Lifecycle GHG Emissions of US LNG Exports

Concepts, Methodologies, Data and Results

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Prepared by: ICF

Prepared for:

NATURAL ALLIES FOR A CLEAN ENERGY FUTURE

PAGE PARTNERSHIP TO ADDRESS GLOBAL EMISSIONS

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Conversion Factors

Example Gas Compositions and Conversion Factors (based on 14.7 psi pressure base)

Natural Gas Component	US Pipeline Gas Composition (%)	LNG Made from US Pipeline Gas (%)	LNG from Australia NWS Gas Composition (%)	Btu/scf	Pounds/ Mscf
Methane	95.91%	97.56%	87.3%	1,030	42.3
Ethane	1.45%	1.48%	8.3%	1,743	79.3
Propane	0.48%	0.49%	3.3%	2,480	116.3
C_4+	0.16%	0.16%	1.0%	3,216	153.3
CO_2 *	1.70%	0.00%	0.0%	-	116.0
N_2	0.30%	0.31%	0.0%	-	73.8
Sum	100.00%	100.00%	100.00%		
Btu/scf	1,030	1,048	1,159		
Pounds / Mscf	44.50	43.26	48.95		
Metric tons per million scf	20.18	19.62	22.20		
Bil. scf per million metric tons	49.54	50.96	45.04		
Bil scf/day per mm MT/year (Bcfd/MTPA)	0.136	0.140	0.123		
MTPA/Bcfd	7.37	7.16	8.10		

Source: ICF estimates

* US pipelines have 2% or 3% limit on inerts (carbon dioxide and nitrogen). To make LNG all CO_2 must be removed.

Abbreviations

Abbreviation	Meaning
AEO	EIA Annual Energy Outlook
ANL	Argonne National Laboratory
Bcf/day (or Bcfd)	Billion cubic feet of natural gas per day
BOG	Boil off gas
Btu	British thermal unit, used to measure fuels by their energy content.
cm	Cubic meter
CO2	Carbon dioxide
CO2e	Carbon dioxide equivalent
DES	Delivered Ex Ship
DOE	US Department of Energy
EIA	U.S. Energy Information Administration, a statistical and analytical agency within the U.S. Department of Energy
EPA	US Environmental Protection Agency
EPA GHGI	US EPA's National Greenhouse Gas Inventory
FOB	Free on Board
g	Grams
GHG	Greenhouse gas
GHGRP	EPA's GHG Reporting Rule
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model
IEA	International Energy Agency
IGU	International Gas Union
IPCC	Intergovernmental Panel on Climate Change
kg	Kilograms
kWh	Kilowatt-hour
LCA	Lifecycle analysis
LNG	Liquefied Natural Gas
Mcf	Thousand cubic feet (volume measurement for natural gas)
MJ	Megajoule
MMbbl	Million barrels of oil or liquids
MMBOE	Million barrels of oil equivalent wherein each barrel contains 5.8 million Btus.
MMBtu	Million British Thermal Units. Equivalent to approximately one thousand cubic feet of gas
MMcf	Million cubic feet (of natural gas)
MTPA	million metric tons per annum
MWh	Megawatt-hour
NACEF	Natural Allies for a Clean Energy Future
NGA	EIA's Natural Gas Annual
NGL	Natural Gas Liquids
PAGE	Partnership to Address Global Emissions
PJ	Petajoules
TBtu	Trillion BTUs
Tcf	Trillion cubic feet of natural gas

ES. Executive Summary

ES.1 Introduction to Lifecycle GHG Emissions of US LNG Exports: Concepts, Methodologies, Data and Results

This Study was prepared by ICF for Natural Allies for a Clean Energy Future (NACEF) and the Partnership to Address Global Emissions (PAGE). The purpose of the Study is to provide a detailed explanation of how lifecycle analyses (LCAs) of greenhouse gas (GHG) emissions for US exports of liquefied natural gas (LNG) are estimated and how those estimated emissions compare with the LCA GHG emissions of alternative fuels such as coal and petroleum products. The Study presents a Base Case analysis using transparent, well-documented and consistent data and methods and, where uncertainties exist for important parameters used to make these estimates, the Study also provides sensitivity analyses.

- *The Study shows that US LNG exports have lower lifecycle GHG emissions compared to using coal alone, fuel oil alone or the expected mix of alternative fuels (summed across all countries importing US LNG) that would most likely replace imported US LNG.*
- *Without US LNG exported abroad, that energy would be replaced with 54% coal, 34% fuel oil, 16% domestic natural gas, and 7.8% renewable sources.*
- *Under this Study's Base Case assumptions, shifting from US LNG to coal increases GHG emissions by 47.7% to 85.9%. Shifting US LNG to fuel oil increases emissions by 24.8% to 41.8%.*
- *The majority of other studies reviewed here show similar results to this Study when comparing LNG with coal and fuel oil in power-plant or industrial applications.*
- *The limited number of studies that show US LNG as having more LCA emissions than coal tend to use outlier data, apply questionable emission factors that differ greatly from the US EPA GHG inventory and the GREET factors designated by Congress in the Inflation Reduction Act, highlight improbable scenarios, and fail to account for relative end-user fuel efficiencies which favor natural gas.*

Additionally, the Study compares its results to other studies and identifies how the application of assumptions such as methane leak rates and the global warming potent (GWP[1]) factor can affect the results. The Study primarily deals with lifecycle GHG analysis of LNG and alternative fuels for the historical year of 2022 but also looks at what emissions might look like in the year 2030 if the downward trend in methane emissions from the oil and gas systems as estimated in the Environmental Protection Agency's National GHG Inventory (EPA GHGI) were to continue.

ES.2 Conclusions Related to Differences in Methodologies

- The LNG supply chain includes several steps or segments, each of which has its own energy consumption and GHG emissions profile. The carbon intensity of LNG is the sum of all of these segments adjusted for losses along the supply chain. The example shown below is for LNG made from Marcellus natural gas and exported from the US East Coast to France under the Study's Base Case assumptions. The left-hand portion of the chart

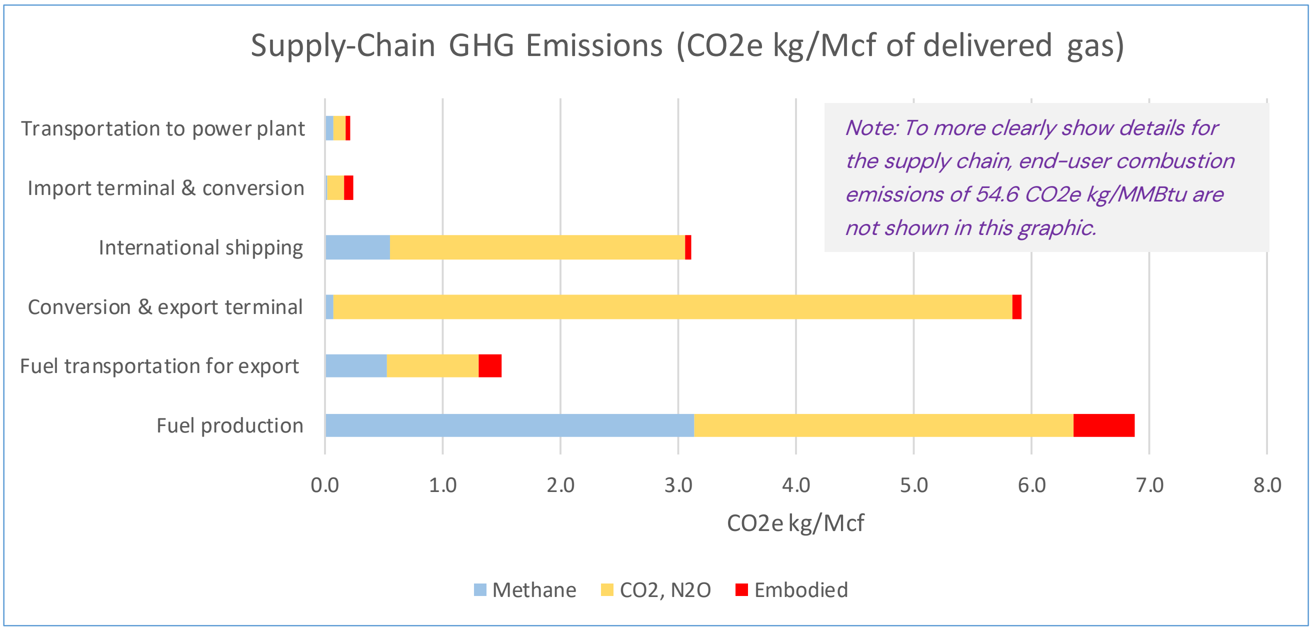
[1] The GWP is a factor by which one mass unit (e.g., a kilogram) of a GHG such as methane is multiplied to approximate the global warming potential of carbon dioxide. A methane GWP of 28 means that 1 kg of methane has the same global warming potential as 28 kg of CO_2.

represents emissions measured at each supply chain segment in units of kilograms of carbon dioxide equivalent per thousand cubic feet of natural gas. The right-hand side of the chart shows emissions scaled up to represent emissions delivered to a consumer. The scale up factor accounts for consumption of natural gas and releases of natural gas along the supply chain. Because of these losses, more than one unit of supply in the early portions of the supply chain is needed to ultimately deliver one unit to the consumer. The result for this example is an LCA of 72.48 CO_2e kg/Mcf or 69.87 CO_2e kg/MMBtu. The emissions for the regasified LNG delivered to consumers (excluding the final step of combustion by the consumer) are also shown graphically in units of CO_2e kg/Mcf at the bottom of the chart.

Exhibit 1: Example LNG LCA Analysis under Base Case Assumptions

Summary of LNG LCA Analysis: ICF Base Case Assumptions with Embodied

Marcellus, East Coast to France	Measured at Each Supply-Chain Segment (CO2e kg/Mcf of gas exiting segment)				Scaling Factor between Segment and Customer	Delivered to Customer (CO2e kg/Mcf of delivered gas)			
	Methane	CO2, N2O	Embodied	Total		Methane	CO2, N2O	Embodied	Total
Fuel production	2.76	2.84	0.45	6.05	*113.7%*	3.14	3.22	0.52	6.88
Fuel transportation for export	0.46	0.69	0.17	1.32	*113.9%*	0.53	0.78	0.20	1.50
Conversion & export terminal	0.07	5.60	0.08	5.74	*103.2%*	0.07	5.78	0.08	5.92
International shipping	0.55	2.50	0.05	3.10	*100.5%*	0.55	2.51	0.05	3.11
Import terminal & conversion	0.03	0.14	0.08	0.24	*100.2%*	0.03	0.14	0.08	0.24
Transportation to power plant	0.07	0.11	0.03	0.21	*100.0%*	0.07	0.11	0.03	0.21
NG Combustion	0.14	54.46	0.00	54.60	*100.0%*	0.14	54.46	0.00	54.60
Sum at Customer				71.27		4.53	67.00	0.95	72.48

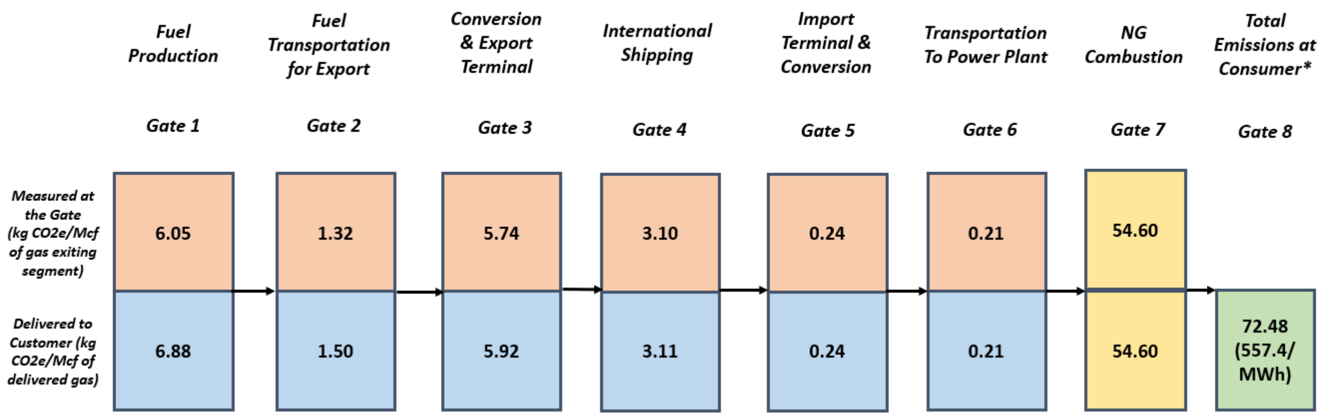


- There are several ways in which analysts have estimated the GHG emissions for LNG both in terms of emissions from the LNG supply chain itself and in terms of the alternative fuels to which LNG may be compared. It is important to understand the scope, methodology and data used by these analysts when comparing different estimates and determining their accuracy, usefulness, and relevance.
- The energy consumption along the LNG supply and the resulting carbon dioxide emissions are much better understood and more easily estimated than emissions from methane releases. Therefore, the differences in estimates of the carbon intensity of LNG

among studies are often due to differences in the estimates of methane release rates (typically represented as the percent of gas production or throughput that is released to the atmosphere in each supply chain segment) and the translation of methane release rates into a carbon dioxide equivalent mass units (most often done using a global warming potential (GWP) factor and an estimate of what portion of the released natural gas is made up of methane.)

- Another important difference among studies is where along the LNG supply chain (the so-called supply chain "gates") the carbon intensity is being calculated and how comparisons are done between LNG and alternative fuels. The ultimate and arguably most relevant point of measure is the "end-user energy services" gate, which takes into account the carbon intensity of the entire supply chain that brings the re-gasified LNG (or alternative fuel) to the end-user and the efficiency of converting that fuel into a useful energy service. The useful energy service might be a megawatt hour of electricity (MWh) from a power plant or a thousand pounds of steam from an industrial boiler.
- Exhibit 2 recasts the data previously shown in Exhibit 1 into the "gates" concept wherein LNG exports pass through eight gates, starting from production and going to consumption by end users. The top part of each rectangle (shown in beige) under each gate represents emissions as measured at each supply chain segment. The bottom portion of each rectangle (shown in blue) are those same emissions scaled up for losses (natural gas releases and fuel consumption) that will occur in later segments. As the gas moves from left to right in the diagram, more GHG emissions accumulate. The last gate is the sum of the scaled-up values for gates #1 to #7. Gate #8 is also shown on the basis of one megawatt-hour of electricity using a heat rate of 7,690 Btu/kWh (the 2022 weighted average for countries importing US LNG).

Exhibit 2: Gate Concepts from Production to End-user Consumption



**Note – Gate #1 to 7 are incremental values per Mcf of natural gas. The total emissions shown at Gate #8 are cumulative (value in parenthesis is given in units per 1 MWh electricity generated). Values for this chart are derived from Exhibit 1 and apply to Marcellus Shale gas exported from the US East Coast to France.*

- To compare emissions between imported LNG and other fuels, the most significant end-use gate to consider is electricity generation. Because the energy conversion efficiency of gas-fired power plants is higher than those of coal or oil-fired plants, the carbon intensity comparisons with coal and fuel oils is more favorable toward LNG at the end-user energy services gate of power generators (measured in kilograms of carbon dioxide equivalent per megawatt of electricity or CO_2e kg/MWh) as compared to the "delivered to end user" gate (measured in CO_2e kg/MMBtu).

- Exhibit 3 uses the weighted average LCA GHG values for US LNG, coal and fuel oil and the weighted average heat rates for power plants in countries importing US LNG in 2022 to show LCA GHG values for those fuels delivered to large consumers and those fuels converted to electricity. The exhibit shows that coal converted to electricity has 85.9% higher GHG emissions than US LNG whereas the difference measured for delivered and combusted fuel is 47.7%. The same pattern exists for fuel oil, which has 41.8% more GHG emission compared to US LNG when both are converted to electricity using weighted average heat rates.

Exhibit 3: Analysis for Delivered Fuels versus Conversion to Electricity

GWP = 28 CH_4 Calib = 1	LCA for Delivered Fuel: Base Case		Fuel Converted to Electricity: Base Case		
	CO_2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO_2e kg/MWh	Percent Difference from US LNG
US LNG	71.6	0.0%	7,690	550.3	0.0%
Coal	105.7	47.7%	9,680	1,023.2	85.9%
Fuel Oil	89.3	24.8%	8,736	780.5	41.8%

Note: This table is for the Study's Base Case. See Exhibit 42 to Exhibit 44 for similar tables for all cases.

- Another difference among studies is whether the so called "embodied GHG emissions" are being quantified and included. Embodied GHG emissions (as used here) are those associated with the manufacturing and construction of facilities, equipment and infrastructure used to produce, process, and transport the LNG and alternative fuels to end-users. For example, the emissions associated with drilling and completing a gas well, including the emissions associated with producing and delivering all materials and equipment to the well site. For a gas pipeline, embodied emissions would be the GHGs associated with manufacture, production and delivery of all materials and equipment used to construct the pipeline and ancillary facilities and the emissions related to construction process itself. It is common for studies to ignore embodied emission since they are difficult to estimate and there are no universally accepted standards for estimating them when both existing and new infrastructure may be employed in the supply chain. For this analysis, ICF has calculated embodied emissions as if new infrastructure assets (e.g., pipelines, gas carriers) are built and their embodied emission are spread over the production/throughput volumes expected over the asset's expected useful life (typically 20 to 30 years). In the example LCA shown in Exhibit 1, embodied emissions for delivered LNG came to 0.95 CO_2e kg/Mcf or 1.3% of the total of 72.46 CO_2e kg/Mcf.

ES.3 Set Up of Cases Presented in this Study

- The analytic cases produced for this report include a Base Case that has a "methane release calibration" based on the EPA GHGI 2022 release rates by segment of the natural gas and oil supply chains. In recognition of the uncertainty in these estimates, Sensitivity Cases were created to determine the effect of increasing assumed methane releases by

44.6% (per Argonne National Laboratory (ANL) GREET[2] assumptions), by 88% (per International Energy Agency (IEA) estimates), and by 200% (per estimates derived from remote sensing surveys).

- The Base Case GWP value for methane is 28, which is based on the IPCC Fifth Assessment Report (AR-5) 100-year Biogenic Methane factor and is used now by EPA for the EPA GHGI and for the Greenhouse Gas Reporting Program survey of large GHG emitters. Sensitivity Cases were created to use the corresponding AR-5 20-year value of 84.[3]
- The Study's Base Case includes "embodied GHGs" associated with the manufacturing and construction of facilities, equipment and infrastructure used to produce, process, and transport the LNG and alternative fuels to end-users. A Sensitivity Case excludes them to provide a more direct comparison to studies that do not include embodied emissions.
- The world GHG emission impact of US LNG exports in 2022 was calculated in the Study by estimating the supply chain GHG to produce LNG and ship it from each US exporting facility to each country that received LNG from that facility in 2022.
- Using IEA data on energy consumption by country and sector, this Study estimated how much natural gas (and US LNG) and other fuels were used in each sector of each importing country. For each energy source, this Study estimated GHG emissions for both the "delivered to end use gate" and "end-use energy services gate" concepts.

ES.4 Results from the Cases

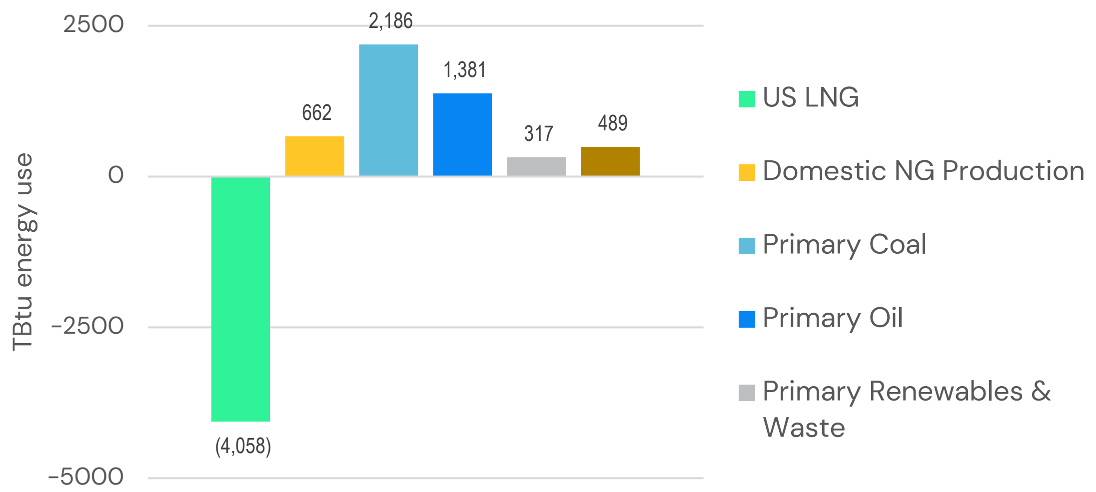
- Employing a counterfactual assumption that no US LNG was produced or traded in 2022, the Study estimated how much alternative fuels and electricity would have substituted for the unavailable US LNG. For all but one of the Cases (Sensitivity #10), this substitution was conducted assuming that the disruption to US LNG supplies would have taken place over several years and that medium-term demand elasticities would allow substitution to many kinds of alternative fuels including renewable energy. The Study then calculated the GHG associated with those substitute energy sources.
  - Coal is estimated to supply 2,186 trillion Btu (TBtu), or 53.9% of the 4,058 TBtu of unavailable energy in US LNG.
  - Substitution by fuel oil and other petroleum products is estimated as 1,381 TBtu, or 34% of the unavailable energy in US LNG.
  - Substitution by domestically produced natural gas (in importing countries that have natural gas production) is estimated to contribute 16.3%, or 662 TBtu, of the unavailable energy in US LNG.
  - Primary renewable energy and waste fuel is estimated to have contributed 317 TBtu, or 7.8% of the energy in the unavailable US LNG.
  - Total primary energy summed across all fuels goes up by 489 TBtu. This occurs primarily because the heat rates of non-gas power plants are greater than those of

[2] Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model (GREET) model was developed under sponsorship of DOE to examine the lifecycle impacts of efficiency technologies and energy systems. GREET now has more than 40,000 registered users worldwide. See GREET: The Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model | Argonne National Laboratory (anl.gov)

[3] Since methane oxidizes in the atmosphere and turns into CO_2, its global warming impact is greater in the years immediately after it is released as compared to decades later. Therefore, if averaged over 100 years, the methane GWP is estimated as 28 times CO_2 while if averaged over the first 20 years (when the methane is mostly still methane) the impact is estimated as 84 times CO_2.

gas-fired power plants. The second reason is that the direct use of natural gas in many applications requires less primary energy than substitute electric technologies if electricity generation has high heat rates and associated transmission and distribution losses.

Exhibit 4: Estimated Shift in Global Primary Fuel Use, 2022 Base Case



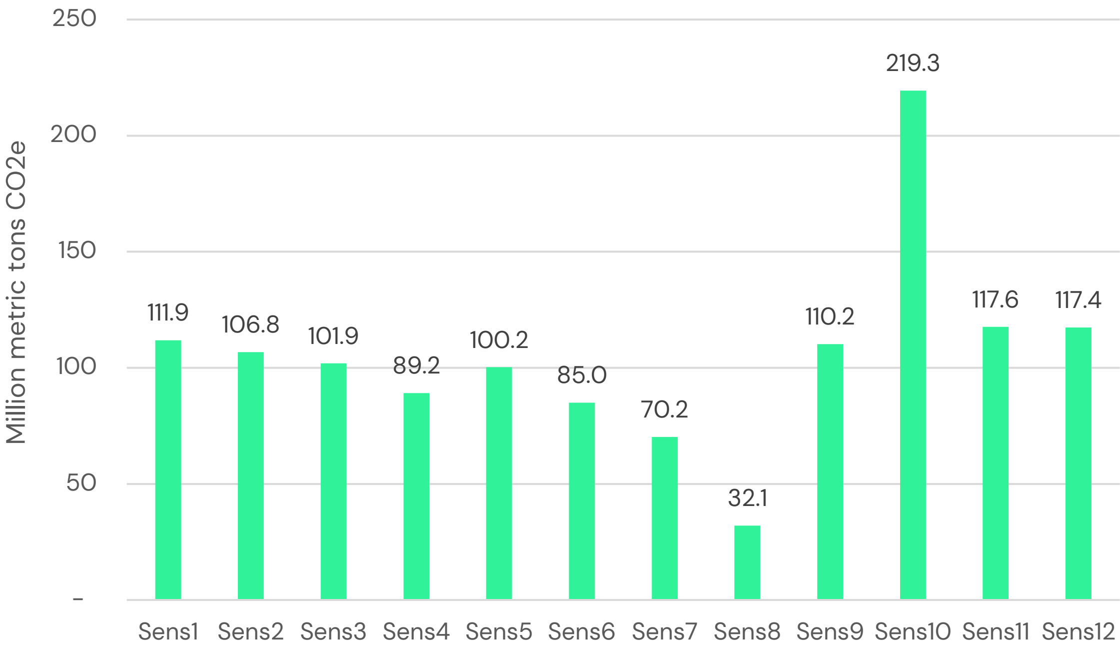
- In total, 12 Cases were analyzed including the Base Case (Case #1) and 11 Sensitivity Cases for which assumptions were varied as summarized in Exhibit 5. The first four Cases (#1 to #4) are based on a methane GWP of 28 and the following four cases (#5 to #9) use a methane GWP of 84. Within each set of four cases, the "CH_4 Release Calibration" for oil and natural gas supply chains are assumed to range from the values estimated in the EPA GHGI as a combined rate of 1.33% (for production, gathering & boosting, gas processing, gas transmission plus gas distribution) up to three times those values, or a combined release rate of 3.99%. These are shown in the table as ratios to the EPA GHGI of 1.0, 1.446, 1.88 and 3.0, respectively. Also shown in the table in the last column are the modelling results of the Cases in terms of how much each million Btu of US LNG exports reduces world GHG emissions. All Cases show that US LNG exports reduce world GHG emissions. This statistic (which can also be expressed in terms of how much world GHG emissions would go up in the absence of US LNG exports) is discussed more fully below.

Exhibit 5: Assumptions Used Across Study Cases and Resulting Reductions in World GHG Emissions

Sensitivity#	Embodied Added?	CH4 Release Calibration	CH4 GWP Basis AR5	Substitutability by Renewables	Study Result: Net Emission Rate Reduction in World GHG (CO_2e kg/MMBtu of US LNG)
1 - Base Case	w/Embodied	1.000	AR-5, 100-year	1	27.5
2	w/Embodied	1.446	AR-5, 100-year	1	26.3
3	w/Embodied	1.880	AR-5, 100-year	1	25.1
4	w/Embodied	3.000	AR-5, 100-year	1	21.9
5	w/Embodied	1.000	AR-5, 20-year	1	24.8
6	w/Embodied	1.446	AR-5, 20-year	1	21.1
7	w/Embodied	1.880	AR-5, 20-year	1	17.4
8	w/Embodied	3.000	AR-5, 20-year	1	8.0
9	w/o Embodied	1.000	AR-5, 100-year	1	27.1
10	w/Embodied	1.000	AR-5, 100-year	0	54.0
11	w/Embodied	0.496	AR-5, 100-year	1	29.0
12	w/Embodied	0.496	AR-5, 20-year	1	29.1

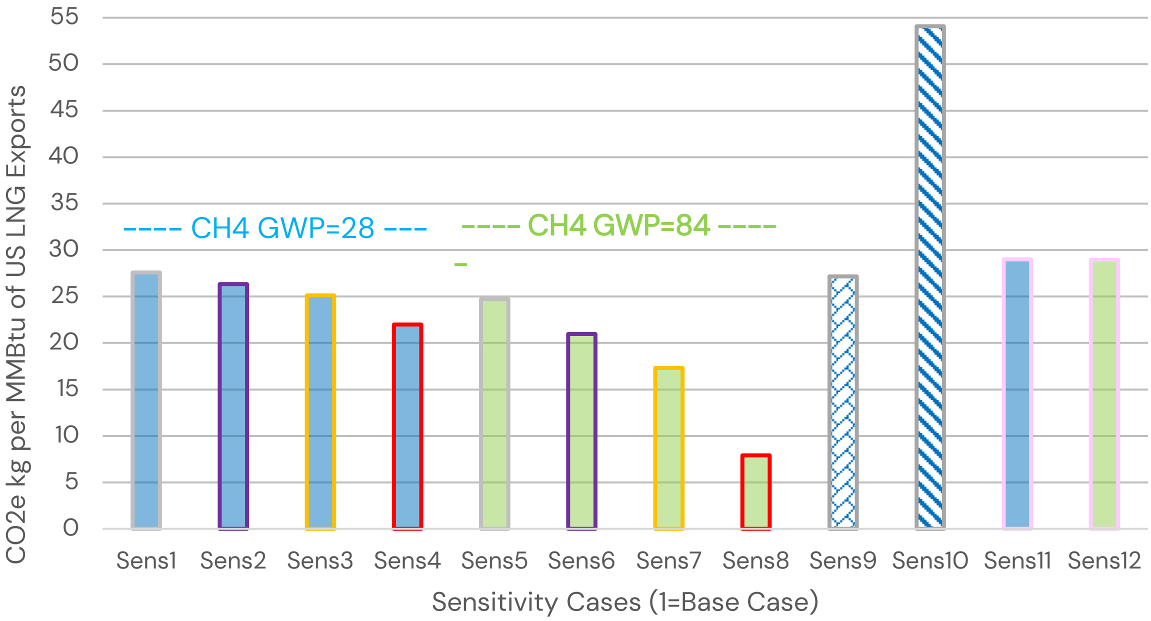
- Sensitivity Case #9 is the same as the Base Case, except that Embodied Emissions are removed from LNG and all competing fuels. Likewise, Sensitivity #10 is the same as the Base Case except that it assumes that there is little opportunity to switch to renewable or waste energy either because the counterfactual disruption to US LNG supply were to occur abruptly or the expansion of renewables and waste fuels were assumed to be already taking place at the maximum possible rate. For this Sensitivity #10, switching to renewables and waste fuels does not occur and the difference is made up by more use of coal, petroleum products and domestic natural gas.
- The last two Sensitivity Cases use the "Progress 2030" assumption that methane emissions along the natural gas supply chain will decline in the next few years. These reductions are expected to result from several factors including EPA and Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations, the effects of the Inflation Reduction Act's (IRA) Waste Emission Charge, the demands from gas purchasers for low-emission gas sources, equipment turnover and voluntary industry actions. For these sensitivities, a reduction in the methane release rate of approximately 60% is assumed to occur by 2030. There are two Sensitivities that apply "Progress 2030" levels of methane releases: Sensitivity Case #11 uses a methane GWP of 28 and Sensitivity Case #12 uses a methane GWP of 84.
- As shown in Exhibit 6, the net impact of US LNG in the Base Case was to decrease 2022 world GHGs by 111.9 million metric tons compared to the estimated mix of alternative fuels. Among the 11 Sensitivity Cases, the net GHG reductions from US LNG ranged from 32.1 to 219.3 million metric tons per year. The lowest impact of 32.1 million tons per year occurs with Sensitivity #8 which combines a methane GWP of 84 with the highest modeled methane release calibration of three times the EPA GHGI values. The largest impact of 219.3 million tons per year occurs with Sensitivity #10 wherein no switching to renewables or waste fuels occurs and, as a result, there is more dependence on coal and fuel oils. All the cases examined here show that the US LNG exports result in a net reduction in the world's GHG emissions compared to the use of the estimated mix of alternative fuels.

Exhibit 6: Increase in GHG Emissions Caused by Removing US LNG Exports (2022)



- Exhibit 7 shows the net GHG impacts of US LNG in units of kilograms of GHG reduction per million Btu of US LNG exports. Because the natural gas supply chain has more methane releases as compared to the alternative fuels, the increase in emissions caused by having to substitute for US LNG declines when one assumes higher methane release rates and larger methane GWPs. In the Base Case, the net positive impact of US LNG is 27.5 CO_2e kg/MMBtu of US exported LNG and this falls to as low as 8.0 in the Sensitivity Case #8.

Exhibit 7: Net Impacts in GHG Measured per Unit of US LNG Exports (2022)

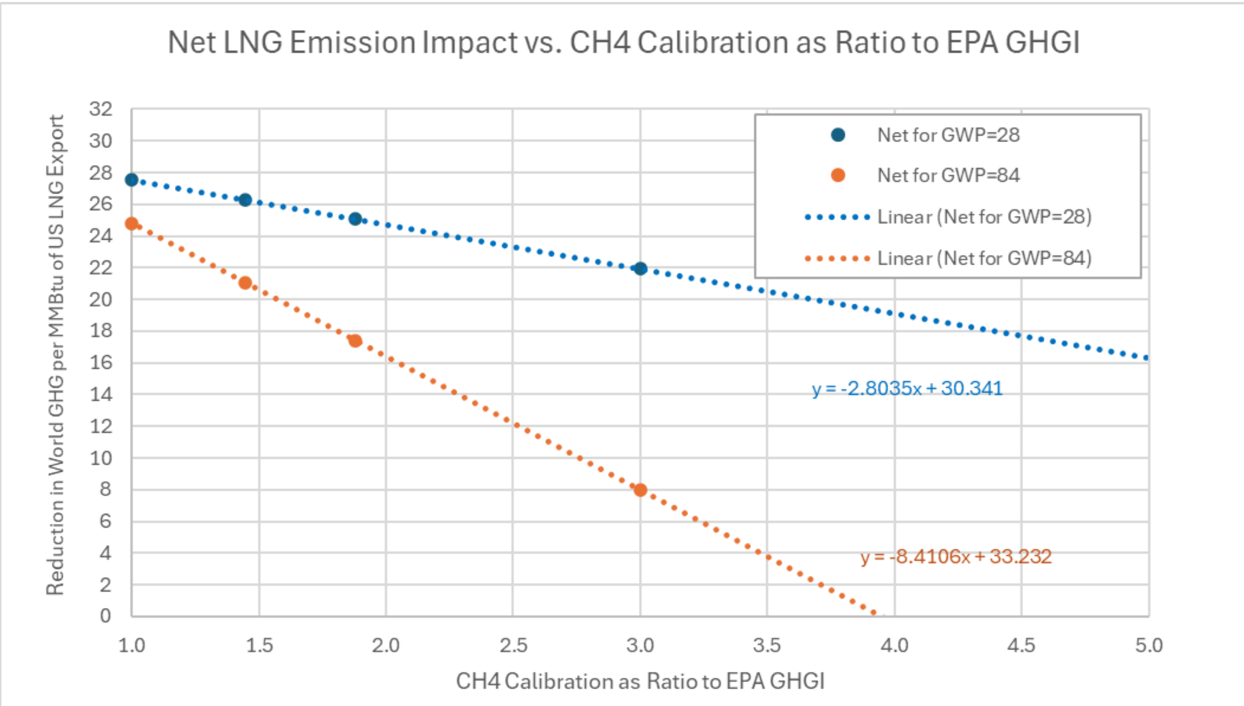


Note: The colored border of each column represents the methane release calibration used. Grey indicates a calibration value of 1, purple uses 1.446, orange uses 1.88, red uses 3.0, and pink uses 0.496.

ES.5 Estimate of "Breakeven" Methane Release Rates

- Exhibit 8 depicts another way to show the effects of the assumed methane GWP of 28 or 84 and methane release calibration values ranging from 1 to almost 4. The blue dots represent the Sensitivity Cases #1 to #4, which are based on a methane GWP of 28. The blue dashed line is a regression line through those points. The orange dots and orange dashed line correspond to Sensitivity Cases #5 to #9, which use a methane GWP of 84. The x-axis of the chart is the methane release calibration value expressed as a ratio to the 2022 EPA GHGI for oil and gas systems. For each of the GWP assumptions, the four related Sensitivity Cases fall in a straight line.
- For the methane GWP of 28, the straight line crosses the x-axis at a value of 10.82 times the EPA GHGI methane release value. In other words, with a methane GWP of 28, methane releases could be up to 10.82 times higher than what is stated in the EPA GHGI and US LNG still would reduce worldwide GHG emissions compared to the mix of alternative fuels that would most likely substitute for the US LNG. This point is sometimes referred to as the "breakeven point" since that is where the GHGs from US LNG would equal those of alternative fuels.
- The regression line for the cases with a methane GWP of 84 is steeper and crosses the x-axis at 3.95 times the EPA GHGI methane release values. This means that methane releases could be up to nearly four times higher than EPA estimates and the export of US LNG would still reduce the worlds GHG emissions when the global warming potential of one mass unit of methane is assumed to be 84 times that of carbon dioxide. In other words, for a GWP of 84 the breakeven point for US LNG is 3.95 times the EPA GHGI methane release values for oil and gas systems.

Exhibit 8: Net LNG Emissions Impacts Using Various EPA GHGI CH_4 Calibrations



- It is noteworthy that US LNG exports can be shown to have benefits of reduced worldwide GHG emissions even when both a high methane GWP is applied and methane calibration values of three or more times the EPA GHGI are used. This occurs in large part because these same methane-related assumptions also affect the LCA GHG values of petroleum products, domestically produced natural gas in the importing countries, and to a lesser extent domestic and imported coal. The LCA of coal is affected because coal mine fugitive emissions are subject to any increases in the methane GWP and the emissions attributable to the uses of petroleum products and electricity for coal mining, processing, and transportation are affected when the methane GWP or the methane calibration for oil and gas operations are changed. These effects are shown in Exhibit 9 which depicts the average LCA values for US LNG delivered to large customers, domestic natural gas delivered to large customers, delivered coal, and delivered petroleum products (chiefly residual and distillate fuel oils).

Exhibit 9: LCA Factors for All Fossil Fuels are Affected by GWP and Methane Release Assumptions

	Calculated CO_2e kg/MMBtu (Higher Heating Value) all Countries 2022				
Sensitivity#	Imported US LNG (CO_2e kg/MMBtu)	Domestic NG Prod. (CO_2e kg/MMBtu)	Coal (CO_2e kg/MMBtu)	Oil (CO_2e kg/MMBtu)	Renewables & Waste (CO_2e kg/MMBtu)
1 Base Case	71.6	64.5	105.7	89.3	15.6
2	73.4	66.2	105.7	90.2	15.6
3	75.2	67.8	105.8	91.0	15.6
4	79.8	72.1	105.8	93.2	15.6
5	80.1	72.3	112.2	92.4	15.6
6	85.6	77.4	112.3	95.0	15.6
7	91.0	82.3	112.4	97.5	15.6
8	104.8	95.2	112.6	103.9	15.6
9	70.4	63.3	104.9	88.2	7.7
10	71.6	64.5	105.6	89.4	15.3
11	69.5	62.5	105.7	88.4	15.6
12	73.8	66.5	112.1	89.5	15.6

ES.6 Potential Impact of Expected Growth in US LNG Exports

- The Study estimates for all of the Cases presented here reflect 2022 actual exports of US LNG. Looking to the future, DOE's Energy Information Administration in its 2023 Annual Energy Outlook Reference Case expects US LNG exports to grow from 3,959 bcf in 2022 to 6,880 bcf by 2030. That is an expected increase of 74% in annual export volumes over eight years.

- *DOE's Energy Information Administration expects US LNG exports to increase by 74% by 2030.*

- Thus, if all other assumptions are held constant, the benefits of US LNG exports could be 74% greater in the year 2030 due to there being a larger demand for US LNG. For example, if the net Base Case impact were to remain at 27.5 CO_2e kg/MMBtu of US LNG exports, the reduction in the world's GHG that could be attributed to US LNG exports in 2030 would reach 194 million tons of CO_2e per year. Applying the full range of impacts estimated in the Sensitivity Analyses (8.0 to 54.0 CO_2e kg/MMBtu of US LNG exports), the reduction in the world's GHG emissions that could be attributed to US LNG exports in 2030 would be projected to be between 56 and 381 million tons of CO_2e per year.

ES.7 Comparisons to Other Studies

- This Study contains a literature review of life cycle assessments to compare the results and assumptions of other studies to those of this Study. This review included prominent studies, models, and databases that contain emission calculations related to the production and supply of natural gas, LNG, and other fuels. This literature review also provided an illustration of the impact that the assumptions, methodology, and scope considered in each study have on the determined results. Details of this review are contained in Chapter 6 of this Study.
- One study which has received public attention (including from the White House when it announced its "Temporary Pause on Pending Approvals of Liquefied Natural Gas Exports" on January 26, 2024[4]) is a 2023 LCA analysis published by Robert Howarth of Cornell University.[5] The study quantifies LCA emissions generated from the supply chain used to export domestically produced natural gas as LNG. The study states that:

  > *The greenhouse gas footprint of LNG is always substantially larger than for natural gas consumed domestically (regardless of time scale), because of the large amount of energy needed to liquefy and transport the LNG. Greenhouse gas emissions from LNG are also larger than those from domestically produced coal, ranging from 28% to 2-fold greater for the average cruise distance of an LNG tanker, evaluated on the 20-year time scale. Even when evaluated on the 100-year time scale, emissions from LNG range from being equivalent to coal to being 64% greater.*

  These conclusions by Howarth are not supported by this Study and are contradicted by other similar analyses including those conducted by DOE's NETL and the National Petroleum Council. Several methodological choices and assumptions implemented by Howarth result in emissions for LNG that are higher than those of this Study.
- Exhibit 10 provides a comparison of emissions between the Howarth study and in a similar scenario (e.g., for a one-way shipping distance of 10,066 nautical miles and using national average methane release rates) under this Study's Base Case assumptions. The Howarth results - converted to a methane GWP of 28 and expressed in units of CO_2e kg/MMBtu higher heating value – are 99.84 CO_2e kg/MMBtu while the corresponding value using this Study's Base Case assumption are 75.23 CO_2e kg/MMBtu – a difference of 33%. The major points of difference and the apparent reasons for these differences are:
  - Methane releases from upstream and midstream segments (production, gathering and boosting, gas processing, plus gas transmission and storage) are 13.50 CO_2e kg/MMBtu higher in the Howarth assessment - representing 54.8% of the total difference. This result comes from using a higher methane release calibration value that is roughly

[4] FACT SHEET: Biden-Harris Administration Announces Temporary Pause on Pending Approvals of Liquefied Natural Gas Exports | The White House
[5] The Greenhouse Gas Footprint of Liquefied Natural Gas (LNG) Exported from the United States; Howarth, 2023; Cornell University

equivalent to three times the EPA GHGI value - an assumption that is similar to the methane calibration value used in this Study's Sensitivities #4 and #8. While such an assumption can be considered to be within the outer ranges of uncertainty for methane releases from oil and gas systems, it may not be appropriate as a "best estimate" to be used for policy decisions. For example, the ANL GREET Model – which has been designated by Congress in the IRA and by the IRS[6] as the basis for determining 45V hydrogen tax credits - uses a methane calibration value of 1.446, or less than half of the Howarth assumption.

- Carbon dioxide emissions from upstream and downstream segments are 9.68 CO_2e kg/MMBtu higher in the Howarth estimates and represent 39.3% of the total difference. Howarth's referenced source for this value is a New York State report (see Chapter 6) that applies to gas delivered to that state. Since New York has no LNG export terminals, that reference is not particularly relevant. Moreover, the value itself is unusually high. Compared again to the ANL GREET model, the Howarth calculations for upstream and downstream carbon dioxide emissions are about twice the GREET values.

Exhibit 10: Comparison of Howarth LNG Analysis and Base Case Assumptions

Howarth World Average Distance Case Results				
Howarth, 2-stroke engine tankers powered by LNG, 10,066 nm one-way	**CO2 (kg/MMBtu HHV)**	**CH4 (kg/MMBtu HHV)**	**CH4 (CO2e kg/MMBtu HHV, GWP=28)**	**All CO2e (kg/MMBtu HHV, GWP=28)**
Upstream & midstream emissions	14.15	0.68	18.98	33.13
Liquefaction	7.05	0.02	0.50	7.54
Emissions from tanker	3.55	0.05	1.39	4.94
Final transmission & distribution	0.00	0.06	1.71	1.71
Combustion by final consumer	52.51	0.00	0.00	52.51
Total	**77.26**	**0.81**	**22.58**	**99.84**

Results of this Study, Base Case Assumptions				
10,066 nm one-way, open rack re-gasifier	**CO2 (kg/MMBtu)**	**CH4 (kg/MMBtu)**	**CH4 (CO2e kg/MMBtu, GWP=28)**	**All CO2e (kg/MMBtu, GWP=28)**
Upstream & midstream emissions	4.47	0.20	5.48	9.95
Liquefaction	5.71	0.00	0.07	5.77
Emissions from tanker	6.00	0.02	0.54	6.54
Final transmission & distribution	0.24	0.00	0.10	0.33
Combustion by final consumer	52.50	0.00	0.14	52.64
Total	**68.91**	**0.23**	**6.32**	**75.23**

[6] Treasury Sets Out Proposed Rules for Transformative Clean Hydrogen Incentives | Clean Energy | The White House

- The high end of Howarth's comparison range (i.e., LNG is 28% to 2-fold greater than coal for the average cruise distance LNG) comes from comparing coal to LNG shipped by a steam-powered LNG carrier that uses bunker fuel for power and releases boil-off gas to the atmosphere. Such a configuration would have never made economic sense since the boil-off gas can be readily used as fuel in the carrier's boiler. As importantly, steam-powered carriers are the oldest and least fuel-efficient ships in the world's LNG carrier fleet and are used for only 2% of the ton-miles of US export shipments. (See Exhibit 28: Summary of U.S. LNG Shipping Operations 2022) Therefore, the shipping scenario that yields the "2-fold greater" result is improbable and, in any case, nearly irrelevant for the US from which steam carriers are seldom used.
- As stated above, the end-use application of the fuel should be considered when LCA emissions are being compared between LNG and alternative fuels. One notable methodological error by Howarth is that he compares the GHG LCAs of LNG and coal on the basis of combustion of delivered fuel without considering fuel efficiency differences. As was shown earlier in Exhibit 3, accounting for fuel efficiencies has a noticeable impact on emission results in the case of power generation (the most important end-use comparison between LNG and coal), where natural gas-fired power plants are more efficient than coal power plants.
- In summary, the Howarth results should be considered with caution because:
    - The methane release values employed by Howarth for the LNG supply chain are at the high end of the uncertainty range and may not be appropriate as a "best estimate" to be used for policy decisions.
    - Howarth's estimates for carbon dioxide emissions from upstream and downstream segments are contradicted by the "bottom up" estimates presented in this report and values estimated in the ANL GREET model.
    - The steam carrier shipping scenario that produces the high end of Howarth's comparison with coal is improbable and, in any case, nearly irrelevant for the US where steam carriers are seldom used.
    - The most appropriate way to compare using US LNG versus other fuels is to take into account relative fuel efficiencies. In the power sector, this means that approximately 1.26 Btu's of coal or 1.14 Btu's of fuel oil must be burned to replace each Btu of LNG. By not taking this into account, Howarth miscalculates the relative GHG impacts of coal and fuel oil compared to LNG.

1. Introduction

1.1 What is a Life Cycle Assessment (LCA) analysis?

A life cycle assessment (LCA) analysis provides a quantification of the amount of greenhouse gas (GHG) emissions that are generated across a particular set of infrastructure or operations. GHGs are generated from a variety of sources including fugitive losses, intentional venting of gases due to maintenance or operational requirements, combustion emissions generated during fuel consumption, land use clearances, construction activities, and the combustion of final supply products. The scope of an LCA can vary and depends on the type of fuel utilized, the end-use application, and the origin and destination of the fuel supply being considered.

1.2 Purpose and Scope of Study

The purpose of this study is to perform a lifecycle assessment analysis (LCA) of greenhouse gas emissions of US exports of LNG and compare with those from the use of alternative fuels such as coal and petroleum products. The analysis compares the LCA results of US LNG against emissions from LNG sourced from other countries and domestic coal and imported coal consumption in several consuming countries in Europe and Asia. ICF's methodology for estimating GHG emissions is a "bottom up" approach that covers all parts of the supply chain and provides a high level of detail to address questions from regulators, interested stakeholders, and the general public.

The results of this study are also compared to those from other similar studies (e.g., NPC, NETL, Howarth of Cornell University) to illustrate how assumptions such as the methane leak rate and the global warming potent (GWP) factor applied to methane can affect LCA results. Study results include the lifecycle analysis of LNG and alternative fuels for a historical year (2022) using a range of estimated emission factors applicable to that year. Also, two of the Sensitivities reflect reductions in methane emissions along the natural gas supply chain which are expected to result from EPA regulations, the effects of the Waste Emission Charge, the demands from gas purchasers for low-emission gas sources, and voluntary industry actions.

1.3 Main Takeaways

The main conclusions or takeaways from this study are:

- While the supply chains for LNG and alternative fuels are complex and there are uncertainties in the value of some parameters used in their respective LCA analyses, the process for conducting LCA analyses is well-established, and many credible studies exist on the GHG characteristics of LNG and competing fuels. This Study presents information on how these analyses are conducted, provides a Base Case analysis and Sensitivities, and explains many of the differences that exist among studies.
- The Study uses public and reliable data to construct a Base Case and Sensitivities employing well-established calculation processes. In nearly all of the cases examined here, US LNG exports are shown to have lower lifecycle GHG emissions compared to using coal alone, fuel oil alone or the expected mix of alternative fuels that would most likely replace imported US LNG.

- The majority of other studies reviewed here show similar results to the Study when comparing LNG with coal in power-plant or industrial applications. This is also usually the case for other studies looking at LNG versus fuel oil.
- The few studies that show US LNG as having more LCA emissions than coal tend to:
  - Use outlier data or assumptions drawn from the high end of the uncertainty range.
  - Apply emission factors derived from incompletely documented or unsuitable sources which contradict well regarded and widely used sources such as the ANL GREET model.
  - Investigate and highlight improbable scenarios which may be nearly irrelevant for the US.
  - Fail to account for relative end-user fuel efficiencies which favor natural gas. For example, in the power sector, approximately 1.26 Btu's of coal or 1.14 Btu's of fuel oil must be burned to replace each Btu of LNG. By not taking this into account, some studies miscalculate the relative GHG impacts of crude and fuel oil compared to LNG.

These problems lead to erroneous conclusions or -- at best -- results that are at the high end of the uncertainty range and may not be appropriate as a "best estimate" to be used for policy decisions.

2. Natural Gas and LNG Supply Chain Segments and Their GHG Emissions

2.1 Introduction Supply Chain Segments

The production, transportation, and supply of natural gas requires an extensive network of complex infrastructure and industrial processes. Each segment is defined by the necessary operations and equipment for the processes required, with emissions for each stage dependent on the methane leakage rate, the gas composition, and the required amount of energy use. In this analysis, results consider the natural gas supply pathway associated with the US production of natural gas, domestic processing and transportation to US liquefaction facilities, LNG carrier transportation, regasification, and delivery of exported gas for use in international power generation. More details on all natural gas segments and the sources of emissions associated with each are discussed below.

2.2 Oil and Gas Production and Gathering & Boosting

2.2.1 Segment Description and Sources of Emissions

Gas production refers to the exploration, drilling, and well operations associated with the production of natural gas. Volumes of gas are produced from geologic reservoirs that each consist of unique pressure and temperature characteristics. The hydrocarbon resources found within each reservoir determine the type of production as well as the characteristics of the extraction process. Produced volumes may contain natural gas, crude oil, as well as combination of sand, water, and other drilling material products. Some separation of these products occurs at the wellhead, but most commonly the natural gas must undergo further treatment downstream at a gas processing facility before delivery to the final consumer.

Emissions produced from this segment consist of fugitive emissions from flanges, valves, and other components related to equipment such as separators, heaters, dehydrators, chemical injection pumps, wellhead compressors, pneumatic devices, or piping used in support of well operations. There are energy requirements associated with drilling and pumping activities, which produce CO_2 from the combustion of fuel products (such as lease fuel or purchased electricity and diesel). The amount of energy required to extract each volume of gas is determined by reservoir conditions, with more intensive operations producing more emissions.

Emissions are generated during flaring operations, which are sometimes required based on the operations at a given wellsite, as well as for maintenance activities. Gas production sites may occasionally also utilize liquids unloading, a process which removes produced water that has accumulated within the wellbore, to increase or restore the flow of gas production. Liquids unloading may require venting of gases to atmosphere based on the operational characteristics at the wellsite.

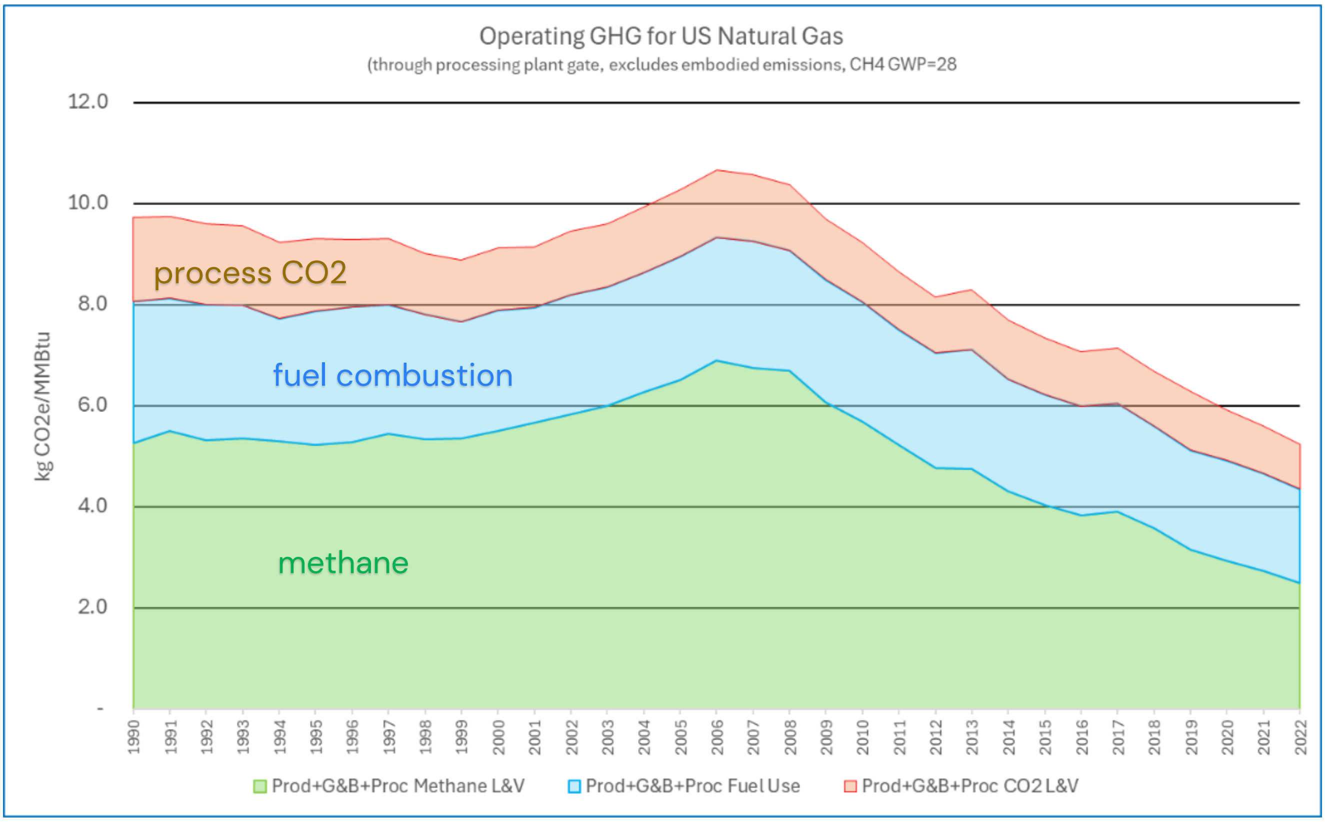
2.2.2 Methodology for Production and G&B

The ICF estimates of production-related GHG emissions are based on "bottom up" calculations that are calibrated to regional or nationwide parameters. The most important calibration sources are the US EPA's National Greenhouse Gas Inventory (EPA GHGI) which determine the Base Case methane release rates for all natural gas supply chain segments (production, gathering & boosting, processing, transmission & storage, and distribution). The specific values used for US methane release calibration of each segment in the Base Case and Sensitivities are discussed in Chapter 3 of this report. The other major source of calibration values for GHG calculations for the US is the US Department of Energy's Energy Information

Administration (EIA) estimates of natural gas energy consumption in oil and leases, gas processing plants, and natural gas transmission lines. These appear in EIA's "Natural Gas Annual" publication.[7]

National average emission rates from 1990 to 2022 as calculated from the EPA GHGI emission data and EIA gas consumption data for the gas supply chain are shown in Exhibit 11. The green area in this chart shows the implication of the EPA GHGI methane emission rates on the national average carbon intensity of natural gas through the gas processing stage. This chart is based on a methane GWP of 28. Emission of CO_2 in process gas streams (mostly from acid gas removal or AGR units.) is shown as the top area. It too is derived from the EPA Inventory. CO_2 from combustion is the blue area and it was computed by ICF based on EIA energy use statistics for lease consumption (encompassing the segment we are calling "production" plus "gathering & boosting") and gas plant gas consumption. The total for 2022 comes to 5.25 CO_2e kg/MMBtu of which 2.50 CO_2e kg/MMBtu is methane releases, 1.85 CO_2e kg/MMBtu is fuel combustion and 0.89 CO_2e kg/MMBtu is process CO_2 from AGR units. Note that chart is only operating emissions and excludes embodied emissions. Embodied emissions have added on average about 0.59 to 0.69 CO_2e kg/MMBtu from 2010 to 2022 per ICF estimates.

Exhibit 11: Operating GHG Emissions for US Natural Gas Based on EPA GHGI and EIA



Source: ICF calculations based on EPA National GHG Inventory and EIA Natural Gas Annual.

For GHG emissions for oil and gas production outside the US, ICF uses many of the same engineering process descriptions and parameters as those in the US but adapts them to the particulars of fields in those countries (e.g. drilling depths, production mechanisms, gas-to-oil ratios, fluid types, etc.) and where available country-specific upstream methane leak rates from IEA's Methane Tracker and country-specific carbon intensities for grid electricity used in producing, processing and transporting natural gas and petroleum products.

[7] Natural Gas Annual 2022 (NGA) - Energy Information Administration - With Data for 2022 (eia.gov)

2.2.2.1 Venting & Flaring (not related to storage tanks)

The estimation of the amount of methane and CO_2e released in the production of oil and gas is taken from EPA's National Inventory of GHGs. For a recent year, the category of vented and flared (other than related to storage tanks) the EPA Inventory shows 15.8 million metric tons in units of CO_2e of which 14.0 million metric tons is from flare combustion and 1.4 million tons is from un-combusted or vented methane. These volumes were allocated among states based on the volume of gas reported in EIA's Natural Gas Annual to have been flared in each state (overwhelmingly associated-dissolved gas from oil wells) and an assumption of a 98% flare combustion efficiency. In total for the US, venting and flaring that is not related to storage tanks contributes 2.56 CO_2/bbl. of crude oil and condensate that is produced.

Outside of the US, venting and flaring that is not related to storage tanks is estimated to contribute 11.78 CO_2 kg/bbl. This is a much higher number than for the US due to the prevalence in many countries of widespread and inefficient flaring. The amount of flaring in each field was taken from published studies if available (largely from the OCI work) or assumed to be equal to each country's average flaring factor (measured in cubic feet of flared gas per barrel of oil produced) as reported in the World Bank's Global Flaring Tracker Report.[8] The international flared volumes were converted to CO_2e assuming a 93% combustion efficiency.

2.2.2.2 Lease Compression of Natural Gas

Natural gas is used on oil and gas leases for several purposes including the compression of natural gas; the heating of produced oil and other fluids for separation/ stabilization/ treatment/ dehydration; to power various fluid (mostly for oil and water) pumps; and to make steam used for enhanced thermal recovery. Based on the total amount of natural gas reported by EIA in the Natural Gas Annual to be consumed by all such lease uses, ICF has estimated that – after accounting for all other uses – approximately of 2.36% of gas produced is consumed to compress natural gas on leases and in gathering & boosting facilities. This same 2.36% factor is used for estimating GHG emissions for international oil and gas fields.

2.2.2.3 Oil Stabilization

As stated above a certain amount of natural gas is consumed on leases to heat the produced oil for the purposes of separating the oil from water and gas and thereby stabilizing the oil so that it can be efficiently and safely transported while not harming the environment by releasing dissolved volatile organic compounds (VOCs). Approximately 52,000 Btus of natural gas are used per barrel of oil produced for oil stabilization with lighter oils requiring less energy (because they separate from other fluids more easily) and oil produced at high gas-to-oil ratio needing more (because they are likely to contain high amounts of dissolved gases). Oil stabilization contributes an average of 1.91 CO_2 kg/bbl. to US oil production and an average of 2.40 CO_2e kg/bbl. for international fields.

2.2.2.4 Storage Tank Fugitives

Storage tanks temporarily hold produced oil on the lease until it can be removed to market by truck or pipeline. During this time, some amounts of methane and other dissolved gases likely will be released from the oil and collect at the top of the tank where they then could be:

[8] Global Gas Flaring Tracker Report (worldbank.org)

- Released directly into the atmosphere (believed to be 2% of such tank fugitive volumes in the US per the EPA National GHG Inventory)
- Captured and burned in a flare (believed to be 70% of US volumes which are combusted with 98% efficiency)
- Captured and put into a vapor recovery unit (VRU) where the gases will be recovered for lease uses or sold (believed to be 28% of US volumes).

Using the split shown in parenthesis, ICF estimates that storage tank fugitives contribute 1.26 CO_2e kg/bbl. to the production footprint of US oils.

For the calculation for the international fields, ICF assumed that a smaller fraction of tank fugitives would be sent to VRUs (14% versus 28% for the US), more would be directly released (16% versus 2% in the US), and the same fraction would be flared (70%). Also, the flaring efficiency for the international fields was assumed to be lower (93% versus 98% in the US). With these assumptions, ICF estimates that storage tank fugitives contribute 2.71 CO_2 kg/bbl. to the production footprint of international fields.

2.2.2.5 Methane Leaks

A certain portion of the vented and flared gas volumes and the storage tank fugitive volumes discussed above would occur in the form of un-combusted methane entering the atmosphere. In addition to methane release through production flares and storage tank vents and flares, methane can be released on oil and gas leases through several other pathways including leaky valves, flanges and meters; pneumatic devices that bleed methane into the atmosphere when actuated; faulty compressor seals; un-combusted compressor and other engine fuel; certain kinds of liquid unloading procedures; and the venting of well tubing and boreholes, pipelines and other equipment during repair and maintenance activities. The total of all production related methane leaks is calibrated to the national and regional methane emissions values discussed in Chapter 3 and shown in Exhibit 20.

2.2.2.6 Electricity & Natural Gas for Oil, Water and CO_2 Pumps and Compressors

There are several kinds of pumps that are operated on an oil and gas lease. The largest of these are pumps that help lift oil and produced water from the bottom of the wells to the surface. If the field is undergoing secondary and tertiary recovery, there will also be pumps (and possibly compressors) to move pressurized fluids (that is, water, water mixed with chemicals, steam, CO_2, or miscible gases like methane or propane) down injection wells into the producing reservoir. Such pumps and compressors can be powered by gas-fired prime movers or electric motors. If electric motors are used, they can draw power from the electric grid or be served by onsite power generation.

The energy used to lift oil and water out of a well undergoing artificial lift is about 0.14 kWh per 1,000 feet of reservoir depth. Since water must be lifted along with the oil, the ratio of produced water to oil is an important parameter in determining energy used per barrel of oil produced. The average water-to-oil ratio for US oil wells is about 5.1 barrels of water per barrel of oil according to the EPA National GHG Inventory and that ratio differs substantially among oil fields. It is common for mature fields that are undergoing secondary recovery using water floods to operate with water-to-oil ratios above 10.

Additional electricity is needed for tertiary recovery, especially CO_2 floods which typically require 107 kWh of electricity to compress each ton of CO_2 that is produced with the oil and then reinjected back into the reservoir. Given that 0.52 metric tons of CO_2 are injected per barrel of oil produced, this means 56.17 kWh are needed per barrel produced from CO_2 floods – more than 10 times the amount typically used for artificial lift.

ICF estimates US oil and gas fields consume 49,745 MWh of electricity-equivalent each day for pumping and miscellaneous uses. This comes to an installed equipment capacity of slightly more than 2,000 MW. For the onshore US, ICF has assumed that 30% of this energy comes from grid electricity and that the rest comes from onsite use of self-produced fuels (mostly natural gas used in either direct drive configurations or as electric motors fed by electricity generated onsite). For the rest of the world, grid electricity is assumed to supply 15% of onshore oil and gas field pumping and miscellaneous electricity use. In all countries, offshore energy is supplied by self-produced natural gas or oil.

The GHG gas impacts of using grid electricity varies by region based on what fuel sources are used to generate electricity. The values for GHG emissions associated with electricity in each state of the US and non-US country includes both the direct emissions from fuel combustion at the power plants plus the emissions associate with producing and delivering the fuel to the power plant, plus the emissions associated with building the power plant, plus the non-fuel emissions associate with plant operations.

For the US on average, GHG emissions related to pumping and miscellaneous energy uses contribute 1.78 CO_2e kg/bbl. of oil production. For international fields, the same statistic is 1.82 CO_2e kg/bbl.

2.2.2.7 Natural Gas for Steam

The final component of GHG emissions from oil and gas production comes from the use of steam to improve recovery of heavy oils. In the US this occurs primarily in shallow oil reservoirs in California where approximately three barrels of steam are injected to produce one barrel of oil. The net energy used to make steam is about 437,000 Btu per barrel of steam or 1.3 MMBtu per barrel of oil produced. Steam is also used extensively in Canada in situ oil sands production and is employed in few oil fields outside of the US and Canada, most notably in Venezuela and Indonesia. For the US on average, GHG emissions related to making steam contribute 1.28 CO_2e kg/bbl. of oil production. Outside of the US and Canada, the same statistic is 0.28 CO_2e kg/bbl. Steam is not used to produce non-associated gas.

2.2.2.8 Embodied Emissions from Drilling and Completing Wells and Construction of Production Facilities and G&B

Embodied emissions for oil and gas production include the GHG's associated with the construction of oil and gas wells. This comes mostly from the energy (almost entirely from diesel fuel) used to drill and complete the wells and to move materials to and from the well sites. Another large portion is associated with manufacturing of the equipment and materials used in the well's construction including oil country tubular goods, cement, sand, gravel, onshore production equipment, and offshore production platforms. For onshore wells, another component is the land disturbances related to clearing the areas needed for drilling pads, roads and gathering line rights of way. As shown in Exhibit 12, for onshore horizontal hydraulically fractured wells, these emissions add up to about 3,000 metric tons of CO_2e or 200 kg per measured foot of well depth. Offshore deepwater wells consume much more energy and require considerably more material. The GHG emission related to their construction is about 9,700 tons or about 600 kg per foot of measured depth. The higher GHG values for offshore well construction are offset by the higher well productivity for offshore wells and so the construction-related emissions per unit of production are typically lower for offshore wells as compared to onshore wells.

Exhibit 12: Examples of Estimated GHG Emissions Related to Well Construction

	US Horizontal Fracked Wells	Offshore Deepwater
True Vertical Depth (ft.)	7,500	14,000
Lateral Length or Deviation (ft)	8,000	2,000
Total depth (ft)	15,500	16,000
GHG in metric tons CO_2e		
Diesel use	1,648	4,923
Land disturbances	383	-
Production of well equipment and materials	980	4,814
Sum tons CO_2e / well	3,011	9,737
Sum kg CO2e / foot	194	609

The emission factors used to model US and international well construction and production facilities are 150 kg/foot for onshore wells that are not hydraulically fractured, 200 kg/foot for onshore fractured wells and 600 kg/foot for offshore wells. Onshore wells that are not hydraulically fractured require less materials (frack sand and water) and use less energy in their completion as compared to fracked wells and so their construction related emissions are modeled as 150 CO_2e kg/foot compared to 200 CO_2e kg/foot for fracked wells. Additionally, 100 metric tons of GHG emissions are assigned per well to the construction of lease equipment and gathering systems for handling produced fluids. On average for the US, construction of wells and production facilities adds up to 0.45 kilograms of CO_2e per MMBtu of oil and gas produced. Of this amount, 0.41 CO_2e kg/MMBtu is for the wells and 0.04 CO_2e kg/MMBtu is for the production facilities. Outside of the US, well and production facilities construction contribute 0.34 CO_2e kg/MMBtu of oil and gas production. This is a lower number than the US because the international fields are larger with higher per-well recoveries.

2.3 Gas Processing

2.3.1 Segment Description and Sources of Emissions

Although some impurities may be removed at the wellhead, most produced natural gas must undergo further processing before delivery to consumers. Gas processing facilities remove additional impurities such as CO_2, nitrogen (N_2), or hydrogen sulfide, while also separating and recovering entrained natural gas liquids (NGLs) for use in other petroleum products. The separated NGLs may consist of ethane, propane, butane, and pentanes+ volumes depending on the raw gas composition. After a series of separation processes, facilities provide sales-quality dry natural gas to downstream consumers via pipeline from the facility.

Emission sources relevant to this industry segment include fugitive methane emissions from onsite reciprocating and centrifugal compressors, pneumatic devices, dehydrators, and other processing equipment. In addition to combustion emission from compressor exhausts, gas processing facilities also vent CO_2 volumes directly to atmosphere during acid gas removal. Acid gas removal is the process which removes CO_2 and hydrogen sulfide (H_2S) from raw natural gas.

2.3.2 Methodology for Gas Processing

The embodied emissions related to the construction of gas processing plants (including the contribution of materials/equipment, land use impacts and fuels used for materials transport and construction) is estimated as 0.103 CO_2e kg/MMBtu of dry gas and NGLs leaving the processing plants. Natural gas fuel consumption at gas processing plants is calibrated by state from the EIA Natural Gas Annual. This is about 2.1% of input volume where acid gas removal is not needed and an additional 2,100 Btu/Mcf of each percentage point of gas composition with acid gases that are removed. Pipeline gas quality specifications require that essentially all hydrogen sulfide be removed and that carbon dioxide be limited to —typically— no more than 2% (for some pipeline the spec is <3% CO_2). Grid electricity use at gas processing plants is not reported by any government survey but is estimated by ICF as 0.20 kWh per Mcf. As with lease uses of grid electricity, GHGs associated electricity purchased by gas processors is estimated using a state or national carbon intensity that includes embodied emissions, fuel supply chain emissions and electricity transmission losses.

Methane release at gas processing plants for the Base Case is 0.13% per EPA GHGI. Additionally, Sensitivities presented in this Study use values of 1.446, 1.88 and 3.0 times the EPA GHGI value. Releases of carbon dioxide from acid gas recovery units (AGRs) are based on the values reported in the EPA GHGI, usually at the level of AAPG Basins. As was shown earlier in Exhibit 11, in 2022 AGR releases added 0.89 CO_2e kg/MMBtu to the average US carbon intensity for natural gas.

2.4 Gas Pipelines

2.4.1 Segment Description and Sources of Emissions

This industry segment consists of large diameter pipeline systems used to transport sales-quality natural gas to residential, commercial, and industrial consumers. These pipelines operate at high pressure and span much longer distances than gathering and boosting pipeline systems. Operations are supported by a series of compressors, engines, and turbines (found within compressor stations), as well as metering and regulating equipment to control and monitor pressures and ensure volumes are transported properly. The distance between compressor stations is based on the diameter of the pipeline, the composition and volume of the gas, and the amount of horsepower needed based on the suction and discharge pressures. Typically, the distance between compressor stations is about 65 miles.

Fugitive emissions occur from the pipeline during transportation of the gas, with leakage rates dependent on the distance and gas composition. There are also fugitive emissions generated from the equipment found at compressor stations which are used to pressurize the gas. Combustion emissions again occur from fuel use along the supply chain, and gas pipelines are also sometimes required to blowdown (i.e., release) additional volumes of gas for safety and maintenance requirements.

2.4.2 Methodology for Natural Gas Pipelines

As with gas processing plants, the embodied emissions for gas pipelines include the contribution of materials/equipment, land use impacts and fuels used for materials transport and construction. These amounts can vary considerably based on the size of pipeline (length, diameter, wall thickness) and the terrain through which the pipeline is being built. Based on building a 36-inch diameter pipeline which operates at 95% utilization rate, those embodied emissions would come to about CO_2e 0.55 kg/MMBtu of natural gas per 1,000 miles distance. Based on the natural gas consumption by gas pipeline as reported in EIA's Natural Gas Annual Energy, ICF estimates fuel use by gas pipelines to be approximately 4% per 1,000 miles.

As with the other supply chain segments, Base Case methane release from gas pipelines is based on the EPA GHGI (an average of 0.22% of throughput) and that value is varied in the Sensitivities presented in this Study. Assuming an average historical transmission distance of 800 miles, for modeling purposes the pipeline methane release rate is represented as 0.27% per 1,000 miles.

Using EPA GHGI and EIA data, calculated pipeline operating GHG emissions per unit of natural gas delivered to US consumers or exported (by pipeline or LNG) comes to 2.874 CO_2e kg/MMBtu. Of this amount, 1.058 CO_2e kg/MMBtu is methane release, 0.032 CO_2e kg/MMBtu is carbon dioxide releases and 1.785 CO_2e kg/MMBtu is pipeline fuel use. As stated earlier, embodied emissions would add roughly 0.55 CO_2e kg/MMBtu per 1,000 miles.

There is no public source of information regarding the origin of natural gas that is converted to LNG in the US or the pipeline transmission pathways the gas took to reach the liquefaction plants. For modeling purposes, this Study estimated the likely origins of the gas and the related transmission pathways based on the general pipeline flow patterns revealed in pipeline bulletin board data and ICF's propriety modelling of monthly gas production, transmission and consumption. It was assumed that gas origins and transportation pathways for gas going into the liquefaction plants were similar to those of all gas consumers in the region in which the liquefaction plant is located.

Through this process, this Study estimated that there were twenty US areas/nodes which contributed substantial quantities of gas for 2022 LNG exports including approximately 19% from WTX/Panhandle, 17% from Gulf Coast/GOM, 41% from ETX/N.LA/Ark., and 23% from the Appalachian Basin. Transportation to the seven liquefaction plants operating in 2022 took place along roughly 115 US pipeline corridors. The average pipeline distance from gas processing plant to liquefaction plant was estimated as 506 miles across all liquefaction plants with a range of 320 to 940 miles among the individual liquefaction plants.

2.5 Liquefaction Plants

2.5.1 Segment Description and Sources of Emissions

After pipeline transportation, volumes of natural gas which have been purchased for export are delivered to liquefaction facilities. These facilities further process and liquefy the gas in preparation for marine transportation to international markets. The liquefaction process consists of the removal of additional CO_2 and water, while also implementing a series of refrigeration processes used to drop the temperature and condense the received gas. These processes are performed to allow for easier marine transport, as the gas volume decreases significantly (>600 times) as a liquid. After the additional processing, the liquefied gas (now LNG) can be temporarily stored onsite before transfer to LNG marine carriers via loading arm.

Emissions in this segment are generated from fugitive leakage and combustion of fuel onsite in support of operations (i.e., engine and turbine exhaust). Like the gathering and boosting and gas pipeline segments, onsite blowdowns may also be periodically performed to allow for required maintenance.

2.5.2 Methodology for Liquefaction

GHG emissions at each US liquefaction plant in 2022 are estimated in the Study based on exported volumes reported in Mcf to DOE's Office of Fossil Energy. On average the GHG emissions associated with a gas-fired liquefaction are approximately 5.74 CO_2e kg/MMBtu of output, measured at the plant and including embodied emissions. This breaks out into 5.04 CO_2e kg/MMBtu for plant fuel, 0.562 CO_2e

kg/MMBtu for process CO_2, 0.066 CO_2e kg/MMBtu for methane releases, and 0.078 CO_2e kg/MMBtu for embodied emission related to plant construction.

Much of the data for these estimates came from EPA GHG Reporting Rule Subpart W filing by US liquefaction plants. (See Exhibit 13) Most of these emissions come from fossil fuel combustion, primarily to run gas turbines that drive refrigeration compressors. This energy use is about 8.1% of the Btu contained in the output LNG. For liquefaction plants using electric drive, this Study assumes that electricity use is 9.22 kWh/Mcf of LNG output. This is translated into CO_2e using the estimate 2022 carbon intensity for Texas electricity of 443.8 CO_2e/MWh delivered to customers. Electric-drive LNG plants also consume a small amount of natural gas for process heat and during flaring of vented gas. This is estimated as 0.05% of gas output.

Any CO_2 contained in the feed gas must be removed to prevent dry ice forming in heat exchangers. These quantities are <u>not</u> reported in GHGRP subpart W. We have estimated these assuming approximately 1.06 mol percent in the feed gas (that is, CO_2 is 2.77% of input gas by weight). Methane leaks and vents reported in GHGRP subpart W are about 0.005% of output, but these do not include all potential sources. For ICF's modelling purposes, methane leaks and vents are assumed to be 0.012% (the same assumption of 0.01% used by the NPC for releases plus we add a 0.002% factor for unburned gas in gas turbines from EPA's AP-42).

Exhibit 13: 2021 Material and Energy Balances for Gas-fired Liquefaction Plants

Material and Energy Balances for 2021 Subpart W Gas-fired Liquefaction Plants						metric tons CO2 emissions at plants	Source of data
Variable	Mcf	Btu/scf	TBtu	kg/Mcf	metric tons		
Gas input	3,156,195,909	1,026	3,238.3	20.119	63,500,550	-	*calculated*
Fuel burned	232,204,273	1,026	238.2	20.119	4,671,795	12,641,201	*adapted from Subpart W*
AGR , L&V emissions of CO2	30,992,759	-	-	52.730	1,634,248	1,634,248	*Not in Subpart W. Calculated by ICF assuming 1.06% CO2 in inlet gas*
Leaks and vents CH4	146,462	1,012	0.1	19.220	2,815	-	*adapted from Subpart W*
LNG output	2,892,852,416	1,037	2,999.9	19.770	57,191,692		*adapted from Subpart W*
Balance	*0.00*		*0.00*		*0*	*14,275,449*	
Uses + losses vs NG INPUT	8.34%		7.36%		9.94%		
Uses + losses vs LNG OUTPUT	9.10%		7.95%		11.03%		

GHG Emission Type	CH4 kg/MMBtu	CO2e kg/MMBtu GWP CH4=28, N2O=265	Methane Leak Rate vs Output	
Methane	9.73E-04	0.027	0.005%	
N2O	8.99E-06	0.002		*These are emissions at the plant and exclude supply-chain and embodied emissions.*
CO2		4.935		
Sum		4.964		

Note: This excludes Freeport (electric drive) and Elba Island (partial data). Based on gas composition estimated for Marcellus. Balances will differ slightly for other gas feedstocks. Energy use versus output Btu's is modelled as 8.1% the same as the NPC estimate.

2.6 Gas Carriers

2.6.1 Segment Description and Sources of Emissions

After liquefaction and loading, gas carriers are used to transport LNG to international markets for regasification and consumption. These carriers transport large volumes of fuel and can travel between approximately 3,000 to 10,000 one-way nautical miles based on the origin and destination. The vessels can be powered using a variety of fuels, but most carriers utilize onboard LNG. During transportation, onboard LNG fuel located within cryogenic storage experiences external heating. This causes some amount of the gas to undergo vaporization, also known as boil-off. LNG carriers typically capture and utilize boil-off gas for propulsion and onboard power requirements. Some newer carriers reliquefy the boil off and return it to the storage tanks.

While gas carriers experience a small amount of vented and fugitive losses, most of the emissions associated with gas carriers are due to a concept called methane slip. Methane slip refers to quantity of un-combusted methane gas that is produced from engine exhaust, which can vary based on the type of engine. Therefore, the total amount of emissions that are generated during a voyage are dependent on the transportation distance (meaning the amount of fuel required) and the configuration of the vessel propulsion and power (type of engine and fuel used).

2.6.2 Methodology for LNG Carriers

Each shipment of LNG is contained in a database maintained by the US Department of Office of Fossil Energy and Carbon Management.[9] That database includes the liquefaction plant from which the LNG is exported, the export volume in thousand standard cubic feet (Mcf) of gas, the destination country and the LNG carrier name. ICF linked the LNG carrier name to data from the International Gas Union (IGU)[10] to find additional information on each gas carrier including its capacity, cargo type, vessel type, and propulsion type. A statistical summary of this data can be found in this Study in Exhibit 27 and later exhibits.

The distance between each US liquefaction plant and destination country was found using Google Maps and other online data sources for port-to-port distances. Based on the vessel's propulsion type, ICF estimated the fuel use and what portion of the fuel would be boil-off gas versus fuel oil. The calculations also included an estimate of how much methane would be released during each voyage from methane slip from the engines. Some of the key data for these fuel-use and emission calculations are shown in Exhibit 14.

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[9] Natural Gas Imports and Exports Monthly Reports | Department of Energy

[10] IGU World LNG Report 2023 Appendix 3: Table of global active LNG fleet as of end-of-April 2023, Appendix 4

Exhibit 14: Assumed LNG Shipping Characteristics

Propulsion Type		Approx. Energy Efficiency (averages)		Approx. Methane Emissions When Using LNG (averages)				
		Efficiency as %	Energy Conversion (Btu/kWh)	CH4 kg/ MMBtu of LNG Consumed	CH4 Emissions as % of LNG Consumed	CH4 Emission (kg/MWh or g/kWh)	Minimum Fuel Oil Use as Percent	Daily Boil Off Rates (% of capacity)
Steam	Steam boiler & turbine	28.0%	12,186	0.004	0.02%	0.04	0.0%	0.25%
Steam reheat	Steam boiler & turbine with reheat	36.4%	9,374	0.004	0.02%	0.03	0.0%	0.11%
SSDR	Slow speed diesel with re-liquefaction	45.7%	7,464	0.779	4.19%	5.82	5.0%	0.19%
DFDE	Dual-fuel diesel electric	48.0%	7,108	0.779	4.19%	5.54	5.0%	0.14%
TFDE	Tri-fuel diesel electric	48.0%	7,108	0.779	4.19%	5.54	5.0%	0.13%
STaGE	Steam Turbine and Gas Engine	54.5%	6,261	0.404	2.18%	2.53	5.0%	0.10%
X-DF	Low-pressure, slow-speed dual fuel (X-DF)	50.0%	6,824	0.404	2.18%	2.76	1.0%	0.10%
ME-GI	High pressure dual fuel, 2 stroke engines	53.0%	6,438	0.044	0.24%	0.29	5.0%	0.10%
ME-GA	Low pressure dual fuel, 2 stroke engines	50.0%	6,824	0.404	2.18%	2.76	1.0%	0.10%
Average of Operating Fleet All Prop. Types		42.9%	8,492	0.388	2.09%	2.76	2.77%	0.16%

Source: Energy efficiency and emission factors adapted from by Pavlenko et al 2020 for methane from marine LNG as quoted in: FULLTEXT01.pdf (diva-portal.org)
Actual energy efficiencies vary as a function of carrier speed and other factors. Values shown here are used as scaling factors.

The actual amount of fuel used by a given ship will depend on many factors including the ship's speed and how the carrier's auxiliary engines (often providing electricity for vehicle operation) are operated. In this Study, the GHG emission are calculated for a nominal 145,000 cubic meter carrier with DFDE/TFDE propulsion assuming fuel consumption of 6,152 MMBtu/day when the carrier is underway at 19.5 knots. Fuel consumption is 20% of this amount for loading days (or when waiting at canals) and 30% for discharging days.

As an example of these algorithms, a shipment from the US East Coast to France over 4,043 one-way nautical miles would result in GHG emissions of 3.095 CO_2e kg/Mcf (2.984 CO_2e kg/MMBtu). These emissions are made up of 0.551 CO_2e kg/Mcf of methane releases, 2.496 CO_2e kg/Mcf for fuel combustion and 0.048 CO_2e kg/Mcf for embodied emissions.

2.7 Regasification Plants

2.7.1 Segment Description and Sources of Emissions

After natural gas is liquefied and transported by LNG carrier, it must be heated and regasified before delivery to the consumer. Once the LNG carrier arrives at the destination market, the import terminal typically unloads the vessel's cargo fuel into onsite storage. The regasification plant then utilizes heat exchangers to heat and regasify the LNG volumes before eventually delivering the gaseous natural gas via pipeline to end use power plants and other residential, commercial, and industrial consumers.

Greenhouse gases produced in this industry segment are low when compared to the overall natural gas supply chain. Sources consist of combustion emissions from any onsite fuel use, as well as a small amount of fugitive losses.

2.7.2 Methodology for Regasification

Most regasification plants are open rack systems that take heat energy from ocean water or the air to vaporize the LNG. The energy consumption of open rack systems is to pump sea water through the heat exchangers and to pressurize the LNG up to the pressure of the receiving pipeline system. This energy requirement is about 0.25% of LNG throughput. Total GHG emissions for an open rack regasifier would be about 0.242 CO_2e kg/Mcf (0.233 CO_2e kg/MMBtu). These emissions are made up of 0.136 CO_2e kg/Mcf from fuel combustion, 0.027 CO_2e kg/Mcf for methane release and 0.080 CO_2e kg/Mcf for embodied emissions for the construction of the plant. A fired regasifier burns some of the LNG to provide heat for its vaporization. A fired regasification system would use about 1.5% of the LNG and would have total emissions of 0.932 CO_2e kg/Mcf (0.898 CO_2e kg/MMBtu).

2.8 Gas Distribution

2.8.1 Segment Description and Sources of Emissions

Gas distribution refers to the industry segment which connects large-diameter, high-pressure gas transmission lines to low-pressure lines reaching individual consumers. These distribution systems are made up of progressively smaller diameter line pipelines and utilize a system of metering and regulating equipment to lower and control the delivered gas pressure. Distribution systems consist of larger trunk lines, referred to as mains, and smaller service lines which link to individual homes and businesses.

Distribution systems consume little if any natural gas and have little if any combustion emissions.[11] Emissions in this segment occur from fugitive losses during pipeline transportation of the fuel. The rate of fugitive losses dependent upon the material type of each pipeline segment, with older materials such as cast iron producing more emissions. There are also fugitive losses that occur across all metering and regulating operations, as well as from other supporting equipment such as pressure relief valves and customer meters. Finally, similar to other gas pipeline segments, distribution systems can also produce emissions from periodic maintenance blowdowns.

2.8.2 Methodology for Gas Distribution

The feed gas for US LNG liquefaction plants is delivered directly from pipelines and does not pass through gas distribution companies. Therefore, there are no GHG emissions from gas distribution in the US portion of the LNG supply chain. However, consumers of natural gas in importing countries may have the regasified LNG (and other sources of domestic and imported natural gas) be delivered through distribution companies. So, in computing the GHGs of the full supply chain for LNG, there is a component for gas distribution for all residential and commercial customers and a portion of industrial and power customers. This is computed in the Base Case using the US methane release rate of 0.21% from the EPA GHGI. In Sensitivities that increase the US methane leak rates above the EPA GHGI values, that same increase is assumed to apply to gas transmission and distribution in countries that import US LNG.

2.9 Power Generation and Other End-uses and Their Efficiencies

2.9.1 Segment Description and Sources of Emissions

This final industry segment refers to large scale power plants used for the generation of electricity. The emissions associated with power generation are dependent on the configuration of the power plant as well as the type of fuel. CO_2 and CH_4 emissions are generated during the combustion of the fuel and vary based on the gas composition and the combustion efficiency of the boiler or turbine. Nearly all of the natural gas fuel is converted to CO_2 emissions during the combustion process, but some uncombusted CH_4 remains in the exhaust gas.

[11] Gas distribution system in cold climates might burn natural gas to maintain a minimum gas temperature and prevent ice.

One important LCA concept to note that applies to this stage is the end-use application of the fuel being used. For instance, when comparing the LCA results of multiple fuels such as natural gas and coal used to generate electricity, it would not be accurate to present results on the basis of delivery to consumer because the efficiency of the power plant would be excluded. In this example, the end-use application has a significant impact on results because coal power plants are less efficient and therefore require more energy than natural gas-fired power plants to produce the same amount of electricity. This concept can also apply when comparing the LCA results of multiple fuels in other end-use applications where efficiencies may differ among fuels.

2.9.2 Methodology for Power Plants

The heat rates for all types of power plants used in this Study are derived from IEA data on energy consumption and power generation. These are computed separately for each country. On average the heat rate of gas power plants is 7,690 Btu/kWh, for coal power plants 9,680 Btu/kWh and for oil plants 8,736 Btu/kWh.

For industrial facilities, competition among gas, coal and oil is assumed to take place with the same energy efficiency for these fuels in boilers, furnaces, kiln, etc. Competition with electricity is more complex and is discussed in Chapter 4. (see Exhibit 35)

2.10 Fuel LCAs and Material LCAs Used to Estimate Embodied Emissions

As part of the scope of this analysis, Base Case and Sensitivity results include additional GHG impacts associated with "embodied" emissions. These embodied emissions represent the GHGs generated during the construction of all supporting infrastructure within the natural gas supply chain, as well as the production and transportation of all construction materials. The impacts of embodied emissions were quantified by applying emission factors modeled within the Argonne National Laboratory GREET model, a life cycle assessment tool which provides emission impacts for many different fuel and material pathways.[12]

Examples of fuel LCA factors considered in the analysis include diesel, coal, and residual fuel oil. Examples of materials considered in the construction of supporting infrastructure include cement, concrete, glass, lime, and steel requirements (among others). Factors for these are shown in Exhibit 15. Construction GHG impacts were determined by combining LCA factors with a volume of required materials. These volumes were determined using a combination of assumptions which represent the typical material requirements needed in the construction of each type of facility within the supply chain.

[12] Department of Energy (DOE) Argonne National Laboratory Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model; https://www.energy.gov/eere/greet

Exhibit 15: LCA Factors used to determine Embodied Emissions from Construction Materials

Product	kg CO2/MT	kg CH4/MT	kg N2O/MT	kg CO2e CO2/MT
Aluminum (Average Wrought)	14,325.0	27.4	0.2	14,325.0
Asphalt	1,168.4	14.9	0.0	1,168.4
Cement (O/G Well)	940.4	0.4	0.0	940.4
Clean Water	0.2	0.0	0.0	0.2
Concrete	94.8	0.0	0.0	94.8
Copper	3,609.6	8.7	1.0	3,609.6
Diesel Fuel	534.8	4.5	0.0	534.8
Drilling Mud	6.4	0.0	0.0	6.4
Fiber Glass	1,719.1	4.3	0.0	1,719.1
Frac Sand	5.8	0.0	0.0	5.8
Glass	1,613.8	3.9	0.0	1,613.8
Gravel	5.8	0.0	0.0	5.8
High-Density Polyethylene	1,802.4	9.9	0.0	1,802.4
Iron Parts	449.1	3.5	0.0	449.1
Lime	1,262.7	0.7	0.0	1,262.7
Miscellaneous	535.0	5.0	0.0	535.0
Nickel (Average)	10,880.1	52.5	0.5	10,880.1
Stainless Steel	828.0	1.9	0.0	828.0
Steel (Line Pipe)	2,286.0	4.1	0.0	2,286.0
Steel (Machinery+Assembly)	3,145.8	5.6	0.0	3,145.8
Steel (OCTG)	2,286.0	4.1	0.0	2,286.0
Steel (Structural)	2,694.4	4.7	0.0	2,694.4

GWP used in above results: AR-5 100 year; CH_4 - 28 and N_2O - 265

2.11 Accounting for Losses within the Supply Chain and the Conversion of LNG to Electricity

As discussed previously, the term "gate" can be used to describe the scope of emissions included in an LCA carbon intensity for a particular fuel within its production and transportation supply chain. However, there are additional considerations when combining carbon intensity results across more than one supply chain segment. As energy moves between successive stages in the supply chain, a portion of that energy is lost as fugitive emissions, through fuel consumption, or as coproducts (gas processing plant shrinkage) within that stage. Therefore, the overall carbon intensity result determined at each gate must track both the GHG emitted, as well as the inputs and outputs of energy within each segment. To report each segment's contribution to emissions on the basis of 1 MWh of generated electricity (considered the most important end-use application in this analysis), it is necessary to multiple the CO_2e kg/unit GHG emissions for each segment by the number of units needed to ultimately supply 1 MWh to the consumer. This allows for the emissions in segment "A" to be "scaled up" to account for losses in supply chain segments downstream of segment "A."

Exhibit 16 provides an illustration of these concepts by providing details of emissions (the columns) for each segment (the rows) in the left-hand side of the table with total emissions for each segment in the column labeled "Sum Construction and Operation." To calculate the emissions per MWh of electricity generation, the values in that column must be multiplied by the values in column labeled "Units Required to Deliver 1 MWh to Customer." The results appear in the yellow row labeled "Weighted of All Stages" and sum to 555.96 CO_2e kg/MWh for all LCA components.

Note that below the yellow row there is an orange row labeled "Weighted Sum to Customer" which shows emissions per Mcf for delivery to and combustion by a consumer. This might be the appropriate measurement to use in comparing emissions among fuels for industrial customers that use natural gas in boilers, furnaces, and kilns where the energy efficiency among fuels is the same or very similar.

Exhibit 16: Details of LCA Showing Btus Exiting Each Supply Chain Segment

LNG Supply Chain GHG LCA: Wellhead to Electricity Delivery: Case #6

Sensitivity: AR-5, 100, EPA Inventory (1.00), w/Embodied, Open Rack Regas

Gas Source:	*US Marcellus*	*Trans. Mode & Naut. Miles, Exp. Term. to Imp. Term:*	*145000 cm LNG carrier: DFDE: 1-way dist. in nm>>*	*4,043*	*CH4 Calibration* *EPA Inventory (1.00)*
Export (LNG Plant) Location:	*US East Coast*	*Trans. Mode and Miles to Power Plant:*	*Pipeline*	*50*	*Embodied* *Full LCA w/Embodied*
Power Plant Location:	*France*	*Methane Global Warming Potential:*	*AR-5, 100-year Biogenic Methane*	*28*	

			kg CO2e / Unit of Measure (Natural Gas or Electricity) Exiting Each Stage																		
			Construction					Operation													
Stage	Supply Chain Stage	Unit of Measure	Materials	Land Use	Combustion	Methane Release	Other GHG	Materials	Land Use	Combustion (NG)	Combustion (not NG)	Operation Electricity	Formation CO2 (AGR)	Methane Release	Other GHG	Sum Construction and Operation	Btu / Unit (Exiting Stage)	NG Release During Stage	NG/Electricity Consumed in Stage (input vs output)	Units Required to Deliver 1 MWh to Customer	Btus Required per MWh Deliv. to Customer
1	Upstream	Mcf	0.12	0.02	0.18	0.00	0.00					0.115		0.99		1.42	1,086,324	0.220%		8.816	9,576,996
2	Gathering and Boosting	Mcf	0.01	0.02	0.00		0.00			1.61				1.18	0.00	2.82	1,086,324	0.258%	3.15%	8.515	9,250,539
3	Gas Processing	Mcf	0.06	0.02	0.02		0.00			1.01		0.104		0.60	0.00	1.81	1,026,396	0.136%	2.16%	8.806	9,038,147
4	Pipeline to Liquefaction Plant	Mcf	0.10	0.04	0.03		0.00			0.69				0.46	0.00	1.32	1,026,396	0.085%	1.26%	8.687	8,916,561
5	Liquefaction Plant	Mcf	0.05	0.00	0.03		0.00			5.04			0.56	0.07	0.01	5.74	1,037,349	0.012%	8.47%	7.867	8,160,325
6	LNG Carrier	Mcf	0.05		0.00			0.21		1.36	0.92			0.55		3.10	1,037,349	0.105%	2.50%	7.661	7,947,559
7	Regasification Plant	Mcf	0.04	0.01	0.03		0.00			0.14				0.03	0.00	0.24	1,037,349	0.005%	0.25%	7.642	7,927,429
8	Pipeline to Power Plant	Mcf	0.02	0.01	0.01		0.00			0.11				0.07	0.00	0.21	1,037,349	0.014%	0.20%	7.626	7,910,616
9	Power Plant	MWh	0.97	0.10	0.21		0.00	0.03		386.04	0.13			0.80	0.40	388.69	3,412,000	0.022%	53.60%	1.075	3,668,817
10	T&D to Electricity Consumer	MWh													1.72	1.72	3,412,000		7.00%	1.000	3,412,000
	Weighted Sum of All Stages	**MWh**	**4.81**	**1.03**	**2.83**	**0.01**	**0.01**	**1.62**	**0.00**	**495.55**	**7.23**	**1.92**	**4.38**	**34.35**	**2.22**	**555.96**					
	Weighted Sum to Customer	**Mcf**	**0.63**	**0.14**	**0.37**	**0.00**	**0.00**	**0.21**	**0.00**	**64.78**	**0.95**	**0.25**	**0.57**	**4.50**	**0.07**	**72.48**					

3. Assumptions Regarding Methane Release

3.1 Importance of Methane Releases to GHG LCA Results

The amount of methane released during each supply chain segment within the natural gas industry has a significant impact on LCA factor results. This is due to the relative global warming impact methane (CH_4) has as compared to the same mass of carbon dioxide (CO_2). This relative heating amount is quantified using a global warming potential (GWP), which is a factor by which one mass unit of a GHG gas is multiplied to estimate what mass quantity of CO_2 would have the same warming potential.

The implementation of a GWP factor allows for different GHGs to be combined into a single volume on a CO_2-equivalency basis. Over the course of nearly 35 years, there has been a sequence of Assessment Reports released by the Intergovernmental Panel on Climate Change (most recently 2023) which quantify the GWP of different GHGs relative to CO_2.[13] The resulting factors for CH_4 range from 25-36 across the more recent IPCC studies on a 100-year basis (CO_2 is represented by the baseline factor of 1), with the upper range factors reflecting additional climate impact aspects such as methane oxidation or carbon feedback. CH_4 GWP factors can also be expressed on a 20-year basis, with factors being considerably higher on a shorter timeframe (from 84-86).

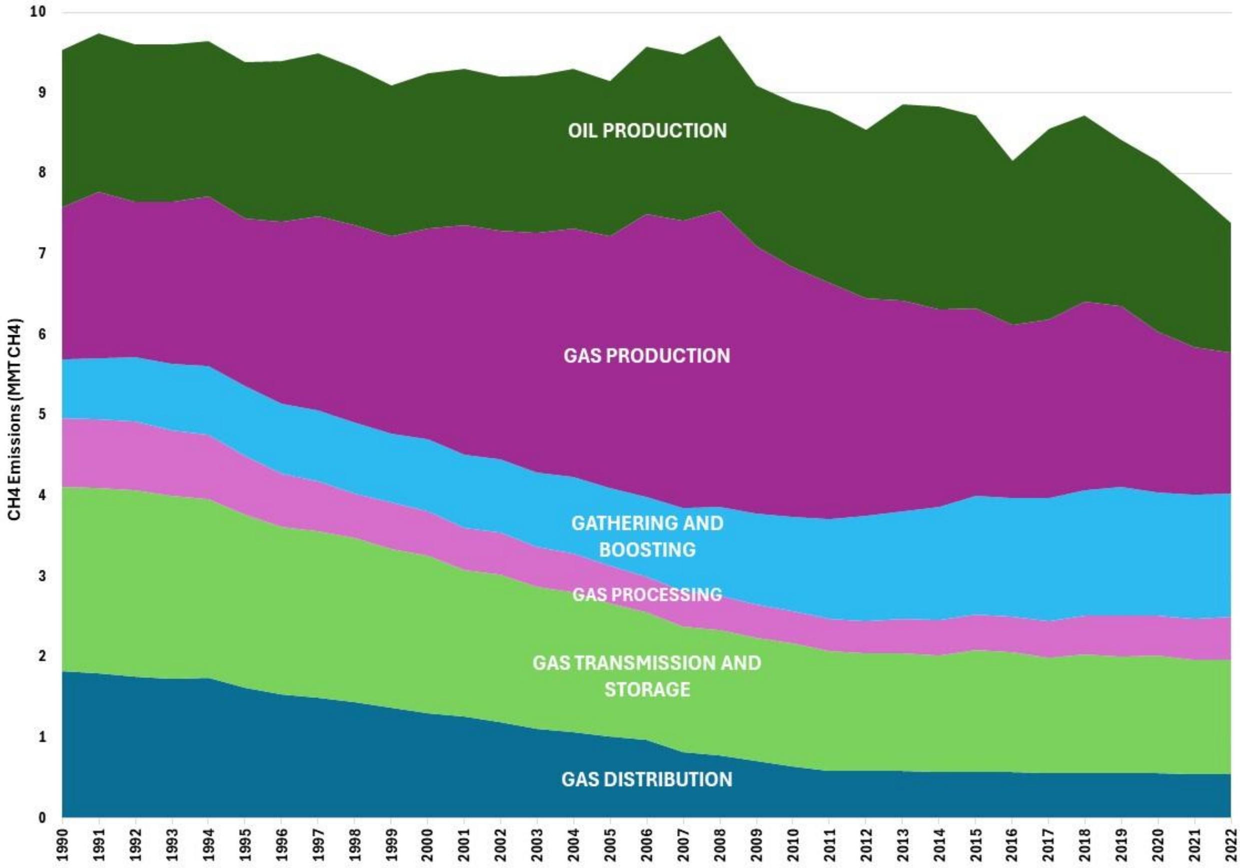
While scientific debate continues regarding the most accurate GWP factor to use for CH_4, this Study utilizes the 100-year AR-5 fossil methane factor of 28 in Base Case results when expressing methane emissions on CO_2-equivalency basis. The reason this particular GWP factor is chosen in this analysis is to provide consistency with prominent emission data sources such as the US EPA GHG Inventory, which recently updated the GWP used for CH_4 from 25 to 28. Certain Sensitivity Cases compute results using a 20-year basis (GWP=84) for CH_4, to provide additional comparisons and further illustrate the impact that methane-related assumptions have on results.

3.2 Historical EPA GHGI Estimates of Oil and Gas System Methane Releases

The US EPA publishes the Inventory of US Greenhouse Gas Emissions and Sinks, an annual publication which provides a quantification of GHG emission estimates from all man-made sources across the US.[14] For the oil and gas sectors, EPA utilizes individual equipment and activity counts with specific emission factors as the methodology (e.g., bottom-up) to determine emissions. Equipment counts and emission estimates are provided for individual sources and by industry segment. Exhibit 17 below provides a quantification of methane emissions for each industry segment within the natural gas supply chain.

[13] Intergovernmental Panel on Climate Change (IPCC); https://www.ipcc.ch/reports/
[14] US Environmental Protection Agency (EPA); https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

Exhibit 17: CH_4 Emissions from Oil and Gas Systems by Industry Segment (million metric tons)



Source: 2024 US EPA Greenhouse Gas (GHG) Inventory, ICF analysis

The methane release rate is a metric which can be used to quantify the volume of emissions generated throughout a fuel supply chain. It is often expressed as a percentage which is determined by taking the total amount of CH_4 emissions divided by a throughput quantity (typically the amount of produced or delivered natural gas) that has been adjusted for composition to represent only the CH_4 molecules. In contrast to a full LCA emission factor, the leakage rate does not include other GHGs (such as CO_2) which are generated from fuel combustion or other energy requirements.

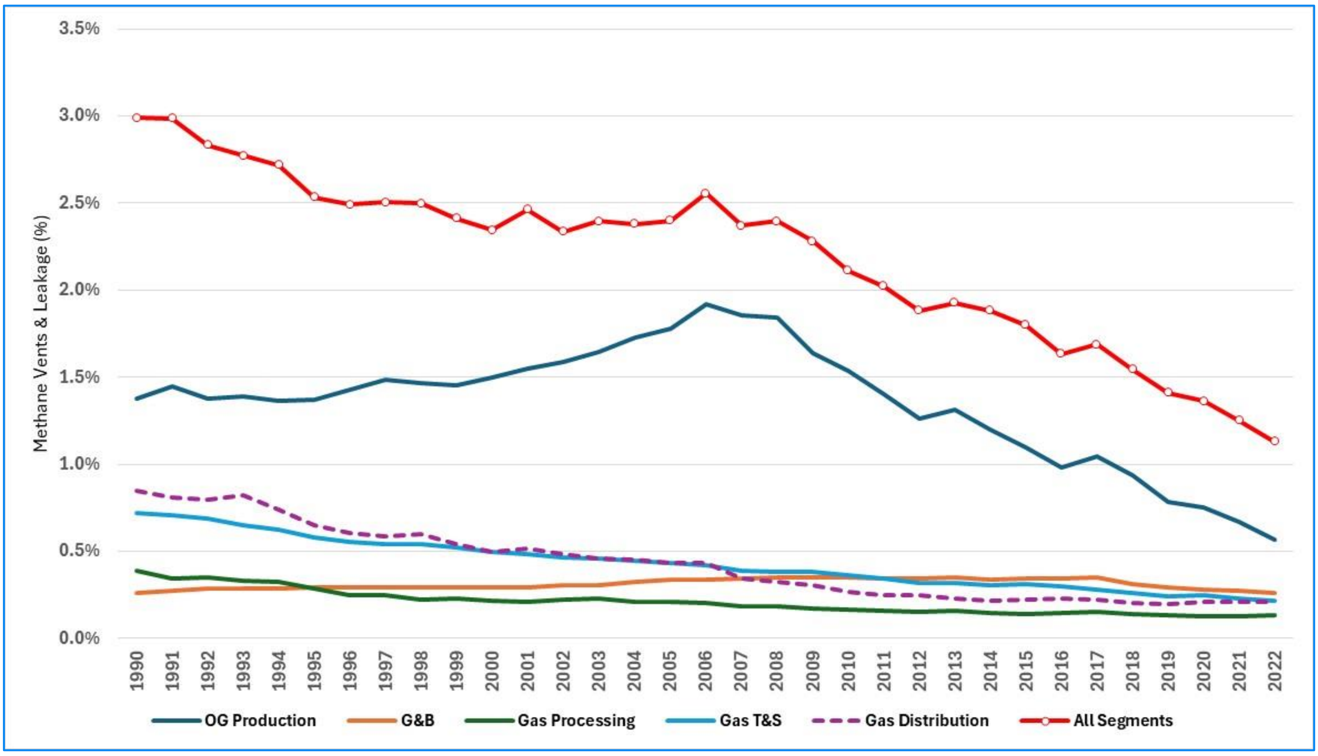
Exhibit 18 provides the implied methane leakage rate for each natural gas supply chain industry segment. The individual industry segment leakage rates are expressed using the total amount of CH_4 for the US as determined by the 2024 EPA GHGI (shown in Exhibit 17), and a relative throughput amount for each individual industry segment. For example, the gas production leakage rate is a function of CH_4 emissions from the wellsite divided by the produced amount of marketed raw natural gas. For results across all segments (red line), the leakage rate is normalized to represent emissions from all supply chain segments on the throughput basis of total natural gas delivered to US consumers plus pipeline and LNG exports.

Historically, the methane release rates for all segments were higher (particularly within gas production), but significant improvements have been made to reduce emissions over time. This is due to several factors including:

- Turnover of older equipment, resulting in newer lower emitting options (less losses)
- Increased focus on GHG issues, including companies implementing voluntary emission reduction actions over time

- Increased regulatory action and requirements such as the federal New Source Performance Standards (NSPS) and the EPA Greenhouse Gas Reporting Program (GHGRP)
- Newer and more accurate methodologies and emission factors in more recent years.

Exhibit 18: 2024 EPA GHG Inventory US Natural Gas & Oil Systems Methane Leakage Rates by Industry Segment



Source: Environmental Protection Agency (EPA), Energy Information Administration (EIA), ICF analysis
Note: The leakage rate for each industry segment is shown on the basis of annual throughput for each segment (i.e., produced natural gas). The combined leakage rate for all industry segments (red line) represents emissions from all segments on the basis of natural gas delivered to consumers.

Exhibit 19 below illustrates the impact that the selected throughput basis has on the methane leakage rate for each natural gas supply chain segment. The first column provides the total CH_4 emissions, consistent with EPA GHGI estimates. The second and third columns provide the throughput represented in each segment's methane leakage rate, as well as a description of the volume considered. Each throughput volume has been adjusted to reflect the CH_4 molecules within the gas based on the composition at each point along the supply chain. To quantify the leakage rate across all industry segments, the emissions must be expressed on a similar throughput basis (in this case, delivered gas consumption plus exports), or the quantities determined using each factor do not accurately reflect the losses or energy consumption along the supply chain.

Exhibit 19: Methane Leakage Rates Computed Using Segment Throughput Volumes

Segment	2022 Emissions (Bcf CH4)	2022 Throughput of each supply chain segment (Bcf CH4)	Basis of Throughput	*2022 CH4 Leakage Rate (%)*
OG PRODUCTION	174.7	30,754	Marketed NG Production	0.57%
GATHERING AND BOOSTING	79.4	30,754	Marketed NG Production	0.26%
GAS PROCESSING	28.1	21,373	Processed NG	0.13%
GAS TRANSMISSION AND STORAGE	73.3	33,931	NG Consumption + Exports	0.22%
GAS DISTRIBUTION	28.3	13,604	NG Delivered Sales by LDCs	0.21%
Total Supply Chain	**383.7**	**33,931**	**NG Consumption + Exports**	**1.13%**

Source: 2024 EPA GHGI, EIA, ICF analysis

Note that the US EPA GHGI relies on two separate models to quantify emissions for natural gas and oil industry systems. Each model reflects emissions from the unique equipment and separate supply chains needed to produce either natural gas or oil. The emissions shown here (and in other results in the analysis) include impacts from oil production to properly account for upstream operations which process both oil and gas. Additionally, the results shown in this section include a small amount of CH_4 emissions from abandoned oil and gas wells (modeled independently from these two models in the EPA GHGI) which may not be reflected in all leakage rates referenced throughout this report.

3.3 Controversies Regarding GHGI Methodology and Results from Remote Sensing Studies

Recently, there have been several studies[15] performed which attempt to validate current quantification methodologies and improve the accuracy of leakage rate estimates by performing measurement of methane emissions using sensors mounted on satellites, airplanes, drones, and ground equipment. Some of these studies calculate airborne methane concentrations and use those data to estimate the methane emitted from all sources in a geographic area. Others sense methane releases at specific locations (e.g., a well pad or pipeline compressor station) and can estimate flux in terms of kilograms released per hour by a facility or specific piece of equipment. The results of these studies suggest that the actual emissions generated from these facilities may be higher than the leakage rates implied from "emission factor" methodologies such as those utilized in the EPA GHG Inventory. Some theories on why these discrepancies occur include diverging emission factors due to abnormal operating conditions and the presence of "super emitters." A "super emitter" refers to a single source or event which emits a significant volume of emissions relative to the overall inventory.

It will take some time to reconcile methane leakage rates computed from emission factors and those estimated from remote sensing surveys. Some sources, such as Argonne's GREET model[16], currently provide options to utilize leakage rates based on either methodology when generating results. This Study approaches this discrepancy similarly by providing results using several different methane leakage rate cases. More detail on how the Base Case and Sensitivities were set up is provided in Section 5.1.

[15] One recent study includes - Quantifying oil and natural gas system emissions using one million aerial site measurements; Sherwin, Stanford University
[16] Department of Energy (DOE) Argonne National Laboratory Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model; https://www.energy.gov/eere/greet

3.4 Comparison of Methane Release Estimates from Different Sources

While the amount of carbon dioxide that is generated during fuel consumption is well documented, the amount of methane released from operating equipment along the natural gas supply chain can vary significantly in each study or data source. As the focus on GHGs continues to intensify, there is an increasing need for accuracy, consistency, and agreement on the methods used when quantifying methane emissions. While there have been several dedicated studies performed and many data sources now exist, there continues to be debate between industry, academia, and environmental organizations among others on the amount of methane leakage that occurs during natural gas production, transportation, and supply.

A review was conducted of the underlying calculations, data assumptions, and parameters used in several natural gas supply chain life cycle assessment studies and emission databases for comparison with this analysis. Results provide a quantification of the amount of methane emitted through the natural gas fuel supply chain with some minor variances in scope. The exhibits that follow provide methane leakage rates associated with the production, processing, and transmission of natural gas as determined by different sources which were reviewed as part of this analysis. Exhibit 20 provides a regional breakdown of methane leakage rates from natural gas production operations for various basins and data sources. Each column represents an individual source, with factors either directly reported by that data source or calculated from reported emissions data and reported or assumed throughput volumes.

Exhibit 20: Regional Methane Leakage Rates from Natural Gas Production by Basin and Data Source

Basin Name	EPA 2024 Inventory (CY 2022)	EPA 2022 GHGRP	NPC SLING GHG Model	Sherwin	OCI+
Anadarko	0.85%	0.46%	0.33%	-	0.90%
Appalachian	0.22%	0.49%	0.32%	0.60%	0.98%
Appalachian (Eastern Overthrust Area)	-	0.05%	0.03%	-	-
Arkla	0.24%	0.09%	-	-	-
Arkoma	0.38%	0.28%	-	-	1.16%
Denver	0.44%	0.31%	-	0.90%	0.60%
East Texas	-	0.21%	0.08%	-	1.19%
Fort Worth Syncline	1.24%	1.18%	-	3.10%	1.08%
Green River	0.84%	0.43%	-	-	1.06%
Gulf Coast	0.61%	0.45%	-	-	0.55%
Gulf of Mexico	1.43%	0.31%	-	-	0.58%
Permian	0.28%	0.21%	0.08%	2.01%	0.81%
Piceance	1.21%	0.78%	-	-	-
Powder River	0.92%	0.29%	-	-	0.37%
San Joaquin	0.53%	0.04%	-	2.23%	0.10%
San Juan	1.56%	1.03%	-	-	0.94%
Uinta	2.49%	1.59%	0.59%	4.80%	0.97%
Williston	0.46%	0.30%	-	-	0.25%
Production Emissions National Average	**0.47%**	**0.24%**	**0.46%**	**1.82%**	**0.81%**

Emissions shown only represent NG production. Emissions from gathering and boosting, processing, and transmission/storage are not included (an addt'l 0.61% based on EPA Inventory).

Sources: ICF analysis of US EPA GHG Inventory and US EPA GHGRP data, National Petroleum Council Streamlined Life Cycle Assessment of Natural Gas – Greenhouse Gases (SLiNG-GHG) model, Oil Climate Index plus gas (OCI+)

Exhibit 21 provides national level methane leakage rates from production through gas transmission, illustrating the range of differences that can occur between each data source's chosen methodology. It is common for the scope of emissions to be expressed differently, either for specific regions (as shown in Exhibit 20) or to represent a derived national average. Each study may also rely on either top-down or bottom-up methodologies which typically result in very different methane leakage rates. The throughput considered in the leakage factors shown is also not always applied consistently, resulting in additional methodological differences. Comparable throughput quantities are not available for all sources and the assumptions used are not always fully transparent or discernable in every study. All studies reviewed as part of this analysis are provided in Appendix A.

Exhibit 21: Methane Leakage Rates from Natural Gas Production, G&B, Processing, and Transmission from Various Studies and Emission Data Sources

	EPA 2024 Inventory (CY 2022)	NPC SLING GHG Model	Howarth 2024	Abrahams	Mallapragada 2018	Sherwin
ICF Interpretation of Throughput Basis	% marketed natural gas production	methane emitted per methane portion of gas delivered from the transmission network	% of methane in the natural gas produced	Not identified	% of gross production of natural gas	% of methane produced
Specified National Average Factor	1.16%	0.98%	2.80%	3.00%	1.20%	3.46%
Normalized to Gas Transmission Delivered	*1.30%*	*0.98%*	*3.14%*	*3.36%*	*1.34%*	*3.88%*

3.5 Considerations for Methane Leakage Rate Differences

Understanding that many uncertainties exist regarding methane emissions, this Study presents results across several cases which incorporate different methane release rates. The Base Case assumption aligns the leakage rate with US EPA GHGI emission results, as previously discussed in Section 3.2. This represents a combined rate of 1.33% (simple sum) across production, gathering & boosting, gas processing, gas transmission, and gas distribution operations. In recognition of certain discrepancies, ICF also incorporates a "CH_4 Release Calibration" to account for the differences in measurement methodologies. This "CH4 Release Calibration" factor represents a ratio of the EPA GHGI factor with the implied leakage rate as determined by other sources. Sensitivity Cases were created to determine the effect of increasing assumed methane releases by 44.6% (per ANL GREET assumptions), by 88% (per IEA estimates) and 200% (per estimates derived from remote sensing surveys). These differences are represented in results by using ratios to the EPA GHGI of 1.0, 1.446, 1.88 and 3.0.

As discussed in more detail in the previous section, the methodology to determine emissions for each source varies. The ANL GREET derived factor incorporates a leakage rate which adjusts for discrepancies which often occur when comparing the results from bottom-up and top-down measurement studies. The International Energy Agency (IEA) also provides methane emission estimates for various NG supply chain segment combinations and countries. The adjustment ratio between the IEA Methane Tracker[17] estimate for US oil and gas system and EPA GHGI is modelled as 1.88 – a multiyear average. Exhibit 22 shows the most recent data from IEA for 2023 and the most recent EPA GHGI data for 2022. The calculated ratio is 1.94 but this would be slightly lower if adjusted for the growth in US natural gas production from 2022 to 2023. Finally, the highest ratio represented in this analysis is meant to account for studies which have performed aerial remote sensing site level surveys. These studies have typically determined that much higher leakage amounts exist than sources which rely on bottom-up methodologies.

Exhibit 22: Comparison of IEA and US EPA GHGI Reported CH4 Emissions (kt CH_4)

IEA Segment	IEA Methane Tracker (2023)	US EPA Inventory (2022)	Ratio
Oil & Gas - Upstream	10,604	5,130	2.07
Oil & Gas - Downstream	2,309	1,957	1.18
Satellite-detected large O&G leak:	869	-	NA()
Total Oil & Gas	**13,782**	**7,087**	**1.94**

Source International Energy Agency (IEA), US EPA

[17] International Energy Agency (IEA), Methane Tracker Database; https://www.iea.org/data-and-statistics/data-product/methane-tracker-database#emission-data-2024

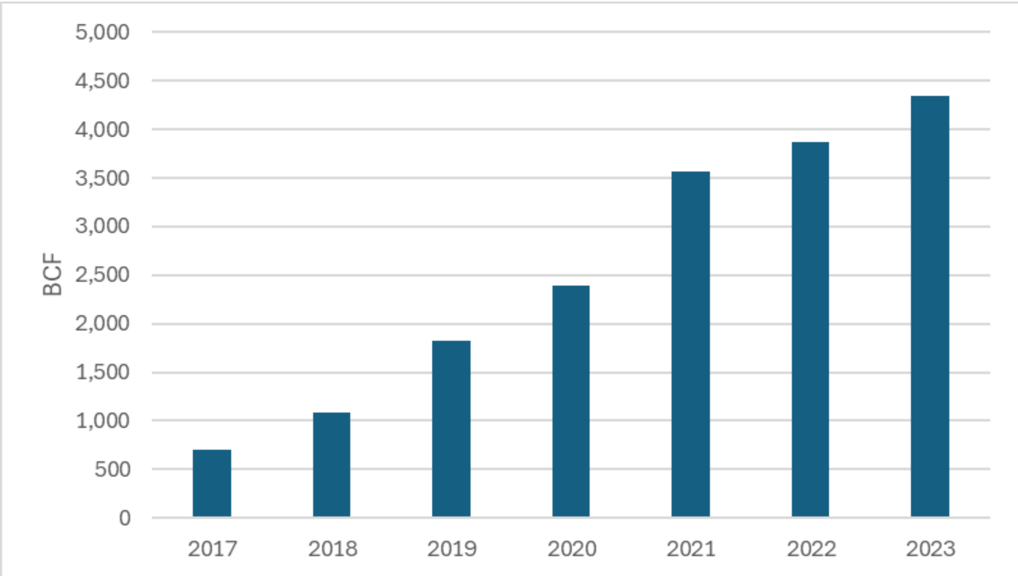
4. Volumes, Destinations and Market of US LNG Exports

4.1 Historical Export Volumes

The United States has emerged as a dominant player in the global LNG market, achieving the status of the world's largest LNG exporter in 2022. This remarkable growth trajectory has positioned the U.S. ahead of other major exporters like Australia and Qatar. Over the past decade, U.S. LNG exports have experienced consistent expansion. In 2023, the average daily export volume reached 11.9 billion cubic feet per day (Bcf/d), representing a substantial 12% increase compared to the previous year.

Currently, there are 15 North American LNG export terminals will be built and/or expanded: Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, Elba Island, Golden Pass, LNG Canada Phase 1 & 2, Woodfibre, Calcasieu Pass Phase 1, Plaquemines Phase 1 & 2, and Port Arthur Phase 1, Costa Azul, Saguaro, and Rio Grande. EIA's Annual Energy Outlook projects annual average LNG export volumes for North America in 2024 to be 12.83 Bcfd. North American LNG export terminal capacity utilization is projected to average about 92.4% in 2024. Exhibit 23 portrays the growth in U.S. LNG Export volumes from 2017 to 2023.

Exhibit 23: Historical U.S. LNG Export Volumes



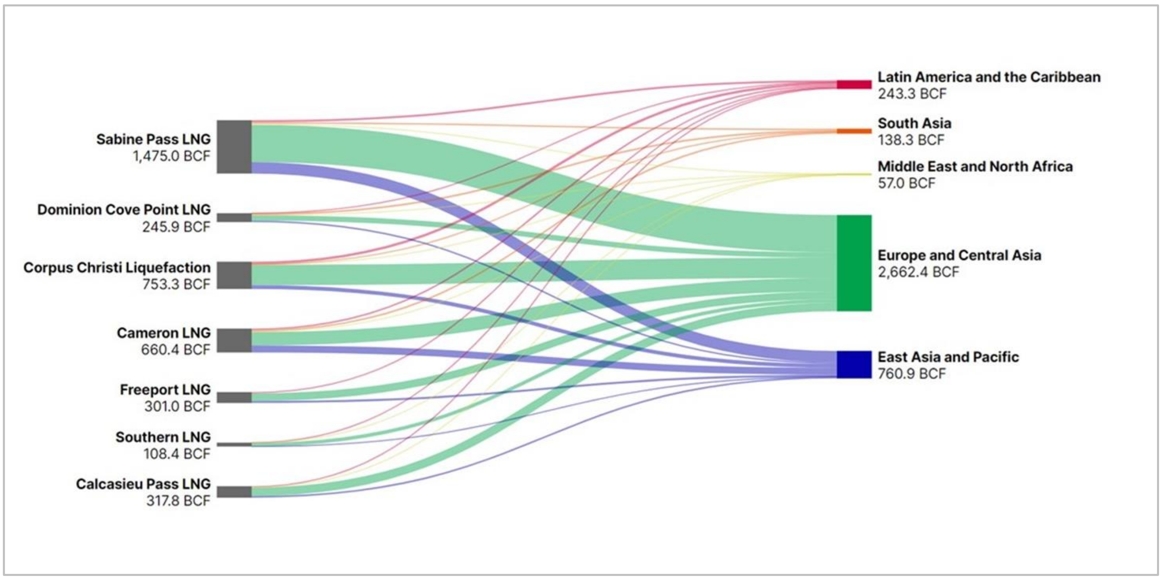
Source: EIA

4.2 2022 Exports by Liquefaction Plant and Destination

2022 saw a remarkable shift in global LNG shipment landscape across the globe. On March 25, 2022, the White House announced a joint Task Force with the European Commission to "reduce Europe's dependence on Russian fossil fuels and strengthen European energy security as President Putin wages his war of choice against Ukraine." The announcement said this Task Force "will work to ensure energy security for Ukraine and the European Union (EU) in preparation for next winter and the following one while supporting the EU's goal to end its dependence on Russian fossil fuels."

As a result of this initiative a number of U.S. source LNG shipments were diverted to Europe to help alleviate the supply crunch in the region. U.S. LNG export facilities also ramped up their utilization levels in order to export even greater volumes to keep the global LNG supply stable. According to International Energy Administration (IEA), in 2021, the EU imported around 45% of natural gas from Russia which accounted for close to 40% of its total gas consumption. According to EIA, U.S. LNG Export volumes grew by 9% or 300 BCF to help Europe's near term supply needs. According to Exhibit 24 below, approximately 69% of U.S. LNG Shipments headed to Europe and Central Asia.

Exhibit 24: 2022 U.S. LNG Exports by Liquefaction Plant and Destination



Source: Department of Energy

Exhibit 25 below portrays the top U.S. LNG Shipment destinations in 2022. According to the exhibit, seven of the top ten destinations for U.S. LNG Exports were in Europe. These seven countries received 59% of all U.S. LNG exported in 2022.

Exhibit 25: Major U.S. LNG Imports Destinations in 2022

Country	U.S. LNG Export Volumes (MMcf)
Argentina	66,939
Belgium	80,245
Brazil	71,998
Chile	30,131
China	96,659
Croatia	77,286
Dominican Republic	50,824
France	571,399
Germany	7,112
Greece	69,031
India	122,518
Indonesia	6,579
Italy	116,034
Japan	209,220
Kuwait	57,018
Lithuania	77,212
Malta	5,273
Mexico	3,832
Netherlands	378,329
Pakistan	3,074
Panama	13,759
Poland	127,404
Portugal	69,583
Singapore	22,980
South Korea	292,732
Spain	426,657
Thailand	25,988
Turkey	192,067
United Kingdom	464,462
Taiwan	106,738
Colombia	5,703
Jamaica	130
Bangladesh	12,663
Finland	329

Source: Department of Energy

4.3 Gas Carriers Used for US Exports

Exhibit 26 is a table showing the world fleet of gas carriers by propulsion type. The left-hand side depicts the carriers that were in service as of April 2023 and the right-hand side shows the carriers that were under construction or on order as of that time. Steam was the dominant propulsion system in the early part of the LNG industry's history, but it now represents less than 29% of operating capacity and zero percent of new carriers.

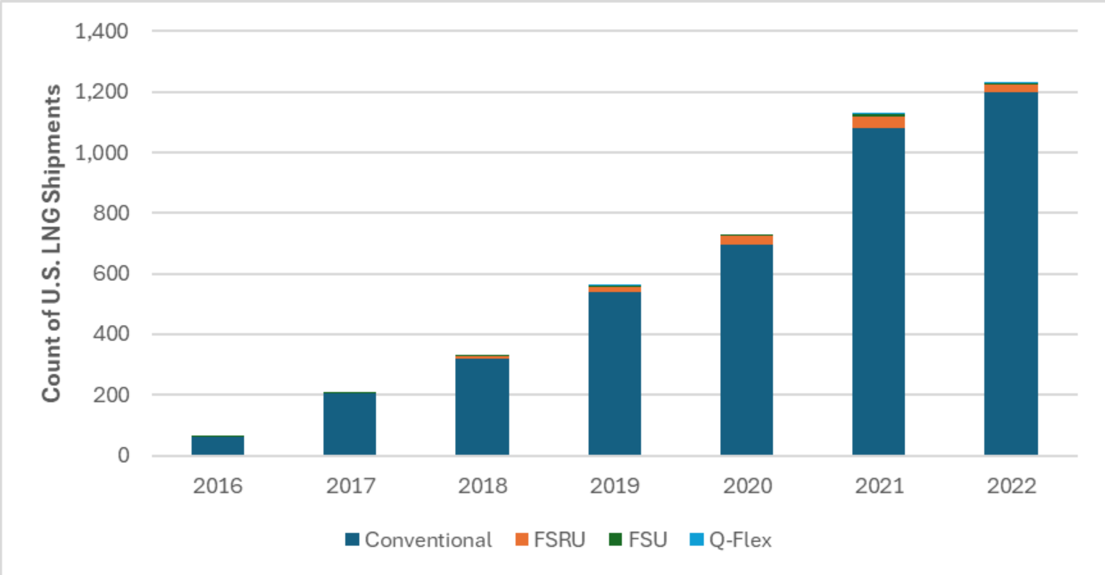
Exhibit 26: Summary of World Operating Shipping Fleet as of April 2023

		World Fleet Operating as of April 2023					Vessels on Order as of April 2023			
Propulsion Type		Average Age	Vessel Count	Capacity in Cubic Meter	Share of Operating Capacity	Average Capacity per Vessel (m^3)	Vessel Count	Capacity in Cubic Meter	Share of On Order Capacity	Average Capacity per Vessel (m^3)
Steam	Steam boiler & turbine	19.8	221	31,012,195	28.5%	140,327				
Steam re-heat	Steam boiler & turbine with reheat	6.1	12	1,871,900	1.7%	155,992				
SSDR	Slow speed diesel with re-liquefaction	14.0	48	10,751,400	9.9%	223,988				
DFDE	Dual-fuel diesel electric	9.0	82	13,244,572	12.2%	161,519	22	3,794,600	7.0%	172,482
TFDE	Tri-fuel diesel electric	8.2	111	18,422,085	16.9%	165,965				
STAGE	Steam Turbine and Gas Engine	4.4	8	1,383,600	1.3%	172,950				
X-DF	Low-pressure, slow-speed dual fuel (X-DF)	2.1	114	19,415,820	17.9%	170,314	145	24,914,357	45.9%	171,823
ME-GI	High pressure dual fuel, 2 stroke engines	4.3	72	12,596,700	11.6%	174,954	22	3,852,000	7.1%	175,091
ME-GA	Low pressure dual fuel, 2 stroke engines		0				122	21,680,000	40.0%	177,705
Sum or Average of All Propulsion Types		**11.0**	**668**	**108,698,272**	**100.0%**	**162,722**	**311**	**54,240,957**	**100.0%**	**174,408**

Source: IGU Report 2023

Information on the number and types of gas carriers used in recent years to transport US LNG is shown in the next several exhibits. Exhibit 27 shows the number of shipments each year from 2016 to 2022 by type of vessel. There were over 1,230 shipments in 2022.

Exhibit 27: Number of U.S. LNG Shipments by Type of Vessel



Source: Department of Energy LNG export data, IGU Report 2023

Additional details on the type of carriers used to ship US LNG in 2022 is shown in Exhibit 28. Each row of the exhibit represents a different propulsion type. The columns show the number of shipments, the nautical miles travelled and the nautical miles times the billion cubic feet shipped (bcf-nm) for each propulsion type. The most widely used propulsion type is X-DF (low-pressure, slow-speed, dual fuel) which made up 62% of the bcf-nm. The second most used propulsion system for US LNG was ME-GI (high-pressure, dual fuel, 2-stroke) which made up 19% of bcf-nm.

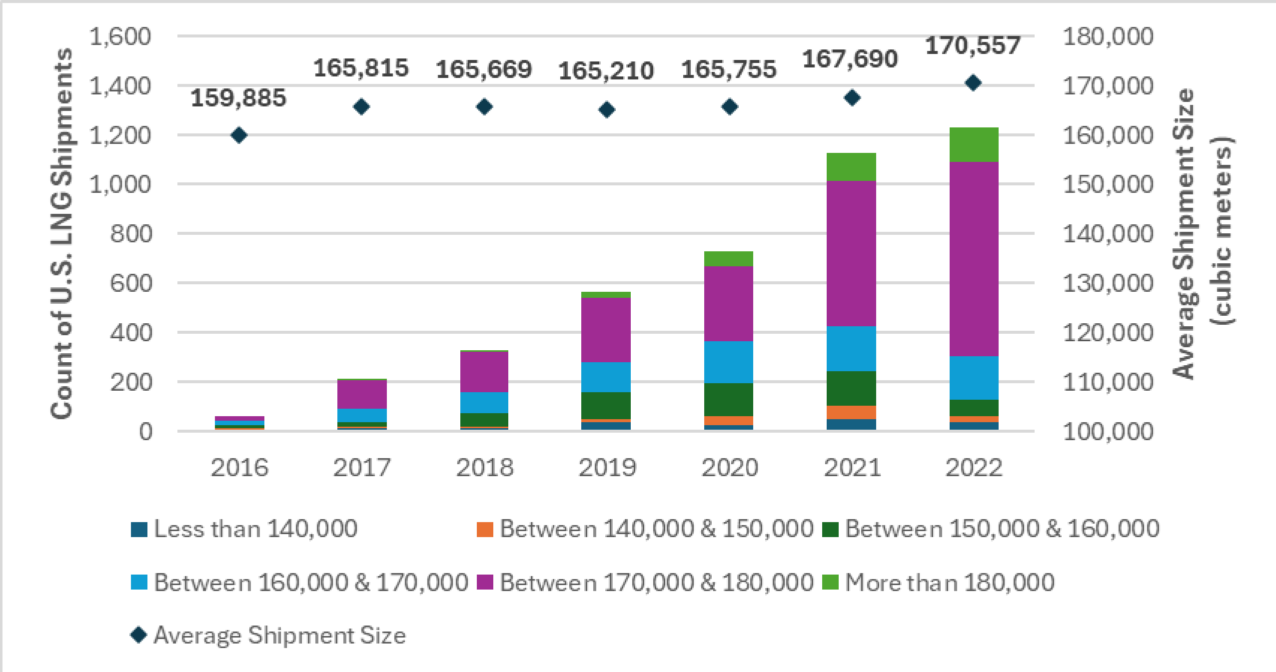
Exhibit 28: Summary of U.S. LNG Shipping Operations 2022

Propulsion Type		Number of Shipments 2022	2022 LNG Volume (BCF)	000's of Nautical Miles Travelled	Shipment 000's of Nautical Miles * Bcf
Steam	Steam boiler & turbine	91	254	593	150,597
Steam re-heat	Steam boiler & turbine with reheat	6	20	32	633
SSDR	Slow speed diesel with re-liquefaction	2	6	17	112
DFDE	Dual-fuel diesel electric	147	441	860	378,973
TFDE	Tri-fuel diesel electric	214	661	1,363	901,335
STAGE	Steam Turbine and Gas Engine	36	125	273	34,199
X-DF	Low-pressure, slow-speed dual fuel (X-DF)	473	1,519	2,925	4,442,496
ME-GI	High pressure dual fuel, 2 stroke engines	261	834	1,566	1,306,355
ME-GA	Low pressure dual fuel, 2 stroke engines	0	-	-	-
Total		**1,230**	**3,861**	**7,629**	**7,214,700**

Source: ICF analysis of Department of Energy LNG export data, IGU Report 2023

The distribution of gas carrier by size is shown in Exhibit 29. The largest share of shipments is in the 170,000 to 180,000 cubic meter size range. The average carrier size for each year is shown in the numbers located over the bars on the chart. In 2016 the average shipment was 159,885 cubic meters and in 2002 it was 170,557 cubic meters.

Exhibit 29: Number of U.S. LNG Shipments by Capacity



Source: Department of Energy, IGU Report 2023. The value at the top of each bar is the average size of LNG carriers used for US export in each year.

4.4 Energy Use in Countries Importing US LNG

Exhibit 30 the energy consumption in all sectors (e.g., residential, commercial, industrial, transportation, and power generation) of countries that imported U.S. LNG in the year 2022. In terms of petajoules (PJ), China leads in energy consumption of coal, oil products, natural gas, and electricity. India leads in energy consumption of renewables and waste. In terms of energy consumption by fuel type as a percentage of total energy consumed by individual countries, Indonesia leads in coal consumption (25%), Singapore leads in consumption of oil products (65%), Argentina in natural gas (36%), Brazil in renewables and waste (28%) and Malta in electricity consumption (40%). Data are presented in Higher heating value (HHV).[18]

Exhibit 30: All-sector Energy Consumption in Countries Importing U.S. LNG (HHV)

Country	Coal, peat, and oil shale	Crude, NGL and feedstocks	Oil products	Natural gas	Renewables and waste	Electricity	Heat
Argentina	26	-	989	865	89	448	-

[18] The lower heating value (also known as net calorific value) of a fuel is defined as the amount of heat released by combusting a specified quantity (initially at 25° C) and returning the temperature of the combustion products to 150° C, which assumes the latent heat of vaporization of water in the reaction products is not recovered.

The higher heating value (also known gross calorific value or gross energy) of a fuel is defined as the amount of heat released by a specified quantity (initially at 25° C) once it is combusted and the products have returned to a temperature of 25° C, which takes into account the latent heat of vaporization of water in the combustion products.

Country	Coal, peat, and oil shale	Crude, NGL and feedstocks	Oil products	Natural gas	Renewables and waste	Electricity	Heat
Belgium	30	-	723	381	97	276	17
Brazil	338	-	4,401	569	2,870	1,983	-
Chile	10	-	728	89	138	286	-
China	22,750	67	25,200	9,213	2,646	28,439	6,386
Colombia	69	-	589	160	193	253	-
Croatia	3	-	123	46	47	58	10
Egypt	69	56	1,305	479	64	609	-
Finland	18	-	274	28	239	277	162
France	108	0	2,547	1,070	506	1,493	167
Germany	235	-	3,439	2,218	743	1,720	367
Greece	3	-	367	50	46	173	1
India	4,664	-	8,854	1,394	7,728	5,035	-
Indonesia	1,849	67	2,847	612	811	1,122	-
Israel	1	-	370	44	5	229	-
Italy	33	-	1,922	1,345	357	1,033	63
Japan	746	2	5,346	1,162	268	3,264	27
Lithuania	7	-	95	45	31	38	31
Malta	-	-	14	-	1	10	-
Mexico	69	-	2,645	389	307	1,080	-
Netherlands	19	63	821	648	64	374	77
Poland	325	-	1,258	476	385	509	236
Portugal	0	-	324	73	96	175	7
Singapore	8	-	499	66	-	198	-
South Korea	367	-	3,904	962	149	1,950	239
Spain	29	-	1,777	549	231	808	-
Thailand	355	24	2,235	247	479	711	-
Turkey	451	-	1,735	1,242	122	1,016	39
United Kingdom	76	-	1,990	1,448	205	987	51

Source: IEA World Energy Balances 2022

Exhibit 31: Power Generation Fuel Mix in Countries Importing U.S. LNG portrays power generation fuel of countries that imported U.S. LNG in the year 2022. In terms of Peta joules (PJ), China leads in generating power using coal, natural gas, nuclear and renewables. Japan leads in generating power using oil products. In terms of power generation by fuel type as a percentage of total fuel used for power generation in individual countries, India leads in power generation from coal (87%), Greece leads in generating power from oil products (22%), Malta using natural gas (95%), France using nuclear (82%) and Lithuania using renewables and waste (75%).

Exhibit 31: Power Generation Fuel Mix in Countries Importing U.S. LNG (HHV)

Country	Coal, peat, and oil shale	Crude, NGL and feedstocks	Oil products	Natural gas	Nuclear	Renewables and waste
Argentina	26	-	141	551	87	57
Belgium	20	-	2	140	479	67
Brazil	145	-	89	394	159	422
Chile	210	-	27	131	-	190
China	59,781	5	392	2,501	4,558	2,783
Colombia	49	11	17	108	-	24
Croatia	14	-	1	33	-	17
Egypt	-	-	196	1,233	-	-
Finland	81	-	18	13	276	186
France	64	-	65	327	3,215	244
Germany	1,750	-	55	725	379	586
Greece	63	-	56	132	-	6
India	13,642	-	78	535	500	949
Indonesia	2,271	-	130	475	-	397
Israel	159	-	3	319	-	1
Italy	243	-	145	963	-	233
Japan	2,756	7	410	2,347	612	432
Lithuania	0	-	4	8	-	36
Malta	-	-	1	14	-	0
Mexico	262	-	248	1,995	118	53
Netherlands	144	-	24	321	45	149
Poland	1,354	-	21	100	-	94
Portugal	-	-	11	122	-	52
Singapore	11	-	14	329	-	29
South Korea	1,931	-	114	1,188	1,921	124
Spain	82	-	90	570	639	93
Thailand	361	-	108	825	-	429
Turkey	1,109	-	13	483	-	91
United Kingdom	75	-	21	923	521	368

Source: IEA World Energy Balances 2022

Exhibit 32: Industrial Consumption by Fuel Type in Countries Importing U.S. LNG portrays the industrial demand by fuel type of countries that imported U.S. LNG in the year 2022. In terms of Peta joules (PJ), China leads in the industrial fuel use of coal, oil products, natural gas, and electricity. India leads in industrial fuel use of renewables and waste. In terms of industrial demand by fuel type as a percentage of total industrial demand by individual countries, Indonesia leads in coal consumption (55%), Singapore leads in consumption of oil products (52%), Argentina in natural gas (56%), Brazil in renewables and waste (45%) and Malta in electricity consumption (59%).

Exhibit 32: Industrial Consumption by Fuel Type in Countries Importing U.S. LNG (HHV)

Country	Coal, peat, and oil shale	Crude, NGL and feedstocks	Oil products	Natural gas	Renewables and waste	Electricity	Heat
Argentina	24	-	25	287	24	157	-
Belgium	19	-	54	145	35	134	13
Brazil	331	-	388	382	1,567	787	-
Chile	9	-	170	44	60	169	-
China	18,033	67	3,143	4,703	-	16,156	4,310
Colombia	66	-	30	60	55	45	-
Croatia	3	-	11	14	3	12	3
Egypt	69	-	247	175	-	170	-
Finland	16	-	43	23	155	125	50
France	94	0.3	101	387	78	388	78
Germany	208	-	156	759	203	747	165
Greece	3	-	33	24	5	43	-
India	4,202	-	1,139	395	3,286	2,125	-
Indonesia	1,849	-	298	423	379	426	-
Israel	1	-	12	41	4	44	-
Italy	33	-	122	425	33	402	23
Japan	711	-	690	445	161	1,143	-
Lithuania	4	-	2	11	5	13	4
Malta	-	-	1	-	-	2	-
Mexico	67	-	224	347	62	637	-
Netherlands	17	-	138	184	7	123	54
Poland	114	-	37	153	99	191	36
Portugal	0	-	25	48	48	61	6
Singapore	8	-	153	58	-	76	-
South Korea	340	-	86	329	93	1,003	140
Spain	23	-	86	295	86	255	-
Thailand	355	-	161	177	309	319	-
Turkey	314	-	150	379	47	465	39
United Kingdom	55	-	99	319	65	306	25

Source: IEA World Energy Balances 2022

4.5 Methodology for Determining which Alternative Fuels Would Substitute for US LNG

4.5.1 Overview of Rebalancing Logic

In the counterfactual world that does not include exports of LNG from the US, it is assumed that that the same amount of energy services (measured in MWh of electricity, pounds of industrial steam, volume of domestic hot water, etc.) are provided to end users but that there are shifts in energy sources used to provide those services. This rebalancing of energy market is assumed to take place in each country that imported US LNG in 2022. The end-use sector in which the end-use consumption would have changed and the mix of replacement fuels is modelled as depending on:

- The volume of natural gas (not just LNG) consumed in each end-use sector.
- The mix of non-natural gas fuels consumed in each sector.
- The volume of natural gas (if any) produced in the importing country.
- The assumed price elasticity of natural gas demand in each sector and the assumed price elasticity of domestic gas supply.

The rebalancing of energy use is calculated by assuming that in the absence of US LNG in the counterfactual world, there would have been higher natural gas prices that would have resulted in less natural gas consumption and greater production of domestic natural gas. The volume of LNG unavailable (measured in PJ or TBtu and adjusted for end-use efficiency in each sector) would have to be offset with either more domestic gas production or a shift to alternative fuels (which also are adjusted for end-use efficiency in each end-use sector).

Since several sectors can use electricity to replace natural gas, the rebalancing of end-use consumption can lead to the need for more power generation. Thus, the loss of US LNG affects power plant energy use in two ways: a) electric loads are increased as end users consume more electricity and b) the LNG used in the power plants is replaced by other primary energy sources.

Note that these calculations are made using some simplifying assumptions to make the solution more tractable. First, it is assumed that each country has a homogenous natural gas market, and that the US LNG "effectively" serves all end-use sectors in equal proportions in that all sectors see the same $/MMBtu increase in natural gas prices and all sectors have some demand response. Secondly, it is assumed that the loss of US LNG does not lead to changes in non-US LNG trade in terms of either an increase in total non-US LNG produced in 2022 or a change in which countries imported that LNG. Thirdly, the possibility of higher natural gas prices leading to demand destruction (e.g., factories closing down and industrial production not taking place at all) or conservation (e.g., setting thermostat to lower temperature) is not analyzed. Stated in other words, the rebalancing that is assumed to occurs due to the loss of US LNG takes place within each country individually by use of more domestic natural gas or the use of more domestic or imported alternative fuels (coal, fuel oil, electricity, etc.). These energy shifts away from US LNG occur in all natural consuming sectors but, as explained below, the largest shifts take place the power (53% of the shifts in all sectors) and the industrial sectors (26%) of countries importing US LNG.

4.5.2 Price Elasticities and Fuel Substitution

The increase of domestic natural production and alternative fuel use depends on the actual energy mix in each country and the assumed price elasticities of domestic gas production and the assumed price elasticity of consumption in each end-use sector. The price elasticity of demand for a commodity, product or service is defined as the percent change in volume demanded divided by the percent change in price. Demand elasticities are typically negative numbers whereby values ranging from zero to -0.99 are said by economists to indicate "inelastic demand" and values greater than -1.0 (in absolute value) are considered to show "elastic demand." Similarly, supply elasticity is defined as the percent change in volume produced divided by the percent change in the price of that commodity, product, or service. The values for supply elasticities are usually positive and, again, are considered to be "elastic" when above 1.0 in absolute value and "inelastic" when below.

A summary of estimated price elasticity for natural gas demand are shown in Exhibit 33. Due to different methodologies, time frames and geographic coverage, the estimated elasticities vary considerably among studies. Short-term elasticities (volume changes occurring within 12 months or less of a price change) are generally estimated to be -0.1 or less while long-rum elasticities (changes over several years) are estimated as 0.2 to a little over 1.0.

Exhibit 33: Price Elasticity Estimate for Natural Gas Demand

Summary for selected studies on price and income elasticities of natural gas demand.

Author	Country	Period	Price Elasticity: Long-run=LR, Short-run=SR
Erias and Iglesias (2022)	25 European Countries	2005–2020	LR: from −0.181 to −0.143
Javid et al. (2022)	Pakistan	1972–2019	SR: from −0.047 to −0.021 LR: −0.19; − 0.13
Farag and Zaki (2021)	Egypt	1983–2015	LR: -0.36; SR: −0.15
Alberini et al. (2020)	Ukraine	2013–2017	SR: −0.16
Dong et al. (2019)	China	2010-2015	-0.35
Gautam and Paudel (2018)	United States	1997–2016	LR: −0.14; −0.2; −0.28
Zhang et al. (2018)	China	1992–2011	LR: from −0.22 to 5.73 SR: from −0.20 to 3.09
Burke and Yang (2016)	Sample of 44 countries	1978–2011	LR: −1.25
Dilaver et al. (2014)	OECD-Europe	1978–2011	LR: −0.16
Bilgili (2013)	8 OECD countries	1979–2006	LR: from −0.345 to −1.292
Yu et al.	China	2006–2009	−0.779
Wadud et al. (2011)	Bangladesh	1981–2008	−0.25

Source: The price and income elasticities of natural gas demand in Azerbaijan: Is there room to export more? | Humanities and Social Sciences Communications (nature.com)

The importance of supply and demand elasticities to this study is that the more elastic demand and supply are for natural gas, the lower will be the price change needed to rebalance the market when a given volume of LNG is removed from the market. High supply elasticities mean that increases in price can elicit a high volume of new supply and high demand elasticities mean that small increases in prices will reduce consumption by a large amount.

The rebalancing of the market after a loss of a certain quantity of supply will occur when the sum of increased supply plus the sum of reduced demand equals the unavailable volume. For this Study, the relative values of supply versus demand elasticities and the elasticity of demand among end-use sectors are what is most important. When supply elasticities are much greater than demand elasticities, more of the market rebalancing from a given loss of supply will take place through changes in supply volumes from other regions and there will be little change in consumption. On the other hand, when demand elasticities are much greater than supply elasticities, the rebalancing of the market after a loss of supply will take place more through substitution by non-oil fuels and conservation while there is little change in volumes from other supply regions. For similar reasoning, end-use sectors with high demand elasticity will see the biggest reduction in natural gas consumption and the largest increase in the use of alternative fuels.

The demand elasticities by sector assumed for this Study are shown in Exhibit 34. The most elastic sector is power generation where operators change dispatch among power plants based on their variable operating costs (which is mostly a function of fuel prices) and where power plant owners switch the fuel used in their multi-fuel power plants. The industrial sector has the next most elastic demand among sectors followed by the residential, commercial, and transportation sectors.

Exhibit 34: Assumed Markups and Price Elasticities for Natural Gas by End-use Sector

Sector	NG Markup Relative to Wholesale Price ($/MMBtu)	Price Elasticity (relative to WH or Deliv. Price)
Production	-$1.00	0.30
Residential	$7.00	-0.15
Commercial and public services	$6.00	-0.20
Industry	$2.50	-0.35
Transport	$8.00	-0.20
Other final consumption	$2.50	-0.20
Electricity, CHP and heat plants	$1.50	-0.40

The natural gas prices seen by each sector are the wholesale price in each country plus a mark-up that covers natural gas transmission, storage, and distribution within each country. These mark-ups are assumed to be the values shown in the second column of Exhibit 34 and are the same for all countries importing US LNG. The importance of the mark-up is that the demand elasticity values apply to the natural gas prices delivered to the end-user. So, sectors with high mark-ups such residential commercial and transportation have effective elasticities measured against wholesale prices that are lower than what is shown in the last column of Exhibit 34, in that a given $/MMBtu in wholesale price translates into a lower percent change in delivered prices as compared to industrial and power sectors which enjoy lower mark ups.

Once the reduction in natural gas consumed in each sector is computed, the mix of alternative fuels that will be substituted is largely a function of what non-natural gas fuels were actually in use in 2022. In other words, the substitute fuels are largely proportionate to the alternative fuels in use. The notable exceptions are in the power sector, where hydro and nuclear generation is assumed not to change (since they are already dispatched fully and expansion of their capacity is very difficult). The other exception is the use of renewables and waste fuels in the power and industrial sector, where the substitutability is specified in setting up the Sensitivties.

The other consideration in computing the final volume shifts among alternative fuels and electricity that might replace unavailable US LNG is the relative energy efficiency each fuel has within each sector. The volume of fuel substituted for the unavailable US LNG has to be adjusted upward (downward) when the alternative fuel has lower (higher) for efficiency. The assumed efficiencies are represented in a simple form in the Study using the values shown in Exhibit 35. Note that for the power sector the heat rates for different types of power plants vary among countries based on heat rates computed from IEA energy consumption of electricity generation data.

Exhibit 35: Assumptions for Relative Energy Efficiencies by Fuel and Sector

Relative End-use Efficiency	Coal	Oil products	Natural gas	Renewables and waste	Electricity
Residential	80.0%	80.0%	80.0%	80.0%	90.0%
Commercial and public services	80.0%	80.0%	80.0%	80.0%	90.0%
Industry	80.0%	80.0%	80.0%	80.0%	90.0%
Transport	64.0%	35.0%	35.0%	35.0%	80.0%
Other final consumption	80.0%	80.0%	80.0%	80.0%	90.0%
Electricity, CHP, and heat plants	*computed from IEA data*	*computed from IEA data*	*computed from IEA data*	*computed from IEA data*	

4.6 LCA of Alternative Fuels

For this study, the LCA GHG emissions of US LNG exports are compared to the LCA GHG emissions of the fuels that would be expected to substitute for US LNG had the US LNG not been available. The greatest volume of substitution is expected to be by coal. The estimated LCA GHG emissions for coal are shown by importing country in Exhibit 36 under Base Case assumptions, including a methane GWP of 28. The left-hand side of the exhibit shows values for domestic coal and the right-hand side for imported coal.

Exhibit 36: LCA Analysis for Domestic and Imported Coal for LNG Importing Countries[19]

Country	Domestic Coal Production					Imported Coal				
	Domestic Coal Production (%)	Average Coal Btu/MT	Methane Leak CH4 kg/MT	Full LCA Emission (kg/MT)	Full LCA Emission kg/MMBtu	Coal Imported (%)	Imported MMBtu/MT	Methane Leak CH4 kg/MT	Full LCA Emission (kg/MT)	Full LCA Emission kg/MMBtu
Argentina	1.06%	24,546,939	4.10	2,470	100.64	98.94%	25,300,109	2.62	2,656	104.98
Bangladesh	100.00%	19,603,311	8.60	2,195	111.97	0.00%	-	-	-	-
Belgium[20]	1.19%	23,794,700	3.06	2,455	103.18	98.81%	24,344,444	2.99	2,577	105.85
Brazil	15.74%	17,435,274	2.19	1,792	102.77	84.26%	25,300,109	2.62	2,653	104.84
Chile	1.20%	26,427,109	3.13	2,600	98.37	98.80%	25,300,109	2.62	2,629	103.92
China	92.78%	26,032,595	5.78	2,753	105.75	7.22%	21,293,194	1.57	2,231	104.76
Colombia	100.00%	26,504,621	2.44	2,635	99.40	0.00%	-	-	-	-
Croatia	0.00%	-	-	-	-	100.00%	24,344,444	2.99	2,568	105.48
Dominican Republic	100.00%	23,794,700	4.87	2,518	105.81	0.00%	-	-	-	-
Egypt	0.00%	-	-	-	-	100.00%	24,342,163	3.86	2,566	105.42
El Salvador	0.00%	-	-	-	-	100.00%	25,300,109	2.62	2,615	103.35
Finland	15.53%	23,794,700	4.87	2,506	105.30	84.47%	24,344,444	2.99	2,593	106.53
France	0.00%	-	-	-	-	100.00%	24,344,444	2.99	2,563	105.27
Germany	50.42%	14,286,605	0.45	1,447	101.27	49.58%	24,344,444	2.99	2,581	106.01
Greece	92.12%	14,286,605	0.88	1,458	102.06	7.88%	24,344,444	2.99	2,559	105.13
India	72.21%	19,601,106	1.23	2,010	102.55	27.79%	21,225,438	1.74	2,198	103.53
Indonesia	97.53%	19,640,683	0.89	1,964	100.00	2.47%	25,847,824	2.37	2,762	106.88
Israel	0.83%	23,794,700	4.87	2,518	105.81	99.17%	26,391,815	2.93	2,724	103.21
Italy	0.00%	-	-	-	-	100.00%	24,344,444	2.99	2,568	105.51

19 These calculations use EIA's carbon dioxide emissions coefficients by coal type and EIA coal production volume by type of coal. Coal emissions including coal mining emissions, methane leaks, electricity, and combustion emissions by country. The methane leaks are based on the IEA Methane Tracker or are imputed based on the type of coal (lignite, subbituminous, bituminous or anthracite).

20 For countries with some domestic coal production but insufficient production and emission data, ICF uses world averages to make estimates (in light blue).

Country	Domestic Coal Production					Imported Coal				
	Domestic Coal Production (%)	Average Coal Btu/MT	Methane Leak CH4 kg/MT	Full LCA Emission (kg/MT)	Full LCA Emission kg/MMBtu	Coal Imported (%)	Imported MMBtu/MT	Methane Leak CH4 kg/MT	Full LCA Emission (kg/MT)	Full LCA Emission kg/MMBtu
Jamaica	0.00%	-	-	-	-	100.00%	25,300,109	2.62	2,610	103.14
Japan	0.36%	26,427,109	4.59	2,648	100.18	99.64%	23,350,133	1.94	2,495	106.83
Jordan	0.00%	-	-	-	-	100.00%	26,391,815	2.93	2,727	103.32
Kuwait	0.00%	-	-	-	-	100.00%	26,391,815	2.93	2,764	104.74
Lithuania	0.00%	-	-	-	-	100.00%	24,344,444	2.99	2,590	106.38
Malaysia	100.00%	19,789,149	4.68	2,098	106.02	0.00%	-	-	-	-
Malta	0.00%	-	-	-	-	100.00%	24,344,444	2.99	2,561	105.19
Mexico	41.91%	22,407,486	10.27	2,706	120.75	58.09%	25,300,109	2.62	2,627	103.82
Netherlands	0.00%	-	-	-	-	100.00%	24,344,444	2.99	2,577	105.86
Pakistan	100.00%	21,155,423	0.87	2,103	99.39	0.00%	-	-	-	-
Panama	0.00%	-	-	-	-	100.00%	25,300,109	2.62	2,608	103.07
Poland	82.21%	20,598,402	4.76	2,207	107.13	17.79%	24,344,444	2.99	2,589	106.34
Portugal	0.00%	-	-	-	-	100.00%	24,344,444	2.99	2,562	105.25
Singapore	0.00%	-	-	-	-	100.00%	23,039,849	1.74	2,424	105.22
South Korea	0.00%	-	-	-	-	100.00%	23,350,133	1.94	2,498	106.98
Spain	0.00%	-	-	-	-	100.00%	24,344,444	2.99	2,561	105.19
Taiwan	0.00%	-	-	-	-	100.00%	23,350,133	1.94	2,498	106.98
Thailand	17.77%	14,286,605	3.31	1,532	107.26	82.23%	23,039,849	1.74	2,432	105.56
Turkiye	40.88%	14,595,237	2.46	1,538	105.36	59.12%	24,344,444	2.99	2,560	105.14
United Arab Emirates	0.00%	-	-	-	-	100.00%	26,391,815	2.93	2,758	104.50
United Kingdom	15.09%	26,930,588	1.08	2,828	105.01	84.91%	24,344,444	2.99	2,578	105.88

The average value for GHG emissions for coal in each country is shown in Exhibit 37. This is the average emission for domestic coal times the 2022 domestic market share plus the emissions for imported coal times the import market share. The supply chain for coal includes a mining and beneficiation step and then several possible transportation steps. The LCA methodology is similar to that used for the natural gas supply chain and uses the same set of emission factors (e.g., CO_2e kg/gallon of diesel fuel, CO_2e kg/metric ton of steel) which are adjusted for different GWP assumptions. Emission from mining fuel use is based on assumed energy use by type of mining (underground versus surface). Mining-related emissions from methane are based on IEA Methane Tracker estimates or are estimated based on coal rank and mining method. The LCA values for coal transportation include in-country rail shipments and, for imported coal, international shipping via bulk carriers.

Exhibit 37: Weighted Average GHG LCA for Coal with and without Embodied[21]

Country	Full LCA w/Embodied		LCA w/o Embodied		Combustion Only	
	Sum with Transportation	Sum kg/MMBtu	Sum	Sum kg/MMBtu	Sum	Sum kg/MMBtu
Argentina	2,654.12	104.94	2,633.27	104.11	2,475.75	97.89
Bangladesh	2,194.96	111.97	2,177.72	111.09	1,912.57	97.56

[21] Data source: computed as average emission for domestic coal times the domestic market share plus the emissions for imported coal times the import market share.

Country	Full LCA w/Embodied		LCA w/o Embodied		Combustion Only	
	Sum with Transportation	Sum kg/MMBtu	Sum	Sum kg/MMBtu	Sum	Sum kg/MMBtu
Belgium	2,575.38	105.82	2,555.15	104.99	2,394.11	98.37
Brazil	2,517.03	104.61	2,497.26	103.78	2,356.29	97.93
Chile	2,628.93	103.85	2,608.28	103.04	2,477.43	97.87
China	2,715.24	105.69	2,693.91	104.86	2,522.24	98.18
Colombia	2,634.67	99.40	2,613.97	98.62	2,541.91	95.90
Croatia	2,567.88	105.48	2,547.71	104.65	2,394.68	98.37
Dominican Republic	2,517.74	105.81	2,497.96	104.98	2,347.29	98.65
Egypt	2,566.05	105.42	2,545.90	104.59	2,378.30	97.70
El Salvador	2,614.79	103.35	2,594.25	102.54	2,477.35	97.92
Finland	2,579.79	106.34	2,559.52	105.51	2,387.32	98.41
France	2,562.84	105.27	2,542.70	104.45	2,394.68	98.37
Germany	2,009.02	104.24	1,993.24	103.42	1,896.20	98.39
Greece	1,544.90	102.45	1,532.77	101.65	1,483.99	98.41
India	2,062.12	102.84	2,045.92	102.03	1,978.29	98.66
Indonesia	1,983.81	100.22	1,968.23	99.44	1,922.99	97.15
Israel	2,722.31	103.23	2,700.92	102.42	2,522.47	95.66
Italy	2,568.46	105.51	2,548.29	104.68	2,394.68	98.37
Jamaica	2,609.54	103.14	2,589.04	102.33	2,477.35	97.92
Japan	2,495.08	106.80	2,475.48	105.97	2,349.91	100.59
Jordan	2,726.88	103.32	2,705.46	102.51	2,523.93	95.63
Kuwait	2,764.38	104.74	2,742.66	103.92	2,523.93	95.63
Lithuania	2,589.64	106.38	2,569.30	105.54	2,394.68	98.37
Malaysia	2,098.07	106.02	2,081.59	105.19	1,928.12	97.43
Malta	2,560.74	105.19	2,540.63	104.36	2,394.68	98.37
Mexico	2,659.86	110.42	2,638.96	109.56	2,440.42	101.31
Netherlands	2,577.21	105.86	2,556.97	105.03	2,394.68	98.37
Pakistan	2,102.60	99.39	2,086.08	98.61	2,049.24	96.87
Panama	2,607.80	103.07	2,587.31	102.26	2,477.35	97.92
Poland	2,274.66	106.97	2,256.79	106.13	2,098.81	98.70
Portugal	2,562.22	105.25	2,542.09	104.42	2,394.68	98.37
Singapore	2,424.31	105.22	2,405.26	104.40	2,312.45	100.37
South Korea	2,498.07	106.98	2,478.45	106.14	2,349.43	100.62
Spain	2,560.75	105.19	2,540.63	104.36	2,394.68	98.37
Taiwan	2,498.07	106.98	2,478.45	106.14	2,349.43	100.62
Thailand	2,272.25	105.76	2,254.40	104.93	2,151.36	100.14
Turkiye	2,141.92	105.21	2,125.09	104.38	2,004.12	98.44
United Arab Emirates	2,757.86	104.50	2,736.19	103.68	2,523.93	95.63
United Kingdom	2,615.46	105.74	2,594.91	104.91	2,451.71	99.12

The estimates for GHG emissions for domestic natural gas in countries that import US LNG are shown in Exhibit 38 and Exhibit 39. These are estimates made by ICF based on data for the major oil and gas fields in each country. The methodology for these estimates is very similar to that used for LCA GHG of US natural gas and was described in Chapter 2 in Section 2.2.

Exhibit 38: GHG LCA for Domestic Natural Gas

(through gas processing, excludes transmission, distribution, and combustion)

Country						Adjusted for GWP= 28	
	Modelled Annual Marketed Gas (TBtu)	Total CO2e tons for prod, G&B, & proc.	Methane in CO2e tons (GWP = 25)	Total GHG in CO2e kg/MMBtu	Methane GHG in CO2e kg/MMBtu (GWP = 25)	Total GHG in CO2e kg/MMBtu	Methane GHG in CO2e kg/MMBtu
Argentina	2,012	12,281,313	5,851,716	6.10	2.91	6.45	3.26
Belgium[22]							
Brazil	929	5,022,140	1,891,550	5.40	2.04	5.65	2.28
Chile	140	875,953	437,066	6.26	3.12	6.64	3.50
China	851	14,021,211	6,112,639	11.00	5.50	11.66	6.16
Croatia	24	167,037	56,274	6.93	2.33	7.21	2.61
Dominican Republic							
France	56	374,939	186,482	6.66	3.31	7.06	3.71
Germany	13	66,571	21,503	5.09	1.64	5.29	1.84
Greece	1	7,783	2,945	6.07	2.30	6.34	2.57
India	1,474	16,464,801	8,882,492	11.00	5.50	11.66	6.16
Indonesia	2,214	16,670,011	8,944,441	7.53	4.04	8.01	4.52
Italy	8	68,331	43,932	8.52	5.48	9.18	6.14
Japan							
Jordan							
Kuwait	189	1,578,898	336,394	8.34	1.78	8.55	1.99
Lithuania							
Malta							
Mexico	1,545	11,557,095	4,310,308	7.48	2.79	7.81	3.12
Netherlands	84	621,062	371,834	7.40	4.43	7.93	4.96
Pakistan	186	1,867,204	692,202	10.03	3.72	10.48	4.17
Panama							
Poland	24	164,975	61,218	6.77	2.51	7.07	2.81
Portugal							
Singapore							
South Korea							
Spain							
Thailand	517	4,689,218	2,903,881	9.07	5.50	9.73	6.16
Turkiye							
United Kingdom	1,741	14,924,977	8,830,729	8.58	5.07	9.18	5.68
Average World ex USA/Can	**82,800**	**695,468,504**	**315,756,414**	**8.40**	**3.81**	**8.86**	**4.27**

Exhibit 39: Natural Gas GHG LCA with and without Embodied Emissions

Country	Full LCA w/Embodied	LCA w/o Embodied	Combustion Only
Argentina	64.25	63.12	53.11
Belgium	-	-	-
Brazil	63.44	62.31	53.11
Chile	64.43	63.30	53.11
China	69.45	68.33	53.11
Croatia	65.00	63.87	53.11

[22] For countries that do not have domestic natural gas production or with insufficient data, ICF uses world averages for estimation.

Country	Full LCA w/Embodied	LCA w/o Embodied	Combustion Only
Dominican Republic	-	-	-
France	64.85	63.73	53.11
Germany	63.08	61.96	53.11
Greece	64.13	63.01	53.11
India	69.45	68.33	53.11
Indonesia	65.80	64.68	53.11
Italy	66.97	65.85	53.11
Japan	-	-	-
Jordan	-	-	-
Kuwait	66.34	65.21	53.11
Lithuania	-	-	-
Malta	-	-	-
Mexico	65.60	64.48	53.11
Netherlands	65.72	64.59	53.11
Pakistan	68.27	67.15	53.11
Panama	-	-	-
Poland	64.86	63.73	53.11
Portugal	-	-	-
Singapore	-	-	-
South Korea	-	-	-
Spain	-	-	-
Thailand	67.52	66.39	53.11
Turkiye	-	-	-
United Kingdom	66.98	65.85	53.11
Average World ex USA/Can	**66.65**	**65.52**	**53.11**

The assumption for GHG LCA's for each type of petroleum product was assumed to be the same all around the world. The values for each product were taken from ANL GREET model except that methane release values and methane GWP values were adjusted to match those of each Base Case and Sensitivity. The values for the Base Case are shown in Exhibit 40.

Exhibit 40: GHG LCA for Petroleum Products from GREET (adjusted to Study Base Case)

	CO2	CH4	N2O				
AR-5, 100-year Biogenic Methane	**1**	**28**	**265**				
Fuel	**Combustion Only Total (kg CO2e/ MMBTU HHV)**	***LCA w/o Embodied (kg CO2e/ MMBTU HHV)***	***Full LCA w/Embodied (kg CO2e/ MMBTU HHV)***	**MMBTU LHV/ MMBTU HHV**	**MMBTU HHV/ Unit**	**Unit**	**MMBTU HHV/ gallon**
Natural Gas	53.11	63.12	64.24	0.903	1.089	Mcf	
Compressed NG	53.11	66.49	67.64	0.903	1.089	Mcf	
Motor Gasoline	70.46	90.57	91.63	0.932	5.058	bbl	120,439
Conv. Diesel	74.20	88.16	89.27	0.935	5.770	bbl	137,380
Low Sulfur Diesel	74.20	88.17	89.27	0.935	5.817	bbl	138,490
Residual Fuel Oil	75.34	86.24	87.34	0.935	6.305	bbl	150,110
Coal	96.25	101.64	102.44	0.942	22.789	mt	

5. Set Up and Results of Base Case and Sensitivities

5.1 Case Set Up

This study incorporates lifecycle analyses of LNG and alternative fuels for the historical year 2022. ICF's review of studies and commentaries on GHG emissions associated with US LNG exports revealed a wide range of assumptions regarding the levels of physical methane releases along the supply chain and the measurement of methane's impact relative to CO_2, typically done using a global warming potential (GWP).

To illustrate the effects of these parameters, this Study contains a series of Sensitivities, the specifications of which are shown in Exhibit 41. The "Base Case" uses EPA GHGI methane release values, a GWP of 28 and ICF's best estimates for all other modeling parameters, while the Sensitivities explore how variations in assumptions can impact the results. The Sensitivities adjust methane release rates, GWP, and consider whether to include "embodied GHGs" associated with manufacturing and constructing facilities, equipment, and infrastructure used to produce, process, and transport LNG and alternative fuels to end-users. They also explore how much substitution of US LNG can be done with renewables and waste fuels. The table below summarizes the key assumptions in the Base Case and Sensitivities.

Exhibit 41: Summary of Base Case and Sensitivity Cases Assumptions

Sensitivity#	Global Warming Potential Factors	Inclusion of Embodied Emissions	Methane Calibration	Substitution by Renewables and Waste Fuels
1-Base Case	AR-5, 100-year Biogenic Methane	Full LCA w/Embodied	EPA Inventory (1.00)	Base Case Substitutability (1.00)
2	AR-5, 100-year Biogenic Methane	Full LCA w/Embodied	ANL GREET (1.446)	Base Case Substitutability (1.00)
3	AR-5, 100-year Biogenic Methane	Full LCA w/Embodied	IEA Estimate (1.880)	Base Case Substitutability (1.00)
4	AR-5, 100-year Biogenic Methane	Full LCA w/Embodied	High Estimate (3.000)	Base Case Substitutability (1.00)
5	AR-5, 20-year Biogenic Methane	Full LCA w/Embodied	EPA Inventory (1.00)	Base Case Substitutability (1.00)
6	AR-5, 20-year Biogenic Methane	Full LCA w/Embodied	ANL GREET (1.446)	Base Case Substitutability (1.00)
7	AR-5, 20-year Biogenic Methane	Full LCA w/Embodied	IEA Estimate (1.880)	Base Case Substitutability (1.00)
8	AR-5, 20-year Biogenic Methane	Full LCA w/Embodied	High Estimate (3.000)	Base Case Substitutability (1.00)
9	AR-5, 100-year Biogenic Methane	LCA w/o Embodied	EPA Inventory (1.00)	Base Case Substitutability (1.00)
10	AR-5, 100-year Biogenic Methane	Full LCA w/Embodied	EPA Inventory (1.00)	Low Substitutability (0.00)
11	AR-5, 100-year Biogenic Methane	Full LCA w/Embodied	Progress 2030 (0.496)	Base Case Substitutability (1.00)
12	AR-5, 20-year Biogenic Methane	Full LCA w/Embodied	Progress 2030 (0.496)	Base Case Substitutability (1.00)

The assumptions for the Base Case and Sensitivity Cases are as follows:

A total of 12 Cases were created including the Base Case (Case #1) and 11 Sensitivity Cases for which assumptions were varied as shown below. The first four Cases are based on a methane GWP of 28 and the following four cases use a methane GWP of 84. Within each set of four cases, the "CH4 Release Calibration" for oil and natural gas supply chains is assumed to range from the values estimated in the EPA National GHG Inventory as a combined rate of 1.33% (a simple sum for production, gathering & boosting, gas processing, gas transmission plus gas distribution) up to three times those values or a combine release rate of 3.99%. These are shown in the table as ratios to the EPA GHGI or 1.0, 1.446, 1.88 and 3.0.

The Base Case GWP value is 28, used currently for the US GHG Inventory and based on the AR-5 100-year Biogenic Methane factor. Some Sensitivity Cases use the corresponding AR-5 20-year value of 84. It primarily relies on the EPA GHG Inventory to estimate methane emissions along the natural gas supply chain. Methane emissions are also estimated for certain supply chain segments based on submissions to EPA's GHGRP subpart W. CO_2 emissions from combustion are estimated mainly from energy consumption data compiled by the EIA, while CO_2 emissions from process gas streams (primarily reservoir CO_2 removed from raw natural gas during processing) are estimated using GHGRP data. In some sensitivities, this rate is increased by 44.6% according to ANL GREET assumptions or by 88% per IEA estimates.

The Base Case includes "embodied GHGs" associated with the manufacturing and construction of facilities, equipment, and infrastructure used to produce, process, and transport LNG and alternative fuels to end-users. Sensitivity Case #9 excludes these embodied emissions to provide a more direct comparison to studies that do not account for embodied emissions.

Sensitivity #10 is the same as the Base Case except that it assumes that there is little opportunity to switch to renewable or waste energy either because the counterfactual disruption to US LNG supply was to occur abruptly or the expansion of renewables and waste fuels were already taking place at the maximum possible rate. For this case, switching to renewables and waste fuels does not occur and the difference is made up by more use of coal, petroleum products, and domestic natural gas.

The last two Sensitivity Cases (#11 and #12) use the so-called "2030 Progress" assumption that methane emissions along the natural gas supply chain will decline in the next few years. These reductions are expected to stem from EPA and PHMSA regulations, the effects of the Waste Emission Charge, the demands from gas purchasers for low-emission gas sources, equipment turnover, and voluntary industry actions. For these sensitivities, a reduction in the methane release rate of approximately 60% is assumed to occur by 2030. Sensitivity Case #11 uses a methane GWP of 28 and Sensitivity Case #12 uses a methane GWP of 84. Note that the application of the "2030 Progress" assumptions also reduce emissions for petroleum products.

5.2 Comparison of Fuels: Btu-to-Btu and Converted to Electricity

The three exhibits shown below present a comparison of the estimated LCA GHG emissions for US LNG exports as compared to average coal and fuel oil. The values are weighted averages among countries based on 2022 US LNG volumes imported into those countries. The left-hand part of the tables shows the "delivered to end user gate" for large industrial and power plant users. For most industrial applications such as boilers, furnaces and kilns, the energy efficiency of natural gas (about 80%) is close to that of coal and fuel oils and so the ratio of the GHGs measured at the "delivered to end user gate" is the relevant comparison. The relative GHG emissions among fuels are shown in the column labeled "Percent Difference from US LNG" where the color green indicates US LNG having lower lifecycle GHG emissions than coal or fuel oil and red indicates the US LNG having higher emissions. The Base Case and Sensitivity Cases #2 to #4 as shown in Exhibit 42 assume a methane GWP of 28 and all show US LNG as having lower emissions compared to coal and fuel oils.

Exhibit 42: Comparisons of Fuel LCAs and Converted to Electricity: Base Case and Sensitivities 2 to 4

	Relevant for Competition in Industrial Boilers, Furnaces & Kilns		Relevant for Competition in Power Plants		
GWP = 28 *CH4 Calib = 1*	LCA for Delivered Fuel: Sensitivity 1		Fuel Converted to Electricity: Sensitivity 1		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	71.6	0.0%	7,690	550.3	0.0%
Coal	105.7	47.7%	9,680	1,023.2	85.9%
Fuel Oil	89.3	24.8%	8,736	780.5	41.8%

GWP = 28 *CH4 Calib = 1.446*	LCA for Delivered Fuel: Sensitivity 2		Fuel Converted to Electricity: Sensitivity 2		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	73.4	0.0%	7,690	564.5	0.0%
Coal	105.7	44.1%	9,680	1,023.5	81.3%
Fuel Oil	90.2	22.9%	8,736	788.0	39.6%

GWP = 28 *CH4 Calib = 1.88*	LCA for Delivered Fuel: Sensitivity 3		Fuel Converted to Electricity: Sensitivity 3		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	75.2	0.0%	7,690	578.2	0.0%
Coal	105.8	40.7%	9,680	1,023.8	77.1%
Fuel Oil	91.0	21.1%	8,736	795.3	37.5%

GWP = 28 *CH4 Calib = 3*	LCA for Delivered Fuel: Sensitivity 4		Fuel Converted to Electricity: Sensitivity 4		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	79.8	0.0%	7,690	613.7	0.0%
Coal	105.8	32.6%	9,680	1,024.5	66.9%
Fuel Oil	93.2	16.8%	8,736	814.2	32.7%

The right-hand side of the three exhibits shows the “energy services gate” for power plants, that is, the conversion of the fuels into electricity. Power plants consume the largest portion of US LNG exports and are modelled as having the greatest substitutability among fuels. Because the energy conversion efficiency of gas-fired power plants is higher than those of coal or oil-fired plants, the carbon intensity comparisons with coal and fuel oils is more favorable toward LNG at the “energy services gate” of power generators (measured in kilograms of carbon dioxide equivalent per megawatt of electricity or kg CO_2e/MWh) as compared to the “delivered to end user” gate (measured in kg CO_2e/MMBtu). Using the weighted average heat rates for power plants in countries importing US LNG in 2022, the Exhibit 16 shows that in the Base Case (i.e., #1) coal converted to electricity has 85.9% higher GHG emissions than US LNG whereas the difference measured for delivered fuel is 47.7%. The same pattern exists for fuel oil which has 41.7% more GHG emission compared to US LNG when both are converted to electricity using weighted average heat rates.

Because the natural gas supply chain has more methane as compared to the supply chain of alternative fuels, the favorable ratio of US LNG versus coal and fuel oil declines when one assumes higher methane release rates as when going from the Base Case (calibrated to the EPA GHGI) to Sensitivity #2 (releases 44.6% higher), #3 (releases 88% higher) and #4 (releases 200% higher or triple the EPA GHGI values). There is also a decline in the GHG advantage of US LNG when a larger methane GWP of 84 is used (Sensitivity #5 to #8). But only in Sensitivity Case #8 where the higher GWP of 84 is combined with the highest methane release rate that triples the EPA GHGI calibration does one of the “delivered to end user gate” comparisons turn against US LNG and appears in red in the exhibit. But even in that case where fuel oil substitution in industrial application would lead to high GHG emissions, the comparison of the GHG associated with conversion of the fuels to electricity shows US LNG still having an advantage over both coal (35.2%) and fuel oil (12.7%).

The three exhibits comparing LCA GHG values on both a Btu-to-Btu basis and converted to electricity basis indicate that US LNG exports can have benefits of reduced worldwide GHG emissions even when both a high methane GWP is applied and methane calibration values of three or more times the EPA GHGI are used. This occurs in large part because the assumptions for GWP value and methane release rates in oil and gas systems also affect the LCA GHG values of petroleum products, domestically produced natural gas in the importing countries, and to lesser extent coal. The LCA of coal is affected because coal mine emissions are subject to any increases in the methane GWP and the emissions attributable to the uses of petroleum products and electricity for coal mining, processing and transportation are affected when the methane GWP or the methane calibration for oil and gas operations are changed.

Exhibit 43: Comparisons of Fuel LCAs and Converted to Electricity: Sensitivities 5 to 8

	Relevant for Competition in Industrial Boilers, Furnaces & Kilns		Relevant for Competition in Power Plants		
GWP = 84 CH4 Calib = 1	LCA for Delivered Fuel: Sensitivity 5		Fuel Converted to Electricity: Sensitivity 5		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	80.1	0.0%	7,690	615.8	0.0%
Coal	112.2	40.1%	9,680	1,086.0	76.4%
Fuel Oil	92.4	15.4%	8,736	807.0	31.0%

GWP = 84 CH4 Calib = 1.446	LCA for Delivered Fuel: Sensitivity 6		Fuel Converted to Electricity: Sensitivity 6		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	85.6	0.0%	7,690	658.2	0.0%
Coal	112.3	31.2%	9,680	1,086.9	65.1%
Fuel Oil	95.0	10.9%	8,736	829.5	26.0%

GWP = 84 CH4 Calib = 1.88	LCA for Delivered Fuel: Sensitivity 7		Fuel Converted to Electricity: Sensitivity 7		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	91.0	0.0%	7,690	699.4	0.0%
Coal	112.4	23.5%	9,680	1,087.7	55.5%
Fuel Oil	97.5	7.2%	8,736	851.5	21.7%

GWP = 84 CH4 Calib = 3	LCA for Delivered Fuel: Sensitivity 8		Fuel Converted to Electricity: Sensitivity 8		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	104.8	0.0%	7,690	805.9	0.0%
Coal	112.6	7.4%	9,680	1,089.9	35.2%
Fuel Oil	103.9	-0.8%	8,736	908.1	12.7%

Exhibit 44: Comparisons of Fuel LCAs and Converted to Electricity: Sensitivities 9 to 12

	Relevant for Competition in Industrial Boilers, Furnaces & Kilns		Relevant for Competition in Power Plants		
GWP = 28 *CH4 Calib = 1*	LCA for Delivered Fuel: Sensitivity 9		Fuel Converted to Electricity: Sensitivity 9		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	70.4	0.0%	7,690	541.0	0.0%
Coal	104.9	49.1%	9,680	1,015.2	87.6%
Fuel Oil	88.2	25.4%	8,736	770.8	42.5%

GWP = 28 *CH4 Calib = 1*	LCA for Delivered Fuel: Sensitivity 10		Fuel Converted to Electricity: Sensitivity 10		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	71.6	0.0%	7,690	550.3	0.0%
Coal	105.6	47.6%	9,680	1,022.5	85.8%
Fuel Oil	89.4	24.9%	8,736	780.6	41.8%

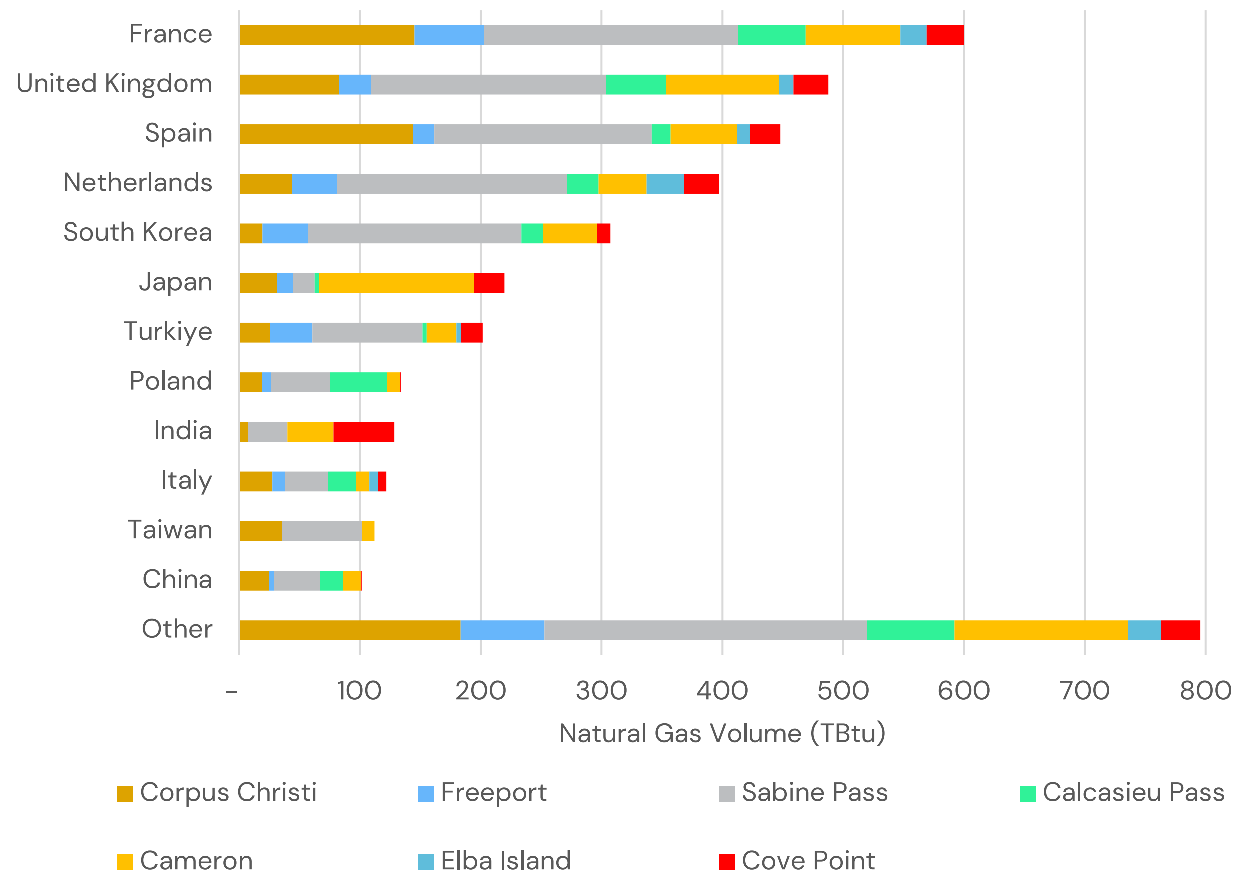
GWP = 28 *CH4 Calib = 0.496*	LCA for Delivered Fuel: Sensitivity 11		Fuel Converted to Electricity: Sensitivity 11		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	69.5	0.0%	7,690	534.4	0.0%
Coal	105.7	52.1%	9,680	1,022.9	91.4%
Fuel Oil	88.4	27.2%	8,736	772.0	44.5%

GWP = 84 *CH4 Calib = 0.496*	LCA for Delivered Fuel: Sensitivity 12		Fuel Converted to Electricity: Sensitivity 12		
	CO2e kg/MMBtu	Percent Difference from US LNG	Average Heat Rate (Btu/kWh)	CO2e kg/MWh	Percent Difference from US LNG
US LNG	73.8	0.0%	7,690	567.9	0.0%
Coal	112.1	51.8%	9,680	1,085.0	91.1%
Fuel Oil	89.5	21.1%	8,736	781.5	37.6%

5.3 Comparison of Cases: Hypothetical Multi-sector, Multi-fuel Switching

In 2022, US LNG exports totaled 3,862 bcf, equivalent to approximately 4,278 PJ or 4,055 TBtu. These exports originated from seven liquefaction plants located in the lower 48 states, as depicted in the accompanying chart. The exports were distributed to 32 different countries, with the top 12 destinations being France, the United Kingdom, Spain, the Netherlands, South Korea, Japan, Turkiye, Poland, India, Italy, Taiwan, and China. These top 12 countries received over 80% of US LNG exports, while the remaining 20 countries accounted for just under 20%. The chart below illustrates the quantity and source of US LNG imports for the top 12 countries with the highest volume of LNG imports from the US in 2022, as well as for all other countries.

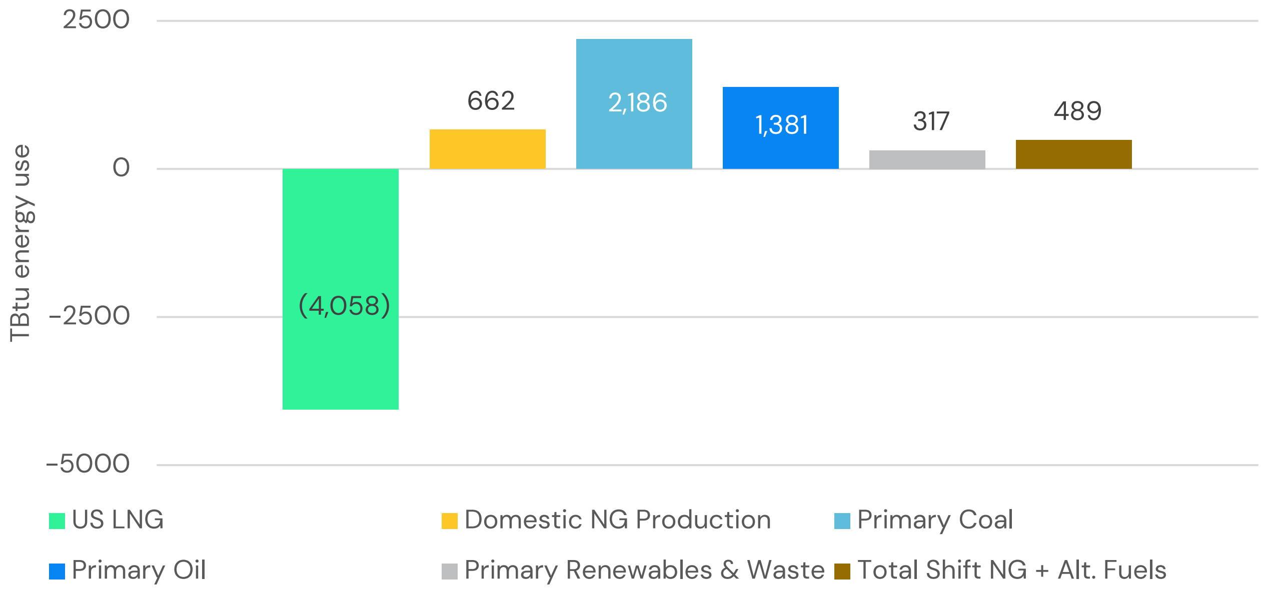
Exhibit 45: 2022 US LNG Import Volume and Originated Liquefaction Plants by Country (TBtu)



As discussed above, this Study uses IEA data on energy consumption by country and sector to estimate how much natural gas (and US LNG) and other fuels were used in each sector of each importing country. Then with a counterfactual assumption that no US LNG was imported in 2022, the Study estimates how much alternative fuels and electricity would have been substituted for the unavailable US LNG.

- In all cases except for Sensitivity Case #10, in the absence of US LNG exports, the estimated substitution among primary fuels for the 4,058 trillion Btus of US LNG exports in 2022 is depicted in the chart below.
- The increase in coal accounts for 2,186 trillion Btus, or 53.9% of the unavailable energy from US LNG exports.
- Substitution by fuel oil and other petroleum products is estimated at 1,381 trillion Btus, or 34%.
- Domestically produced natural gas in importing countries with natural gas production is estimated to contribute 662 trillion Btus, or 16.3%.
- Primary renewable energy and waste fuels are expected to provide 317 trillion Btus, or 7.8%, of the unavailable energy.

Exhibit 46: Estimated Global Shift in Primary Fuel Usage in 2022 (Base Case)



The table below shows the estimated global shift in primary fuel usage in 2022 by end-use sector. It shows that the majority of the shift in fuel occurs in the power and industrial sectors.

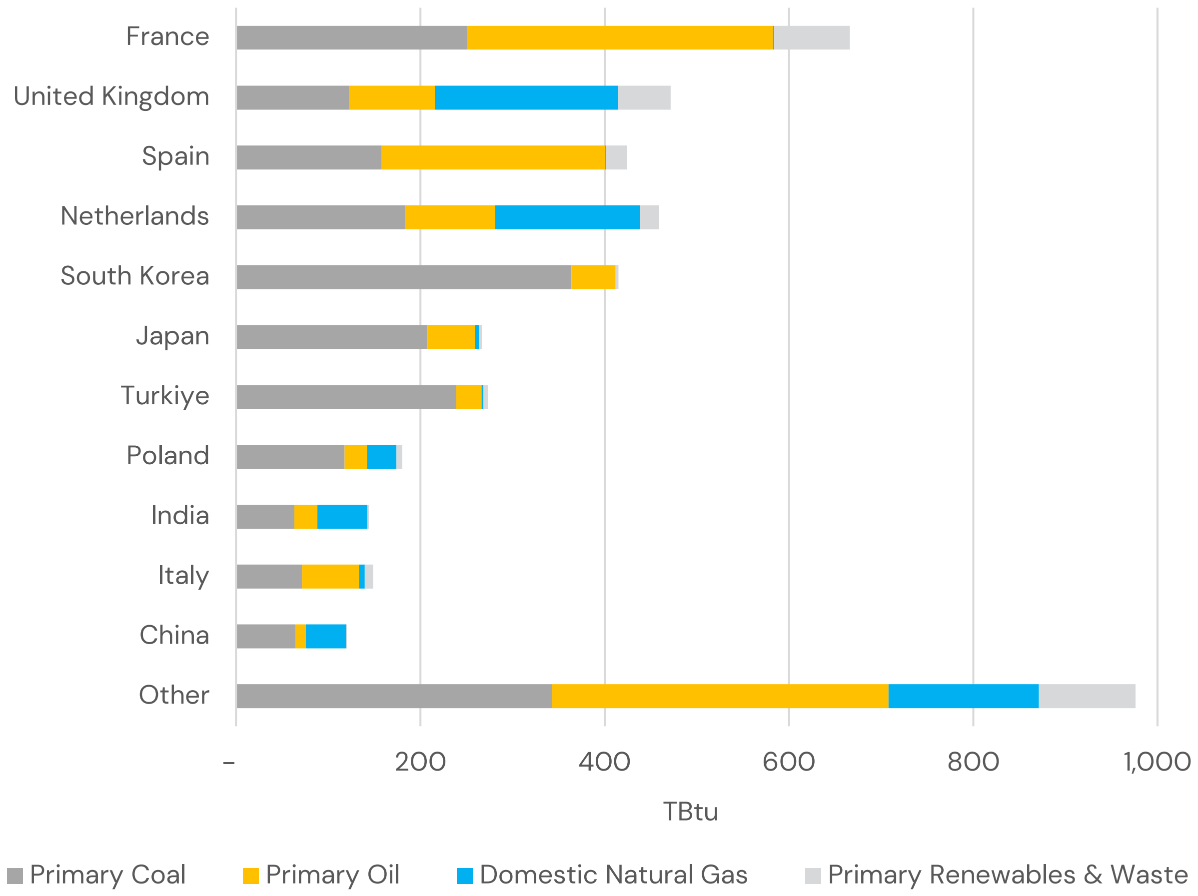
Exhibit 47: Estimated Global Shift in Primary Fuel Usage in 2022 by End-Use Sector (Base Case)

Sector	US LNG (TBtu)	Domestic NG Production (TBtu)	Primary Coal (TBtu)	Primary Oil (TBtu)	Primary Renewables & Waste (TBtu)	Total Shift NG + Alt. Fuels (TBtu)	End-use Electricity (TBtu)	Total End-use Shift NG + Alt. Fuels (TBtu)
Residential	(422)	76	6	139	25	(175)	156	(19)
Commercial and public services	(226)	29	14	59	2	(122)	109	(14)
Industry	(1,042)	165	262	320	26	(269)	240	(30)
Transport	(41)	11	0	29	0	(0)	0	(0)
Other final consumption	(189)	48	1	135	0	(4)	4	(0)
All End-Use Sectors	**(1,919)**	**329**	**283**	**682**	**53**	**(571)**	**508**	**(64)**
Electricity, CHP, and heat plants	(2,139)	333	1,903	699	263	1,060	-	1,060
All Sectors	**(4,058)**	**662**	**2,186**	**1,381**	**317**	**489**	**-**	**489**

The specific mix of primary energy sources would vary significantly across countries, depending on their sectoral energy consumption patterns and their capacity to increase domestic natural gas production to compensate for the loss of US LNG exports.

Exhibit 48 below shows the estimated 2022 primary energy use shift in importing countries.

Exhibit 48: Estimated 2022 Primary Energy Use Shift in Importing Countries (TBtu)



Sensitivity Case #10 assumes that there is little opportunity to switch to renewable or waste energy either because the counterfactual disruption to US LNG supply was to occur abruptly or the expansion of renewables and waste fuels were already taking place at the maximum possible rate. For this case, switching to renewables and waste fuels does not occur and the difference is made up by more use of coal, petroleum products, and domestic natural gas. In the absence of US LNG exports, the estimated substitution among primary fuels for the 4,058 trillion Btus of US LNG exports in 2022 is depicted in the chart below and applies to all cases.

- The increase in coal accounts for 2,838 trillion Btus, or 70.0% of the unavailable energy from US LNG exports.
- Substitution by fuel oil and other petroleum products is estimated at 1,870 trillion Btus, or 46.1%.
- Domestically produced natural gas in importing countries with natural gas production is estimated to contribute 662 trillion Btus, or 26.3%.
- There is no substitution of US LNG export by primary renewable energy and waste fuels in Sensitivity Case #10.

Exhibit 49: Estimated Global Shift in Primary Fuel Usage in 2022 (Sensitivity Case #10)

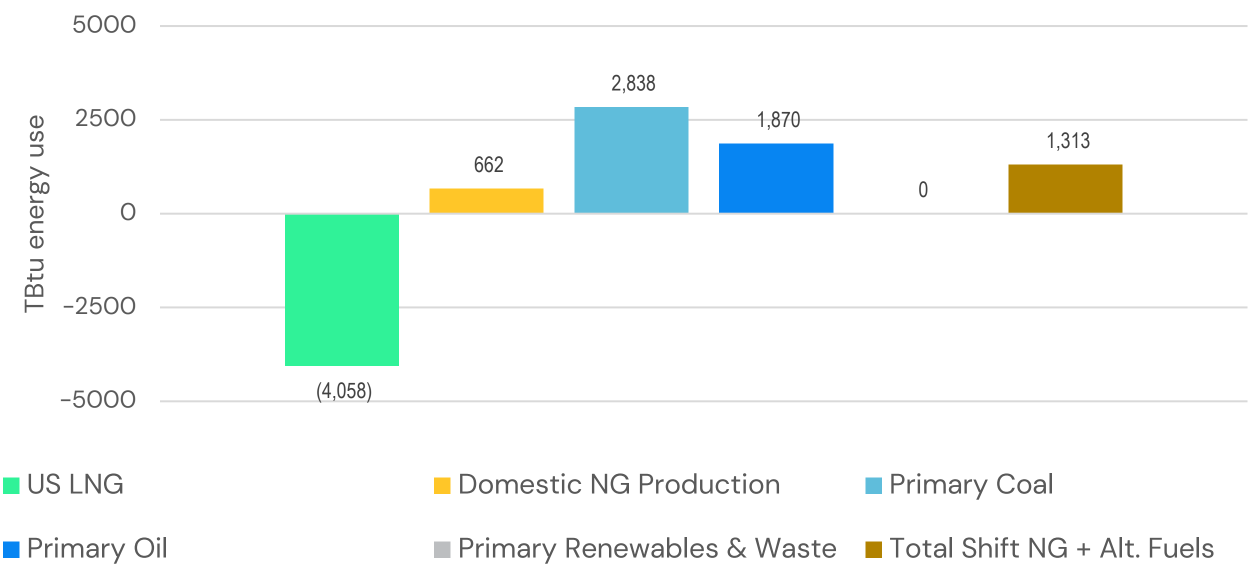


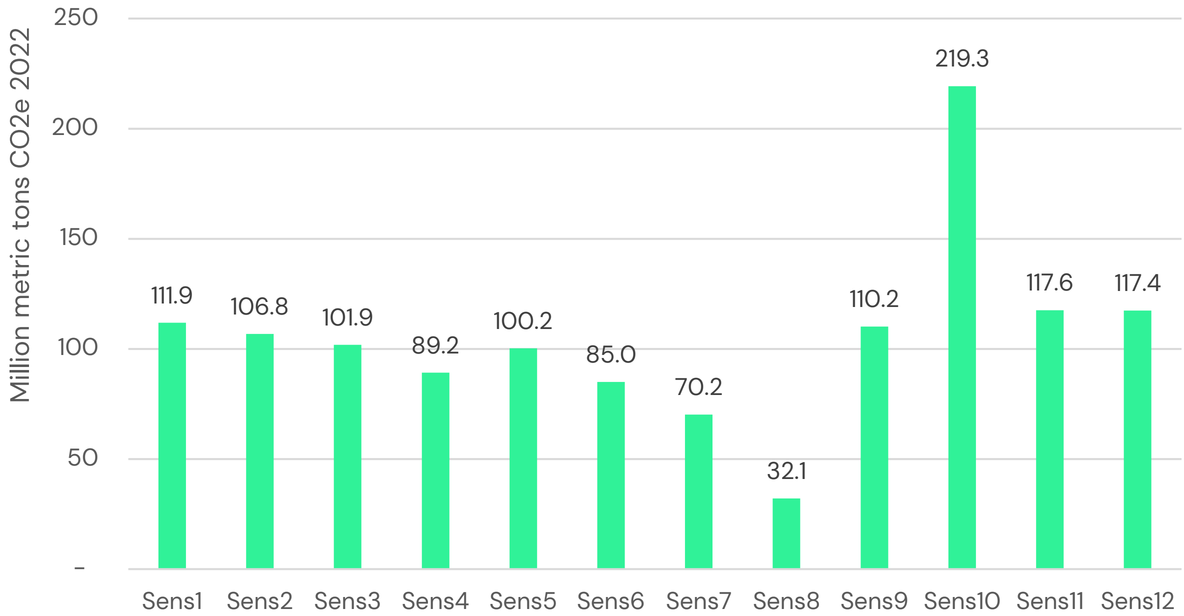
Exhibit 50: Estimated Global Shift in Primary Fuel Usage in 2022 by End-Use Sector (Sensitivity Case #10)

Sector	US LNG (TBtu)	Domestic NG Production (TBtu)	Primary Coal (TBtu)	Primary Oil (TBtu)	Primary Renewables & Waste (TBtu)	Total Shift NG + Alt. Fuels (TBtu)	End-use Electricity (TBtu)	Total End-use Shift NG + Alt. Fuels (TBtu)
Residential	(422)	76	7	149	0	(189)	168	(21)
Commercial and public services	(226)	29	14	60	0	(124)	110	(14)
Industry	(1,042)	165	270	329	0	(278)	247	(31)
Transport	(41)	11	0	29	0	(0)	0	(0)
Other final consumption	(189)	48	1	135	0	(4)	4	(0)
All End-Use Sectors	**(1,919)**	**329**	**292**	**702**	**0**	**(595)**	**529**	**(66)**
Electricity, CHP, and heat plants	(2,139)	333	2,546	1,167	0	1,908	-	1,908
All Sectors	**(4,058)**	**662**	**2,838**	**1,870**	**0**	**1,313**	**-**	**1,313**

Following the estimate of the shift in primary energy use among importing countries in 2022, the Study calculates the GHG emissions linked to these alternative energy sources. This involved estimating the supply chain GHG emissions from the production and transportation of LNG from each US exporting facility to every receiving country in 2022, as well as determining the GHG emissions associated with the use of the substitute energy sources. The study assumes that each country would compensate for the loss of US LNG imports by increasing production or imports of pipeline natural gas, coal, petroleum products, or power from renewables and waste fuels. The model did not account for the trading of non-US natural gas to rebalance energy markets. If non-US LNG trading were included, the distribution of emission increases among countries could differ.

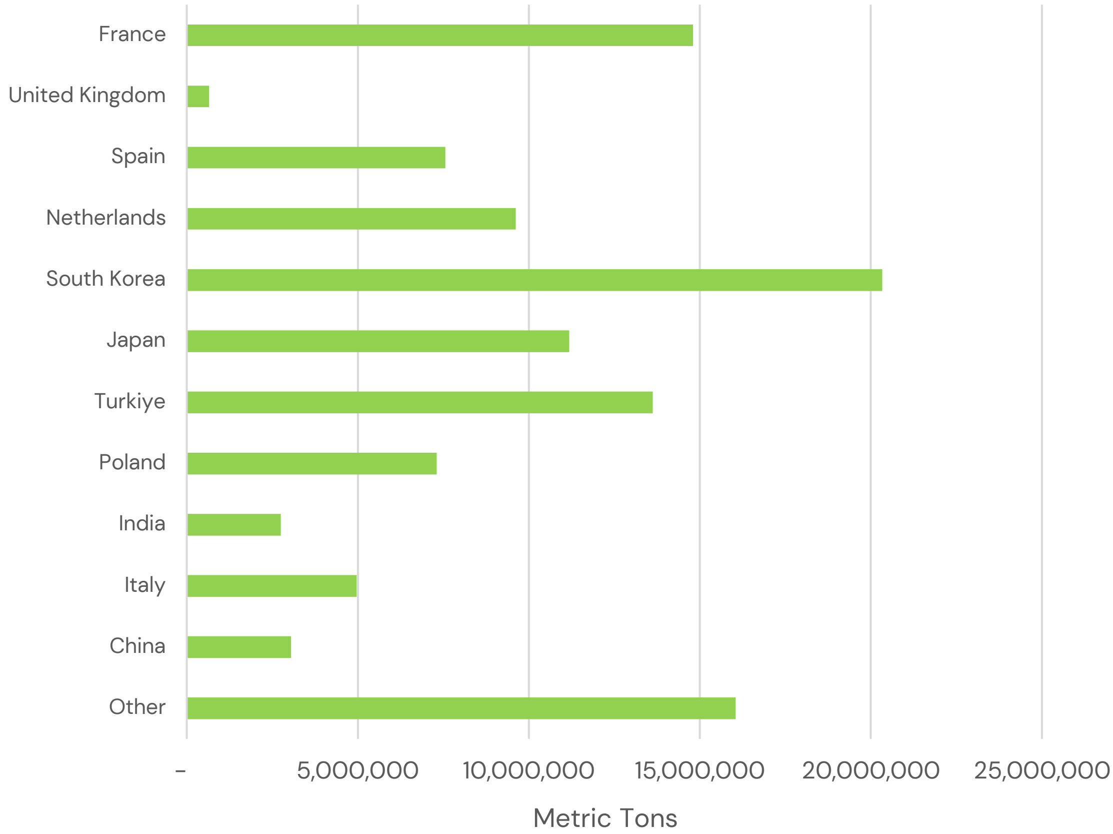
The net GHG emission impact for the Base Case was that, compared to alternative fuels, the use of US LNG decreased world GHGs by 111.8 million metric tons in 2022. Among the 11 Sensitivity Cases, the net positive impacts from US LNG ranged from 32.6 to 219.2 million metric tons per year. The lowest impact of 32.6 million tons per year occurs with Sensitivity #8 which combines a methane GWP of 84 with the highest modeled methane release calibration of three times the EPA GHGI values. The largest impact of 219.2 million tons per year occurs with Sensitivity #10 wherein no switching to renewables or waste fuel occurs. All the cases examined here show that the US LNG exports result in a net reduction in the world's GHG emissions compared to the use of alternative fuels.

Exhibit 51: Increase in GHG Emissions Caused by Removing US LNG Exports (2022)



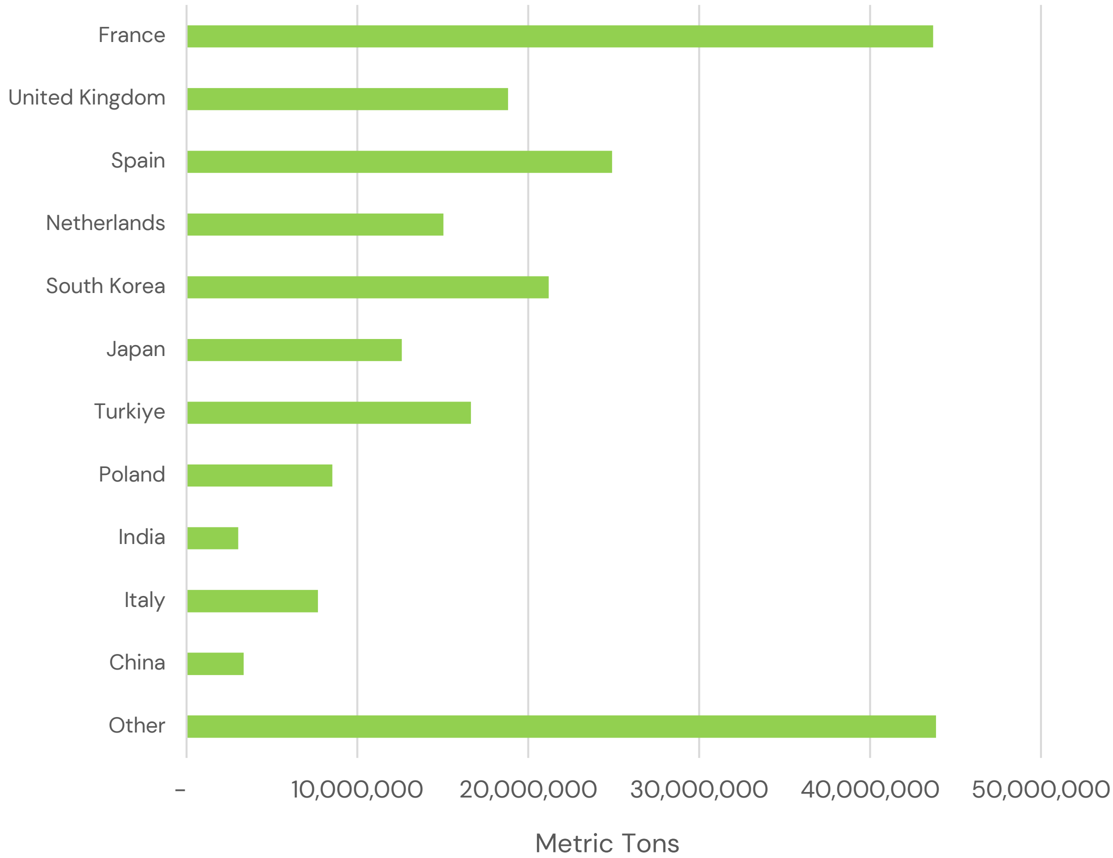
In the Base Case, the hypothetical impact of having no US LNG exports in 2022 would result in an increase of 111.81 million metric tons of GHG emissions. As shown in Exhibit 52 below, the largest increases are expected in South Korea, France, Turkey, Japan, and the Netherlands.

Exhibit 52: GHG Reduction Attributable to 2022 US LNG Exports in Base Case



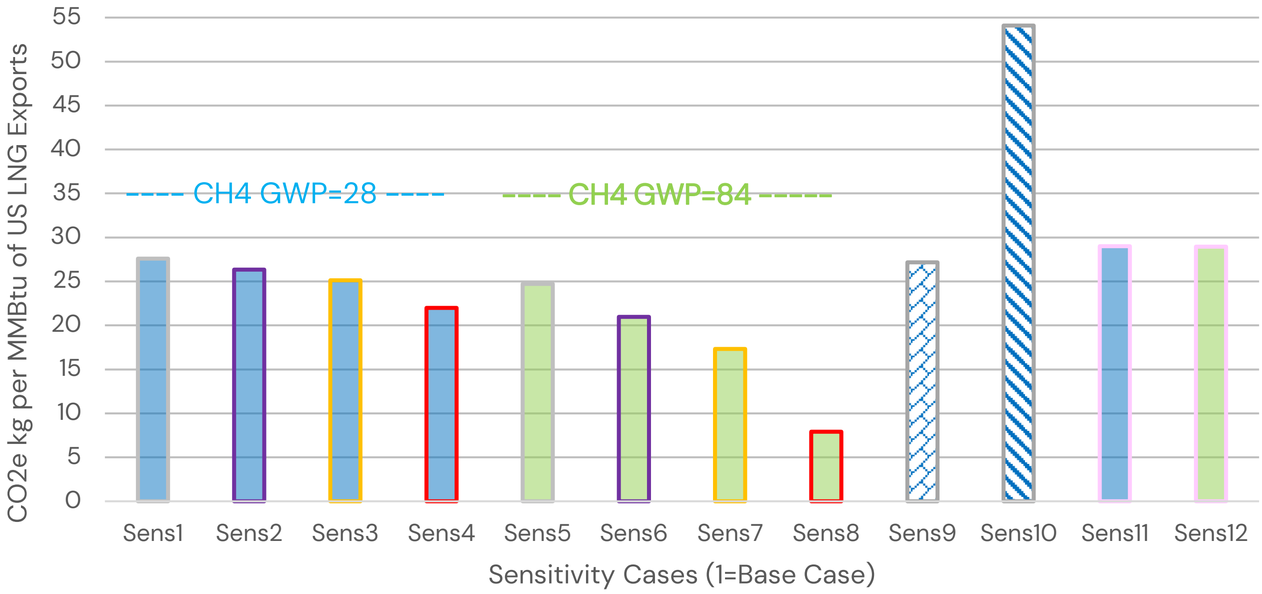
While the GHG reduction due to 2022 US LNG exports varies across the cases, the relative impacts among importing countries remain largely consistent, except in Sensitivity Case #10. In Sensitivity Case #10, which assumes no substitution of US LNG exports by renewables and waste, LNG-importing countries increasingly rely on coal and oil products as alternative fuels. Due to the lower efficiency and higher emission intensity of coal and oil, all countries see a significant increase in GHG reductions attributable to 2022 US LNG exports. Countries estimated to have more renewables and waste as alternative fuels, such as France and the United Kingdom, see the most noticeable impacts.

Exhibit 53: GHG Reduction Attributable to 2022 US LNG Exports in Sensitivity Case #10



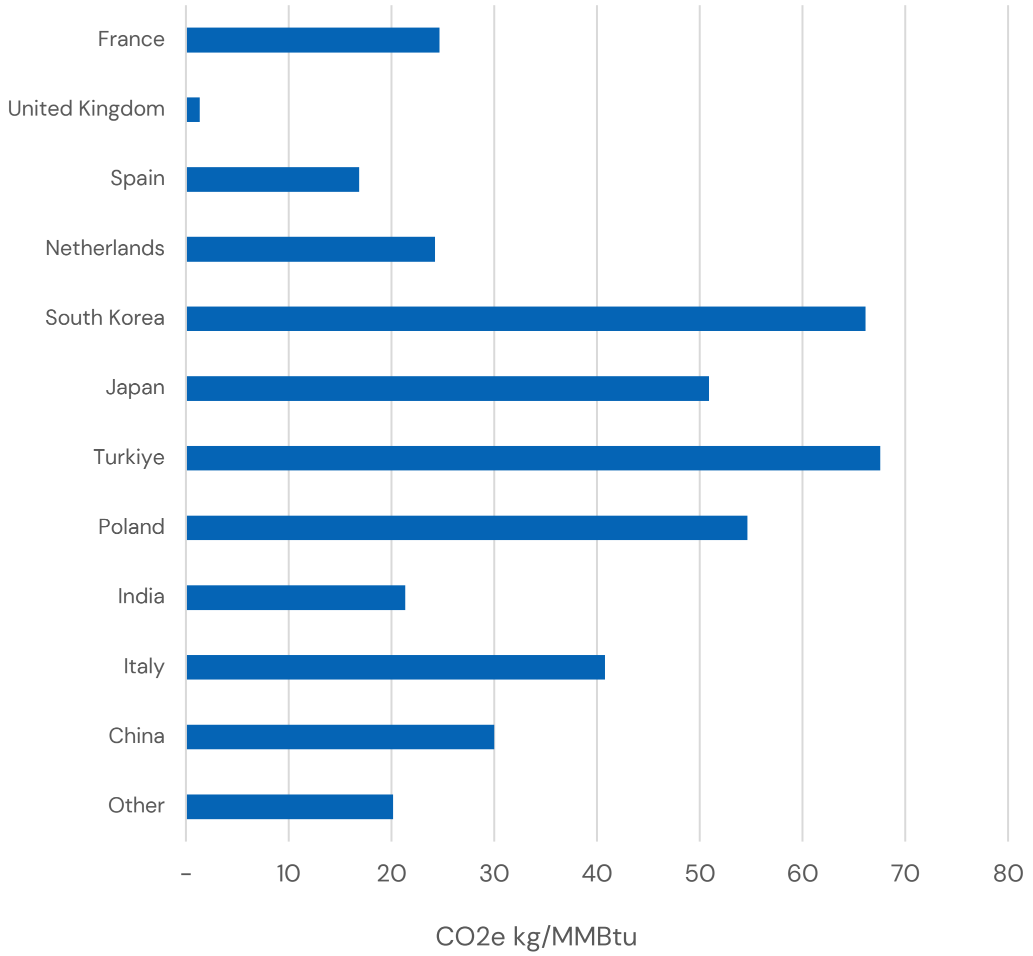
The chart below shows the net impacts in units of kilograms of GHG reduction per million Btu of US LNG exports. Because the natural gas supply chain has more methane releases as compared to the alternative fuels, the increase in emissions caused by having to substitute for US LNG declines when one assumes higher methane release rates and larger methane GWPs. In the Base Case, the net positive impact of US LNG is 27.6 CO2e kg/MMBtu of US exported LNG and this falls to as low as 7.9 in the Sensitivity Case #8.

Exhibit 54: GHG Reductions Caused US LNG Exports vs Use of Alternative Fuels (2022)



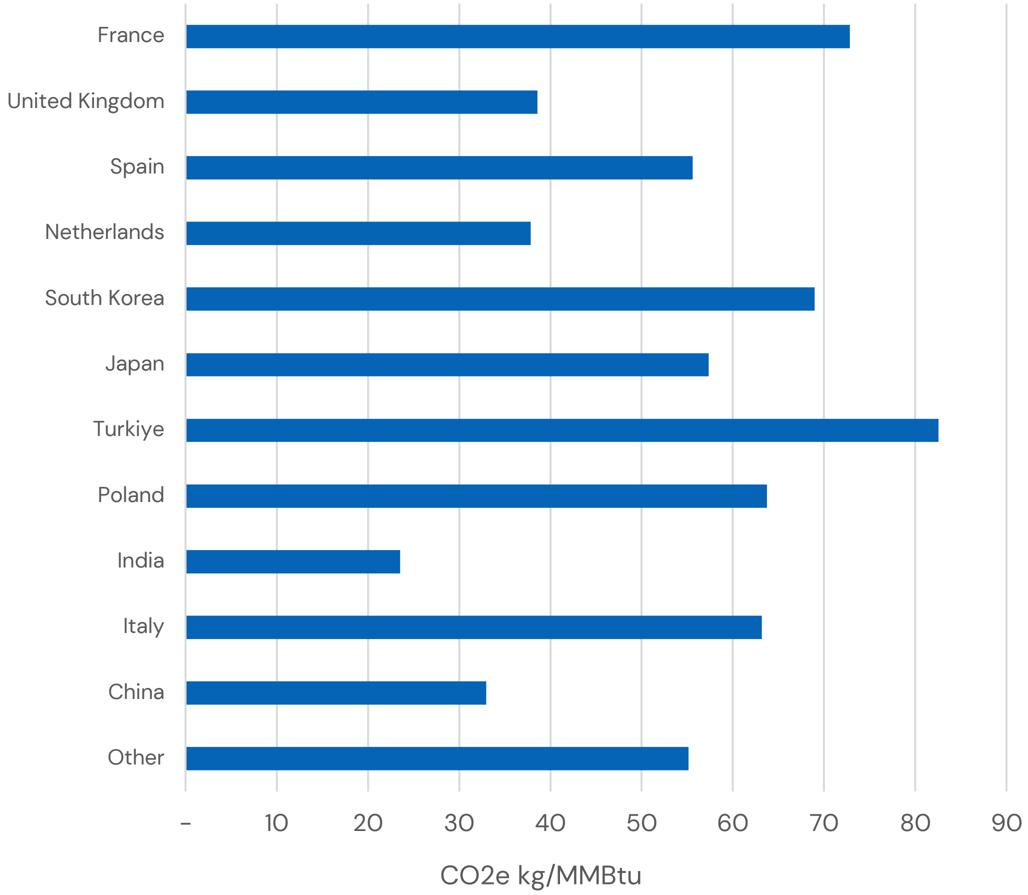
The absence of US LNG exports would lead to a global increase in GHG emissions by 27.6 kg CO_2e per MMBtu of unavailable LNG under the Base Case assumptions. As illustrated by the chart below, the impact per MMBtu of LNG imports would vary significantly among importing countries. The UK is expected to have the lowest impact due to its substantial domestic natural gas production and significant renewable energy contribution to its power sector. Conversely, countries heavily reliant on coal, such as South Korea, Turkey, and Poland, would experience the highest per-MMBtu increases.

Exhibit 55: Per-unit GHG Reductions Attributable to 2022 US LNG Exports (Base Case)



The per-unit GHG reduction due to 2022 US LNG exports varies across the cases due to differing assumptions related to methane GWP and methane calibration. However, the relative impacts among importing countries remain largely consistent, except for Sensitivity Case #10 in which shifts to new renewables or waste fuels are restricted. In Sensitivity Case #10, all countries see a significant increase in per-unit GHG reductions attributable to 2022 US LNG exports. Countries estimated to have more renewables and waste as alternative fuels in the Base Case, such as France and the United Kingdom, see the most noticeable impacts when those options are restricted.

Exhibit 56: Per-unit GHG Reductions Attributable to 2022 US LNG Exports (Sensitivity Case #10 – no new renewables allowed)



6. LCA Considerations and Comparisons between this Study's Results and Other Sources

Life cycle assessments require consideration and resolution of many different factors and assumptions which can make reviewing and comparison of results challenging. This section discusses the fundamental concepts of a life cycle assessment (LCA), as well as some of the implications that should be considered when reviewing LCA study results. It also provides a section detailing the comparisons made by ICF between this analysis and other LCA studies and emission data sources.

6.1 Differing LCA Concepts of What is Being Measured and Compared

6.1.1 Boundaries for LCA Analyses

An LCA must ensure that the supply chain segments quantified in the results include as much of the fuel's life cycle as possible. The boundaries of the supply chain are defined by the scope and intent of the LCA analysis and should always be fully transparent. The results must represent a combination of emissions generated across each of the supply chain segments applicable to the production, transportation, and combustion of the supplied fuel. For instance, when quantifying emissions from the LNG supply chain used in international power generation markets, results must include emissions produced at the natural gas supply basin, as well as during pipeline and marine transportation, liquefaction, regasification, and end-use consumption.

Although GHG emission results for a specific fuel pathway are often comparable, it is still important to understand the scope of the boundary being considered in the LCA analysis. The boundaries considered will also define assumptions used within particular supply chain segments and will cause variations in results. Examples of boundary assumptions that directly impact the LCA result for the supply of LNG would include the transportation distance of a natural gas pipeline system between the supply basin and the liquefaction terminal, or the nautical miles traveled by an LNG carrier from an origin to destination market.

6.1.2 Where in the Supply Chain are Emissions Being Measured

Similar to defined boundaries, LCA results can also be expressed at different points within the supply chain. Limiting the amount of supply chain segment emissions included in a fuel's LCA can be expressed using the term "gate". For example, if the LCA results include emissions from the upstream production and transportation of a fuel but do not include any emissions associated with end-use, those results would be referred to as a cradle-to-gate assessment. In a scenario where results are modeling emissions from the production and delivery of natural gas to a power plant, the gate in this case would refer to the power plant (in other words, delivery to the power plant). Results containing a full evaluation of a fuel's life cycle are commonly referred to as cradle-to-grave, meaning emissions from all supply chain segments are included (as well as disposal).

6.1.3 Allocation of Emission among Products and Coproducts

Another concept that is often encountered when performing an LCA analysis is the consideration for coproducts. Coproducts are associated with many fuel life cycles and where applicable require a quantity of emissions to be allocated to each product. For example, during natural gas processing in addition to producing sales-quality natural gas, processing plants also recover usable coproduct NGLs such as ethane or propane which are used in other manufacturing processes. In this case, only a portion of the emissions generated during this stage should be associated with the sales-quality natural gas. The allocation of emissions is typically performed on an equivalency basis, meaning the proportion of emissions associated with each product within the supply chain segment is based on the relative production amount in terms of total energy (e.g., BTU).

6.1.4 Treatment of Embodied Emissions

Another aspect that must be understood when reviewing an LCA is the extent to which results include the components of a fuel's complete life cycle. The sources of emissions an LCA must always include are those produced during equipment operation, including fugitive leakage and the combustion emissions produced from onsite fuel requirements. LCA results may also include emissions associated with the combustion of the final product, if intended by the scope of the study.

However other LCA concepts such as "embodied emissions" are not always included or transparently addressed. Embodied GHG emissions refer to the emissions generated during the construction of the production facilities and transportation infrastructure utilized in a fuel supply chain. They include the emissions from energy requirements of equipment used during construction, as well as those generated during the production and transportation of any required construction materials to the site. Examples of embodied emissions associated with natural gas production include those generated from the production of diesel fuel used to drill and complete oil and gas wells, as well as energy requirements in the production and transportation of cement and other construction materials used in well casings and any other needed equipment assembled onsite.

Further, other life cycle components such as the eventual decommissioning of facilities (at the end of useful life) can be quantified and included in results. Although LCA results may contain these additional aspects, components such as decommissioning are often excluded given that the emission impacts are very low in magnitude when compared to overall supply chain results. Also, there is considerable uncertainty about how materials and components might be recycled or repurposed. The LCA analysis provided here by ICF does not include end-of-life decommissioning.

6.1.5 Differences in Measuring Emissions of Energy Delivered to Customer versus Energy Services

When comparing the LCA results of LNG and other fuels, the point at which emissions are quantified must be properly taken into account. In cases where only natural gas is being considered, it may be sufficient to express emissions on the basis of delivery to the consumer in any comparisons made. This is because although the upstream production and transportation distance may differ between sources of natural gas, there are no differences between the infrastructure used in any energy services provided by each molecule of gas. However, if comparing LNG with the LCA impacts of other fuels such as coal, emission results must be expressed on the basis of the energy end-use service before valid comparisons can be made. This is because there can be significant differences between the efficiencies of each fuel type's end-use application. For example, when comparing LNG and coal used to generate electricity, because coal power plants are less efficient, more energy is required to produce the same amount of electricity as a natural gas-fired power plant. If the scope of the analysis relies on comparing the delivery of 1 Megawatt-hour of electricity generated between natural gas and coal, emission results must include the end-use energy service emissions, or this efficiency difference is not reflected in the comparison.

6.1.6 Units in which Results are Reported

The results of this study are usually reported in units of kilograms or kilograms of CO_2 equivalent per million Btu (MMBtu) of higher heating value. This follows the US convention of using higher heating value of fuels when reporting their heat content and the widespread use of grams, kilograms, and metric tons of GHGs such as in EPA's National GHG Inventory and in EPA's Greenhouse House Gas Reporting Rule. However, in much of the rest of the world and in many academic journals, GHG emissions are reported in lower heating value and the heat content of fuels is reported in megajoule (MJ) rather than MMBtu. Most commonly outside of the US, the emissions from fuels are reported in grams per MJ.

One MMBtu is always equal to 1,055.056 MJ regardless of fuel. The conversion from higher heating value to lower heating value depends on the chemical composition of the fuel. Approximate conversion factors are shown in Exhibit 57.

Exhibit 57: Approximate Heat Content and GHG Conversion Factors

	LHV MJ/metric ton	HHV MJ/metric ton	Ratio HHV/LHV	Energy unit conversion: MJ/MMBtu	Conversion: multiply CO2 grams/MJ by this to get CO2 kg/MMBtu
Coal	22,727	23,961	1.054	1,055.06	1.001
Natural gas	47,131	52,212	1.108	1,055.06	0.952
LS Diesel fuel	42,602	45,564	1.070	1,055.06	0.986
Residual FO	39,457	42,220	1.070	1,055.06	0.986

source: Lower and Higher Heating Values of Fuels | H2tools | Hydrogen Tools

6.2 Comparison of ICF Results with other LNG LCA Studies

ICF performed a life cycle assessment literature review to compare the results and assumptions of similar studies with this analysis. This review included several prominent studies, models, and databases which contain emission calculations related to the production and supply of natural gas. However, each study varies due to several baseline parameters and assumptions which directly impact results. To best provide comparisons between this analysis and others, there are several aspects which must be identified within each study. These aspects include:

- Source, scope, and methodology of greenhouse gas quantification
- Greenhouse gases included (CH_4, CO_2, N_2O)
- Global warming potential utilized (GWP)
- Throughput used to express results (barrel of oil produced, dry gas production, natural gas delivered, etc.)
- Allocation methodology of GHGs between products
- Inclusion/exclusion of embodied emissions (emissions generated during the construction of infrastructure as well as the energy used to transport the required construction materials)

6.2.1 Results of ICF Literature Review

ICF reviewed several LCA studies which quantified emissions from the production and supply of natural gas. Exhibit 58 and Exhibit 59 that follow provide a comparison of LCA results associated with studies who considered natural gas produced and exported as LNG for the use in power generation in international markets. Each study's results are shown on the basis of 1 MWh electricity generated in the target market. Where available, information related to the underlying assumptions such as the GWP used, CH_4 leakage rate, and boundaries considered as part the scope of the analysis are given in each exhibit.

As previously stated, resulting emissions are a combination of assumptions and methodologies which can make comparisons difficult. Because the scope of each study considers different natural gas production regions and target power generation markets, results are not always directly comparable. Exhibit 59 provides a more detailed breakdown of results, made available by the studies shown. Emissions results from these studies are provided on an individual supply chain basis. All assumptions and results shown are not fully transparent, and some information may be based on ICF interpretation of provided information within each study.

Exhibit 58: Comparison of Exported LNG for Power Generation LCA Results from Various Studies

Study	Origin Country/Region	Destination Country/Region	CH4 GWP	LCA Results (kg CO2e/MWh)
BRG	USA	Europe	29.8	456
BRG	USA	Asia	29.8	487
Abrahams	USA	Average of Asian/Europe	36	655
Kasumu 2015	Canada	Average of Asian/Europe	25	585
Kasumu 2018	Canada	Average of Asian/Europe	25	589
Ghandaehariun	Canada	China	25	589
Mallapragada 2018	USA	USA	30	417
Mallapragada 2018	USA	UK	30	459
Mallapragada 2018	USA	Spain	30	461
Mallapragada 2018	USA	Chile	30	463
Mallapragada 2018	USA	India	30	473
Mallapragada 2018	USA	Japan	30	473
Mallapragada 2019	USA	India	N/A	595

Note: All study references provided in Appendix A. Results from ICF's Base Case modeling from US East Coast (shown later) to several countries range from 567 to 619 CO2e kg/MWh. including embodied emissions for the NG/LNG supply chain and the power plant.

Exhibit 59: Comparison of Exported LNG for Power Generation LCA Results from Various Studies by Industry Segment

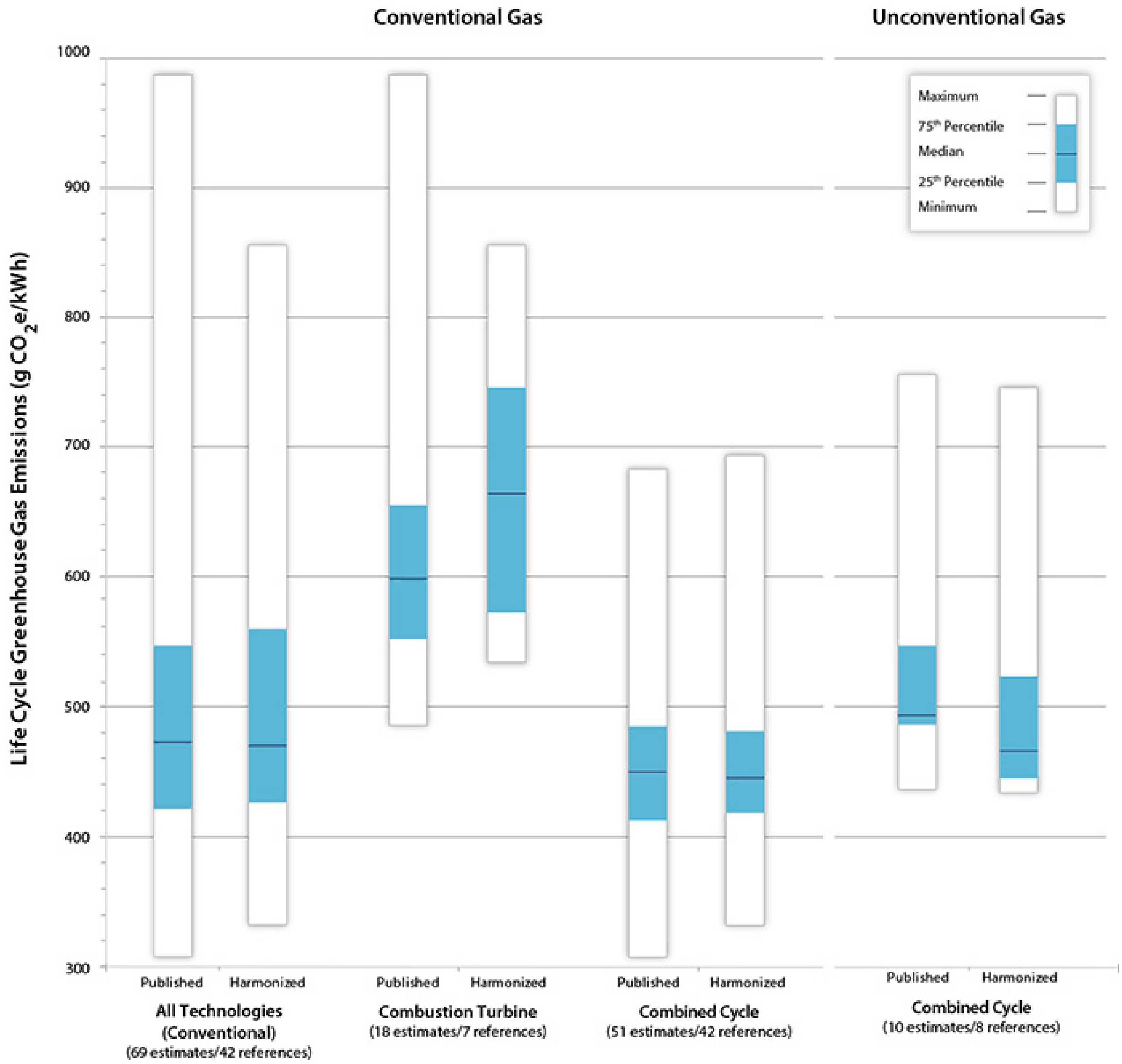
Parameter	Kasumu 2015	BRG	BRG	Mallapragada 2018	Pace	Pace	Abrahams	NETL 2019	ICF
Origin Country/Region	Canada	USA	USA	USA	USA	USA	USA	USA	USA
Destination Country/Region	Average of Europe/Asia	Europe	Asia	India	Germany	China	Average of Europe/Asia	Europe	Varies for results shown
Power Plant Type	Not specified	Not specified	Not specified	NG CCGT	NGCC	NGCC	NGCC	NGCC	NGCC
GWP	25	29.8	29.8	30	30	30	36	36	28
Upstream CH4 Leakage (%)	-	-	-	1.2%	-	-	3%	-	1.3%
Upstream	46.8	50	50	19	45	55	223	88	52.8 to 55.7
Transport within Export Country	6.6	21	21	48	9	11	-	61	11.5 to 12.2
Liquefaction	64.7	35	35	18	38	60	49	38	45.5 to 47.9
LNG Shipping	30.9	11	20	20	17	40	15	28	19 to 64.5
Regasification	17.7	3	3.3	6	1	3	8	4	7.1 to 7.1
Transportation to Power Plant	-	1	1	-	28	28	-	-	1.6 to 1.6
Power Generation	415	334	287	362	393	393	364	416	417.9 to 417.9
Electricity Distribution	3.3	-	-	-	-	-	-	2	1.7 to 1.7
Total (kg CO2e/MWh)	**585.0**	**455.0**	**417.3**	**473.0**	**530.8**	**588.5**	**659.0**	**637.0**	**557.3 to 608.7**

Results vary based on country specific characteristics such as assumed power plant heat rate

All references for studies shown here and reviewed in this literature review are provided in Appendix A. The ICF column is for Marcellus gas exported from the US East Coast including embodied emissions for a new combined cycle power plant and GHGs for electric transmission. An average of 550 CO_2e kg/MWh was computed in this study (see Exhibit 42) for the existing gas-fired fleet in countries importing US LNG (excluding power plant embodied emissions and transmission GHGs).

Exhibit 60 below provides another comparison of LCA results from natural gas power generation by various technology types. The emission results shown represent a harmonization effort of international LCA studies performed by the National Renewable Energy Laboratory (NREL). This analysis is discussed in more detail in section 6.6.

Exhibit 60: LCA Study Harmonization Results by Natural Gas Power Generation Technology Type



Source: National Renewable Energy Laboratory (NREL) Life Cycle Assessment Harmonization. These studies are mostly based on domestic natural gas or pipeline imports. As a rough rule-of-thumb, assuming the gas comes from LNG would add about 100 CO_2e kg/MWh to these values.

6.3 Life Cycle Assessment of the Natural Gas Supply Chain by the National Petroleum Council

The National Petroleum Council (NPC) recently released a life cycle assessment study examining the emissions generated from the natural gas supply chain.[23] The intent of the study was to create a transparent methodology to quantify emissions, and to determine the volume of reductions which are achievable from natural gas operations by 2030 and 2050. The results of the study are generated using the SLiNG GHG Model, a model which calculates emissions for each natural gas supply chain segment using bottom-up assumptions and emission factors.[24]

Emissions were calculated for six baseline natural gas supply chain scenarios (plus a U.S. average), each of which representing a different production region and destination market. Emissions are also generated considering different "gates", with emissions quantified on the basis of gas delivered by transmission pipelines, gas delivered by distribution companies, and finally LNG delivered to regasification facilities (not including regasification emissions). All "gate" results do not apply to every scenario considered, as certain origin-destination pairs do not include distribution companies or natural gas liquefaction and export.

Exhibit 61 below provides a set of NPC results for production scenarios which consider LNG exports. The results represent two oil and gas production regions (Appalachian and Permian) and two LNG destination markets (Asia and Europe). Each case also shows the pipeline mileage considered by NPC to determine the distance each molecule of gas travels between the processing plant and the liquefaction facility. In two additional columns, Exhibit 61 provides results from this analysis which have been generated to reflect similar scenario assumptions – both with and without embodied emissions. In general, most results are comparable between NPC and this Study, but NPC did not include embodied emissions, causing NPC results to be closer to this Study's Base Case <u>without</u> embodied emissions. Additionally, the "This Study" columns of the table were created using a higher methane slip assumption (4.19% representing TFDE/DFDE carriers vs. NPC's 1.89% average of all carrier types) which results in more emissions associated with the LNG shipping segment.

Exhibit 61: Comparison of NPC SLiNG-GHG Model Scenario Results with ICF analysis (kg CO_2e/MMBtu HHV LNG delivered, AR-5 CH_4 GWP – 28)

	Importing Region	Asia			Asia			Europe			Europe		
	Liquefaction Plant Location in US	US Gulf Coast			US Gulf Coast			US Gulf Coast			US Gulf Coast		
	US Supply Source	Appalachian Basin			Permian Basin			Appalachian Basin			Permian Basin		
	Avr. Pipeline Dist. to Liq. Plant (miles	1,149			493			1,149			493		
	Source, Sensitivity	NPC	This Study with Embodied	This Study w/o Embodied	NPC	This Study with Embodied	This Study w/o Embodied	NPC	This Study with Embodied	This Study w/o Embodied	NPC	This Study with Embodied	This Study w/o Embodied
1	*Fuel production*	7.57	7.16	6.61	5.17	6.33	5.11	7.35	6.96	6.43	5.02	6.15	4.97
2	*Fuel transportation for export*	6.53	5.52	4.80	2.13	2.32	2.02	6.33	5.36	4.67	2.07	2.25	1.96
3	*Conversion & export terminal*	4.69	5.94	5.86	4.49	5.86	5.78	4.55	5.78	5.70	4.35	5.70	5.62
4	*International shipping*	4.26	7.31	7.20	4.59	7.14	7.04	2.02	4.19	4.13	2.18	4.10	4.04
5	*Import terminal & conversion*	0.23	0.23	0.16	0.23	0.23	0.15	0.23	0.23	0.16	0.23	0.23	0.15
6	*Transportation to power plant*	0.21	0.21	0.17	0.21	0.21	0.18	0.21	0.21	0.17	0.21	0.21	0.18
7	*NG Combustion*	52.65	52.65	52.65	53.04	53.04	53.04	52.65	52.65	52.65	53.04	53.04	53.04
9	**Total**	**76.13**	**79.02**	**77.46**	**69.87**	**75.13**	**73.33**	**73.33**	**75.39**	**73.91**	**67.09**	**71.68**	**69.97**

Note: The NPC report did not provide GHG estimates for segments 5, 6 or 7. Values shown here for those rows are taken from ICF estimates so that emission delivered to consumer plus combustion can be computed in row#9.

[23] Charting the Course: Reducing GHG Emissions from the U.S. Natural Gas Supply Chain; National Petroleum Council (NPC), April 2024

[24] Streamlined Life Cycle Assessment of Natural Gas – Greenhouse Gases (SLiNG-GHG) Model; National Petroleum Council (NPC)

6.4 Howarth LNG Analysis Discussion and Comparison

One recent study which has received widespread public attention is an LCA analysis originally released in 2023 by Robert Howarth of Cornell University.[25] The study provides a quantification of GHGs emitted from natural gas produced within the US and exported as LNG. The purpose of the analysis is to compare the GHG impacts of exported LNG with coal, with results saying:

> *The greenhouse gas footprint of LNG is always substantially larger than for natural gas consumed domestically (regardless of time scale), because of the large amount of energy needed to liquefy and transport the LNG. Greenhouse gas emissions from LNG are also larger than those from domestically produced coal, ranging from 28% to 2-fold greater[26] for the average cruise distance of an LNG tanker, evaluated on the 20-year time scale. Even when evaluated on the 100-year time scale, emissions from LNG range from being equivalent to coal to being 64% greater.*

The methodology to quantify emissions in the study relies on the use of emission factors which represent the components of the LCA. These factors are based on analysis performed in other sources, including a sequence of earlier studies published by the same author. There is little detail provided in the study on the underlying assumptions used to derive the factors such as the pipeline distance the natural gas travels or the relative impact of the individual supply chain components represented in the upstream emission factor used in results. The methodology and assumptions used in the Howarth study are discussed in more detail in the following sections including comparisons with other sources.

6.4.1 Upstream Emission Assumptions and Comparisons

The Howarth study quantifies fugitive methane emissions by providing emissions factors which represent the upstream industry segments for both LNG and coal. For natural gas, this methane leakage factor includes the production, gathering and boosting, processing, and transmission components of the natural gas supply chain prior to the liquefaction terminal. Howarth applies a methane leakage rate of 2.8% of natural gas production for all scenarios, which is intended to represent the Permian basin. The Howarth study sources this assumption based on the results from a 2024 measurement study which analyzed a large data set of aerial observations from oil and gas producing basins across the US (Sherwin, see Appendix A). This leakage rate is much higher than what is suggested by the EPA GHGI (1.16% on a produced natural gas basis). A comparison of upstream methane leakages from additional sources is provided in Exhibit 21. Upstream fugitive methane emissions from coal are also derived from a single emission factor (stated in the study to be 0.21 g CH_4/MJ LHV) which is based on prior studies also published by Howarth. (See Exhibit 63)

CO_2 emissions generated from the combustion of fuels throughout the upstream supply chain segments of natural gas and coal are quantified in the Howarth study by using emission factors from the New York Department of Environmental Conservation (NYDEC).[27] In the NYDEC analysis, emission factors are derived to represent the upstream emissions of various fuels which are produced outside of the state and imported into New York. The NYDEC results for the products considered in the Howarth analysis (as well as the published values as referenced in the Howarth report) are shown in Exhibit 62 below. The CO_2 emission rate from produced natural gas assumed in the Howarth study is twice as high as the factor determined in

[25] The Greenhouse Gas Footprint of Liquefied Natural Gas (LNG) Exported from the United States; Howarth, October 2023, Cornell University; a revised version of the study was released in May 2024

[26] The high end of this range comes from comparing coal to LNG shipped by a steam-powered LNG carrier that uses bunker fuel for power and releases boil-off gas to the atmosphere. Such a configuration would have never made sense since the boil-off gas can be readily used as fuel in the carrier's boiler. But more importantly, steam-powered carriers are the oldest and least fuel-efficient ships in the world LNG carrier fleet and are used for only 2% of the ton-miles of US export shipments. See Exhibit 28: Summary of U.S. LNG Shipping Operations 2022.

[27] Statewide Greenhouse Gas Emissions Report; New York State Department of Environmental Conservation

the Argonne GREET model[16]. The factors quantified through GREET modeling are also provided for each fuel in Exhibit 62.

Exhibit 62: Comparison of CO_2 Emission Factors (for supply chain) used in Howarth LNG Study

	Howarth			*2021 NYS DEC*			*2023 GREET*		
Fuel Type	**g CO2/ MJ LHV****	**kg CO2/ MMBtu LHV**	**kg CO2/ MMBtu HHV**	**g CO2/ MJ LHV**	**kg CO2/ MMBtu LHV**	**kg CO2/ MMBtu HHV**	**g CO2/ MJ LHV**	**kg CO2/ MMBtu LHV**	**kg CO2/ MMBtu HHV**
Natural Gas	**12.6**	13.3	12.0	12.9	13.6	12.3	6.3	6.6	6.0
Fuel Oil	**15.8**	16.7	15.6	14.3	15.1	14.1	12.1	12.7	11.9
Coal	**3.4**	3.6	3.4	3.3	3.5	3.3	1.5	1.6	1.5

***Original units of emission values referenced in Howarth report.*

6.4.2 Scope of Howarth LNG Analysis End-Use Energy Service

As has been covered in previous sections of this report, the end-use application of the fuel should be considered when LCA emissions are being compared between LNG and alternative fuels. One notable assumption in the Howarth study is the comparison of results between natural gas and coal on the basis of combustion of the fuel. By comparing results between different fuels that exclude the end-use energy service, the operational efficiencies of the end-use application are not represented in the energy requirements used to calculate emissions. This has a noticeable impact on emission results in the case of power generation (the most typical end-use comparison between LNG and coal), where natural gas-fired power plants are more efficient than coal power plants.

6.4.3 Comparison of Results with Howarth LNG Analysis

Exhibit 65 on the following page provides a comparison between the results of the Howarth LNG analysis and a similar interpretation of emissions generated through ICF analysis. The results represent the scenario of natural gas exported using a 2-stroke engine power by LNG, 10,066 nautical miles one-way, the global average distance travelled assumed in the Howarth study. Under a similar scenario and scope, the Howarth study results in emissions which are 33% higher in total than ICF analysis across the natural gas supply chain. This increase is primarily due to the upstream emissions, where both the methane leakage rate and the generated CO_2 combustion emissions assumed in the Howarth study are twice as high (or more) compared with other sources such as the EPA GHGI and Argonne GREET for natural gas.

Exhibit 63: Comparison of Howarth GHG Emission Factors from Coal with ANL GREET Factors

Howarth Coal (original units)	CO2 only	methane		All
	g CO2/MJ LHV	g CH4/MJ LHV	g CO2e/MJ LHV GWP=82	g CO2e/MJ LHV
Upstream	3.4	0.2	17.3	20.7
Combustion	99.0	0.0	0.0	99.0
Sum	102.4	0.2	17.3	119.7

Howarth Coal in g/MJ HHV	CO2 only	methane		All
	g CO2/MJ HHV	g CH4/MJ HHV	g CO2e/MJ HHV GWP=82	g CO2e/MJ HHV
Upstream	3.2	0.2	16.4	19.6
Combustion	93.9	0.0	0.0	93.9
Sum	97.1	0.2	16.4	113.5

Howarth Coal in kg/MMBtu	CO2 only	methane		All
	CO2 kg/MMBtu HHV	CH4 kg/MMBtu HHV	CO2e kg/MMBtu HHV GWP=82	CO2e kg/MMBtu HHV
Upstream	3.4	0.2	17.3	20.7
Combustion	99.1	0.0	0.0	99.1
Sum	102.5	0.2	17.3	119.8

Howarth (this Study's units for GWP=28)	CO2 only	methane		All
	CO2 kg/MMBtu HHV	CH4 kg/MMBtu HHV	CO2e kg/MMBtu HHV GWP=28	CO2e kg/MMBtu HHV
Upstream	3.4	0.2	5.9	9.3
Combustion	99.1	0.0	0.0	99.1
Sum	102.5	0.2	5.9	108.4

ANL GREET for Coal (GWP=28)	CO2 + N2O	methane		All w/o Emb.		All with Emb.
	CO2 kg/MMBtu HHV (+N2O)	CH4 kg/MMBtu HHV	CO2e kg/MMBtu HHV GWP=28	CO2e kg/MMBtu HHV	Embodied	CO2e kg/MMBtu HHV
Upstream	1.507	0.139	3.892	5.399	0.799	6.198
Combustion	95.944	0.011	0.308	96.252		96.252
Sum	97.451	0.150	4.200	101.651	0.799	102.450

Ratio Howarth / GREET for Coal	CO2 + N2O	methane		All w/o Emb.
	CO2 kg/MMBtu HHV (+N2O)	CH4 kg/MMBtu HHV	CO2e kg/MMBtu HHV GWP=28	CO2e kg/MMBtu HHV
Upstream	226%	151%	151%	172%
Combustion	103%	0%	0%	103%
Sum	105%	140%	140%	107%

Exhibit 64: Comparison of Howarth GHG Emission Factors from Diesel Fuel with ANL GREET Factor

Howarth Diesel (original units)	CO2 only	methane		All
	g CO2/MJ LHV	g CH4/MJ LHV	g CO2e/MJ LHV GWP=82	g CO2e/MJ LHV
Upstream	15.8	0.4	33.0	48.8
Combustion	75.0	0.0	0.0	75.0
Sum	90.8	0.4	33.0	123.8

Howarth Diesel in g/MJ HHV	CO2 only	methane		All
	g CO2/MJ HHV	g CH4/MJ HHV	g CO2e/MJ HHV GWP=82	g CO2e/MJ HHV
Upstream	14.8	0.4	30.9	45.6
Combustion	70.1	0.0	0.0	70.1
Sum	84.9	0.4	30.9	115.8

Howarth Diesel in kg/MMBtu	CO2 only	methane		All
	CO2 kg/MMBtu HHV	CH4 kg/MMBtu HHV	CO2e kg/MMBtu HHV GWP=82	CO2e kg/MMBtu HHV
Upstream	15.6	0.4	32.6	48.1
Combustion	74.0	0.0	0.0	74.0
Sum	89.6	0.4	32.6	122.1

Howarth (this Study's units for GWP=28)	CO2 only	methane		All
	CO2 kg/MMBtu HHV	CH4 kg/MMBtu HHV	CO2e kg/MMBtu HHV GWP=28	CO2e kg/MMBtu HHV
Upstream	15.6	0.4	11.0	26.6
Combustion	74.0	0.0	0.0	74.0
Sum	89.6	0.4	11.0	100.6

ANL GREET for Diesel (GWP=28)	CO2 + N2O	methane		All w/o Emb.		All with Emb.
	CO2 kg/MMBtu HHV (+N2O)	CH4 kg/MMBtu HHV	CO2e kg/MMBtu HHV GWP=28	CO2e kg/MMBtu HHV	Embodied	CO2e kg/MMBtu HHV
Upstream	11.980	0.102	2.867	14.847	1.110	15.957
Combustion	74.12	0.003	0.084	74.204		74.204
Sum	86.100	0.105	2.951	89.051	1.110	90.161

Ratio Howarth / GREET for Diesel	CO2 + N2O	methane		All w/o Emb.
	CO2 kg/MMBtu HHV (+N2O)	CH4 kg/MMBtu HHV	CO2e kg/MMBtu HHV GWP=28	CO2e kg/MMBtu HHV
Upstream	130%	385%	385%	179%
Combustion	100%	0%	0%	100%
Sum	104%	374%	374%	113%

Exhibit 65: Comparison of Howarth LNG Analysis with the Study's ICF Base Case Assumptions for Similar Case

Howarth World Average Distance Case Results				
Howarth, 2-stroke engine tankers powered by LNG, 10,066 nm one-way	**CO_2 (kg/MMBtu HHV)**	**CH_4 (kg/MMBtu HHV)**	**CH_4 (CO_2e kg/MMBtu HHV, GWP=28)**	**All CO_2e (kg/MMBtu HHV, GWP=28)**
Upstream & midstream emissions	14.15	0.68	18.98	33.13
Liquefaction	7.05	0.02	0.50	7.54
Emissions from tanker	3.55	0.05	1.39	4.94
Final transmission & distribution	0.00	0.06	1.71	1.71
Combustion by final consumer	52.51	0.00	0.00	52.51
Total	**77.26**	**0.81**	**22.58**	**99.84**

ICF Results, Base Case Assumptions				
ICF Example, 10,066 nm one-way, open rack regasifier	**CO_2 (kg/MMBtu)**	**CH_4 (kg/MMBtu)**	**CH_4 (CO_2e kg/MMBtu, GWP=28)**	**All CO_2e (kg/MMBtu, GWP=28)**
Upstream & midstream emissions	4.47	0.20	5.48	9.95
Liquefaction	5.71	0.00	0.07	5.77
Emissions from tanker	6.00	0.02	0.54	6.54
Final transmission & distribution	0.24	0.00	0.10	0.33
Combustion by final consumer	52.50	0.00	0.14	52.64
Total	**68.91**	**0.23**	**6.32**	**75.23**

	Ratio Howarth to ICF			Delta Howarth minus ICF			Portion of Total Delta		
Comparison of Howarth and ICF Results	CO_2 (kg/MMBtu)	CH_4 (CO_2e kg/MMBtu, GWP=28)	All CO_2e (kg/MMBtu, GWP=28)	CO_2 (kg/MMBtu)	CH_4 (CO_2e kg/MMBtu, GWP=28)	All CO_2e (kg/MMBtu, GWP=28)	CO_2 (kg/MMBtu)	CH_4 (CO_2e kg/MMBtu, GWP=28)	All CO_2e (kg/MMBtu, GWP=28)
Upstream & midstream emissions	317%	346%	333%	9.68	13.50	23.18	39.3%	54.8%	94.2%
Liquefaction	124%	741%	131%	1.34	0.43	1.77	5.4%	1.7%	7.2%
Emissions from tanker	59%	260%	76%	-2.45	0.85	-1.60	-10.0%	3.5%	-6.5%
Final transmission & distribution	0%	1784%	516%	-0.24	1.62	1.38	-1.0%	6.6%	5.6%
Combustion by final consumer	100%	0%	100%	0.01	-0.14	-0.12	0.1%	-0.6%	-0.5%
Total	**112%**	**357%**	**133%**	**8.35**	**16.26**	**24.61**	**33.9%**	**66.1%**	**100.0%**

6.5 Comparison of ICF Results with other Coal LCA Studies

Similar to differences between LNG export studies, coal LCA results are also heavily dependent on the methodology, assumptions, and scope considered in each study. Several studies are available publicly which quantify the LCA emissions generated from the mining and transportation of coal for use in coal-fired power plants. Exhibit 66 below provides a comparison of the results of selected studies. Again, variations exist due to the origin country's methane leakage rate from mining operations, as well as the transportation distance required and assumed coal-fired power plant heat rate.

Exhibit 66: Comparison of Coal Used in Power Generation LCA Results from Various Studies

Parameter	Origin Country/Region	Destination Country/Region	GWP	*Mining/Extraction*	*Transportation*	*Power Generation*	*Total (kg CO2e/MWh)*
Pace	China	China	30	191	161	806	**1,158**
Pace	India	India	30	24	62	784	**870**
Pace	Germany	Germany	30	30	36	884	**950**
Pace	Australia	Japan	30	17	352	748	**1,117**
Pace	Australia	South Korea	30	17	346	748	**1,111**
Yin	China	China	Unknown	44	13	786	**843**
Wang	China	China	Unknown	54	13	979	**1,046**
Xiao	China	China	Unknown	110	55	761	**926**
Mallapragada 2019	India	India	-	-	-	-	**1,005**
Abrahams	China	Average	36	117	-	1,085	**1,202**
NETL 2019	China	China	36	9	11	1,065	**1,085**
NETL 2019	Europe	Europe	36	9	11	1,065	**1,085**
ICF 2020	Germany	Germany	28	48	4	1,115	**1,166**
ICF 2020	China	China	28	105	8	1,067	**1,180**
ICF 2020	India	India	28	48	6	1,067	**1,121**
ICF 2020	USA	Germany	28	152	29	1,067	**1,248**
ICF 2020	USA	India	28	152	54	1,067	**1,272**
ICF 2020	USA	China	28	34	52	1,100	**1,187**
ICF 2020	Colombia	Germany	28	70	30	1,067	**1,168**

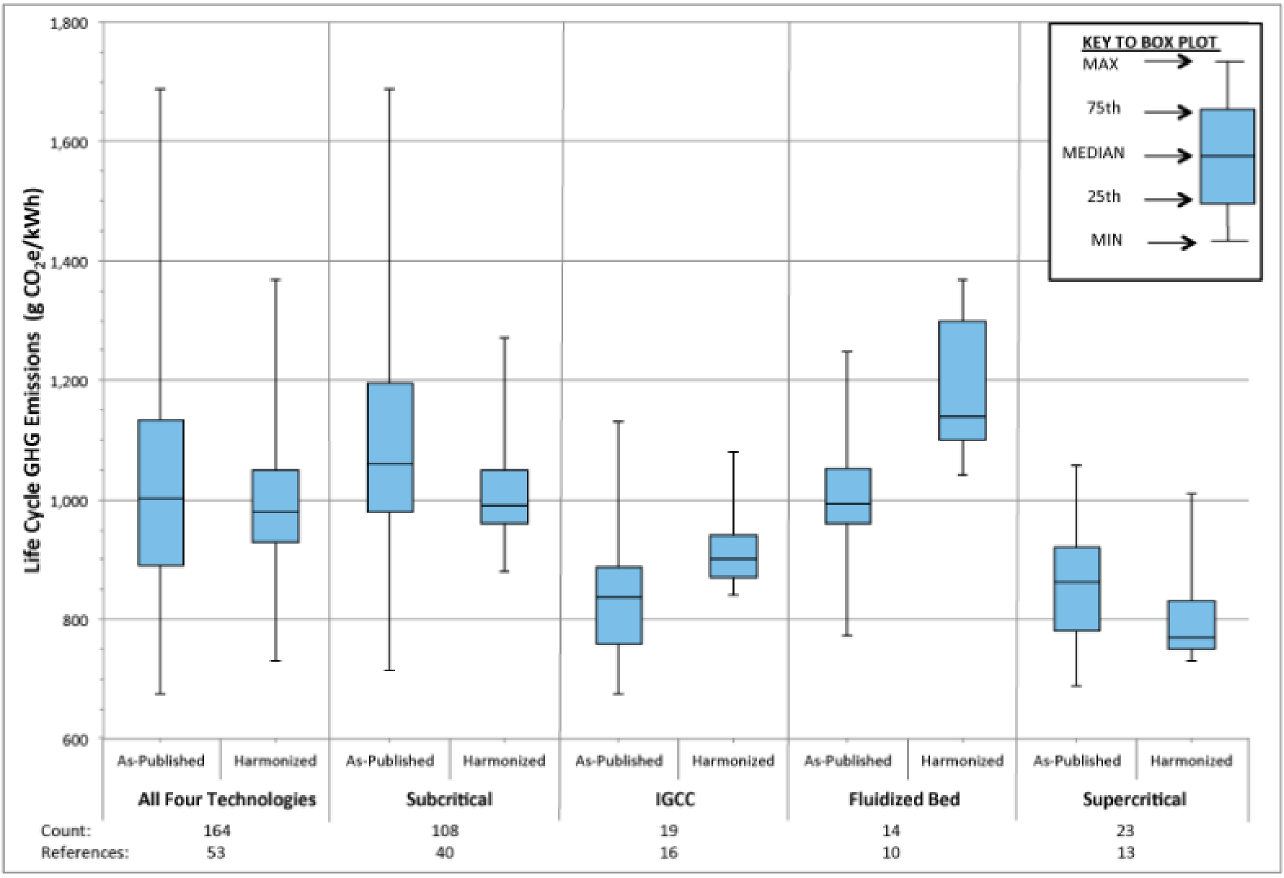
Results vary based on country specific characteristics such as assumed power plant heat rate

Note: ICF results include emissions represent new coal-fired power plants which include SO2 scrubbers.

All references for studies shown here and reviewed in this literature review are provided in Appendix A. The average LCA computed in this study under Base Case assumption and shown in Exhibit 42 is 1,023 CO_2e kg/MWh. This represents the current coal-fired fleet (mostly without SO_2 scrubbers) in countries importing US LNG

Exhibit 67 below provides another comparison of LCA results from coal power generation by technology type. The emission results shown represent a harmonization effort of LCA studies performed by the National Renewable Energy Laboratory (NREL). The median harmonized value for subcritical coal-fired steam plants (the type making up the vast majority of the world's coal fleet) is just under 1,000 CO_2e kg/MWh. This analysis is discussed in more detail in section 6.6.

Exhibit 67: LCA Study Harmonization Results by Coal-Fired Power Generation Technology Type



Source: National Renewable Energy Laboratory (NREL) Life Cycle Assessment Harmonization

6.6 Harmonization of Power Generation LCA Studies for other Fuels

The following exhibits in this section provide the results of a harmonization analysis performed by the National Renewable Energy Laboratory (NREL) for certain fuels used in power generation. This harmonization analysis reviewed hundreds of international LCA studies in order to better quantify the range of emission results determined for different power generation types. The analysis provides LCA results which have each been adjusted to reflect a consistent methodology and set of assumptions in order for proper comparisons to be made. Each figure includes the range of results by fuel and power generation technology type for all references included in the analysis.

Similar harmonization results for natural gas and coal are provided in Exhibit 60 and Exhibit 66 respectively.

Exhibit 68: LCA Study Harmonization Results by Wind Power Generation Technology Type

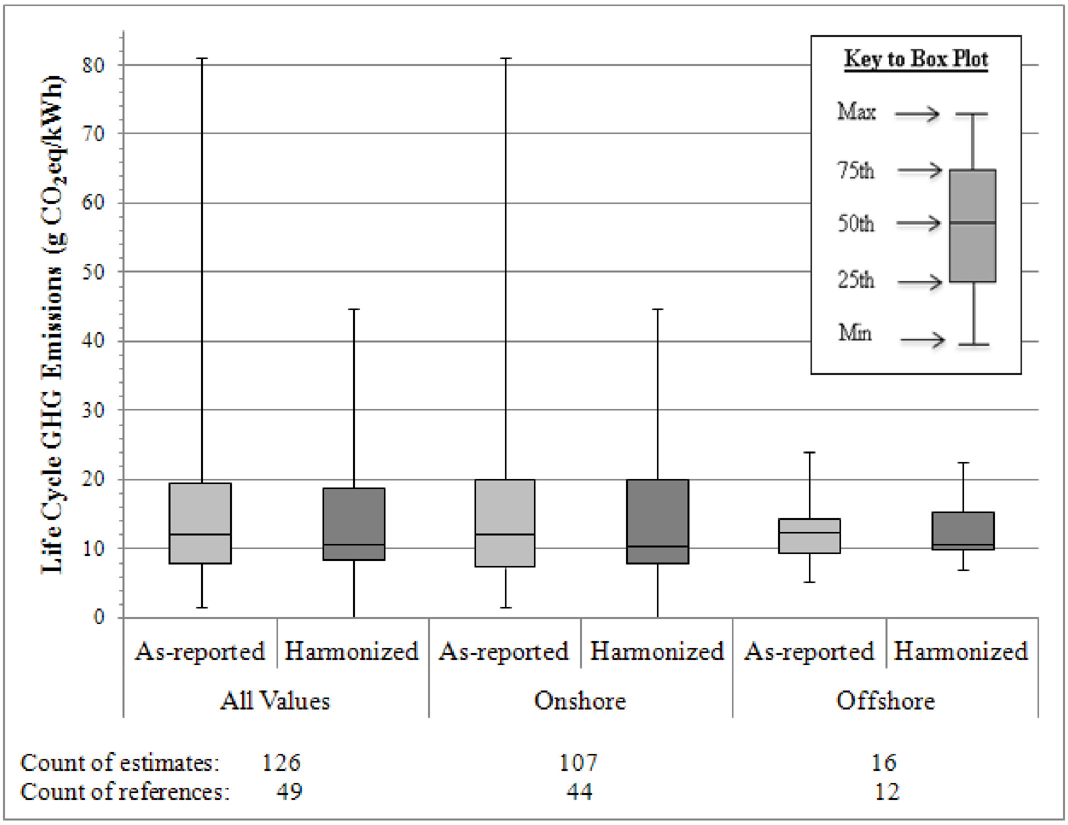


Exhibit 69: LCA Study Harmonization Results by Solar Photovoltaic Power Technology Type

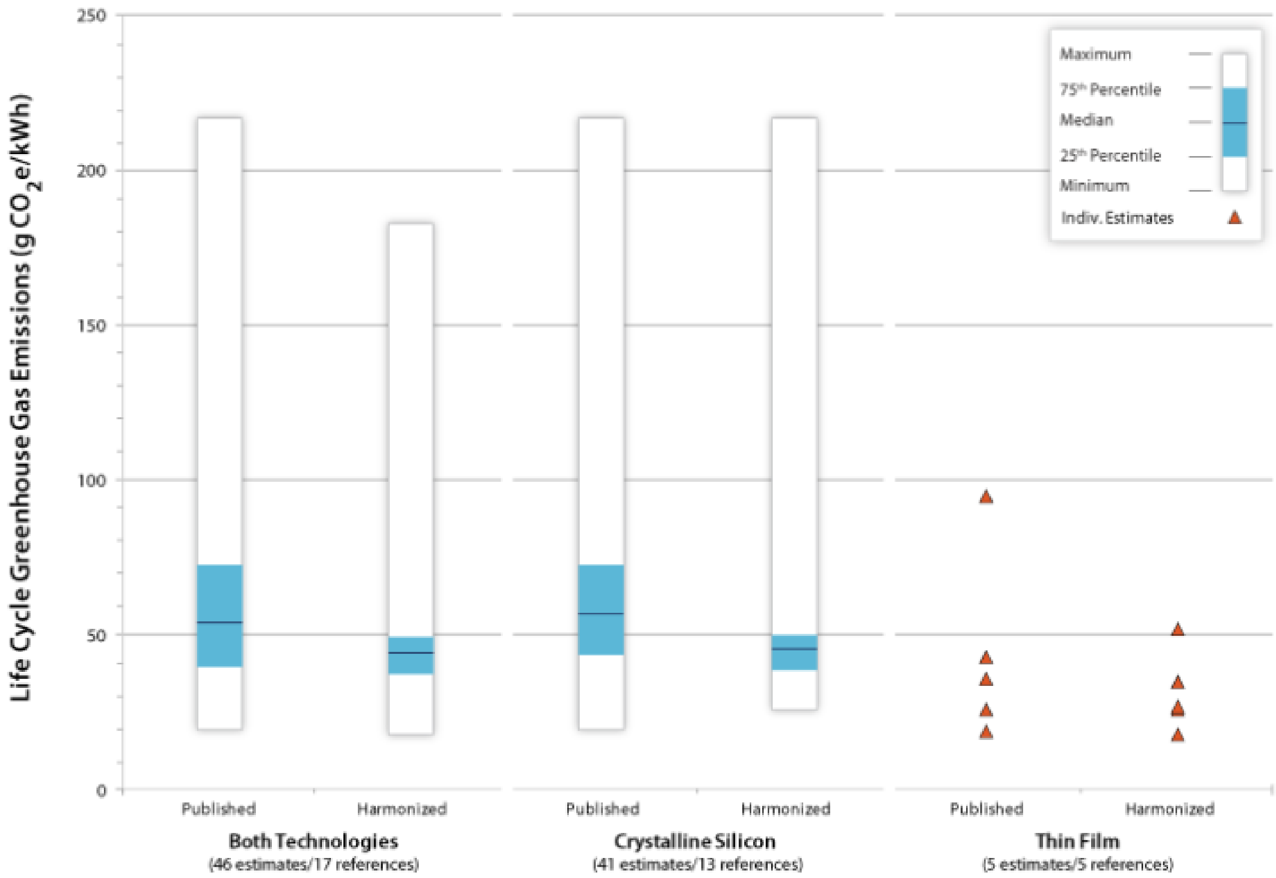
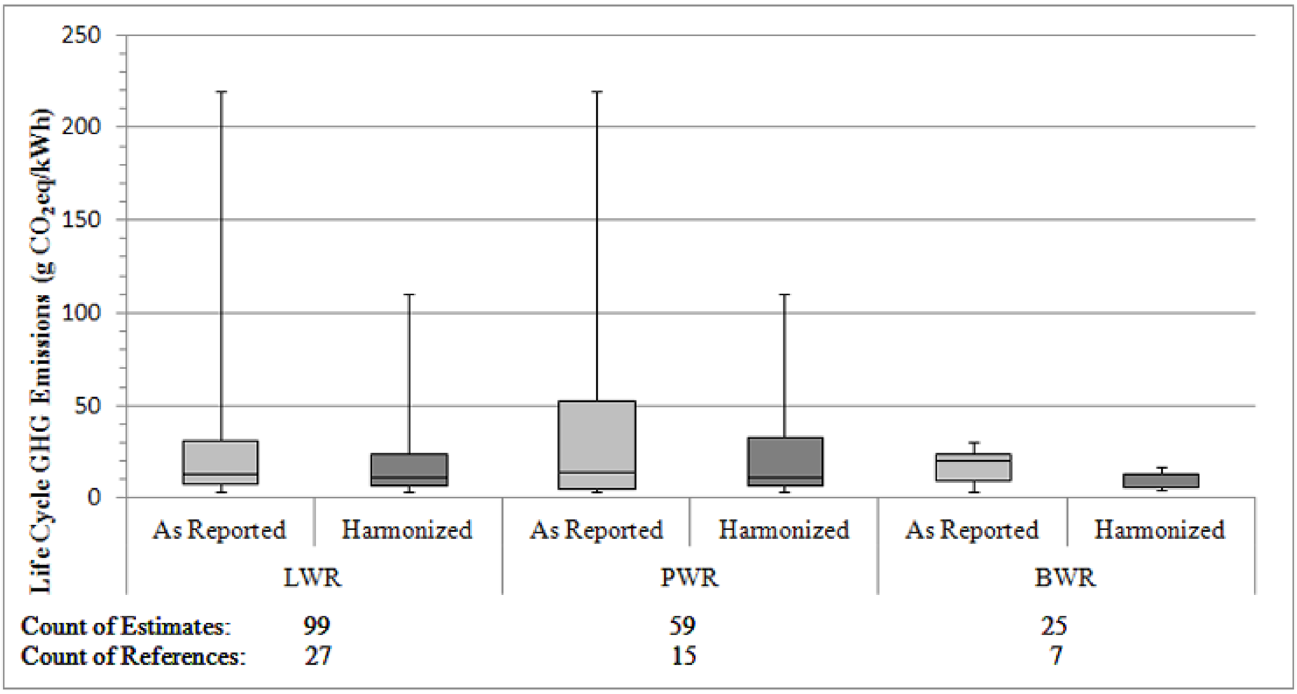


Exhibit 70: LCA Study Harmonization Results by Nuclear Power Generation Technology Type



7. Conclusions and Caveats

7.1 Conclusions

The purpose of this Study was to explain how lifecycle assessments of greenhouse gas emissions of US LNG and alternative fuels are performed and to illustrate these methods by preparing a Base Case assessment and eleven Sensitivities that tested the effects of several of the most important and uncertain LCA parameters. The Study also compiled and compared published LCA analyses performed by others and provided explanations for differences in results among various studies. The key conclusions of the Study are summarized below.

- **Complexity and uncertainties**: The supply chains for LNG and alternative fuels are complex and there are uncertainties in the value of some parameters used in their respective LCA analyses. However, the processes for conducting LCA analyses are well-established, and many credible studies exist on the GHG characteristics of natural gas, LNG and competing fuels.
- **Cases examined**: The Study uses public data to construct a Base Case and Sensitivities employing transparent, well-established calculation processes. In nearly all of the cases examined here, US LNG exports are shown to have lower lifecycle GHG emissions compared to using coal alone, fuel oil alone or the expected mix of alternative fuels that would most likely replace imported US LNG.
- **Fuel-to-fuel comparison for GHGs**: Under this Study's Base Case assumptions, shifting from US LNG to coal increases GHG emission by 47.7% to 85.9%. Shifting US LNG to fuel oil increases emissions by 24.8% to 41.8%. The low end of these ranges represent industrial uses where natural gas and alternatives have the same or very similar end-use efficiencies. The upper end of the ranges represents power plants in which natural gas often generates electricity more efficiently (that is, at lower heat rates) than coal and fuel oils.
- **Expected mix of substitute fuels**: The energy lost without US LNG exports would likely have been replaced in 2022 with 54% coal, 34% fuel oil, 16% domestic natural gas, and 8% renewable sources.
- **Comparison of GHGs to mix of substitute fuels**: Under Base Case assumptions, the net GHG impacts of US LNG would have been a reduction of 27.6 kilograms of GHG per million Btu of US LNG exports. This reduction is equal to about 38.5% of the delivered LNG's GHG emissions (71.6 CO_2e kg/MMBtu). For 2022, total reductions across all importing countries would have summed to 111.9 million metric tons.
- **GHG results of sensitivity cases**: For the eleven Sensitivities examined in this Study, the GHG reduction attributable to US LNG ranged from 8.0 to 54.0 CO_2e kg/MMBtu of exported LNG. The low end of that range (where US LNG has to lowest GHG benefits) is for the Sensitivity that combines a high methane GWP with a high methane leak rate. The high end of the range (where LNG has the highest GHG benefits) is for the sensitivity that uses all Base Case assumptions but assumes that there would not have been time or resources to increase the use renewables and waste fuels beyond what was actually achieved by 2022.
- **Comparisons to other studies are not easily made**: Comparisons among published studies are difficult because dissimilar scenarios are being examined, various underlying assumptions are different, the location or "gate" in the supply chain where GHG's are estimate is incompatible, and units of measurement are different and conversion to a common measurement unit is ambiguous.

Another significant problem is that the published studies do not always state what assumptions are being used (for example, methane GWP) so it is impossible to trace through its calculations to determine the cause of differences in results.

- **This Study agrees with most other studies**: Generally speaking, the majority of other studies reviewed here show similar results to this Study when comparing LNG with coal and fuel oil in power-plant or industrial applications.
- **Why some studies are in disagreement**: The few studies that show US LNG as having more LCA emissions than coal tend to use outlier data, apply emission factors derived from poorly documented or unsuitable sources, highlight improbable scenarios, and fail to account for relative end-user fuel efficiencies which favor natural gas. These problems lead to erroneous conclusions or -- at best -- results that are at the high end of the uncertainty range and may not be appropriate as a "best estimate" to be used for policy decisions.

7.2 Caveats

There are several limitations to this Study's scope that the reader should keep in mind. These include:

- This Study made some simplifying assumptions to make the fuel switching analysis more tractable.
  - First, the Study assumed that each LNG importing country has a homogenous natural gas market in which all sectors would see the same $/MMBtu increase in natural gas prices caused by reduced availability of US LNG and all sectors would have some demand response.
  - Secondly, the Study assumed that the loss of US LNG would not have led to changes in non-US LNG trade in terms of either an increase in total non-US LNG produced in 2022 or a change in which countries imported that LNG.
  - Thirdly, the possibility of higher natural gas prices having led to demand destruction (e.g., factories closing down and industrial production not taking place at all) or more conservation (e.g., setting thermostat to a lower temperature) was not analyzed.

  Stated in other words, the rebalancing that is assumed to have occurred due to the loss of US LNG is assumed to have taken place within each country individually by use of more domestic natural gas or the use of more domestic or imported alternative fuels (coal, fuel oil, electricity, etc.). Had other assumptions been made, this Study's calculated shifts in energy use might have occurred in different proportions among countries and sectors. This might have led to different net effects on world GHG emissions.
- The Study looked only at the year 2022 when US exports had shifted more toward Europe. Looking at different years might also have led to different patterns of energy shifts and GHG emissions.
- The Study determined the mix of fuels that are likely to have been expected to substitute for U.S. LNG in 2022 assuming normal short- to medium-term market dynamics (that is, price driven supply/demand shifts). The Study is not forward-looking and did not project emissions associated with future fuel use or fuel mixes. The Study did not address what long-term changes to fuel mix and GHG emissions could be achieved by government policies in the countries that import U.S. LNG to shift their fuel use further toward low-carbon solutions including nuclear power, solar, wind, biofuels, carbon capture and storage, certified lower-carbon fossil fuels, energy conservation, etc.
- This Study did not address the wider policy issues regarding the overall desirability of US LNG exports. Such considerations might include effects on domestic economic development and job creation, impacts on international relations including enhancing the energy security of US

European and other allies, and the long-term effects of LNG exports on US natural gas availability and prices.

Appendix A: Studies and Data Sources Reviewed for Comparison with ICF analysis

The methodologies, assumptions, and results of the following studies and databases were reviewed and compared with assumptions used in this analysis:

- *2024 US Inventory of Greenhouse Gas Emissions and Sinks; US Environmental Protection Agency (EPA)*
- *Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET); Department of Energy (DOE) Argonne National Laboratory*
- *Methane Tracker Database; International Energy Agency (IEA)*
- *Charting the Course: Reducing GHG Emissions from the US Natural Gas Supply Chain; National Petroleum Council, April 2024*
- *Comparative GHG Footprint Analysis for European and Asian Supplies of US LNG, Pipeline Gas, and Coal; BRG Energy & Climate, April 2024*
- *Call of Duties: How Emission Taxes on Imports Could Transform the Global LNG Market, Di Odoardo, Law; Wood Mackenzie, March 2024*
- *Problems with Greenhouse Gas Life Cycle Analyses of US LNG Exports and Locally-Produced Coal, Kleinberg; Center on Global Energy Policy, Columbia University, April 2024*
- *LNG Shipping Emissions Estimation Tool; Energy Emissions Modeling and Data Lab (EEMDL), University of Texas at Austin, 2024*
- *The Greenhouse Gas Footprint of Liquefied Natural Gas (LNG) Exported from the United States, Howarth; Cornell University, October 2023*
- *Oil Climate Index plus gas, OCI+; Rocky Mountain Institute (RMI), 2024*
- *Quantifying oil and natural gas system emissions using one million aerial site measurements; Sherwin, 2024*
- *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 Update; Roman-White, 2019; National Environmental Technology Laboratory, U.S. Dept. of Energy*
- *Life Cycle Greenhouse Gas Impacts of Coal and Imported Gas-Based Power Generation in the Indian Context; Mallapragada, 2019*
- *Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Liquefied Marcellus Shale Gas Used for International Power Generation; Mallapragada, 2018; Journal of Cleaner Production*
- *Country-Level Life Cycle Assessment of Greenhouse Gas Emissions from Liquefied Natural Gas Trade for Electricity Generation; Kasumu, 2018*
- *Calibrating Liquefied Natural Gas Export Life Cycle Assessment: Accounting for Legal Boundaries and Post-Export Markets; Kasumu, 2015; Canadian Institute of Resources Law*
- *A Well-to-Wire Life Cycle Assessment of Canadian Shale Gas for Electricity Generation in China; Ghandehariun, 2016*

- *Life Cycle Greenhouse Gas Emissions from U.S. Liquefied Natural Gas Exports: Implications for End Uses; Abrahams, 2015; Environ. Sci. Technology*
- *LNG and Coal Life Cycle Assessment of Greenhouse Gas Emissions; PACE Global, October 2015*
- *Life cycle assessment of coal-fired power plants and sensitivity analysis of CO2 emissions from power generation side; Yin, 2017*
- *An LCA Study of an Electricity Coal Supply Chain; Wang, 2014*
- *Comparing Chinese Clean Coal Power Generation Technologies with Life Cycle Inventory; Xiao Bin, 2011*

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