Upstream Emissions of Coal and Gas

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Executive Summary

This report consolidates scientific research and estimates emissions factors for the upstream greenhouse gas emissions of natural gas and coal for The Sierra Club. Upstream greenhouse gas emissions are defined as the greenhouse gas emissions produced during the extraction, processing, and transportation of fossil fuels from their original state underground, to the point of combustion at a power plant or distribution at a city gate. As the national energy landscape transitions from coal towards natural gas production, our research offers timely insight into the true emissions-cost of both fuel types, with particular attention to methane. According to the IPCC 2014 Report, methane is 86 times more potent than carbon dioxide in the first twenty years after it is released. In the first 100 years, it is 34 times more potent.

Our consulting project was to identify and quantify upstream greenhouse gas emissions linked with the electricity sector in equivalent terms of per-unit energy generation; assess regional differences in the coal and natural gas upstream supply chains; recommend a robust method for upstream emissions accounting; and construct a model of our findings. Our analysis identifies regional and technological nuances, as well as potential natural gas super-emitters via satellite data. Each of these variations and/or outliers can jeopardize the accuracy of overarching regional and national leakage rate assumptions.

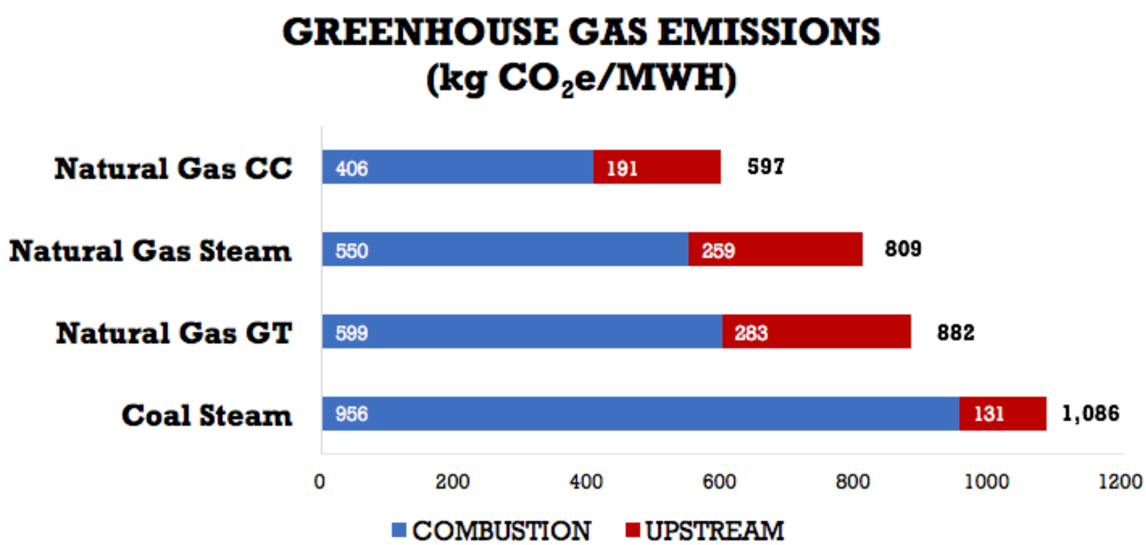

Figure 1. Combustion and estimated upstream greenhouse gas emissions for Natural Gas and Coal for electricity.

This report includes a recommendation for how to account for upstream emissions. The recommendation is based on a methodological approach that will better allow studies to be compared to one another and weigh the results of the studies. Based on the recommended methodology and weighting system, this report finds that the CO_2e emissions per megawatt hour of natural gas burned is 597 for combined cycle power plants and 882 for gas turbine plants. The CO_2e emissions per megawatt hour of coal burned is 1,086.

Contents

Acronyms

SOURCE: WWW.BROOKINGS.EDU/WP-CONTENT/UPLOADS/2016/12/METRO_20161205_COAL_MINE.JPG

CH_4: Methane

CO_2: Carbon dioxide

CO_2e: Carbon dioxide equivalent

EDF: Environmental Defense Fund

EF: Emissions factor

EIA: U.S. Energy Information Administration

EPA: U.S. Environmental Protection Agency

GHG: Greenhouse gases

GHGI: Greenhouse Gas Inventory

GWP: Global warming potential

IPCC: Intergovernmental Panel on Climate Change

LCA: Life cycle analysis

MMBTU: Million British thermal units

MCM: Thousand cubic meters

NASA: National Aeronautics and Space Administration

NETL: National Energy Technology Laboratory

NG: Natural gas

NOAA: National Oceanic and Atmospheric Administration

NREL: National Renewable Energy Laboratory

SAFR: South Appalachian forest region

WRI: World Resource Institute

UNFCCC: United Nations Framework Convention on Climate Change

1. Introduction

1.1 History and Context

On December 12, 2015, nearly 200 countries came to the historic consensus that climate change is a global threat, requiring the end of reliance on fossil fuels as the primary engine of economic growth.[1] Signatory countries aspire to keep global temperatures from rising more than two degrees Celsius, with individual countries required to submit and periodically revise their climate commitments. The United States represents a quarter of the total global greenhouse gas emissions annually. It can provide leadership and inspiration on the global stage. The U.S. electricity sector embodies the most national emissions, and within the electric sector, coal and natural gas combustion are the major components.[2] Therefore, in order to meet these goals, the United States must decarbonize its electricity sector to address climate change quickly and efficiently.

Despite the increasing necessity to move towards a decarbonized future, the U.S. clean energy revolution faces political, ideological and economic hurdles. The Sierra Club's Beyond Coal Campaign is committed to help chart the country's path away from fossil fuels and towards affordable, clean energy. The campaign has become a leader in encouraging the closure of old, dirty power plants through its focus on data-driven economic reasoning and grassroots litigation. At the time of this report's release, the campaign has contributed to the retirement of more than 250 dirty power plants.[3]

1.2 Project Purpose

The Sierra Club requested Columbia University's Environmental Science and Policy program's workshop group to conduct research on existing literature pertaining to upstream emissions of gas and coal as well as to provide a recommendation of how to account for upstream emissions. This report consolidates scientific research and estimates emissions factors for the upstream greenhouse gas emissions of natural gas and coal. Upstream greenhouse gas emissions are defined as the greenhouse gas emissions produced during the extraction, processing, and transportation of fossil fuels from their original state underground, to the point of combustion at a power plant or distribution at a city gate.[3] Our consulting project was to identify and quantify upstream greenhouse gas emissions linked with the electricity sector in equivalent terms of per-unit energy generation; assess regional differences in the coal and natural gas upstream supply chains; recommend a robust method for upstream emissions accounting; and construct a model of our findings. In a field hampered by a lack of standardization and data variability, our report

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[1] Goldenberg, S., Vidal, J., Taylor, L., Vaughan, A., & Harvey, F. (2015). Paris climate deal: Nearly 200 nations sign in end of fossil fuel era. *The Guardian*.

[2] Klein, D. E. (2016). CO_2 emission trends for the US and electric power sector. *The Electricity Journal*, *29*(8), 33-47.

[3] http://content.sierraclub.org/coal/victories#

and model offers a consolidated comparison and analysis of standardized emissions rates. The model helps fill in the full lifecycle emissions calculations for both coal and gas as electricity sources to enable better informed policy decisions as our nation transitions towards a renewable fuels future.

2. Background

Anthropogenic climate change refers to alterations in global climate patterns and is attributed to increased levels of atmospheric greenhouse gases produced primarily by the use of fossil fuels. A major driver of global climate change is carbon dioxide, a byproduct of fossil fuel combustion, and is released during various stages of fossil fuel production and processing. Although methane is referenced less in relation to climate change, it is an even more potent greenhouse gas. It is the primary component of natural gas, representing roughly 98 percent of pipeline-quality gas, and methane emissions are leaked during coal mining and throughout the natural gas supply chain. In total, there are six major greenhouse gases that vary in climatic impact due to differing Global Warming Potentials and atmospheric lifetime.

Our review of the scientific literature of coal and natural gas includes the upstream supply chain, the stages prior to combustion, and each segment's leakage potential; the methodologies used to conduct analysis; regional differences; and high-risk and identified specific sites of significantly higher and stochastic emissions, known as super-emitters.

2.1 Upstream Coal and Natural Gas Processes

Coal and natural gas *upstream* technologies and procedures impact coal and natural gas *lifecycle* greenhouse gas emissions. Coal production is resource-intensive, in terms of degradation of land and methods used to extract the resource, due to the industry's reliance on mountaintop removal, large-scale underground and surface mining operations, and cross-country rail transport. The use of coal for electricity generation has been decreasing over the past few decades; simultaneously, the production of natural gas has been increasing. This is mainly due to, but is not limited to, the improvement in technology and the efficiency of the extraction process of natural gas. Increased supply of natural gas has driven down the price of this fossil fuel considerably.

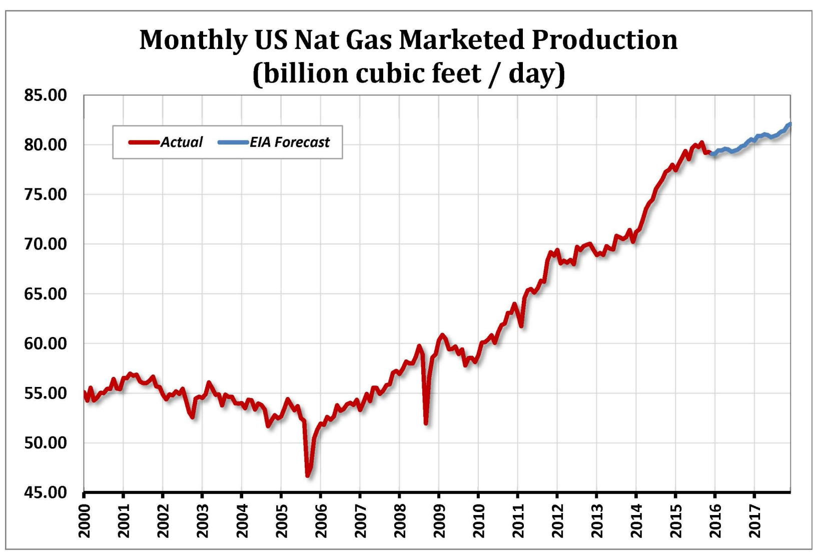

Figure 2. EIA 2017 Forecast for US Natural Gas Marketed Production.

Natural gas's "low-carbon" labeling persisted until soon after the boom in non-conventional gas extraction techniques, including hydraulic fracturing. As innovative technologies allowed shale formations to become the U.S.' fastest growing marginal supply source of natural gas, and increasing research indicated the significant methane leakage rates of these systems, researchers became wary about calling the fuel source "low-carbon." Researchers have since attempted to quantify how massive industry growth, extensive pipeline development and low regulatory oversight increases the chances for fugitive methane emissions.

Concern arises from methane's variable, but nonetheless high global warming potential. According to the IPCC 2014 Report, methane is 86 times more potent than CO_2 in the first twenty years after it is released. In the first 100 years, it is 34 times more potent. This estimate is an upward revision of the IPCC's 2007 calculations, which estimated methane at 72 times more potent in the first twenty years, and 25 times in the first 100 years. This revision between assessments impacts researchers' ability to easily compare chronological methane emissions estimates without additional standardization methodologies and conversions.

Methane is a major component of both coal and natural gas lifecycle emissions. Consequently, if upstream methane emissions are not accurately accounted for within shale natural gas upstream production, the U.S. natural gas supply could compromise its Paris commitments and expedite global warming. Presently, the total amount of natural gas upstream emissions remains ambiguous, and this project attempts to provide an assessment of best available findings.

2.2 Coal Supply Chain

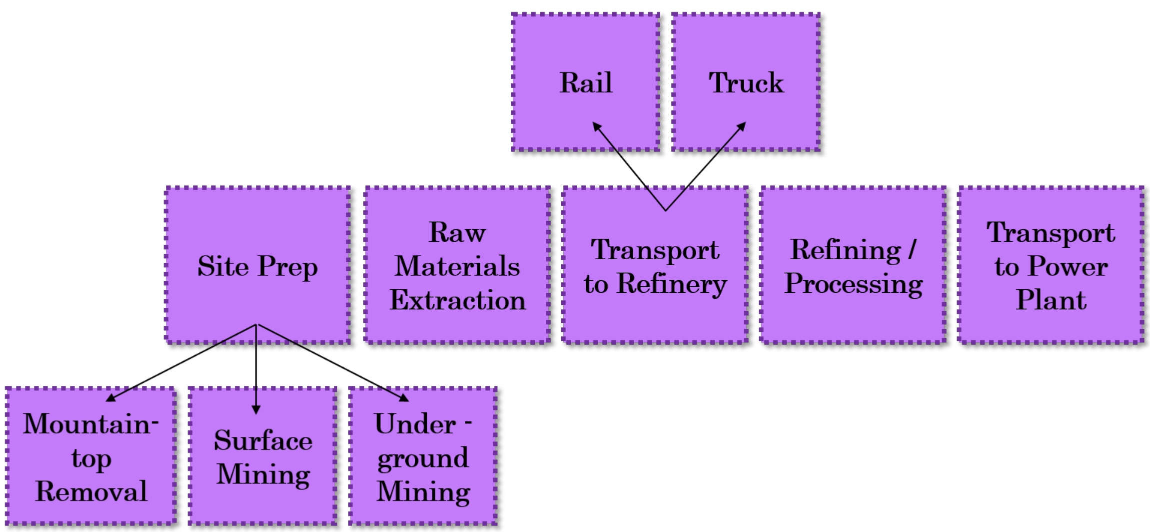

Figure 2. Our representation of the upstream coal supply chain.

Figure 3 depicts the coal upstream supply chain, beginning with site preparation. Besides combustion, the largest contributors to coal's life cycle emissions include mining and transportation to the power plant. Total greenhouse gas emissions are influenced by individual nuances such as age of infrastructure, type of coal mined, differing technologies used to process and refine the coal, and distance travelled from the site to the power plant.

2.3 Regional Differences in Coal Production

The most notable differences in U.S. upstream coal emissions are attributed to the extraction method deployed, the method's site preparation, and the heat content of the coal mined. While it is often difficult to pin down region-specific differences in upstream coal emissions, these variables offer a more accurate analysis of total upstream coal emissions, and align themselves within particular regions. Our assumptions for how we aligned these three variables into a geographical context are described within our comprehensive list of model assumptions (see 'Coal Assumptions').

Extraction methods offer a rational approach to classifying heterogeneity in total emissions within pre-production and production, as the process indicates the site's CO_2 and methane-intensity. Extraction method differences are elaborated within *Figure 4*. For example, on average, surface mining emits less methane than underground mining, but emits a greater percentage of total CO_2 due to large-scale land disturbance associated with the process. There are 305 total underground mines and 529 total surface mines in the U.S. today, according to the U.S. Energy Information Administration.[4]

Coal Extraction Methods		
	Surface Mining	**Underground Mining**
Standard Mining Methods	Strip mining, open-pit mining, and mountaintop blasting	Room-and-pillar and long-wall
Environmental Impact	Destroys large areas of land and natural habitat to recover coal	Destruction of land, surface subsidence, abandoned shafts, extensive surface spoil heaps, mine explosions, collapses and flooding
Percentage of Total U.S. Coal Mine Methane (EPA 2011)	22% or 911 thousand cubic meters	71% or 3,368 thousand cubic meters

Figure 3. Adapted from EPA 2011

Surface mining is a newer alternative to traditional underground mines and, first used in the 1960s, spiked in popularity after the 1973 and 1979 petroleum crises. This method of coal extraction is resource-intensive and often entails blasting away mountaintops to expose coal seams. On average, Kentucky and West Virginia use approximately 1,000 metric tons of explosives

[4] *Annual Coal Report 2015*. (2015). U.S. Energy Information Administration. https://www.eia.gov/coal/annual/pdf/acr.pdf

per day for surface mining.[5] In so doing, 502 mountain peaks have been removed. Such dramatic land disturbances result in cascading environmental consequences, including the burial of headwater streams, polluted waterways, alteration of landform shape and structure, and the creation of artificial stream channels and refuse settling ponds.[6]

Furthermore, surface mining preparation and production causes large-scale deforestation, impacting over 1.2 million acres of land.[7] A 2009 study by Fox and Campbell considered the greenhouse gas emissions associated with the terrestrial disturbances caused by mountaintop coal mining, and estimated the total disturbed forest carbon, including terrestrial soil and non-soil carbon. Focusing their research within the South Appalachian forest region (SAFR), they found that mountaintop removal has resulted in the loss of 6.8% of forests and production of 23.3% of the coal in the U.S. over the last two decades. They calculated that the weighted average of the carbon stocks for the SAFR includes 4.7 (+/- 0.1) kg C/m^2 and 11.1 (+/10.2) kg C/m^2 for the soil and non-soil carbon pools.[8]

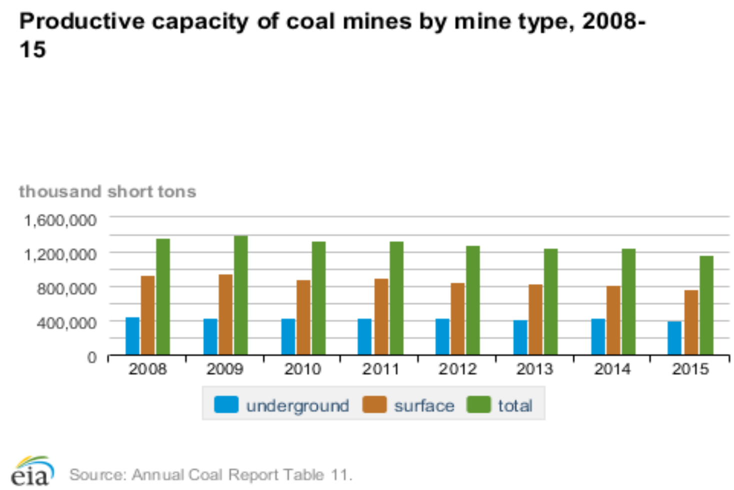

Figure 5. EIA, Annual Coal Report Table 11.

Underground mining is the more traditional coal extraction method. This process emits considerably more methane than surface mining because coal seams deep underground contain far greater methane than those closer to the surface.[9] *Figure 5* illustrates surface mining's dominance for coal production, as well as the industry's overall decline over time.

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[5] Kramer, D. A. (2001). Explosives. *U.S. Geological Survey Minerals Yearbook.*

[6] Ross, McGlynn, & Bernhardt. (2016). Deep Impact: Effects of Mountaintop Mining on Surface Topography, Bedrock Structure, and Downstream Waters. *American Chemical Society*.

[7] Ecological Impacts of Mountaintop Removal. Retrieved April 25, 2017, from http://appvoices.org/end-mountaintop-removal/ecology/

[8] Fox, J. F., & Campbell, J. E. (2010). Terrestrial Carbon Disturbance from Mountaintop Mining Increases Lifecycle Emissions for Clean Coal. *Environmental Science & Technology,44*(6), 2144-2149. doi:10.1021/es903301j

[9] Coal Mine Methane Developments in the United States. *United States Environmental Protection Agency*.

2.4 Natural Gas Supply Chain

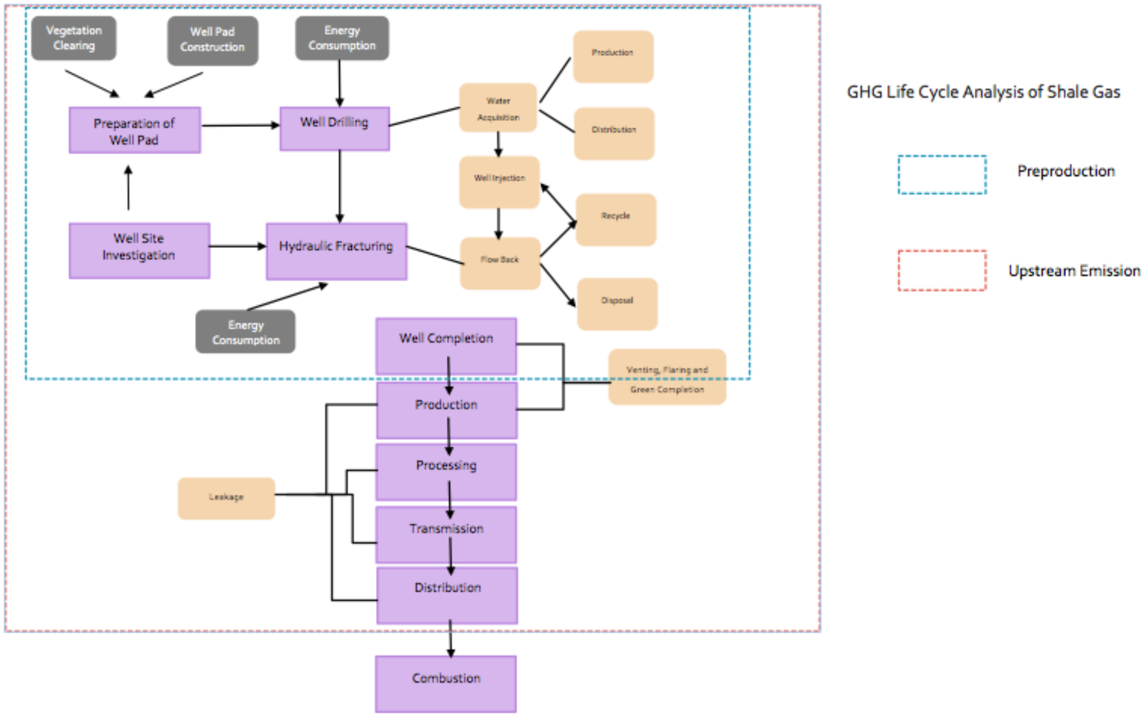

Figure 4. Our representation of the unconventional shale gas supply chain.

The upstream natural gas supply chain is fragmented and complex, creating difficulties in comprehensive emissions accounting. In the U.S. today, about 39% of natural gas is sourced from conventional methods, and the remaining 61% is sourced from unconventional methods, including hydraulic fracturing.[10] Conventional methods follow similar upstream processes, except include the addition of liquids unloading. Our model offers a weighted average that incorporates both conventional and unconventional methods.

Figure 6 illustrates the unconventional shale gas supply chain, isolating the pre-production and entire upstream aspects. Though there is potential for emissions within every step of the upstream supply chain, major sources of emissions come from the venting and flaring of methane during well completion (3.39 kg CO_2e/MMBtu) and gas production (2.44 kg CO_2e/MMBtu).[11, 12]

The pre-production stage constitutes well investigation, site preparation, drilling, fracturing and well completion. Production refers to the actual extraction of the gas to be processed and transported. The gas is then processed onsite in storage pipes or tanks, where assorted

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[10] US Crude Oil and Natural Gas Proved Reserves, Year-end 2015. Rep. Washington D.C.: Department of Energy, 2016.

[11] Refer to “Model Methodologies” for an elaboration on our emissions factors calculations.

[12] Refer to “Model Methodologies.”

hydrocarbons and other miscellaneous impurities are separated from the final product. Leakages are common in this stage, although exact volumes are difficult to measure.[13] Natural gas can also be processed off-site.

During the transmission stage, the processed gas is transported through transmission pipelines for final combustion and electricity use. Indirect fugitive emissions from the transmission stage include emissions associated with pipeline manufacturing and construction, in addition to the electricity consumed to power natural gas infrastructure, equipment and pumps.

2.5 Regional Differences in Natural Gas Production

The EIA reported that, of the eight major shale plays in the continental U.S., Marcellus and Utica regions accounted for 85% of the increase in natural gas production in 2012, driving growth in total production – as depicted in *Figure 7*.[14] Accounting for the unique and variable compositions of different shale plays is necessary to accurately account for what precedes the processing phase of gas in every region.[15] These geographic eccentricities, including variations in pressure, depth, and temperature, influence the extraction process and leakage rates. A visual representation of shale plays is illustrated in *Figure 8*.

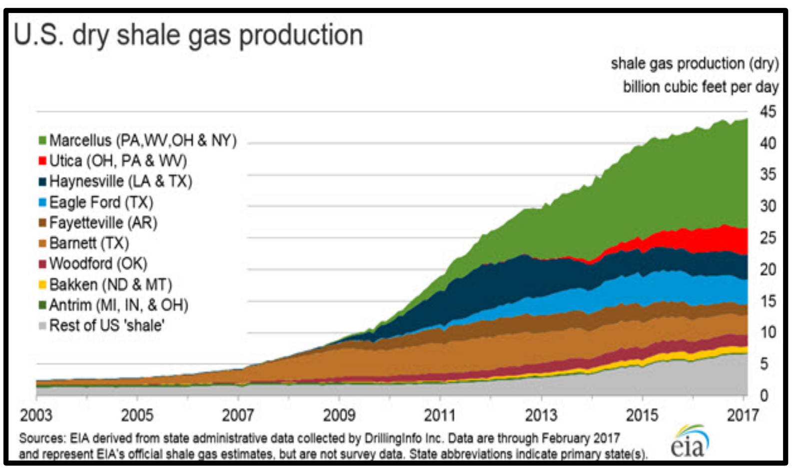

Figure 5. EIA derived from state administrative data through February 2017 and represent EIA's official shale gas estimates, but are not survey data. State abbreviations indicate primary states.

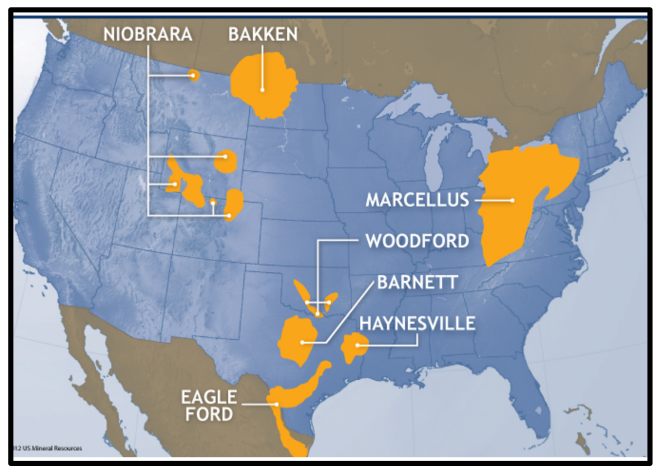

Figure 8. Major Shale Plays in the U.S. Source: usmineralresources.com/assets/images/usmr-northamerica-map.jpg

[13] Howarth, R. W. (2014). A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas. Energy Science & Engineering,2, 47-60. doi:10.1002/ese3.35

[14] Magill, B. (2015, October 13). Study Sees Shortfall in Methane Emissions Estimate. Retrieved April 25, 2017, from http://www.climatecentral.org/news/shale-methane-may-exceed-estimates-19538

[15] AB 2588 Combustion Emission Factors. (2001). Retrieved from Http://ljournal.ru/wp-content/uploads/2016/08/d-2016-154.pdf

A MIT study found in 2012 that Haynesville shale gas is more greenhouse gas-intensive due to the uniquely high-pressure rock formation from which it is extracted. Haynesville is subject to more frequent venting and flaring due to safety reasons because of the region's higher pressure and temperature.[16]

3. Upstream Emissions Research Development

Under the United Nations Framework Convention on Climate Change (UNFCCC), the United States is obligated to annually develop nationally representative estimates of emission sources and sinks of specific greenhouse gases from human activities with 1990 as a temporal baseline. According to the National Renewable Energy Laboratory, the U.S. GHGI uses an engineering-based approach to generate GHG emissions estimates for each source category, with almost 110 source categories tracked within the natural gas sector alone. Presently, the U.S. GHGI relies on potential emission estimates for most source categories, as data on control practices to reduce emissions can be difficult to obtain.

Between 2007 and 2013, the GHGI reported a downward trend in annual U.S. CO_2e emissions, which includes methane emissions, relative to 1990. The declining trend, shown in *Figure 9*, can be partially attributed to electric sector declines in CO_2 emissions. As coal became increasingly uneconomical, other sources, including natural gas and renewable technologies, accounted for the decline. There is potential that the US GHGI report did not accurately portray the impact of increased methane emissions with the natural gas industry's rise.[12] Another element of the declining trend is that natural gas produces half the amount of CO_2 emissions when it is burned compared to when coal is burned, adding to the popularization of the notion that natural gas may be a "bridge fuel" from coal. However, reported rates of CO_2 emissions associated with fossil fuels typically reflect only CO_2 stack emissions, and may or may not report additional methane emissions.

Cumulative change in US annual greenhouse gas emissions relative to 1990

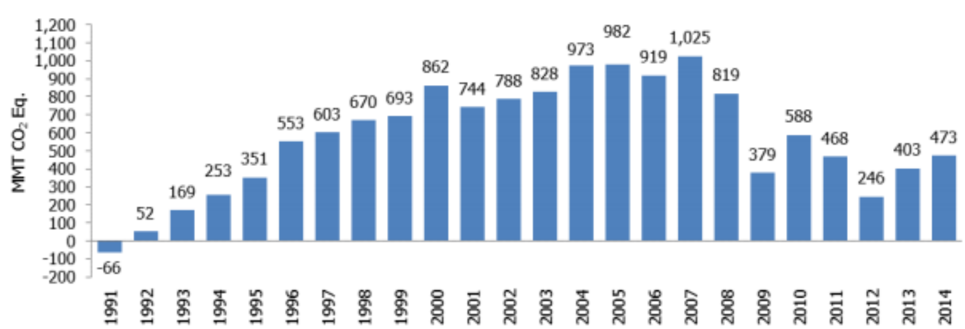

Figure 6. Cumulative Change in Annual U.S. GHG Emissions Relative to 1990. Source: 2016 EPA GHG inventory

[16] O'Sullivan, Francis. Shale Gas Production - The Emissions Question. (2012, Sept. 13). MIT. Web. Retrieved Apr. 17, 2017.

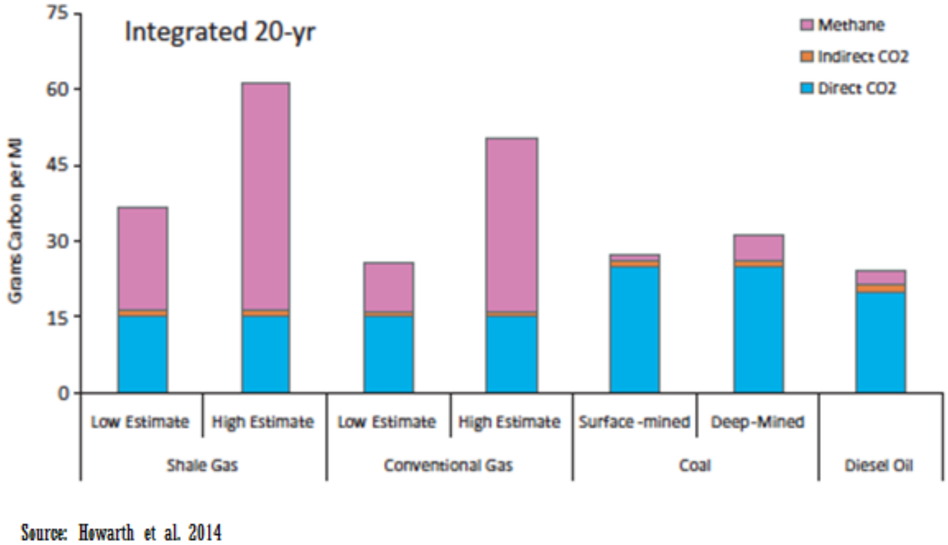

Figure 7 Comparison of the greenhouse gas Comparison of the greenhouse gas footprint of shale gas, conventional natural gas, coal, and oil to generate a given quantity of heat in 20-year time scale (Howarth et al. 2014)

As methane is 86 times more potent than CO_2 in the first 20 years after its release (IPCC 2014), Howarth's peer reviewed analysis suggesting massive methane leakage (2012) stirred public concern, industry pushback and further research by the industry, EPA and academia.[12] Those upstream results are highly variable, as illustrated in *Figure 10*, and suggest that natural gas upstream greenhouse gas emissions are not yet fully understood. Variability is often due to the field's lack of standardization in data collection methodologies and the global warming potential used. However, it is worth noting that Howarth's study concerns full life-cycle emissions analysis and includes all uses for natural gas, including heating and downstream distribution, and doesn't account for electricity generation efficiency.

3.1 Subsequent Research

The Environmental Defense Fund (EDF) has become a leader in the field of upstream emissions analysis. Its natural gas methane emissions initiative has developed into a $16 million series of 16 studies by more than 100 researchers. In tandem, the federal government and the EPA began to release updated, notably higher, estimates of methane emissions from natural gas production. NOAA and NASA are developing satellite imagery of methane emissions, which allow researchers to more easily identify potential natural gas "super-emitters." Although methane satellite imagery does not isolate various sectoral contributions – such as agriculture, shale gas, landfill, and industry – it offers a visual depiction of the country's increasing atmospheric methane concentrations, and therefore how they may influence total national greenhouse gas emissions.

This report's Appendix offers a consolidation of research used for our literature review and model.

4. Variability in Methodologies of Natural Gas Studies

Despite the interest spurred by Howarth's claim of much higher methane emissions than previously known or calculated, current upstream emissions research may not be viable for analyzing and addressing climate change concerns and U.S. energy policy. This is due to a lack of standardization in data collection, study methodologies, global warming potentials used, and final variables determined. To develop a robust, proportional, and comparable model, it is critical to recognize and account for different methodological approaches in most recently available (2012-2017) literature.

Recent research efforts can be divided into two main types of study: case studies based upon empirical data collection and emission factors, and models designed with inputs from consolidated databases. Those that rely on on-site measurements use instruments such as mass spectrometers, filter measurements, satellite images and laser-induced incandescence systems, presented as either observation tables or jpeg images. The data gathered via these studies can be shaped by a range of factors, from climate variables to the maintenance of the specific equipment the researcher is using. Environmental conditions, such as temperature and wind (McEwen et. al. 2012) can also interfere with the dispersion patterns of gases and therefore, their measurements.

For data collection based upon empirical data collection, the two fundamental upstream natural gas data collection methods are bottom-up or top-down. *Figure 11* offers a summation of these methodologies' pros and cons, highlighting a top-down 2013 NOAA study and a bottom-up 2013 study from the University of Texas.

Natural Gas Methane Emissions Quantification Methods		
Example Institution	**NOAA, 2013**	**University of Texas, Austin, 2013**
Common Methodology	WP-3D Research Aircraft over the Haynesville, Fayetteville and northeastern Marcellus shale region	Direct measurements of methane emissions at 190 onshore natural gas production sites
Methane Leakage Rate Estimation	In Haynesville, (8.0+/- 2.7) * 10^7 g CH_4/hour	Equipment leaks measured in this work averaged 0.0205g CH_4/hour per well
Pros	Ability to identify super emitters	Higher accuracy
Cons	Lack of point-source specificity	Time constraint

Figure 8. Summation of Top-Down and Bottom-Up CH_4 upstream emissions quantification methods.

According to the EDF-funded research by Harriss et. Al (2014), top-down data collection results from measuring atmospheric methane enhancements at regional or national scales. Although top-down data collection is less resource intensive, it does not offer accurate insights into the specific source types. Researchers are also unable to specify emissions sources, and sample sizes typically vary. Top-down estimations are often communicated in hourly rates or percentages of production, without complementing findings with total time or total production. Such rates are limiting to other researchers seeking to consolidate and compare datasets, and thus, there are no present opportunities for further application or scalability of these findings. Bottom-up data collection refers to emission measurements made directly from individual components or at the site level. Bottom-up methods offer rich, granular data, but can be resource- and time-intensive.

Upstream natural gas production equipment also varies in components like flaring pipes, which range from steam injections, air multi-pointed nozzles or multiple-fuel nozzles with different flaring rates and efficiencies. There are four main possibilities for tank emission sources: breathing losses (emissions related to vapors produced due to diurnal temperature changes); working losses (occasional displacement during tank filling); and flashing losses (when liquids with entrained gas go under a pressure drop during liquid transfer from a well to a separator) (McEwen et. al. 2012). Lastly, executive decisions greatly influence rig load and production pad dynamics, and by extent, upstream emissions. These differences in boundaries and scope, data collection, consolidation and calculation, environmental conditions and geography, equipment, and assumptions lead to variability in results. We chose our case studies in recognition of these limitations and tried to be transparent about which circumstances allowed extrapolation of research findings.

4.1 Flaring, Venting, and Flareless Completion

Venting and flaring are common practices used during natural gas production to remove excess gas and must be accounted for in upstream GHG assessments. Venting is the direct release of methane gas into the atmosphere, and occurs at a number of points in the oil and gas development process (including well completion, well maintenance; pipeline maintenance; tank maintenance; etc.).

Flaring refers to the burning of gas that is deemed uneconomic to collect and sell or presents a safety concern. The burning of natural gas influences the GWP, and therefore total upstream emissions, of the host-site, as the conversion of CH_4 into CO_2 through combustion represents a reduction in radiative forcing. Flaring also emits many other air pollutants known to be harmful to human health, such as benzene, formaldehyde, and polycyclic aromatic hydrocarbons as well as others.[14]

Newer techniques such as flareless completions can reduce release of by-products into the atmosphere while maintaining safety. During flareless completions, the gas that comes to the surface is separated from fluids and solids using flowback units. The water is discharged to tanks to be reused, the sand is sent to a reserve pit, and the gas is either cycled back through the well bore, or sent to a pipeline to be sold rather than vented or flared. Although flareless completions offer a more environmentally-friendly approach for natural gas production, without robust enforcement of strong regulations, there is little industry incentive to apply this technology. Some make the specious argument that the marginal cost of capturing gas is greater than extracting a new site, and that flareless completion is therefore not in the financial interest of gas developers. However, the "financial interest" argument was discredited by a (2012) study sponsored by Goldman Sachs and the Natural Resources Defense Council (NRDC) that found an investment of

$8,700 to $33,000 per well led to a methane capture rate of 7,000 to 23,000 Mcf/well with a profit of $28,000 to $90,000 per well and a payout in around 6 months.[17]

In accounting for upstream emissions, there is variation in research results on the venting, flaring, and green completion breakdown per boundary studied. *Figure 12* shows 4 typical studies that offer a percentage of each process. Howarth's studies assume that all natural gas production allows 85-100% venting - a big assumption that is dependent on his greater pre-production and production numbers for methane. Francis O'Sullivan of MIT, offers insight into the discrepancies of studies regarding gas handling and offers "Scenario D," a synthetic scenario reflecting a consolidated average amongst the major studies. Scenario D assumes a breakdown of 15% venting, 15% flaring and 70% flareless completion. According to O'Sullivan, the greenhouse gas intensity of a "typical" well could vary by almost 8 times, depending on which gas handling scenario is assumed to be "representative" of field practice.[15]

Different assumptions have been made regarding the practice mix for gas handling during unconventional well completion operations – The lack of verifiable data means that the actual situation remains opaque

Gas handling scenarios for assessing the GHG intensity of contemporary shale well completion operations

	Scenario A	Scenario B	Scenario C	Scenario D
Cold-Venting	85-100%	49%	3%	15%
Flaring	0-15%	51%	4%	15%
Green completions	-	-	93%	70%

- **Scenario A:** Assumptions made by Cornell Group in their evaluation of the GHG intensity of shale well completions[1]
- **Scenario B:** Represents a gas handling scenario for unconventional wells in WY, TX, NM, OK based on state regulation[2]
- **Scenario C:** Mix of gas handling practices reported for unconventional wells in 2011 ANGA survey of ~1,500 completions[3]
- **Scenario D:** Synthetic scenario designed to reflect a practically achievable mix of gas handling practices for well completions in the main shale plays

Figure 9. 1 Howarth, R. et al. Methane and the greenhouse-gas footprint of natural gas from shale formations. Climatic Change 106, 679-690 (2011). 2 Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Supporting Document (EPA, Washington DC, 2010) 3 ANGA Comments to EPA on New Source Performance Standards for Hazardous Air Pollutants Review (America's Natural Gas Alliance, January 19, 2012)

[17] Harvey, Susan, Vignesh Govvrishankar, and Thomas Singer. (2012, Mar.). Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste. *Goldman Sachs and NRDC.*

4.2 Pipeline Gas Leaks

Our literature review also highlighted the relationship between pipeline distance and natural gas upstream emissions. As *Figure 13* denotes, the further gas must travel, the more emissions are released into the atmosphere, due to, among other variables, the pressure required to transport natural gas. Additional emissions arise from the electricity (sourced from the natural gas) required to power the compressors transporting the gas. Although pipeline distance is not included within our model, it is a critical component to include when constructing a comprehensive life cycle analysis (LCA) for natural gas.

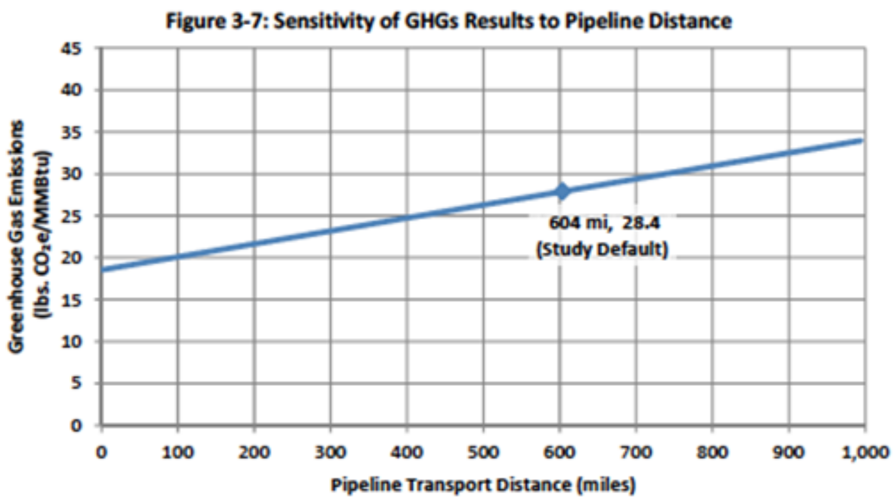

Figure 10. NETL, Life Cycle Analysis of Natural Gas Extraction and Power Generation, May 29, 2014

4.3 Super-Emitters

High-risk emitters considerably skew regional and national data. Some high-emitting operations occur by design (such as via flash gas - natural gas released from a well steam when the liquid undergoes a pressure drop - and liquid unloadings – the process of cleaning wells of accumulated liquids to facilitate natural gas flow), and also by abnormal process emissions, such as malfunctions upstream and equipment issues.[18] In the Barnett Shale, a recent study found that the highest emitting 1 and 10% of sites accounted for roughly 44 and 80% of total CH_4 production emissions, respectively.[19] Harriss et al. determined through both bottom-up and top-down methodologies that the Barnett Shale region's methane emissions estimates were much higher than those denoted by the U.S. EPA's Greenhouse Gas Inventory. Their bottom up estimate for Barnett oil and gas is ~1.5 times higher than expected based on the Greenhouse Gas Inventory.

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[18] Zavala-Araiza, D. *et al.* (2015). Reconciling divergent estimates of oil and gas methane emissions. *Proc. Natl. Acad. Sci. USA* 112, 15597–15602.

[19] Harriss, Alvaraz, Lyon, Zavala-Araiza, Nelson, Hamburg. (2015). Using Multi-Scale Measurements to Improve Methane Emission Estimates from Oil and Gas Operations in the Barnett Shale Region, Texas. *American Chemical Society.* Environmental Defense Fund, Austin, Texas.

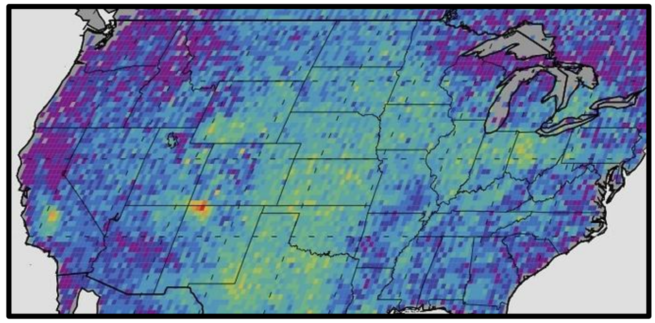

Figure 14. Satellite imagery of methane hotspots. Source: NASA/JPL-Caltech/University of Michigan

The study notes that the bottom up estimate may be higher than the inventory simply due to its more elaborate measurement processes, and inclusion of many more gathering compressor stations, suggesting further inventories need to carefully account for them. With regards to top-down accounting, the study's top-down tools estimate that 71-85% of Barnett Shale region's observed methane emissions are attributable to fossil-based sources.[20] Therefore, both top-down and bottom-up methodologies attribute high atmospheric methane to the Barnett Shale region.

Figure 14 is a 2015 visualization of what is considered the "largest concentration of the greenhouse gas methane seen over the United States," according to scientists at NASA and the University of Michigan. This one small "hot spot" in the U.S. Southwest represents more than triple the standard ground-based estimate for methane. [19]

5. Current Federal Regulatory Framework

Regulatory measures play a critical role in handling methane leakage. The 1970 Clean Air Act, EPA's 1972 Clean Water Rule, the 1976 Toxic Substance Control Act and the 2014 Clean Power Plan give the US government the authority to design and implement regulations that could significantly reduce fugitive methane emissions. However, the Trump Administration reversed several Obama-era policies in a March 28, 2017 Executive Order[21], including requirements for methane emissions reporting during fracking activities. Furthermore, the Trump Administration recommended that the EPA's budget undergo a 31% reduction.[22] Additionally, 2017 EPA Administrator Scott Pruitt announced plans to rescind the Clean Water Rule and revise, which water bodies are under legal protection.[23] Given regulatory rollbacks, lack of federally sponsored data collection, and general uncertainty in voluntary fugitive emission controls, assumptions regarding changes in midstream emissions of methane are highly speculative.

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[20] Northon, Karen. (2016, Oct. 9). "Satellite Data Shows U.S. Methane 'Hot Spot' Bigger than Expected." NASA. Retrieved April 16, 2017.

[21] Presidential Executive Order on Promoting Energy Independence and Economic Growth. (2017, March 28). Retrieved April 25, 2017, from https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1

[22] News, C. S. (2017, April 13). EPA regulation cuts likely to hurt children most, experts say. Retrieved April 25, 2017, from http://www.cnn.com/2017/04/13/health/epa-cuts-children-health/

[23] EPA's Pruitt Seeks State, Local Input on Rescinding, Revising Clean Water Rule. (n.d.). Retrieved April 25, 2017, from http://www.naturalgasintel.com/articles/110124-epas-pruitt-seeks-state-local-input-on-rescinding-revising-clean-water-rule

6. Model Framework

6.1 Boundaries and Scope

Our project scope is to determine the upstream greenhouse gas footprint of coal and natural gas in equivalent units of electricity generation. Based on the literature review we have conducted, we built our own model by collecting emission factors and refining them into comparable units.

As seen below in *Figure 15*, our model distills the complex natural gas supply chain into four categories, defined by assumptions elaborated upon later in this report.

	NATURAL GAS	COAL
PRE-PRODUCTION	Site Prep Venting/Flaring	Site Prep Land Use Change
PRODUCTION	Workover/Extraction Emissions	Surface/Underground Mining
PROCESSING/ REFINING	Energy Use Fugitive Emissions	Energy Use
TRANSPORTATION	Pipeline Leakage	Rail and Truck Emissions

Figure 15. Examples of significant emissions sources within upstream coal and natural gas processes.

Our boundaries and scope also defines an endpoint for upstream accounting. We are not including the emissions required to build the infrastructure, the vehicle-mile emissions, and those necessitated for materials production.

For natural gas, we also made the distinction between natural gas produced for electricity generation and natural gas used for heating and industrial processes. This report focuses solely on the former, within the U.S. electricity sector.

7. Natural Gas Assumptions

7.1 Methane Global Warming Potential

Gases in the atmosphere can contribute to global warming both directly and indirectly. Direct impacts occur when the gas absorbs radiation. The IPCC developed the Global Warming Potential (GWP) concept to standardize comparisons of each greenhouse gas to trap heat in the atmosphere. According to the 2013 IPCC, the GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram of a trace substance relative to that of 1 kg of a reference gas. A defined global warming potential represents a critical component of our model's calculations, and the foundation for controversy amongst various other studies. Our model accounts and addresses the variation in GWP based upon a report's publication date, and variations between 20-year and 100-year time frames.

Furthermore, as this is merely a “scientific concept,” some scientists like Howarth calculate and employ their own GWP. Our model calculates emissions factors using the IPCC 2014 20-year GWP.

Methane Global Warming Potential (IPCC)		
IPCC 2007	20 Year	72
	100 Year	25
IPCC 2014	**20 Year**	**86**
	100 Year	34

Figure 16. Global Warming Potentials for Methane. Source: IPCC

7.2 Assumptions for Four-Stage Breakdown

1. **Pre-production, includes 4 sub-stages:**
    a. Well-pad construction (or preparation): vegetation clearing, setting up drill pad, the act of searching for potential subsurface reservoirs of gas or oil, procuring water and materials, constructing the well pad, preparing access roads, laying gathering lines, and building other necessary infrastructure, all emissions assumed to be CO_2
    b. Well drilling: drilling of a hole in the rock layer from which natural gas will then be extracted. Can be either vertical or horizontal (only for shale gas), all emissions assumed to be CO_2
    c. Hydrofracturing (only shale): emissions associated with transporting water to the site and energy associated with pumping water into create fractures, all emissions assumed to be CO_2
    d. Well completion (shale and natural gas): A generic term used to describe the events and equipment necessary to bring a well into production once drilling operations have been concluded, including the assembly of equipment required for safe and efficient production from a gas well. The process of well completion primarily includes the flowback of fluids and gases to the surface through the well borehole. Emissions come from venting and flaring (shale and conventional), as well as green completion (shale only)
2. **Production, includes three sub-stages**
    a. Workovers: usually only once during the lifetime of a well. Mostly occur in shale wells, the venting of natural gas to increase production. Emissions associated with energy use to run the workover, but all emissions assumed to be CH_4

b. Liquids unloading: only for conventional gas, the process of removing liquid from the wellbore that would otherwise slow production in a mature well. Emissions associated with energy use to run the water unloading, but all emissions assumed to be CH_4

c. Fugitive at well: venting and leakage from the well: all emissions assumed to be CH_4

3. **Processing, includes two sub-stages**

a. Fugitive at plant: leakage and venting associated during refining process; all emissions assumed to be CH_4

b. lease/plant energy: venting and flaring of CO_2, emissions associated with energy consumption during processing; all emissions assumed to be CO_2

4. **Transmission/transportation, includes two sub-stages**

a. Fugitive transmission: usually leaks from pipelines and some venting, emissions are especially significant in compressor stations. All emissions assumed to be CH_4. Because this is post-refining, methane content in natural gas is considered to be 95%

b. Compression fuel: Energy necessary to power compressors. All emissions assumed to be CO_2

7.3 Conversion Assumptions

Conversion Assumptions			
Natural Gas Density	=	0.7	g/m3
1g Natural Gas *Before* Refining	=	0.9	g CH4
1g Natural Gas *During* and *After* Refining	=	0.95	g CH4
1 MMBtu	=	1055.06	MJ
1g CO2	=	0.2727273	g C
1 MMBtu	=	293.297	KWh

Figure 17. Conversion values used in our representation model.

7.4 Backfill of Data Gaps

We converted the raw data of emissions factors to kg CO_2/MMBtu and populated a data table separated by shale and conventional gas, as well as the study it was referring to. Many studies only took note of certain steps in the upstream process. To avoid unfair bias toward studies with less robust analysis, we backfilled the data (Figure 18).

		Study Name:												Unweighted Average:	
	all units are in kg CO2e/MMBtu	Weber and Clavin (2012)		Howarth et al. (2011)		Burnham et al. (2011)		Littlefield et al. (2016)		DOE(2014)		EPA (2014)			
100%	Weights	45%	45%	5%	5%	5%	5%	10%	10%	10%	10%	25%	25%		
		Conventional	Shale	Conventional	Shale	Conventional	Shale	Conventional	Shale	Conventional	Shale	Conventional	Shale	Summary (Conventional)	Summary (Shale)
Pre-prodution	Well pad construction	0.1688096	0.1688096											0.1688096	0.1688096
	Well Drilling	0.211012	0.211012											0.211012	0.211012
	Hydraulic Fracturing		0.3481698											0	0.3481698
	Well Completion (flowback and drillout)	0.546943104	3.64628736	0.016518145	3.13844754									0.281730624	3.39236745
	Total Preproduction	0.958416504	1.33570596											0.958416504	1.33570596
Production	Liquids Unloading	11.54657664		0.429471769	0	1.98217739								4.652741934	0
	Workover		1.816995944											0	1.816995944
	Flaring	0.1688096	0.1688096			0.49482314	0.49482314							0.33181637	0.33181637
	Fugitive at the well	8.20414656	8.20414656	1.816995944	1.816995944	1.20582458	1.20582458		0.71028023			5.18709867	8.11315433	4.103516439	4.01008033
	Total Production									1.56	2.44			1.56	2.44
Processing and Refining	Lease/Plant Energy	3.376192	3.376192			0.87780992	0.87780992							2.12700096	2.12700096
	Fugitive at the plant	5.46943104	5.46943104			0.24777217	0.24777217							2.858601607	2.858601607
	Total Processing			0.165181449	0.165181449				0.41295362	0.00103238	0.00161475	1.14237552	1.78679248	0.436196451	0.591635577
Transportation and Transmission	Compression fuel	0.422024	0.422024											0.422024	0.422024
	Fugitive transmission	5.77328832	5.77328832			1.10671571	1.10671571							3.440002016	3.440002016
	Total Transmission and Transportatior	6.68486016	6.68486016	4.129536237	4.129536237				0.74331652	0.00343249	0.00536877	2.053896	3.212504	3.217931222	2.955117138

Figure 18. Model without backfilled data for the six studies we used in our analysis

The original natural gas data table, with emissions factors in kg CO_2/MMBtu, was used to create unweighted averages for each individual step of the upstream process, separated by conventional and shale numbers. The averaged numbers were used again to populate a new table, filling in steps of the upstream process for each study, that were not included in their analysis (Figure 19).

7.5 Process for Weighting Studies

		Backfilled Model:											
	all units are in kg CO2e/MMBtu	Weber and Clavin (2012)		Howarth et al. (2011)		Burnham et al. (2011)		Littlefield et al. (2016)		DOE(2014)		EPA (2014)	
	Weights	45%	45%	5%	5%	5%	5%	10%	10%	10%	10%	25%	25%
		Conventional	Shale	Conventional	Shale	Conventional	Shale	Conventional	Shale	Conventional	Shale	Conventional	Shale
Pre-prodution	Well pad construction	0.1688096	0.1688096	0.1688096	0.1688096	0.1688096	0.1688096	0.1688096	0.1688096	0.1688096	0.1688096	0.1688096	0.1688096
	Well Drilling	0.211012	0.211012	0.211012	0.211012	0.211012	0.211012	0.211012	0.211012	0.211012	0.211012	0.211012	0.211012
	Hydraulic Fracturing	0	0.3481698	0	0.3481698	0	0.3481698	0	0.3481698	0	0.3481698	0	0.3481698
	Well Completion (flowback and drillout)	0.546943104	3.64628736	0.016518145	3.13844754	0.281730624	3.39236745	0.281730624	3.39236745	0.281730624	3.39236745	0.281730624	3.39236745
	Total Preproduction	0.926764704	4.37427876	0.396339745	3.86643894	0.661552224	4.12035885	0.661552224	4.12035885	0.661552224	4.12035885	0.661552224	4.12035885
Production	Liquids Unloading	11.54657664	0	0.429471769	0	1.982177394	0	4.652741934	0	4.652741934	0	4.652741934	0
	Workover	0	1.816995944	0	1.816995944	0	1.816995944	0	1.816995944	0	1.816995944	0	1.816995944
	Flaring	0.1688096	0.1688096	0.33181637	0.33181637	0.49482314	0.49482314	0.33181637	0.33181637	0.33181637	0.33181637	0.33181637	0.33181637
	Fugitive at the well	8.20414656	8.20414656	1.816995944	1.816995944	1.205824581	1.205824581	4.103516439	0.710280233	4.103516439	4.01008033	5.18709867	8.11315433
	Total Production	19.9195328	10.1899521	2.578284083	3.965808258	3.682825115	3.517643665	9.088074743	2.859092547	9.088074743	6.158892644	10.17165697	10.26196664
Processing and Refining	Lease/Plant Energy	3.376192	3.376192	2.12700096	2.12700096	0.87780992	0.87780992	2.12700096	2.12700096	2.12700096	2.12700096	2.12700096	2.12700096
	Fugitive at the plant	5.46943104	5.46943104	2.858601607	2.858601607	0.247772174	0.247772174	2.858601607	2.858601607	2.858601607	2.858601607	2.858601607	2.858601607
	Total Processing	8.84562304	8.84562304	4.985602567	4.985602567	1.125582094	1.125582094	4.985602567	4.985602567	4.985602567	4.985602567	4.985602567	4.985602567
Transportation and Transmission	Compression fuel	0.422024	0.422024	0.422024	0.422024	0.422024	0.422024	0.422024	0.422024	0.422024	0.422024	0.422024	0.422024
	Fugitive transmission	5.77328832	5.77328832	3.440002016	3.440002016	1.106715711	1.106715711	3.440002016	3.440002016	3.440002016	3.440002016	3.440002016	3.440002016
	Total Transmission and Transportatior	6.19531232	6.19531232	3.862026016	3.862026016	1.528739711	1.528739711	3.862026016	3.862026016	3.862026016	3.862026016	3.862026016	3.862026016

Figure 19. Backfilled natural gas model.

Studies used in our analysis were varying in sample size and scope of study. To account for this in our model, we used a weighing system to attain a number for total upstream emissions that was more robust and comparable to our overall qualitative findings from our literature review.

The first criterion of our weighing system was based on the extensiveness of each paper. For example, in the natural gas model, the Weber and Clavin paper was an amalgamation of six different complete studies, while the Howarth and Burnham papers used individually reported numbers. In addition, papers that had fewer numbers of emission factors reported were also weighed lower because we would have used more backfilled numbers to complete the analysis for those studies, as seen in the coal model for Jaramillo et al. and Whitaker et al. (Figure 23). And finally, we used the date of publication as another factor in our weighing system. Recent papers with more accurate measurements are weighted higher than older ones.

7.6 Consolidating National Averages to Fill Regional Data Gaps

Due to a lack of standardized regional information per shale play, we recommend that the model aggregate data from the collected studies for a national average, rather than regional averages more reflective of geographic variation. Thus, the emissions factors that stem from our recommendations offer a fair estimate at the national level and are a starting point for further research and investigation into upstream emissions. While a national value may be useful to inform general federal policies regarding upstream emissions, it is worth noting that regional data does vary based upon geophysical differences, as well as local regulations and enforcement. In fact, our model is structured in such a way that it could be adapted for region-specific averages of upstream emissions, if, and when, more regional data becomes available. Currently, the major obstacle in performing regional calculations is a lack of comprehensive usable data. Limited regional data can still be useful for identifying super-emitters within a given area. These outliers, however, tend to skew regional averages of upstream emissions, particularly in regards to methane emissions. This report's consolidated studies offered regional variation, but also a plurality of sample sizes. Several were often restricted to a handful of natural gas wells on a given day, which is hardly adequate for extrapolating larger-scale regional averages. Presently, it is more feasible to compare upstream averages according to extraction method, namely conventional and unconventional, and the resulting values will still reflect national averages.

7.7 Inability to Incorporate Temporal Leakage Rates

In collecting emissions factors for use in our model, it was necessary to convert reported data into standard units to compare measurements. Upon reviewing available literature, it became clear that many studies reported findings as temporal rates (example: unit/time, such as kg CH_4/hour), whereas others presented leakage percentages or leakage totals. Temporal leakage rates measure the quantity of methane gas released over a period, such as cubic meters per hour or grams per second. Measurements like these are often recorded to pinpoint methane leakage hotspots at a given moment. For example, most recent EDF-sponsored research is hyper-localized and communicates methane leakage in these temporal units.

When solidifying our model's parameters, however, we assume temporal leakage rates cannot offer comparable emissions factors. Although this information is helpful in identifying overarching trends, potential super-emitters, and emissions-sources within the upstream supply chain, the data cannot be incorporated into a consolidated, standardized model without offering the specific size of the boundary studied, total time studied, and volume of production of the well or region during the study's time-range. Studies that make use of defined parameters such as a leakage per gas well or as a percentage of production or consumption are more translatable, and can be converted in order to calculate regional or national averages. For more information on temporal leakage rates, please refer to our Appendix for a consolidated table of findings.

7.9 Accounting for MMBtu Produced vs. MMBtu Consumed

In calculating final natural gas upstream emissions factors, we standardized factors based upon their location along the natural gas supply chain. These conversions must do with both the changing methane composition of natural gas along the upstream processing chain, as well as accounting for the reduction of natural gas at any given point in the chain. If emissions factors are reported prior to the refining process, we assume that 90% of the natural gas is composed of methane. If emissions factors are reported during or after the refining process, we assume that 95% of the natural gas is composed of methane, due to the removal of ethane, butane, propane, and other component gases. Furthermore, leakage rates can be reported at any point between extraction and “consumption” at a power plant gate. Because all emissions factors being considered must ultimately be converted in terms of MMBtu consumed at the plant, some emissions factors required mass-ratio conversions that accounted for prior gas leakage further upstream as well as mass loss due to the refining process. This report assumes that gas “consumed” at the power plant is 90% of gas “produced” at the point of extraction, as a ratio that accounts for the aforementioned factors. This way, the reduction of total gas throughout the various upstream processes is factored in per unit of energy produced and reported in comparable terms of MMBtu.

8. Coal Assumptions

8.1 Coal Emissions Conversions

Upstream emissions measurements of coal required conversion based on the heat content of various coal types in order to ascertain totals and averages per unit of energy generated. Coal is available for electricity production in different forms, including bituminous, sub-bituminous, lignite, and in rare cases, anthracite. Each of these types of coal maintains unique physical properties, including a heat content or heating value. The heating value relates to the carbon content of the coal, but for electricity generation purposes, simply describes the slightly differing amounts of energy produced during combustion. For example, a given quantity of bituminous coal will produce more energy than an equivalent quantity of sub-bituminous coal. It was necessary to account for these differences by converting upstream emissions measurements according to the heat content of the coal type being extracted. Furthermore, disparate reported units were converted to short tons of coal, for standardized comparison. Heat contents and other conversion factors are listed below.

Coal Emissions Conversions				
Unit	=	**Amount**	**Secondary Unit**	**Additional Notes**
1 MMBtu	=	0.04011231	Short Tons Bituminous	
1 MMBtu	=	0.057971014	Short Tons Subbituminous	
1 MMBtu	=	0.070372977	Short Tons Lignite	
1 MMBtu	=	0.050890527	Short Tons Coal (Applied for National Rates)	Number based on 2015 EIA rank of coal
1 cf	=	1.46E+01	Btus	Number based on EPA coal mine methane units converter
Density of Coal	=	49.309	Lb/cf (Applied for National Rates)	Weighted average based on 2015 EIA rank of coal
Density of Anthracite	=	54	lb/cf	
Density of Bituminous	=	49.5	lb/cf	
Density of Lignite	=	47	lb/cf	

Figure 20. Upstream emission factors for Coal from our Representation model

8.2 Assumptions for Regional Variation

The regional assumptions and associated rounding described below are based upon the EIA 2015 Annual Coal Report.

Coal Regional Variation Assumptions			
Region	Extraction Method	Coal Type	Heat Content (Short Tons per MMBtu)
Powder River Basin	100% Surface Mining	100% Sub-Bituminous	0.057971014
Illinois Basin	78% Underground Mining, 22% Surface Mining	100% Bituminous	0.040112314
Appalachian Basin	75% Underground Mining, 25% Surface Mining	100% Bituminous	0.040112314

Figure 21. Regional assumptions from our representation's methodology.

8.3 Further Adjustment for Regional Variance for Coal

Our research allowed for a comparable regional analysis for upstream coal greenhouse gas emissions, and the final model accounts for variation between the Powder River, Illinois, and Appalachian Coal Basins, using the assumptions stated previously. However, our research indicated a lack of comparable, standardized data for the major natural gas shale plays.

8.4 Backfilling Coal Data

Methodologies like those used for natural gas were applied to coal data. However, we also converted our raw data to kg CO_2/short ton. We populated the data table with emissions factors from studies that we found and averaged these numbers to determine subtotal averages for each step of the coal upstream process, preparing us to backfill the data (Figure 21).

			Pre-production and production (kg CO2e/short ton)				Refining (kg CO2e/short ton)	Transport (kg CO2e/short ton)
Year	Name of Study	Weights:	Surface mining	Surface methane	Underground minin	Underground methane		
1999	ICF	5%		95.21559514				
2012	Whitaker et al.	5%				1249.020771		
2015	Jaramillo et al.	5%		133.6963938				
2011	Wigley	15%		0.149014343		0.330016057		
2009	DOE	27%	54.43114913			36.29		36.29
2008	Deutsche Bank	28%	7.746038793	146.555054	4.04397459	76.51199925		19.65002231
1999	Spath et al.	5%	51.86963333					97.97597407
2002	Hayhoe et al.	10%		668.2087754		348.8517655		
	Subtotal averages	100%	38.01560708	208.7649665	4.04397459	342.2003968	0	51.30447638

Figure 22. Model without backfilled data for the six studies we used in our analysis.

Using the subtotaled averages seen at the bottom of the figure above, we populated each study in a new table so that each study had numbers for all steps of production. (Figure 22).

	Backfilled Model:		Pre-production and production (kg CO2e/short ton)				Refining (kg CO2e/short ton)	Transport (kg CO2e/short ton)
Year	Name of Study	Weights:	Surface mining	Surface methane	Underground minin	Underground methane		
1999	ICF	5%	38.01560708	95.21559514	4.04397459	342.2003968	0	51.30447638
2012	Whitaker et al.	5%	38.01560708	208.7649665	4.04397459	1249.020771	0	51.30447638
2015	Jaramillo et al.	5%	38.01560708	133.6963938	4.04397459	342.2003968	0	51.30447638
2011	Wigley	15%	38.01560708	0.149014343	4.04397459	0.330016057	0	51.30447638
2009	DOE	27%	54.43114913	208.7649665	4.04397459	36.28743275	0	36.28743275
2008	Deutsche Bank	28%	7.746038793	146.555054	4.04397459	76.51199925	0	19.65002231
1999	Spath et al.	5%	51.86963333	208.7649665	4.04397459	342.2003968	0	97.97597407
2002	Hayhoe et al.	10%	38.01560708	668.2087754	4.04397459	348.8517655	0	51.30447638

Figure 23. Backfilled coal model.

9. Model Methodology

To create a comprehensive rate of emissions for upstream natural gas and coal, we constructed a Microsoft Excel database to consolidate academic research.

9.1 Emissions Factors Collection, Consolidation and Organization

We first reviewed the present research landscape, pulling emissions factors that address life-cycle emissions for electricity generation. The team limited natural gas research to papers only written after 2012 - to safeguard against data variation due to the hydraulic fracturing boom of the early 2000s. We upheld a more flexible temporal range for coal research, and incorporated analysis from 1985 onwards.

After finalizing our review process, we consolidated emissions factors for coal and natural gas into a master excel spreadsheet. This database served to organize, filter and prioritize our findings. Within the spreadsheet, we indicated the emissions factor and unit, the study year, geographic and temporal boundaries and scope, sponsored organizations, author names, fuel sources and specific upstream processes, as well as the determination of whether this factor represented pre-production, production, processing and refining, and/or transportation. These core categories informed further analysis amongst studies, and this assumption allowed for more simplified categorization later in our process.

9.2 Standardization of Units

All emission factors collected are initially constructed within their original studies using differing units, production stages, and fuel types. To create consistency and allow future comparability, we converted CH_4 and CO_2 masses into uniform kg CO_2e units. We then ensured that all units were conveying a uniform GWP - more specifically, we ensure all units express the IPCC 2014 20-year GWP. For those that were not, we used GWP multipliers to adjust the results. We then divided these units by energy production factors to achieve comparable standard units of kg CO_2e/MMBtu. Our model necessitated standardized emissions factors to compare values.

9.3 Development of Final Model

The final database offers users the ability to identify, filter and manipulate the upstream emissions for coal and natural gas. It also allows for continued updates as more research results are published. Our intention is to consolidate large amounts of information into an accessible format, so that one can isolate studies, authors, regions, and/or specific supply chain processes with ease. More critically, uniform emissions factors offer insight into the full life cycle analysis of coal and natural gas. Refer to *Figure 24* for a visual representation of our Excel Model. Please note that this image only depicts three studies, but the actual analysis uses six studies.

	all units are in kg CO2e/MMBtu	Backfilled Model:					
		Weber and Clavin (2012)		Howarth et al. (2011)		EPA (2014)	
	Weights	45%	45%	5%	5%	25%	25%
		Conventional	Shale	Conventional	Shale	Conventional	Shale
Pre-prodution	Well pad construction	0.17	0.17	0.17	0.17	0.17	0.17
	Well Drilling	0.21	0.21	0.21	0.21	0.21	0.21
	Hydraulic Fracturing	0.00	0.35	0.00	0.35	0.00	0.35
	Well Completion (flowback and drillout)	0.55	3.65	0.02	3.14	0.28	3.39
	Total Preproduction	0.93	4.37	0.40	3.87	0.66	4.12
Production	Liquids Unloading	11.55	0.00	0.43	0.00	4.65	0.00
	Workover	0.00	1.82	0.00	1.82	0.00	1.82
	Flaring	0.17	0.17	0.33	0.33	0.33	0.33
	Fugitive at the well	8.20	8.20	1.82	1.82	5.19	8.11
	Total Production	19.92	10.19	2.58	3.97	10.17	10.26
Processing and Refining	Lease/Plant Energy	3.38	3.38	2.13	2.13	2.13	2.13
	Fugitive at the plant	5.47	5.47	2.86	2.86	2.86	2.86
	Total Processing	8.85	8.85	4.99	4.99	4.99	4.99
Transportation and Transmission	Compression fuel	0.42	0.42	0.42	0.42	0.42	0.42
	Fugitive transmission	5.77	5.77	3.44	3.44	3.44	3.44
	Total Transmission and Transportation	6.20	6.20	3.86	3.86	3.86	3.86

Weighted Upstream Subtotals:

	Summary (Conventional)	Summary (Shale)	Summary (Conventional)	Summary (Shale)
Pre-production:	0.77	4.22	0.66	4.12
Production:	13.64	8.43	9.09	6.16
Refining and Processing:	6.53	6.53	4.99	4.99
Transportation and transmission:	4.80	4.80	3.86	3.86

Upstream total weighted	25.73	23.97	(kg CO2e/MMBtu of NG Produced)
for consumption	28.59	26.64	(kg CO2e/MMBtu of NG Consumed)
Pro-rata	10.03	14.62	(kg CO2e/MMBtu of NG Consumed)
Total	24.66	(kg CO2e/MMBtu of NG Consumed)	

Figure 24. Screenshot of present MS Excel model framework.

10.Key Findings

10.1 Coal

By averaging the upstream emissions factors for coal collected from several academic papers, the above results (Figure 25) were calculated using the weighted average system described in the Assumptions section. The upstream coal emissions per unit of energy produced amounted to a national average of 13.02 kg CO_2e/MMBtu, using a 20-year GWP. However, results varied across regions, and the upstream emissions averages for major coal-producing basins can be found in the preceding graph. Coal from the Powder River Basin in Wyoming and Montana averaged 15.77 kg CO_2e/MMBtu produced, whereas Appalachian Basin Coal and Illinois Basin coal averaged 9.48 and 9.43 kg CO_2e/MMBtu, respectively.

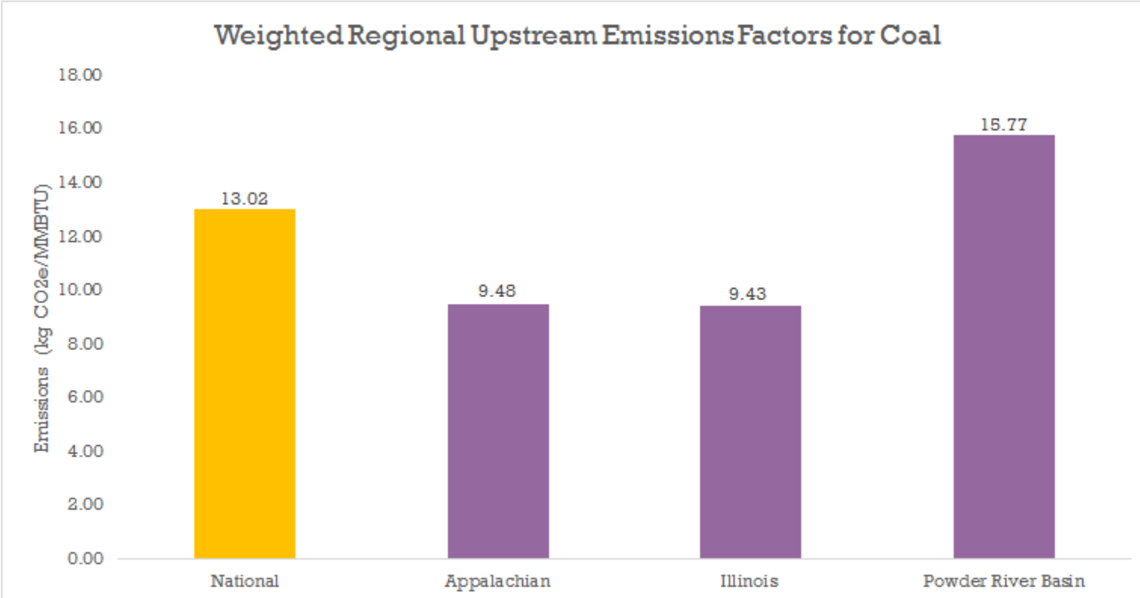

Figure 25. National and regional averages of weighted coal upstream emissions in kg CO_2e/MMBtu.

10.2 Analysis of Coal

Powder River Basin (PRB) coal accounts for roughly half of U.S. production, and produces more upstream emissions per unit of energy than other major mining regions because it favors sub-bituminous, surface mined coal. Two factors contribute to the significant differences between PRB coal and the coal mined from more eastern locations in the Illinois and Appalachian Basins. First, the PRB produces sub-bituminous coal, compared to mostly bituminous coal in Illinois and Appalachia. Sub-bituminous coal has a lower heating value than bituminous coal, which means a relatively larger quantity of it is required to produce the same amount of energy.

Secondly, the emissions intensity of different extraction methods contributes to regional variation in coal mining. Surface mining is the primary method in the PRB and involves incredible land use change, converting CO_2 sinks to CO_2 sources. Conversely, underground mining is more common in the Appalachian and Illinois basins, which releases CH_4 from coal bed methane seams, but is less land intensive by area. In short, extraction methods and coal types both influence regional differences in upstream coal emissions calculations.

10.3 Natural Gas

Figure 26 reflects national upstream emissions totals per unit of energy for natural gas used in electricity generation, according to several publications and sources using a 20-year warming potential. The totals are also sub-divided by production stage, with data gaps backfilled by averaging totals across studies, as described further in the Methodologies section. Moreover, each column is proportionately averaged between conventional and unconventional gas production estimates, according to available production data. The upstream totals range from a low of 9.01kg CO_2e/MMBtu (using the 2011 figures found by Burnham et al.) to a high of 32.06 kg

CO_2e/MMBtu found by Weber and Clavin in 2012. The EPA's 2014 upstream emissions estimates fall approximately in the middle of that range, at 21.85 kg CO_2e/MMBtu.

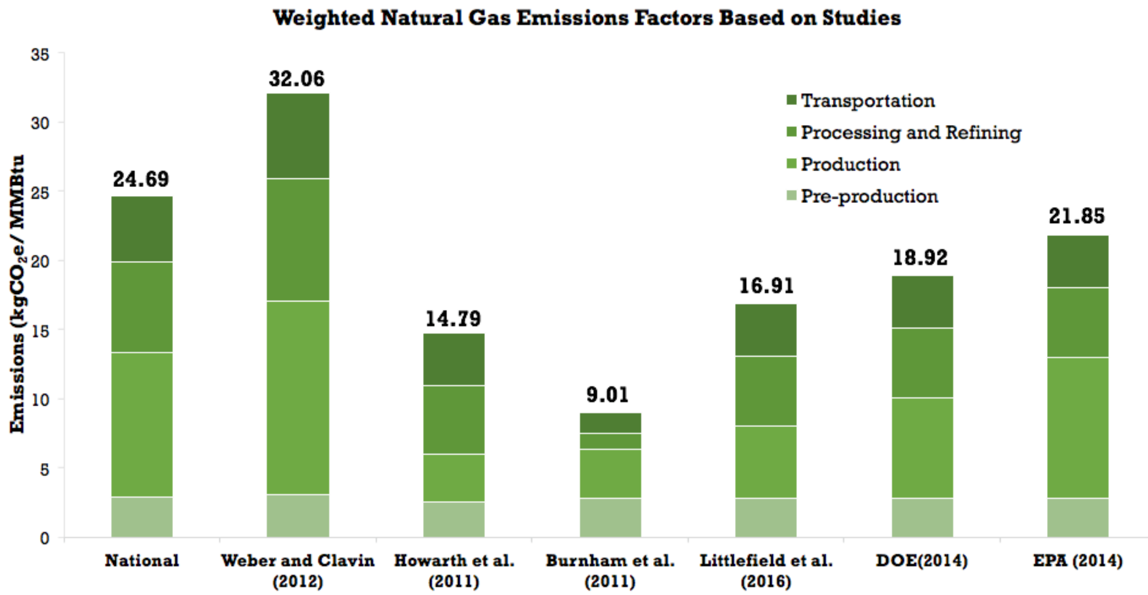

Figure 26. National and regional averages of weighted natural gas upstream emissions in kg CO_2e/MMBtu.

10.4 Analysis of Natural Gas

Variation in the upstream emissions total of natural gas electricity production is not entirely unexpected. The academic papers above cited numerous sources and time periods using various data collection methods, as discussed previously. Assumptions about industry venting, flaring, and gas capture during well completion ranged widely and likely contributed to the observed discrepancy among sources. The observed level of fugitive emissions also varied at all stages, contributing to high totals in the 2012 Weber and Clavin paper, and lower totals elsewhere. Furthermore, many recent regional studies considered for this report could not be used because the measurements were incompatible with this data model. The associated temporal leakage rates reported, however, tend to corroborate the higher estimates calculated using this model. As more data becomes available, these estimates can be refined and expanded upon.

10.5 Analysis of Key Findings

Figure 27 compares national averages for greenhouse gas emissions of coal and natural gas as used in electricity production, using a 20-year GWP. By combining our upstream emissions findings with available combustion emissions data, we can arrive at a total emissions figure per unit of energy generated. It is worth noting that this does not consider any downstream emissions from electricity distribution, and that this data only reflects emissions from the electricity sector. As the graph indicates, natural gas emits roughly half the greenhouse gases that coal does during combustion, in terms of warming potential.

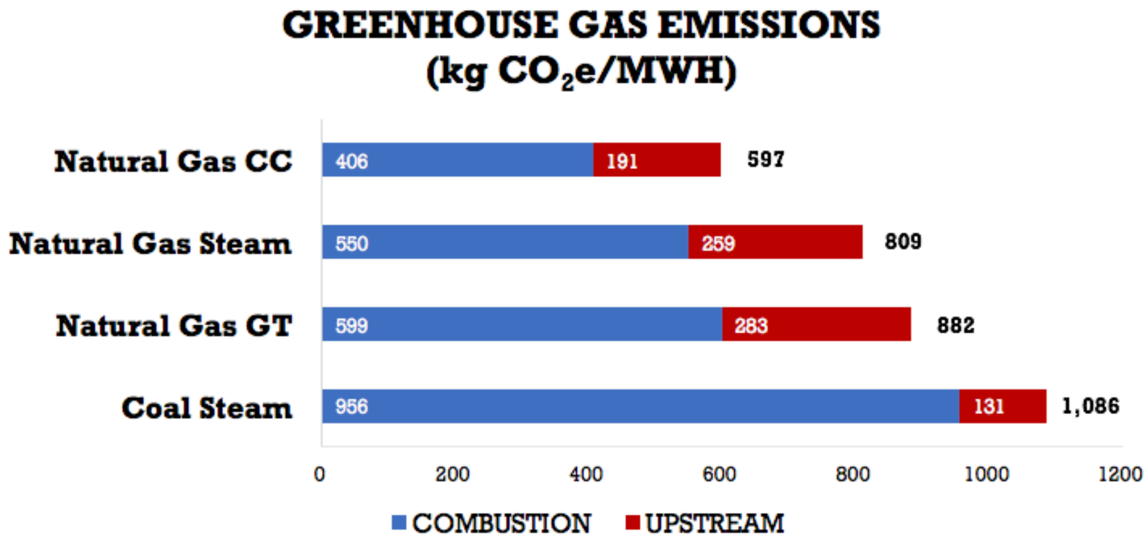

Figure 27. Comparative analysis of our estimated upstream emissions and average combustion emissions for natural gas and coal.

However, when upstream emissions are included in comparison, natural gas emits closer to three-quarters of coal's emissions total. The latter proportion offers a more accurate portrayal of the relative climate impact these two fossil fuels have in the generation of electricity, according to our calculations. For climate policies regarding electricity sector emissions targets, both upstream and combustion emissions should be considered, rather than just combustion emissions.

11. Renewables in Comparison

Renewables offer the lowest-carbon intensive electricity source, but are not entirely carbon-neutral. When replacing fossil fuel-intensive coal and natural gas with renewable alternatives like hydropower, wind turbines and solar power, one must still consider their upstream emissions and environmental impact. The main sources of greenhouse gas emissions are found in land-use change for technology installation, materials production, and overall operational energy use. A 2012 Life Cycle Assessment of renewable energy dissected the relevant greenhouse gas emission intensities for wind turbine materials, which includes 1.48 kg CO_2e/kg (Cast iron), 1.45 kg CO_2e/kg (reinforcing steel), 1.72 kg CO_2e/kg (low-alloy steel), and 4.50 kg CO_2e/kg (chromium steel). The life cycle emissions for competitors were estimated to be 3-7 g/KWh for hydropower, 14-32 g/KWh for concentrating solar, and 29-80 g/KWh for solar photovoltaic power.[24] Although these technologies necessitate some greenhouse gas emissions, total life cycle emissions are negligible in comparison to the upstream emissions of coal and natural gas, without even addressing the emissions required for fossil fuel combustion.

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Appendix

Compilation of Coal Studies Used for Model

Year	Study	Author Name	Specific Upstream Process	Model Category	Emissions Factor
1999	Method for Estimating Methane Emissions from Coal Mining	ICF	Surface mining methane	Production	95.215595 kg CO2e/short ton
2012	Life Cycle Greenhouse Gas Emissions of Coal - Fired Electricity Generation	Whitaker et al.	Underground mining regions	Production	1249.020771 kg CO2e/short ton
2015	Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation	Jaramillo et al.	Surface mining methane	Total Upstream	133.6963938
2011	Coal to gas: the influence of methane leakage	Wigley	Surface mining methane	Pre-Production and Production	0.149014343 kg CO2e/short ton
2011	Coal to gas: the influence of methane leakage	Wigley	Underground mining methane	Pre-Production and Production	0.330016057 kg CO2e/short ton
2009	Terrestrial Carbon Disturbance from Mountaintop Mining Increases Lifecycle Emissions for Clean Coal	DOE	Surface mining	Production	54.43114913 kg CO2e/short ton
2009	Terrestrial Carbon Disturbance from Mountaintop Mining Increases Lifecycle Emissions for Clean Coal	DOE	Underground mining methane	Production	36.29 kg CO2e/short ton
2008	Natural Gas LCA Update	Deutsche Bank	Surface mining	Production	7.746038793 kg CO2e/short ton
2008	Natural Gas LCA	Deutsche Bank	Surface methane	Pre-Production and	146.555054 kg

	Update			Production	CO2e/short ton
2008	Natural Gas LCA Update	Deutsche Bank	Underground mining	Production	4.04397459 kg CO2e/short ton
2008	Natural Gas LCA Update	Deutsche Bank	Underground methane	Pre-Production and Production	76.51199925 kg CO2e/short ton
1999	Life Cycle Assessment of Coal-fired Power Production	Spath et al.	Surface mining	Production	51.86963333 kg CO2e/short ton
2002	Substitution of Natural Gas for Coal: Climatic Effects of Utility Sector Emissions	Hayhoe et al.	Surface methane	Pre-Production	668.2087754 kg CO2e/short ton
2002	Substitution of Natural Gas for Coal: Climatic Effects of Utility Sector Emissions	Hayhoe et al.	Underground methane	Pre-Production	348.8517655 kg CO2e/short ton

Compilation of Natural Gas Studies Used for Model

Year	Study	Author Name	Specific Upstream Process	Model Category	Emissions Factor
2011	Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum	Burnham et al.	Liquids Unloading (Conventional)	Production	1.98217739 kg CO2e/MMBtu
2011	Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum	Burnham et al.	Flaring (Conventional)	Production	0.49482314 kg CO2e/MMBtu
2011	Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum	Burnham et al.	Flaring (Shale)	Production	0.49482314 kg CO2e/MMBtu
2011	Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum	Burnham et al.	Fugitive at well (Conventional)	Production	1.20582458 kg CO2e/MMBtu
2011	Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum	Burnham et al.	Fugitive at well (Shale)	Production	1.20582458 kg CO2e/MMBtu
2011	Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum	Burnham et al.	Lease/Plant Energy (Conventional and Shale)	Processing & Refining	0.87780992 kg CO2e/MMBtu
2011	Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum	Burnham et al.	Fugitive at Plant (Conventional and Shale)	Processing & Refining	0.24777217 kg CO2e/MMBtu
2011	Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum	Burnham et al.	Fugitive transmission (Conventional and Shale)	Transportation and Transmission	1.10671571 kg CO2e/MMBtu

2016	Using Common Boundaries to Assess Methane Emissions: A Life Cycle Evaluation of Natural Gas and Coal Power Systems	Littlefield et al.	Fugitive at well (Shale)	Production	0.71028023 kg CO2e/MMBtu
2016	Using Common Boundaries to Assess Methane Emissions: A Life Cycle Evaluation of Natural Gas and Coal Power Systems	Littlefield et al.	Total Processing (Shale)	Processing & Refining	0.41295362 kg CO2e/MMBtu
2016	Using Common Boundaries to Assess Methane Emissions: A Life Cycle Evaluation of Natural Gas and Coal Power Systems	Littlefield et al.	Total Transmission & Transportation	Transportation & Transmission	0.74331652 kg CO2e/MMBtu
2014	Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation	DOE	Total Production (Conventional)	Production	1.56 kg CO2e/MMBtu
2014	Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation	DOE	Total Production (Shale)	Production	2.44 kg CO2e/MMBtu
2014	Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation	DOE	Total Processing (Conventional)	Processing	0.00103238 kg CO2e/MMBtu
2014	Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation	DOE	Total Processing (Shale)	Processing	0.00161475 kg CO2e/MMBtu
2014	Comparative Life-cycle Air Emissions of Coal, Domestic	DOE	Total Transmission & Transportation	Transportation & Transmission	0.00343249 kg CO2e/MMBtu

	Natural Gas, LNG, and SNG for Electricity Generation		(Conventional)		
2014	Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation	DOE	Total Transmission & Transportation (Shale)	Transportation & Transmission	0.00536877 kg CO2e/MMBtu
2014	US GHG Inventory	EPA	Fugitive at well (Conventional)	Production	5.18709867 kg CO2e/MMBtu
2014	US GHG Inventory	EPA	Fugitive at well (Shale)	Production	8.113154 kg CO2e/MMBtu
2014	US GHG Inventory	EPA	Total Processing (Conventional)	Processing & Refining	1.14237552 kg CO2e/MMBtu
2014	US GHG Inventory	EPA	Total Processing (Shale)	Processing & Refining	1.786792 kg CO2e/MMBtu
2014	US GHG Inventory	EPA	Total Transmission & Transportation (Conventional)	Transportation & Transmission	2.053896 kg CO2e/MMBtu
2014	US GHG Inventory	EPA	Total Transmission & Transportation (Shale)	Transportation & Transmission	3.212504 kg CO2e/MMBtu
2012	Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications	Weber and Clavin	Total Pre-production (Conventional and Shale)	Pre-Production	0.958416504 kg CO2e/MMBtu
2012	Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications	Weber and Clavin	Liquids Unloading (Conventional)	Production	11.54657664 kg CO2e/MMBtu
2012	Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications	Weber and Clavin	Workover (Shale)	Production	1.816995944 kg CO2e/MMBtu
2012	Life Cycle Carbon Footprint of Shale Gas: Review of	Weber and Clavin	Flaring (Conventional and	Production	0.1688096 kg CO2e/MMBtu

	Evidence and Implications		Shale)		
2012	Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications	Weber and Clavin	Fugitive at Well (Conventional and Shale)	Production	8.20414656 kg CO2e/MMBtu
2012	Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications	Weber and Clavin	Lease/Plant Energy (Conventional and Shale)	Processing & Refining	3.376192 kg CO2e/MMBtu
2012	Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications	Weber and Clavin	Fugitive at the plant (Conventional and Shale)	Processing & Refining	5.46943104 kg CO2e/MMBtu
2012	Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications	Weber and Clavin	Compression Fuel (Conventional and Shale)	Transportation & Transmission	0.422024 kg CO2e/MMBtu
2012	Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications	Weber and Clavin	Fugitive Transmission (Conventional and Shale)	Transportation & Transmission	5.77328832 kg CO2e/MMBtu
2011	Methane and the greenhouse-gas footprint of natural gas from shale formations	Howarth et al.	Well Completion: Flowback and Drillout (Conventional)	Pre-Production	0.016518145 kg CO2e/MMBtu
2011	Methane and the greenhouse-gas footprint of natural gas from shale formations	Howarth et al.	Well Completion: Flowback and Drillout (Shale)	Pre-Production	3.13844754 kg CO2e/MMBtu
2011	Methane and the greenhouse-gas footprint of natural gas from shale formations	Howarth et al.	Liquids Unloading (Conventional)	Production	0.429471769 kg CO2e/MMBtu
2011	Methane and the greenhouse-gas footprint of natural gas from shale formations	Howarth et al.	Fugitive at the well (Convenional and Shale)	Production	1.816995944 kg CO2e/MMBtu

2011	Methane and the greenhouse-gas footprint of natural gas from shale formations	Howarth et al.	Total Processing (Conventional and Shale)	Processing & Refining	0.165181449 kg CO2e/MMBtu
2011	Methane and the greenhouse-gas footprint of natural gas from shale formations	Howarth et al.	Total Transmission & Transportation (Conventional and Shale)	Transportation & Transmission	4.129536237 kg CO2e/MMBtu

Compilation of EDF Studies and Emissions Factors

Year	Study	Author Name	Study Region	Upstream Process	Emissions Factor	Margin of Error	Methodologies
2017	Assessing the Methane Emissions from Natural Gas-Fired Power Plants and Oil Refineries	Tegan Lavoie et al.	Indiana	Refining	140 kg CH_4/hour	70	Aircraft top-down and ground level bottom-up measuring of 3 NG power plants
2015	Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers	David Allen, Adam Pacs, David Sullivan	Appalachian Region	Production	1.7 scf/hour		
2015	Pneumatic Controllers	David Allen, Adam Pacs, David Sullivan	Gulf Coast	Production	11.9 scf/hour		
2015	Pneumatic Controllers	David Allen, Adam Pacs, David Sullivan	Mid-Continent	Production	5.8 scf/hour		
2015	Pneumatic Controllers	David Allen, Adam Pacs, David Sullivan	Rocky Mountain	Production	0.8 scf/hour		
2014	Assessment of Methane Emissions from Oil and Gas Production Pads Using Mobile Measurements	Halley Brantley et al.	Barnett Shale	Total fugitive emissions per well	0.33 g CH_4/second		Disputes Allen - says his study wasn't thorough. Claims there's weak correlation between emission- and production rates.
2014	Assessment of Methane Emissions from Oil and Gas Production Pads Using Mobile Measurements	Halley Brantley et al.	Denver-Julesburg Shale	Total fugitive emissions per well	0.14 g CH_4/second		
2014	Assessment of Methane Emissions from Oil and Gas Production Pads Using Mobile Measurements	Halley Brantley et al.	Pinedale Shale	Total fugitive emissions per well	0.59 g CH_4/second		