FAILING THE "CLIMATE TEST"

LNG Projects Awaiting Final Investment Decision Do Not Stand Up to U.S. Government Analysis

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Pipeline pieces awaiting installation in the Permian Basin, West Texas, 2019. Oil Change International.

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An oil well fire near Pecos, Texas, in the Permian Basin, 2019. Oil Change International

ESSENTIAL CONTEXT AND KEY FINDINGS

In December 2024, the Biden Administration's Department of Energy (DOE) issued a study of the socio-economic and environmental impacts of U.S. liquefied natural gas (LNG) exports. One volume of the study demonstrates how to estimate the increase in global greenhouse gas (GHG) emissions caused by U.S. LNG exports from individual terminals using company-specific data.

The DOE has a strong precedent of considering the GHG emissions impact of LNG terminals as part of its public interest determination required by the Natural Gas Act. While previous studies have assumed without justification that U.S. LNG exports substitute 1-for-1 with other fossil fuels, the new study uses the Global Change Assessment Model, a well-established tool, to estimate the market and energy displacement effects of increasing U.S. exports. Thus, the new study describes a more holistic approach that is better suited to assessing the climate impacts of U.S. LNG exports in a world with soaring rates of renewable energy adoption and important, albeit uncertain, climate policy influences.

The new methodology implies a "climate test" as it shows how much companies would need to reduce production-through-liquefaction GHG emissions, relative to the sector average, to be considered "climate neutral." We apply this methodology to a selection of planned projects and assess the scenarios and assumptions used.

- Applying the DOE's methodology to five planned LNG projects—Venture Global CP2, Cameron LNG Phase II, Sabine Pass Stage V, Cheniere Corpus Christi LNG Midscale 8-9, and Freeport LNG Expansion—indicates that each of them would result in a net increase in global GHG emissions regardless of the climate policy, energy demand, and technology assumptions underlying the calculation. In practical terms, all five LNG projects appear to fail a climate test that the DOE put forward to ensure approvals are consistent with the public interest.
- Sustainability measures cannot make increasing LNG exports consistent with limiting warming to 1.5°C. Even if major steps were taken to reduce the GHG emissions associated with LNG production through liquefaction—such as gas supply basin switching, LNG terminal methane abatement, and powering liquefaction with renewable electricity—increasing LNG exports from the Gulf Coast would still lead to global GHG emissions increases above the level consistent with the DOE's most stringent climate mitigation scenario.
- Under a scenario with safer and more realistic constraints on the availability of carbon capture and storage (CCS), the climate impact of increasing LNG exports would be even greater because deeper reductions in fossil fuel production would be necessary. The DOE's most conservative CCS assumption under a Net Zero scenario surpasses feasible scale-up rates based on historical technology analogues and results in gas sector CCS volumes five times higher than in the International Energy Agency Net Zero Emissions scenario.
- While the methodology presented in the 2024 LNG Study is a major improvement upon previous federal analyses, it still fails to sufficiently account for emissions from large, accidental releases (such as "super-emitter" events), equipment malfunction, and malpractice. High rates of methane emissions during the ocean transport stage of the LNG supply chain are also not represented. Incorporating measurement-based data and more realistic assumptions would make clearer the immense climate impact of building new LNG infrastructure, especially in the near-term.

Key recommendations

- The U.S. Department of Energy should use the "climate test" to reject pending and future LNG export applications. Further, the Department of Energy should use its authority under the Natural Gas Act to reevaluate the public interest status of LNG projects that received authorizations without consideration of climate impacts or under analyses that predate the 2024 LNG Study.
- Congress should pass legislation that makes it a statutory requirement under the Natural Gas Act to assess the climate impact of gas exports and reject applications that would increase global GHG emissions under a credible scenario to limit warming to 1.5°C. Additionally, U.S. federal agencies should require all new proposed fossil fuel production and infrastructure projects to meet a similarly high standard under the National Environmental Policy Act.
- Energy purchasers, financial institutions, and foreign governments should refrain from entering into long-term offtake agreements for U.S. LNG and financing of LNG infrastructure. Instead, these parties should prioritize measures that accelerate the renewable energy transition and plan for a managed phase-out of fossil fuels. Group of Seven nations, in particular, should abide by their 2022 commitment to stop financing overseas fossil fuel infrastructure with taxpayer money.
- Where it is not possible to entirely phase out gas imports, foreign parties should insist upon transparent, independent, and representative measurement-based evidence to substantiate U.S.-based claims of methane abatement (e.g., under the European Union Methane Regulation).

The liquified natural gas tanker is maneuvered by tug boats as it docks at the Calcasieu Pass LNG export terminal in Cameron, Louisiana

BACKGROUND

In December 2024, the Biden Administration's Department of Energy (DOE) published a long-awaited update to the agency's analysis of liquefied natural gas (LNG) exports. The multi-volume analysis, termed the 2024 LNG Export Study, represents the most comprehensive government assessment to-date of the energy, economic, and environmental impacts of U.S. LNG exports.

The official notice of availability of the study explains that its purpose is "to inform [DOE's] public interest review of, and ultimately decisions in, certain applications to export LNG to countries with which the United States does not have a free trade agreement (FTA) [...]"[1] In other words, the study should hold relevance to the U.S. federal government's decisions whether to issue key authorizations to major LNG projects, including both expansion projects like Cheniere Sabine Pass Stage V and new terminals like Venture Global CP2.

Among other determinations, the study found that unconstrained LNG exports would increase U.S. household and wholesale domestic energy costs, that communities near LNG facilities are overburdened with pollution, and that very large LNG projects yield higher direct lifecycle greenhouse gas emissions than many of the world's countries.[2] As explained in a statement by Secretary of Energy Jennifer Granholm, the study "reinforces that a business-as-usual approach is neither sustainable nor advisable."[3]

Introduction to the "climate test"

Perhaps nowhere is it clearer in the study how the authors intend for it to be applied than in its treatment of greenhouse gas (GHG) emissions: the study proposes a step-by-step analysis that can be applied at the project level to estimate how pending and future applications to export LNG could impact global emissions levels.[4] Further, the study provides "breakeven rates," which indicate the emissions performance that an individual project would need to achieve to be considered effectively climate neutral based on assumptions like market substitution. No other topic addressed by the study is granted this kind of project specificity.

In this report, we apply DOE's project-specific analysis to five major LNG projects that are pending final authorization: Venture Global CP2, Cameron LNG Phase II, Sabine Pass Stage V, Cheniere Corpus Christi LNG Midscale 8-9, and Freeport LNG Expansion.[5] Framing the analysis as a pass or fail "climate test," our findings make clear that none of the projects would pass muster—even with highly optimistic assumptions of facility-level flaring efficiency, upstream methane leakage rates, and downstream carbon capture and sequestration (CCS) availability. This fills a gap in the DOE's 2024 LNG Study, which demonstrates how the methodology can be used to assess hypothetical projects and presents liquefaction stage GHG emissions data for actual LNG projects that were operating in 2020, but does not carry out a full analysis of operating or proposed projects.

Salience of the analysis in a post-Trump 2.0 world

It is not lost on us that the second election of Donald J. Trump complicates what might otherwise have been a near-term shift in U.S. LNG export policy. President Trump's support for fossil fuels is expected to bring "positivity to the energy industry,"[6] and the administration has signaled that it will issue authorization decisions "as expeditiously as possible."[7] Yet, this does not guarantee the projects will succeed.[8]

LNG terminals depend on public and private financial backing, insurance, and purchase contracts, as well as authorizations issued by the U.S. government. The titanic scale of LNG terminals means they take years to build and decades to pay off. Notably, there are indications that the LNG industry is overprojecting long-term demand.[9]

What makes the climate test of the 2024 LNG Study particularly relevant is that future U.S. administrations could potentially use it to rescind LNG export applications that were rubber stamped under Trump based on more evidence-based findings of climate impact.[10] Further, many public and private LNG backers and purchasers have their own climate pledges, targets, and policies, which require consideration of climate impacts in their own right. Notable public examples include the Group of Seven (G7) pledge to end public finance for overseas "unabated" fossil fuel development, except for in "limited circumstances … consistent with a 1.5 °C warming limit and the goals of the Paris Agreement,"[11, 12] and the European Union (EU) Methane Regulation,[13] which requires that fossil fuel imports to the EU, as well as fossil fuel companies operating in the EU, meet emissions disclosure and methane abatement standards. Many private sector LNG backers possess climate commitments but have demonstrated a weak commitment to phasing out fossil fuels.[14, 15] Still, these parties should strongly consider the climate, environmental and social impacts; regulatory uncertainty; and stranded asset risk of investing in new LNG projects.

Freeport LNG, LNG facility in the United States, is located in Freeport, Texas near residential areas, outdoor recreation, and playgrounds.

EXPLANATION OF DOE'S PROJECT-LEVEL GHG ANALYSIS

The concept underpinning DOE's proposed GHG analysis is that of "consequential emissions": the change in global GHG emissions that is modeled to occur as a result of introducing incremental U.S. LNG volumes to the market. It can be understood as the difference between estimates of global GHG emissions with and without the volume of LNG under study, assuming that energy markets respond to changes in energy supply in certain ways (e.g., substituting for U.S. LNG with alternative energy sources and/or reduced energy demand).

Although the method proposed by DOE appears to be novel, the concept of substitution in global energy markets is not.[16] In fact, since 2014 every final LNG export authorization order issued by DOE has cited studies of LNG insisting that the "net" emissions impact of LNG is negative by comparison to an energy-equivalent volume of coal or foreign gas (Figure S1). Other U.S. federal agencies have also commonly used fuel displacement analyses to assess the GHG impact of projects under the National Environmental Policy Act (NEPA).[17]

What is novel about the method proposed by the 2024 LNG Export Study is that it uses scenarios modeled with the Global Change Assessment Model (GCAM) to assess the fuel displacement effects of exporting U.S. LNG, instead of assuming without justification that U.S. LNG substitutes 1-for-1 for other fossil fuels. While a full explanation of the newly proposed method is beyond the scope of this report, a high-level characterization of DOE's modeling approach and method for determining consequential emissions are provided below.

Modeling approach

In Appendix A of the 2024 LNG Study, the GCAM model is used to assess the global energy and emissions implications of increased U.S. LNG export levels under different assumptions, which characterize global climate policies and technology availability (Table 1).

Scenario design

Three global climate policies assumptions are represented: *Defined Policies*, which explicitly represents key provisions of U.S. climate policies and elsewhere in the world constrains CO_2 emissions to levels consistent with policies;[18] *Commitments*, which assumes all countries achieve their pledges under the 26th Conference of the Parties to the United Nations Framework on Climate Change; and *Net Zero 2050*, which assumes the world achieves net-zero CO_2 emissions by 2050. The global mean warming (50% likelihood) associated with the assumptions are 2.7°C, 1.6°C, and 1.4°C, respectively.

Two technology availability assumptions are represented: *High CCS*, which uses GCAM's default assumptions about CCS and carbon management alternatives; and *Moderate CCS*, which uses cost assumptions that favor wind, solar, and grid battery technologies over CCS, as well as capping global CCS levels so they do not exceed 8.7 GtCO2 by 2050 and capping global bioenergy levels to 100 EJ annually. These technology availability assumptions are combined only with the *Commitments* and *Net Zero 2050* scenarios. We note that while the *Net Zero (Moderate CCS)* scenarios are the most stringent scenarios included in the 2024 LNG Study, they still depend on CCS levels that we—and many other civil society organizations—consider problematic to accommodate the continued use of fossil fuels.[19] Specifically, they contain roughly 13–14 EJ of gas consumption equipped with CCS in 2030 and 86–91 EJ in 2050—volumes up to five times higher than the IEA's Net-Zero by 2050 scenario. These CCS assumptions are likely not feasible: research has shown that the IEA Net-

Zero scenario itself assumes an amount of CCS across all sectors in 2030 that is four times higher than the upper bound of "feasible deployment" based on historical analogue technology deployment pathways.[20]

For each set of assumptions, DOE models three scenarios with different levels of U.S. LNG exports: *Existing/FID Exports*, which constrains export levels to the capacity of LNG projects that are currently operating or planned with a final investment decision (FID); *Model Resolved,* which uses GCAM to determine economically driven levels of U.S. LNG exports; and *High Exports*, which lowers the cost of U.S. LNG such that export levels are forced above the *Model Resolved* level by a certain amount in five year increments. Qualitatively, the *High Exports* scenarios approximate strong political support for maximizing the usage of U.S. LNG export capacity, even when it is not cost-effective under default *Model Resolved* assumptions, or higher demand specifically for U.S. LNG in foreign markets.

Sensitivity cases that explore the economic competitiveness of U.S. gas in the global gas market are also executed (not shown by Table 1). These cases are characterized by *High U.S. Supply*, which makes U.S. gas more cost-competitive, *Low U.S. Supply*, which makes U.S. gas less cost-competitive, and *High Middle East Supply*, which makes gas from the Middle East region more cost-competitive.[21] By combining these assumptions with the *Defined Policies: Model Resolved* and *Defined Policies: Existing/FID Exports* scenarios, respectively, DOE obtains six sensitivity cases.

Table 1. Scenario design in the 2024 LNG Study *

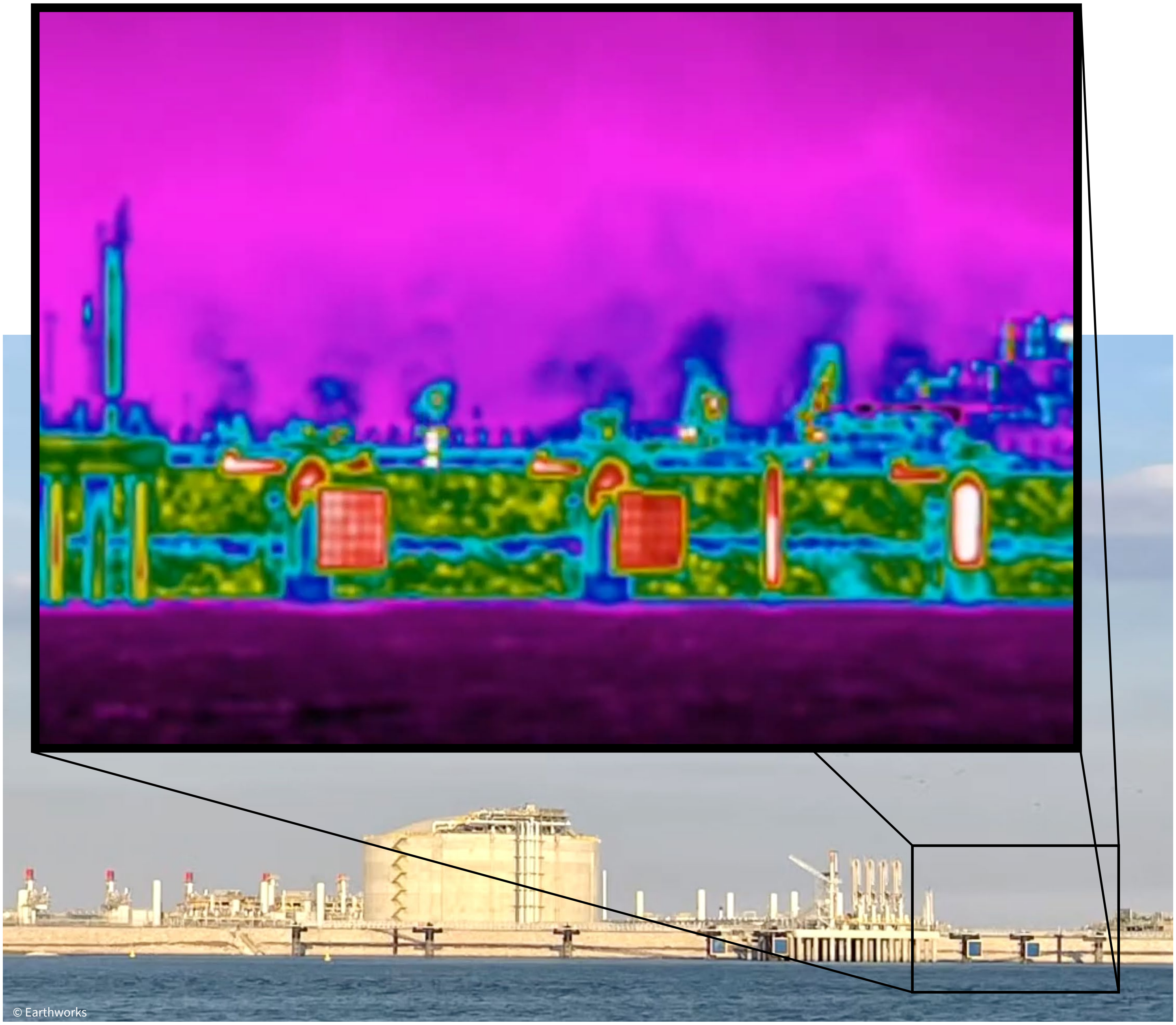
Key assumptions				
Global Climate Policies	**Technology availability [a]**	**U.S. LNG Export Levels**	**Scenario full name**	**Scenario abbreviation**
Defined Policies		Model Resolved	Defined Policies: Model Resolved	DP: MR
		Existing/FID Exports [c]	Defined Policies: Existing/FID Exports	DP: ExFID
		High Exports	Defined Policies: High Exports	DP: Hi Exp
Commitments	High CCS	Model Resolved	Commitments (High CCS): Model Resolved	C (High CCS): MR
		Existing/FID Exports	Commitments (High CCS): Existing/FID Exports	C (High CCS): ExFID
		High Exports	Commitments (High CCS): High Exports	C (High CCS): Hi Exp
	Moderate CCS	Model Resolved	Commitments (Moderate CCS): Model Resolved	C (Mod CCS): MR
		Existing/FID Exports	Commitments (Moderate CCS): Existing/FID Exports	C (Mod CCS): ExFID
		High Exports	Commitments (Moderate CCS): High Exports	C (Mod CCS): Hi Exp
Net Zero 2050	High CCS	Model Resolved	Net Zero 2050 (High CCS): Model Resolved	NZ (High CCS): MR
		Existing/FID Exports	Net Zero 2050 (High CCS): Existing/FID Exports	NZ (High CCS): ExFID
		High Exports	Net Zero 2050 (High CCS): High Exports	NZ (High CCS): Hi Exp
	Moderate CCS [b]	Model Resolved	Net Zero 2050 (Moderate CCS): Model Resolved	NZ (Mod CCS): MR
		High Exports	Net Zero 2050 (Moderate CCS): High Exports	NZ (Mod CCS): Hi Exp

* Source: Table 1. Appendix A in 2024 LNG Study. P. A-11.

a Technology availability assumptions (High CCS and Moderate CCS) are combined only with Commitments and Net Zero 2050 climate policy assumptions

b In the Net Zero 2050 (Moderate CCS): Model Resolved scenario, U.S. LNG exports fall below the existing/FID exports level. Thus, a Net Zero 2050 (Moderate CCS): Existing/FID Exports scenario would resolve to the same outcomes as the Net Zero 2050 (Moderate CCS): Model Resolved scenario, and is therefore not shown.

c Existing/FID exports refer to LNG capacity that is currently operational or LNG projects with export authorizations from DOE that have reached final investment decisions (FID) on their projects, as of December 2023.



Optical gas imaging taken by certified thermographers at Earthworks with a FLIR GF320 camera shows emissions at Calcasieu Pass LNG in Cameron, Louisiana.

Emissions impact of U.S. LNG exports

Equation 1 shows how the average consequential GHG intensity of U.S. exports is estimated for a given *Model Resolved* or *High Exports* scenario compared to the corresponding *Existing/FID* scenario.[22] There are a total of 12 *scenario n* options, including sensitivity cases, that are valid inputs to Equation 1.[23]

A negative result would indicate U.S. LNG exports reduce global emissions, as might be expected if GCAM finds that LNG primarily displaces higher emissions fuel sources, while a positive result would suggest the opposite.

$$\textit{Consequential GHG Intensity of US Exports}_{\textit{scenario n}}$$
$$= \frac{\textit{Global Emissions}_{\textit{scenario n}} - \textit{Global Emissions}_{\textit{scenario base}}}{\textit{U.S.LNG Exports}_{\textit{scenario n}} - \textit{U.S.LNG Exports}_{\textit{scenario base}}} \quad (1)$$

The following subsection explains how the *project-level* consequential GHG intensity is determined, building on the results of the GCAM analysis.[24]

Method characterization

For a given project, the consequential GHG intensity is determined by the sum of two terms, as shown by Equation 2.[25] The first term, *project direct emissions intensity*, is calculated at the project level. The second term, *project non-direct emissions intensity*, is a scenario-dependent variable that is calculated by DOE independently of the LNG project. (We adopt the convention used in the 2024 LNG Study of referring to these terms in shorthand as simply *project direct emissions* and *project non-direct emissions* in most places.)

$$\textit{Consequential GHG Intensity of US Exports}_{\textit{scenario n, project p}} = \textit{Project Direct Emissions}_{\textit{project p}} + \textit{Project Non-Direct Emissions}_{\textit{scenario n}} \quad (2)$$

where:

Project direct emissions include liquefaction emissions and all upstream emissions of producing and processing the natural gas before liquefaction, and;

Project non-direct emissions include emissions not included in the definition of emissions. This includes direct emissions from ocean shipping, regasification, importing country transport of the gas, and use (unspecified) of the export gas, plus the direct and indirect market effects. For many scenarios the term is negative, owing to fossil fuel displacement.

If the two terms balance out, the consequential GHG intensity associated with the project under evaluation is estimated to be zero.

Derivation of the project non-direct emissions term

Project non-direct emissions are calculated by subtracting the *average* project direct emissions from the consequential GHG intensity of U.S. exports for a given scenario, as shown by Equation 3.[26] Project non-direct emissions are negative for scenarios where the consequential GHG intensity of LNG exports modeled by GCAM is smaller than the average project direct emissions. The DOE's explanation of project non-direct emissions specifies that it is an "interim value [...] and should not be used as the basis for interpreting study findings."[27]

$$\textit{Project Non-Direct Emissions}_{\textit{scenario n}} = \textit{Consequential GHG Intensity of US Exports}_{\textit{scenario n}} - \textit{Project Direct Emissions}_{\textit{average}} \quad (3)$$

where:

Consequential GHG intensity of US exports is the result of Equation 1, and;

Average project direct emissions are estimated by DOE using a combination of self-reported data and bottom-up modeling. For the upstream through transmissions segment, DOE uses the U.S. average GHG intensity of domestic natural gas (production through transmission), as determined by the DOE/NETL Life Cycle Analysis of Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile study, published in 2024 (*2024 LCA Study*).[28, 29] For liquefaction stage emissions, DOE uses U.S. Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program (GHGRP) data for the year 2020 and gap-filling adjustments to estimate the production weighted average liquefaction stage GHG intensity of six LNG terminals.[30] The result obtained by DOE, 14.5 g CO2e/MJ of exported LNG (low heating value [LHV] basis), is held constant across all scenarios.

Project-level inputs

At the project level, estimates of the emissions intensity of LNG from gas production through liquefaction are summed to determine the project direct emissions term of Equation 2. The calculation of this term can be divided into three steps:

1. Estimate production through transmissions GHG emissions (i.e., GHG emissions up to the terminal gate);
2. Estimate liquefaction stage emissions (gate to gate);
3. Align emissions to a common functional unit and take the sum.

The final step produces the estimated project direct emissions term that is added to project non-direct emissions in Equation 2 to calculate the project-level consequential GHG intensity of LNG exports.

Determination of breakeven rates

DOE also uses a comparison of the average project direct emissions and project non-direct emissions terms under each scenario to calculate "breakeven rates," or "the percent change difference between an individual project's emissions intensity and the default assumptions that would result in consequential GHG intensity of zero for the project" (Equation 4).

$$\text{Breakeven Rate}_{\text{scenario } n} = \frac{-(\text{Project Non-Direct Emissions}_{\text{scenario } n})}{\text{Project Direct Emissions}_{\text{average}}} - 100\% \quad (4)$$

For example, the Defined Policies: Model Resolved scenario has a breakeven rate of -43%, which is the percent change from 14.5 g CO2e/MJ, the average project direct emissions, to 8.2 g CO2e/MJ, the project direct emissions level that would result in zero consequential emissions under the Defined Policies: Model Resolved scenario. (This project direct emissions level results from setting the consequential GHG intensity term to zero in equation 3, noting that -8.2 g CO2e/MJ is the project non-direct emissions value for Defined Policies: Model Resolved.)

In the subsequent section of this report, we first calculate the project-level inputs to DOE's consequential emissions analysis for five LNG projects. We then compare the project direct emissions of each LNG terminal to the breakeven rates associated with all 12 scenarios. Finally, we examine the consequential GHG intensity of each project based on the Defined Policies: Model Resolved scenario—the dominant scenario used in the 2024 LNG Study—and the Net Zero (Moderate CCS): High U.S. Exports scenario—the scenario with the deepest emissions reductions and least reliance on CCS and biofuels in the 2024 LNG Study.

Drilling rigs at a hydrofracking installation near Westhoff, Texas.

APPLYING THE CLIMATE TEST TO FIVE PROPOSED LNG PROJECTS

Using the methodology laid out in the 2024 LNG Study, we assess five proposed LNG projects that are currently not authorized to export LNG to non-FTA countries and do not have an FID.[31] The annual emissions associated with these projects cannot be determined with certainty, in part because the projects are as-of-yet unbuilt. Therefore, we assume that the GHG intensity of these projects is well-represented by existing LNG terminals, as shown by Table 2.

For all the terminals except Venture Global Calcasieu Pass, we use data from the reporting year 2020 to align with the calculations used in the 2024 LNG Study. For Calcasieu Pass, which exported its first LNG cargo in March 2022, we use data from the reporting year 2023.

The 2024 LNG Study expresses combined GHG emissions using IPCC AR6 100-year global warming potential (GWP) values by "default" and 20-year GWP values where otherwise noted.[32] Our results are expressed using only 100-year GWP values. We note that in the 2024 LNG Study, using 20-year values increases the average project direct emissions of U.S. exports but tends to reduce the difficulty of the climate test. This is because using a 100-year value emphasizes the effect of U.S. LNG exports driving up net fossil fuel demand, which is very difficult to offset through methane abatement, whereas using a 20-year value emphasizes the mitigation potential associated with methane reductions. Using a 20-year value also amplifies flaws in the DOE methodology, which disproportionately underestimates methane emissions by failing to sufficiently account for large, accidental releases, equipment malfunction, malpractice, and methane slippage across various stages of the LNG supply chain (as explained in Section 5. Weaknesses of the 2024 LNG Study emissions calculation).

In this section, we use the names of the proxy terminals in all figures and tables. We emphasize, however, that the emissions results should be considered representative of the five proposed LNG projects that are awaiting final non-FTA export authorization and FID.

Table 2. Proposed/not authorized LNG projects and proxy terminals used to estimate their respective life cycle GHG emissions intensities

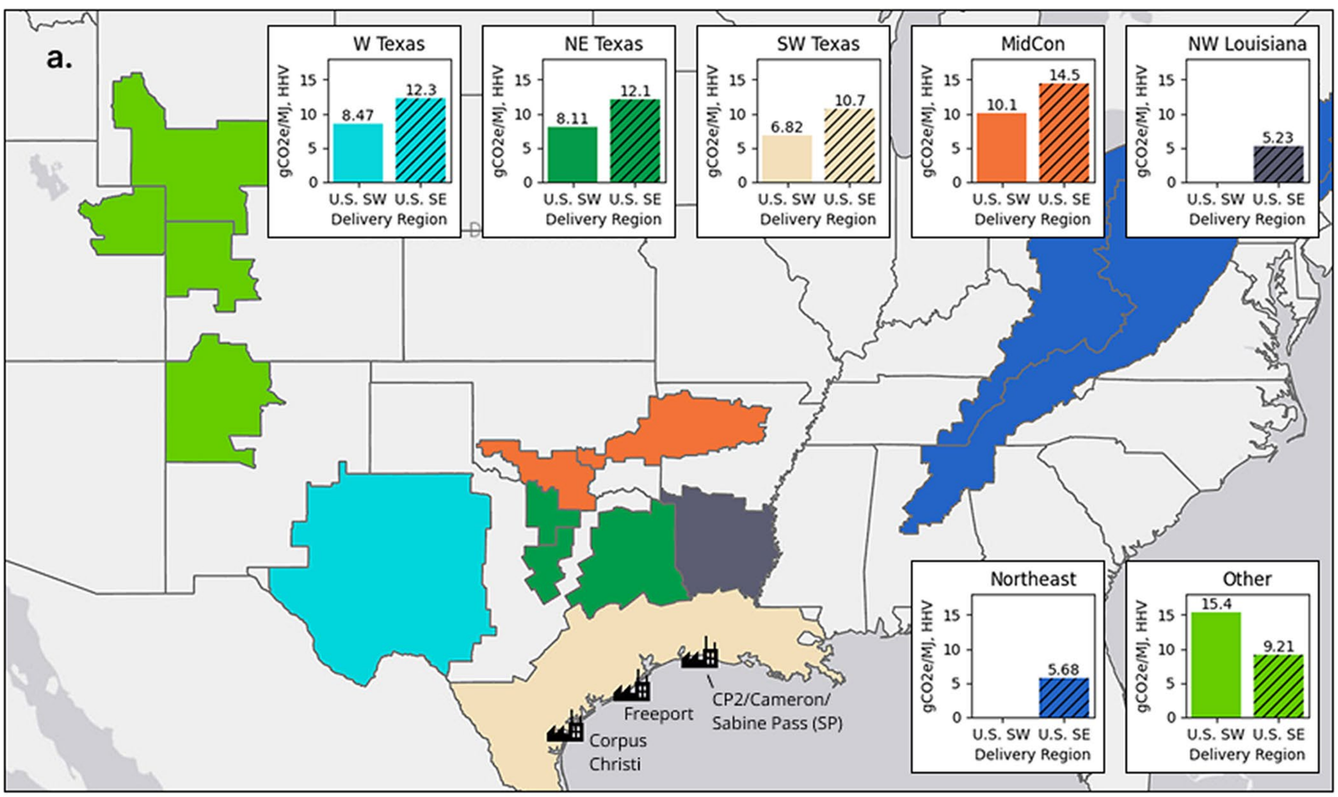
Proposed LNG project	Proxy terminal (and reporting year)
Venture Global CP2	Venture Global Calcasieu Pass (2023)
Cameron LNG Phase II	Cameron LNG, LLC (2020)
Sabine Pass Stage V	Sabine Pass LNG Terminal (2020)
Cheniere Corpus Christi LNG Midscale 8-9	Corpus Christi Liquefaction (2020)
Freeport LNG Expansion	Freeport LNG (2020)

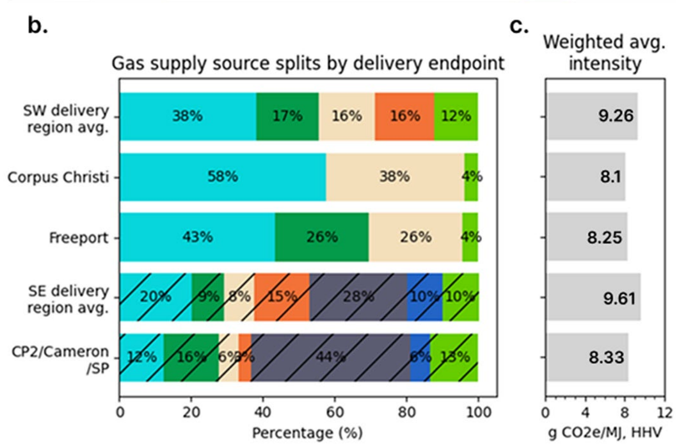
Step 1: Estimate production-through-transmission GHG emissions

We obtained gas supply sourcing estimates by LNG terminal from RBN Energy, a well-reputed energy markets analytic firm that operates a proprietary model of methane gas production, demand, and flows.[33] We obtained estimates of production-through-transmission GHG intensity by gas production scenario and gas delivery region pair from the 2024 LCA Study. In the 2024 LCA Study, each gas production scenario represents gas production from a given basin using a given extraction technology.

Using a crosswalk (Table S1), we mapped the gas supply source regions used by RBN to the gas production scenarios used by DOE and calculated the weighted average GHG intensity by gas supply source and delivery region pair, and the weighted average GHG intensity by delivery region overall. Further, we used the crosswalked 2024 LCA Study data and the LNG terminal sourcing estimates from RBN to calculate the weighted average GHG intensity by LNG terminal. These data are expressed with a functional unit of 1 MJ of gas, high heating value (HHV) basis, delivered to the LNG terminal gate in Figure 1.

Figure 1. Production-through-transmission GHG intensity by gas supply source and delivery region, and weighted average intensity per select delivery region and LNG terminal





a. Map of gas supply regions with bar charts showing production-through-transmission GHG intensiity by gas supply and delivery regioin. Icons show location of LNG terminals. **b.** Gas supply source splits by delivery endpoint (LNG terminal or delivery region average). **c.** Weighted average productioin-through-transmissiion GHG intensity by delivery endpoint (LNG terminal or delivery region average).

Step 2: Estimate liquefaction stage emissions

We obtained liquefaction stage GHG emissions intensity values for Cheniere Corpus Christi, Freeport LNG, Cameron LNG, and Sabine Pass from the 2024 LNG Study. DOE based these values on company-reported data from the Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program (GHGRP), 2020 reporting year. To account for "known data gaps with regards to natural gas liquefaction facilities, including not accounting for GHG emissions from acid gas removal units (AGRU) and electricity consumption for compressors," and "minor differences in the combustion factors used in the calculation of emissions from GHGRP Subpart C data and those used by NETL in its LNG modeling," DOE applied several adjustments to the company-reported data. DOE also converted the GHGRP emissions data from AR4, 100-year values to AR6, 100-year values.

Notably, DOE did not incorporate reported emissions data from the Freeport LNG Pretreatment facility into its analysis. By our assessment, using these data would have increased Freeport LNG's liquefaction stage GHG emissions by around 630,000 t CO_2e.[34]

For Venture Global Calcasieu Pass, which was not included in the 2024 LNG Study because it did not export its first cargo until March 2022, we estimate liquefaction stage GHG emissions using the approach laid out in the 2024 LNG study based on company-reported emissions data from the EPA GHGRP, 2023 reporting year (for calculation details, see Section S1).

Estimated liquefaction stage emissions are shown in Table 3 and expressed with three different functional units: 1 kg of LNG exported, 1 MJ of LNG exported (HHV), and 1 MJ of LNG exported (lower heating value [LHV] basis).

Table 3. Liquefaction stage GHG intensity by LNG terminal

Terminal	GHG emissions (t CO2e)	LNG Mass Exported (Mg)	kg CO2e/ kg LNG	g CO2e/ MJ LNG HHV	g CO2e/ MJ LNG LHV
Venture Global Calcasieu Pass †	2,955,440	9,871,086	2.99E-01	5.51E+00	6.11E+00
Cameron LNG, LLC *	3,182,562	7,767,049	4.10E-01	7.54E+00	8.36E+00
Sabine Pass LNG Terminal *	4,394,024	18,667,328	2.35E-01	4.33E+00	4.80E+00
Corpus Christi Liquefaction *	1,831,780	7,969,529	2.30E-01	4.23E+00	4.69E+00
Freeport *	1,825,509	8,486,405	2.15E-01	3.96E+00	4.39E+00

* Source (all data in indicated rows): Table 12. Appendix C in 2024 LNG Study.

† Source: Greenpeace USA analysis of Venture Global LNG. U.S. EPA Greenhouse Gas Reporting Program (Data Year 2023). For calculation details, see Section S1.

Step 3: Align emissions to common functional unit

To calculate the total project direct emissions per LNG terminal, the GHG intensity values from Figure 1 and Table 3 need to be converted to the same functional unit and summed. To match the 2024 LNG Study, we use 1 MJ of LNG exported on a lower heating value (LHV) basis as the final unit[35] and assume that around 1.07 kg of methane gas are delivered to the liquefaction plant per 1 kg of gas throughput from the plant.[36]

For each LNG terminal, Table 4 shows the aligned production-through-transmission and liquefaction stage results, the sum total project direct emissions, and the percent change difference between the individual terminal's GHG intensity and the average project direct emissions value, 14.5 g CO2e/MJ, determined by the 2024 LNG Study.[37]

Table 4. Summary of Project Direct Emissions by LNG terminal

	GHG intensity (g CO2e/MJ LNG, LHV)			
Terminal	**Production through transmission**	**Liquefaction stage**	**Total Project Direct Emissions *Sum of previous two columns***	**Percent change difference from default Project Direct Emissions (14.5 g CO2e/MJ)**
Venture Global Calcasieu Pass	9.87E+00	6.11E+00	1.60E+01	+10.21%
Cameron LNG, LLC	9.87E+00	8.36E+00	1.82E+01	+25.73%
Sabine Pass LNG Terminal	9.87E+00	4.80E+00	1.47E+01	+1.18%
Corpus Christi Liquefaction	9.60E+00	4.69E+00	1.43E+01	-1.43%
Freeport	9.78E+00	4.39E+00	1.42E+01	-2.31%

Step 4: Compare to benchmarks and estimate consequential GHG intensity

The percent change difference between each LNG terminal's GHG intensity and the default value can be directly compared to breakeven rates to assess whether exports from the terminal would result in a consequential GHG intensity above or below zero. Figure 2 illustrates this comparison for all LNG terminals in our analysis.

In Figure 2, the height of each bar represents the GHG intensity of the respective terminal expressed as percent change from the default value. In order to have a consequential intensity of zero or lower relative to a given scenario, the bar representing a terminal must cross the dashed line representing the given scenario's breakeven rate (ranging from -8% to -87%). This condition is not met for any of the terminals under any scenario.

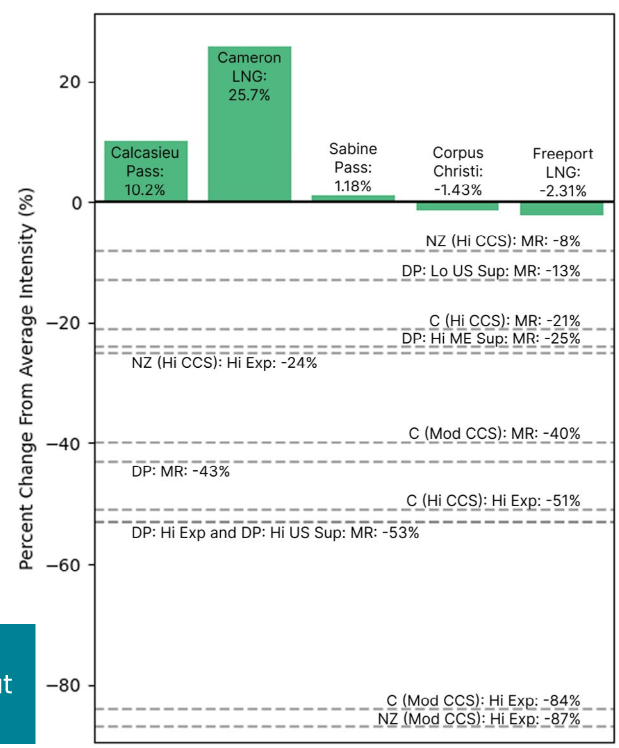


Figure 2. GHG intensity by LNG terminal, expressed as percent change from the default GHG intensity, vs. breakeven rates that would result in zero consequential emissions by scenario

Table 5 shows the consequential GHG intensity of each LNG terminal under the Defined Policies: Model Resolved and Net Zero (Moderate CCS): High Exports scenarios. As stated on page 13, the latter scenario is highlighted because it is the DOE scenario with the deepest emissions reductions and least reliance on CCS and biofuels, and the former scenario is shown because it is the dominant scenario used in the 2024 LNG Study.

For the Defined Policies: Model Resolved scenario, the terminals are each estimated to have a consequential GHG intensity ranging from 5.97 to 10.0 g CO2e/MJ. For the Net Zero (Moderate CCS): High Exports scenario, the values range from 12.3 to 16.3 g CO2e/MJ.

Table 5. Calculation table and consequential GHG intensity results by LNG terminal for (1) Defined Policies: Model Resolved and (2) Net Zero (Moderate CCS): High Exports

		(1) Defined Policies: Model Resolved vs. Existing/FID		(2) Net-Zero (Moderate CCS): High Exports vs. Existing/FID	
LNG Terminal	**Project Direct Emissions**	**Project Non-Direct Emissions**	**Consequential GHG emissions** ***Sum of Project Direct and Project Non-Direct Emissions***	**Project Non-Direct Emissions**	**Consequential GHG emissions** ***Sum of Project Direct and Project Non-Direct Emissions***
Venture Global CP2	1.60E+01	-8.2	7.78E+00	-1.9	1.41E+01
Cameron LNG Phase II	1.82E+01	-8.2	1.00E+01	-1.9	1.63E+01
Sabine Pass Phase V	1.47E+01	-8.2	6.47E+00	-1.9	1.28E+01
Cheniere Corpus Christi LNG Midscale 8-9	1.43E+01	-8.2	6.09E+00	-1.9	1.24E+01
Freeport LNG	1.42E+01	-8.2	5.97E+00	-1.9	1.23E+01

All assessed LNG projects fail the climate test

All five LNG terminals we assess using the DOE's methodology fail to achieve a GHG intensity equivalent to or lower than the breakeven rates presented in the 2024 LNG Study. In equivalent terms, there are no scenarios assessed by the DOE under which increasing LNG exports from these terminals (or similar terminals) would result in climate benefits. We surmise that if the DOE were to apply a "climate test" to the five proposed projects named in Table 2, consistent with the 2024 LNG study, all five of the projects would fail.

This conclusion holds true regardless of whether the LNG projects are evaluated against scenarios that accelerate climate change mitigation or not. Likewise, it holds true even for the DOE's *High CCS* scenarios, under which CCS deployment is unconstrained. Further, the climate impact of U.S. exports is shown to be higher when U.S. export levels are buoyed by political support, as in the *High Exports* scenarios, rather than driven by default economic assumptions, as in the *Model Resolved* scenarios.

Although the *Moderate CCS* scenarios do not sufficiently limit CCS dependence to resolve our concerns about feasibility, mitigation deterrence, and social/environmental sustainability, they show that the climate impact of U.S. exports is much greater when CCS levels are reduced. Under a scenario with safer and more realistic constraints on the availability of CCS, the climate impact of U.S. exports would be even greater because deeper reductions in fossil fuel production would be necessary. Still, in the absence of a more ambitious alternative, we use the *Net Zero (Moderate CCS)* scenario as a reference for the next section of this report and recommend for policymakers to likewise use this scenario as a default reference with an understanding of its limitations.

Flaring from the Venture Global Calcasieu Facility is visible for miles in the night sky.

CLEANER PRODUCTION CANNOT MAKE LNG 1.5ºC ALIGNED

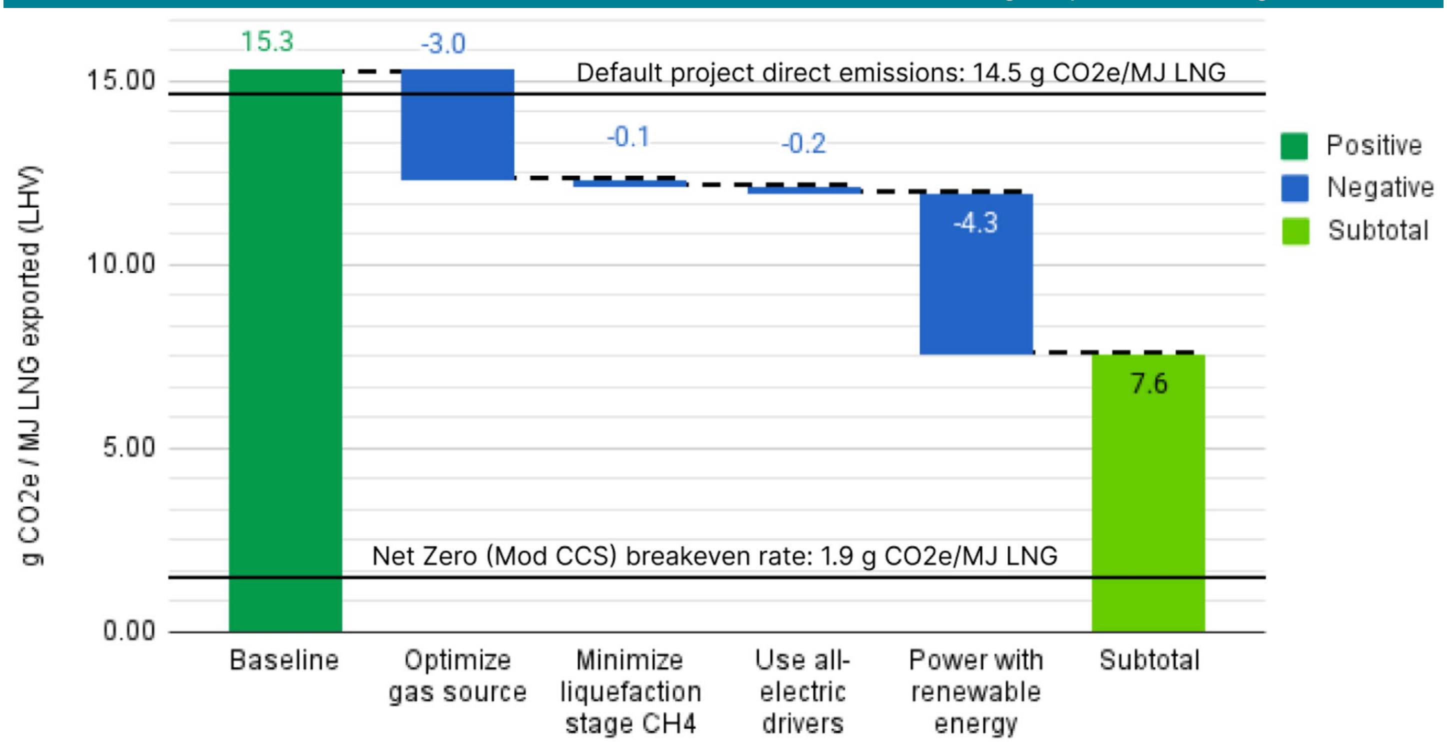
Even if major steps were taken to reduce the GHG emissions associated with LNG production through liquefaction, LNG projects along the Gulf Coast would continue to fail the breakeven analysis under the Net Zero (Moderate CCS) scenario.

Figure 3 shows how the production weighted average GHG intensity of U.S. exports from the five LNG terminals under study would change as a result of the following four measures:

1. **Optimizing gas supply.** LNG operators purchase gas from only the lowest GHG intensity supply source region (Southwest Texas for the Southwest delivery region and Northeast Louisiana for the Southeast delivery region);
2. **Minimizing liquefaction stage CH_4.** LNG operators eliminate all liquefaction stage methane emissions associated with flaring inefficiencies, equipment leaks, and blowdown methane emissions;
3. **Using all-electric drivers.** LNG operators use all-electric drivers to power liquefaction, substituting grid-factor power generation for gas combustion at the terminal;
4. **Powering with renewable energy.** LNG operators use high-integrity renewable energy (i.e., 24/7 time matching and additionality criteria met) to power liquefaction.

For calculation details and a full explanation of the analysis, see Section S3.

Figure 3. Key mitigation steps do not close the gap between average LNG project GHG intensity and breakeven rate. Dark green bar shows weighted average project direct GHG emissions based on analysis in this report. Blue bars show weighted average reduction potential from four key mitigation steps. Light green bar shows weighted average project direct GHG emissions if all mitigation steps are implemented. Horizontal line shows the breakeven rate associated with NZ (Mod CCS): High Exports v. Existing/FID.



At a maximum, these measures could change the GHG intensity of U.S. exports by -48% compared to the default value estimated by the DOE; however, the breakeven rate for the Net Zero (Moderate CCS) scenario is -87%. The magnitude of this difference, even after all mitigation steps have been taken, suggests that no realistic mitigation can make U.S. LNG exports aligned with limiting warming to 1.5ºC. This reflects that while emissions performance both upstream of the LNG facility and at the facility itself are important, the net increase in global GHG emissions caused by increasing LNG exports is primarily due to the manner in which they displace renewable energy and drive up overall energy demand.

There are caveats to this optimization analysis, which reflect both limitations in the data and questions about the effectiveness of corporate sustainability practices at generating real-world emissions reductions and avoiding adverse impacts. First, methane emissions are likely underestimated in both the baseline and emissions savings estimates due to DOE's reliance on bottom-up and company-reported data. Second, because U.S. gas travels through a network with limited physical traceability, there is a risk that gas purchased by LNG companies to mitigate emissions would reflect the trade of virtual attributes without impacting the broader mix of gas production. Similarly, it is well-known that some renewable energy procurement strategies are unlikely to increase the amount of renewable energy on grids.[38] Third, we note that electrifying liquefaction processes without building out an attendant supply of renewable energy would likely increase the use of dispatchable fossil fuel power sources on the grid and increase costs for other energy users. Fourth, a consideration of climate justice suggests that renewable energy must be viewed as a valuable public good to be used wisely and that positioning renewable energy as a tool to continue fossil fuel extraction in the global North is highly problematic.[39]

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A flare is visible in front of steam rising from the Quail Run Energy Center and the Odessa Actor Power Plant in Odessa, Texas.

WEAKNESSES OF THE 2024 LNG STUDY EMISSIONS CALCULATION

The 2024 LNG Study uses GCAM, a well-established model, to examine the impacts of increased LNG exports on global energy balances and emissions, which substantially improves the agency's assessment of the life cycle emissions of U.S. LNG exports by accounting for how LNG interacts with energy demand in destination markets. However, significant shortcomings remain in the DOE's approach, which suggest underestimation of the GHG emissions impact of U.S. exports.

Systematic underestimations and optimistic assumptions

Many peer-reviewed studies indicate gas sector production-through-transmission emissions are higher than DOE's assumption of a 0.56% methane emissions rate—a rate which could underestimate such emissions by a factor of four or more (Table S2). It is more challenging to assess liquefaction stage emissions due to the potential for companies to under-report emissions, wide range of flaring efficiency rates in the scientific literature, high temporal variability, and shortage of independent measurements. DOE's proposed approach does not sufficiently mitigate these factors and results in an average estimated liquefaction stage methane rate on the lower side of published research—0.316 g CH_4/kg LNG (0.00645 g CH_4/MJ LNG, LHV).[40] This matters because it is logical to assume that if the emissions from producing and liquefying LNG are greater, the consequential emissions of LNG exports are also greater.[41]

Two recent peer-reviewed, large-scale, aerial measurement-based studies indicate leakage rates ranging from 2-2.95% of gross oil and gas production.[42, 43] Likewise, DOE's basin-level methane intensity estimates are very low compared to measurement-based estimates. For example, measurement-based estimates assessed by DOE are roughly 2 to 7 times higher for the Permian basin and 3 to 4 times higher for the Anadarko basin.[44] One major reason for DOE's low emissions estimate is its "bottom-up" methodology, primarily based on company data self-reported to the EPA. This approach assumes equipment is operated and performs according to theoretical or manufacturer's specifications and has been criticized for failing to account for malpractice, malfunction, and accidental releases. In particular, bottom-up estimates fail to capture the effect of large, so-called "super-emitter," events.[45, 46, 47]

Similarly, DOE relies on company-reported liquefaction emissions, which are extremely variable and seemingly implausible to validate without frequent, independent measurements. For example, a 2021 Clean Air Task Force report found the largest source of methane emissions from LNG import, export, and storage "appears to be irregular venting from blowdowns, which represents over 80% of emissions in estimates."[48] Yet, DOE's analysis assumes emissions from a single year are representative of the average, but this is not the case due to huge year-to-year fluctuations in reported blowdown methane emissions. For example, total blowdown methane emissions reported in 2020 were <5% of blowdown methane emissions reported by Freeport LNG alone in 2016.[49, 50]

DOE estimates flaring-related emissions based on company-reported flare gas volumes and an assumed 98% efficiency rate. However, a peer-reviewed study published in 2023 found flare efficiency rates were highly variable and contingent on operating conditions: four of six flares assessed under normal conditions had efficiency rates lower than 98%, two of which were lower than 60%.[51] A 2015 literature review of liquefaction terminal methane intensity found a range spanning 0.01 to 4.22 g CO_2e/MJ HHV.[52] DOE's study does not reference these academic sources, yet includes favorable comparisons to two studies funded by Cheniere and partially conducted by Cheniere engineers.[53, 54]

Characterization of Permian gas

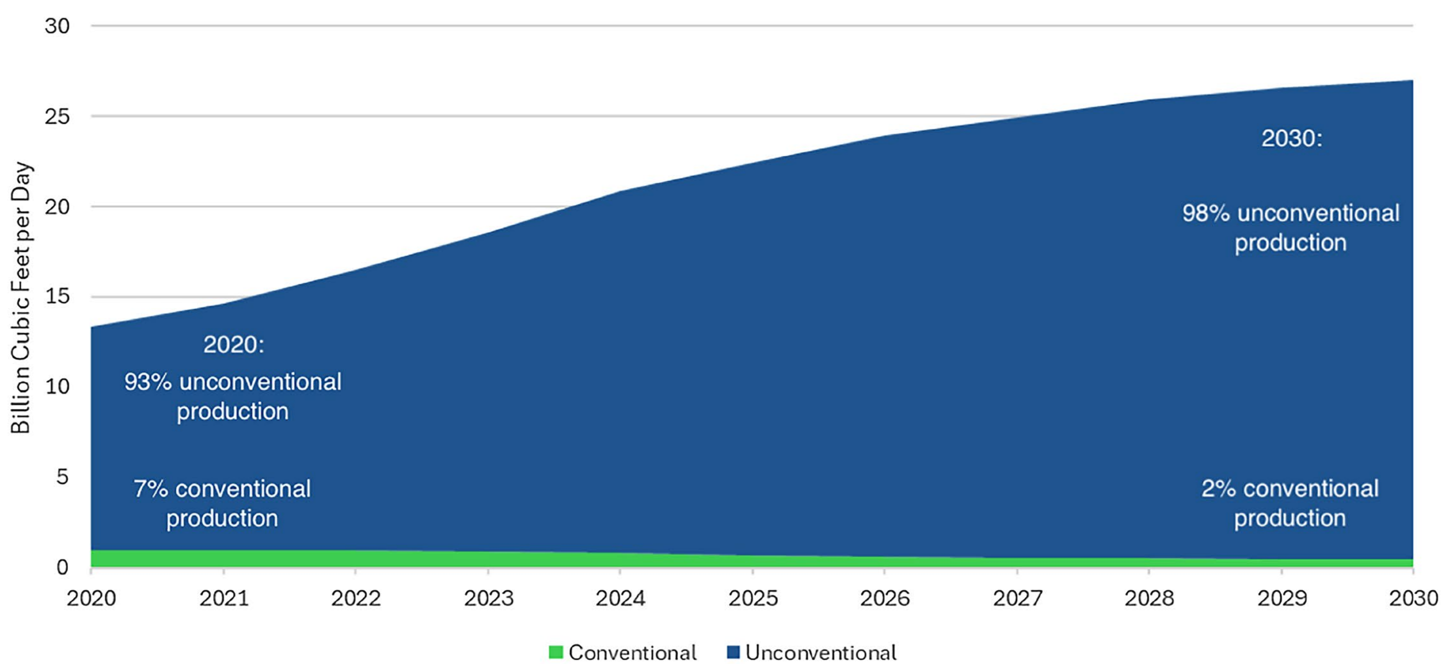
The DOE may drastically overestimate the proportion of Permian gas that is extracted with "conventional" technology, which is treated as having lower emissions than shale gas extracted with fracking and horizontal drilling.[55] Whereas the 2024 LCA Study, on which the DOE study bases its estimates of upstream methane emissions, indicates that 58% of Permian gas production was conventional in 2020,[56] Rystad Energy Ucube data categorizes just 7% of Permian gas production in 2020 as conventional (Figure 4).[57] Rystad services are widely used by oil and gas industry professionals and track production from over 60,000 assets globally.

Rystad data further show that the proportion of conventional production in the Permian Basin is decreasing: conventional production fell to 4% of total gas production in 2024 and is projected to be just 2% by 2030 (Figure 4).

The DOE's Energy Information Administration provides figures that also contrast with NETL's assessment. A comparison of its data on "Dry Shale Gas Production" for the Permian Basin compared with total gas production in the basin from its "Drilling Productivity Report" suggests that shale production, which is generally considered unconventional, accounted for 66% of total gas production in the basin in 2020.[58, 59]

There is evidence that the Permian basin has very high methane leakage rates. One study found rates as high as 9.4% of gas production in the New Mexico portion of the basin,[60] with other studies finding leakage rates across the basin around 3.7%.[61]

Figure 4. Permian Basin gas production by well technology, 2020–2030



Source: Rystad Energy (accessed April 2025)

Coarse representation of ocean transport

Because GCAM does not appear to differentiate between ocean vessel types, the 2024 LNG Study likely fails to capture the distinct—and potentially higher—GHG emissions profile of LNG carriers.[62] These ships use "boil-off" gas from LNG cargo tanks as their primary fuel, which, while generating lower CO_2 emissions than conventional marine fuels, has been found to result in significant methane slip from their engines.[63, 64] Consequently, the DOE likely underestimates the potent near-term warming effect of U.S. LNG exports when using a 20-year GWP to calculate the average consequential GHG intensity of exports.[65] It is harder to judge whether GCAM overestimates or underestimates emissions from the ocean transport stage of the LNG supply chain using a 100-year GWP. We emphasize, however, that the long-term climate impact of LNG exports remains a high concern. Further, the degree to which ocean transport emissions influence the consequential GHG intensity of U.S. exports is likely higher under more stringent climate scenarios, where LNG exports displace renewable energy, than under scenarios where U.S. exports compete with fossil fuels that may also require long-distance ocean transport.

More realistic assumptions of emissions would make clearer the immense climate impact of additional LNG exports

The modeling of consequential emissions from increasing LNG exports finds that net emissions increase as a result of greater LNG exports due to the displacement of cleaner energy sources and increases in gas consumption. This effect is greater in scenarios where reductions in fossil fuel consumption and emissions constrain climate change. The large body of evidence cited above demonstrates that upstream emissions from U.S. gas production are likely higher than those used in the DOE's study and a small but growing body of evidence suggests midstream methane emissions are also higher, which indicates that the likely impact of increasing LNG exports is greater than the DOE study and our analysis find.[66] As the current administration deregulates the oil and gas sector, eliminating the methane rule passed in the Inflation Reduction Act[67] and reducing the EPA's ability to record and track data on oil and gas equipment and emissions,[68] there is a significant chance that emissions from the U.S. oil and gas sector, including those associated with LNG supply and production will rise.

Ultimately, this analysis underscores that there is no way to make LNG compatible with staving off grave and potentially irreversible levels of global warming. To the contrary, DOE's scenario exercise shows that pathways aligned with limiting warming to 1.5ºC involve reducing LNG exports below the level that is possible given projects that are already operating or have FID.[69]

Seeking to build new LNG capacity—even with costly mitigation measures—is illogical. Our analysis affirms that the only reasonable response to the worsening climate crisis is for the LNG industry to halt all new construction, plan for phasing out existing capacity, and simultaneously mitigate emissions.

Horses and cattle graze near a hydrofracking installation on the Eagle Ford Shale play in DeWitt County, Texas.

CONCLUSION AND RECOMMENDATIONS

The DOE set up a climate test for LNG export terminals that was relatively generous in terms of its assumptions for production-through-liquefaction GHG intensity and CCS availability. Yet none of the assessed LNG terminals come near to passing it. Further, we show that measures to reduce GHG emissions from the oil and gas industry, while important, are incapable of making LNG compatible with climate goals.

The U.S. federal government has the tools that are needed and a distinct responsibility to halt the authorization of new exports. Prospective importers and financial backers of U.S. LNG also have incentives to consider the greenhouse gas emissions associated with the fuel.

We make the following recommendations:

- The DOE should use the "climate test" to reject pending and future LNG export applications. Further, the DOE should use its authority under the Natural Gas Act to reevaluate the public interest status of LNG projects that were authorized to export LNG to non-FTA countries without consideration of climate impacts or under analyses that predate the 2024 LNG Study.
- Congress should pass legislation that makes it a statutory requirement under the Natural Gas Act to assess the climate impact of gas exports and reject applications that would increase global GHG emissions under a credible scenario to limit warming to 1.5ºC. U.S. federal agencies should require all new proposed fossil fuel production and infrastructure projects to meet a similarly high standard under NEPA.
- Prospective buyers of U.S. LNG should refrain from entering into long-term offtake agreements and instead prioritize measures that accelerate the renewable energy transition.
- Financial institutions and governments should end their financing for new fossil fuel infrastructure, including LNG infrastructure, and plan for a managed phase-out of fossil fuel assets. G7 nations, in particular, should avoid using public money to finance global LNG projects, as implied by the G7 Climate, Energy and Environment Ministers' Communiqué signed in 2022.[70]
- Where it is not possible to entirely phase out gas imports, foreign parties should insist upon transparent, independent, and representative measurement-based evidence to substantiate U.S.-based claims of methane abatement (e.g., under the European Union Methane Regulation).


CITGO

SUPPLEMENTARY MATERIALS

Figure S1. LCA studies cited by DOE in LNG export authorization orders since 2014

Note: Three-letter project abbreviations used. Each block represents a single non-FTA final export order. CAM = Cameron LNG, FRE = Freeport LNG, COV = Cove Point LNG, COR = Corpus Christi LNG, SAB = Sabine Pass LNG, ELB = Elba Island LNG, GOL = Golden Pass LNG, DEL = Delfin LNG, CAL = Calcasieu Pass LNG, POR = Port Arthur LNG, WOO = Woodside LNG (formerly Driftwood LNG), GUL = Gulfstream LNG, EAG = Eagle LNG, PLA = Plaquemines LNG, TEX = Texas LNG, RIO = Rio Grande LNG, ALA = Alaska LNG

DOE commissioned the first federal life cycle analysis (LCA) study of U.S. LNG exports in 2014. According to a routinely cited authorization order for Sabine Pass, this study was "intended to inform DOE/FE's decision-making under NGA section 3(a) and to provide additional information to the public."[71] An update to the study was finalized in 2020, after which the DOE immediately began to cite it in authorization orders for projects such as Texas LNG and Rio Grande LNG.

A systematic review confirms that since 2014, all 28 final authorization orders issued by DOE to export LNG to non-FTA countries have cited LCA studies of the GHG emissions associated with U.S. LNG exports. 17 of these authorization orders were issued during President Donald J. Trump's first term in office. DOE prepared a standalone LCA for Alaska LNG because the 2014 and 2019 studies covered LNG exports from the lower 48 states only.

While this analysis demonstrates that DOE has been prudent in considering GHG emissions under the scope of its public interest analysis of LNG export applications, studies that it has relied on have contained major flaws. In particular, the studies do not assess whether increased U.S. LNG export volumes may increase global GHG emissions by contributing to a net increase in fossil fuel production and consumption. Instead, they compare the LCA emissions from U.S. LNG to the energy equivalent emissions from coal and/or alternative sources of gas.

Table S1. DOE gas production scenario to RBN supply source region crosswalk

DOE Scenario Gas production basin and extraction technology	AAPG Geologic Province	RBN Source
Alaska - offshore	Not assigned	Excluded
Anadarko - conv	360	MidCon
Anadarko - shale	360	MidCon
Anadarko - tight	360	MidCon
Appalachian - shale	160 and 160-A	Northeast
Arkla - conv	230	Northwest LA
Arkla - shale	230	Northwest LA
Arkla - tight	230	Northwest LA
Arkoma - conv	345	MidCon
Arkoma - shale	345	MidCon
East Texas - conv	260	Northeast TX
East Texas - shale	260	Northeast TX
East Texas - tight	260	Northeast TX
Fort Worth - shale	420	Northeast TX
GoM - offshore	Not assigned	Other
Green River - conv	535	Other
Green River - tight	535	Other
Gulf - conv	220	Southwest TX
Gulf - shale	220	Southwest TX
Gulf - tight	220	Southwest TX
Permian - conv	430	West TX
Permian - shale	430	West TX
Piceance - tight	595	Other
San Juan - CBM	580	Other
San Juan - shale	580	Other
South Oklahoma - shale	350	MidCon
Strawn - shale	415	Northeast TX
Uinta - conv	575	Other
Uinta - tight	575	Other

The onshore gas production scenarios used by DOE represent pairings of (1) clearly defined geologic provinces coded by the American Association of Petroleum Geologists (AAPG) and (2) extraction technologies. Gas supply source regions used by RBN are clearly defined for regions in Texas and Louisiana, as well as the Northeast, but the boundaries of the MidCon region are not clearly defined by model documentation.

Our crosswalk reflects the assumption that the RBN MidCon region is well-represented by the Anadarko, Arkoma, and South Oklahoma basins, and that the RBN Other region includes all basins further west, namely the Green River, Piceance, San Juan, and Uinta basins, as well as Gulf of Mexico offshore production.

Table S2. Measurement Informed Estimates of Oil and Gas Industry Direct Emissions

Study	Basin(s)	Basin Leakage Rate/Range (% of production)	US Average (% of production)
Measurement Informed Estimates of **Upstream** Oil and Gas Emissions			
Peischl et al (2016)	Bakken (Williston Basin)		4.20-8.40%
Omara et al (2018)	Marcellus	0.27%	0.59-1.50%
	Pinedale	0.65%	
	Uinta	3.50%	
	Upper Green River	0.50%	
	Barnett	0.15%	
	Denver-Julesberg	1.60%	
	Fayetteville	0.03%	
	Eagle Ford		
Allen et al (2013)	Gulf Coast		0.42%
	Midcontinent		
	Rocky Mountain		
	Appalachian		
Brantley et al (2014)	Barnett	0.72%	
	Denver-Julesberg	1.36%	
	Pinedale	0.58%	
Caulton et al (2019)	Marcellus	0.45-0.64%	
Measurement Informed Estimates of Combined **Up-** and **Mid-stream** Oil and Gas Emissions			
Sherwin et al (2024)	Permian	0.75-9.63%	2.95%
	San Joaquin		
	Denver-Julesberg		
	Unita		
	Appalachian (PA)		
Riddick et al (2024)	Delaware	2.80%	
Barkley et al (2017)	Marcellus	0.27-0.45%	
Measurement Informed Estimates of Combined **Up-**, **Mid-**, and **Down-stream** Oil and Gas Emissions			
Howarth et al (2011)	Haynesville		1.70-6.0% (conventional gas) 3.60-7.90% (fracked wells)
	Barnett		
	Piceance		
	Unita		
	Denver-Julesberg		
Alvarez et al (2018)	Haynesville		2.30%
	Barnett		
	Northeast PA		
	San Juan		
	Fayetteville		
	Bakken		
	Uinta		
	Weld County		
	West Arkoma		
Shen et al (2022)	98% of U.S. O&G production		2%
Karion et al (2015)	Barnett	1.30-1.90%	
Zavala-Araiza et al (2015)	Barnett	1.50%	

Section S1. Calculation details for Calcasieu Pass liquefaction stage emissions

To estimate liquefaction stage emissions for Calcasieu Pass, we closely emulate the approach presented in Step 3 of Appendix C of the 2024 LNG Study. This approach uses company-reported GHG emissions from the EPA GHGRP as the starting point (Table S1-1), and uses additional calculations to fill "known data gaps" and improve consistency with the assumptions used by NETL. The calculations include:

- Adding CO2 emissions from acid gas removal units based on the "appropriate regional post-processing NG [natural gas] compositions reported in the natural gas baseline report and assuming that all CO2 is removed from the pipeline gas and vented" [72] (Table S1-2);
- Recalculating CO2 and CH4 emissions from flaring based on the reported amounts of natural gas sent to flaring in Subpart W (Table S1-3) and assuming a 98% mass conversion efficiency from CH4 to CO2 with the remaining 2% emitted as CH4. The results of this calculation are shown in Table S1-4. [73]
- Recalculating speciated GHG emissions from fuel use to address "minor differences in the combustion factors used in the calculation of emissions from GHGRP Subpart C data and those used by NETL in its modeling." [74] Fuel use volumes based on reported data in Subpart C are shown in Table S1-5, and recalculated GHG emissions by unit type based on NETL fuel factors are shown in Table S1-6.

The final estimates for Calcasieu Pass, divided between Subpart W and C emissions sources, are shown by Tables S1-7 and S1-8.

Table S1-1. Reported GHG emissions for Calcasieu Pass (EPA GHGRP, reporting year 2023)

GHG	Subpart C	Subpart W	Total	AR4 CO2e	AR6 CO2e
CO2	2,288,396.40	513,708.30	2,802,104.70	2,802,104.70	2,802,104.70
CH4	43.13	1,315.08	1,358.21	33,955.25	40,474.66
N2O	4.313	0.424	4.74	1,411.63	1,293.20
			Total reported CO2e:	2,837,471.58	2,843,872.56

Table S1-2. Estimated GHG emissions from acid gas removal units

Delivery region	Mass fraction CO2 entering AGRU facility	LNG thousand cubic feet exported	LNG Mass Exported (tons)	Mass CO2 removed
Southeast	0.26%	4.90E+08	9.87E+06	2.57E+04

Table S1-3. Flare gas volumes based on Subpart W reported data

NG sent to flare (MMscf)	Feed gas sent to flare - CH4 molar fraction	Feed gas sent to flare - CO2 molar fraction	Mass of CH4 sent to flare (tons)	Mass CO2 sent to flare (tons)
9.98E+03	3.93E-01	5.62E-01	7.41E+04	2.91E+05

Table S1-4. Recalculated flare gas emissions, assuming 98% combustion efficiency

Mass CO2 from CH4 Combustion (tons)	Total CO2 emissions (tons)	CH4 Slip (tons)
1.99E+05	4.90E+05	1.48E+03

Table S1-5. Fuel use data based on Subpart C reported data

Unit type	Fuel	Fuel unit	Reported fuel quantity	Reported CO2 emissions (tons)	Fuel quantity (back calculated)	NETL fuel factor	NETL fuel unit	Converted fuel quantity
Simple Cycle	Natural Gas	scf/yr	NA	1.10E+05	2.03E+09	NG Centrifugal compressor	tons NG	4.08E+04
Other combustion	Natural Gas	scf/yr	NA	2.18E+06	4.01E+10	NG Combustion	tons NG	8.07E+05

Table S1-6. Recalculated emissions from fuel combustion

Unit	GHG	NETL fuel GHG factor (kg/kg NG)	Calculated GHG emissions
Simple Cycle	CO2	2.66E+00	1.09E+05
	CH4	2.08E-04	8.49E+00
	N2O	7.24E-05	2.95E+00
Other combustion	CO2	2.83E+00	2.28E+06
	CH4	5.42E-05	4.37E+01
	N2O	0.00E+00	0.00E+00

Table S1-7. Post-adjustment subpart W GHG emissions

GHG	Flare stack	AGRU*	Other (reported)	Total	AR4 CO2e	AR6 CO2e
CO2	489,702.36	25,664.82	0.00	515,367.18	515,367.18	515,367.18
CH4	1,481.26	0.00	21.98	1,503.24	37,580.91	44,796.45
N2O	0.00	0.00	0.00	0.00	0.00	0.00
				Total CO2e:	552,948.10	560,163.63

Table S1-8. Post-adjustment subpart C GHG emissions

GHG	Total	AR4 CO2e	AR6 CO2e
CO2	2,392,913.07	2,392,913.07	2,392,913.07
CH4	52.24	1,305.96	1,556.70
N2O	2.95	880.47	806.60
	Total CO2e:	2,395,099.49	2,395,276.37

Section S2. Calculation details for project direct emissions mitigation analysis

The cumulative emissions reductions associated with four mitigation measures are estimated for the five LNG terminals in our analysis and then summarized using the production weighted average. This section explains the assumptions and calculations used, as well as the terminal-by-terminal results.

- **Optimizing gas supply.** This measure assumes that LNG operators purchase gas exclusively from the supply region with the lowest production-through-transmission GHG intensity for the delivery region of the terminal: Southwest Texas for terminals in the Southwest delivery region and Northeast Louisiana for terminals in the Southeast delivery region. Due to the complexity of the U.S. gas network, the limited physical traceability of gas, the high share of gas that LNG operators purchase from gas marketers who do not provide sourcing information, and the systematic exclusion of high emissions sources from reported inventories, [75] we assume that further measures to optimize gas supply purchasing would not be indicative of additional emissions reductions. Terminal-by-terminal calculations are provided in Table S2-1.
- **Minimizing liquefaction stage methane emissions.** This measure assumes that LNG operators eliminate all liquefaction stage methane emissions associated with flaring inefficiencies, equipment leaks, and blowdown methane emissions. For this estimation, we first calculate the adjusted Subpart W GHG emissions for each LNG terminal, consistent with the approach described in Step 3 of Appendix C of the 2024 LNG Study (and emulated in Section S1 of this report for Calcasieu Pass). To calculate the emissions reduction associated with this measure (Table S2-2), we assume that the CH_4 emissions in the adjusted Subpart W inventory are fully "avoidable."
- **Using all-electric drivers.** This measure assumes that all LNG terminals use electric drivers for liquefaction instead of on-site fuel combustion. Similarly to the previous step, we first calculate the adjusted Subpart C GHG emissions for each LNG terminal. We also estimate the hypothetical power consumption (and associated grid emissions) that each terminal would require for operations. To calculate the emissions reduction associated with using all-electric drivers instead of on-site fuel combustion, we substitute the adjusted subpart C GHG emissions for each terminal with the estimated grid emissions (Table S2-3).

  To estimate the hypothetical power consumption of each terminal, we use Freeport LNG's power consumption per ton of exported LNG. The grid emissions intensity factor assigned to each terminal is dependent on the state where the terminal is located. For terminals in Texas, we use the same grid emissions intensity factor as the 2024 LNG Study, which is based on ERCOT generation mix data and GHG emissions modeling using the NETL Grid Explorer Tool. For terminals in Louisiana, we use a consistent approach to estimate the grid intensity factor using generation mix data for Louisiana from the EIA and emissions modeling using the same NETL Grid Explorer Tool.
- **Powering with renewable energy.** This measure assumes that all LNG terminals use high-integrity renewable energy to power liquefaction. To estimate the cumulative emissions reduction associated with this measure (Table S2-4), we assume that the grid-based emissions calculated in the previous step can be reduced to zero.

The baseline GHG intensity for this analysis, 15.3 g CO2e/MJ LNG exported (LHV), is the production weighted average across all five terminals of project direct emissions (shown in Table 6). It is higher than the default (average) project direct emissions calculated by the 2024 LNG Study because the latter includes a different sample of LNG terminals and assumes that the average production-through-transmission intensity of U.S. exports is well-represented by the average intensity of the U.S. gas sector.

Detailed terminal-by-terminal calculations of adjusted Subpart C and W emissions can be found in the **Supplementary Workbook** to this report.

Table S2-1. Optimizing gas supply calculation table

Terminal	Delivery region	Optimal gas supply source	LNG Quantity Exported (MMcf)	GHG intensity - optimal gas supply		GHG intensity - baseline	
				per MJ gas delivered to facility (HHV)	per MJ LNG exported (LHV)	per MJ gas delivered to facility (HHV)	per MJ LNG exported (LHV)
Cheniere Corpus Christi	Southwest	Southwest TX	395,716	6.82E+00	8.09E+00	8.10E+00	9.60E+00
Freeport LNG	Southwest	Southwest TX	421,381	6.82E+00	8.09E+00	8.25E+00	9.78E+00
Venture Global Calcasieu Pass	Southeast	Northwest LA	490,135	5.23E+00	6.20E+00	8.33E+00	9.87E+00
Cameron LNG, LLC	Southeast	Northwest LA	385,662	5.23E+00	6.20E+00	8.33E+00	9.87E+00
Sabine Pass LNG Terminal	Southeast	Northwest LA	926,901	5.23E+00	6.20E+00	8.33E+00	9.87E+00
			Production weighted average	5.73E+00	6.79E+00	8.28E+00	9.82E+00
			Change in intensity	-2.55E+00	-3.03E+00		

Table S2-2. Minimizing liquefaction stage CH4 emissions calculation table

U.S. LNG Facility Name	Avoidable CH4 emissions (Mg CO2e)	LNG Mass Exported (Mg)	GHG intensity reduction (kg CO2e/kg LNG)	GHG intensity reduction (g CO2e/MJ LNG HHV)	GHG intensity reduction (g CO2e/MJ LNG LHV)
Sabine Pass LNG Terminal	5.05E+04	1.87E+07	2.71E-03	4.98E-02	5.52E-02
Freeport	6.65E+03	8.49E+06	7.83E-04	1.44E-02	1.60E-02
Corpus Christi Liquefaction	4.62E+04	7.97E+06	5.80E-03	1.07E-01	1.18E-01
Cameron LNG LLC	2.20E+05	7.77E+06	2.84E-02	5.23E-01	5.79E-01
Venture Global LNG	4.48E+04	9.87E+06	4.54E-03	8.36E-02	9.26E-02
		Production Weighted Average	6.99E-03	1.29E-01	1.43E-01

Table S2-3. Using all-electric drivers calculation table

U.S. LNG Facility Name	Energy efficiency of liquefaction (MWh/ton LNG)	GHG intensity of grid power (kg CO2e/ MWh)	LNG Mass Exported (Mg)	Power demand (MWh)	Emissions from power (Mg CO2e, 100-yr GWP, AR6)	Adjusted subpart C emissions (Mg CO2e, AR6 100-yr GWP)	Emissions reduction from electrification (Mg CO2e)	GHG intensity reduction (kg CO2e/kg LNG)	GHG intensity reduction (g CO2e/ MJ LNG HHV)	GHG intensity reduction (g CO2e/ MJ LNG LHV)
Sabine Pass LNG Terminal	4.09E-01	5.00E+02	1.87E+07	7.63E+06	3.82E+06	4.13E+06	3.15E+05	1.69E-02	3.11E-01	3.45E-01
Freeport	4.09E-01	5.00E+02	8.49E+06	3.47E+06	1.74E+06	1.74E+06	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Corpus Christi Liquefaction	4.09E-01	5.00E+02	7.97E+06	3.26E+06	1.63E+06	1.55E+06	-7.52E+04	-9.43E-03	-1.74E-01	-1.92E-01
Cameron LNG LLC	4.09E-01	5.64E+02	7.77E+06	3.18E+06	1.79E+06	1.95E+06	1.63E+05	2.10E-02	3.87E-01	4.29E-01
Venture Global LNG	4.09E-01	5.64E+02	9.87E+06	4.04E+06	2.28E+06	2.40E+06	1.20E+05	1.22E-02	2.24E-01	2.48E-01
							Production Weighted Average	9.92E-03	1.83E-01	2.02E-01

Table S2-4. Powering with renewable energy calculation table

U.S. LNG Facility Name	Avoided emissions from power (Mg CO2e, 100-yr GWP, AR6)	LNG Mass Exported (Mg)	GHG intensity reduction (kg CO2e/ kg LNG)	GHG intensity reduction (g CO2e/ MJ LNG HHV)	GHG intensity reduction (g CO2e/ MJ LNG LHV)
Sabine Pass LNG Terminal	3.82E+06	1.87E+07	2.04E-01	3.77E+00	4.17E+00
Freeport	1.74E+06	8.49E+06	2.04E-01	3.77E+00	4.17E+00
Corpus Christi Liquefaction	1.63E+06	7.97E+06	2.04E-01	3.77E+00	4.17E+00
Cameron LNG LLC	1.79E+06	7.77E+06	2.31E-01	4.24E+00	4.70E+00
Venture Global LNG	2.28E+06	9.87E+06	2.31E-01	4.24E+00	4.70E+00
		Production Weighted Average	2.13E-01	3.93E+00	4.35E+00

ENDNOTES

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26 Step 8: Subtract National Average Upstream Natural Gas and Liquefaction Plant GHG Performance to Determine Project Non-Direct Emissions Intensity. Appendix C in 2024 LNG Study.

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EARTHWORKS