Global Liquefied Natural Gas Industry Expansion May Imperil Paris Agreement Temperature Targets

Shuting Yang[1], Sara Hastings-Simon[2,3], and Arvind P. Ravikumar*[1]
[1]Harrisburg University of Science and Technology, Harrisburg, PA 17101
[2]The Payne Institute, Colorado School of Mines, Golden, CO 80401
[3]School of Public Policy, University of Calgary, Calgary, AB T2N 1N4

*Corresponding author. E-mail: ARavikumar@HarrisburgU.edu

ABSTRACT

The shift from coal to natural gas (NG) in the power sector has led to significant reductions in carbon emissions, earning NG the moniker of a bridge-fuel. The cheap NG that led to this shift is now fueling a global expansion in liquefied natural gas (LNG) infrastructure, particularly in the US, Canada, and Australia. In this work, we assess the viability of LNG expansion in reducing global carbon emissions through coal-to-gas switching in the power sector. In the near term (pre-2030), coal-to-gas substitution reduces global carbon emissions across all temperature targets – here, the potential for emissions reductions through coal-to-gas switching is 'LNG-limited', where there is significantly more coal power generation than the LNG required to substitute it. However, we find that long-term planned LNG expansion is not compatible with the Paris climate targets of 1.5ºC or 2ºC – here, the potential for emissions reductions through coal-to-gas switching is 'coal-limited'. The rapid decline in the share of coal power globally limits the potential for coal to gas substitution. In all scenarios analyzed, low upstream methane leakage and significant coal-to-gas substitution are critical to realizing the near-term climate benefits of LNG. Investors and governments should consider stranded risk assets associated with potentially shorter lifetimes of LNG infrastructure in a Paris-compatible world.

Keywords: LNG, life cycle emissions, coal-to-gas switching, Paris Agreement, climate policy

1 Introduction

Natural gas (NG) accounted for about a quarter of global primary energy demand in 2017 [1]. The rise of NG as a major fuel source in electricity generation has led to significant reductions in carbon emissions by displacing generation from high-emitting coal plants [2-8]. For every unit of electricity generation, NG power plants emit roughly half as much carbon dioxide (CO_2) as coal [9]. The U.S. Energy Information Administration (EIA) in its international energy outlook projects that global demand for NG will increase by over 40% between 2018 and 2040, with a majority of the growth in developing economies [1]. NG consumption for electricity generation in non-OECD countries will increase more than 60%, at 1.5% per year, compared to a rate of 0.9% per year in OECD countries [1]. Growth in global demand is driven by several factors including the closures of nuclear power plants in Europe and Asia that have further increased imports of NG to substitute for the loss of carbon-free power [10-12]. Growing NG demand from these two regions, coupled with the favorable economics of shale gas, has led to an expansion in global liquefied natural gas (LNG) trade [13-15] that is outpacing domestic growth – the share of LNG in the global NG market increased from roughly 5.8 % in 2001 to over 10.7% in 2017 [16, 17].

The arguments for expanding LNG use are relatively straightforward. When used to generate power NG produces lower carbon emissions and fewer criteria pollutants compared to coal, so the coal-to-gas substitution can help address climate change and air quality in the developing world. It provides significant economic potential and job growth in exporting countries, potentially offsetting job losses and declining revenues in other fossil resource sectors. LNG also offers greater trade flexibility and allows cargoes of NG to be delivered over large distances. Finally, the availability of LNG from several geologically distinct resource basins in North America, Middle East, and Australia can potentially improve energy security in importing nations by providing 32diverse supply options that are resilient to local resource disruptions [18-20].

The Paris Agreement signed in 2015 codified a global commitment to keep global temperatures ‘well below’ 2ºC above pre-industrial level and to ‘pursue efforts to limit the temperature increase even further to 1.5ºC by mid-century [21]. Achieving these targets will require significant reductions in global carbon emissions by mid-century, compared to 2019 levels. Several scenarios developed by the IPCC in line with the temperature targets of the Paris Agreement estimate a reduction in the consumption of coal, oil, and NG [22, 23]. The rate of reduction in carbon emissions and therefore fossil-fuel consumption varies based on the carbon budget available in each scenario. Although not predictive, these scenarios illustrate the trajectory of global emissions required to achieve temperature-based climate action goals. Exploring the evolution of fossil fuels in these scenarios can provide critical insights into the viability of new fossil fuel projects around the world.

The climate benefit of coal-to-gas substitution is threatened by two factors – the degree to which NG is used to substitute for existing coal or decrease growth in coal use, and methane leakage across the NG supply chain [24]. Methane is a short-lived and potent greenhouse gas (GHG) whose warming potential is 34 times that of carbon dioxide over a 100-year time frame [25]. Recent field measurements of methane leakage across the U.S. have shown a significant underestimation in official EPA inventories [26-29]. Furthermore, the difference in methane leakage rates globally increases the disparity in the emissions impact of LNG [30]. Thus, the emissions advantage of a coal-to-gas transition will be a function of the life cycle emissions associated with the LNG supply chain. Recent life cycle assessment (LCA) studies on global LNG trade have demonstrated a wide range of emissions intensity for power generation, ranging from about 427 g CO_2e/kWh to over 740 g CO_2e/kWh [8, 31-34]. The high uncertainty in these estimates can be attributed to differences in system boundaries, methane leakage, and various assumptions related to LNG liquefaction and regasification. In addition, the argument for climate benefits from increasing LNG use relies on coal-to-gas substitution, as NG that displaces new renewable energy will lead to an increase in carbon emissions [35].

In this work, we analyze the cumulative climate impacts of the global LNG industry and evaluate its role in reducing global carbon emissions in the electricity sector. In this process, we compile a comprehensive and up-to-date database of all existing, under-construction, approved, and proposed LNG projects around the world. We then evaluate life cycle carbon emissions associated with this infrastructure and discuss the impact of methane leakage rates across global NG basins on the emissions intensity of LNG. Next, we quantify the coal-to-gas substitution potential and discuss the role of LNG as a decarbonization tool for the electricity sector within the context of IPCC scenarios that limit global warming to three temperature targets – 1.5ºC and 2ºC as enshrined in the Paris Agreement, and 3ºC representing a business-as-usual scenario. We show that long term use of LNG is fundamentally incompatible with the 1.5ºC Paris target and increases annual carbon emissions by 2040 compared to a business-as-usual scenario. However, LNG can play a limited role in reducing global carbon emissions through 2030 by substituting for existing inefficient coal-power generation. This suggests that LNG can be effective in regions where there are significant NG power plants that are underutilized due to fuel availability limitations and significant coal-power generation for displacement. Finally, we conclude with a discussion of the stranded asset risk for exporting countries from stringent climate policy and limitations to coal-to-gas substitution in importing countries.

2 Methods

2.1 Global Liquefaction Facility Database

We build a comprehensive database of global LNG projects by compiling and integrating data from government agencies, international industry-affiliated trade unions (e.g., international gas union (IGU), International Group of Liquefied Natural Gas Importers (GIIGNL)), non-profit organizations, and public LNG project announcements [36-38]. All LNG projects in this database were compiled under four categories: existing projects, under-construction projects, approved projects, and proposed projects. Whenever possible, proposed projects were verified using secondary sources such as news releases or other publicly available documents. LNG projects that have been canceled or on-hold (as of October 2020) are not included in the analysis.

The start year of each project in the database is based on operational status – we use the year of the first LNG shipment for existing projects and the expected year of the first shipment for other categories. For some approved and proposed projects that are in initial stages and the start year of operation has not been announced, we make assumptions based on the average time between approval and operation for existing projects. The detailed process of assigning start year and the impact of start year on global LNG capacity is discussed in Supplementary Information section S2.

Although the expected operational life of LNG projects is around 25 to 35 years, several LNG facilities have been operating for more than 30 years, with the earliest in-service LNG facility in operation for 46 years [17]. Our base-case scenario assumes a 35-year operational lifetime. The sensitivity of cumulative emissions to assumptions on project lifetimes is discussed in section 3.3.

2.2 Life cycle GHG emissions from LNG export

We evaluate life cycle GHG emissions from LNG use in electricity generation based on peer-reviewed literature and publicly available data across five stages of the LNG supply chain – upstream, liquefaction, transportation and shipping, regasification, and end-use. We quantify the cumulative emissions from LNG export projects from 17 countries by estimating the total emissions from the LNG supply chain up to 2050, the end of the study period. In addition to CO_2-related combustion emissions, we additionally include methane emissions from NG production, processing, and transportation.

Prior LCA studies of LNG exhibit large variation in emissions based on differences in system boundaries, modeling approaches, and data sources [32]. Here, we conduct a systematic literature review of peer-reviewed LCA studies of LNG projects to identify parameter estimates in the base-case scenario. Besides, we also analyze a best-case (lower bound) and worst-case (upper bound) scenario in the sensitivity analysis for critical parameters. Methane leakage rates for exporting countries and 5 U.S. shale basins are derived from the International Energy Agency (IEA) methane tracker database [30]. Further details on methodology and assumptions of emission scenarios are provided in Supplementary Information section S1.

2.3 Emission pathways and LNG-related climate impact

We use global emission trajectories from the IPCC's shared socioeconomic pathways (SSPs) to explore the additional impact of LNG-related emissions. The socioeconomic assumptions of the SSPs were translated by six different integrated assessment models (IAMs) into estimates of future energy use characteristics and emissions. Based on publicly available data, we identified 13, 18, and 48 SSPs that provide pathways to limit peak warming to below 1.5ºC, 2ºC, and 3ºC, respectively [39-41]. We extract the annual total CO_2 emissions, coal and NG based electricity, and expected global mean temperatures from all selected SSPs and average data from each category across the scenarios to represent the mean and variance around expected temperature trajectories (see Supplementary Table S6 for details).

The climate impact of GHG emissions from global expansion in LNG trade depends on end-use applications. To evaluate impacts from structural changes in the power sector, we calculate net GHG emissions associated with the use of LNG under different coal-to-gas substitution scenarios ranging from no fuel switching (all LNG is used for additional power generation, or 0% substituting for coal) to full fuel switching (all LNG is used to displace existing or new coal, or 100% substitution). For comparison, we also analyze the case where coal-based power generation is replaced by zero-carbon energy sources. The temperature change under different scenarios of LNG use is calculated based on net cumulative emissions change across three different periods – 2020 - 2030, 2020 - 2040, and 2020 – 2050 (see Supplementary Fig.S7 for details). Since the magnitude of warming is determined by cumulative CO_2 emissions, the corresponding temperature benefit from coal-to-gas switching is evaluated using the metric of transient climate response to cumulative emissions (TCRE) [41] (further details can be found in Supplementary Table S7).

3 Results

3.1 Global cumulative export/import capacity

Figure 1 shows the global cumulative LNG import and export capacity through 2050. As of August 2020, 134 million metric tonnes per annum (MTPA) of new liquefaction capacity is under-construction, 203 MTPA is approved, and 330 MTPA is proposed or awaiting final investment decision (FID). Together, these projects would increase global liquefaction capacity by 155% from 430 MTPA in 2019 to 1097 MTPA. Global cumulative export capacity will reach a peak of 1014 MTPA in 2030, while global import capacity will grow to 894 MTPA by 2030. Until about 2025, existing import terminal capacity from past gas infrastructure booms in Asia will outpace growth in export capacity, potentially increasing landed LNG prices with sustained growth in demand. However, the recent economic shock from the COVID pandemic and the ensuing reduction in demand for NG has depressed global gas prices – spot prices for LNG in Asia declined from a high of $8 - $10 per mmBtu in 2016 to under $4 per mmBtu recently.

Growth in new LNG export capacity between 2017 and 2025 surpasses global import capacity, resulting in an increasing over-capacity of export terminals by the mid-2020s. This analysis is based on 100% utilization rates of facilities' nameplate capacity. Thus, the estimated net supply capacity is the upper bound of demand-and-supply balance given that the global average utilization rate for import terminals in 2019 was only 43%, while that of export terminals was over 80% [38]. For example, U.S. liquefaction facilities averaged a 93% capacity utilization rate in 2019 [42].

Notably, there is a "transition" of the dominant exporters and importers (Figure 1b) – the United States and Canada account for 48% and 26% of all in-development growth of global export capacity, respectively, becoming the two largest exporters. This growth in export capacity is accompanied by consolidation in export markets, making NG prices vulnerable to supply shocks. For example, the share of LNG trade from the top three exporters, as indicated by available export capacity, increases from 50% (Australia, Qatar, and the US) in 2018 to over 65% (US, Canada, and Qatar) in 2030.

On the import side, the growth in regasification terminals continues to lag growth in liquefaction terminals. Between 2020 and 2050, 344 MTPA of new import capacity is expected to come online, compared to 668 MTPA of export capacity. Although LNG imports have been dominated by Japan and South Korea in recent years because of a decline in nuclear power generation capacity, developing countries in Asia and the European Union are poised to become major demand centers. About 63% of under-construction and proposed regasification capacity will be built across developing nations in Asia. Among these countries, China is likely to be the largest demand center for LNG and accounts for 39% of the global under-construction and proposed import capacity. Nevertheless, matching the expected growth in export capacity will require the construction of import terminals in developing countries to address capacity mismatch and potential downward pressure on prices. With governments around the world emphasizing a low-carbon economic recovery from the pandemic, including recent announcements by China and Japan to achieve a net-zero emissions economy around mid-century, it is unclear if the expected demand growth will materialize.

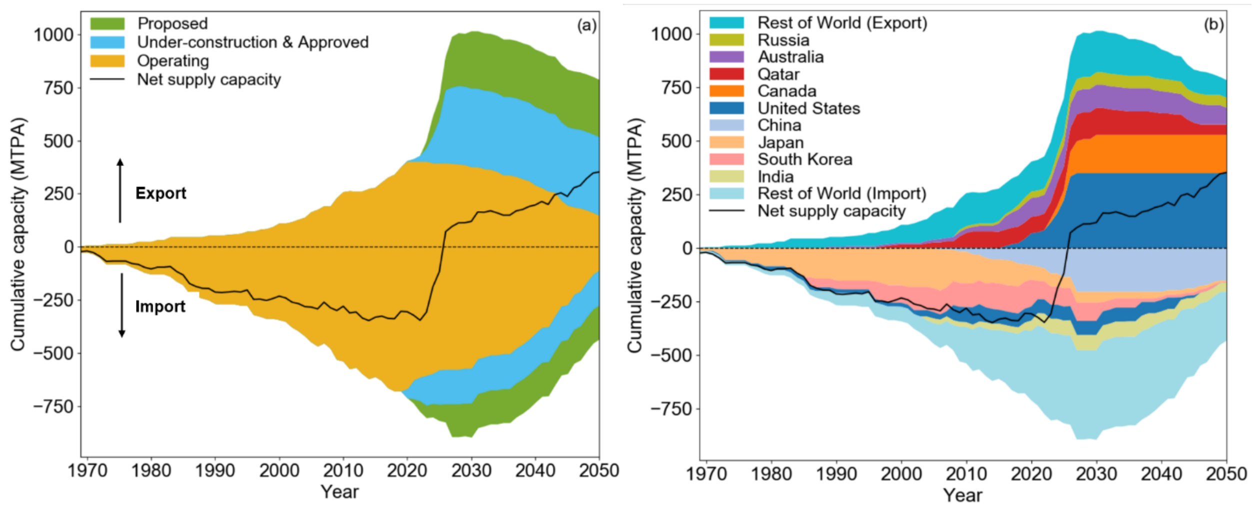

Figure 1. Global cumulative LNG export (positive values) and import (negative values) capacity from 1969 to 2050. (a) Cumulative capacity of existing, under-construction, and proposed projects. (b) Cumulative LNG export and import capacity by country. The black solid line shows net export (supply) capacity over time. Until about 2024, global import capacity exceeds export capacity. Beyond 2024, the growth in export capacity outpaces growth in import capacity.

3.2 Attributional life cycle emission intensity of LNG

A major benefit of using LNG to replace coal-fired power plants stems from the lower carbon intensity of NG compared to coal. In recent years, several groups have undertaken detailed life cycle assessment studies to estimate the net emissions impact of LNG use in power generation and district heating applications. These studies have concluded that in addition to air quality benefits, LNG provides net GHG reductions as long as methane leakage is below 3.2% [26]. Because NG basins around the world exhibit significant variation in methane leakage, the emissions impact of resulting LNG will also vary.

Figure 2 shows the attributional life cycle emission intensity of LNG for power generation across major LNG exporting nations and US NG basins. Emissions are divided across five stages – upstream, liquefaction, shipping, re-gasification, and end-use (see Methods and Supplementary Information section S1). The life cycle emissions intensity of LNG use in power-generation varies from about 520 g CO_2e/kWh for gas sourced in Qatar to over 810 g CO_2e/kWh for gas sourced from the Uintah Basin in the US. These figures correspond to methane leakage rates of 0.1% and 6.6%, respectively. Thus, depending on the source of NG, the contribution of upstream methane leakage to life cycle emissions can vary from 10% of total life cycle emissions at low leakage rates to over 40%. This has potential international implications in a climate constrained world. NG from Russia, with a leakage rate of 6.3%, results in a life cycle emissions intensity of 802 g CO_2e/kWh. By contrast, the life cycle emissions intensity from gas sourced from the US LNG Marcellus shale basin with a leakage rate of 0.4% is 531 g CO_2e/kWh, 34% lower than that of Russian gas. Even comparing Russian pipeline exports by removing the contribution of the liquefaction, transportation, and re-gasification stages, the life cycle emissions intensity only reduces to 725 g CO_2e/kWh, over a third higher than life cycle emissions from Marcellus shale LNG.

Life cycle emissions associated with LNG exports from the US vary considerably. In the base-case scenario with a methane leakage rate of 2.3%, the life cycle emissions used in power generation is estimated to be about 610 g CO_2e/kWh, similar to several recent LCA studies [8, 31-34]. This estimate is about 39% less than that of life cycle emissions of coal-fired electricity at 1001 g CO_2e/kWh. However, depending on the US source basin for NG, the life cycle emissions impacts can vary from 531 g CO_2e/kWh in the Marcellus basin to 811 g CO_2e/kWh in the Uintah Basin. The differences in methane leakage rates across basins have been documented in prior studies and are likely attributable to differences in basin and production characteristics, state-level emissions reduction policies, and operator maintenance practices [24]. In general, NG sourced from oil-rich, associated gas basins such as the San Juan, Bakken, and Permian have higher methane leakage rates than dry gas basins such as the Marcellus, Barnett, and Fayetteville. Thus, the emissions impact of US LNG exports should be estimated at the individual supplier level and weighted based on the volumes of NG from different basins. A scientifically robust measurement and monitoring protocol would be required to verify the upstream emissions intensity of US-sourced NG and its role in reducing global carbon emissions.

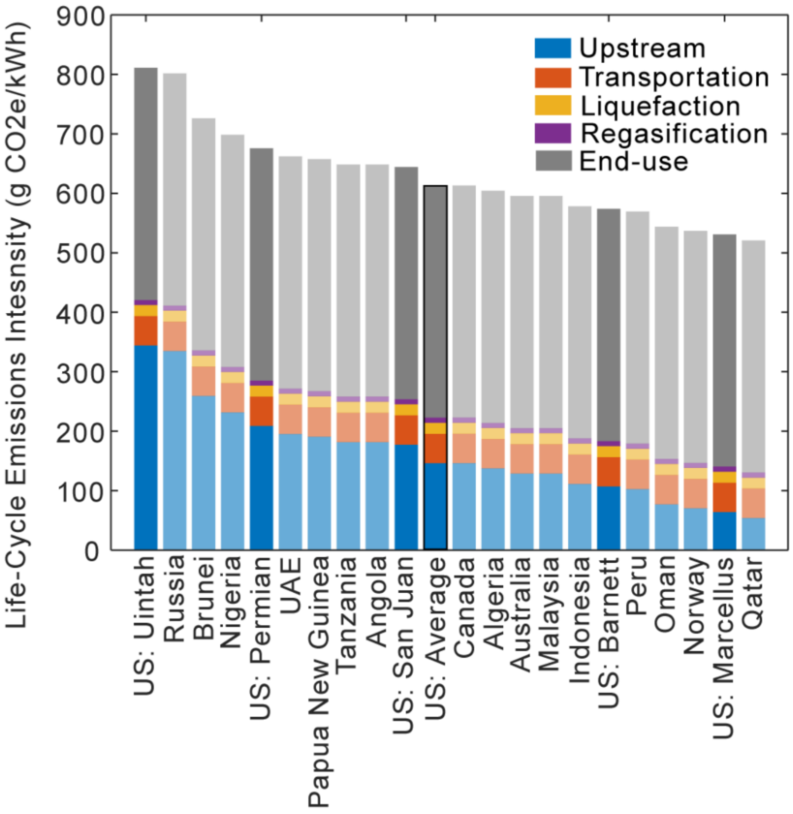

Figure 2. Attributional life cycle emission intensity of LNG from different NG supplying countries across the upstream (blue), liquefaction (yellow), transportation (orange), regasification (purple), and end-use (gray) stages. Emissions from US basins are shaded darker, compared to emissions

associated with non-US basins. In the base-case scenario, the average methane leakage rate is 2.3% and is shown here enclosed in a black box.

3.3 Climate implication of LNG emissions

Figure 3 shows the cumulative climate impact of LNG through 2050 as a function of life cycle methane leakage and infrastructure lifetime. Critically, we describe this impact within the context of international climate policy by showing LNG-related emissions as a fraction of the global carbon budget under different temperature targets. We make two important observations.

First, cumulative emissions increase as methane leakage and infrastructure lifetime increases, with a base-case emission of 79 Gt CO_2e. Overall, the cumulative emissions impact can range from less than 50 Gt CO_2e (low leakage, short lifetime) to over 120 Gt CO_2e (high leakage, long lifetime). With a base-case infrastructure lifetime of 35 years, cumulative emissions increase by 90% as upstream fugitive emission increases from 0.1% to 10%. Even if average methane emissions globally remained at 2.3%, cumulative emissions increase by 38% as infrastructure lifetime increase from 20 years to 50 years. Thus, the growth rate in cumulative life cycle emissions is significantly higher as a function of methane leakage compared to that of infrastructure lifetime. Given that existing LNG terminals are relatively new with an average age of 13 years, reducing the life cycle impact of LNG strongly relies on addressing upstream methane emissions.

Second, life cycle emissions from LNG take up significant fractions of the global carbon budget under various IPCC emissions scenarios. Achieving the goal of 1.5°C temperature target requires a median reduction in NG use of 3% and 25% by 2030 and 2050, respectively, compared to 2010 levels [43]. However, the expansion of LNG liquefaction and regasification capacity from under-construction and proposed projects will increase global NG use and put increased pressure on reducing coal and oil use beyond those estimated in the IPCC scenarios. Under the most stringent temperature target of 1.5ºC, cumulative life cycle emissions from LNG takes up 18% of the carbon budget through 2050. This reduces to 13% and 9% of carbon budgets for mean global warming of 2ºC and 3ºC, respectively. These contributions to the total carbon budget are in addition to emissions from direct NG use that are transported by pipelines. By comparison, total NG related emissions in the IPCC scenarios takes up 15%, 12%, and 11% in the carbon budgets for 1.5°C, 2°C, and 3°C pathways, respectively. Thus, including the contribution from LNG from under-construction and proposed terminals in the cumulative emissions, NG related emissions take up 33%, 25%, and 20% of the global carbon budget in the 1.5°C, 2°C, and 3°C scenarios, respectively. Even with a conservative and unrealistic assumption that LNG represents all NG use in the future, LNG-related emissions still exceed the carbon budgets associated with NG in the 1.5°C and 2°C scenarios. More critically, the median emissions pathways that limit global warming to 1.5ºC suggests that global carbon emissions should reach near-zero prior to 2050, with significant negative emissions thereafter. In this scenario, any emissions associated with LNG in 2050 will be fundamentally incompatible with the 1.5ºC target without a significant deployment of negative emissions technologies. A 1.5ºC compatible world will increase the risk of stranded LNG assets, particularly in exporting countries that have proposed new terminals far beyond 2020.

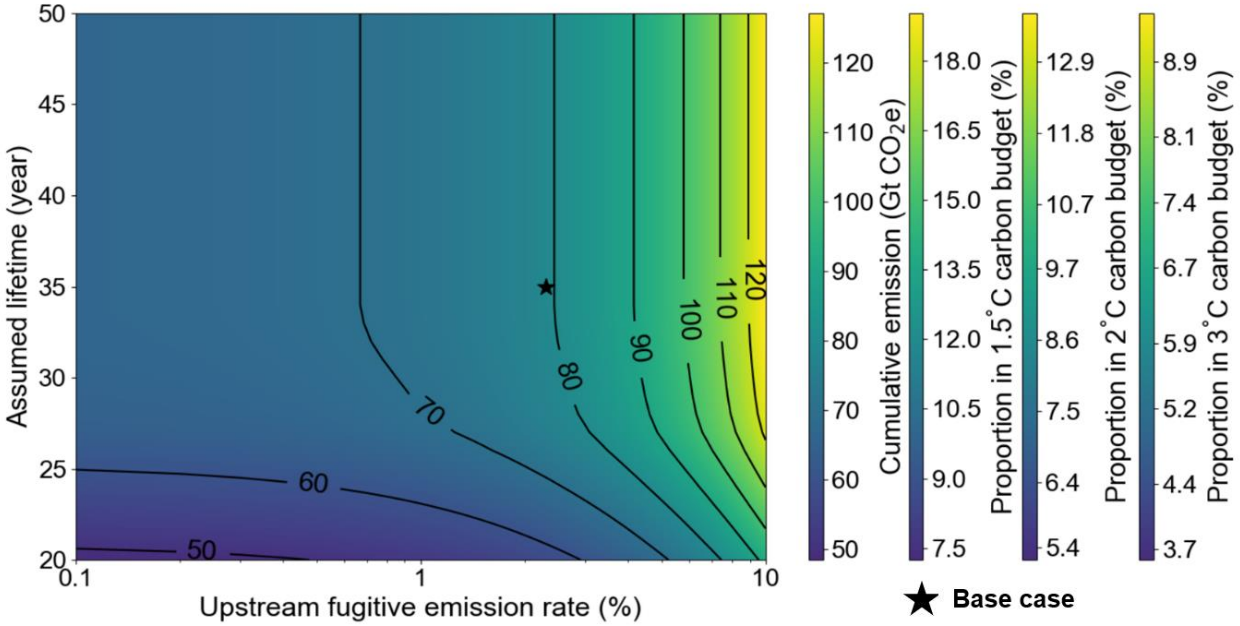

Figure 3. Cumulative life cycle LNG emissions and proportion in total carbon budgets under 1.5ºC, 2ºC, and 3ºC scenarios as a function of infrastructure lifetime (y-axis, years) and upstream fugitive emission rate (x-axis, %). The star shows the result of the base case scenario with a 2.3% upstream emission rate and a 35-year infrastructure lifetime.

Because the main argument for LNG has been to reduce global carbon emissions through a coal-to-gas transition, we quantify the impact of LNG-related emissions within the power sector under 1.5°C, 2°C, and 3°C pathways. Figure 4a-c shows global annual emissions associated with electricity from coal and NG under three temperature targets as a function of various LNG end-use scenarios: baseline, 0% coal-to-gas substitution (no displacement of new or existing coal), 100% coal-to-gas substitution (all LNG is used to replace new or existing coal) and a coal-to-clean energy transition for comparison. Here, the baseline scenario corresponds to the median emissions pathways of the various temperature compatible SSP pathways (see Methods and Supplementary Information section S3). We note several critical insights.

First, in the near-term until around 2038, 100% coal-to-gas substitution reduces global carbon emissions across all scenarios for the three temperature pathways. This implies that LNG can reduce emissions as a viable near-term solution to reducing coal-based power generation through a coal-to-gas substitution. Coal-dependent countries that have significant dormant NG power plant capacity such as India could potentially use LNG as a bridge to transition to a cleaner, lower-carbon power sector.

Second, there is no scenario where LNG use reduces global carbon emissions that excludes coal-to-gas substitution in the power sector – that is, an increase in LNG exports must be coupled with a substitution of LNG for coal to reduce emissions. When all LNG capacity is used for new electricity generation to meet growing demand with 0% coal-to-gas switching, global carbon emissions will be higher compared to the baseline scenario. Net emissions benefits can be achieved if at least 59% of LNG capacity is used for coal-to-gas substitution in the power sector. Emission reduction as a function of various coal-to-gas switching rates is discussed and shown in Figure 5.

Third, substituting coal-based power generation with carbon-free sources results in emissions reductions significantly higher than coal-to-gas substitution in all scenarios. While not surprising, this illustrates a critical source of uncertainty for LNG demand that relies on climate and energy policies in importing countries. Growing concern over climate change in Asia and Europe, coupled with a desire for domestic fuel security or control can result in policies that increase zero-carbon sources in the power sector and reduce demand for LNG, leading to an increased stranded asset risk for LNG exporters or increased use of LNG in other sectors with a corresponding increase in emissions. Thus, while LNG can help reduce emissions from the power sector globally, long-term planning for new import and export infrastructure should be based on an eventual transition away from fossil sources.

Fourth, long-term LNG expansion is not compatible with 1.5ºC pathways even under 100% coal-to-gas substitution. This is because coal use around the world declines rapidly between 2020 and 2040 in all 1.5ºC scenarios such that there is not enough coal for LNG to substitute to counteract the emissions from additional LNG in the total budget. That is, a 1.5°C pathway is one where coal use declines independent of the need for additional LNG. Figure 4d shows the annual net coal-based power generation after 100% coal-to-gas substitution under 1.5°C, 2°C, and 3°C pathways. For the median 1.5°C scenario, 2030 is the threshold year when the climate benefits of coal-to-gas switching start eroding from additional LNG emissions. Before 2030, the potential for emissions reductions is 'LNG-limited' when there is sufficient coal-based power generation to be substituted by all LNG to offset the impact of LNG expansion (net coal-based power generation > 0). The extent of climate benefits depends solely on the availability of LNG for substitution. Beyond 2030, the potential for emissions reduction is 'coal-limited', where the declining share of coal power globally reduces the climate benefits of coal-to gas-switching (net coal-based power generation < 0). Here, global LNG volumes exceed those required to substitute all remaining coal and the excess LNG will generate additional emissions. For 2ºC pathway, the corresponding threshold year is 2038. However, this constraint does not apply in 3ºC pathway – throughout the 2020 – 2050 study period, coal-to-gas substitution has the potential to reduce global carbon emissions. Specifically, if business-as-usual climate policy takes global temperatures on a 3ºC trajectory, there is a significant advantage in reducing emissions through a widespread coal-to-gas transition at low methane leak rates. It is also worth noting that the availability of coal capacity to be substituted by gas is estimated under a scenario where all coal plants are assumed to be able to be substituted by gas. This is the best-case scenario as several factors such as availability of pipeline infrastructure, technical constraints, and age of the coal plants will limit the potential for substitution. Using IPCC estimates of coal use in the 3ºC pathway, we find that 47% and 65% of total coal-based generation must be substituted by LNG to achieve net-zero change in total emissions in 2030 and 2050, respectively. Thus, a 3ºC pathway world will continue to be 'LNG limited' in reducing global carbon emissions through 2050.

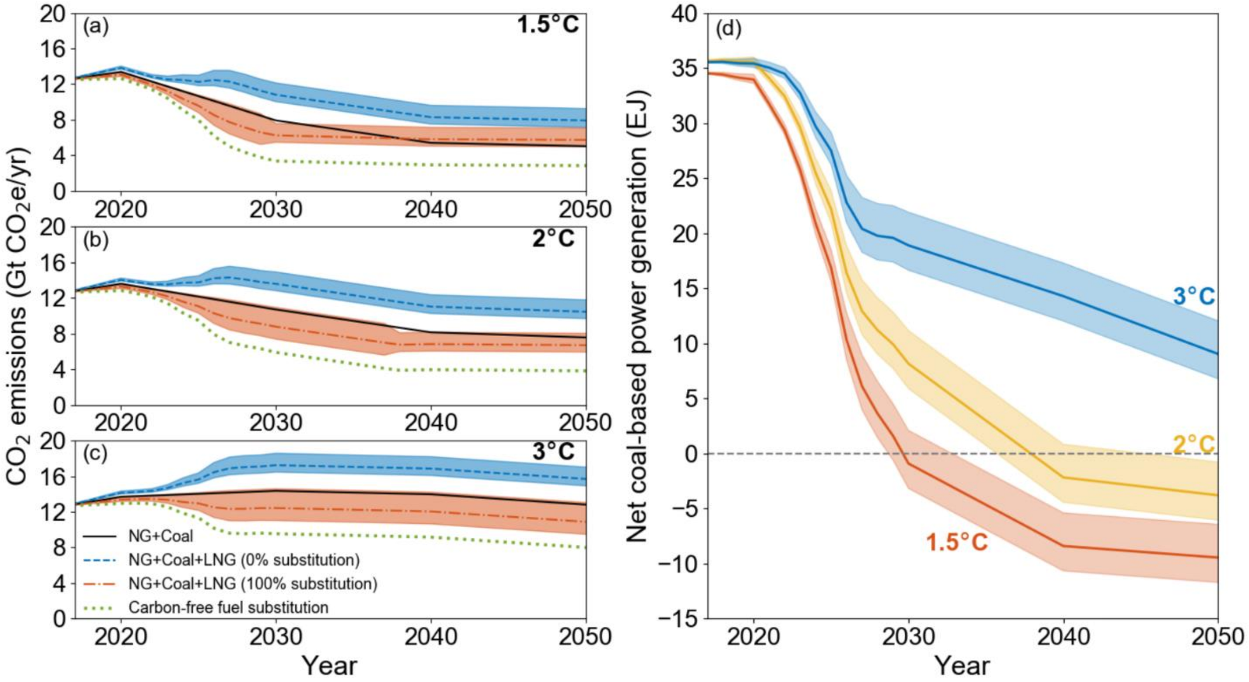

Figure 4. (a-c) Power sector CO_2 emissions from coal and NG, as a function of different LNG use cases in 1.5ºC, 2ºC, and 3ºC pathways. Emissions in the baseline IPCC scenarios are shown as a black line. Blue dashed line represents emissions in scenarios with 0% coal-to-gas switching and the red dashed line represents emissions in scenarios with 100% coal-to-gas switching. Shaded regions represent the lower and upper bound of emissions when considering the lowest (low-emission scenario) and highest (high-emission scenario) emissions from each stage of the LNG value chain, respectively. Green dotted line represents the scenario where coal is substituted by the same amount of carbon-free fuel as LNG with a 100% switching rate. (d)Net coal-based power generation after 100% coal-to-gas switching rate in 1.5ºC (red line), 2ºC (yellow line), and 3ºC (blue line) pathways. Shaded regions indicate the lower and upper bound in low-emission scenario and high-emission scenario, respectively.

Figure 5(a) shows the annual net emission (new emission after coal-to-gas switching minus baseline emission of 1.5ºC pathway) as a function of the coal-to-gas substitution fraction of LNG. In the 1.5ºC pathway, the LNG contribution to global carbon emissions reduces as the fraction of coal-to-gas substitution increases. Correspondingly, the annual net emissions compared with that of the baseline scenario reach zero or negative, resulting in positive climate benefit as shown in Figure 5a. Net-zero additional emissions can be achieved if at least 59% of LNG is used for coal-to-gas switching – the additional emissions from 41% of LNG is balanced by the reduction in coal emissions from the substitution. Whereas there is no emission reduction benefit after 2038 even with a 100% substitution rate of LNG because of the significant reduction in global coal use. Figure 5b shows the cumulative net emissions in the 1.5°C scenarios across different coal-to-gas substitution rates. The cumulative reduction in emissions prior to 2038 gets slowly eroded as more LNG comes online even as remaining coal generation declines. Even though there is a net climate benefit through 2050, it is smaller than that realized in 2038 when emission reduction from coal-to-gas substitution is maximized.

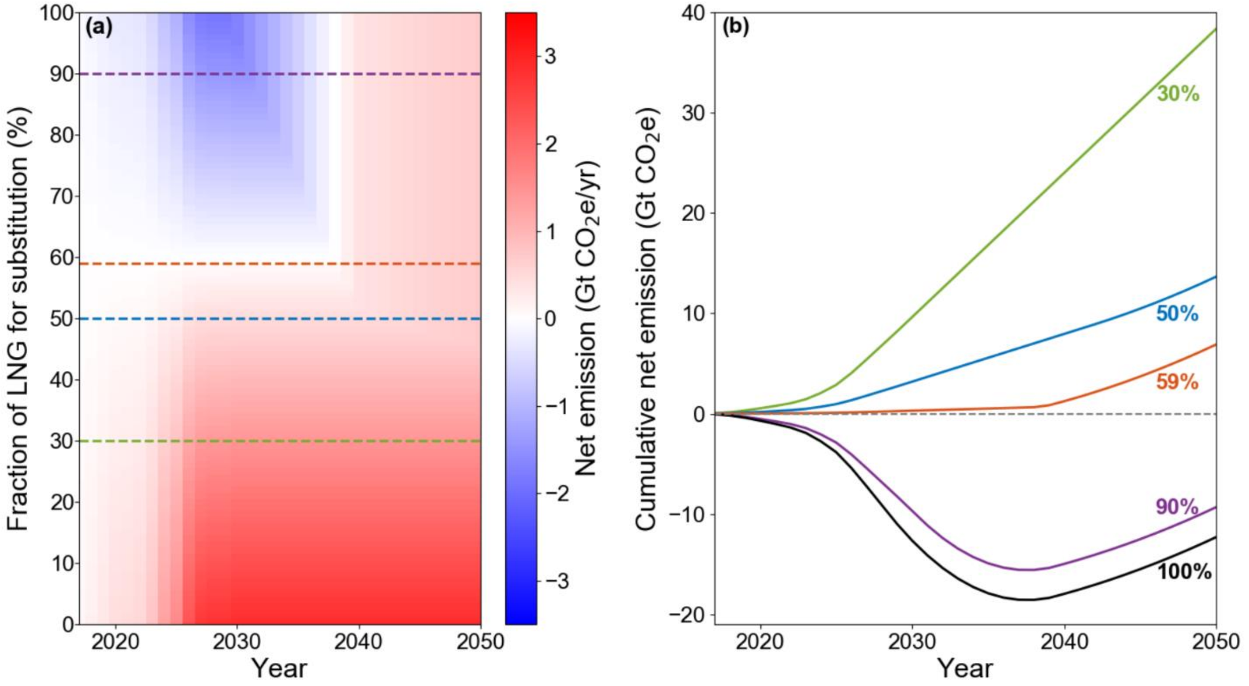

Figure 5. (a) Annual net emission after coal-to-gas switching as a function of coal-to-gas substitution fraction of LNG. Net negative emissions indicate positive climate benefits resulting from coal-to-gas switching. (b) Cumulative net emission through 2050 at coal-to-gas substitution rates of 30% (green), 50% (blue), 59% (orange), 90% (purple), and 100% (black).

Figure 6 shows the decadal change in average global temperatures associated with fuel switching in the power sector in 1.5ºC, 2ºC, and 3ºC pathways across different coal-to-gas substitution scenarios. The low-emissions, base-case, and high-emissions scenarios correspond to the sensitivity of different variables in the life cycle emissions estimates as shown in SI section S1. In general, improved mitigation of global warming through LNG growth is associated with a longer timescale and a higher carbon budget (2°C+ scenarios) in base-case and low-emission scenarios. There is no positive climate benefit in the high-emission scenario where LNG life cycle emissions are higher. Positive net emissions in the high-emission scenario after substitution result in temperature increases in all timescales under 1.5ºC, 2ºC, and 3ºC pathways. While this temperature increase is negligible in the near-term, it is comparable to the temperature reductions realized in the base-case scenario. This trend is especially prominent in the 1.5°C scenario given the rapid reduction in coal use beyond 2030.

In the 1.5°C pathway, the temperature benefit of coal-to-gas switching depends on the period of the fuel substitution and life cycle emissions of LNG. In the base-case scenario with a 2.3% methane leak rate, the net climate benefit in the near-term (before 2040) is larger than that in the longer term (2020 to 2050). This is because coal-to-gas substitution in the 1.5°C pathways beyond 2038 is coal-limited, leading to higher emissions over the long term.

In the 2ºC and 3ºC pathways, the climate benefits of coal-to-gas switching increase with time because of significant coal-based power available for substitution. In the base-case scenario, the global reduction in temperature is about 0.02ºC, or 2% compared to the baseline (see Supplementary Information Fig. S7). By contrast, switching coal-based power with carbon-free generation results in a temperature benefit up to about 0.06ºC, or a 10% reduction compared to baseline. Coal-to-gas switching can be a significant source of emissions reductions in a world that is headed to 3ºC of warming, assuming low LNG related life cycle emissions. In the short term (10 years), temperature change and reduction rate are similar in all three pathways from both LNG substitution and carbon-free fuel substitution. During the relatively long-time horizon (20 – 30 years), carbon-free fuel substitution results in a higher temperature reduction in 3°C pathway.

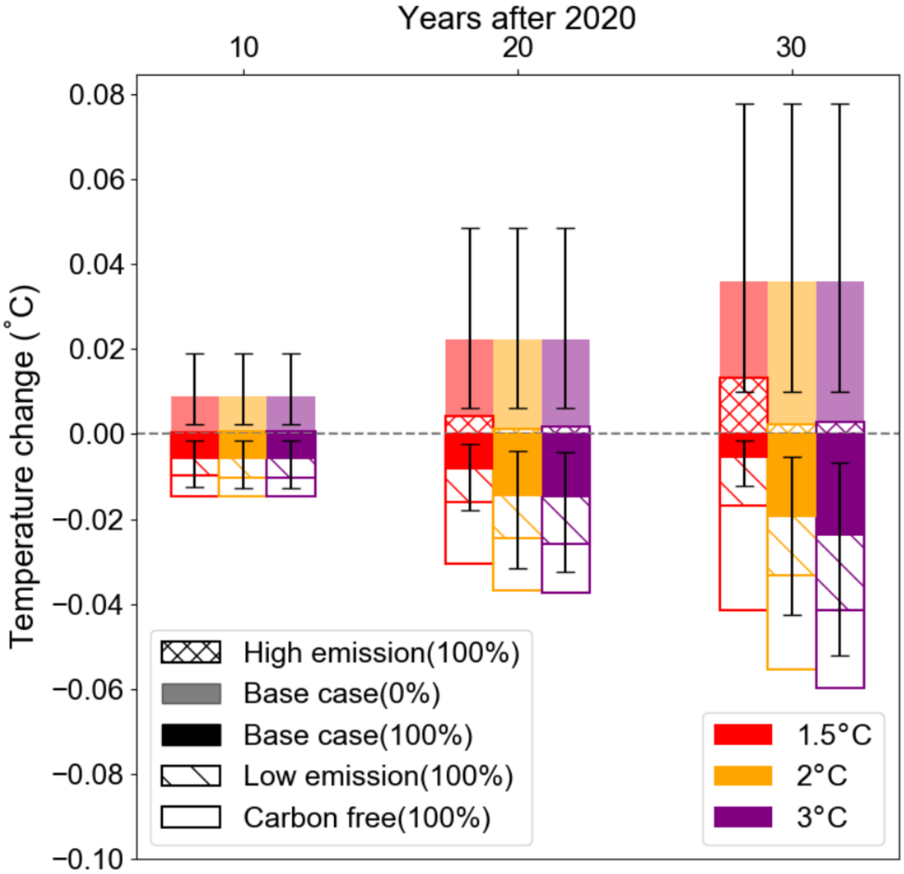

Figure 6. Absolute temperature change as a function of different coal-to-gas substitution scenarios in 1.5ºC (red), 2ºC (yellow), and 3ºC (purple) pathways during three periods: 2020 to 2030, 2020 to 2040, 2020 to 2050. The figure shows five scenarios – base-case with 0% coal-to-gas substitution (light shade), base-case with 100% coal-to-gas substitution (dark shade), low life cycle LNG emissions with 100% coal-to-gas substitution (right slant shading), high life cycle LNG emissions with 100% coal-to-gas substitution (crosshatch shading), and 100% coal-to-carbon free substitution (open bars). Positive and negative temperature changes represent the warming and

cooling effect, respectively, compared to baseline IPCC scenarios. Error bars illustrate 5% and 95% uncertainty of the base-case 0% and 100% coal-to-gas substitution scenarios.

4 Discussion and Implication

In this study, we analyze the climate impact of expected cumulative carbon emissions from currently operating and planned LNG export facilities. We find that the expansion of the LNG industry as planned is incompatible with the 1.5ºC temperature target of the Paris Agreement by 2050. This incompatibility derives from the significant reduction in coal-based power generation in all IPCC 1.5ºC scenarios leaving little room for coal-to-gas substitution. The power sector is thus 'coal limited' in the ability of LNG to reduce global emissions. Beyond 2030, coal-to-gas substitution starts eroding from the emissions gains made prior to 2030 as the reduction in coal-related emissions is lower than the additional emissions from LNG that is not used to substitute coal. In the 2°C pathway, coal-to-gas substitution provides maximum emission reduction benefits until 2038 when the volume of LNG available is larger than that required to substitute all coal-fired generation. In both the 1.5°C and 2°C scenarios, domestic policies in importing countries to move to carbon-free generation or increase reliance on domestic fuel sources create significant uncertainty in the long-term viability of LNG export projects. In a scenario where the global temperature is on a 3°C pathway, the power sector is 'LNG limited' through 2050 – there is enough coal-fired generation around the world to substitute with LNG and reduce global emissions. In this way, the role of the expansion of LNG could be considered as insurance against a potential lack of global climate action to limit temperatures to 1.5°C or 2°C pathways. This has several implications for our approach to LNG expansion including the need to plan for the potential for stranded assets and avoid carbon lock-in. For example, project economics could be evaluated under shortened time frames, and regulatory approvals could prioritize projects that are viable under shortened lifetimes. Where public support for projects is desirable, it could be structured in a way that reflects and considers the risk of stranded assets. Where a decision is made to pursue projects as an "insurance" for a 2ºC or higher pathway, the project could be explicitly structured as a cost for this insurance with near term profits shared/allocated/used accordingly. Similarly, the risk of creating carbon lock-in should be carefully managed to ensure an LNG build-out does not create pressure to extend the lifetime of gas power plants.

Moreover, it is also important to consider the limited benefit of coal-to-gas switching on the 2050-time horizon, even on a 3°C pathway, in evaluating the cost of such an "insurance". Future work should compare the cost and feasibility of the emission reductions that can be achieved through LNG growth coupled with coal-to-gas switching with that of a switch to non-fossil power sector alternatives. With the recent global momentum against the development and financing of new coal plants, this work demonstrates the sensitivity of climate benefits of LNG to the availability of coal plants presents significant uncertainty to the long-term viability of LNG export facilities.

In all cases, methane leakage plays an important role in the climate impact of LNG consumption. The contribution from exporting countries to global emission reductions through

LNG is limited by upstream actions to reduce methane leakage. The variation in leakage rates across global gas basins suggests that countries that effectively address methane emissions could have an emissions advantage in LNG exports in a climate-conscious world. Our study highlights the importance of future technological developments in methane monitoring in helping regulatory agencies and large customers to directly verify methane leakage across the NG supply chain. Unlike methane leakage, any emissions reductions from coal-to-gas substitution are clearly taking place within the importing country as a result of the decision to make this substitution and are attributable only to the actions of the importing country. It is imperative that any reduction in global emissions arising from a coal-to-gas substitution is not claimed by both the importing and exporting country in GHG emissions accounting.

This study focused on electricity generation given the importance of NG in the power sector and the current interest in the potential for LNG to reduce emissions through coal-to-gas switching. However, LNG can also be used in transportation, residential heating and cooking, and petrochemical production. The existence of these additional potential end uses further complicates the emissions savings from fuel-switching, but some general conclusions can be drawn from the findings as our results on total emissions from LNG apply to any combustion end-use. Future studies on the cumulative emissions impact of LNG can explore the potential for emissions reductions through the substitution of non-gas fuels in the heating and transportation sectors.

The findings of this study may help investors and regulators to consider stranded asset risks associated with the expanding LNG industry in the context of global climate action. While we show that LNG can play a limited role in the near to medium term in addressing global carbon emissions within the power sector, there are several risks for its long-term viability. These risks, including the stringency of global climate action, should be carefully weighed against the long lifetimes of LNG infrastructure when making investment decisions. This is particularly important for countries such as the US and Canada that are poised to become two of the largest exporters and are considering significant government support for new development such that stranded assets will have significant implications for public finances. For major importers, the simple model presented here can help policymakers understand the potential for carbon lock-in before greenlighting an expansion of NG power plants or import terminals.

Acknowledgments

The authors acknowledge funding from Harrisburg University of Science and Technology.

Author contributions

A.P.R. and S.H.S. conceived the study. S.Y. compiled and verified the data underlying this study and developed the technical analyzes. S.Y., A.P.R., and S.H.S. discussed and interpreted the results. All authors contributed to writing the paper.

Additional information

Supplementary dataset is available online: https://doi.org/10.7910/DVN/TDYYLN

Competing interests

The authors declare no competing interests.

Supporting Information

S1. Calculation of life cycle emissions from LNG operational chain

Life cycle assessment (LCA) of liquefied natural gas (LNG) was conducted by quantifying the GHG emissions associated with each stage of the LNG operational chain: upstream (exploration and production), liquefaction, transportation, regasification, and end-use. We estimate parameter values based on a systematic literature survey of publicly available, peer-reviewed LCA studies. For parameters with multiple published values, we use the median estimate for base-case scenario analysis and the range for the low- and high-emission scenarios.

To convert methane leakage estimates from natural gas (NG) production and transportation to CO_2 equivalent estimates, we use 100-year global warming potential (GWP) (fossil methane with climate-carbon feedback) from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) [44]. The exception to the use of AR5 GWPs is for the emissions estimates in the literature for liquefaction and regasification life cycle stages that used GWP values from the IPCC second or fourth assessment report. However, because the majority of liquefaction and regasification emissions originate from fuel combustion rather than from CH_4 leakage or venting [45], it is likely that these estimates would not change the overall LNG life cycle emission. The estimates for each stage are shown in Table S1.

Table S1 Summary of estimated emissions intensity of each LNG stage. The units are g CO_2e/MJ unless otherwise noted.

Parameter	Type	Value		
		Low	Base-case	High
Upstream	Assumed parameter	3.1	17.2	44.5
Liquefaction	Adapted from literature	3.9	5.8	7.4
Transportation	Calculated	0.19	2.1	6.2
Regasification	Adapted from literature	0.36	1	1.6

End-use (g CO_2e/kWh)	Calculated	343	402	455
Life cycle emission intensity (g CO_2e/kWh)	Calculated	400	632	1052

S1.1 Upstream

The complexity and scale of upstream operations, as well as the level of control over operations that producers have, make upstream emissions a prime target for reduction efforts. The upstream stage of the LNG supply chain includes exploration, production, and pipeline transmission of NG to the liquefaction facility. Emissions are mainly associated with fugitive methane leaks, venting, and fuel combustion. Prior studies across US shale basins have estimated fugitive emissions rates between 1 and 9% and a recent model suggests that the most likely value is 2−4% since 2000 [29]. In this study, we take 2.3% as our central assumption of CH_4 fugitive emission rate, based on a recent meta-analysis of published methane emissions studies across several US basins [24]. Also, we explore the impact of differences in methane leakage across US shale basins and globally on the life cycle emissions of LNG. Global methane leakage rates are derived from the International Energy Agency (IEA) Global Methane Tracker and supplemented with data from peer-reviewed studies [30, 46-49]. The methane leakage rates considered in this analysis range from 0.1% in Qatar to 6.4% in Russia. Estimates of non-methane fugitive emissions from the upstream stage (e.g., lease and plant energy emission and operational transmission emissions (compression combustion)) were adapted from Weber et al. (2012) [50]. Non-operational emissions associated with the transmission (e.g., steel use in pipelines and land-use changes) are not considered in this case. Detailed calculations of upstream emissions are shown in Table S2.

Table S2 Parameters and assumptions used to estimate upstream emission

Parameter	Unit	Assumption		
		Low	Base-case	High
Upstream fugitive methane emission rate [24, 51-56]	%	0.1	2.3	6.4
Upstream production and transportation emissions [50]	g CO_2e/MJ	2.64	5.56	10.71
Average CH_4 content in NG	vol%		90	
CH_4 density	kg/m³		0.657	

S1.2 Liquefaction

In the liquefaction stage, emissions are associated with fuel consumption at plants, flare combustion, and vented emissions. Inputs of liquefaction emissions are obtained from simulation results suggested by Abrahams et. al (2015) [33], which were derived from a constructed distribution built upon estimates of prior studies and industry reports. In the base-case scenario, we use an emissions intensity estimate of 5.8 g CO_2e/MJ, with low and high sensitivity cases of 3.9 g CO_2e/MJ and 7.4 g CO_2e/MJ, respectively.

S1.3 Transportation

Transportation emission is primarily from the combustion of fossil fuels in main engines, auxiliary engines, and boilers of LNG shipping vessels, which are highly dependent on the carbon content of fuel and fuel consumption. In our simplified case scenario, we make several assumptions:

(1) LNG tankers return to the origin port. Because there is a network of tankers, in reality, rather than being commissioned at its original port of origin, the tanker would likely be sent to the nearest port for its next LNG cargo.

(2) tankers are fueled by diesel for the whole trip. LNG tankers are powered by either re-gasified cargo LNG, bunker fuel, or diesel. We take diesel was taken as the prototype as the choice of fuel has a limited(?) impact of the tanker fuel source on greenhouse gas emissions on a per-unit basis [33]. Total transportation emission of LNG export is determined by shipping distance (D), tanker speed (s), rated power of engine (r), emission factor of shipping fuel (EF), cargo capacity (C_c), and the export capacity of each year (C_e). For a particular year, transportation emission of LNG export is the result of the emission from one cargo and the number of cargoes of that year. Thus, transportation emission is calculated as follows:

$$Emission = \frac{2\mathrm{D}}{\mathrm{s}} \times r \times EF \times \frac{C_e}{C_c}$$

The corresponding parameters are shown in Table S3. Global average shipping distance is estimated as the average sea distances between 41 global major LNG flows as shown in Figure S1 [36]. The average LNG shipping distance in the base-case scenario is assumed to be 8000 km.

Table S3 Parameters and assumptions used to estimate upstream emission

Parameter	Unit	Assumption		
		Low	Base-case	High
Weighted LNG cargo capacity [36]	m^3		137600	
Shipping distance [36, 57]	km	750 (Algeria-France)	8000	23800 (Russia (Archangel)-Japan (Aboshi))
Average carrier speed [58]	km/h		35.2	
Emission factor (diesel) [9]	g CO_2e/MJ		70	
Engine rated power (diesel) [33]	MW/hr		60	
LNG density [59]	kg/m^3		450	

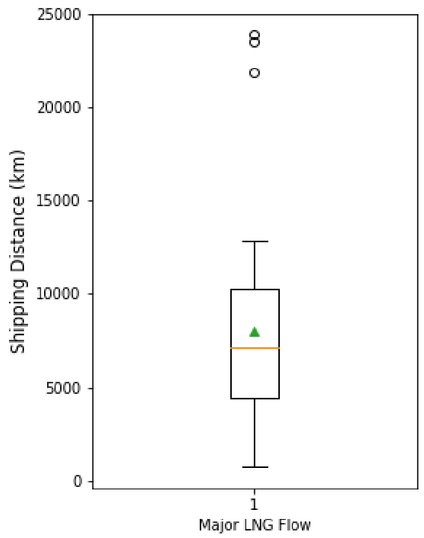

Fig S1. Estimates of shipping distance of 41 global major flows.

Global averaged cargo capacity is calculated by conducting weighted averaging based on LNG fleet statistics in 2018 [36], as shown in Table S4.

Table S4 LNG cargo capacity and fleet statistics in 2018

Cargo capacity (m^3)	Number of fleets
< 25000	33
25000-50000	11
50000-90000	7
90000-150000	219
150000-170000	127
170000-210000	120

S1.4 Regasification

We take 0.36 and 1.6 g CO_2e/MJ as the lower and upper bounds of the possible range of regasification emissions – this assumes that 0.15 – 3% of gas is used on-site at the regasification terminal [45, 60]. The base case estimate for regasification emission is 1 g CO_2e/MJ [33].

S1.5 End-use

The end-use emission from combustion was calculated based on the parameters and assumptions outlined in Table S6. The parameters and efficiency of NG-fueled power plants are also shown in Table S5.

Table S5 Parameters and assumptions used to estimate end-use emission and fuel transition

Parameter	Unit	Assumption		
		Low	Base-case	High

LNG Calorific value (energy content) [59]	MJ/kg		53.6	
NG emission factor [61]	g CO_2e/ft^3		53.1	
Heat content of natural gas [62, 63]	Btu/ft^3	1074	1038	966
Natural gas plant heat rate [64, 65]	Btu/kWh	6935	7732	8281

S1.6 Sensitivity analysis of GWP on cumulative LNG export emission

Between 2017 and 2050, the cumulative emission of LNG export is calculated in three emission scenarios: low-emission, base-case, and high-emission scenarios. For the upstream emission estimates, both 100 and 20-year GWP for methane (fossil methane with climate carbon feedbacks) from the IPCC AR5 were used and estimated cumulative emissions are shown in Figure S2. The difference in estimates is negligible in the low-emissions scenario because of the low methane leakage across the LNG supply chain. Cumulative emission increases by around 22% and 30% in base-case and high-emission scenarios, respectively when using 20-year GWP compared to 100-year GWP values.

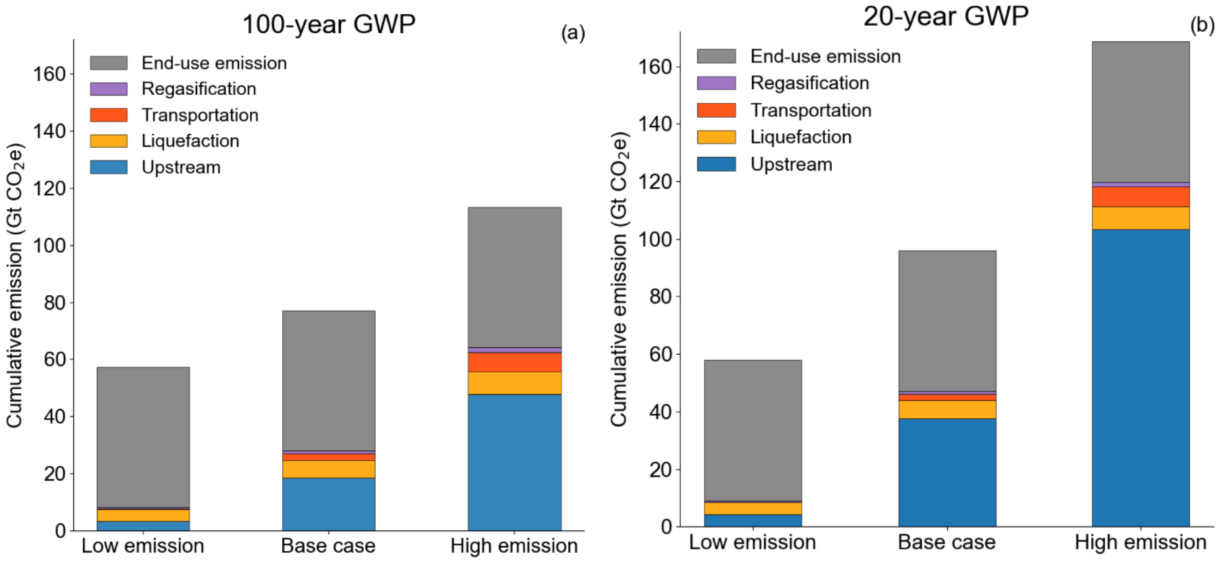

Fig S2. Cumulative lifecycle LNG emission between 2017 to 2050 based on (a) 100-year GWP, and (b) 20-year GWP, in the low-emissions, base-case, and high emissions scenarios.

S1.7 Sensitivity analysis of upstream emission rate on attributional GHG emissions from LNG supply chain

Addressing the methane leakage challenge is critical to reducing the lifecycle emissions across the LNG supply chain. Figure S3 shows the relative contribution of each stage of emission in the LNG supply chain as a function of upstream methane leakage in the base-case scenario. For methane leakage rates below 1%, emissions across the LNG life cycle prior to end-use contribute only about 20% to the overall emissions with the remaining 80% coming from the combustion. However, the contribution of upstream methane leakage to total emissions increases as methane leakage increases – at a leak rate of 10%, upstream emissions are responsible for nearly 50% of total emissions. The results from top-down aircraft-based measurements of methane emissions across six major US oil and gas production areas are also shown as dotted lines in Figure S3. In our base-case scenario using the national average methane leak rate of 2.3%, about two-thirds of life cycle emissions can be attributed to end-use.

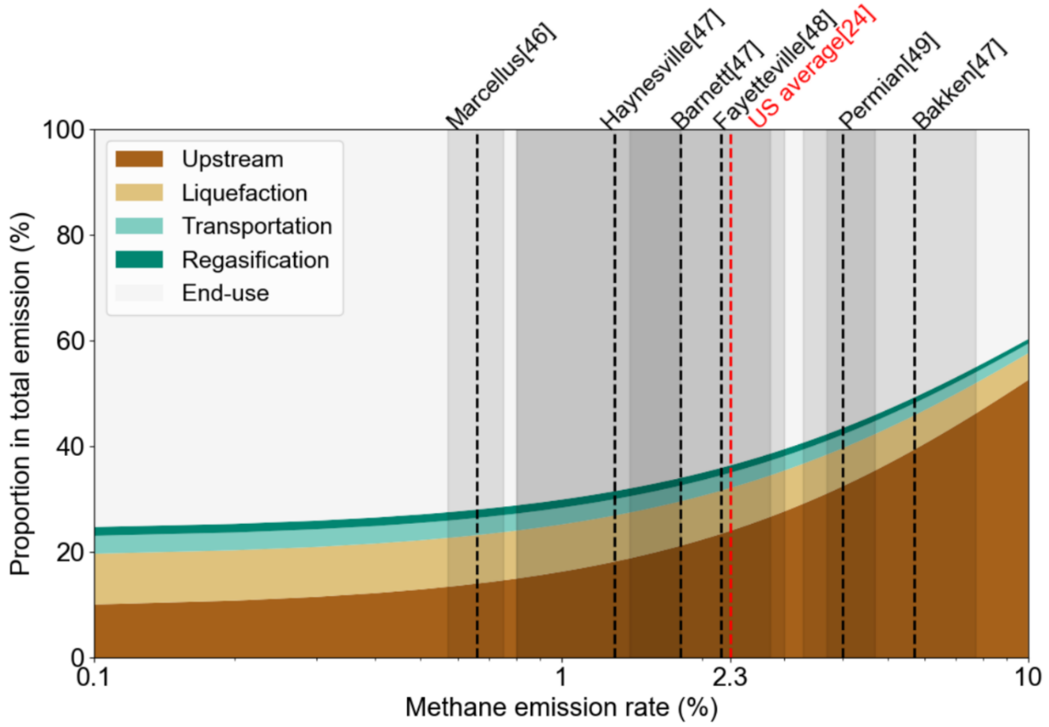

Fig S3. Fractional emissions contribution of each stage of the LNG supply chain as a function of upstream methane emission rate. The red dashed line indicates the base case scenario with an assumed leak rate of 2.3% and the fraction of emissions from each stage in total emission are: upstream 24%, liquefaction 8.1%, transportation 2.9%, regasification 1.4%, and end-use 63.6%. Reported estimates of methane emissions from aircraft-based top-down (TD) studies for six major US oil and gas production areas are listed and represented by black dashed lines with shaded errors [46-49]. These results have been harmonized by considering transmission and local distribution to be comparable with the national production normalized emission rate of 2.3% [24].

S2. Impact of start year on global LNG export and import capacity

The criterion for assigning start years to the projects without announced operational dates is based on data from existing projects and operator projections. First, we add five years to projects that are ready for construction and six additional years to those that are waiting for a final investment decision by 2020 [66] under normal circumstances. Second, one and three year(s) are added to projects that only involve adding new trains or expanding existing terminal infrastructure, respectively. To test the sensitivity of global liquefaction and regasification capacity to project start date, we consider delays in the construction of proposed and under-construction terminals by two and four years. As shown in Figure S4, the peak export and import capacity and net supply capacity (export minus import) depend on project start dates. In the base-case scenario with an averaged 35-year lifetime of facilities, both global cumulative export and import capacity will reach peaks in 2030. The balance of supply and demand will happen in 2025. In the 2-year delay scenario, the peak of cumulative export capacity will also happen in 2032, whereas maximum cumulative import capacity will occur in 2029 with a delayed timing of supply and demand balance in 2027. In the 4-year delay scenario, peak export and import capacity will occur in 2034 and 2031, respectively. In 2029, the net supply capacity will approach zero. It worth noting that the breakeven time of export and import capacity is proportional to the delay in the start year of proposed and under-construction projects.

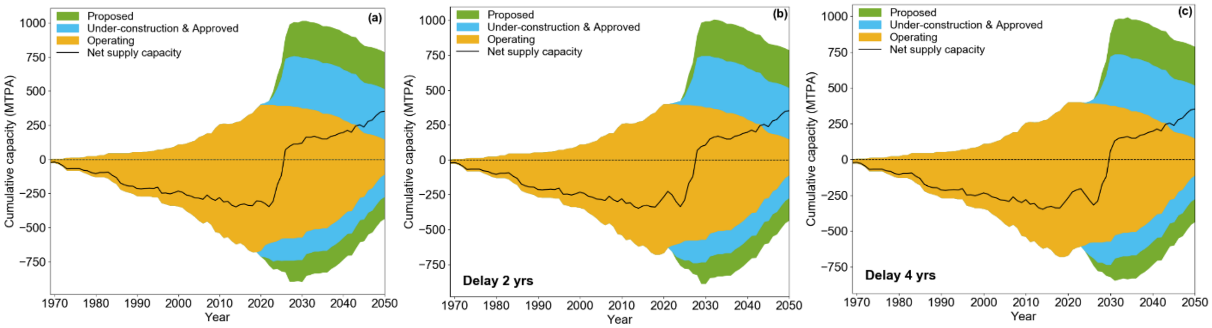

Fig S4. Global cumulative export and import capacity from 1969 to 2050. Export and import capacities are presented as positive and negative numbers, respectively. (a) Cumulative capacity of existing, under-construction, and proposed projects under the base-case assumption. (b) Cumulative capacity of existing, under-construction, and proposed projects if proposed and under-construction projects are delayed 2 years. (c) similar to (b) but projects are delayed four years. The black solid line is the net capacity indicating global annual exporting capacity minus importing capacity.

S3. Viability of LNG expansion

IPCC uses scenarios called ‘pathways’ to explore possible changes in future energy use, greenhouse-gas emissions, and temperature. This study follows the framework of IPPC’s “Shared Socioeconomic Pathways” (SSPs), which is an important input to the upcoming sixth assessment report investigating five different ways to explore how societal choices will affect GHG emissions and, therefore, how the climate goals of the Paris Agreement could be met. Given current policies, we chose the SSPs that reflect temperature trajectories aiming to limit peak warming to below 1.5°C, 2°C, and 3°C. Corresponding scenarios are selected using Integrated Assessment Modeling Consortium (IAMC) 1.5°C Scenario Explorer and detailed criteria used for filtering data are shown in Table S6 [67].

Table S6 Criteria applied for selecting scenarios using IAMC 1.5°C Scenario Explorer

Temperature Target	Category	Project	Numbers of scenarios

1.5°C	1.5°C high overshoot	SSP/SSP (1.9Wm2)	13
	1.5°C low overshoot		
	Below 1.5°C		
2°C	Higher 2°C	SSP	18
	Lower 2°C		
3°C	Above 2°C (with additional filter: median warming at peak (MAGICC6): 2.1~3.1°C	SSP	48

In the pre-processing procedure, the annual total CO_2 emissions, generated secondary energy from NG and coal in the electricity sector, and expected global mean temperature were extracted from the selected pathways and averaged as the reference inputs for our calculations. Since SSPs were developed and established in 2016, LNG projects that start operating since 2017 were treated as new contributions to the budgets of SSPs pathways. The cumulative emission of LNG export between 2017 to 2050 was calculated to analyze the compatibility and impact of LNG expansion on global emission budgets and temperature targets.

S3.1 Impact of LNG expansion on global emission budget

Figure S5 shows the average annual global emissions across all analyzed SSPs that limit peak warming to below 1.5°C, 2°C, and 3°C. In addition, it shows the emissions from existing, proposed, and under-construction LNG infrastructure through 2050. As shown in Figure S5, emissions from existing and under-construction LNG infrastructures in 2050 will take up roughly 140%, 20%, and 9% of the carbon budget of 1.5ºC, 2ºC, and 3ºC, respectively.

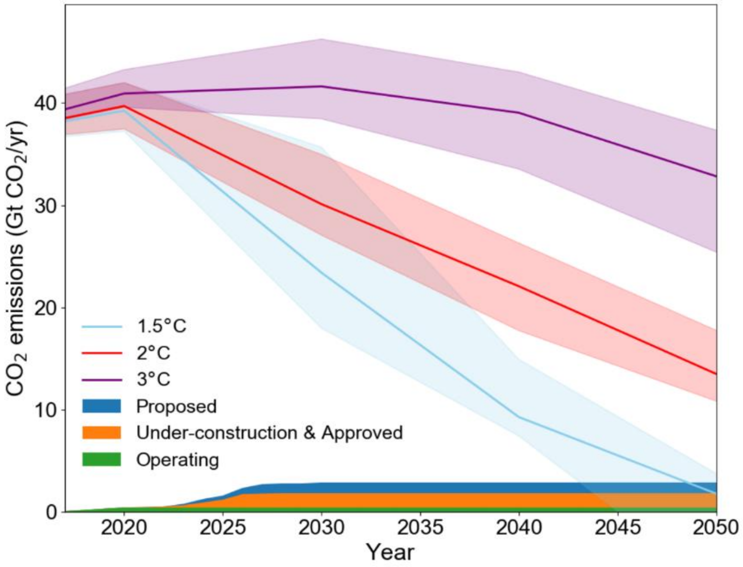

Fig S5. Cumulative emissions from existing, under-construction, and proposed LNG export projects for electricity generation based on a 100-year GWP, 35-year assumed lifetime, and 2.3% average fugitive leak rate. Colored solid lines and the light shades are 1.5°C, 2°C, and 3°C emission scenarios with 25th and 75th percentile.

S3.2 Climate benefit from coal-to-gas switching

The emissions reduction potential for LNG is a function of coal-to-gas substitution rates in the power sector. The efficiency of the NG power plant, heat content of NG, and NG emissions factor are important parameters required for determining end-use emissions of the LNG life-cycle assessment. Approximate heat rate of NG-fueled plants for electricity net generation in the United States is 7732 Btu/kWh (44.1% efficiency) in 2019 [68], which is derived from electric power plants in the utility and electricity-only independent power producer sectors. Combined heat and power plants, and all plants in the commercial and industrial sectors are excluded from the calculations. In our analysis, we take this number as the power plant efficiency in the base-case scenario. The efficiency range of 41.2% ~ 49.2% is designed to be representative of NG-fueled power plants in the destinations [69]. Policies that specify acceptable NG composition and heat rates vary by region – typical limits include a maximum of 4% of inert gases (nitrogen, argon, and CO_2) and a heat rate in the 966~1074 Btu/ft^3 range [63]. We use the heat content of NG deliveries to electric power consumers in the US as the central input in the base-case scenario. Our study does not include transmission emissions in the end-use stage because we assume power plants at the destination are local nearby regasification facilities.

In the low-emission scenario of 1.5ºC pathway, a 39% substitution rate of LNG achieves net-zero additional emissions (Figure S6). In contrast, net-zero additional emission cannot be achieved in the high-emission scenario under 1.5ºC pathway for all coal-to-gas substitution rates. The breakeven point in the base-case scenario is 59%. In 2ºC and 3ºC pathway with sufficient coal budgets, positive emission reduction can be always achieved in three emission scenarios.

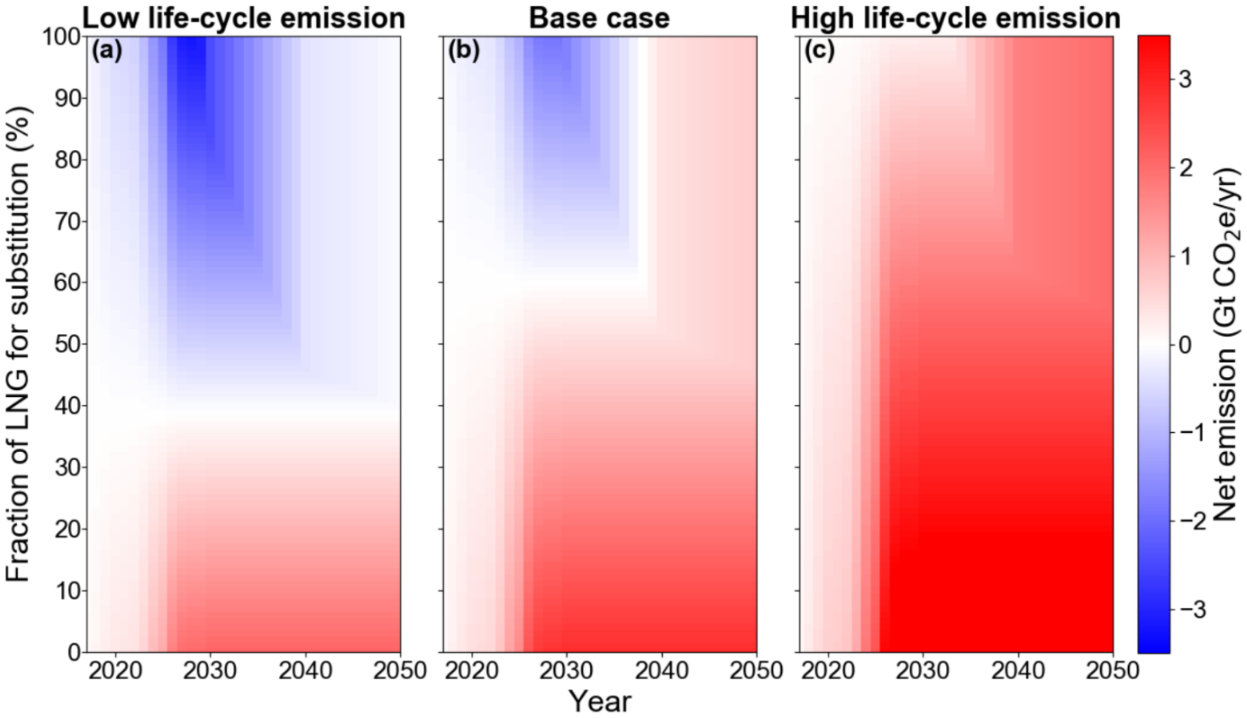

Fig S6. Net emission of coal plus NG benefiting from coal-to-gas switching regarding various substitution fraction of LNG in low-emission (a), base-case (b), and high-emission scenario (c).

Earth System Models (ESMs) have helped quantify the gradient of the approximately linear and scenario-independent relationship between cumulative emissions of CO_2 and resultant global mean warming [70-75]. Using ESM-based estimates along with observational constraints, IPCC's AR5 assessed the transient climate response to cumulative emissions (TCRE—the global mean warming following a 1000 GtC injection of CO_2 into the atmosphere) to be likely (greater than 66% probability) between 0.8 and 2.5°C [76]. Figure S7 shows the expected average temperature change of 1.5°C, 2°C, and 3°C pathway. Since the magnitude of warming is determined by cumulative CO_2 emissions, the corresponding temperature benefit from coal-to-gas switching is evaluated using the TCRE metric. Parameters used to estimate climate benefit from coal-to-gas switching is shown in Table S7.

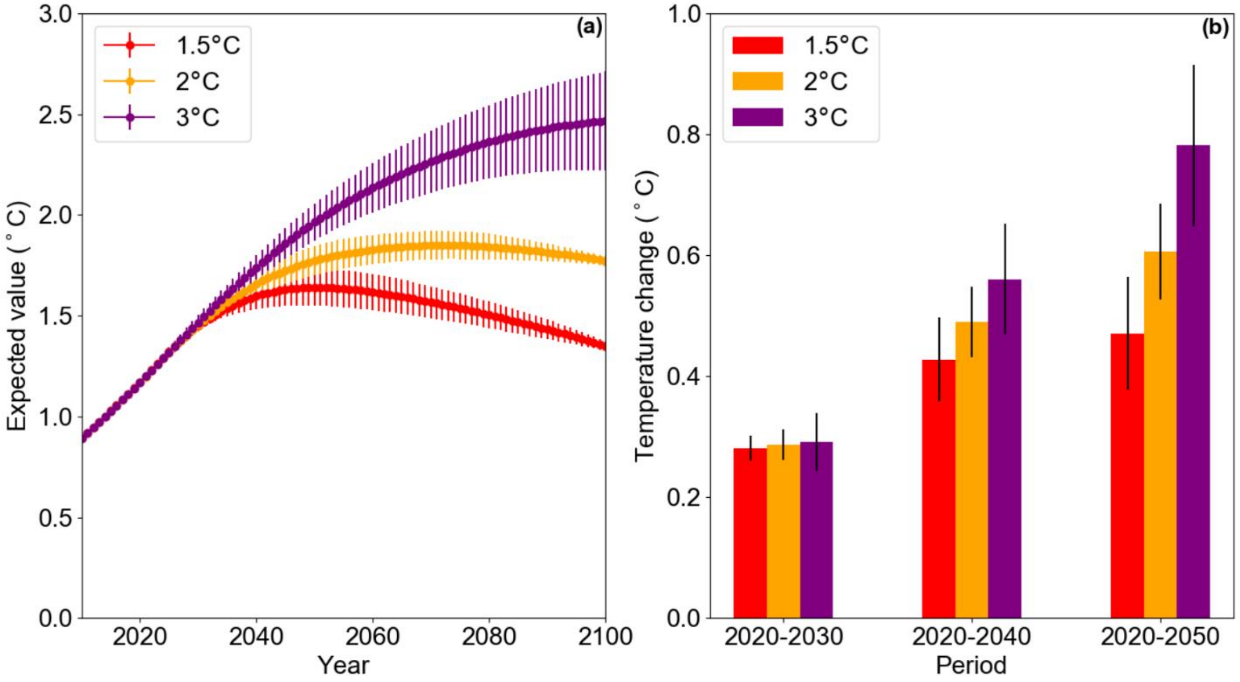

Fig S7. (a) Expected temperature trend of 1.5°C, 2°C, and 3°C from 2010 to 2100. (b) Average temperature change during three periods: 2020 to 2030, 2020 to 2040, 2020 to 2050. Error bars show one standard deviation.

Table S7 Parameters used to estimate climate benefit from coal-to-gas switching

Parameters	Unit	Values
Coal-to-gas switching rate	%	0-100
TCRE[41]	°C/Gt CO_2e	0.00047 (0.00013-0.00102, 5%-95% uncertainty)
Natural gas lifecycle emission (carbon) intensity[77]	g CO_2e/kWh	469
Coal lifecycle emission (carbon) intensity[77]	g CO_2e/kWh	1001

References:

[1] EIA. "International Energy Outlook 2019." https://www.eia.gov/outlooks/ieo/pdf/ieo2019.pdf (accessed January 8, 2020).

[2] L. M. Cathles, "Assessing the greenhouse impact of natural gas," *Geochemistry, Geophysics, Geosystems*, vol. 13, no. 6, pp. n/a-n/a, 2012, doi: 10.1029/2012GC004032.

[3] M. Levi, "Climate consequences of natural gas as a bridge fuel," *Climatic Change,* vol. 118, no. 3-4, pp. 609-623, 2013, doi: 10.1007/s10584-012-0658-3.

[4] A. Gilbert and B. Sovacool, "Benchmarking natural gas and coal-fired electricity generation in the United States," *Energy*, vol. 134, p. 622, 2017.

[5] Z. Hausfather, "Bounding the climate viability of natural gas as a bridge fuel to displace coal," *Energy Policy* vol. 86, pp. 286-294, 2015, doi: https://doi.org/10.1016/j.enpol.2015.07.012.

[6] X. Zhang, N. Myhrvold, and K. Caldeira, "Key factors for assessing climate benefits of natural gas versus coal electricity generation," *Environmental Research Letters,* vol. 9, no. 11, 2014, doi: 10.1088/1748-9326/9/11/114022.

[7] R. Lueken, K. Klima, W. M. Griffin, and J. Apt, "The climate and health effects of a USA switch from coal to gas electricity generation," *Energy,* vol. 109, no. C, pp. 1160-1166, 2016, doi: 10.1016/j.energy.2016.03.078.

[8] P. Jaramillo, W. M. Griffin, and H. S. Matthews, "Comparative life-cycle air emissions of coal, domestic natural gas, LNG, and SNG for electricity generation," *Environmental science & technology,* vol. 41, no. 17, pp. 6290-6296, 2007, doi: 10.1021/es063031o.

[9] EIA. "Carbon Dioxide Emissions Coefficients." https://www.eia.gov/environment/emissions/co2_vol_mass.php (accessed May, 2020).

[10] E. Lim, "South Korea's Nuclear Dilemmas," *Journal for Peace and Nuclear Disarmament,* vol. 2, no. 1, pp. 297-318, 2019, doi: 10.1080/25751654.2019.1585585.

[11] R. Rehner and D. McCauley, "Security, justice and the energy crossroads: Assessing the implications of the nuclear phase-out in Germany," *Energy Policy,* vol. 88, pp. 289-298, 2016, doi: 10.1016/j.enpol.2015.10.038.

[12] J. Moore and T. Gustafson, "WHERE TO NOW? Germany Rethinks its Energy Transition," *German politics and society,* vol. 36, no. 3, p. 1, 2018, doi: 10.3167/gps.2018.360301.

[13] T. Kompas and T. N. Che, "A structural and stochastic optimal model for projections of LNG imports and exports in Asia-Pacific," *Heliyon,* vol. 2, no. 6, 2016, doi: 10.1016/j.heliyon.2016.e00108.

[14] D. S. Mallapragada, I. Naik, K. Ganesan, R. Banerjee, and I. J. Laurenzi, "Life Cycle Greenhouse Gas Impacts of Coal and Imported Gas-Based Power Generation in the Indian Context," *Environmental science & technology,* vol. 53, no. 1, pp. 539-549, 2019, doi: 10.1021/acs.est.8b04539.

[15] F. Shaikh, Q. Ji, and Y. Fan, "Assessing the stability of the LNG supply in the Asia Pacific region," *Journal of Natural Gas Science and Engineering,* vol. 34, pp. 376-386, 2016, doi: 10.1016/j.jngse.2016.07.011.

[16] D. Jacobs, "The Global Market for Liquefied Natural Gas," RBA Bulletin, September 2011.

[17] IGU. "2019 World LNG Report." https://www.igu.org/sites/default/files/node-news_item-field_file/IGU%20Annual%20Report%202019_23%20loresfinal.pdf (accessed January 2, 2020).

[18] S. L. Sakmar, "The Globalization and Environmental Sustainability of LNG: Is LNG a Fuel for the 21st Century?," presented at the World Energy Congress, Montreal, Canada, 2010.

[19] D. A. Wood, "A review and outlook for the global LNG trade," *Journal of Natural Gas Science and Engineering,* vol. 9, pp. 16-27, 2012, doi: 10.1016/j.jngse.2012.05.002.

[20] K. B. Medlock, A. M. Jaffe, apos, and M. Sullivan, "The global gas market, LNG exports and the shifting US geopolitical presence," *Energy Strategy Reviews,* vol. 5, pp. 14-25, 2014, doi: 10.1016/j.esr.2014.10.006.

[21] UNFCCC. "Paris agreement. FCCC/CP/2015/L.9/Rev1." http://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf (accessed November, 2020).

[22] J. Rogelj *et al.*, "Scenarios towards limiting global mean temperature increase below 1.5 °C," *Nature Climate Change,* vol. 8, no. 4, pp. 325-332, 2018, doi: 10.1038/s41558-018-0091-3.

[23] K. Riahi *et al.*, "The Shared Socioeconomic Pathways and their energy, land use, and greenhouse gas emissions implications: An overview," *Global Environmental Change,* vol. 42, p. 153, 2017.

[24] R. A. Alvarez *et al.*, "Assessment of methane emissions from the U.S. oil and gas supply chain," *Science (New York, N.Y.),* vol. 361, no. 6398, pp. 186-188, 2018, doi: 10.1126/science.aar7204.

[25] IPCC, "Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]." IPCC, Geneva, Switzerland, 2014.

[26] A. A. Ramón, W. P. Stephen, J. W. James, L. C. William, and P. H. Steven, "Greater focus needed on methane leakage from natural gas infrastructure," *Proceedings of the National Academy of Sciences - PNAS,* vol. 109, no. 17, pp. 6435-6440, 2012, doi: 10.1073/pnas.1202407109.

[27] A. R. Brandt *et al.*, "Methane Leaks from North American Natural Gas Systems," (in English), *Science,* Editorial Material vol. 343, no. 6172, pp. 733-735, Feb 2014, doi: 10.1126/science.1247045.

[28] R. Harriss, R. A. Alvarez, D. Lyon, D. Zavala-Araiza, D. Nelson, and S. P. Hamburg, "Using Multi-Scale Measurements to Improve Methane Emission Estimates from Oil and Gas Operations in the Barnett Shale Region, Texas," (in English), *Environmental Science & Technology,* Editorial Material vol. 49, no. 13, pp. 7524-7526, Jul 2015, doi: 10.1021/acs.est.5b02305.

[29] S. Schwietzke, W. M. Griffin, H. S. Matthews, and L. M. P. Bruhwiler, "Natural gas fugitive emissions rates constrained by global atmospheric methane and ethane," *Environmental science & technology,* vol. 48, no. 14, pp. 7714-7722, 2014, doi: 10.1021/es501204c.

[30] IEA. "Methane Tracker 2020." https://www.iea.org/reports/methane-tracker-2020 (accessed August, 2020.

[31] A. Q. Gilbert and B. K. Sovacool, "Carbon pathways in the global gas market: An attributional lifecycle assessment of the climate impacts of liquefied natural gas exports from the United States to Asia," *Energy policy,* vol. 120, pp. 635-643, 2018, doi: 10.1016/j.enpol.2018.05.063.

[32] Y. Nie *et al.*, "Greenhouse-gas emissions of Canadian liquefied natural gas for use in China: Comparison and synthesis of three independent life cycle assessments," *Journal of Cleaner Production,* vol. 258, 2020, doi: 10.1016/j.jclepro.2020.120701.

[33] L. S. Abrahams, C. Samaras, W. M. Griffin, and H. S. Matthews, "Life cycle greenhouse gas emissions from U.S. liquefied natural gas exports: implications for end uses," *Environmental science & technology,* vol. 49, no. 5, pp. 3237-3245, 2015, doi: 10.1021/es505617p.

[34] Y. Zhang *et al.*, "Life cycle assessment and optimization analysis of different LNG usage scenarios," *The International Journal of Life Cycle Assessment,* vol. 23, no. 6, pp. 1218-1227, 2018, doi: 10.1007/s11367-017-1347-2.

[35] X. Zhang, N. Myhrvold, Z. Hausfather, and K. Caldeira, "Climate benefits of natural gas as a bridge fuel and potential delay of near-zero energy systems," *Applied Energy,* vol. 167, pp. 317-322, 2016, doi: 10.1016/j.apenergy.2015.10.016.

[36] GIIGNL. "GIIGNL Annual Report 2019." https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_annual_report_2019-compressed.pdf (accessed January, 2020).

[37] "Global Energy Monitor. Global Fossil Infrastructure Tracker." http://ggon.org/fossil-tracker/ (accessed May, 2020).

[38] IGU, "2020 WORLD LNG REPORT ", 2020. [Online]. Available: https://www.igu.org/app/uploads-wp/2020/04/2020-World-LNG-Report.pdf

[39] R. Joeri *et al.*, "Paris Agreement climate proposals need a boost to keep warming well below 2 °C," *Nature,* vol. 534, no. 7609, p. 631, 2016, doi: 10.1038/nature18307.

[40] Z. Hausfather and G. P. Peters, "Emissions - the 'business as usual' story is misleading," *Nature,* vol. 577, no. 7792, p. 618, 2020, doi: 10.1038/d41586-020-00177-3.

[41] J. Rogelj *et al.*, "Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development," in *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. In Press.*, 2018.

[42] EIA. "Natural Gas Weekly Update." https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/12_12/#itn-tabs-1 (accessed May, 2020).

[43] IPCC, "Summary for Policymakers," in "Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty," World Meteorological Organization, Geneva, Switzerland, 2018.

[44] *Climate Change 2013 - The Physical Science Basis* (Climate Change 2014). Intergovernmental Panel on Climate Change, 2013.

[45] I. Tamura *et al.*, "Life Cycle CO_2 Analysis of LNG and City Gas," *Applied Energy,* vol. 68, no. 3, pp. 301-301, 2001.

[46] Z. R. Barkley *et al.*, "Quantifying methane emissions from natural gas production in north-eastern Pennsylvania," *Atmospheric Chemistry and Physics,* vol. 17, no. 22, p. 13941, 2017, doi: 10.5194/acp-17-13941-2017.

[47] J. Peischl *et al.*, "Quantifying Methane and Ethane Emissions to the Atmosphere From Central and Western U.S. Oil and Natural Gas Production Regions," *Journal of Geophysical Research: Atmospheres,* vol. 123, no. 14, pp. 7725-7740, 2018, doi: 10.1029/2018JD028622.

[48] J. Peischl *et al.*, "Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions," *Journal of Geophysical Research: Atmospheres,* vol. 120, no. 5, pp. 2119-2139, 2015, doi: 10.1002/2014JD022697.

[49] Y. Zhang *et al.*, "Quantifying methane emissions from the largest oil-producing basin in the United States from space," *Science advances,* vol. 6, no. 17, pp. eaaz5120-eaaz5120, 2020, doi: 10.1126/sciadv.aaz5120.

[50] C. L. Weber and C. Clavin, "Life cycle carbon footprint of shale gas: review of evidence and implications," *Environmental science & technology,* vol. 46, no. 11, pp. 5688-5695, 2012, doi: 10.1021/es300375n.

[51] A. Venkatesh, P. Jaramillo, W. M. Griffin, and H. S. Matthews, "Uncertainty in life cycle greenhouse gas emissions from United States natural gas end-uses and its effects on policy," *Environmental science & technology,* vol. 45, no. 19, pp. 8182-8189, 2011, doi: 10.1021/es200930h.

[52] R. Howarth, R. Santoro, and A. Ingraffea, "Methane and the greenhouse-gas footprint of natural gas from shale formations," *Climatic Change*, vol. 106, no. 4, pp. 679-690, 2011, doi: 10.1007/s10584-011-0061-5.

[53] A. Burnham, J. Han, C. E. Clark, M. Wang, J. B. Dunn, and I. Palou-Rivera, "Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum," *Environmental science & technology*, vol. 46, no. 2, pp. 619-627, 2012, doi: 10.1021/es201942m.

[54] P. R. O'Donoughue, G. A. Heath, S. L. Dolan, and M. Vorum, "Life Cycle Greenhouse Gas Emissions of Electricity Generated from Conventionally Produced Natural Gas: Systematic Review and Harmonization," *Journal of Industrial Ecology*, vol. 18, no. 1, 2014, doi: 10.1111/jiec.12084.

[55] I. J. Laurenzi and G. R. Jersey, "Life cycle greenhouse gas emissions and freshwater consumption of Marcellus shale gas," *Environmental science & technology*, vol. 47, no. 9, pp. 4896-4903, 2013, doi: 10.1021/es305162w.

[56] T. Stephenson, J. E. Valle, and X. Riera-Palou, "Modeling the relative GHG emissions of conventional and shale gas production," *Environmental science & technology*, vol. 45, no. 24, pp. 10757-10764, 2011, doi: 10.1021/es2024115.

[57] "Port distance calculator." https://sea-distances.org/ (accessed October, 2020).

[58] H. Rogers, "The LNG Shipping Forecast costs rebounding outlook uncertain," The Oxford Institute for Energy Studies, 2018. [Online]. Available: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/02/The-LNG-Shipping-Forecast-costs-rebounding-outlook-uncertain-Insight-27.pdf

[59] IGU. "Natural Gas Conversion Guide." http://agnatural.pt/documentos/ver/natural-gas-conversion-guide_cb4f0ccd80ccaf88ca5ec336a38600867db5aaf1.pdf (accessed October, 2020).

[60] J. Ruether, M. Ramezan, and E. Grol, "Life-Cycle Analysis of Greenhouse Gas Emissions for Hydrogen Fuel Production in the United States from LNG and Coal " presented at the Second International Conference on Clean Coal Technologies for our Future, Sardinia, Italy, 2005.

[61] EIA. "Carbon Dioxide Emissions Coefficients." https://www.eia.gov/environment/emissions/co2_vol_mass.php (accessed October, 2020).

[62] EIA. "NATURAL GAS." https://www.eia.gov/dnav/ng/ng_cons_heat_dcu_nus_a.htm (accessed November 18, 2019.

[63] B.-Y. Yu and I. L. Chien, "Design and Economic Evaluation of a Coal-to-Synthetic Natural Gas Process," *Industrial & Engineering Chemistry Research*, vol. 54, no. 8, pp. 2339-2352, 2015, doi: 10.1021/ie503595r.

[64] EIA. "Average Tested Heat Rates by Prime Mover and Energy Source." https://www.eia.gov/electricity/annual/html/epa_08_02.html (accessed October, 2020.

[65] T. J. Skone, "Life Cycle GHG Footprint of a U.S. Energy Export Market for Coal and Natural Gas," NETL, 2014. [Online]. Available: https://www.netl.doe.gov/projects/files/LifeCycleGHGFootprintofaUSEnergyExportMarketforCoalandNaturalGas_100714.pdf

[66] "The progression of an LNG project." https://www.pwc.com/gx/en/mining/publications/assets/pwc-lng-progression-canada.pdf (accessed April, 2020).

[67] D. Huppmann *et al.* "*IAMC 1.5°C Scenario Explorer and Data hosted by IIASA*." Integrated Assessment Modeling Consortium & International Institute for Applied Systems Analysis. https://data.ene.iiasa.ac.at/iamc-1.5c-explorer (accessed November, 2020).

[68] EIA. "Total energy." https://www.eia.gov/totalenergy/data/browser/index.php?tbl=TA6#/?f=A (accessed November 17, 2019.

[69] S. Roman-White, S. Rai, J. Littlefield, G. Cooney, and J. T. Skone, "Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 Update," National Energy Technology Laboratory, Pittsburgh, 2019. [Online]. Available: https://www.energy.gov/sites/prod/files/2019/09/f66/2019%20NETL%20LCA-GHG%20Report.pdf

[70] R. A. Myles *et al.*, "Warming caused by cumulative carbon emissions towards the trillionth tonne," *Nature,* vol. 458, no. 7242, p. 1163, 2009, doi: 10.1038/nature08019.

[71] H. D. Matthews, P. G. Nathan, A. S. Peter, and Z. Kirsten, "The proportionality of global warming to cumulative carbon emissions," *Nature,* vol. 459, no. 7248, p. 829, 2009, doi: 10.1038/nature08047.

[72] K. Zickfeld, M. Eby, H. D. Matthews, and A. J. Weaver, "Setting cumulative emissions targets to reduce the risk of dangerous climate change," *Proceedings of the National Academy of Sciences - PNAS,* vol. 106, no. 38, pp. 16129-16134, 2009, doi: 10.1073/pnas.0805800106.

[73] J. Rogelj, M. Meinshausen, and R. Knutti, "Global warming under old and new scenarios using IPCC climate sensitivity range estimates," *Nature climate change,* vol. 2, no. 4, pp. 248-253, 2012, doi: 10.1038/nclimate1385.

[74] T. C. Johns *et al.*, "Climate Change under aggressive mitigation: The ENSEMBLES multi-model experiment," *Climate dynamics,* vol. 37, no. Issue 9-10, pp. 1975-2003, 2011, doi: 10.1007/s00382-011-1005-5.

[75] P. G. Nathan, K. A. Vivek, M. Damon, and R. A. Myles, "Constraining the Ratio of Global Warming to Cumulative CO_2 Emissions Using CMIP5 Simulations," *Journal of climate,* vol. 26, no. 18, pp. 6844-6858, 2013, doi: 10.1175/JCLI-D-12-00476.1.

[76] M. Collins *et al.*, "Long-term Climate Change: Projections, Commitments and Irreversibility," in *Climate Change 2013*, T. F. Stocker, D. Qin, G.-K. and M. T. Plattner, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley Eds. Cambridge, United Kingdom and New York, NY, USA.: Cambridge University, 2013.

[77] W. Moomaw, P. Burgherr, G. Heath, M. Lenzen, J. Nyboer, and A. Verbruggen, "2011: Annex II: Methodology. In IPCC: Special Report on Renewable Energy Sources and Climate Change Mitigation," ed, p. 10.