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A Comparison of Alternative Fuels for Shipping in Terms of Lifecycle Energy and Cost

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Abstract: Decarbonization of the shipping sector is inevitable and can be made by transitioning into low- or zero-carbon marine fuels. This paper reviews 22 potential pathways, including conventional Heavy Fuel Oil (HFO) marine fuel as a reference case, "blue" alternative fuel produced from natural gas, and "green" fuels produced from biomass and solar energy. Carbon capture technology (CCS) is installed for fossil fuels (HFO and liquefied natural gas (LNG)). The pathways are compared in terms of quantifiable parameters including (i) fuel mass, (ii) fuel volume, (iii) life cycle (Well-To-Wake—WTW) energy intensity, (iv) WTW cost, (v) WTW greenhouse gas (GHG) emission, and (vi) non-GHG emissions, estimated from the literature and ASPEN HYSYS modelling. From an energy perspective, renewable electricity with battery technology is the most efficient route, albeit still impractical for long-distance shipping due to the low energy density of today's batteries. The next best is fossil fuels with CCS (assuming 90% removal efficiency), which also happens to be the lowest cost solution, although the long-term storage and utilization of CO_2 are still unresolved. Biofuels offer a good compromise in terms of cost, availability, and technology readiness level (TRL); however, the non-GHG emissions are not eliminated. Hydrogen and ammonia are among the worst in terms of overall energy and cost needed and may also need NOx clean-up measures. Methanol from LNG needs CCS for decarbonization, while methanol from biomass does not, and also seems to be a good candidate in terms of energy, financial cost, and TRL. The present analysis consistently compares the various options and is useful for stakeholders involved in shipping decarbonization.

Keywords: maritime; marine fuel; alternative fuels; decarbonization; hydrogen; ammonia; methanol

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1. Introduction

The decarbonization of the shipping sector has long been neglected by the world due to its comparatively low CO_2 emission. However, 96% of the bunker fuels used to power ships are made of marine diesel oil (MDO), heavy fuel oil (HFO), or marine gas oil (MGO), which produce as much as 3.114 kg CO_2 per kg of HFO combusted. Shipping is responsible for 2.8% of annual global emissions or 1036 Mt of CO_2e per annum [1]. In addition to CO_2 emission, the shipping sector emits approximately 1.4 Mt of particulate matter (PM), nearly 15% of global NOx emissions, and approximately 13% of global SOx emissions per annum [1]. The current situation is unsustainable and therefore solutions are being sought, with alternative fuels being researched intensively.

In 2018, IMO announced a long-term goal to reduce GHG emissions from the shipping industry by 50% by 2050 compared to emissions in 2008. In addition, on 1 January 2020, the sulphur content of maritime fuel was limited to 0.5%, or 0.1% in IMO-enforced Emissions Control Areas (ECAs). These new limits were made compulsory following an amendment to Annex VI of the International Convention for the Prevention of Pollution from Ships

(MARPOL). Now, the majority of ships use very low-sulphur fuel oil (VLSFO) to comply with the new limit and no safety issues have, to date, been reported to IMO. Shipowners can also use low- or zero-sulphur fuels, for example, LNG or biofuels. Options of alternative marine fuels being discussed worldwide include LNG, hydrogen, ammonia, methanol, biofuels, and electricity. However, given that the investment made today is for the long term as vessels are designed with long lifespans, there is a dilemma. Each of the fuels being discussed have their own strengths and weaknesses. A proper quantitative comparison is important to prepare stakeholders, shipowners, and policy makers for fuel transition.

Various zero and low carbon fuels are being developed towards commercial scale, for instance, the world's first hydrogen-powered cargo ship operated by Heidelberg Cement and Felleskjøpet [2], and the world's first green ammonia-fueled tanker, which is planned to be delivered by 2024 under MS Green Ammonia [3]. In addition to these developing technologies, LNG and battery-based ships have also been commercialized. There is no one solution for all kinds of ships. Hence, it is good to have a proper comparison between various alternative fuels as a guideline for shipowners and policy-makers in selecting the best decarbonization strategy.

Hansson et al. [4] carried out marine fuel assessment for seven alternative fuels and ranked LNG as the most potential fuel, HFO second, and then fossil methanol followed by biofuels. The ranking was based on ten performance criteria including economic, environmental, technical, and social aspects. Deniz and Zincir [5] carried out environmental and economical assessment for four alternative marine fuels including methanol, ethanol, LNG, and hydrogen and concluded that LNG is the most suitable alternative marine fuel, followed by hydrogen. Ren and Liang [6] suggested hydrogen as the most sustainable fuel, followed by fossil methanol and hydrogen. In another paper published by Ren and Lützen [7], nuclear power was suggested as the most sustainable alternative energy source, followed by LNG and wind energy. Ren et al. [7] emphasize that weighting of the various performance criteria has significant impact on the ranking of alternative fuels. Gray et al. [1] use the Pride of Hull ferry as the case study for comparison of fuel performance and identified biomethane and biomethanol as promising drop-in fuels, whereas hydrogen and ammonia constitute a promising pathway for the long term. Foretich et al. [8], with empirical research quantifying the challenges and opportunities for alternative fuels for maritime applications, concluded that biofuels are promising marine fuels for the future. In addition, based on a state-of-the-art survey conducted on the decarbonization of the shipping industry via the analysis of 294 papers published from 2000 to 2020, it was indicated that more research should focus on low-cost biofuels, which have high potential [9]. However, Xing et al. [10] suggested methanol as the most promising alternative fuel, whereas green hydrogen and ammonia could play important role in domestic and short sea shipping. Apart from these, various players in the maritime industry, such as DNV.GL [11] and ABS, have also carried out alternative fuels assessment. ABS, with its publication of Low Carbon Shipping Outlook series, identified green ammonia and hydrogen as the future zero carbon fuels [12]. In general, the ranking of alternative fuels is highly dependent on the type of fuels included in the assessment, the performance criteria used, and the weighting given to each criterion.

In recent studies, the importance of life cycle (Well-To-Wake) studies has been emphasized as life cycle assessment is proven to be a more suitable measure of fuel performance. The selection of feedstock and fuel production pathways have been proven to have great impact on the overall carbon emission and fuel cost. Looking only at the fuel transformation process at the final stage (Tank-To-Wake) can give a distorted view. For example, burning hydrogen does not release CO_2, but if the hydrogen is produced from fossil fuels without carbon capture and storage, then its use as fuel cannot be considered as carbon-free. Hence, it is important to use WTW assessment in fuel analysis. Today, most of the literature has focused on the life cycle economic and environmental analysis of fuel; however, the WTW energy assessment of marine fuel has not received enough attention. Winebrake et al. [13] used the total Energy & Emissions Analysis of Marine Systems (TEAMS) model to analyze fuel life cycle emission and energy use for six fuel pathways, including five fossil fuel pathways and one renewable biodiesel pathway [14]. The TEAMS model is derived based on the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model. It calculates the energy used by different fuel pathways for different marine vessels. However, there is still limited literature available on the life cycle energy consumption of alternative fuels such as H_2, NH_3, and methanol. Development of such modelling requires many inputs as it involves multiple processes from feedstock processing until the formation of energy carriers and the onboard utilization of fuel. Hence, ASPEN simulation is used here for the WTW energy assessment. A literature review has been conducted on the production pathways of various alternative fuels to obtain sufficient data for ASPEN modelling. This paper aims to provide a more thorough marine fuel assessment with the incorporation of energy assessment and combination with other important parameters for a more precise comparison.

In this research, a total of 22 alternative pathways were included, covering a broad range of fuel options available in the market. Importantly, performance criteria including the WTW energy and Technology Readiness Level (TRL) were included. The assessment quantified the potential of various alternative fuels by comparing the values of fuel mass, fuel volume, WTW energy, WTW cost, WTW GHG emission, and non-GHG emission of alternative pathways. The difference between various alternative fuels from conventional HFO for various parameters was quantified as a ratio to HFO, known as relative values, which allowed a visualization of the difference between various pathways. In addition, an example based on defined weighting factors for selected performance criteria was included to show the application of these results in marine fuel analysis. Future studies could include ship type, size, or carrying capacity, and voyage routing, as part of the assessment.

In the next section, the research methodology is presented. Section 3 includes the results of a quantitative assessment (Section 3.1) and an example assessment (Section 3.2). Section 4 includes a discussion, while Section 5 summarizes the conclusions.

2. Methods

Figure 1 summarizes the process workflow for this research. The research started by defining alternative fuel pathways, followed by data acquisition to establish the database for quantitative marine fuel assessment. After that, quantitative assessment and comparison were carried out for various alternative fuels. Lastly, an example combining qualitative and quantitative assessment was selected to demonstrate the application of the results obtained.

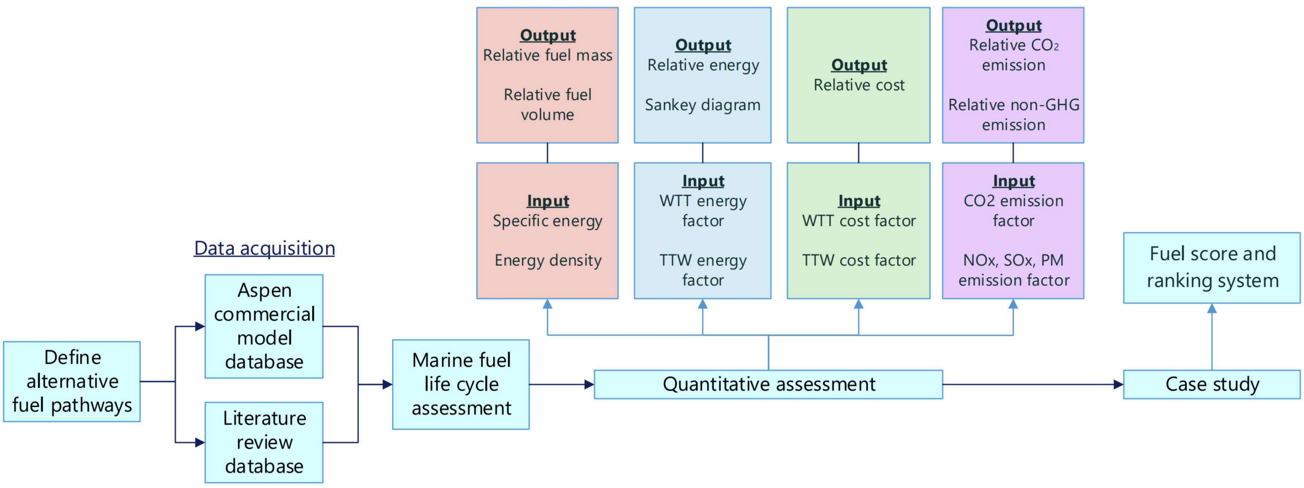

Figure 1. Research process flow diagram.

Figure 2 and Table 1 show the 22 pathways studied here. These were different due to the different primary energy source (fossil-fuels, biomass, or renewable energy), processing, energy carrier, and propulsion system (reciprocating engine and fuel cell). Some pathways included CCS installation so that consistent comparison could be made. HFO without CCS was included as a reference.

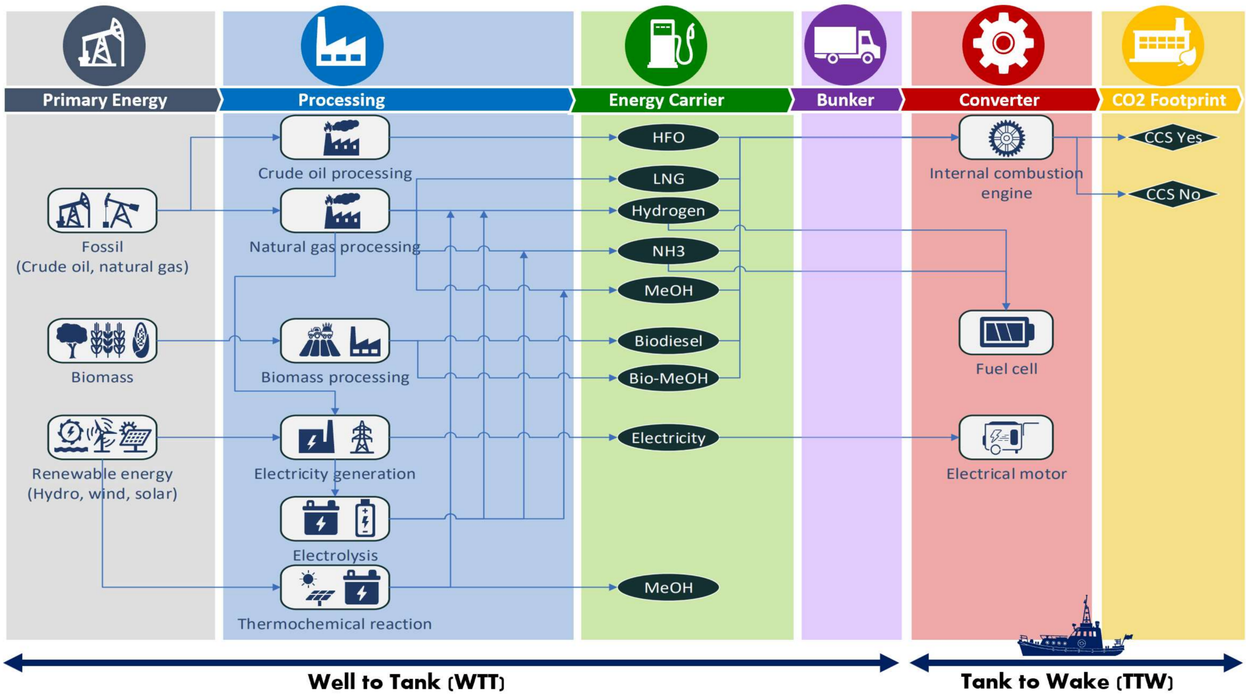

Figure 2. Potential marine fuel pathways. CCS: carbon capture and storage; EM: electrical motor; FC: fuel cell; ICE: internal combustion engine; LNG: liquefied natural gas; MeOH: methanol.

Table 1. Potential marine fuel pathways.

Marine Fuel Pathways	Abbreviations
Pathway 1: Base Case: Crude–HFO–ICE [a]	HFO (Base case)
Pathway 2: Crude–HFO–ICE–CCS	HFO (CCS)
Pathway 3: NG–LNG–ICE	LNG
Pathway 4: NG–LNG–ICE–CCS	LNG (CCS)
Pathway 5: NG–H_2–ICE	BLUE H_2
Pathway 6: NG–H_2–FC	BLUE H_2 (FC)
Pathway 7: NG–NH_3–ICE	BLUE NH_3
Pathway 8: NG–NH_3–FC	BLUE NH_3 (FC)
Pathway 9: NG–MeOH–ICE	MEOH
Pathway 10: NG–MeOH–ICE–CCS	BLUE MEOH (CCS)
Pathway 11: NG–Electricity–EM	NG-E
Pathway 12: NG–Electricity–H_2–FC [b]	BLUE E-H_2 (FC)
Pathway 13: NG–Electricity–NH_3–FC [b]	BLUE E-NH_3 (FC)
Pathway 14: NG-Electricity–MeOH–ICE [b]	BLUE E-MEOH
Pathway 15: Biomass–Biodiesel–ICE [c]	BIO-DIESEL
Pathway 16: Biomass–Bio-MeOH–ICE [c]	BIO-MEOH
Pathway 17: Solar–Electricity–EM	SOLAR E
Pathway 18: Solar–Electricity–H_2–FC	SOLAR E-H_2 (FC)
Pathway 19: Solar–Electricity–NH_3–FC	SOLAR E-NH_3 (FC)
Pathway 20: Solar–Electricity–MeOH–ICE	SOLAR E-MEOH
Pathway 21: Solar–Thermochemical–H_2-FC	SOLAR T-H_2 (FC)
Pathway 22: Solar–Thermochemical–MeOH	SOLAR T-MeOH

[a] HFO (Pathway 1) is included as a reference case. [b] NG-electricity-derived fuels (Pathways 12, 13, 14) are included for completeness. [c] Biofuels (Pathways 15, 16) are assumed to be carbon-neutral pathways and no CCS is required.

First, energy and cost factors needed to be acquired to be used as inputs for calculation. In this research, data acquisition was carried out by employing simulation results from the ASPEN commercial model and data extracted from a literature review.

ASPEN HYSYS, as a premier chemical process simulator, has a dedicated property package to predict the behaviour and reactions of hydrocarbons [15]. In addition, with its integrated economic and energy analysers, ASPEN can give consistent energy and cost estimates. In this research, ASPEN HYSYS simulation was utilized to obtain energy intensity and cost as there are limited existing data on these for marine fuel production from future pathways. Although some articles have reported the energy intensity and cost of alternative fuel production individually, different researchers may have different assumptions and opinions, which may result in inconsistency of energy and cost factors. Here, an ASPEN commercial model was built covering fossil-based and biomass-based pathways, while for solar-based pathways, data from the literature were used. The ASPEN model covers most processes involved throughout fuel's life cycle, excluding the energy converters ICE, fuel cell, and electrical motor, for which, in this study, literature estimates were used. ASPEN modelling only covers fossil-based and biomass-based marine fuels, constructed from an ASPEN example model [16]. For NG-based fuels, the ASPEN example titled the "natural gas plant model" was used. The example included the processing of feedstock from the wellhead up to the NGL (Natural Gas Liquid) recovery stage, which included natural gas sweetening to remove acid gas, dehydration to remove excessive water, and then NGL recovery to separate larger hydrocarbons so that a pure methane stream was produced. After NGL recovery, the methane-rich stream was fed into subsequent unit operations to begin various types of marine fuel production. In this research, the continuation of marine fuel processing steps was modelled based on commercialized production paths. For example, the production of H_2 was based on the Linde H_2 production plant [17], which started with steam reforming, followed by a water–gas-shift reaction, and lastly H_2 was separated and purified using a pressure swing adsorber (PSA) before being cooled cryogenically to a storage condition of −253 °C at atmospheric pressure. More details about the ASPEN simulation models are available in Appendix A.

In addition, carbon capture was also modelled based on the sweetening technology of the ASPEN example titled the "natural gas plant model" [18] for the removal of CO_2 from the exhaust stream of an internal combustion engine, if required. See Table 2 for useful references used in the present ASPEN modelling. In the further simulation using ASPEN, the economic and energy analysers were utilized for a detailed cost and energy simulation. A database for other pathways that could not be simulated using ASPEN was acquired from the literature review; the sources are also stated in Table 2.

Utilizing data obtained from the ASPEN simulation and the literature, the energy, cost, GHG emission, and non-GHG emission per unit of propulsion energy were obtained. These data were used to analyse the energy and cost efficiency, and the also emission profile, of any ships when different fuels were being used onboard. For the reciprocating engine propulsion system, a typical efficiency of 45% was used, taken as an average value between old and newer ships. The same efficiency was used for all fuels, under the assumption that the basic engine technology would not change drastically in terms of efficiency with fuel switching. The exact value did not matter when comparing the relative energy and lifecycle costs of alternative fuels using the same propulsion system. The exact efficiency value was important for comparing with fuel cell systems, but the 45% values chosen were likely to be sufficient given the uncertainties involved in the fuel cell efficiency.

Table 2. Sources for the database of marine fuel assessment (refer to Tables A1 and A2 in Appendix B for details).

Sources of Database	Aspen Modelling	Literature Review	
Marine Fuel Pathways	**References**	**Energy Database**	**Cost Database**
Base Case: Crude–HFO–ICE	[19]	[20]	
Crude–HFO–ICE–CCS	[18,19]	[20]	
NG–LNG–ICE	[21],	[20]	[11]
NG–LNG–ICE–CCS	[18,21]	[20]	
NG–H_2–ICE	[17,21]	[20]	[11]
NG–H_2–FC	[17]	[22,23]	[11]
NG–NH_3–ICE	[21,24,25]	[20]	[11]
NG–NH_3–FC	[24,25]	[22,23]	
NG–MeOH–ICE	[21],	[20]	[11]
NG–MeOH–ICE–CCS	[18,21]	[20]	
NG–Electricity–EM	[21,26–28]	[22,29]	[11]
NG–Electricity–H_2–FC	[21]	[22,23,30]	
NG–Electricity–NH_3–FC	[21]	[22,23,29,30]	
NG-Electricity–MeOH–ICE	[21]	[20,29,30]	
Biomass–Biodiesel –ICE	[31]	[20]	[11]
Biomass–Bio-MeOH –ICE	N.A.	[20]	
Solar–Electricity–EM	N.A.	[22]	[32]
Solar–Electricity–H_2–FC	N.A.	[22,23,30,33]	[11,32]
Solar–Electricity–NH_3–FC	N.A.	[20,23,30]	[11,32]
Solar–Electricity–MeOH–ICE	N.A.	[20,30]	[32]
Solar–Thermochemical–H_2–FC	N.A.	[22,23]	[32]
Solar–Thermochemical–MeOH	N.A.	[20]	[32]

Sankey energy flow diagrams were plotted to demonstrate the life cycle energy flow when different marine fuels were used onboard of a vessel. In this research, Sankey MATIC online software produced by Steve Bogart was used to create Sankey diagrams [34]. To assist visualization, multiple colours were used to represent the different energy flows. Red colour was used to indicate energy losses from various processes during marine fuel production and during energy conversion, and other colours including grey, blue, and green were used to indicate the remained propulsion energy from fossil fuels, blue fuels, and green fuels, respectively. The leftmost column of Sankey diagram shows the total energy required from primary energy to produce the same amount of propulsion energy for all pathways. Total propulsion energy is shown on the rightmost column of the Sankey diagram. Sankey diagrams are shown here for some options, and more extensively in the Appendices A–C.

Finally, CCS was used either at the production phase of fossil-based non-carbon alternative fuels (H_2, NH_3, MeOH), or at the use phase for HFO and LNG. For both, a capture efficiency of 90% was used. Details are given in the Appendix C. For LNG, estimates of the fugitive CH_4 emissions at the production phase are also included to provide estimates of CO_2-equivalent greenhouse gas emissions.

Following the quantitative calculation of energy, emissions, and cost from ASPEN, subjective fuel assessment criteria were defined based on various important characteristics of an ideal marine fuel, as given below:

1. High specific energy (kJ/kg) and energy density (kJ/m^3) for low fuel mass and storage volume.
2. Less energy intensiveness and lower fuel production cost for a cost-competitive fuel.
3. Low life cycle GHG emissions (g CO_2e/kJ) and the ability to achieve 50% carbon reduction by 2050.
4. Low non-GHG emissions (NOx, SOx, PM) to comply with IMO ECA regulations.
5. Fuel is scalable to meet the additional demand from shipping apart of the existing industry demand.

6. Fuel is safe to be used onboard with narrow flammability range, non-toxicity, non-corrosiveness, and availability of rules and regulations for onboard application.
7. Mature technology including bunkering infrastructure, an energy converter, and fuel production facilities.

Based on these ideal characteristics of marine fuel, a quantitative analysis was conducted through a comparison of the quantifiable characteristics of alternative fuel. The values of the quantifiable characteristics were obtained using established databases, and then these values were divided by the values of HFO reference case to obtain the dimensionless relative values. In this assessment, 6 performance parameters were included as below. The outcome of assessment is discussed in Section 3.1.

1. Relative mass.
2. Relative volume.
3. Relative WTW energy.
4. Relative WTW cost.
5. Relative WTW GHG emission.
6. Relative non-GHG emission.

However, as the potential of an alternative fuel is affected by many parameters, in addition to the quantifiable characteristic of fuel, other criteria such as the scalability of fuel production, safety of fuel, availability of regulations and guidelines for fuel handling, and technology readiness levels will also affect the applicability of the alternative fuel at large scale. Hence, to facilitate policy making and economic decisions, a detailed example with the inclusion of both quantitative and qualitative criteria is provided. See Table 3 for all parameters included in this example with their respective weighting factors. The values of weighting factors have significant impacts on the outcome of marine fuel score and ranks; hence, it is important to take note on the definition and weighting values of these factors in this paper, where this was conducted with the purpose of demonstrating the procedure.

Table 3. Marine fuel assessment criteria and their respective weightages.

	Marine Fuel Assessment	**Weightage (%)**
Quantitative factors	Relative fuel mass onboard	7.5%
	Relative fuel volume onboard	7.5%
	Relative life cycle (WTW) energy	20%
	Relative life cycle (WTW) cost	20%
	Relative WTW GHG emission	20%
	Relative WTW non-GHG emission	5%
Qualitative factors	Fuel production scalability	5%
	Fuel safety	5%
	Availability of regulations and guidelines	5%
	Technology readiness	5%

The qualitative criteria were categorized into 3 categories of scores, with the highest being 10 points (representing by green circle), followed by medium score of 7 points (represented by a yellow square), and lastly 3 points was the lowest score (represented by a red triangle). This score system was used to quantify the qualitative criteria. The first factor, which is the scalability of fuel production, is related to the availability of primary energies; as a rule of thumb, the primary energies should fulfil current demand from existing industries before supplying for marine fuel production, and hence, the fuel was categorized as unlikely to be scaled if the current production was not able to fulfil current demand from other industries. The second factor is the safety of fuel, which was quantified based on levels of flammability, toxicity, and corrosiveness. Next, the availability of regulations and guidelines for fuel bunkering and handling onboard of ship was also assessed. Technology readiness was assessed based on the status of technologies; while some technologies that had been commercialized were given the highest score, others that were available at small scale and in the research and development state were categorized under the medium and lowest score, respectively. See Table 4 for the summary of the scoring system.

Table 4. Score of qualitative factors and the definition of each score.

Sources of Database	Score = 10	Score = 7	Score = 4
Fuel production scalability	Scalable	Scalable, but challenging	Unlikely
Fuel safety	Safe, non-toxic, non-corrosive	Intermediate, acutely toxic, corrosive	Dangerous, very toxic, very corrosive
Availability of regulations and guidelines	Available	Require amendment	Not available
Technology readiness	Commercialized	Small scale	R&D

3. Results

3.1. Quantitative Assessment

3.1.1. Relative Fuel Mass and Volume Assessment

High energy density (kJ/kg) and specific energy (kJ/m^3) are desirable characteristics of marine fuels as they imply that the fuel requires a smaller storage tank, and has a lighter mass. For a more precise indication of the mass and volume of marine fuels onboard the ship, overall system efficiency and energy consumption or loss are considered in determination of fuel mass and volume. Figure 3 shows the relative mass and volume of alternative fuels. HFO without installation of CCS is used as the base case. From Figure 3, we can observe that the mass and volume of ammonia and methanol are relatively larger than HFO. Hydrogen is lighter than HFO; however, its storage volume is 3.6 to 4.5 times larger depending on the type of energy converters, and hence, usage of hydrogen may not be favourable for a long-distance vessel. This result is aligned with the hydrogen mass and volume reported by Mckinlay et al. [35], who stated that the volume requirement of hydrogen is within the viable range for onboard usage. Biodiesels possess similar properties as HFO, and LNG has a similar total mass but is 1.9 to 2.3 times larger in volume. Among all, LNG and biodiesel seem to be the most suitable alternative fuels. Usage of electricity as the energy carrier in batteries needs to be 16 times heavier and 8 times larger in volume and is excluded from Figure 3.

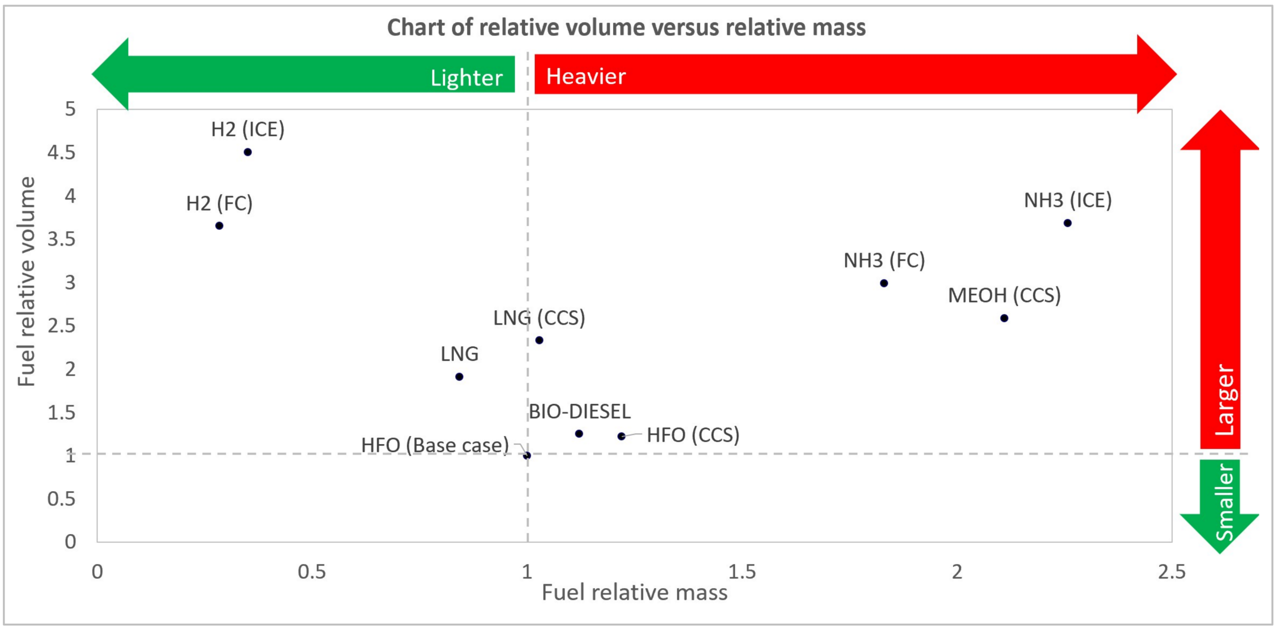

Figure 3. Relative mass and volume of various marine fuels.

3.1.2. Relative Energy Assessment

Energy consumption during fuel production and consumption is closely related to fuel economy. In this section, the relative well-to-wake energy for various marine fuels is presented in Figure 4. The WTW energy for the electricity pathways is lower than HFO, due to a large extent to a highly efficient energy conversion process using electrical motors with up to 95% efficiency. Next, the WTW energy for biodiesel is equivalent to HFO due to its simple fuel production processes with less energy loss. However, since the HFO reference case is not a zero-carbon option, installation of CCS is required to make HFO a zero-carbon fuel. Note that HFO even with CCS is not completely zero-carbon due to the realistic CCS capture efficiency of 90% used here—see Section 3.1.4 for more details. From Figure 4, we can observe that approximately 20% additional energy is required for the operation of CCS, which causes this pathway to be more energy intensive than electricity, biodiesel, and NG-based H_2 with a fuel cell as an energy converter. All other alternative fuels such as ammonia and methanol produced from different feedstock and green H_2 are comparatively more energy intensive than HFO with a CCS installation, making them less attractive in terms of energy.

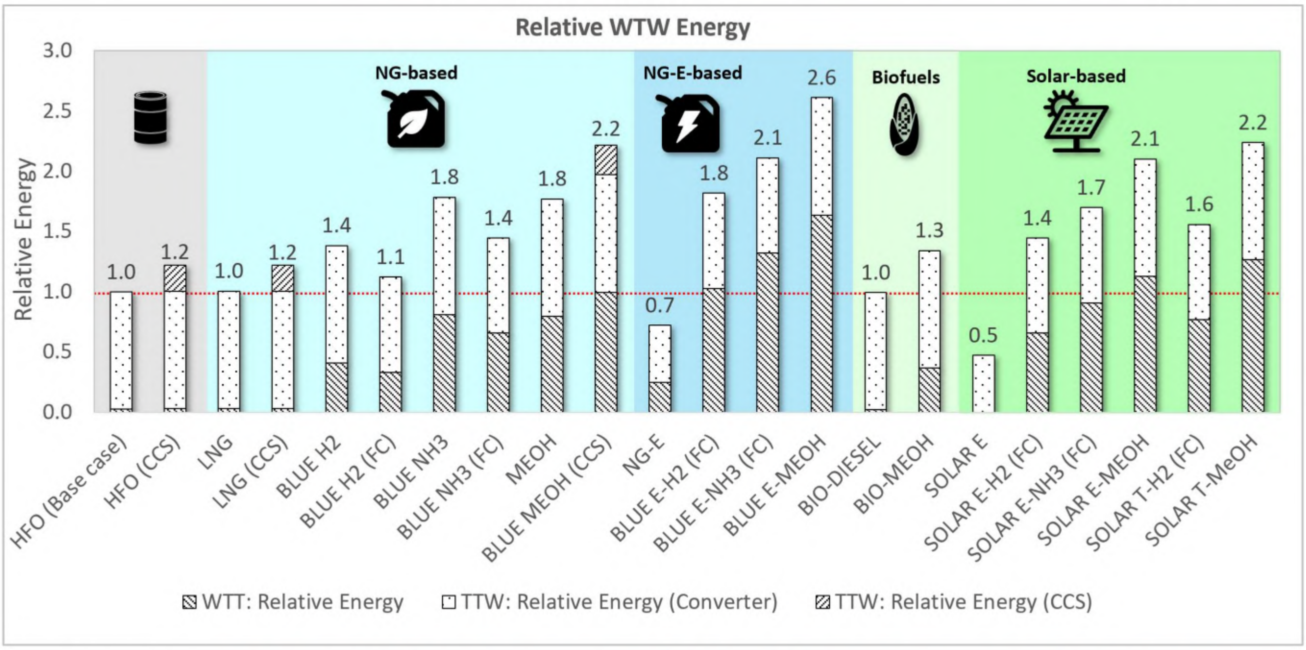

Figure 4. Relative Well-to-Wake energy, separated into Well-to-Tank and Tank-to-Wake contributions.

It is also interesting to investigate the energy consumption from Well-To-Tank (WTT) and Tank-To-Wake (TTW) perspectives, which are shown in Figures 5 and 6. In general, TTW energy consumption is related to the efficiency of the energy converters. In this study, three types of energy converters are involved: an internal combustion engine, a fuel cell, and an electrical motor with 45% [20], 60% [23], and 92.5% [22] energy efficiencies, respectively. On the other hand, the energy loss during fuel production (WTT) has a greater difference between different pathways. As shown in Figure 5, the energy consumption for the production of hydrogen, ammonia, and methanol is 13 to 67 times higher than conventional fossil-fuel production. The energy consumption is highly dependent on the type of feedstock and processes involved during fuel production. For example, the production of NH_3 from NG steam reforming consumes 26.8 more energy than the production of HFO, whereas production of NH_3 from solar electricity consumes 37.1 times more energy. See the next paragraph to visualize the cause of this huge energy difference.

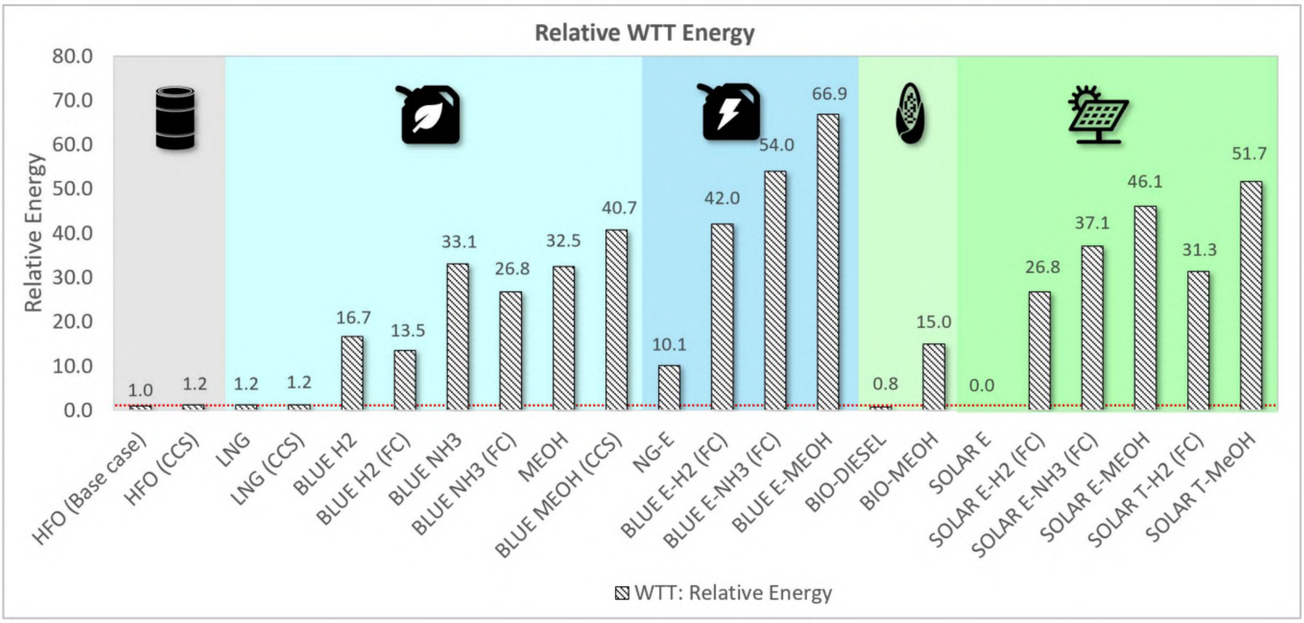

Figure 5. Relative Well-to-Tank Energy for alternative fuels.

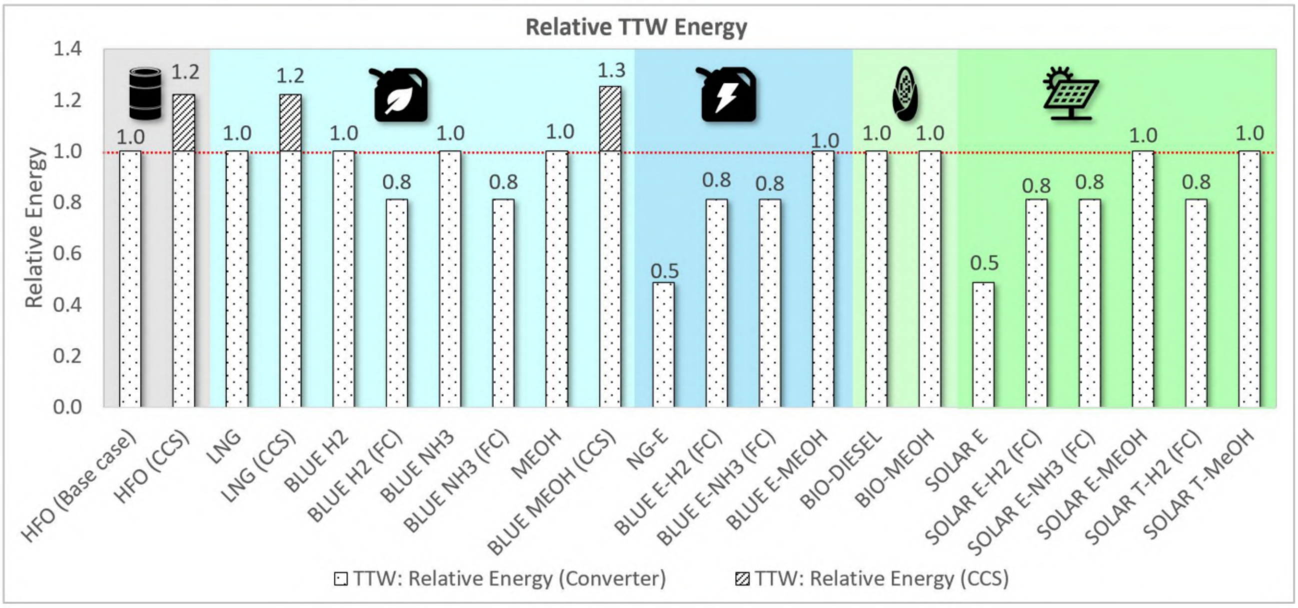

Figure 6. Relative Tank-to-Wake Energy for alternative fuels.

One of the outcomes of the lifecycle ASPEN modelling is that it allows a better understanding of the energy losses, visualized here with Sankey diagrams. From the Sankey diagram in Figure 7, we can observe how is 100% of energy is lost and 30.4% of energy remains for the propulsion of the ship; in addition, about 45.3% of energy from feedstock is lost during fuel production, with the majority of the energy loss occurring via steam reforming (SMR) and NH_3 production. Then, out of the 54.7% of energy left after fuel production, only 30.4% of energy is converted into propulsion energy, while 24.3% of the energy is lost from the fuel cell and electrical motor during energy conversion. Besides, comparisons of the energy flow between various pathways can be made utilizing Sankey diagrams. For example, NH_3 production from natural gas steam reforming and solar electrolysis has different overall energy efficiencies; the difference is illustrated using Sankey diagrams in Figures 7 and 8. As shown in these figures, 53.5% of energy is lost during the production of NH_3 from solar electricity, which is higher than the 45.3% of energy lost if NH_3 is produced from NG steam reforming. This difference is due to the highly energy-intensive electrolysis process, which consumes more energy than the SMR process. Anyway, the NH_3 produced from both pathways are very energy intensive compared to other fossil fuel pathways. Sankey diagrams for other potential fuel pathways are included in the Appendix C, Figures A9–A30. These figures can help policymakers and technology developers visualize the overall energy flow of marine fuel pathways.

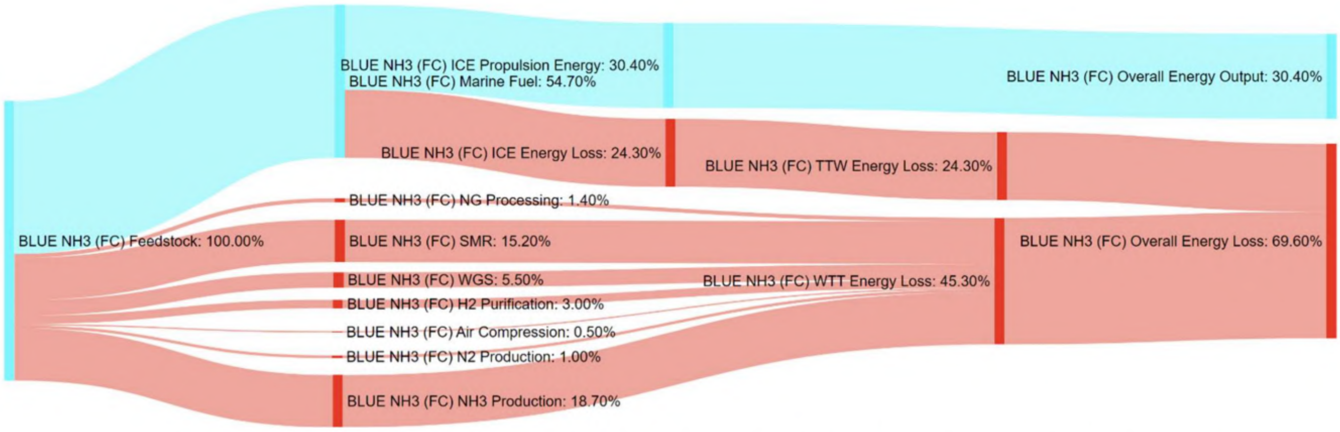

Figure 7. Sankey energy flow diagram for ammonia produced via steam reforming of natural gas.

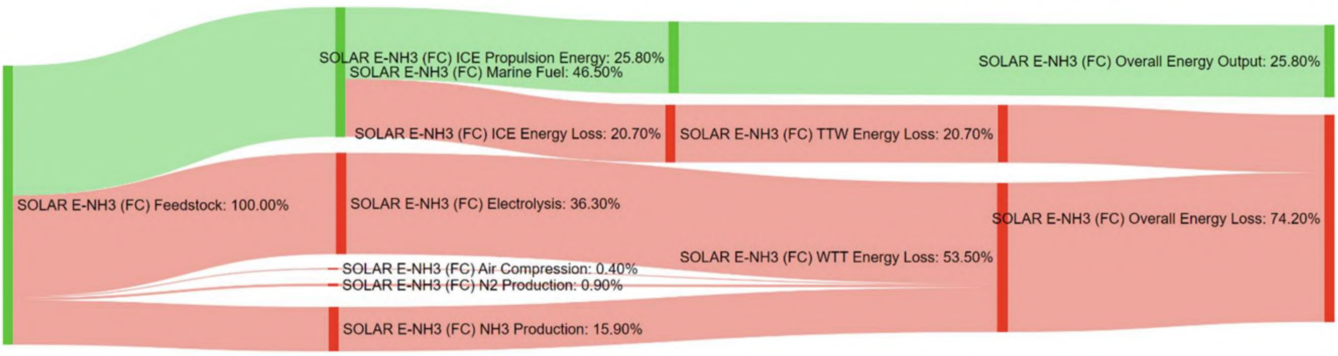

Figure 8. Sankey energy flow diagram for ammonia produced via solar electrolysis.

3.1.3. Relative Cost Assessment

Figure 9 shows the overall cost of various alternative pathways relative to the cost of HFO. From the chart, it is shown that CCS installation is the cheapest solution towards decarbonization of shipping industry, which would increase the overall cost by nearly 20% only, while transition to LNG with CCS installation would increase the overall cost by 30% and biodiesel would increase the overall cost by 90%. On the other hand, transition into methanol requires at least 2.2× of the conventional overall fuel cost, and transition into hydrogen and ammonia produced using different pathways would increase the overall cost by more than 3×, mainly caused by the high TTW operating cost and capital cost of energy converters such as fuel cells.

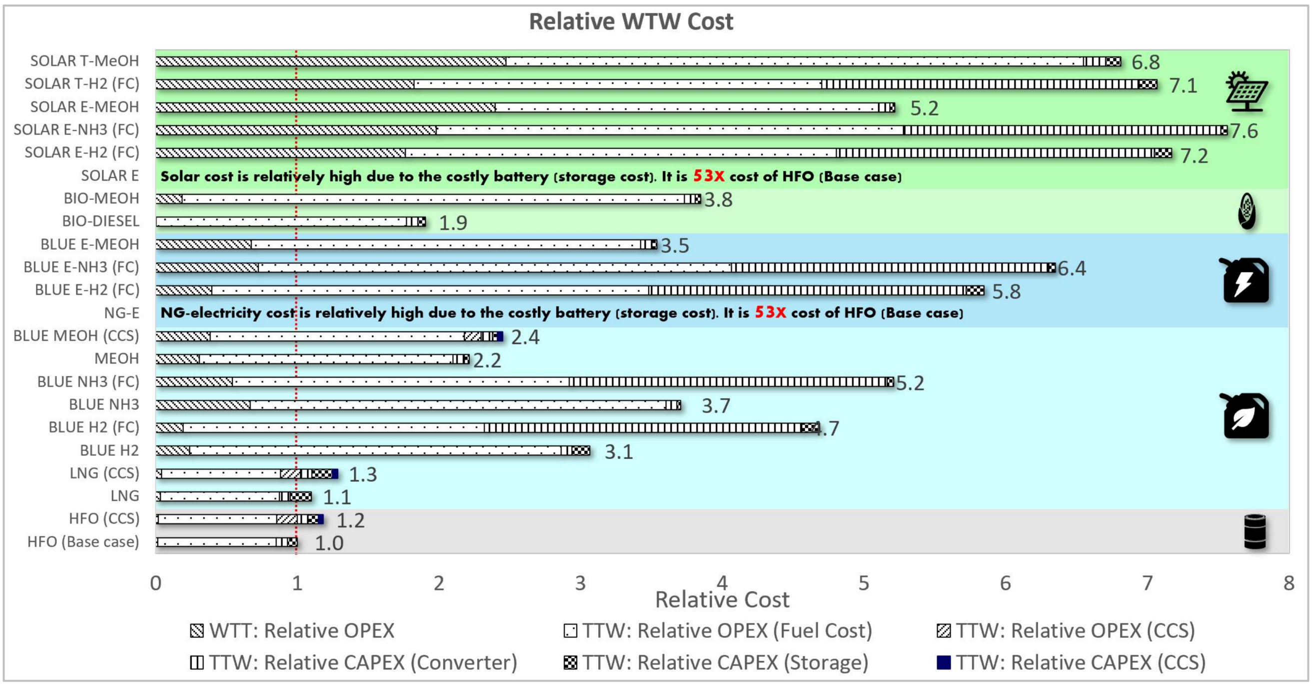

Figure 9. Relative Well-to-Wake cost, separated into Well-to-Tank and Tank-to-Wake contributions.

Similar to the trend of well-to-tank energy, the fuel production costs estimated per unit of energy consumed also show huge differences between pathways. The cost of production of alternative fuels is 2 to 185 times higher than HFO. Hence, fuel producers would be reluctant to produce these highly energy-intensive fuels unless they can sell them at a higher price or pricing is enforced by regulation. For TTW costs, the fuel cost is the largest contributor. Fuel cost is closely related to the feedstock cost, process complexity, and maturity of fuel production [36]. Hence, if alternative fuels can be produced with more mature technology and at lower prices, fuel transition would appear to be more economic.

3.1.4. Relative WTW GHG and Non-GHG Emissions Assessment

Apart from fuel cost, an important quantitative assessment is the environmental impact of the fuel. Life cycle GHG emission (WTW) is an indicator of fuel environmental performance, which accounts for GHG emissions starting from fuel production until the fuel consumption stage. In general, all NG-based marine fuel pathways include upstream fugitive methane emission in the total WTW GHG emission; however, methane slippage from the LNG's ICE is assumed to be negligible due to the large uncertainty regarding the value, in addition to the fact that many manufacturers have claimed that methane slippage from engines has been greatly eliminated as technological improvement has continued [37]. An assumption was made that 90% of the carbon emitted from the electricity used for the production of blue fuels is captured. Next, biodiesel is assumed to be carbon-neutral considering that biomass consumes CO_2 during the growth phase. The production of methanol from solar electricity and solar thermal energy consumes CO_2, so the amount of CO_2 consumed in methanol synthesis is counted as carbon reduction and shall be considered as negative carbon in the determination of WTW GHG. See Figure 10 for the WTW GHG assessment.

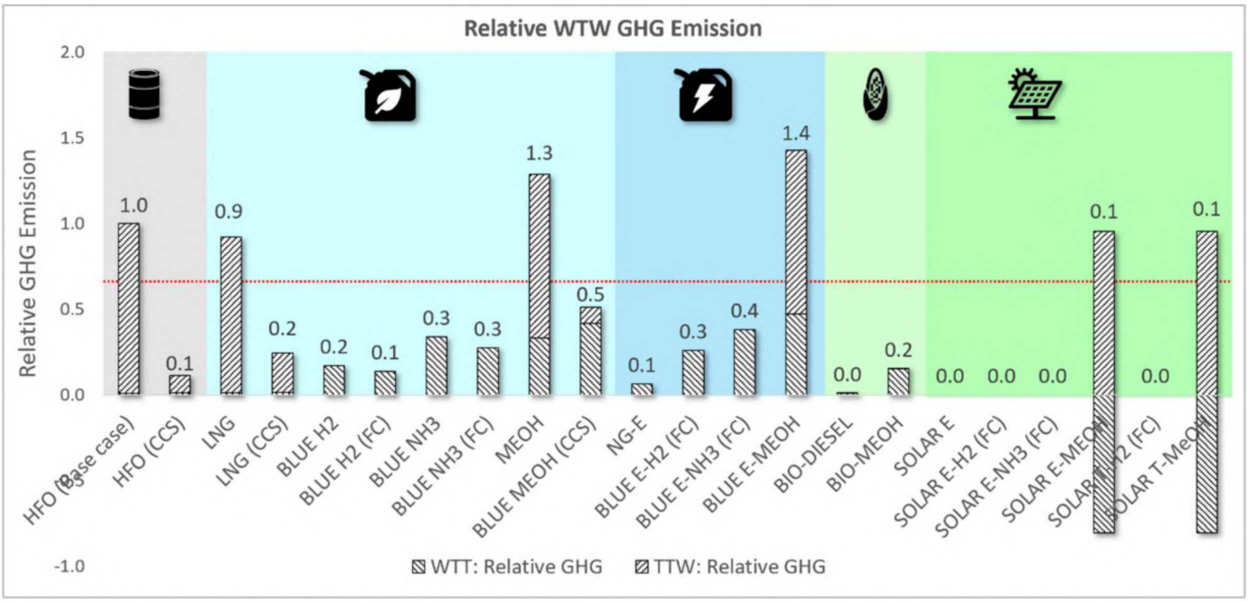

Figure 10. Relative Well-to-Wake GHG emission, separated into Well-to-Tank and Tank-to-Wake contributions.

As shown in Figure 10, HFO, LNG, and methanol are among the fuels with higher TTW carbon emissions, and hence, CCS installation is required to make them low carbon fuels in the TTW stage, which is shown by the HFO (CCS), LNG (CCS), and BLUE MEOH (CCS) pathways. With the installation of CCS, HFO and LNG become cleaner with overall carbon emissions being as low as 10 to 20% of those of conventional marine fuel. However, this statement is only valid with the assumption that CCS is able to capture 90% of the CO_2 in the exhaust stream. With CCS integration, these fuel pathways would be compatible with blue hydrogen and ammonia in terms of carbon emission. However, the CO_2 emission from methanol is among the highest contributed by the high WTT CO_2 emission during fuel processing, which is also stated in a review paper [36]. All hydrogen and ammonia pathways give a lower GHG emissions than conventional HFO and LNG. Green fuels produced from renewable energy, including solar electricity, green hydrogen, and green ammonia, have net zero carbon emissions throughout the marine fuel lifecycle, whereas green methanol has a mere 10% carbon emission. However, the GHG emission of the production of renewable electricity (such as the carbon footprint of manufacturing solar panels and wind turbines) is not included due to the large uncertainties associated with these values. For consistency, any GHG emissions associated with constructing the plants that produce the other fuels are also not included.

Other pollutants, including NOx, SOx, and PM, must also be considered. From Figure 11, it can be seen that many alternative pathways can reduce the non-GHG emissions, except for biofuels, which tend to have similar NOx emissions to HFO, roughly speaking [38]. There is some evidence that biofuels reduce particulate emissions [38], which agrees with the result of environmental assessment conducted by Foretich et al. [8]. Fuel cells do not produce NOx, while it is not clear whether hydrogen-reciprocating engines produce more or less NOx than HFO. It may be expected that hydrogen may allow leaner combustion modes to be used and, hence, produce lower NOx, but as such technologies are still in the design phase, stronger statements on NOx from hydrogen, ammonia, and methanol from combustion cannot be made. Ammonia would also need significant NOx post-combustion clean up, if burnt in reciprocating engines, while we might expect negligible NOx if used in fuel cells. Due to the lack of data on NH_3 from reciprocating engines, in Figure 11, NH_3 and H_2 in engines are given the same value as HFO; however, it is understood that NH_3 at least may need costly clean-up.

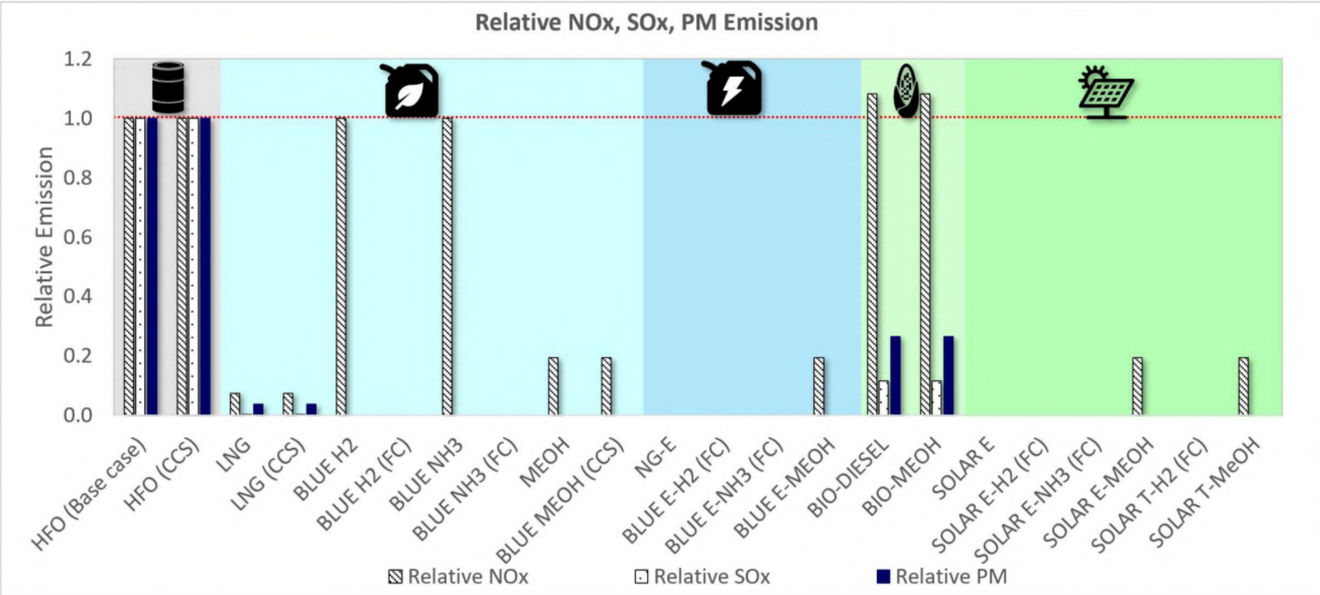

Figure 11. Non-GHG emission (NOx, SOx, PM) of alternative fuels.

3.1.5. Summary of Quantitative Assessment

Figure 12 summarizes the results from the quantitative assessment by putting the relative values of mass, volume, WTW energy, WTW cost, and WTW GHG emission in a single chart. The smaller the relative value, the higher the potential of the fuel pathway, as the ideal characteristics of marine fuel are low mass, low volume, low WTW energy, low WTW cost, and low WTW GHG emission.

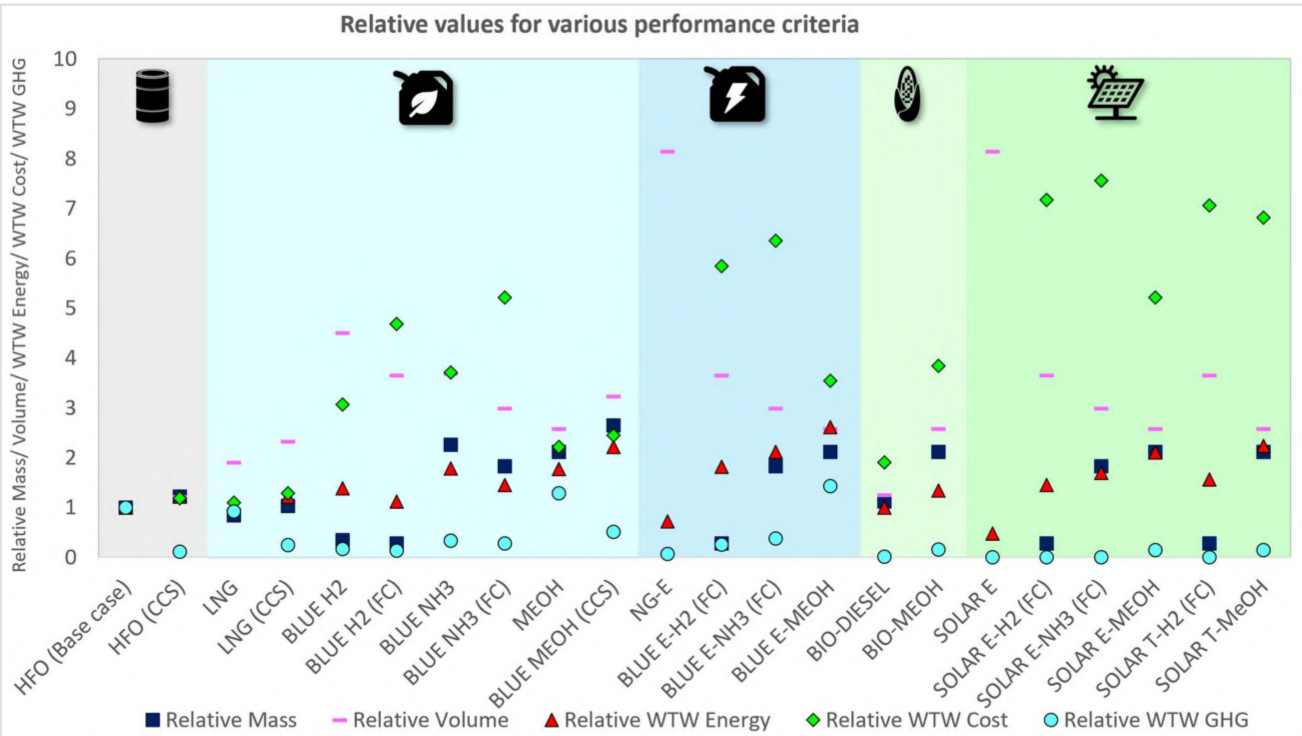

Figure 12. Summary of quantitative assessment.

With reference to Figure 12 and Table 5, the relative values of various alternative pathways can be compared. For example, HFO with CCS installation increases the fuel mass and volume by 22%, the WTW energy and cost are increased by 22% and 18% respectively, but WTW GHG emission is reduced by 89% with as little as 11% relative to WTW GHG emissions. Another example, which is the blue hydrogen produced from natural gas, has a 72% reduction in fuel mass but 265% increments of fuel volume. The production of blue hydrogen also consumes 12% more energy and results in 369% higher costs. Importantly, this alternative pathway reduces overall CO_2 emissions by 86%. This is achieved when blue electricity is used for hydrogen production; otherwise, carbon emissions would be much higher. Hydrogen can only play a role as a zero-carbon fuel if it is produced from renewable energy; for instance, the hydrogen produced from solar electricity and solar-thermal processes. Production of hydrogen using natural gas electricity also gives a lower CO_2 emission; however, the overall cost is 12% higher than that of steam-reforming hydrogen.

Table 5. (**a**) Summary of quantitative assessment, percentages relative to the reference case (HFO without CCS); (**b**) summary of quantitative assessment normalized into scores between 1 and 10.

(a)

Fuel Type	Relative Mass	Relative Volume	Relative WTW Energy	Relative WTW Cost	Relative WTW GHG	Relative NOx	Relative SOx	Relative PM
HFO (Base case)	100%	100%	100%	100%	100%	100%	100%	100%
HFO (CCS)	122%	122%	122%	118%	11%	100%	100%	100%
LNG	84%	191%	101%	110%	92%	7%	0%	4%
LNG (CCS)	103%	233%	122%	129%	24%	7%	0%	4%
BLUE H_2	35%	450%	138%	306%	17%	100%	0%	0%
BLUE H_2 (FC)	28%	365%	112%	469%	14%	0%	0%	0%
BLUE NH_3	226%	368%	178%	371%	34%	100%	0%	0%
BLUE NH_3 (FC)	183%	299%	145%	521%	27%	0%	0%	0%
MEOH	211%	259%	177%	221%	129%	19%	0%	0%
BLUE MEOH (CCS)	264%	324%	222%	245%	51%	19%	0%	0%
NG-E	1669%	814%	72%	5304%	6%	0%	0%	0%
BLUE E-H_2 (FC)	28%	365%	182%	585%	26%	0%	0%	0%
BLUE E-NH_3 (FC)	183%	299%	211%	635%	38%	0%	0%	0%
BLUE E-MEOH	211%	259%	261%	354%	143%	19%	0%	0%
BIO-DIESEL	112%	125%	100%	190%	1%	108%	11%	26%
BIO-MEOH	211%	259%	134%	384%	15%	108%	11%	26%
SOLAR E	1669%	814%	47%	5375%	0%	0%	0%	0%
SOLAR E-H_2 (FC)	28%	365%	145%	717%	0%	0%	0%	0%
SOLAR E-NH_3 (FC)	183%	299%	170%	757%	0%	0%	0%	0%
SOLAR E-MEOH	211%	259%	210%	522%	15%	19%	0%	0%
SOLAR T-H_2 (FC)	28%	365%	156%	707%	0%	0%	0%	0%
SOLAR T-MeOH	211%	259%	224%	681%	15%	19%	0%	0%

Table 5. *Cont.*

(b)						
Fuel Type	**Fuel Mass Score 1–10 (Heaviest to Lightest)**	**Fuel Volume Score 1–10 (Small to Large)**	**WTW Energy Score 1–10 (High Energy Intensity to Low)**	**WTW Cost Score 1–10 (High Cost to Low)**	**WTW GHG Emission Score 1–10 (High Emission to Low)**	**Non-GHG Emission Score Score 1–10 (High Emission to Low)**
HFO (Base case)	9.6	10.0	7.8	10.0	3.7	1.2
HFO (CCS)	9.5	9.7	6.9	9.7	9.3	1.2
LNG	9.7	8.9	7.8	9.9	4.2	9.7
LNG (CCS)	9.6	8.3	6.9	9.6	8.5	9.7
BLUE H_2	10.0	5.6	6.2	7.2	8.9	7.2
BLUE H_2 (FC)	10.0	6.7	7.3	4.9	9.1	10.0
BLUE NH_3	8.9	6.6	4.5	6.3	7.9	7.2
BLUE NH_3 (FC)	9.2	7.5	5.9	4.2	8.3	10.0
MEOH	9.0	8.0	4.5	8.3	1.9	9.5
BLUE MEOH (CCS)	8.7	7.2	2.7	8.0	6.8	9.5
NG-E	1.0	1.0	9.0	1.0	9.6	10.0
BLUE E-H_2 (FC)	10.0	6.7	4.3	3.4	8.4	10.0
BLUE E-NH_3 (FC)	9.2	7.5	3.1	2.7	7.6	10.0
BLUE E-MEOH	9.0	8.0	1.0	6.5	1.0	9.5
BIO-DIESEL	9.5	9.7	7.8	8.8	9.9	5.9
BIO-MEOH	9.0	8.0	6.3	6.1	9.0	5.9
SOLAR E	1.0	1.0	10.0	1.0	10.0	10.0
SOLAR E-H_2 (FC)	10.0	6.7	5.9	1.5	10.0	10.0
SOLAR E-NH_3 (FC)	9.2	7.5	4.8	1.0	10.0	10.0
SOLAR E-MEOH	9.0	8.0	3.1	4.2	9.1	9.5
SOLAR T-H_2 (FC)	10.0	6.7	5.4	1.7	10.0	10.0
SOLAR T-MeOH	9.0	8.0	2.6	2.0	9.1	9.5

In terms of energy, the use fossil fuels with CCS installed results in 22% higher energy; natural gas-based hydrogen, ammonia, and methanol imply 12%, 45%, and 122% higher energy to produce the same propulsion energy, whereas the solar-based hydrogen, ammonia, and methanol imply 45%, 70%, and 110% higher energy. The energy intensity of biodiesel is the same as the HFO reference case, whereas bio-methanol implies 30% higher energy. Hence, biodiesel is the most energy-efficient alternative pathway for decarbonization, followed by steam-reforming hydrogen, and then CCS installation and other alternative pathways. The installation of CCS is energy intensive; however, based on the results obtained here, the energy requirement for the production of cleaner fuels such as hydrogen, ammonia, and methanol is much higher than that of the installation of CCS downstream of the internal combustion unit.

In terms of cost, the use of fossil fuels with CCS installed results in 18–29% higher costs; natural gas-based hydrogen, ammonia, and methanol increase the overall cost by 369%, 421%, and 145%, respectively, whereas solar-based hydrogen, ammonia, and methanol increase the overall cost by 617%, 647%, and 422%, respectively, while biodiesel and bio-methanol increase the overall cost by 90% and 284%. Hence, CCS installation is the more economical means of decarbonization, followed by biofuels, whereas solar-based alternative fuels are the costliest solutions.

Based on the results in Table 5a, the total score of each marine fuel, based on various assessment criteria, is normalized into a score between 1 and 10, as shown in Table 5b. In general, these categorized into three categories of scores. A score between 1 and

4 corresponds to the lowest potential category (represented by a red triangle), scores from 4 to 7 equate to the potential category (represented by a yellow square), and lastly, scores from 7 to 10 points are categorized as high-potential marine fuel (represented by a green circle).

3.2. An Example Procedure for Reaching Fuel Selection

For a thorough assessment covering not just quantitative parameters but also other parameters such as scalability, applicability of fuel onboard, and technologies' readiness levels, a few qualitative parameters are included in this section. Based on the definition in Table 4, qualitative assessment was conducted based on the results shown in Figure 13.

Fuel type	Scalability Scalable Difficult Unlikely	Flammability, toxicity, corrosiveness (Follow the worst score)	Regulation & guidelines Completely Available Available, need amendment Not Available	Technology readiness Commercialized Small scale R&D
HFO (Base case)	Scalable	Safe,Non-toxic,Non-corrosive	IGF Code	Commercialized
HFO (CCS)	Scalable	Safe,Non-toxic,Non-corrosive	IGF Code	Commercialized
LNG	Scalable	Safe,Non-toxic,Non-corrosive	IGF Code	Commercialized
LNG (CCS)	Scalable	Safe,Non-toxic,Non-corrosive	IGF Code	Commercialized
BLUE H2	Scalable	Dangerous,Non-toxic,Non-corrosive	Require amendment of IGF Code	Small scale
BLUE H2 (FC)	Scalable	Dangerous,Non-toxic,Non-corrosive	Require amendment of IGF Code	Small scale
BLUE NH3	Scalable	Intermediate,Very toxic,Corrosive	IGC not allow, IGF Code require approval	Small scale
BLUE NH3 (FC)	Scalable	Intermediate,Very toxic,Corrosive	IGC not allow, IGF Code require approval	Small scale
MEOH	Scalable	Intermediate,Acutely-toxic,Corrosive	Require amendment of IGF Code	Small scale
BLUE MEOH (CCS)	Scalable	Intermediate,Acutely-toxic,Corrosive	Require amendment of IGF Code	Small scale
NG-E	Scalable	Safe,Non-toxic,Non-corrosive	Part 6, Chapter 2, Section 1, Battery power	Commercialized
BLUE E-H2 (FC)	Not economic	Dangerous,Non-toxic,Non-corrosive	Require amendment of IGF Code	Small scale
BLUE E-NH3 (FC)	Not economic	Intermediate,Very toxic,Corrosive	IGC not allow, IGF Code require approval	Small scale
BLUE E-MEOH	Not economic	Intermediate,Acutely-toxic,Corrosive	Require amendment of IGF Code	Small scale
BIO-DIESEL	Challenging	Safe,Non-toxic,Corrosive upon degradation	ISO 8217:2017 fuel standard	Small scale
BIO-MEOH	Challenging	Intermediate,Acutely-toxic,Corrosive upon degradation	Require amendment of IGF Code	Small scale
SOLAR E	Unlikely	Safe,Non-toxic,Non-corrosive	Part 6, Chapter 2, Section 1, Battery power	Commercialized
SOLAR E-H2 (FC)	Unlikely	Dangerous,Non-toxic,Non-corrosive	Require amendment of IGF Code	Small scale
SOLAR E-NH3 (FC)	Unlikely	Intermediate,Very toxic,Corrosive	IGC not allow, IGF Code require approval	Small scale
SOLAR E-MEOH	Unlikely	Intermediate,Acutely-toxic,Corrosive	Require amendment of IGF Code	Small scale
SOLAR T-H2 (FC)	Unlikely	Dangerous,Non-toxic,Non-corrosive	Require amendment of IGF Code	Small scale
SOLAR T-MeOH	Unlikely	Intermediate,Acutely-toxic,Corrosive	Require amendment of IGF Code	Small scale

Figure 13. Summary of qualitative assessment with colour code showing the score. (= 10, = 7, = 4).

By using the results in Table 5 and Figure 13, an example assessment was carried out following the pre-assigned weighting factors (see Table 3). The result is presented using a total score system in Figure 14. The total score in last column of Figure 14 was calculated based on assigned weighting. Fossil-based marine fuel with the installation of CCS achieved the highest score, followed by biodiesel, hydrogen produced via steam reforming, and then electricity produced by various means. Ammonia and methanol produced from various pathways achieved lower scores and, hence, were deemed to have less potential as marine fuels. However, the results in the case study would change significantly following a different weighting percentage of each parameter, and thus, the discussion here is intended to serve as an example to demonstrate the methodology.

Marine Fuel	Onboard fuel mass ● = Light ■ = Medium ▲ = Heavy	Onboard fuel volume ● = Small ■ = Medium ▲ = Large	Relative WTW Energy ● = Low ■ = Medium ▲ = High	Relative WTW Cost ● = Low ■ = Medium ▲ = high	Relative WTW GHG Emissions ● = Low ■ = Medium ▲ = High	Relative Non-GHG Emissions ● = Low ■ = Medium ▲ = High	WTT Scalability ● = Scalable ■ = Challenging ▲ = Unlikely	Fuel safety ● = Safe ■ = Intermediate ▲ = Dangerous	Regulations & guidelines ● = Available ■ = Amendment ▲ = N.A.	Technology readiness ● = Commercial ■ = Small scale ▲ = R&D	Total Scores
HFO (base case)	●	●	●	●	▲	▲	●	●	●	●	78.3
HFO (ICE,CCS)	●	●	■	●	●	▲	●	●	●	■	85.3
NG-LNG (ICE)	●	●	●	●	■	●	●	●	●	●	82.4
NG-LNG (ICE,CCS)	●	●	■	●	●	●	●	●	●	■	86.6
NG-H2 (ICE)	●	■	■	●	●	●	●	▲	■	■	73.8
NG-H2 (FC)	●	■	●	■	●	●	●	▲	■	■	74.2
NG-NH3 (ICE)	●	■	■	■	●	●	●	▲	▲	■	65.1
NG-NH3 (FC)	●	●	■	■	●	●	●	▲	▲	■	66.8
NG-MeOH (ICE)	●	●	■	●	▲	●	●	■	■	■	62.5
NG-MeOH (ICE,CCS)	●	●	▲	●	■	●	●	■	■	■	67.0
NG-E (EM)	▲	▲	●	▲	●	●	●	●	●	●	65.6
BLUE-E-H2 (FC)	●	■	■	▲	●	●	■	▲	■	■	62.1
BLUE-E-NH3 (FC)	●	●	▲	▲	●	●	■	▲	▲	■	55.2
BLUE E-MeOH (ICE)	●	●	▲	■	▲	●	■	■	■	■	48.5
BIODIESEL (ICE)	●	●	●	●	●	■	■	■	●	■	85.9
BIO-MeOH (ICE)	●	●	■	■	●	■	■	■	■	■	72.6
SOLAR E (EM)	▲	▲	●	▲	●	●	▲	●	●	●	65.5
SOLAR-E-H2 (FC)	●	■	■	▲	●	●	▲	▲	■	■	63.4
SOLAR-E-NH3 (FC)	●	●	■	▲	●	●	▲	▲	▲	■	58.7
SOLAR E-MEOH (ICE)	●	●	▲	■	●	●	▲	■	■	■	62.8
SOLAR-T-H2 (FC)	●	■	■	▲	●	●	▲	▲	■	■	62.7
SOLAR-T-MeOH (ICE)	●	●	▲	▲	●	●	▲	■	■	■	57.3

Figure 14. Score for alternative fuels (Score 1–10; ● ≥ 7; 7 > ■ > 4; ▲ ≤4).

4. Discussion

The decarbonization of shipping is thought to be achievable with a variety of primary energy sources, fuel production pathways, and propulsion technologies. The work in this paper quantified many of these approaches from overall energy, cost, and feasibility perspectives. For fossil fuels, CCS must be employed but virtually no other change is needed, while fuels produced from solar electricity do not have carbon emissions but are costly and may require alterations in the supply chain and in terms of propulsion. For instance, this research showed that hydrogen produced from natural gas reforming is ranked higher than renewable hydrogen, due to its lower energy intensity and cost during fuel production and its level of scalability affected by feedstock availability. This is aligned with the review paper [39], which stated that switching to LNG is one of the readily available solutions and natural gas-based hydrogen and ammonia can serve as a bridge between current fossil fuels and future hydrogen-based fuels.

The most important factor to be considered would be overall carbon emission. As a carbon-neutral solution, biofuels have high potential as future fuels, and can be used as drop-in fuels, thus minimizing the need to modify existing technologies. Next, CCS installation for fossil-based fuels can potentially reduce CO_2 emissions (at lower cost) and energy consumption as compared to other clean fuels such as blue hydrogen, ammonia, and methanol. Transition into methanol is not so promising as the production of methanol is very energy intensive and has resulted in higher CO_2 emissions during the production phase. Only with bio-methanol can CO_2 emissions be greatly reduced [1] to meet the IMO 2050 target. All hydrogen and ammonia pathways give lower CO_2 emissions; however, transition into hydrogen or ammonia [40] through the blue pathway [41] would not lead to zero carbon use in the maritime industry unless a green production pathway is used.

In terms of energy, electricity is the most energy-efficient alternative fuel, followed by biodiesel, steam-reforming hydrogen, installation of CCS for fossil fuels, bio-methanol, and then other alternative pathways. Electrification is the most efficient route; however, the low energy density and high battery cost have made it unsuitable for long distance shipping. Biofuels are a carbon-neutral solution—especially biodiesel [8], with its energy-efficient production processes—and are high-potential fuels [9]. Hydrogen efficiency is highly dependent on the production and utilization method. Hydrogen that is produced from natural gas and applied on fuel cells can be more efficient than the green hydrogen produced via electrolysis. An important finding from the energy assessment is that the installation of CCS, which is itself energy intensive, has lower energy consumption compared to the production of cleaner fuels such as hydrogen, ammonia, and methanol. In general, fuels derived from electrolysis and natural gas electricity are highly energy intensive, making them a costly alternative.

In terms of financial performance, the fuel production cost and converter cost make up most of the overall cost. The installation of CCS for fossil fuels incurs the lowest cost, followed by biodiesels, methanol produced from natural gas, and bio-methanol. Hydrogen and ammonia can be more cost-competitive than methanol if a dual fuel engine is used as an energy converter; otherwise, the cost of the fuel cell may result in high investment requirements for the technology and vessel retrofication, making them a costly alternative. On the other hand, renewable alternative fuels can only be cost-competitive if the fuel production cost can be reduced; otherwise, the production of hydrogen, ammonia, and methanol from natural gas would be preferred over the renewable options. However, these alternative fuels are still more expensive than CCS installation. CCS installation and biodiesel seem to be the more economical means of decarbonization and are the most promising for short-term or long-term decarbonization solutions. However, it must be noted that the non-perfect capture of CO_2 in today's CCS systems and the fact that biofuel production may involve some CO_2 emissions (e.g., from today's transport systems) are factors that could complicate the cost factors if carbon taxing is used in the future.

If renewable electricity were abundant, solar fuels such as hydrogen or ammonia could be used for decarbonization, but at a high energy penalty. There are pending issues with certification and regulation on fuel handling and bunkering. Looking into the TRL of various alternative fuels, biofuels, and methanol, LNG and electrification (for short-distance routes) are more mature, whereas hydrogen and ammonia, with either ICE and FC, are still under development and need significant technological and supply chain developments.

Considering all the above factors together, it seems that fossil-based marine fuel with installed CCS is the best option for short-term decarbonization in terms of energy penalties, financial costs, and TRL, followed by biofuels, blue hydrogen, methanol, blue ammonia, and electrification (for short-distance routes) [10]. Generally, hydrogen, ammonia, and methanol produced via various pathways have high energy and financial costs and need further technological developments. The CCS option, of course, has the long-term problem of what to do with the captured CO_2, but this is not addressed in this paper.

5. Conclusions

This study carried out the life cycle assessment of 22 alternative pathways and quantified the potential of alternative marine fuels by means of comparison to the currently most-used conventional HFO, based on ASPEN modelling. The relative values for six assessment parameters were calculated and visualized in form of charts. Detailed Sankey energy flow diagrams were produced for each alternative pathway, and are included in Appendix C. The relative fuel mass and volume onboard is shown in Figure 3, the relative energy intensity of fuel is shown in Figure 4, the relative cost of fuel is shown in Figure 9, and the environmental impact of alternative fuel is analysed in Figures 10 and 11. Finally, all parameters were combined in a single graph (see Figure 12) and table (Table 5) for the purpose of comparison. In short, CCS installation is the most cost-effective alternative pathway (18% more costly than conventional marine fuel), electricity is the most energy-efficient pathway (decreases the overall energy by 27–50%), conventional fuel with CCS and biodiesel require lesser volumes (only 22% and 25% more storage volume than that of the reference case due to the energy requirement of CCS and the lower energy density of biodiesel) and require minimal modification on existing infrastructure, and hydrogen and ammonia need the highest amount of energy for production but emit zero carbon and particulate emissions; however, they may still need NOx clean-up. Each alternative pathway has strengths and weaknesses, making the present data important for guiding fuel selection and supporting the decision making of stakeholders in the decarbonization of the maritime sector. In the last part of this paper, an example ranking of all pathways was carried out by using these results and some additional subjective qualitative criteria, such as technology readiness levels, regulations, and fuel scalability. Fossil-based marine fuel with installed CCS achieved the highest score, followed by biodiesel, hydrogen produced via steam reforming, and then electricity produced by various means, while ammonia and methanol produced from various pathways achieved lower scores. Biofuels seem to be a good compromise in terms of energy, cost, and emissions, while methanol from biomass seems also to be a low-cost solution; however, non-CO_2 emissions do not appear to be reduced.

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Appendix A

ASPEN HYSYS simulation was utilized to obtain energy and cost data. Currently, there are limited data regarding the energy intensity of marine fuel production from different pathways. Although some articles have reported the energy intensity and cost of alternative fuel production, due to the differences in the assumptions made in the studies, the results are not consistent. In this research, the ASPEN commercial model was built based on commercialized operation of similar production plants. Refer to Table 2 for the sources of the process conditions. These models included the entire life cycle of alternative fuel, including the fuel production stage and the energy conversion, using internal combustion engines.

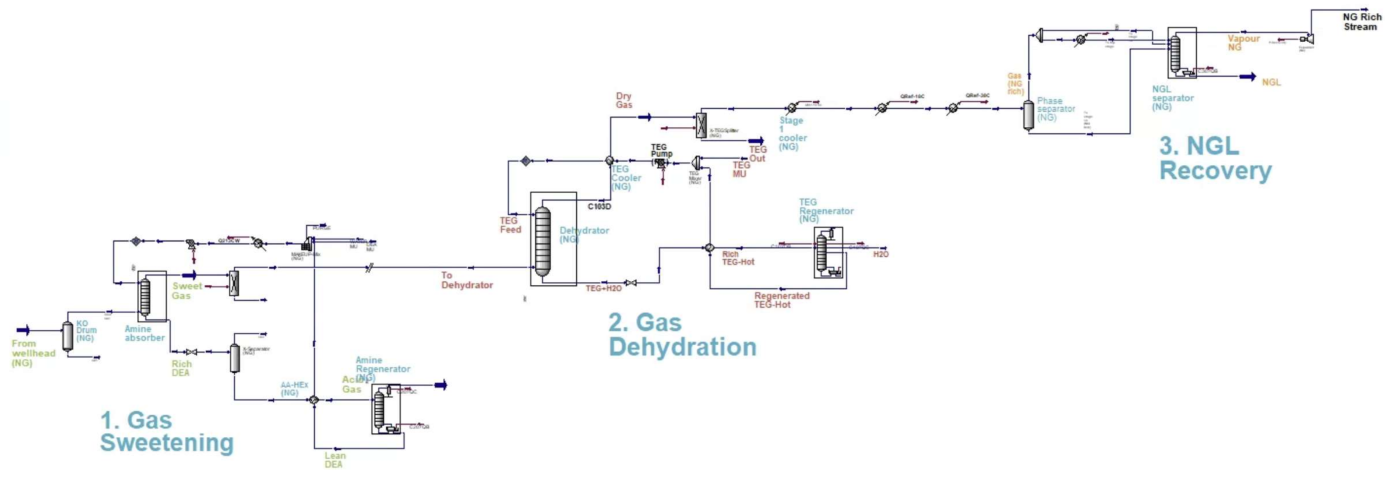

Figure A1. Aspen example—"Natural Gas Plant Model".

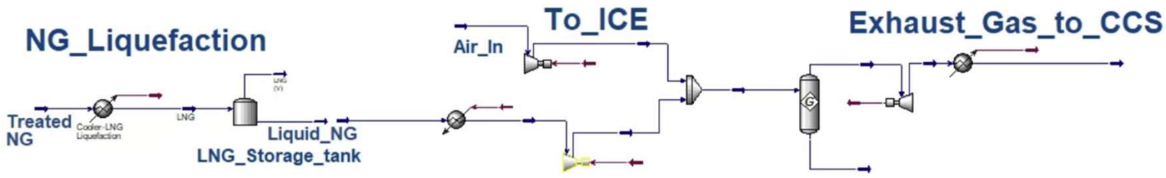

Figure A2. ASPEN simulation model for the production and consumption of LNG (Pathways 3 and 4).

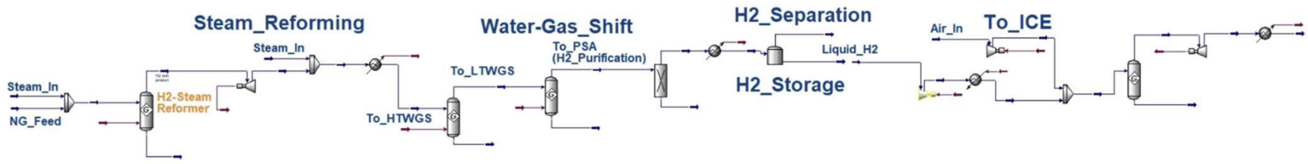

Figure A3. ASPEN simulation model for the production and consumption of NG-based H_2 (Pathways 5 and 6).

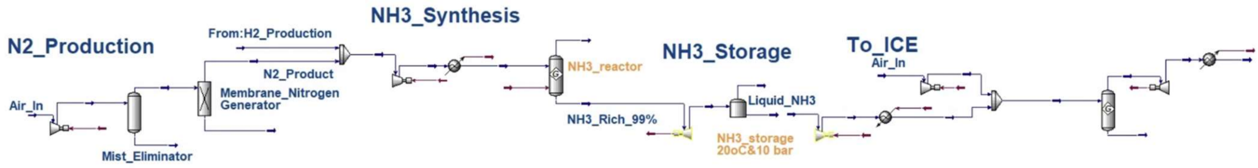

Figure A4. ASPEN simulation model for the production and consumption of NG-based NH_3 (Pathways 7 and 8).

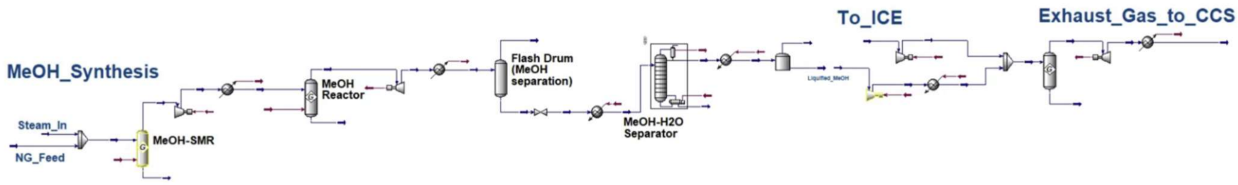

Figure A5. ASPEN simulation model for the production and consumption of NG-based MeOH (Pathways 9 and 10).

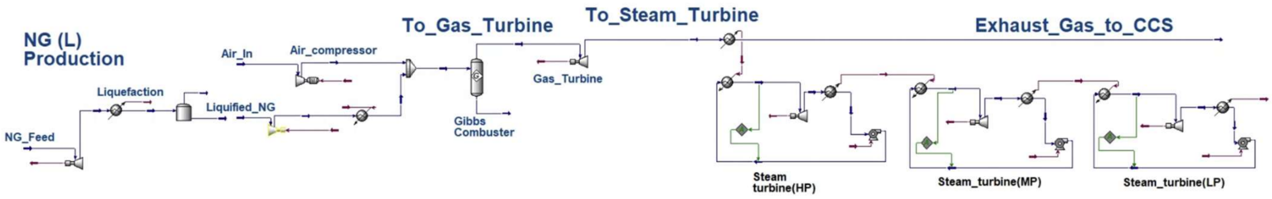

Figure A6. ASPEN simulation model for the production of NG-based electricity (Pathway 11).

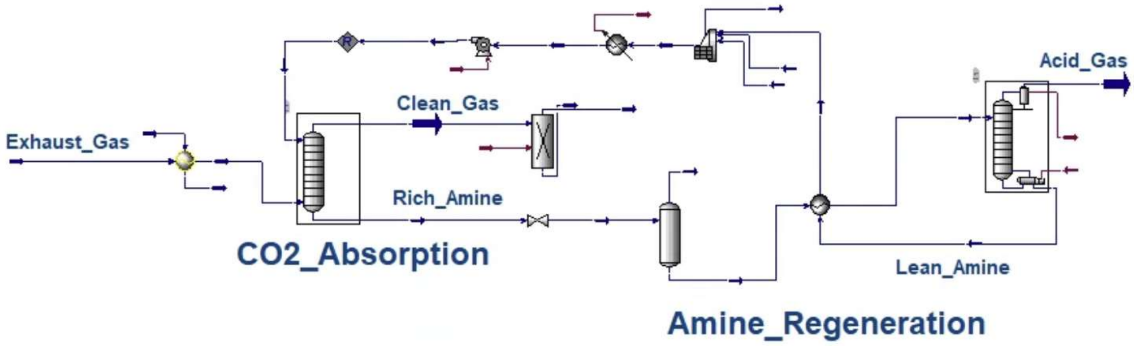

Figure A7. ASPEN simulation model for carbon capture technology (CCS).

Figures A1–A7 shows the simulation layout for natural gas-based fuels (Pathways 3, 4, 5, 6, 7, 8, 9, 10 stated in Table 1, excluding fuel cells and electrical motor energy converters due to ASPEN's limitations) in the same environment, considering feedstock from the same source and the same property package, to ensure a more consistent simulation. The ASPEN simulation model for pathways 3, 4, 5, 6, 7, 8, 9, 10, and 11 started from natural gas feed extracted from the wellhead using the ASPEN example titled "natural gas plant model" (refer to Figure A1). This example included processing units for acid gas removal, dehydration, and NGL separation to produce pure methane stream for the production of electricity, hydrogen, ammonia, and methanol (refer to Figure A2 for the simulation layout of LNG production and utilization). The production of LNG started after NGL recovery, whereby the NG rich stream was cooled and underwent a liquefaction process to produce LNG, which was stored at −163 °C and atmospheric pressure. After that, ASPEN model for internal combustion engine was built using a Gibbs reactor. Reference was made to the gas engine model developed by Ekwonu et al. [21]. The ICE model included a pre-heater, compressor, cooler, mixer, expander, and reactor. In addition, carbon capture was also modelled on the basis of the sweetening technology based on the ASPEN example titled "natural gas plant model" [18] for the removal of CO_2 from the exhaust stream of an engine (see Figure A7).

Figure A3 shows the ASPEN model for the production of hydrogen and energy conversion using an internal combustion engine. The production of H_2 was based on the Linde H_2 production plant [17], starting with the steam reforming process that occurs in the existence of high temperature steam, which was simulated using a Gibbs reactor. Outlet stream from the steam reformer was set at 1300 °C and 23.3 bar, and was directed to an expander and then a cooler prior to the water–gas shift reaction. This process was undertaken to prepare a low pressure and cooler stream that favours water–gas shift reactions. The reaction involved was $CH_4 + H_2O = CO + 3H_2$. Next, a two-stage water–gas-shift reaction was simulated using two Gibbs reactors. The reaction involved was $CO + H_2O = H_2 + CO_2$ to produce hydrogen-rich stream. Lastly, H_2 was separated from CO_2 using a pressure swing adsorber to produce hydrogen with 99% purity. The H_2 stream was then cooled cryogenically in a storage condition of −253 °C at atmospheric pressure. Next, process of marine fuel utilization was modelled for the case of an internal combustion engine (ICE) as an energy converter, similarly to the LNG pathway. However, the other energy converter, which was the H_2 fuel cell, was not modelled in ASPEN due to ASPEN's limitations. No carbon capture was required to clean the exhaust gas from the engine as H_2 combustion is clean.

Figure A4 shows ASPEN model for the production of ammonia and energy conversion using an internal combustion engine. The production path was based on Linde's ammonia production plant, also known as the Linde Ammonia Concept (LAC) plant [24]. The LAC plant primarily comprises a modern hydrogen plant, a standard nitrogen plant, and high-efficiency ammonia synthesis. The hydrogen plant is simulated as per ASPEN model in Figure A3. In the nitrogen plant, Membrane Nitrogen Generators (MNG), which have low operating costs, are used to separate nitrogen from air. In our simulation, the membrane was modelled in a component splitter and the operating cost and energy consumption were accounted for by the air compressor unit, which compressed air to high pressure (8 barg). The compressed air was directed to pass through a MNG, which selectively permeated oxygen, water vapor, and other impurities to the side, leaving the pure nitrogen stream alone, and a high-purity nitrogen stream, of up to 95% to 99.5% purity, could be produced [42]. After the production of pure nitrogen and hydrogen streams, ammonia synthesis was simulated with a Gibbs reactor at 100 °C and 200 bar [25]. The ammonia product was then sent to an expander to prepare ammonia at a storage condition of 20 °C and 10 bar. The reaction involved in the ammonia reactor was $3H_2 + N_2 = 2NH_3$.

Figure A5 shows the ASPEN model for the synthesis of methanol. In this study, methanol synthesis was modelled at 80 bar and 190 °C using a Gibbs reactor. Steam reforming of natural gas for methanol production was slightly different from that conducted for H_2 production. Similarly, both of the SMR processes occurred in the existence of high temperature steam and were simulated using a Gibbs reactor. For methanol production, the outlet stream from steam reformer was set at 1300 °C and 39.3 bar and was directly sent to a heat exchanger or cooler. The reaction involved was $CH_4 + H_2O = CO + 3H_2$. For methanol production, a water–gas shift reaction was not required. The product stream for steam reformer was directly sent to a methanol synthesis reactor. The optimal conditions for methanol synthesis to take place were at a temperature of around 200 °C and a pressure between 50 and 100 bar. The reactions involved in the methanol reactor were $CO_2 + 3H_2 <=> CH_3OH + H_2O$ and $CO + 2H_2 <=> CH_3OH$. Products from methanol reactor consisted of unreacted feed and produced water as by product that needed to be separated from methanol. A flash drum could be used to separate the liquid methanol from more volatile gas stream by lowering the temperature and pressure of the stream. Next, a mixture of water and methanol could be separated using a distillation column. A methanol–water distillation column was simulated by specifying the reflux ratio at 0.5 and a boil-up ratio of 40. These values were obtained via trial and error to obtain 99.5% pure methanol as distillate. Pure methanol was stored at 20 °C and 1 atm. The methanol was converted into propulsion by using an internal combustion engine. As the methanol combusted with the emission of CO_2, CCS installation was required to capture up to 90% of CO_2 from the exhaust gas.

Figure A6 shows ASPEN simulation model for electricity generation from natural gas combustion in a power plant using a combined cycle gas turbine. For combined cycle power generation, reference was made to the steam cycle simulation developed by Inside Mines [26]. Considering blue electricity, CCS installation was required for this pathway. The steam turbine design was based on Siemens steam turbine, model SST-6000 series design [28]; for steam turbines rated from 300 MW to 1200 MW, the steam parameters were 300 bar and 600–630 °C. Figure A7 shows the ASPEN simulation model for carbon capture technology. Carbon capture using Amine absorption, which was developed following the Aspen example model titled "natural gas plant model" [18], was used to obtain the energy factor of CCS installation. The model of Amine absorption was simulated using Amine property package. CO_2 absorber was operated at 40 °C with Diethanolamine (DEA) as absorbents, and then Amine generation was carried out at a 120 °C.

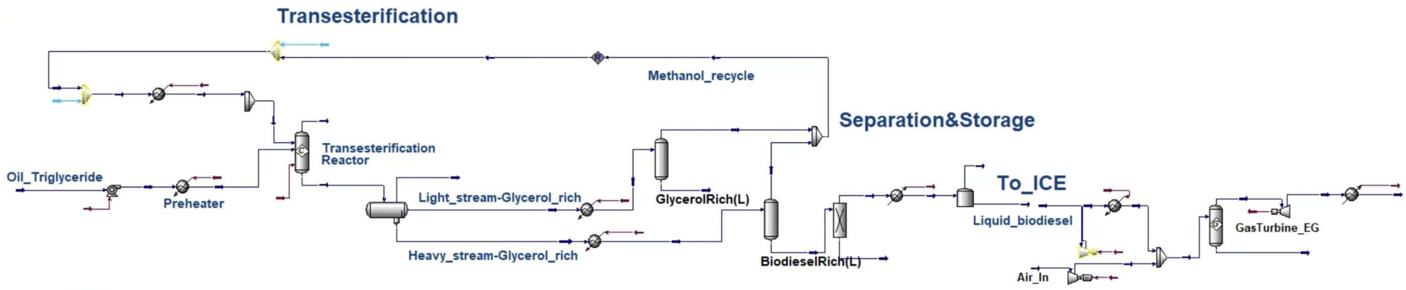

Figure A8. ASPEN simulation of biodiesel production via transesterification.

Figure A8 shows bio-based marine fuels (Pathways 15 in Table 1) used for the production of biodiesel from soybean via transesterification; this process was simulated using the process model suggested by Mello et al. [31], assuming a conversion rate of 98%, and the reaction took place at atmospheric pressure and 60 °C. To ensure complete transesterification, the molar ratio of methanol to vegetable oil = 6:1 and the catalyst content was 1% wt. of vegetable oil. An additional unit operation was added for biodiesel separation and purification and to cool the biodiesel to a storage condition of 25 °C. The energy consumption during the planting and harvesting processes of the soybean were excluded due to unavailable information. Besides, it was assumed that biodiesel was a zero-carbon option of marine fuel, and no carbon capture was required even though combustion of biodiesel produces carbon dioxide, as we were considering the life cycle of biodiesel starting from the growth of a plant, which uses CO_2 in photosynthesis.

Appendix B

In this research, the database was acquired from different resources including the data obtained from ASPEN simulation and for cases where simulation was not possible, data from the literature were used. By using these databases, the assessment and comparison of various alternative fuels was carried out. Table A1 shows the database used for energy assessment, and Table A2 shows the database of cost assessment.

Table A1. Table of energy factors and their sources.

Marine Fuel	WTT Energy Consumption Factor (Energy Consumed (KJ)/KJ of Fuel Produced)	TTW Energy Consumption Factor (Energy Consumed (KJ)/KJ of Propulsion Energy)	Efficiency Factor Engine/Fuel Cell Efficiency
BASE CASE: CRUDE–HFO–ICE	HFO processing = 0.02 (Aspen)	TTW = (considered in efficiency factor)	ICE = 45% [19]
CRUDE–HFO–ICE–CCS	HFO processing = 0.02 (Aspen)	TTW = (considered in efficiency factor) CCS = 0.2 (Aspen)	ICE = 45% [19]
NG–LNG–ICE–CCS	NG processing = 0.025 (Aspen) Liquefaction = 0.006 (Aspen)	TTW = (considered in efficiency factor) CCS = 0.197 (Aspen)	ICE = 45% [19]
NG–H_2–ICE	NG processing = 0.025 (Aspen) H_2 production_SMR = 0.2538 (Aspen) WGS = 0.092 (Aspen) H_2 purification (PSA) = 0.05 (Aspen)	TTW = (considered in efficiency factor)	ICE = 45% [19]
NG–H_2–FC	NG processing = 0.025 (Aspen) H_2 production_SMR = 0.2538 (Aspen) WGS = 0.092 (Aspen) H_2 purification (PSA) = 0.05 (Aspen)	TTW = (considered in efficiency factor)	Electric motor = 92.5% [21] Fuel cell = 60% [22]
NG–NH_3–ICE	NG processing = 0.025 (Aspen) H_2 production_SMR = 0.279 (Aspen) WGS = 0.101 (Aspen) H_2 purification (PSA) = 0.055 (Aspen) N2 production = 0.027 (Aspen) NH_3 production = 0.343 (Aspen)	TTW = (considered in efficiency factor)	ICE = 45% [19]
NG–NH_3–FC	NG processing = 0.025 (Aspen) H_2 production_SMR = 0.279 (Aspen) WGS = 0.101 (Aspen) H_2 purification (PSA) = 0.055 (Aspen) N2 production = 0.027 (Aspen) NH_3 production = 0.343 (Aspen)	TTW = (considered in efficiency factor)	Electric motor = 92.5% [21] Fuel cell = 60% [22]
NG–MEOH–ICE–CCS	NG processing = 0.031 (Aspen) SMR = 0.409 (Aspen) MeOH production = 0.175 (Aspen) MeOH separation = 0.201 (Aspen)	TTW = (considered in efficiency factor) CCS = 0.21 (Aspen)	ICE = 45% [19]
NG–ELECTRICITY–EM	NG processing = 0.0222 (Aspen) Liquefaction = 0.0175 (Aspen) CCGT = 0.52 [28] CCS = 0.2403 (Aspen)	TTW = (considered in efficiency factor)	Electric motor = 92.5% (literature)
NG–ELECTRICITY–H_2–FC	NG processing = 0.0222 (Aspen) Liquefaction = 0.0175 (Aspen) CCGT = 0.52 (52% based on literature) CCS = 0.2403 (Aspen) Electrolysis (H_2 production) = 0.6 [29]	TTW = (considered in efficiency factor)	Electric motor = 92.5% [21] Fuel cell = 60% [22] Overall TTW efficiency = 92.5%∗60% = 55.5%
NG–ELECTRICITY–NH_3–FC	NG processing = 0.0222 (Aspen) Liquefaction = 0.0175 (Aspen) CCGT = 0.52 [28] CCS = 0.2403 (Aspen) Electrolysis (H_2 production) = 0.6 [29] N2 production = 0.027 (Aspen) NH_3 production = 0.343 (Aspen)	TTW = (considered in efficiency factor)	Electric motor = 92.5% [21] Fuel cell = 60% [22]
ELECTRICITY–MEOH–ICE	NG processing = 0.0222 (Aspen) Liquefaction = 0.0175 (Aspen) CCGT = 0.52 [28] CCS = 0.2403 (Aspen) Electrolysis (H_2 production) = 0.6 [29] MeOH production = 0.175 (Aspen) MeOH separation = 0.201 (Aspen)	TTW = (considered in efficiency factor)	ICE = 45% [19]
BIOMASS–BIODIESEL–ICE	Soybean processing = negligible (Assume) Transesterification & separation = 0.02 (Aspen)	TTW = (considered in efficiency factor)	ICE = 45% [19]
BIOMASS–BIO-MEOH –ICE	Syngas production= zero (assume) MeOH production = 0.377 (Aspen)	TTW = (considered in efficiency factor)	ICE = 45% [19]
SOLAR–ELECTRICITY–EM	Solar electricity generation = zero (Assume)	TTW = (considered in efficiency factor)	Electric motor = 92.5% [21]
SOLAR–ELECTRICITY–H_2–FC	Solar electricity = zero (Assume) Electrolyser = 0.6 [29] Compression = 0.06 [32]	TTW = (considered in efficiency factor)	Electric motor = 92.5% (literature) Fuel cell = 60% [22]
SOLAR–ELECTRICITY–NH_3–FC	Solar electricity = zero (Assume) Electrolyser = 0.6 [29] N2 production = 0.02 (Aspen) NH_3 production = 0.343 (Aspen)	TTW = (considered in efficiency factor)	Electric motor = 92.5% (literature) Fuel cell = 60% [22]
SOLAR–ELECTRICITY–MEOH–ICE	Solar electricity = zero (Assume) Electrolyser = 0.6 [29] MeOH production = 0.377 (Aspen)	TTW = (considered in efficiency factor)	ICE = 45% [19]

Table A2. Cost factors and their sources.

	WTT Cost Factor		TTW Cost Factor			
Marine Fuel	**Energy Cost Factor (Aspen) ($/kJ Propulsion Energy) * For Solar Is from Literature [32]**	**Energy Cost Factor (Aspen) ($/kJ Propulsion Energy)**	**Fuel Cost ($/kJ Propulsion Energy) Data from Literature, Verified by [11]**	**Converter (ICE/FC) ($/kW) [11]**	**Storage Cost ($/kJ LNG Equivalent) [11]**	**CCS Capital Cost [43]**
BASE CASE: CRUDE–HFO–ICE	4.86×10^{-7}	N.A.	1.78×10^{-5}	1.00×10^{-3}	3.01×10^{-5}	0
CRUDE–HFO–ICE–CCS	4.86×10^{-7}	3.03×10^{-6}	1.78×10^{-5}	1.00×10^{-3}	3.01×10^{-5}	5.84×10^{-6}
NG–LNG–ICE–CCS	1.22×10^{-6}	3.03×10^{-6}	1.78×10^{-5}	1.00×10^{-3}	1.20×10^{-4}	5.84×10^{-6}
NG–H_2–ICE	8.68×10^{-6}	N.A.	5.56×10^{-5}	1.00×10^{-3}	2.41×10^{-4}	0
NG–H_2–FC	8.68×10^{-6}	N.A.	4.50×10^{-5}	1.15×10^{-4}	2.41×10^{-4}	0
NG–NH_3–ICE	2.40×10^{-5}	N.A.	6.22×10^{-5}	1.00×10^{-3}	4.01×10^{-5}	0
NG–NH_3–FC	2.40×10^{-5}	N.A.	5.05×10^{-5}	1.15×10^{-4}	7.52×10^{-5}	0
NG–MEOH–ICE–CCS	1.35×10^{-5}	2.55×10^{-6}	3.35×10^{-5}	1.00×10^{-3}	4.01×10^{-5}	5.84×10^{-6}
NG–ELECTRICITY–EM	5.05×10^{-6}	N.A.	5.01×10^{-5}	0	3.71×10^{-1}	0
NG–ELECTRICITY–H_2–FC	5.05×10^{-6}	N.A.	1.29×10^{-4}	1.15×10^{-4}	2.41×10^{-4}	0
NG–ELECTRICITY–NH_3–FC	1.96×10^{-5}	N.A.	1.34×10^{-4}	1.15×10^{-4}	7.52×10^{-5}	0
ELECTRICITY–MEOH–ICE	1.31×10^{-5}	N.A.	1.37×10^{-4}	1.00×10^{-3}	4.01×10^{-5}	0
BIOMASS–BIODIESEL –ICE	4.50×10^{-8}	N.A.	3.55×10^{-5}	1.00×10^{-3}	3.01×10^{-5}	0
BIOMASS–BIO-MEOH –ICE	8.07×10^{-6}	N.A.	3.35×10^{-5}	1.00×10^{-3}	4.01×10^{-5}	0
SOLAR–ELECTRICITY–EM	1.11×10^{-5} [32]	N.A.	1.20×10^{-5}	0	3.71×10^{-1}	0
SOLAR–ELECTRICITY–H_2–FC	1.61×10^{-5} [32]	N.A.	5.26×10^{-5}	1.15×10^{-4}	1.20×10^{-4}	0
SOLAR–ELECTRICITY–NH_3–FC	2.56×10^{-5} [32]	N.A.	7.87×10^{-5}	1.15×10^{-4}	7.52×10^{-5}	0
SOLAR–ELECTRICITY–MEOH–ICE	1.92×10^{-5} [32]	N.A.	1.46×10^{-4}	1.00×10^{-3}	4.01×10^{-5}	0

Appendix C

Sankey diagram is a very important finding in this research, it shows the energy flow and energy lost from each of the processes throughout marine fuel lifecycle. The energy flow from left to right most column, whereby left most column shows the total energy required from feedstock which start with 100% of energy. The energy losses during fuel production and energy conversion are indicated by the red colour bars, and finally the percentage of total energy lost, and energy left for ship propulsion are shown in the right most column.

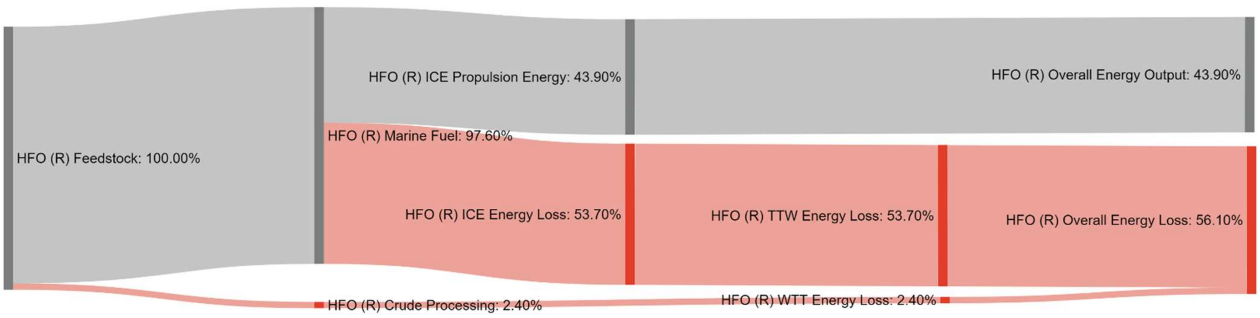

Figure A9. Sankey diagram for HFO base case, HFO (R).

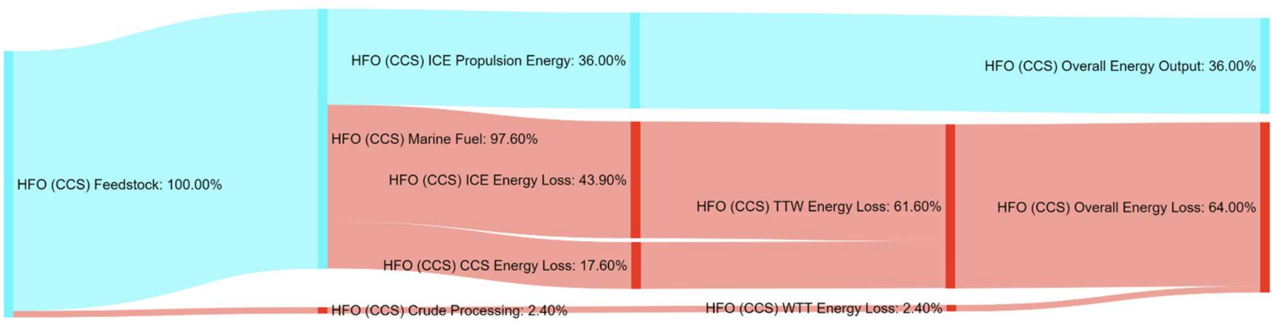

Figure A10. Sankey diagram for HFO with carbon capture, HFO (CCS).

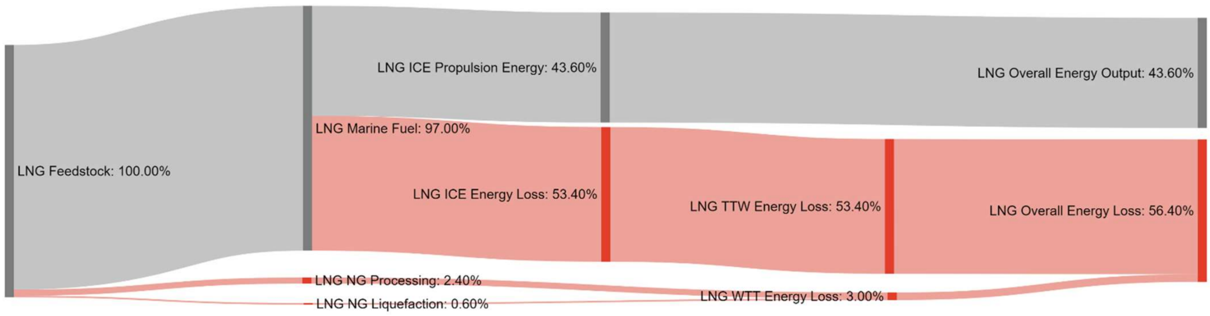

Figure A11. Sankey diagram for LNG, LNG.

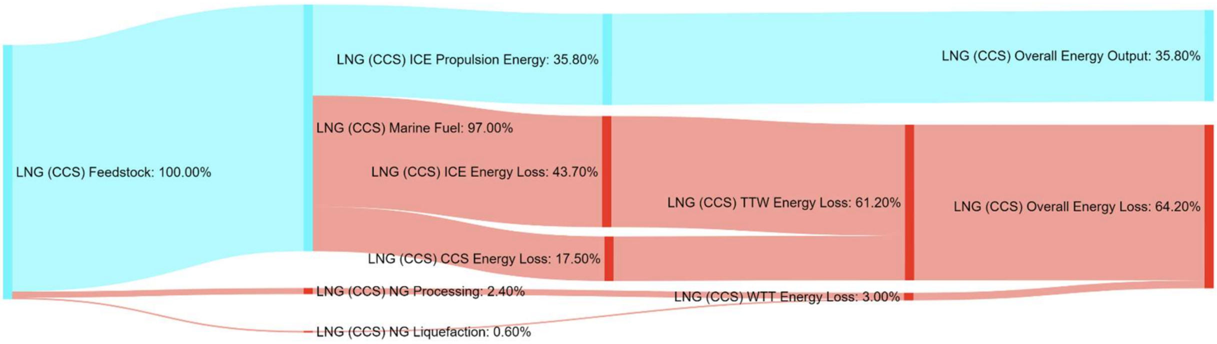

Figure A12. Sankey diagram for LNG with carbon capture, LNG (CCS).

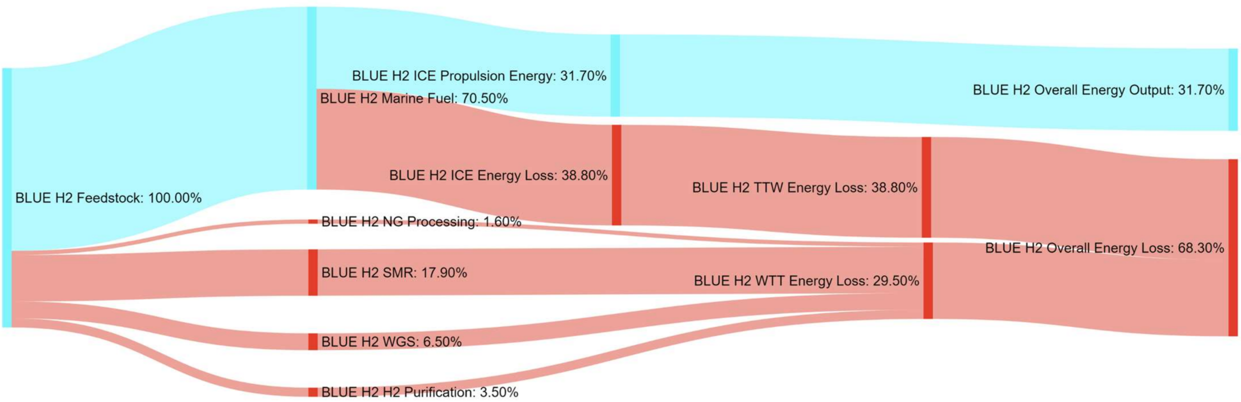

Figure A13. Sankey diagram for hydrogen produced using natural gas with internal combustion engine as a converter, BLUE H_2.

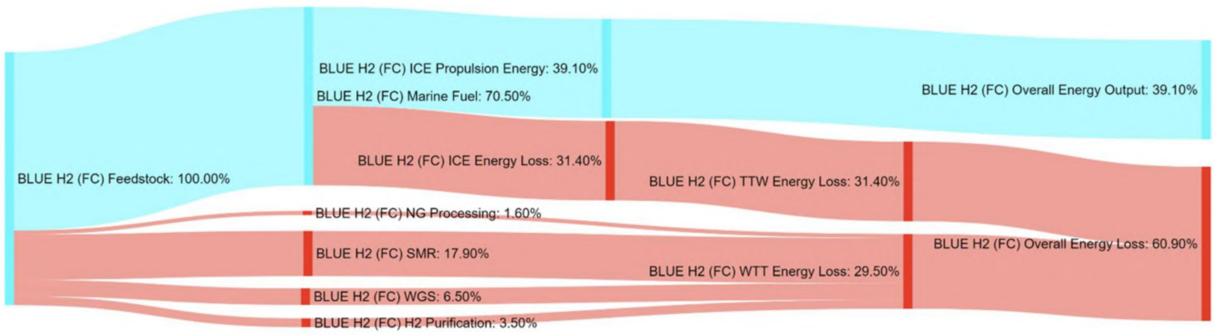

Figure A14. Sankey diagram for hydrogen produced using natural gas with fuel cell as a converter, BLUE H_2 (FC).

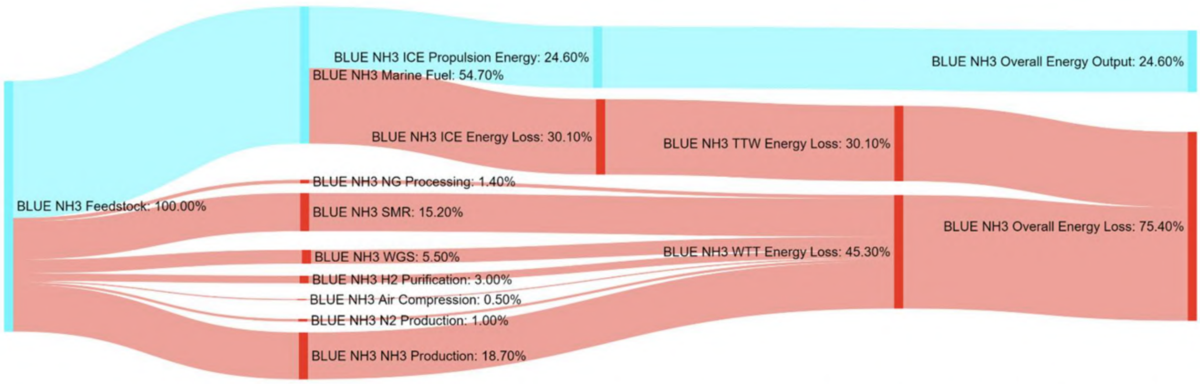

Figure A15. Sankey diagram for ammonia produced using natural gas with internal combustion engine as a converter, BLUE NH_3.

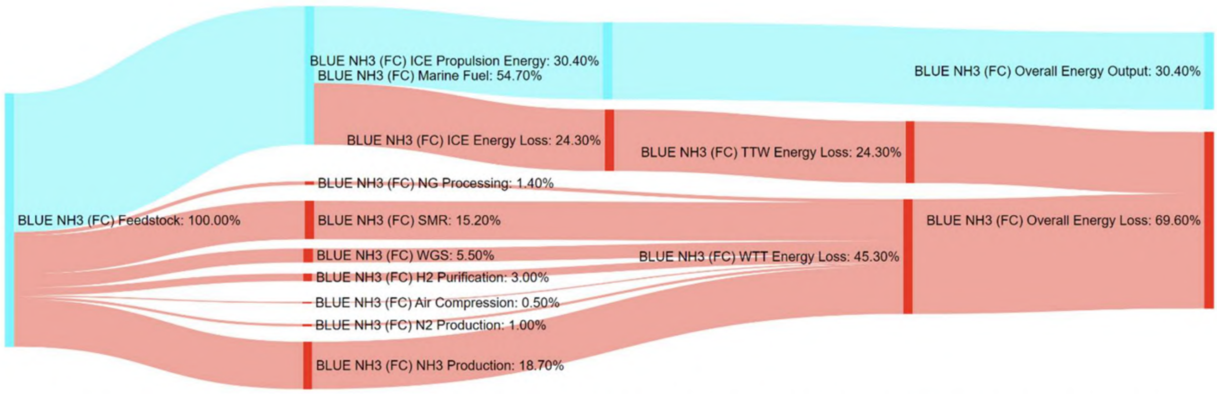

Figure A16. Sankey diagram for ammonia produced using natural gas with fuel cell as a converter, BLUE NH_3 (FC).

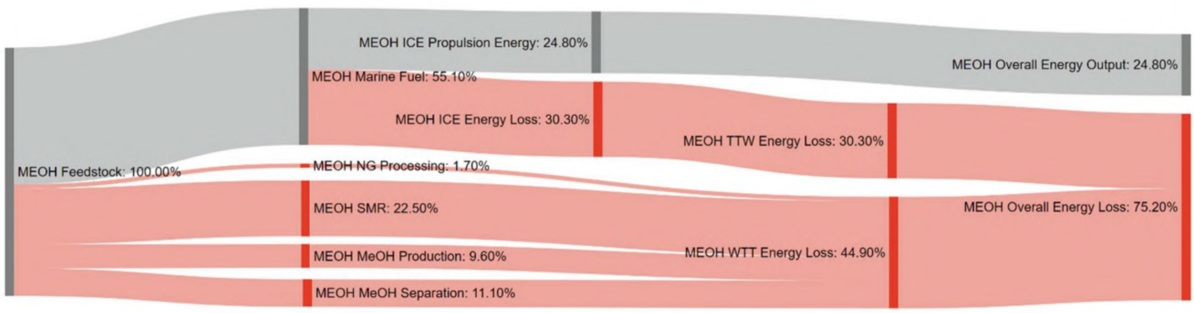

Figure A17. Sankey diagram for methanol produced using natural gas with internal combustion engine as a converter, MEOH.

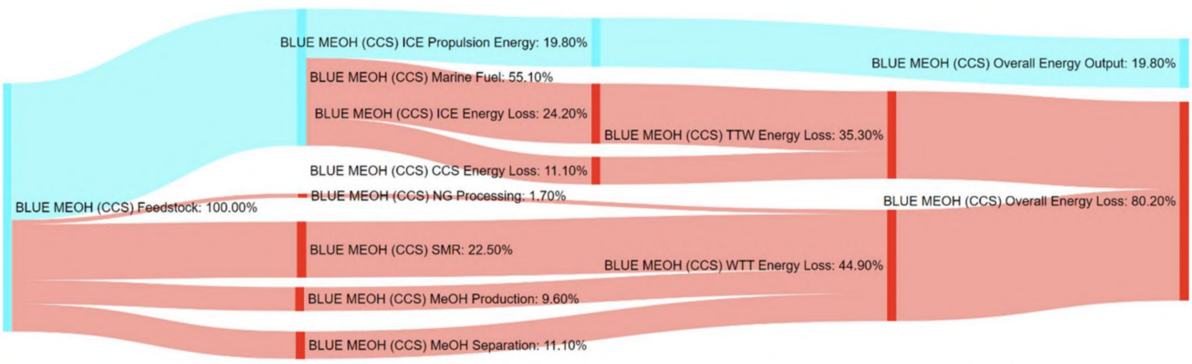

Figure A18. Sankey diagram for methanol produced using natural gas with carbon capture, BLUE MEOH.

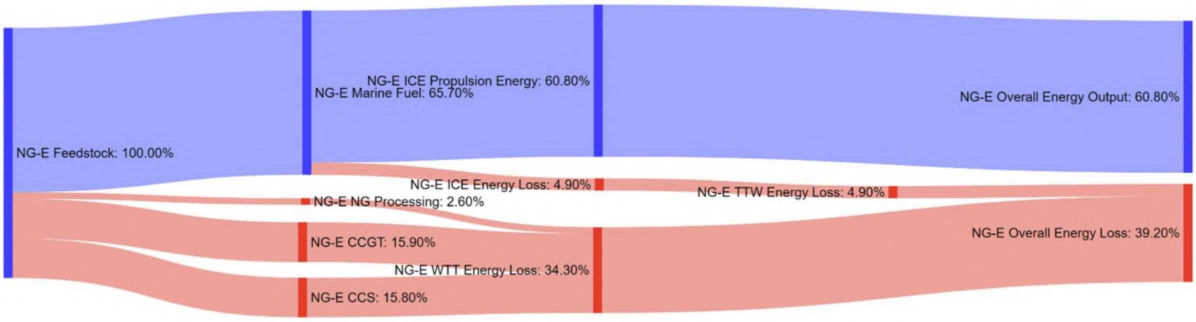

Figure A19. Sankey diagram for electricity produced from natural gas, NG-E.

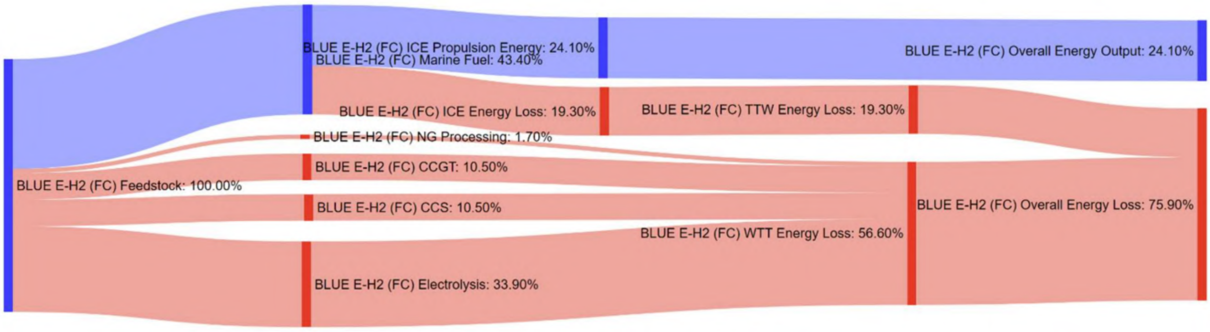

Figure A20. Sankey diagram for hydrogen produced from natural gas electricity, NG-E-H_2 (FC).

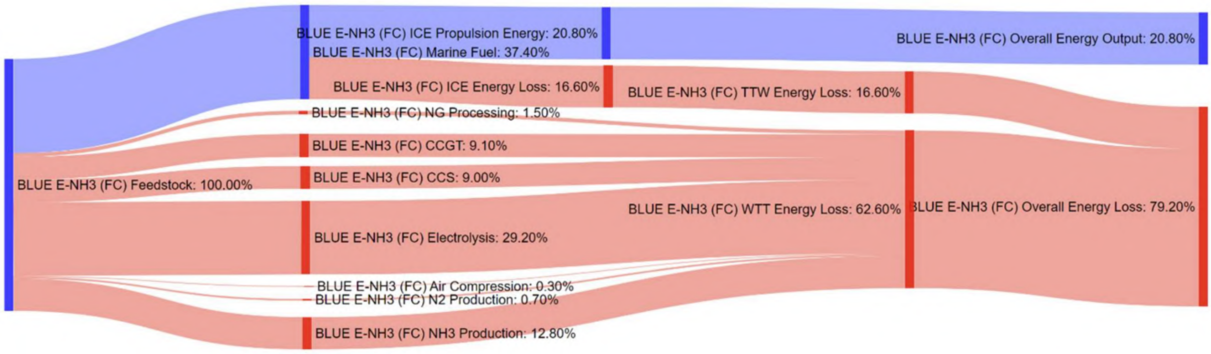

Figure A21. Sankey diagram for ammonia produced from natural gas electricity, NG-E-NH_3 (FC).

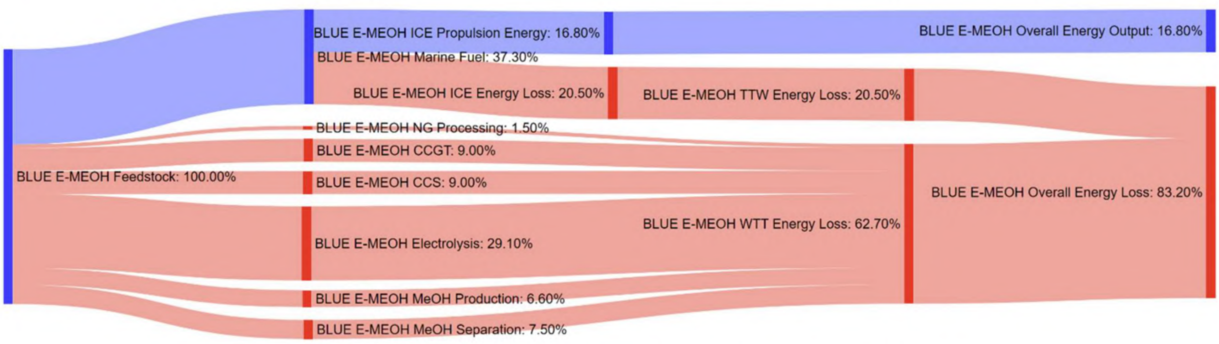

Figure A22. Sankey diagram for methanol produced from natural gas electricity, NG-E-MEOH.

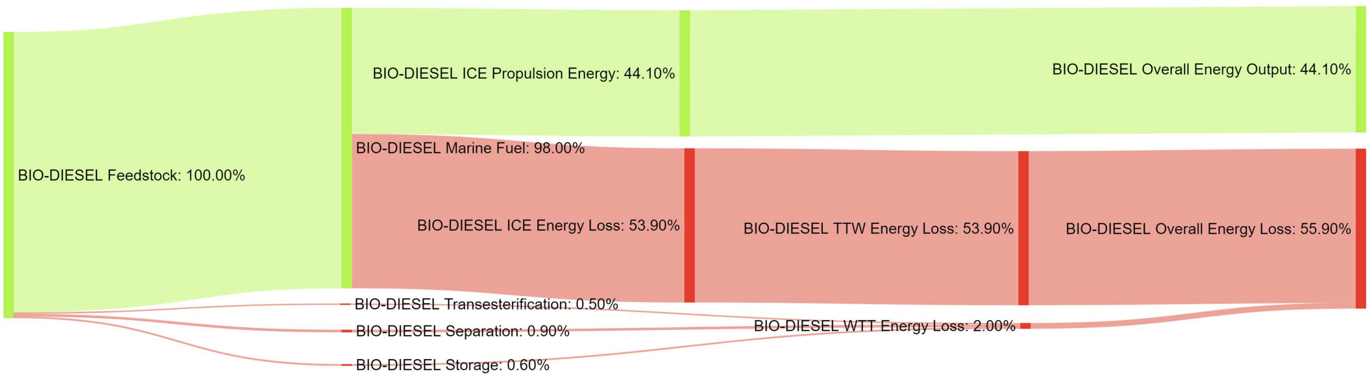

Figure A23. Sankey diagram for biodiesel produced from biomass, BIO-BIODIESEL.

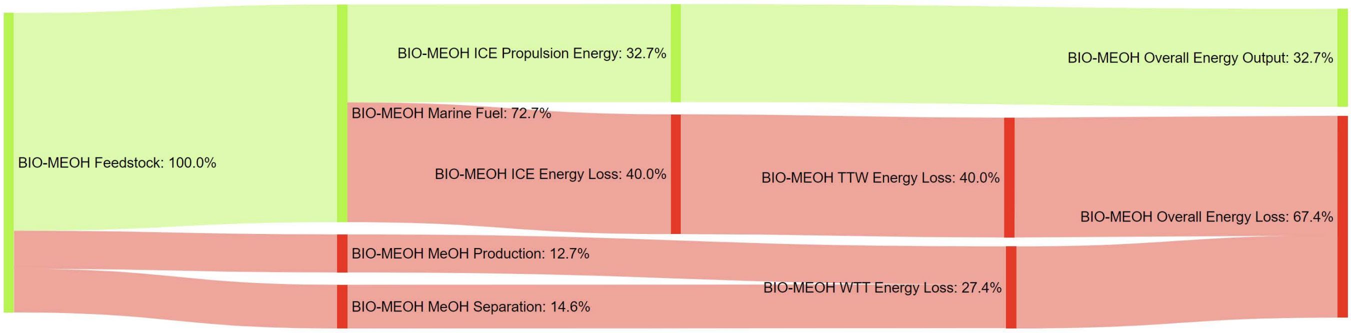

Figure A24. Sankey diagram for bio-methanol produced from biomass, BIO-MEOH.

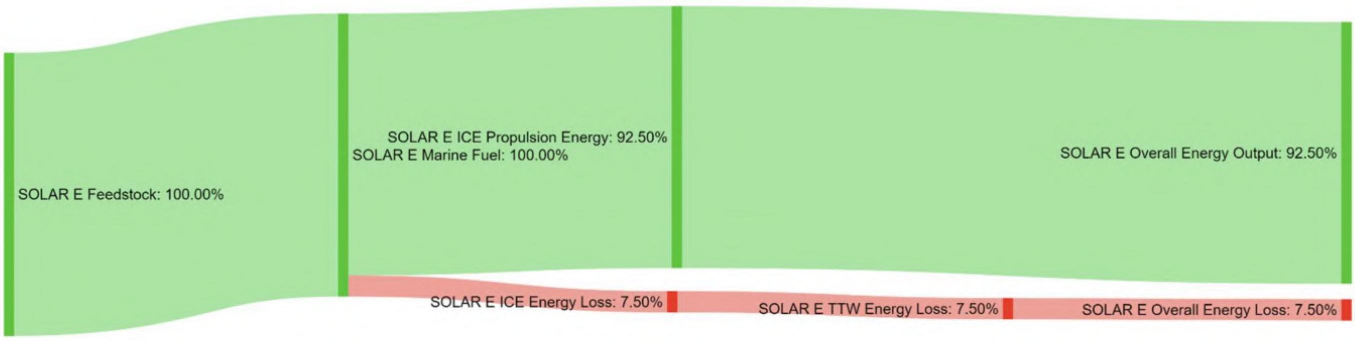

Figure A25. Sankey diagram for electricity produced from solar, SOLAR-E.

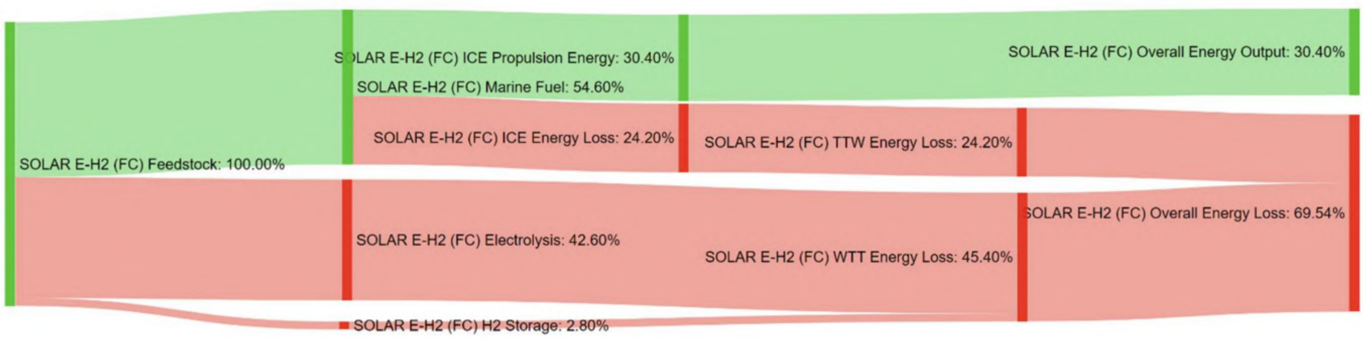

Figure A26. Sankey diagram for hydrogen produced from solar electricity, SOLAR-E-H_2 (FC).

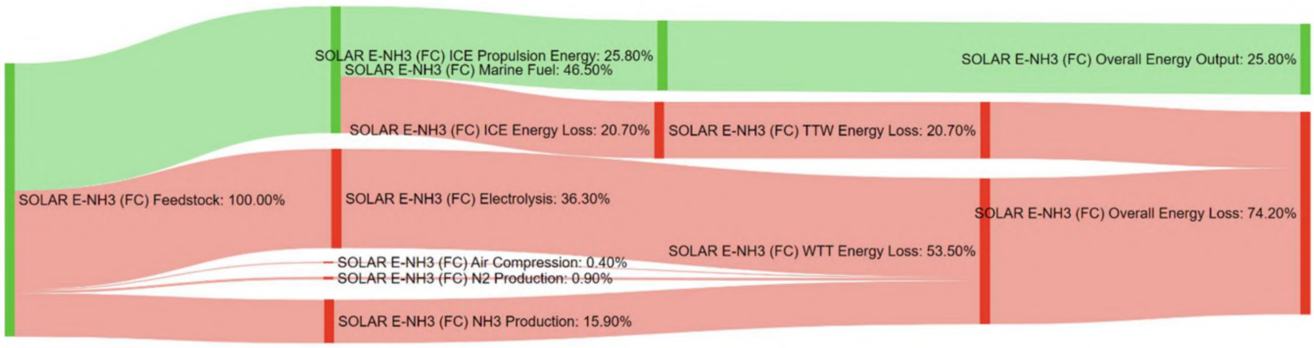

Figure A27. Sankey diagram for ammonia produced from solar electricity, SOLAR-E-NH_3 (FC).

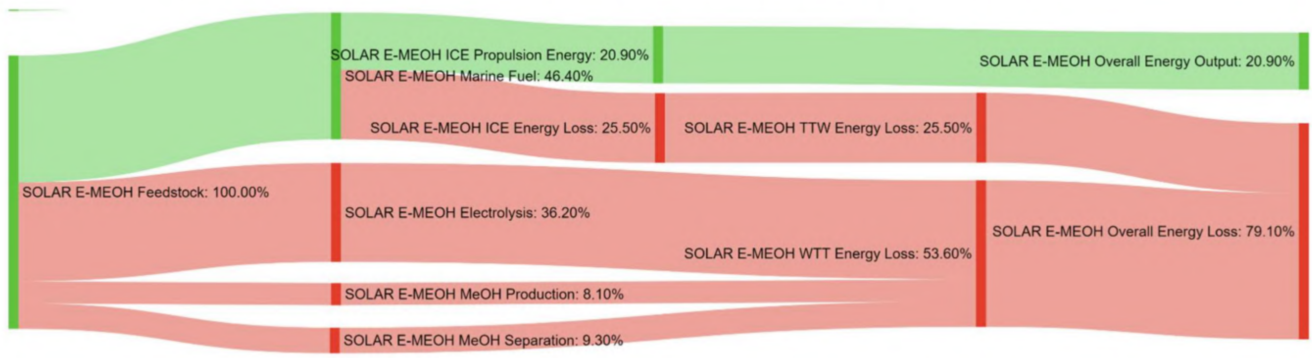

Figure A28. Sankey diagram for methanol produced from solar electricity, SOLAR-E-MEOH.

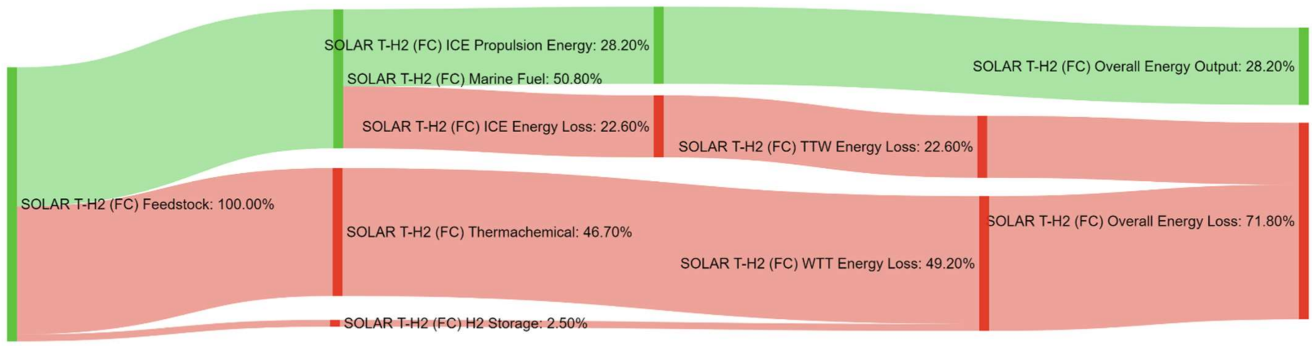

Figure A29. Sankey diagram for hydrogen produced from solar thermal energy, SOLAR-T-H_2 (FC).

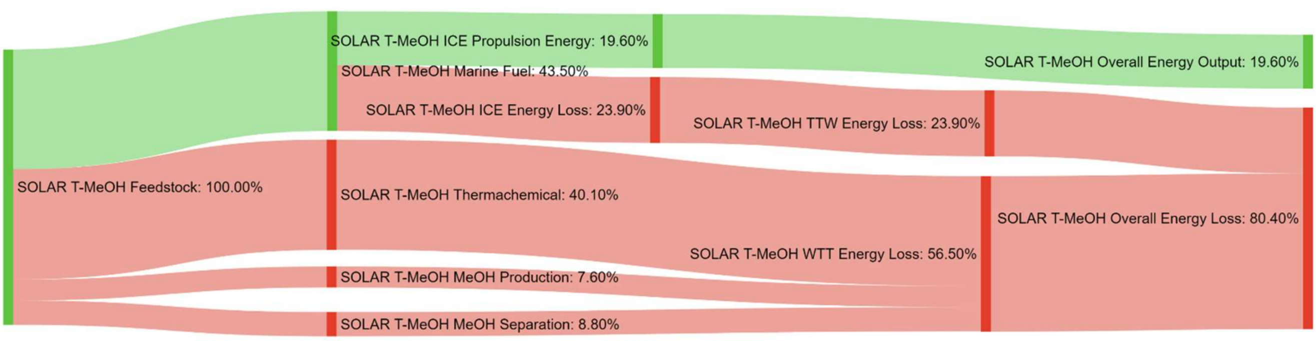

Figure A30. Sankey diagram for methanol produced from solar thermal energy, SOLAR-T-MEOH.

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