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Helping the climate by replacing liquefied natural gas with liquefied hydrogen or ammonia?

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Abstract

The war in Ukraine caused Europe to more than double its imports of liquefied natural gas (LNG) in only one year. In addition, imported LNG remains a crucial source of energy for resource-poor countries, such as Japan, where LNG imports satisfy about a quarter of the country's primary energy demand. However, an increasing number of countries are formulating stringent decarbonization plans. Liquefied hydrogen and liquefied ammonia coupled with carbon capture and storage (LH_2-CCS, LNH_3-CCS) are emerging as the front runners in the search for low-carbon alternatives to LNG. Yet, little is currently known about the full environmental profile of LH_2-CCS and LNH_3-CCS because several characteristics of the two alternatives have only been analyzed in isolation in previous work. Here we show that the potential of these fuels to reduce greenhouse gas (GHG) emissions throughout the supply chain is highly uncertain. Our best estimate is that LH_2-CCS and LNH_3-CCS can reduce GHG emissions by 25-61% relative to LNG assuming a 100-year global warming potential. However, directly coupling LNG with CCS would lead to substantial GHG reductions on the order of 74%. Further, under certain conditions, emissions from LH_2-CCS and LNH_3-CCS could exceed those of LNG, by up to 44%. These results question the suitability of LH_2-CCS and LNH_3-CCS for stringent decarbonization purposes.

1 Introduction

Due to the war in Ukraine, and in order to substitute for pipeline gas from Russia, Europe more than doubled (+141%) its liquefied natural gas (LNG) imports in only one year [1]. With 10.6 billion cubic feet per day, the US has been the largest exporter of LNG in the first half of 2022. This is about one fifth of total global trade in 2022 (51.7 billion cubic feet per day) [2]. In other resource-poor countries, such as Japan and Korea, imported LNG serves as a crucial source of energy [3]. All of these countries face a net-zero decarbonization challenge in the coming decades. Thus, there is interest in replacing existing LNG production, trade, and use with alternative low-carbon energy pathways. Two options that can be either derived from natural gas or from renewable energy, and that have been discussed in the context of low-carbon energy trade are liquefied hydrogen (LH_2) and liquefied ammonia (LNH_3). Due to the current high costs of hydrogen produced by renewable electrolysis, and in order to avoid stranded natural gas assets, a large share of both hydrogen and ammonia will likely continue to be produced from natural gas in the near to intermediate term, and may be coupled with CO_2 capture and storage (CCS; so called 'blue' hydrogen/ammonia) in order to reduce CO_2 emissions. Today, renewable or 'green' LH_2 and LNH_3 are about two to three times more expensive than their 'blue' counterparts [4]. However, for 'blue' hydrogen pathways there are a number of possibilities regarding the choice of energy carrier for the ocean transportation stage (LNG, LH_2, LNH_3), and the choice of where key transformations take place (exporting country, importing country), particularly the CO_2 capture. Further, there are fundamental unresolved questions pertaining to the net primary energy intensity and GHG emissions surrounding these choices.

The current body of literature has tended to focus on various aspects of the potential blue hydrogen and ammonia pathways in isolation. One line of research studied the indirect global warming potential of hydrogen [5]. Others focused on the formation of boil-off gas during production and distribution of LNG and LNH_3 [6]. Again others studied engine slip from LNG tankers, i.e. unburned hydrocarbons that directly escape into the atmosphere [7], or pipeline leakages. A common assumption is that for producing low-emission energy carriers, natural gas will be first converted to either hydrogen or ammonia, which are then liquefied and exported [8]. Indeed, recent shipments of LNH_3 and LH_2 from Saudi Arabia to South Korea were produced from natural gas with CCS [9]. One potential alternative would be to export LNG, with subsequent conversion to hydrogen and/or ammonia in the importing country. This option may be a more practical solution for countries with abundant natural gas resources but limited CO_2 storage reservoirs, and has the benefit of using existing LNG production and transportation infrastructure.

At present, no comprehensive analysis framework exists that simultaneously takes into consideration the thermodynamic conversion efficiencies, fugitive emissions, and the secondary climate impacts thereof, which would be necessary to compare the efficacy of these different pathways in addressing climate change. It is therefore unknown to date what the resulting overall environmental profile of different blue hydrogen and ammonia pathways are, and how they compare to LNG, and LNG with CCS. Such knowledge gaps mask the potential climate impacts related to these possible pathways and do not allow for well-informed investment decisions into hydrogen and ammonia technologies.

Here we bring together previously separate strands of the literature and present the first comprehensive framework that takes into account all factors known to date that influence supply chain emissions of different pathways of liquefied energy carriers. We do so by using thermodynamic analysis and by providing comprehensive estimation of the energy conversion efficiency and GHG emissions from LNG, LNG-CCS, LH_2-CCS, and LNH_3-CCS production considering fugitive emissions (leakage, boil-off-gas formation, ship engine slip) and direct and indirect global warming potentials along the entire supply chain in order to provide a complete environmental profile of LNG and its lower carbon alternatives. We also consider that ammonia and hydrogen may be exported as LNG with subsequent conversion in the importing country (pathways 3 and 4), which, to the best of our knowledge, has not yet been considered in the literature (Figure 1). Our work allows for thorough quantification and consideration of each pathway's direct and indirect GHG emissions which can guide investment decisions into hydrogen and ammonia technologies.

2 Methods and data

For an ‘apples-to-apples‘ comparison from primary energy to end-use service provision, we assume that all pathways start with natural gas and end with a combustion turbine to produce electric power (Figure 1A). This is an end use that is already important for grid operations today, and is understood to become more important as wind and solar energy are scaled up [10]. Each of the three energy carriers considered (natural gas, hydrogen, ammonia) can be used to drive a combustion turbine, at similar efficiencies. While the main analysis deliberately excludes ‘green‘ hydrogen and ammonia, the energy intensities and emissions estimated downstream of the initial transformation from natural gas would still apply to such pathways (see more details in section 3.3; also see pathways 5.1 and 6.1 in the SI, spreadsheet tabs ’summary’ and ‘charts‘). For the sake of comparability we further assume that the energy used for each process, such as liquefaction or regasification, in each pathway 1-6 is supplied by the energy carrier itself (natural gas, hydrogen or ammonia), and not from purchased energy carriers of unknown emissions intensity, such as electricity.

In addition, we do not consider fuel cells in the main analysis (but do include them in a sensitivity analysis as pathways 5.2 and 6.2, see SI tab ‘charts‘), which would increase the energy efficiency of power production compared to combustion turbines. Fuel cells could be powered by any of the three energy carriers considered, but seem unlikely in this application given their comparatively higher capital costs [11], and particularly as these units would tend to be operated at low capacity factors.

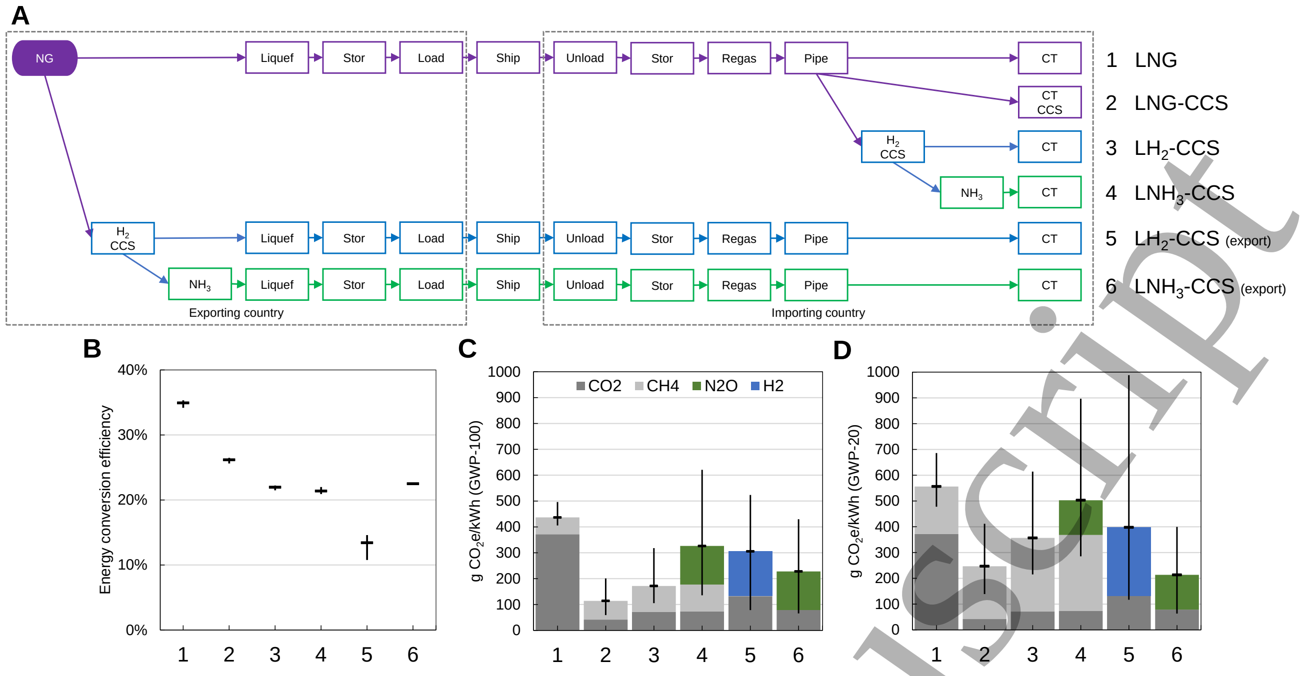

Figure 1: Overview of analyzed pathways. (A) Process flow chart. (B) Total energy conversion efficiencies of each pathway. (C) Total GHG emissions of each pathway based on 100-year global warming potential, and (D) based on 20-year global warming potential. Horizontal dashes in (B), (C), and (D) indicate best estimates, whereas whiskers indicate low and high estimates. NG = natural gas; Liquef = liquefaction; Stor = storage; Regas = regasification; Pipe = pipeline transmission; H_2 CCS = hydrogen production with carbon capture and storage; NH_3 = ammonia synthesis; CT (CCS) = combustion turbine (with carbon capture and storage). The complete dataset will be made available in an online repository.

In fact, a recent study illustrates scenarios of 100% clean electricity in the US in which up to 700 GW of hydrogen combustion turbines would be installed by 2035; the analysis similarly did not consider hydrogen fuel cells in this application [10].

Figure 1A shows a flowchart of all analyzed pathways including key processes such as liquefaction, storage, loading onto a ship, overseas shipping, ship unloading, storage, regasification, pipeline transport, and combustion in a gas turbine. Pathways that include CCS, ammonia or hydrogen include additional steps.

2.1 Liquefaction

Liquefaction of gaseous energy carriers is necessary for storage and overseas shipping. Table 1 reports storage temperatures for LNG, LNH_3 and LH_2. We assume that liquefaction of natural gas consumes about 8.5% of the natural gas feedstock based on the GREET life cycle assessment model [12]. This is comparable to Jordaan et al. [13] who report an average of 6.7% and Balcombe et al. [14] who assume 9.4% based on the mean of eight previous studies. The energy penalty for liquefying hydrogen is assumed to be 30% [15]. This is comparable to Cooper et al. [8] who quote loss estimates in the literature ranging from 15 to 41%, and assume a 33% loss for their blue hydrogen pathway calculations. Al-Breiki et al. [16] quote 40%. GREET [12] assumes a 25% loss. In stark contrast, the energy penalty of liquefying ammonia is only 0.1% or 0.0186 MJ per kg of ammonia [17].

2.2 Storage, transport and distribution

The duration of storage before and after shipping is assumed to be three days [18]. Al-Breiki et al. show that boil-off gas (BOG) can form during storage and transport due to the temperature difference between the inside and the outside of storage tanks. BOG evaporates directly into the atmosphere. Due to a lack of a complete data set we assume that BOG from LNH_3 is 100% gaseous ammonia, while BOG from LH_2 is 100% gaseous hydrogen, and BOG from LNG is 100% gaseous methane. Table 1 reports assumed BOG rates for storage, loading and ship transport. For example, BOG rates are chosen as 0.075% per day for LNG, 0.015% per day for LNH_3, and 0.66% per day for LH_2 in accordance with Al-Breiki [18]. For the low estimates shown in Figure 1B, C, and D we assume that half of BOG can be recovered due to regasification on-board the ship and/or in the port.

	Storage (%/d)	Load (%/d)	Transport (%/d)	Storage temperature (C)
LNG	.750	.100	.120	−160
LNH_3	.015	.0370	.025	−34
LH_2	.660	.520	1.06	−250

Table 1: Rates of boil-off gas formation during different supply chain stages. The complete dataset will be made available in an online repository.

We assume a ship journey of about 5,000 nautical miles (1 nm = 1.852 km), or 15 days, which roughly corresponds to a journey from Australia to Japan, which was the most common voyage for LNG shipping in 2021.[1] For the high estimates shown in Figure 1B, C, and D we assume a journey twice as long (10,000 nautical miles and 30 days [19]). This assumption roughly corresponds to a journey from the world's largest LNG export terminal, Sabine Pass in the US, to Japan's largest LNG regasification terminal, Chiba, via the Panama Canal.[2] [3] [4] Pipeline transport is assumed to be 100 km, which roughly corresponds to the Chiba-Kashima gas pipeline in Japan.[5]

2.3 Regasification

Compared to liquefaction, regasification is a relatively inexpensive process in terms of energy requirements. For example, LNG regasification requires heat of about 0.6 MJ per Nm^3, which is roughly equal to 1.7% of the energy content of LNG (35.7 MJ/Nm^3). Regasification of LH_2 incurs a 3.3% energy penalty (0.35 MJ per Nm^3 over 10.7 MJ per Nm^3).[6] According to Al-Breiki et al. [20], 1.37 MJ is required to regasify 1 kg of LNH_3, which translates to an energy penalty of 7.4%.

2.4 Hydrogen production, ammonia synthesis and carbon capture and storage

Conversion of natural gas to hydrogen has an efficiency of about 73% [12] minus an assumed 10% energy penalty for the process of capturing and storing carbon dioxide. We illustrate pathways where the conversion from natural gas to hydrogen can occur in either the importing country or in the exporting country (Figure 1A). We assume an emissions rate of 9.37 kg CO_2 per kg of delivered hydrogen from natural gas [21] multiplied by a 90% carbon capture rate [12] for 'blue' hydrogen production. We further assume that NH_3 is synthesized from H_2 and N using the Haber-Bosch process. The additional energy required to synthesize NH_3 from H_2 is relatively small, about 10% according to Bird et al. [22].

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[1] https://tinyurl.com/5525xzd5

[2] https://sea-distances.org/

[3] https://www.offshore-technology.com/data-insights/top-ten-active-lng-regasification-terminals-in-asia/

[4] https://www.statista.com/statistics/1263943/largest-operational-lng-terminals-by-capacity-us

[5] https://tinyurl.com/3nauxewh

[6] https://tinyurl.com/4jsbyjws

2.5 End use

We assume that each of the three gaseous energy carriers, natural gas, hydrogen and ammonia, are fired in a gas combustion turbine in order to create electricity for final end use. This is an end use that is already important for grid operations today, and is understood to become more important as wind and solar energy are scaled up [10]. The efficiency of the combustion turbine is assumed to be 40% [23]. In pathway 2 we assume that the combustion turbine is equipped with CCS which incurs a 10% energy penalty (same assumption as for hydrogen production from natural gas production with CCS). We note that NH_3 and H_2 could also be converted into electricity using fuel cell technology, however fuel cell technology is still in its infancy, while combustion technology is more mature and widely used, especially in stationary industrial settings. (For the sake of completeness we illustrate the overall efficiency of 'green' ammonia and hydrogen fuel cell pathways, see SI tab 'charts'). N_2O emissions rates from ammonia combustion are estimated as 0.5 g per kWh for the central case [24], 1 g per kWh for the high estimate [25], and 0.1 g per kWh for the low estimate [26]. CO_2 and CH_4 emissions rates from natural gas combustion turbines are based on Spath et al. [27, see Table 5 on page 12 therein].

2.6 Direct and indirect global warming potential

Since hydrogen reacts with and depletes hydroxyl radicals, which are a key component in the breakdown of methane, hydrogen indirectly leads to increasing levels of methane in the atmosphere. Therefore, hydrogen has been assigned an indirect global warming potential. We assume an indirect GWP on a 100-year timescale of 5, 10 and 15 as our low, central, and high estimates which is well within the range of previously reported values [5, 28, 29]. The direct global warming potential of other greenhouse gases is well documented [30].[7] [8] [9] The complete dataset used for all calculations will be made available in an online repository.

	GWP-100			GWP-20		
	low	central	high	low	central	high
H_2	5	10	15	16	40	64
CH_4	27	30	34	84	85	86
N_2O	265	298	310	239	269	280
CO_2	1	1	1	1	1	1

Table 2: The direct and indirect global warming potential (GWP) of various gases over different time horizons (100 years and 20 years). The complete dataset will be made available in an online repository.

3 Results

3.1 Energy losses

Figure 1B illustrates the overall energy conversion efficiency of each pathway while Figure 2 provides a closer look on efficiency losses of each process in the supply chain of pathways 2 and 5 which are the most and least efficient alternatives to LNG (please see stage losses charted out for all pathways in the SI tab "Loss"). For each, by far the largest energy losses (60%) occur at the combustion turbine (CT). An additional 10% loss is assumed for CCS in pathway 2. Pathways involving hydrogen include several highly energy-intensive processes such as the production of 'blue' hydrogen (H_2-CCS) via autothermal reforming (37% loss, pathways 3, 4, 5 and 6), liquefaction of hydrogen (30% loss, pathway 5), and boil-off gas formation during ocean transport (16% loss, pathway 5).

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[7] https://tinyurl.com/yn98kexc

[8] https://www.iea.org/reports/methane-tracker-2021/methane-and-climate-change

[9] https://tinyurl.com/5xbhrwpz

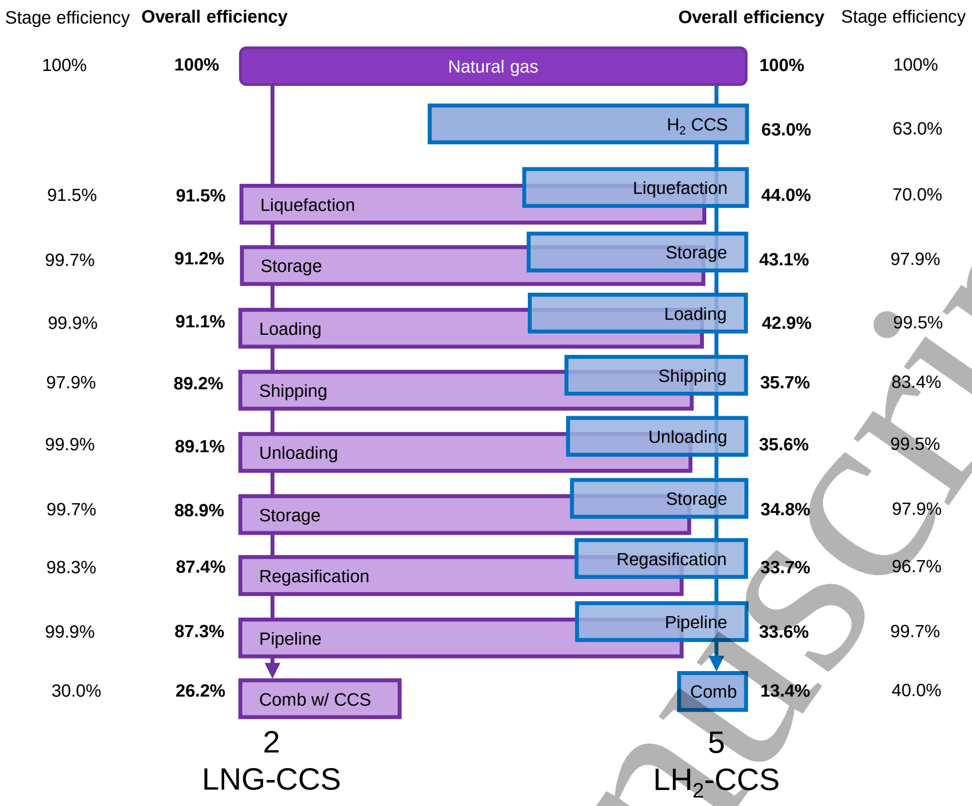

Figure 2: Comparing stage efficiencies and cumulative efficiencies of pathways 2 (LNG-CCS) and 5 (LH_2-CCS). Bar chart and Sankey diagram representations of all pathways are included in the SI (see tab 'charts'). The complete dataset will be made available in an online repository. H_2 = hydrogen; CCS = carbon capture and storage; Comb = combustion.

3.2 Greenhouse gas emissions

Liquid hydrogen is stored and transported at -250°C, and boil-off gas is formed due to the large temperature difference relative to the atmosphere, and needs to be discharged in order to manage the pressure in the storage tanks. LNG and LNH_3 are stored at -160°C and -34°C, respectively, and as such, losses due to boil-off are lower than for LH_2 (1.8%, and 0.4%, pathways 1-4 and 6). In pathways 1-5 the boil-off gas is discharged as CH_4 or H_2 and therefore contributes to global warming, with a best estimate of 40-65 g CO_2e/kWh for shipping LNG (pathways 1-4, low and high estimates range from 18-148 g CO_2e/kWh), and 54 g CO_2e/kWh for shipping LH_2 (pathway 5, with a range from 12 to 143 g CO_2e/kWh), assuming a 100-year global warming potential (GWP-100, Figure 1C). The large range of estimates is a result of our assumptions on shipping distance which ranges from 5,000 nautical miles for the low and best estimates, to 10,000 nautical miles for the high estimate. Further, GWP-100 is assumed 5 (low), 10 (best estimate), and 15 (high) for hydrogen, and 27 (low), 30 (best estimate), and 34 (high) for methane emissions. Finally, for the low estimates we assume that half of the boil-off gas can be re-liquefied.

Other large sources of GHG emissions include autothermal reforming with CCS (pathways 3-6) with best estimates ranging from 70 to 132 g CO_2e/kWh depending on the specific pathway. Further, the combustion of natural gas in gas turbines causes 372-373 g CO_2e/kWh (pathway 1), while the capture of carbon emissions reduces that number to 43 g CO_2e/kWh with a range from 22 to 64 g CO_2e/kWh (pathway 2).

Combustion of ammonia in a gas turbine causes 149 g CO_2e/kWh due to an assumed emissions factor of 0.5 g N_2O/kWh and a GWP-100 of 298 (best estimate, pathways 4 and 6). For our low estimate we assume an emissions factor 0.1 g N_2O/kWh and a GWP-100 of 265, resulting in 27 g CO_2e/kWh, and for the high estimate we assume 1 g N_2O/kWh and a GWP-100 of 310, resulting in 310 g CO_2e/kWh.

Other leakages occur throughout the transmission and distribution process including storage, loading, unloading, regasification, pipeline transport and engine slip during shipping, and are smaller in comparison but can make a substantial contribution in sum. In particular, leakages of methane during LNG transmission and distribution processes in pathways 1-4 can amount to 23-38 g CO_2e/kWh (best estimate with a low-high range from 14 to 51 g CO_2e/kWh). As such, these processes combined could contribute 2-27% of total emissions.

Taken together, our best estimate is that LH_2 pathways (3, 5) can reduce GHG emissions by 55-61% relative to LNG, whereas LNH_3 pathways (4, 6) can reduce emissions by 25-48%. However, the uncertainties of our findings are high, indicated by the whiskers in Figures 1C and D, and we estimate that in a worst-case scenario LNH_3 could increase emissions by up to 25% relative to LNG (pathway 4). Assuming GWP-20, LNH_3 pathways become relatively more favorable from a GHG perspective (Figure 1D). However, this also results in LH_2 potentially increasing GHG emissions by 44% over LNG in a worst-case scenario. This is a direct result of the estimated global warming potential of hydrogen and methane being roughly a factor of 3 and 4 times higher when assuming a 20-year horizon compared to a 100-year horizon (10 vs 40 for hydrogen and 30 vs 85 for methane), whereas for N_2O GWP-20 is slightly lower than GWP-100 (269 vs 298 for a central estimate).

3.3 A note on ‘green’ ammonia and hydrogen

As noted above, our main analysis excludes ‘green’ ammonia and hydrogen pathways but processes downstream of the initial transformation from natural gas to hydrogen would still apply. Put differently, all emissions other than CO_2 would probably be similar. As such, Table 3 illustrates relative emissions of the LNG-CCS, ‘green’ hydrogen and ‘green‘ ammonia pathways relative to LNG. Our best estimate under GWP-100 assumptions is that ‘green’ ammonia only achieves a 66% reduction in GHG emissions, while LNG-CCS achieves 74% and ‘green’ hydrogen 85%. However, under GWP-20 assumptions, emission reductions from ‘green’ hydrogen are lower than those from LNG-CCS and may even increase emissions under unfavorable conditions (–8%, ‘High estimate’). The full set of results is included in the SI (see pathways 5.1, 5.2, 6.1 and 6.2, tabs ‘summary‘ and ‘charts‘).

	GWP-100				GWP-20			
	LNG (1)	LNG-CCS (2)	LH_2 green (5 green)	LNH_3 green (6 green)	LNG (1)	LNG-CCS (2)	LH_2 green (5 green)	LNH_3 green (6 green)
Best estimate	0%	74%	85%	66%	0%	56%	52%	76%
High estimate	0%	60%	63%	13%	0%	42%	–8%	59%
Low estimate	0%	85%	96%	93%	0%	87%	88%	95%

Table 3: Reduction of GHG emissions from LNG-CCS, ‘green‘ LH_2 and ‘green’ LNH_3 pathways relative to LNG under GWP-100 and GWP-20 assumptions.

4 Discussion

Considering that the cost of deploying LNH_3 and LH_2 options is expected to be considerably higher than LNG and LNG with CCS [11], and taking into account the high uncertainty around the GHG mitigation potential of these options, there are open questions pertaining to the suitability of liquefied hydrogen and ammonia for stringent and cost-effective GHG mitigation of natural-gas based energy exports.

Our best estimates indicate that liquefied ‘blue‘ hydrogen and ammonia pathways could reduce GHG emissions from LNG by roughly 50% (LH_2-CCS: 55-61%, LNH_3-CCS: 25-48%). Further, assuming that ammonia and hydrogen supply chains are strictly monitored and controlled, and losses are minimized, these options could achieve even higher emission reductions. However, without any controls in place, emissions from liquid ‘blue‘ ammonia and hydrogen pathways could exceed the emissions from LNG with, or even without CCS.

Combustion processes cause the largest energy losses, followed by hydrogen production. Additional losses from other processes throughout the supply chain are non-negligible and can significantly contribute to global warming.

Alternative hydrogen and ammonia pathways could make use of fuel cells rather than combustion turbines, and potentially lead to stronger emissions savings. Ammonia fuel cells for example could avoid N_2O emissions from ammonia combustion in gas turbines but there is nonetheless a risk of toxic ammonia leakage along the supply chain as well as indirect formation of additional N_2O due to the nitrogen cycle [31].

The limitations of our study include the use of various data sources due to the unavailability of one comprehensive and consistent dataset. Disparate data sources create data uncertainty, which however was alleviated by comprehensive uncertainty analysis. Also, some data sets were incomplete. For example, the composition of BOG is unclear and was therefore assumed to be 100% hydrogen, methane, or ammonia, whereas in reality some relatively small amounts of other gases may be present. Finally, an important simplification we had to make was to assume that all processes in the analyzed pathways were powered by the respective fuels (natural gas, ammonia, or hydrogen), whereas in reality some processes may be powered by electricity or other energy carriers. This assumption is appropriate for a 'like-for-like' comparison of the end-to-end thermodynamic efficiency and GHG emissions of these various energy carrier pathways. In the real world this assumption would likely be accurate for the shipping component; LNG ships are currently powered by LNG, and ammonia and liquefied hydrogen are both under consideration as maritime shipping fuels in general, so it is reasonable to assume that the energy carrier choice would match the ship drivetrain choice. Where the simplification could depart from how these pathways would likely be implemented in the real world is the energy used for liquefaction and regasification, processes which could use purchased grid electricity, or self-produced electricity in remote locations. However, the uncertainty on the GHG emissions and primary energy intensities of electricity is large, spanning from renewable energy to coal-fired electricity, and the accounting conventions adopted for translating from renewable electricity to primary energy would also become important in the comparative analysis. This analysis is intentionally structured to focus on the energy carriers themselves, and the energy footprints and GHG emissions intensities incurred due to the properties of the energy carriers, without needing to consider the heterogeneity of the surrounding energy systems. For many countries LNG imports and exports form a major share of their current energy portfolio but ambitions to transition towards hydrogen-based energy carriers are increasing. For example, Japan is planning to import 'blue' LH_2 from Australia with carbon being captured in the Australian Gippsland basin (pathway 5), as well as LNH_3 from Indonesia with CO_2 being stored in Central Sulawesi (pathway 6) [32]. Other regions of the world that already operate 'blue' hydrogen production plants, such as the EU and China, may increasingly import LNG from large exporters such as the US and Nigeria in order to convert the gas domestically (pathways 3 and 4).

Given the large variation in results and the high uncertainties in the input data it is difficult to provide specific recommendations on which technology pathways should be promoted. It will ultimately depend on relative technology costs as well as the policy landscape which technology or technologies will be adopted by countries and/or ship fleet operators. Climate policies should however recognize the indirect warming potential of hydrogen as well as non-zero GHG emissions from ammonia. Here we highlight the potential climate impacts related to various possible pathways, and argue that proper quantification and consideration of each pathway's direct and indirect GHG emissions should occur before substantial investments are made. Future research should aim at reducing uncertainties in the data by collecting field data (such as measured ammonia combustion emissions) when such data becomes available.

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Declaration of interests

The authors declare no competing interests.

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