-level lifecycle emissions inventories can similarly be used to address other climate policy dilemmas at the national or sub-national level.

Third, ongoing efforts to reduce methane leakage offer perhaps the single best approach to further enhance the climatic benefits of natural gas, and to ensure that it remains more than an ephemeral (and possibly dangerous) bridge to climate protection. One report identified large cost effective opportunities related to leak detection and repair, reduced venting of associated gas, and replacement of high-emitting pneumatic devices. [16] New green completion rules developed by the EPA to control volatile organic compounds are also expected to drive reductions of methane emissions. [17] We find that applying CCS to natural gas plants is a key way to manage concerns about methane leakage for fuel switching. Higher rates of methane leakage lead to much lower benefits compared to traditional natural gas generation, especially in the short term.

In sum, fuel switching from coal to natural gas works best as a climate mitigation tool when accompanied by better leakage control, green completions, and carbon capture, and when coal plants with the worst lifecycle emissions are replaced first.

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