Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum: Supporting Information

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1. Key GREET Parameters

Table S1 lists the key parameters and data sources for natural gas pathways for the GREET simulations in this analysis.

Table S1. Key Parameters for Natural Gas Simulation in GREET (mean values with ranges in parentheses)

	Units	Conventional	Shale	Distribution	Source
Well Lifetime	Years	30	30		Argonne assumption
Well Methane Content	%	85 (69-95)	80 (40-97)	Weibull	Hanle ¹
Production over Well Lifetime	NG million cubic feet	1,017 (785-1,249)	3,460 (1,600-5,320)	Normal	Conv: EIA ² ; Shale: Mantell ³
Well Completion and Workovers (Venting)	metric ton NG/completion or workover	0.71	177 (13.5 - 385)	Weibull	EPA ⁴
CH ₄ Reductions for Completion/Workovers	%	0	41 (37-70)	Gamma	EPA ⁵ ; NG STAR ⁶
Number of Workovers per well lifetime	workovers/lifetime	2	2		EPA ⁴
Liquid Unloadings (Venting)	metric ton NG/unloading	0.86	0		EPA ⁴
Liquid Unloading Events	unloadings/year	31 (11-51)	0	Normal	EPA ⁴
CH ₄ Reductions for Liquid Unloadings	%	12 (8-15)	0	Normal	EPA ⁵ ; NG STAR ⁶
Wells Requiring Unloadings	%	41.3	0		EPA ⁴
Well Equipment (Leakage and Venting)	g CH ₄ per million Btu NG	209 (114-303)	209 (114-303)	Normal	GAO ⁷ ; EPA ⁵
CH ₄ Reductions for Well Equipment	%	28 (18-37)	28 (18-37)	Normal	EPA ⁵ ; NG STAR ⁶
Well Equipment (CO ₂ from Flaring)	g CO ₂ per million Btu NG	454 (369-538)	454 (369-538)	Normal	GAO ⁷ ; EPA ⁵
Well Equipment (CO ₂ from Venting)	g CO ₂ per million Btu NG	41	41		EPA ⁵
Processing (Leakage and Venting)	CH ₄ : % of NG produced	0.15 (0.06-0.23)	0.15 (0.06-0.23)	Weibull	EPA ⁵
Processing (CO ₂ from Venting)	g CO ₂ per million Btu NG	878 (615-1140)	878 (615-1140)	Normal	EPA ⁵
Transmission and Storage (Leakage and Venting)	CH ₄ : % of NG produced	0.39 (0.2-0.58)	0.39 (0.2-0.58)	Weibull	EPA ⁵
Distribution (Leakage and Venting)	CH ₄ : % of NG produced	0.28 (0.09-0.47)	0.28 (0.09-0.47)	Weibull	EPA ⁵

2. Natural Gas Background Information and Key Activity Factors

Production of NG from shale formations has occurred since the first gas well was completed in 1821 in Fredonia, New York. Field-scale development occurred in the 1920s in the Ohio Shale and the 1930s in the Antrim Shale. However, shale formations typically have low permeability, which created both technical and economic challenges to large-scale development. Large-scale shale gas production started with Mitchell Energy and Development Corporation in the Barnett Shale and with their success many other companies followed suit by tapping into this natural gas bearing geologic formation or play. Advances in drilling technologies and increases in NG prices led to rapid expansion into other formations including the Haynesville, Marcellus, and other shales.

The two technological advances that led to rapid expansion of shale gas development were horizontal drilling and hydraulic fracturing. In horizontal drilling, a well is drilled down to the depth of the play and turned approximately 90 degrees to the horizontal to run laterally through the play for 600 to 2,000 meters. For the purposes of our analysis, the horizontal shale gas wells were based on designs for the 4H, 5H, and 6H Carol Baker wells and modified according to the depth of the shale play.⁸⁻¹⁰ Vertical wells draw from a much smaller area within a play. For the vertical well design of the conventional gas scenario, an example design from the Mississippi Smackover was adjusted to the national average depth of gas wells.^{11,12} Because of the long lateral reach of horizontal wells, they can access more of the play increasing production on a per well basis.¹³

Due to the low permeability of shale, which limits the flow of NG within the formation, producers hydraulically fracture the formation to enable the flow of NG. This is accomplished by pumping fracture fluid at a predetermined rate and pressure sufficient to create fractures in the target formation. The fracture fluid for shale formations is typically water-based with proppants to maintain fracture openings once established and the pumping of fracture fluid has ceased. For this analysis, constituents were based upon fracking data made available by Range Resources, which released frac fluid information for several of its Marcellus wells.⁸⁻¹⁰ The details of the GHG emissions from material and energy requirements for drilling and well construction for both SG and NG wells are documented in Clark *et al.*³⁹ This analysis also examines the emissions from transportation and management of fracturing fluids. These emissions are incorporated into this study and can be seen in Figure 2 of the paper.

Downstream from the production sector, NG passes through a processing stage in which undesirable elements of raw gas such as NG liquids are removed. The processed NG enters the transmission and storage (T&S) stage, in which NG is moved long distances through high-pressure pipelines. Compressor station facilities, where turbines and compressors force the gas through the large diameter pipes, dot the transmission pipeline network. At times, NG is delivered directly from the transmission network to industrial customers. Alternatively, the gas may be stored underground or liquefied and stored in above-ground tanks. Before residential and commercial customers access the gas, its pressure is reduced and it travels through the distribution network of low-pressure pipes that are often underground.

Tables S2 and S3 detail key activities that result in fugitive GHG emissions from natural gas recovery, processing, transmission, storage, and distribution.

Table S2. Selected Activity Factors for the Recovery of Natural Gas

Stage	Sample Activity Data for Shale and Conventional Gas Unless Otherwise Noted
Well Completions	<ul style="list-style-type: none"> • Drill out CH₄ venting • Flow back CH₄ venting (shale only)
Workovers	<ul style="list-style-type: none"> • CH₄ venting
Liquid Unloading	<ul style="list-style-type: none"> • CH₄ venting (conventional only)
Miscellaneous Venting	<ul style="list-style-type: none"> • Field separation equipment • Gathering compressors • Normal operations • Condensate collection • Compressor Venting • Upsets
Flaring	<ul style="list-style-type: none"> • CO₂ emissions

Table S3. Selected Activity Factors for the Processing, Transmission, Storage, and Distribution Sectors

Sector	Sample Activity Data
Processing	<ul style="list-style-type: none"> • Processing plants • Centrifugal compressors • Acid gas removal vents (CO₂ source) • Blowdowns/venting
Transmission and Storage	<ul style="list-style-type: none"> • Reciprocating and centrifugal compressors • Dehydrator vents • Pneumatic devices
Distribution	<ul style="list-style-type: none"> • Miles of mains and services by material (iron, steel, plastic, copper) • Metering and regulating stations • Residential customer meters

3. Methodological Details

In this section, we provide further details about our methodology. We also explain EPA methodologies in developing the U.S. GHG Inventory, a significant data source for our work. Finally, this section contains detailed explanations of Howarth *et al.*'s methodology as a basis for understanding differences between the results of those researchers and our own.

Figure S1 illustrates NG system emission trends and reveals the significant impacts of EPA's methodology changes for the 2011 inventory, which included adding separate emission factors for shale gas wells, as compared to previous versions.^{5,53}

Figure S1. Estimated NG System CH₄ Emissions^{5,53}

3.1 Natural Gas Estimated Ultimate Recovery

To compare natural gas with other energy technologies, it was necessary to determine the estimated ultimate recovery (EUR) of gas from a well. For shale gas wells, a range was developed for EURs according to the per-well weighted average of four major plays: Marcellus, Barnett, Haynesville, and Fayetteville. The high estimates were based upon industry average targeted EURs.³ The low estimates were based upon a review developed for EIA of emerging shale resources.⁴⁰ As there is a great deal of variability in EUR within a play, the INTEK analysis captured the variability by evaluating the EUR for the best area, the average area, and the below average area in a play. INTEK further presented EURs for active portions and undeveloped portions of major plays. Generally, the active portions of the play had larger EURs than the undeveloped areas. The active EURs reported in INTEK were similar to the industry average targeted EURs with the exception of the Marcellus play. While the active reported EURs reported by INTEK were lower for the Marcellus than the industry average targeted EUR, the industry average targeted EUR was contained within the range of EURs presented for the best, average, and below average Marcellus developed area EURs. We averaged the high and low values, see Table S4, to estimate our base-case shale gas well EUR of 3.5 billion cubic feet (Bcf).

Table S4. Lifetime production estimates according to play

	Low EUR Estimates (Bcf) ⁴⁰	High EUR Estimates (Bcf) ³
Barnett	1.4	3.0
Marcellus	1.4	5.2
Fayetteville	1.7	2.6
Haynesville	3.5	6.5
Per-Well Weighted Average	1.6	5.3

For the conventional NG EUR, we assumed an average production rate over the lifetime of the well according to EIA production data and EPA well compositional makeup recognizing that production rates typically decline over time to estimate a base-case EUR of 1.0 Bcf.^{2,5} Our estimate of conventional EUR is comparable to an analysis of Texas wells prior to large-scale shale gas production.¹⁴ For emissions after recovery, we based our emission calculations on total production of SG and NG as we did not need to differentiate by gas source.²

3.2 Natural Gas Well Completions, Workovers, Liquid Unloadings, Leakage and Venting

To estimate emissions from conventional well completions, we use the updated value from EPA⁴ of 0.71 metric tons NG per conventional well completion (EPA mislabeled the units in the report and thus must be converted to using the methane content of NG, which we estimated to be 84.6% for conventional wells). We divided this emission factor by our estimate of EUR. As mentioned above, the EUR was determined by dividing the conventional gas production by the total number of producing conventional gas wells in 2009.² Furthermore, the total number of conventional gas producing wells was determined by multiplying the total number of wells reported by EIA by the percent of conventional gas wells to total gas wells by EPA.^{2,5}

For conventional well completion emissions, Howarth *et al.* also cite the EPA.^{4,15} This is converted to an NG emission factor assuming a 78.8% methane content. The NG emission factor is multiplied by the total well count in 2007 and divided by the total NG produced in 2007 to arrive at the percent methane produced over the well lifecycle. It is likely that the differences in approach and production years account for the differences in emissions between our study and Howarth *et al.*¹⁵ Nonetheless, these emissions are significantly smaller than those for unconventional wells, as they do not require hydraulic fracturing.

Another issue with these estimates can be demonstrated by examining Howarth *et al.*¹⁵, which included some of the data from the NG STAR program.⁴¹⁻⁴⁴ Several of these estimates based their flowback emissions on initial production (IP) rates, which are calculated following hydraulic fracturing and flowback. In practice, the flowback initially brings up mostly sand and frac fluids, and as the sand and water are removed from the well, the gas concentration increases. When the well builds to a high enough pressure, the operators stop venting and send the gas to the gathering lines. Therefore using IP for the entire flowback period will overestimate completion emissions. In Howarth *et al.*'s estimate for the Haynesville shale, which was used as their high-end estimate for the range of completion emissions, they used IP estimates from an industry report¹⁶, which highlighted several high volume wells in this play. They assumed flowback would last 10 days (as they did not have a reference for this play) and

when multiplied by the IP (roughly 24,000 Mcf/day) for these high producing wells, the resulting emissions might be overestimated for this play. With these methodological issues, it is clear that the emission factors require further development to help reduce the uncertainties involved with shale well completions.

Our unloading estimates are significantly higher than Howarth *et al.*¹⁵ which estimated liquid unloadings from GAO.⁴⁵ The GAO estimates were based upon 2006 estimates from the Western Regional Air Partnership, which determined emissions in part from surveying operators, and on 2008 estimates from EPA, which were developed prior to their methodological change.

Howarth *et al.* developed their methane emissions for well equipment leakage and venting from GAO and calculated an emission leakage range between 0.3% (for best available technology) and 1.9% of NG produced.^{15,45} Howarth *et al.* did not provide estimates of CO₂ emissions for flaring or venting.¹⁵

3.3 Determination of Natural Gas Recovery Sector Emissions Reductions

The EPA updated emission factors for shale gas well completions and NG liquid unloadings because the methane reductions reported by the NG STAR program were larger than the total emissions for each activity calculated using its previous methodology. Howarth *et al.*¹⁵ discussed potential emission reduction opportunities for NG pathways but did not assume any reductions. In our analysis, which is primarily based on EPA data, the unmitigated emission factors for each activity in the NG recovery sector were adjusted to represent real world conditions. However, EPA⁴ only provided aggregated emissions reductions for both NG STAR program and the National Emission Standards and Hazardous Air Pollutants (NESHAP) regulations, and as a result, the reduction estimates do not provide details on which activity's emissions are reduced in the real world.

As the focus of this analysis is to not only determine total emissions from shale and conventional NG pathways but also to examine the key issues and uncertainties, we needed to separate the recovery reductions based on our key parameters. Therefore, we examined data from the NG STAR program⁶ to estimate emissions reductions for each activity. We grouped the recovery sector technologies listed in NG STAR documentation and their respective CH₄ reductions into three categories: (1) unconventional well completions, (2) conventional liquid unloadings, and (3) well equipment venting and leakage. As the NG STAR program only provides partially aggregated results to protect confidential business information, the reduction data lack details. However, we were able to separate out most of the reductions from RECs and liquid unloading-based technologies through background information provided by EPA and thus able to estimate the equipment emissions.¹ For example, the emission savings reported by NG STAR program partners for RECs were the largest category of savings, ranging from 33% to 56% of the reductions from the production sector for each year from 2005 to 2009.

The NESHAP regulations set standards to reduce emissions of hazardous air pollutants, though these regulations have a secondary benefit in reducing methane emissions. In EPA GHG inventory estimates, emissions from flaring are included under NESHAP reductions, as states such as Wyoming require that vented emissions from well completions and workovers be flared. Assuming that Wyoming state law requires completion flaring while Texas, Oklahoma, and New Mexico do not, EPA⁴ estimated that approximately 51% of unconventional wells were located in Wyoming and then extrapolated this percentage of completions that are required to be flared to all unconventional wells in the United States.

The EPA conducts quality assurance and control checks of the NG STAR reductions prior to incorporating them into its inventory estimates. However, as this information is confidential and the emission reductions from NG STAR and NESHAP are considerable, about 30% of the unmitigated emissions in 2009, more detailed information is needed to examine and verify these reductions. In order to address some of the uncertainty in these estimates, we developed distribution functions for these reductions. For shale completions, most of the uncertainty was due to flaring assumptions so our low-reduction scenario assumed only reductions from the NG STAR program (38%), while our base case assumed a small amount of flaring based on the number of wells in Wyoming along with the NG STAR reductions (41%), and finally our high-reduction scenario assumed the same amount of flaring as EPA⁴ along with NG STAR reductions (70%). For the second category, liquid unloadings, uncertainty results from NG STAR accounting practices as they do not report emission reduction projects that have exceeded an agency-prescribed sunset period, even though those emissions are still being reduced in practice. Therefore, we developed a low-reduction scenario for liquid unloadings based on reported NG STAR reductions (8%) and a high-reduction scenario where we adjusted for the sunset period (15%), while our base case is the average of those two. For the third category, well equipment, we developed a low-reduction scenario based on NG STAR and NESHAP reductions (18%) and a high-reduction scenario where we attempted to adjust for the sunset period (37%), while our base case is the average of those two.

3.4 Natural Gas Processing, Transmission and Storage, and Distribution

To calculate GHG emissions from the NG processing, transmission and storage (T&S), and distribution sectors, we divided the average emissions from these sectors by the average production of NG for this same time period.^{2,5} If NG exports were significant during this time period, this approach could underestimate emissions in the T&S and distribution sectors. Exports, however, were four percent of production in 2009, the year that saw the greatest volume of NG exports in the period between 2005 and 2009.² The use of NG production volume in the calculation of the emission factors is therefore reasonable.

Significant differences exist between our analysis of these sectors and that of Howarth *et al.* who, for the processing sector, used the mean emission facility-level gas processing fugitive CH₄ emission factor provided in the American Petroleum Institute's (API) Compendium, 0.19% to estimate processing sector emissions.^{15,17} They developed a range of 0% to 0.19% for these emissions. The lower bound of zero represents wells that produce pipeline-ready gas that needs no processing. They did not explicitly estimate CO₂ emissions from AGR vents in their analysis. Shires *et al.* use data from the 1990s, such as the 1993 volume of total gas processed; they state that the uncertainty associated with the reported emission factor is plus or minus 82.2%, placing the emission factor between 0.03% and 0.35% of total gas processed.¹⁷

In their analysis, Howarth *et al.*¹⁵ did not distinguish between the T&S and distribution sectors whereas our analysis breaks out emission factors for these sectors. The low value from Howarth *et al.*'s analysis (1.4%), Table S5 illustrates the derivation of this value is an estimate of emissions from the Russian NG transmission and distribution network.¹⁸ The estimate of NG leakage in the Russian T&S and distribution sectors is likely an overestimate of emissions for these sectors in the U.S. for several reasons. First, an examination of emissions suggests that the activity and emission factors for the two systems will be different. Specifically, compressor emissions in the Russian T&S sector indicate that the

emission factor for this sector in Lelieveld *et al.*¹⁸ is likely too high to be representative of T&S sector emissions in the U.S. Second, the estimate of leakage from the distribution sector was based on outdated U.S. emission rates from 2002 and earlier. In the U.S., this sector has seen emissions decrease significantly (13% between 1990 and 2009) with the adoption of lower-emitting technology such as plastic piping.⁵

Table S5. Derivation of Lelieveld *et al.*¹⁸ estimate of natural gas losses during transmission and distribution in Russia

Natural Gas Sector	Methane Loss (% of Total Throughput)	Data Source
Domestic Russian transmission	0.7% (0.4-1.6%)	Field measurements in Russia
Domestic Russian distribution	0.5 – 0.8%	Assumed the % of produced NG leaked in the Russian and U.S. distribution networks would be roughly equivalent
Domestic Russian gas spills at wells	0.1 ± 0.04%	Re-evaluation of data from Dedikov <i>et al.</i> ¹⁹
Total	1.4% (1.0 - 2.5%)	

The high value (3.6%) that Howarth *et al.* cite for the T&S and distribution sectors is the average of two years' estimates of lost and unaccounted for gas (LUG) in Texas.²⁰ LUG is an accounting term for the difference between the volume of gas produced and that sold. Percival²⁰ points out drawbacks to using LUG as an estimate of leaked NG. First, accuracy differences between wellhead and process plant measurement devices, compounded by ambient temperature variations, introduce discrepancies between measured volumes of produced and processed gas. Additionally, when NG is processed, high value liquids and impurities are separated, further widening the gap between the volumes of gas measured at the wellhead and post-processing. Finally, LUG calculations can include NG produced at the wellhead that is used as a process fuel in equipment used for gathering and processing, thereby depleting the amount of gas that ultimately is sold. Howarth *et al.* asserts that these factors (except gas theft) are randomly distributed and therefore will not yield a high or low bias in estimates of NG leakage. However, others assert that LUG will consistently overestimate actual emissions to the atmosphere.^{20,21} In summary, LUG is not a reliable means of quantifying NG leakage in the T&S and distribution sectors.

3.5 Treatment of Emissions from Early 1990s Natural Gas Systems to Current Systems

Key emission factors for NG systems in previous GREET versions were based on Harrison *et al.* (1996), which examined the NG system found in the early 1990s.²² However, as NG use in the U.S. increases, certain subsystems expand (such as NG wells and storage facilities), but other subsystems may not (such as NG transmission and distribution pipelines). To address this situation, previous input parameters to GREET implicitly assumed that only production and processing capacity would be added to the NG system to handle the increased demand between the early 1990s and now. The T&S and distribution sectors, however, had extra capacity and would not be expanded. As a result, emission factors from

Harrison *et al.* were modified prior to use in the previous version of GREET.^{22,36} As presented in Table S6, we updated CH₄ emission factors for NG in this study and as a result, the emission factors for the T&S and distribution sectors are markedly higher than in previous GREET analyses. Though, the most significant change from the previous GREET version is due to increased production emissions for both conventional NG and shale gas.

Table S6. Comparison of previous and current GREET emission factors with Harrison *et al.*^{22,36}

Sector	CH ₄ Emissions: Percent of Volumetric Natural Gas Produced			
	Harrison <i>et al.</i> ²²	Previous GREET Conv. NG ³⁶	New GREET Conv. NG	New GREET Shale Gas
Production	0.38	0.35	1.93	1.19
Processing	0.16	0.15	0.15	0.15
Transmission	0.53	0.27	0.39	0.39
Distribution	0.35	0.18	0.28	0.28

3.6 Coal Venting

Coal mining releases the methane generated through anaerobic digestion of plant material during the process of coal formation. Methane emissions come from several major mining activities: ventilation air and degasification systems at underground mines, direct release at surface mines, post-mining operations at both underground and surface mines, and leakage at abandoned underground mines. The concentration of methane at a coal seam increases with higher pressures and lower temperatures; while methane amounts vary by the geologic conditions at each mine, typically deep underground mines produce larger methane emissions than surfaces mines.²³ Figure S2 presents the fuel pathway for underground- and surface-mined coal.

Figure S2. System Boundary for Underground- and Surface-Mined Coal Pathways

The largest source of fugitive coal mining emissions, accounting for nearly 60% of the total, is from ventilation air and degasification systems at underground mines.⁵ In 2009, 135 of the 540 underground mines used ventilation systems, which dilute methane levels by circulating fresh air into the mine to reduce concentrations below levels that could cause an explosion.⁵ These systems release significant amounts of methane to the atmosphere, even though the emissions are at very low concentrations. The Mine Safety and Health Administration (MSHA) typically conducts quarterly air sampling of the mines utilizing ventilation systems; while all mines are periodically tested for methane content and safety conditions.⁴ The EPA uses the MSHA database of these measurements, which records all emissions

above the detection limit (greater than 50 part per million) to calculate the total emissions from underground mining. They have found that roughly 20% of the mines emit more than 100 Mcf per day account and estimate that those account for more than 85% of emissions from active underground mines. The EPA ignores the potential emissions for mines with the non-detectable emissions; DOE guidelines specify that these emissions can be estimated but account for very small amounts.

In mines that have very high concentrations of methane, degasification systems are used to remove the gas by pumping it through a network of boreholes and gas gathering pipelines. Drainage wells can be used for several years in advance of coal mining operations and can involve hydraulic fracturing, similar to shale gas operations, to remove methane and water from the seam. The EPA reports that 50% to 90% of the gas from the coal seam can be recovered by pre-mine drainage. However, systems that are employed during mining operations recover less methane and typically vent it to the atmosphere. Currently, 20 underground mines utilized degasification systems, while 13 of those collected the gas to sell it to a pipeline and one mine used the gas to heat the ventilation air. The rate of collection and utilization of this gas expanded rapidly in the second half of the 1990's and the early 2000's as NG prices grew; however recently the rate has plateaued at roughly 30% and in the future the economics of capture and utilization may be affected by the abundance of shale gas.

There is a relatively low level of uncertainty for the absolute emissions of underground mining as of the extensive data collected by MSHA; however, there is some uncertainty created in our estimates of emissions per mass of coal produced, as the absolute emissions are not highly perfectly correlated to coal production. As the Inventory does not separate uncertainty for each activity, we examined variation in year-by-year emissions per ton of coal produced similar to the overall uncertainty presented for coal mining in the Inventory.⁵ We therefore assumed an uncertainty of plus 16% and minus 13%.

Currently there are 867 surface mines in the U.S.; at these mines methane is released when the overlying rock and sediments are removed exposing the coal. There is considerable uncertainty in the actual surface emissions as the EPA developed emission factors based on sampling methane content of surface coal in each of the 18 coal sub-basins they classified. Emission factors were estimated to be between one and three times the average in situ content. The EPA assumed twice the methane content in the basin; thus, we assumed an uncertainty of plus or minus 50%.⁵

After mining at both underground and surface mines, the coal goes through several operations that release CH₄ to the atmosphere, such as storage and cleaning. For these operations, the emissions are also calculated based CH₄ content of the basin. Emission factors were estimated to be between 25% and 40% times the average in situ content. The EPA assumed the emissions would be 32.5% of the methane content in the Inventory; thus, we assumed an uncertainty of plus or minus 23%.⁵

Abandoned (or closed) underground mines that no longer produce coal can still vent CH₄ to atmosphere. The rate of emissions declines after initial closure but can reach a steady-state of emissions over many years. However, if the mine floods, it may quickly stop producing for periods. There is a relatively large uncertainty (plus 32% and minus 27%) associated with these emissions, which emanate from fissures, boreholes and other leakage points. Hence, EPA estimates emissions using equations that take into account factors such as the coal's adsorption isotherm, permeability, and pressure at abandonment.⁵

Table S7 provides GREET emission factors we used in this analysis.

Table S7. Coal Methane Emission Factors Used for Simulation in GREET (means values with ranges in parentheses)

	Units	CH ₄ Emissions	Distribution	Source
Underground Mine Ventilation/Degasification Venting	g CH ₄ per million Btu coal	279 (215-360)	Weibull	EPA ⁵
Underground Mine Post Mining Venting	g CH ₄ per million Btu coal	42 (32-52)	Normal	EPA ⁵
Abandoned Underground Mine Venting	g CH ₄ per million Btu coal	39 (18-63)	Weibull	EPA ⁵
Surface Mine Venting	g CH ₄ per million Btu coal	43 (21-64)	Normal	EPA ⁵
Surface Mine Post Mining Venting	g CH ₄ per million Btu coal	6.9 (5.3-8.5)	Normal	EPA ⁵

In comparison with our analysis, Howarth *et al.* cite IPCC, Lightly and Shires *et al.* to estimate that underground mine emissions are 8.4 cubic meters per ton of coal (or approximately 310 grams CH₄ per million Btu of coal), while surface mine emissions are 2.3 cubic meters per ton of coal (or approximately 84 grams CH₄ per million Btu of coal).^{15,17,24,25}

3.7 Coal Infrastructure

From previous studies, GREET already included the fuel consumption for coal mining. To be consistent with other pathways in this study, materials (infrastructure) required for coal mining are added from the data by NETL, show, in Table S8.²⁶

Table S8. Material Requirements Coal Mine Infrastructure

	Per kg coal produced	Per million Btu coal produced
Cold-Rolled Steel	1.47×10^{-5} kg/kg coal	5.94×10^{-7} MT/million Btu
Hot-dip Galvanized Steel	1.52×10^{-6} kg/kg coal	5.60×10^{-8} MT/million Btu
Steel Plate	1.80×10^{-4} kg/kg coal	1.11×10^{-5} MT/million Btu
Steel, Stainless, 316	6.77×10^{-8} kg/kg coal	4.74×10^{-9} MT/million Btu
Stainless Steel Cold Roll 431	6.77×10^{-8} kg/kg coal	2.42×10^{-9} MT/million Btu
Rebar	1.41×10^{-6} kg/kg coal	9.65×10^{-8} MT/million Btu
Rubber	4.45×10^{-7} kg/kg coal	1.80×10^{-8} MT/million Btu
Concrete	6.06×10^{-5} kg/kg coal	2.45×10^{-6} MT/million Btu
Polyvinylchloride Pipe	1.30×10^{-7} kg/kg coal	5.25×10^{-9} MT/million Btu
Cast Iron	3.38×10^{-7} kg/kg coal	1.37×10^{-8} MT/million Btu
Copper Mix	8.11×10^{-9} kg/kg coal	3.28×10^{-10} MT/million Btu
Asphalt	1.11×10^{-3} kg/kg coal	1.64×10^{-3} million Btu/million Btu coal

Even though NETL elaborated six steel products, they are considered identical in GREET. Asphalt is assumed to have the same upstream energy and emissions per energy unit as residual oil. However, since asphalt is not combusted as residual oil, no emissions from its application are accounted for in our simulations. Also, other carbon emissions during asphalt's combustion (such as VOC, PM) are not taken into account because they are included by the non-combustion emissions in the fuel cycle. The lower heat value of asphalt is 16,680 Btu/lb.

3.8 Oil Flaring and Venting

Figure S3 presents the fuel pathway for oil production for both crude oil and from oil sands.

Figure S3. System Boundary for Crude Oil and Oil Sands Pathways

In this analysis we use volumes of flaring emissions for each country (2008 reference year) estimated by satellite data and combine it with EIA oil production data for the same countries to calculate a ratio of gas flared to crude oil produced.^{46,47} We then compiled a list of U.S. oil imports from EIA, and after adding the U.S. crude oil production, we calculated the proportional contribution of each country to the average barrel of crude oil used in U.S. refineries.⁴⁸ Table S9 provides the list of oil production and flaring data by region.

Table S9. 2008 Oil Production and Flare Data⁴⁶⁻⁴⁸

	Estimated Gas Flared	Crude Oil Production	Gas Flared per Oil Produced	U.S. Crude Oil Origin		Flared Gas Contribution to Average U.S. Barrel	
	Billion cubic meters (bcm)	Thousand barrels per day (kbpd)	Cubic meters per barrel (m3/bbl)	Thousand barrels per day (kbpd)	%	Cubic meters per U.S. average barrel (m3/bbl)	%
Africa	36.19	10,056	9.86	1,910	13.37	1.72	50.94
Nigeria	15.18	2,211	18.80	776	5.43	1.02	30.28
Congo (Kinshasa)	0.39	22	48.81	9	0.06	0.00	0.00
Rest Africa	20.62	7,823	7.22	1,125	7.87	0.70	20.66
Asia	6.92	6,984	2.72	88	0.62	0.02	0.64
Vietnam	0.52	346	4.13	27	0.19	0.01	0.23
Rest Asia	6.40	6,638	2.64	61	0.43	0.01	0.40
Europe	1.31	3,852	0.93	161	1.13	0.01	0.43
FSU	39.17	12,486	8.59	322	2.25	0.17	4.93
Russia	35.24	9,934	9.72	230	1.61	0.16	4.64
Azerbaijan	0.13	1,012	0.36	75	0.52	0.00	0.00
Rest FSU	3.80	1,540	6.75	17	0.12	0.01	0.29
Middle East	19.53	19,880	2.69	1,687	11.81	0.43	12.79
Iraq	9.13	2,400	10.42	449	3.14	0.33	9.71
Rest Middle East	10.40	17,480	1.63	1,238	8.67	0.10	3.08
North America	6.71	15,586	1.18	8,348	58.43	0.64	18.90
United States	2.06	9,141	0.62	5,317	37.22	0.23	6.82
Canada	2.07	3,294	1.72	1,899	13.29	0.23	6.78
Rest North America	2.58	3,151	2.24	1,132	7.92	0.18	5.29
South America	6.39	7,208	2.43	1,755	12.28	0.38	11.37
Venezuela	2.83	2,471	3.14	951	6.66	0.21	6.20
Rest South America	3.56	4,736	18.12	804	5.63	0.17	5.17
TOTAL	116.22	76,053	22.29	14,271	100.0	3.37	100.0

Determination of flare efficiencies is a critical for estimating the GHG effects of associated gas flaring. Flare efficiency is defined as the ratio of the “mass rate of carbon in the form of CO₂ produced by the flame” to the “mass rate of carbon in the form of hydrocarbon fuel exiting the flare”.²⁷ The flare efficiency value typically used in the literature is 98%, although in rare occasions efficiencies can drop as low as 70%.^{4,27,28}

We also determined associated gas flaring and venting for oil produced domestically. For U.S.-origin crude the EPA GHG Inventory shows venting of 719 Gg of CH₄ at the wellhead, or equivalently 0.91 bcm.⁵ The estimated gas flared volume for the U.S. is 2.06 bcm giving a ratio of vented to flared gas of 0.44. This ratio compares well with the values for all U.S.-bound crude as U.S.-originated crude should have lower associated flared gas volumes.

Another important data point for calculating the GHG effects of gas venting and flaring is the composition of the considered associated gas. Some references point out the similarities between associated gas and NG.²⁸ We have used full composition data from a Word Bank-sponsored study.²⁹ The study presents a range of representative gas compositions, classified according to the percentage of C3 and C4 hydrocarbon gases present. Our typical gas composition contains 5% C3+C4, while we consider a distribution between 0% and 15%. In order to model the gas composition we use carbon content (weight % Carbon, to estimate CO₂ emissions after flaring), methane content (very important for vented gas and non-burned flared portion), CO₂ content (also mostly for vented and non-burned flared portion), and the lower heating value (LHV), of the three representative gas compositions, shown in Table S10.

Table S10. Associated Gas Composition

	Unit	0% C3+C4	5% C3+C4	15% C3+C4	Distribution
C content	wt%	69.40	71.08	73.71	Weibull
CH ₄	mol%	87.00	82.26	73.95	Weibull
CO ₂	mol%	2.80	2.65	2.38	Normal
LHV	Btu/ft ³	941	1026	1209	Triangular

We estimated the average flaring emissions to be 1,063 grams CO₂ per million Btu of crude oil and the vented emissions to be 60 grams CH₄ per million Btu of crude oil. We also updated the methane emissions from surface mined oil sands as emissions from tailing ponds were roughly 110 grams CH₄ per million Btu of oil sands.³⁰ Howarth *et al.* assume that indirect CO₂ emissions are about 8% of direct emissions from fossil fuel combustion for recovery, processing, and transporting oil, while methane leakage is 130 grams CH₄ per million Btu of oil citing NETL.^{15,31} Howarth *et al.* did not examine emissions from oil sands.¹⁵

3.9 Oil Infrastructure

This study includes the drilling stage for the infrastructure of petroleum pathways, which consumes

various fuels and materials. Fuel consumption is estimated from the 1997 U.S. Census data and the U.S. oil and NG production in 1997 from EIA, shown in Table S11.³²

Table S11. Fuel consumed for drilling oil and gas wells in 1997

	Per Year	Per Oil and Gas Produced
Diesel fuel	3.36 million bbl	494 Btu/million Btu
Residual Oil	2.55 million bbl	410 Btu/million Btu
NG	600 million ft ³	16 Btu/million Btu
Gasoline	32.7 million gal	104 Btu/million Btu
Undistributed fuels	2.83 million bbl	456 Btu/million Btu
Oil Production	2.35 billion bbl	N/A
Gas Production	24.2 trillion ft ³	N/A

In the U.S. Census, the cost of undistributed fuels is presented as for the establishments that did not report detailed data, which is assumed as residual oil here. For material consumptions for oil wells, it is assumed that oil well designs are similar to gas well designs as well their material requirements per unit depth, which are obtained from those per well divided by the average well depth for conventional wells. Then, the material requirements per million Btu of oil produced is obtained by multiplying those per unit depth by the average well depth per production weighted by the produced amount for U.S. consumption.³²

4. End-Use and Global Warming Potential Parameters

In Table S12, we list the end use efficiencies we incorporated into our GREET simulations. GREET uses lower heating values.

Table S12. End Use Efficiency Assumptions for GREET Simulations (mean values with ranges in parentheses)

Power Plant	Units	Values	Distribution	Sources
NGCC efficiency	%	47 (39-55)	Normal	Average of 2007 and 2008 data based on Form EIA-906, “Power Plant Report” ⁴⁹
NG boiler efficiency	%	33.1 (33.0-33.5)	Weibull	General Motors Corporation et al. ³³
Supercritical Coal Boiler efficiency	%	41.5 (39.0-44.0)	Normal	International Energy Agency ³⁴
Subcritical Coal Boiler efficiency	%	34.1 (33.5-34.4)	Weibull	General Motors Corporation et al. ³³
Vehicles				
Gasoline passenger car - fuel economy	Miles per gallon – gasoline equivalent	29 (23-32)	Triangular	Honda Civic LX, MY 2007-11 ³⁵ ; assumed high is 10% better, low 20%; based on driving behavior
CNG passenger car - fuel economy	Ratio of gasoline car	0.95 (0.9-1.0)	Normal	Mid-value is based on GREET 5% reduction, high-value is based on assumption that fuel economy can reach the same level as gasoline ³⁶ , low-value is based on data from CNG vehicles from the 1990s
Diesel transit bus - fuel economy	Miles per gallon - diesel equivalent	3.5 (3.0-3.7)	Triangular	Mid-value is based on Transportation Energy Data Book Ed. 29, ⁵⁰ assumed that high-value is 5% better, low-value 15% worse; based on vehicle technology and driving behavior
CNG transit bus - fuel economy	Ratio of diesel bus	0.85 (0.80-0.90)	Normal	Low-value is 20% reduction based on numerous transit bus studies ^{37,51,52} ; high based on Cummins claims ³⁷ ; mid is average of high and low

Table S13 compares the global warming potentials (GWP) used in our and Howarth *et al.*’s study. It also provides the sources of these values in each body of work.

Table S13. Global Warming Potentials of Greenhouse Gases

	100-Year GWPs			20-Year GWPs			Source
	CO ₂	CH ₄	N ₂ O	CO ₂	CH ₄	N ₂ O	
GREET	1	25	298	1	72	289	IPCC ²⁴
Howarth <i>et al.</i>	1	33	Not used	1	105	Not used	Shindell <i>et al.</i> ³⁸

5. Additional Results

Figure S4 presents sensitivity analysis results for the shale and NG pathways for a 20-year GWP horizon.

Figure S4. Sensitivity Analysis Results for Shale and NG Pathways (20-Year Time Horizon)

From the conventional NG tornado charts, it is clear that CH₄ venting during liquid unloadings contributes the most uncertainty to our GHG emissions for the 20-year time horizons, followed by the CH₄ venting from well equipment. The large uncertainty is due to a wide range of the number of unloadings required for these wells and emissions resulting from this activity. Since the GWP of CH₄ is much higher under 20-year time horizon, the impact of the CH₄ venting during liquid unloading becomes more prominent.

The shale gas tornado chart shows a similar trend to conventional NG outside of liquid unloadings, which are assumed to be not required for these wells. The other major difference between the two pathways is that SG completion and workover emissions are a much more significant factor as compared to conventional NG. However, they only have a moderate impact on the uncertainty of life-cycle emissions, though it is more pronounced under the 20-year time horizon. Under both the 100- and 20-year time horizons, CH₄ venting from well equipment shows the largest impact on life-cycle GHG emissions as difference between estimates from EPA and GAO are significant.^{5,7}

In Table S14, we compare relative life-cycle GHG emissions for different fuel pathways and end uses.

Table S14. Life-Cycle GHG Emission Changes

	100-Year GWPs				20-Year GWPs			
	NG	SG	Oil	Coal	NG	SG	Oil	Coal
Per MJ (% Relative to GHG Emissions of Conventional Natural Gas)								
This Study	0%	-6%	22%	41%	0%	-12%	-2%	13%
Howarth <i>et al.</i> ¹⁵	0%	17%	-3%	21%	0%	33%	-36%	-24%
Per kWh (% Relative to GHG Emissions of Coal Boiler)								
Boiler	-27%	-31%	N/A	0%	-9%	-19%	N/A	0%
Combined Cycle /Supercritical	-49%	-52%	N/A	-17%	-36%	-43%	N/A	-17%
Per Vehicle Mile Traveled (% Relative to GHG Emissions and Oil Consumption of Gasoline Car)								
GHG Change	-3%	-8%	N/A	N/A	25%	12%	N/A	N/A
Per Vehicle Mile Traveled (% Relative to GHG Emissions and Oil Consumption of Diesel Transit Bus)								
GHG Change	5%	-1%	N/A	N/A	34%	20%	N/A	N/A

Note: Negative and positive numbers denote reductions and increases, respectively, compared to conventional NG.

The oil results are weighted averages of conventional crude (91%) and oil sands (9%) emissions to account for their relative impact on current U.S. consumption. The coal results are also weighted averages of surface (69%) and underground (31%) mining. We apply the same weighted-factor for Howarth *et al.*'s surface and underground coal results, while he does not differentiate between conventional crude and oils sands.

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