Techno-economic assessment of zero-carbon fuels.

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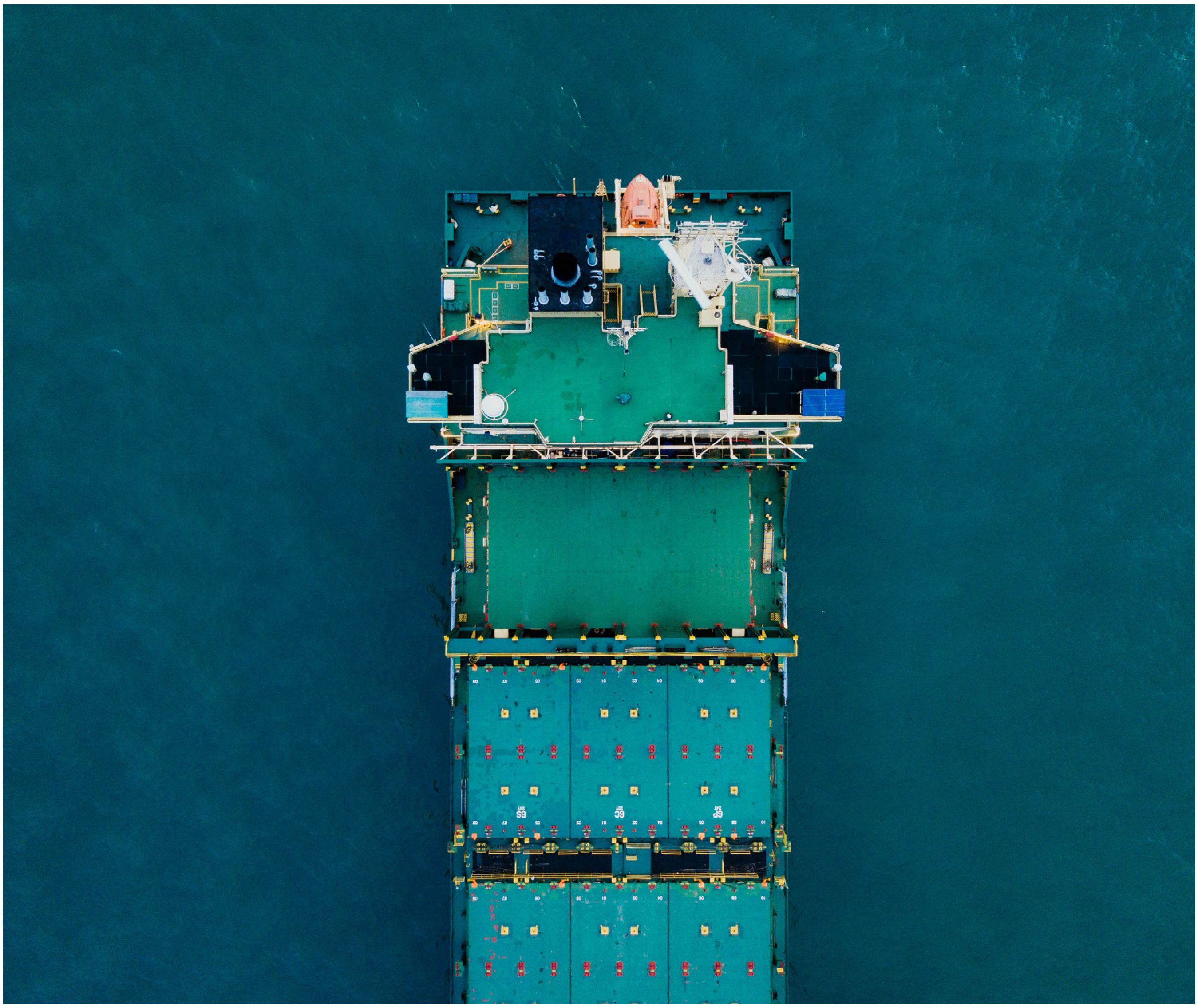

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Executive summary.

The marine industry is currently facing a substantial environmental challenge. In 2012, international shipping was estimated to have contributed about 2.2%[1] to the global emissions of carbon dioxide (CO_2). Although international shipping is the most energy-efficient mode of mass transport and only a modest contributor to the current global CO_2 emissions, its contribution is set to increase as other sectors decarbonise and the demand for shipping services increases.

As already acknowledged by the Kyoto Protocol, CO_2 emissions from international shipping cannot be attributed to any national economy due to its global nature and complex operation. As a result, International Maritime Organization (IMO) has been energetically pursuing the limitation and reduction of greenhouse gas (GHG) emissions from international shipping, in recognition of the magnitude of the climate change challenge and the intense focus on this topic. Therefore, the marine industry needs to continue to improve its energy efficiency and emission controls. However, while these steps are important, they are insufficient if shipping is to fall in line with the Paris Agreement's long-term temperature goal, so a move away from the current fossil-based fuels is also necessary.

With this challenge in mind, the marine industry is currently searching for ways to deliver its fair share of the global decarbonisation challenge. Lloyd's Register (LR) and University Maritime Advisory Services (UMAS) have been working together to provide valuable insights that help the industry to think about this pivotal transition. We have published a series of papers on the commercial viability of Zero-Emission Vessels (ZEVs) and potential transition pathways, Refs [(01, 2016) (02, 2017) (03, 2019)]. The combined expertise of LR and UMAS provides a unique perspective on the decarbonisation of shipping.

This paper is an example of this collaboration; it examines three important elements of zero-carbon fuels when compared with traditional fossil-based fuels. All candidate fuels considered in this paper have some emissions associated with them because of the ways they would be produced and transported. However, all these fuels have very low CO_2 emissions, and they may have the potential to become zero CO_2 emissions. Therefore, we refer to these fuels as zero-carbon fuels.

First, the paper provides estimates of the economic viability (investment readiness) of zero-carbon fuelled ships when compared with a reference ship using Low Sulphur Heavy Fuel Oil (LSHFO). Second, the paper analyses the technology feasibility (technology readiness) of the vessel and bunkering technologies needed to support zero-carbon fuelled ships. Finally, it provides a high-level insight into the community readiness of zero-carbon fuels from the perspectives of lifecycle emissions and how the energy landscape is evolving in other sectors and what this means to the decarbonisation of the shipping sector.

In this paper, we have derived an overall interconnected system of fuels and technologies that each form viable routes to ZEVs. The downstream components of this system, including bunkering, storage, processing and conversion of the new fuels, are screened and analysed to ultimately derive a Technology Readiness Level (TRL) for the current state of the technology, and an assessment of the outstanding barriers to achieving full deployment into the maritime fleets.

The economic case for ZEVs is mainly driven by the relevant energy/fuel price and how this evolves through the 2020s and 2030s to 2050. It is important to consider how the fuel prices may evolve under the influence of the wider energy system, understanding the role that international shipping plays in this system, and the ability it has to influence, or not, the demands on new fuels.

This evolution over time means that different zero-carbon fuel options are more competitive in different decades and there is not one option which is the most competitive from today through to 2050.

In the short term, biofuels look marginally more competitive than fuels derived from renewable electricity or from natural gas with carbon capture and storage (NG with CCS). However, there are significant challenges related to the sustainability and availability of biofuels. Therefore, in the mid-long term, any biofuel pathway is uncompetitive and prone to restrictions or higher prices resulting from supply constraints and does not necessarily lead onto more resilient options such as hydrogen or ammonia derived from NG or renewable electricity.

[1] International Maritime Organization www.imo.org

For example, ammonia produced from hydrogen, where the hydrogen is produced from NG with CCS, can be considered to be comparable to biofuels in the short term and becomes the lowest cost zero-carbon option out to the 2050s. Furthermore, over time, the production and supply of ammonia can transition from NG to hydrogen produced from renewable energy, providing a more resilient long-term transition pathway.

Although certain pathways look more resilient than others from the perspective of asset longevity, fuel price is the predominant factor that impacts the total cost of operation (TCO). In anticipation of the impacts of the evolution of the global energy demands, and the associated uncertainty of biofuels being available and sustainable, a fuel which can be produced from NG or renewable electricity may offer longer-term advantages that are not seen in the very short term.

As part of this paper, we also assessed the technology readiness for the various zero-carbon solutions and provide an insight into the current barriers to market. The objective of the assessment is to establish the current 'readiness' of technologies considered to be critical in the application of zero-carbon fuels for shipping. The screening and assessment process is fuel-agnostic and ultimately assigns a TRL to indicate the development status of a technology on a scale ranging from 'basic principles observed' to 'product and production fully operational'. The allocation of a TRL is defined by the Research & Innovation Policy Tool 'EARTO' scale which is intended for the planning of innovation management. We examined the technology readiness of zero-carbon fuels and its usage regarding onboard procedures of bunkering, vessel storage, processing, conversion onboard and propulsion.

Regardless of which zero-carbon fuels emerge as favoured from an economic perspective, from an onboard technology perspective, ZEVs are likely to be technologically possible in the next two years. To be confident around future investments, we will also require confidence around the fuel supply chain, both in terms of the fuel availability in the quantities required and the land-based infrastructure for production, supply and distribution.

From a technology readiness perspective, methanol, liquefied natural gas (LNG) and diesel are more mature than hydrogen and ammonia as rules and regulations currently exist and there are vessels already using these fuels. From an onboard technology perspective, there is minimal difference, for example, between using bio-methanol, e-methanol or NG-methanol; the same applies to LNG (bio-LNG, fossil-LNG and e-LNG).

One of the important barriers for new fuels such as ammonia and hydrogen is the storage and bunkering infrastructure. This means regulatory actors (Class and Flag) need to collaborate with original equipment manufacturers (OEMs) to enable the uptake.

In addition to investment and technology readiness, community readiness is an important aspect of readiness for change. What may be ready from an investment and technology perspective may not be ready from other stakeholders' perspectives. Future fuels will be expected to meet not only GHG emission criteria, but also other air pollutant standards (e.g. nitrogen oxides (NOx) and particulates) as well as contribute to broader sustainability criteria at regional and national levels.

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The profits we generate fund the Lloyd's Register Foundation, a charity which supports science and engineering-related research, education and public engagement around everything we do. All of this helps us stand by the purpose that drives us every single day: working together for a safer world.

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UMAS undertakes research and consultancy using models of the shipping system, shipping big data (including satellite Automatic Identification System data), and qualitative and social science analysis of the policy and commercial structure of the shipping system. Research and consultancy is centred on understanding patterns of energy demand in shipping and how this knowledge can be applied to help the maritime and shipping sector transition to a low-carbon future. UMAS is world-leading in two key areas. Firstly, using big data to understand the trends and drivers of shipping energy demand and emissions and, secondly, developing and applying models to explore future demands and scenarios for future markets and policies.

Our mission is to accelerate the transition to an equitable, globally sustainable energy system through world-class maritime and shipping research, consultancy, education and policy support.

UMAS

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Contents.

1. Introduction.

The IMO's initial GHG strategy represents a significant ambition for the shipping sector. It sets a GHG reduction pathway of at least 50% by 2050 based on a 2008 baseline, with a strong emphasis on reducing by 100% by 2050 if this can be shown to be possible, as shown in Figure 1. This is a clear signal of the industry's commitment to reduce GHG emissions from international shipping by ending the use of fossil-based fuels by mid-century.

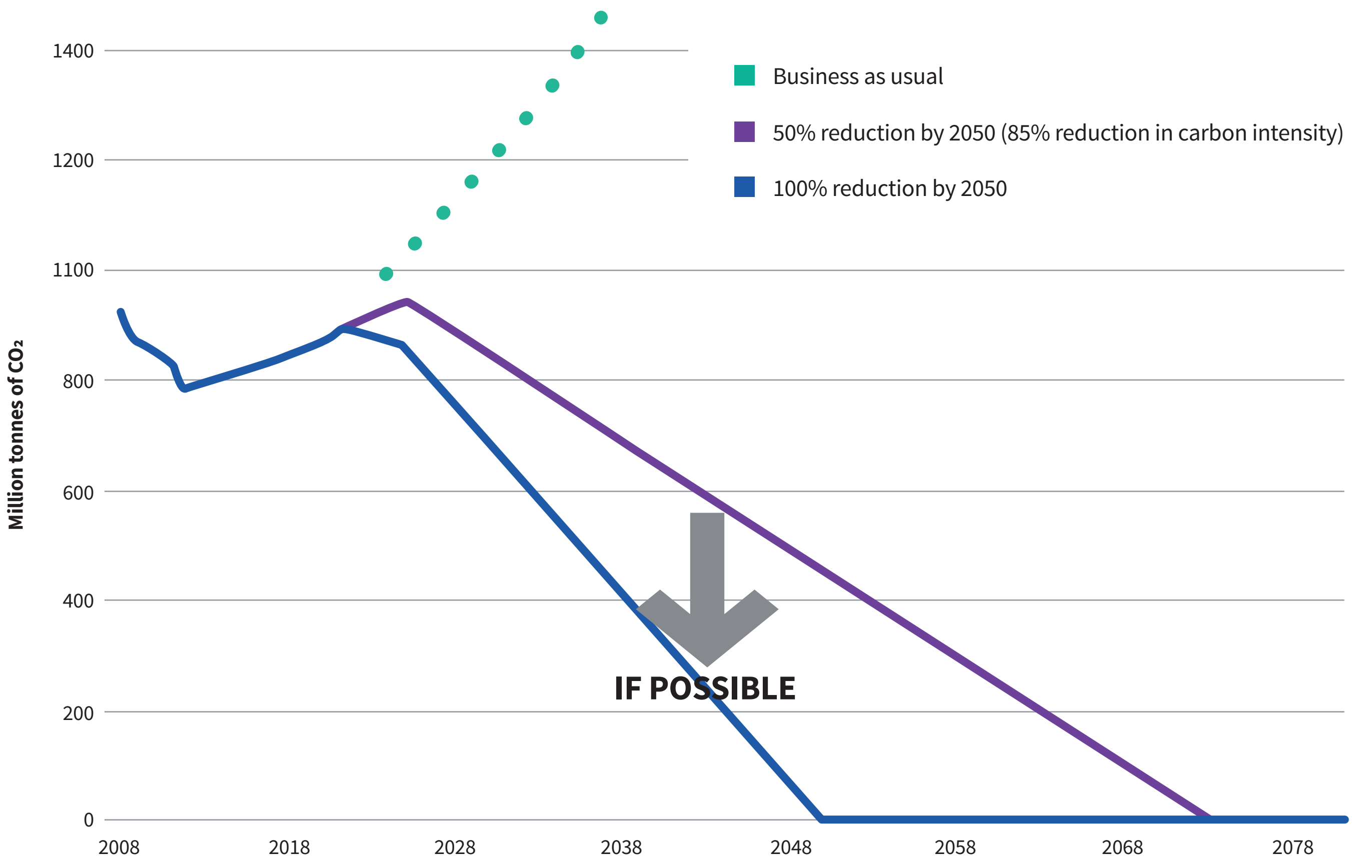


Figure 1 – Pathways for international shipping's carbon dioxide (CO_2) emissions.

This commitment aligns the shipping sector with a 2°C pathway, as shown in [Ref (01, 2016)], and will require a substitute for fossil-based fuels because energy efficiency improvements alone will not be sufficient. To achieve this, ZEVs need to be entering service by 2030, and anyone planning to finance, design or build a ship in the 2020s will need to consider how it can switch to a zero-carbon fuel later in its operational life.

The need for technological changes and mechanisms that, in various combinations, achieve this level of ambition is becoming more urgent and in [Ref (02, 2017)], we identified the drivers for the viability of ZEVs to be a competitive solution compared to existing fossil-based fuelled ships.

Our third paper, [Ref (03, 2019)], investigated pathways in which fuels derived from one energy source will become the dominant fuels in 2050. This paper identified several differences and thresholds among the pathways, as well as a number of similarities.

We used the datasets generated from the previous work to provide a preliminary analysis of the competitiveness of several ZEVs over time. This paper presents information on the various zero-carbon fuels and assesses their economic viability and technology feasibility when compared with a reference ship using LSHFO. The objective of this paper is to present a technical and economical representation of various zero-carbon fuels when compared with a conventional fossil-based fuel.

2. Approach.

The IMO's GHG roadmap is ambitious, but this ambition is necessary if shipping is to transition in line with the Paris Agreement (the Paris Agreement's central aim is to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2˚C above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5˚C). To achieve this roadmap, ZEVs and their associated fuels will need to be entering the fleet in 2030 and form a significant proportion of newbuilds from then on.

This transition to a new mix of fuels now has broad government and industry buy-in. It is inevitable that a policy process starts with the definition of the objective, but the question we are increasingly asked is: 'How are we going to achieve this in practice?'

To deliver this vision, we need to define the optimum zero-carbon options through an assessment of:

- Investment readiness level (including the wider energy system and the dependable production of future fuels)
- Technical readiness level (although technical readiness as a whole includes safety, specific safety considerations are not included in this paper)
- Community readiness level (including social impacts and understanding of other sectors)

LR and UMAS, in collaboration, started our journey by analysing the various decarbonisation options and pathways. Following the Low Carbon Pathways 2050 paper, we conducted a survey of shipowners, forming our second paper. We started by understanding what is needed to make ZEVs a reality, which we did by listening to the thresholds that shipowners believe will need to be passed for various zero-carbon fuels and technological options. We discussed a range of factors involved in implementing zero-carbon fuels and technologies, including relative costs, the global supply chain, carbon pricing and upstream emissions, in order to identify what is most important in influencing a decision. We also considered the likelihood of costs being passed on in the supply chain, and whether shipping customers would be willing to pay more for zero-carbon shipping. The survey revealed a broad consensus on the need for decarbonisation, with an overwhelming majority of shipowners regarding ZEVs as central to this process.

It also underlined that shipping as a business will adopt ZEVs if they are economically viable and technically feasible. Therefore, we have chosen to focus our work on the economic analysis, including the costs/impacts associated with capital expenditure, the operational costs associated with storage, handling and cargo-carrying capacity, and how carbon pricing can influence this. This paper uses the same approach and economic model that has been co-developed by LR and UMAS and used in our previous publications referenced above.

We firstly identified ZEV technologies that are most viable to deliver vessels that can match the capabilities of today's conventional fossil-based fuelled ships. This was achieved by calculating and comparing the lifetime economics and technical feasibility of all the possible combinations of 21 ZEV technologies (see Appendix A) across three ship types. We have assessed each technology to determine the implications for bunkering, vessel storage, processing conversion onboard and propulsion. Explanations of these variables are provided in the following sections of the paper.

All analyses are performed against a reference ship using LSHFO with a two-stroke internal combustion engine (ICE) to ensure compliance with sulphur emissions regulations. Regarding the effects of carbon pricing, we have further refined these results by conducting sensitivity studies on the ZEV technologies. Zero-carbon fuels often have lower energy densities and higher storage costs when compared to the baseline; furthermore, current vessel fuel storage capacities are often larger than needed to cover the distances travelled between ports and are designed to allow the operator to minimise fuel costs by bunkering at particular global locations. For this reason, it was assumed that a reduction of 20% is applied relative to the current baseline bunker capacity.

Zero-carbon fuels will need to be available and produced mainly from renewable electricity, bio-energy, and/or fossil fuels with CCS. Those included in this analysis are represented in Table 1.

	Zero-carbon energy source					
Energy source	**Methanol**	**Hydrogen**	**Ammonia**	**Electricity**	**Diesel**	**LNG**
NG with CCS		NG-hydrogen	NG-ammonia			
Biomass	bio-methanol				bio-diesel	bio-LNG
Renewable electricity	e-methanol	e-hydrogen	e-ammonia	batteries	e-diesel	e-LNG

Table 1 – Zero-carbon energy sources considered in this paper.

Notes for Table 1:

- Many types of biofuels exist depending on processes and feedstock.
- Fuels produced from renewable electricity are referred to as electro-fuels and are prefixed by an 'e'.
- It is recognised that electricity and batteries are not fuels in the traditional sense.
- All of the hydrogen options store hydrogen as liquid.

3. Investment readiness of zero-carbon solutions.

In this section, we assess the economic viability of several zero-carbon fuel options. To make sure we include a wide range of technologies and energy carriers, we have considered 21 different ZEVs (Appendix A). We have distinguished each fuel type by the potential different primary energy sources used to produce the fuel and the potential method of converting the fuel onboard. For example, a methanol ZEV has been analysed four times using two different primary energy sources (biomass and renewable electricity) and two different methods of conversion (ICE and fuel cell (FC)). The various operational requirements and logistical challenges faced by shipping mean that a wide range of potential technologies were considered to make this paper representative. We have considered the most promising technologies; however, this is not an exhaustive list, and other candidates may exist. We have excluded some other well-established technologies from this paper bearing in mind the societal challenges of nuclear power and the operational challenges of using wind power as the primary method of propulsion.

Shipowners and operators will look for a number of factors or market conditions when considering investments in future zero-carbon fuels. Favourable conditions include a moderate level of carbon pricing and a moderate increase in the capital investment necessary. In this paper, we also considered these aspects and demonstrated the economic feasibility of these technologies.

3.1. Energy source price scenarios.

Fuel price projections beyond 2020 are uncertain, especially for fuels with extensive processing to convert electrical power to liquid fuel. These production and processing technologies for high volumes of liquid fuels are still in the development phase, making estimates of future projections difficult. Furthermore, the supply versus demand dynamics are unknown. To allow for this uncertainty and to test whether the conclusions drawn from the analysis are robust and viable, we have defined different foreseeable future scenarios where we vary the prices of the primary energy sources in order to identify the breakeven point against the reference ships and understand the economic implications on the ZEVs. These primary energy source scenarios are listed in Table 2 below:

Scenarios	Biofuel price	Renewable electricity price	NG price	Carbon price
1	Lower	Lower	Lower	No
2	Lower	Lower	Lower	Yes (~288 $/tonne in 2050)
3	Upper	Upper	Upper	No
4	Upper	Upper	Upper	Yes (~288 $/tonne in 2050)

Table 2 – Energy source price scenarios.

The sensitivity analyses are based on the scenarios listed in Table 2 above. These analyses are undertaken by changing two important parameters: carbon price and fuel price. The upper and lower bounds are a function of the average renewable electricity and NG price as estimated from 2020 to 2050. The lower bound assumes the price of renewable electricity reduces from 0.05 $/kWh in 2020 to 0.02 $/kWh in 2050, whereas the upper bound assumes a reduction from 0.1 $/kWh in 2020 to 0.05 $/kWh in 2050[2]. Similarly, the lower bound assumes the price of NG of 5 $/million BTU LHV constant over time and 12 $/million BTU LHV for the upper bound. When used, the assumed carbon price varies from 101 $/tonne in 2030, through 194 $/tonne in 2040 to 288 $/tonne in 2050[3].

Bio-derived fuels are considered to be not scalable in volume but limited to the volumes of production that are available from sustainable waste sources or un-competed, and sustainable land use (e.g. land not used for afforestation or food production). Discussion continues on the magnitude of sustainable volumes, multiple supply pressures [Ref (04, 2015)] and expanding competitive demands (negative emissions energy technologies, other transport sectors, industry, domestic heating etc.). We represent the supply/demand uncertainty through an upper bound and lower bound scenario. The upper bound represents the case where other sectors with greater market power and higher costs of substitution absorb the available supply and set the price of biofuels significantly higher than a shipping sector substitution price. The lower bound represents the scenario where some supply volume is available to shipping (albeit less than shipping's total demand), and then the biofuel volume and price is assumed to reach an equilibrium with price set by the substitution to the next cheapest alternative (in this case as represented by fossil-based fuel in combination with carbon price).

Appendix B details assumptions made in this paper.

[2] Derived from www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf

[3] BEIS (2017) 'Data tables 1 to 19: supporting the toolkit and the guidance', available at https://webarchive.nationalarchives.gov.uk/20190105010941/ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/696677/Data_tables_1-19_supporting_the_toolkit_and_the_guidance_2017__180403_.xlsx

3.2. Case study ship type.

This analysis is conducted on an ~82,000 DWT bulk carrier, the operational and technical specification of which is shown in Figure 2 below.

81,911 Capacity (DWT)	76,869 Average capacity (DWT) fleet 2016	10,840 Power main engine (kW)	542 Power auxiliary engine (kW)
14.30 Design speed knots	178 SFOC main engine (gm/kWh)	MDO Fuel type in ECA	2760 Total bunker capacity reference ship HFO (m^3)
355 Days active per year (operational)	0.6 Laden/ballast ratio	230 Days at sea per year	12.8 Operational speed knots

Figure 2 – Ship particulars of bulk carrier size category of 60,000-99,999 DWT (case study ship).

Note for Figure 2:

- More detailed information about the ship particulars can be found in Appendix B Section B8.

The economic viability, defined as the TCO, is the sum of the additional costs relative to the reference ship. The TCO is a function of the fuel-related voyage costs per year, the capital investment costs due to the new engine and fuel storage system, and the impact on revenue due to additional space requirements of the fuel storage. The exact definition of the TCO is described:

TCO = additional fuel-related voyage costs per year + additional capital cost of new engine + additional capital cost of fuel storage system + impact on revenue due to the space requirements of the fuel storage system.

The voyage cost per year includes the carbon price on operational emissions depending on the scenarios.

3.3. Total cost of operation.

The TCO of the reference ship running with LSHFO does not change between the low and high price scenarios because the same LSHFO price projection is used in both scenarios. In contrast, the baseline changes when evaluating the scenarios with a carbon price; the voyage cost of the reference ship varies from approximately 3.2 million $ in 2020 to 4.3 million $ in 2050 in Scenarios 1 and 3, whereas it varies from 3.2 million $ in 2020 to 12.5 million $ in the scenarios with the carbon prices. We have presented the results for the bulk carrier case study ship in Figures 3a and 3b below.

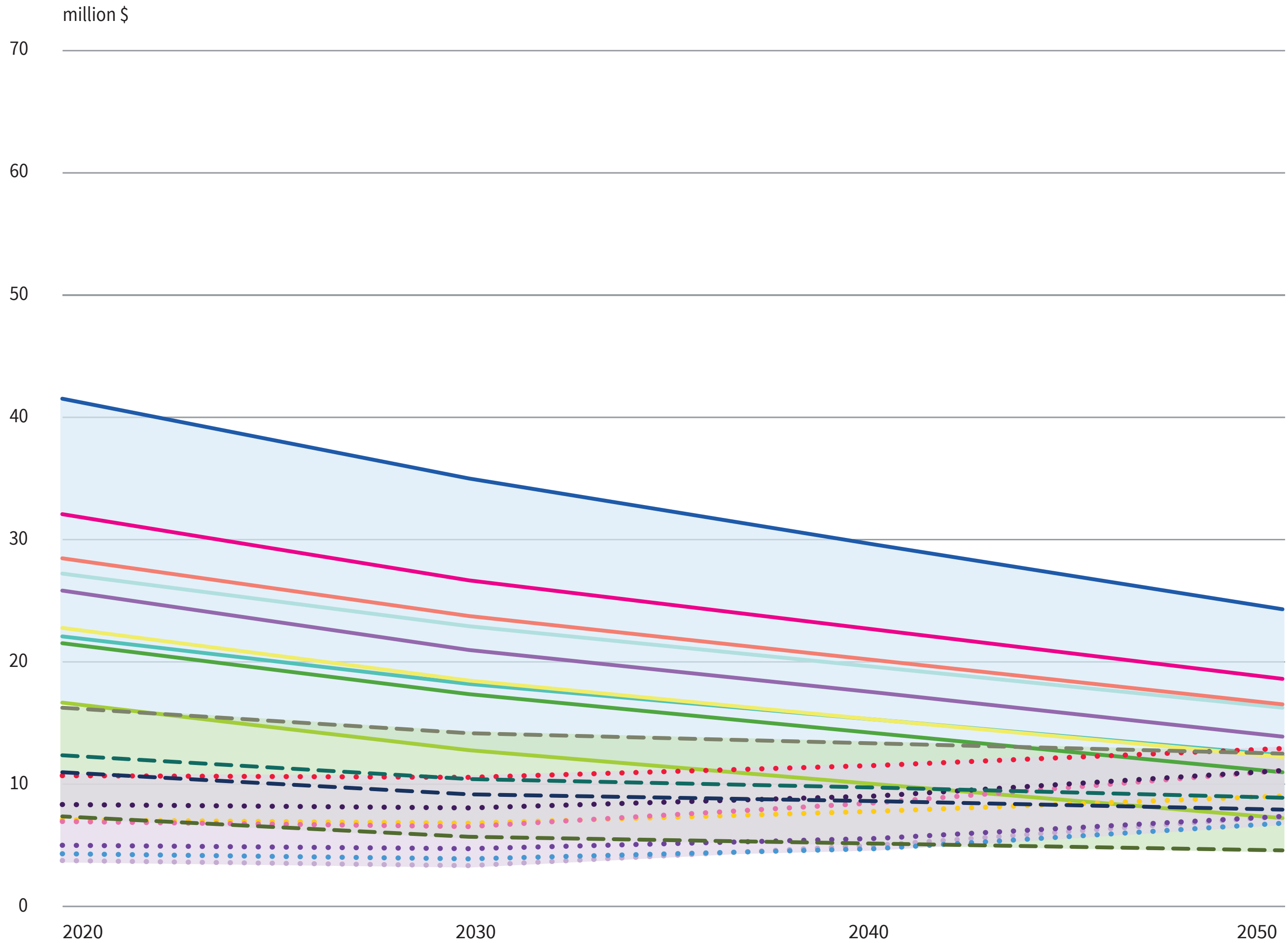
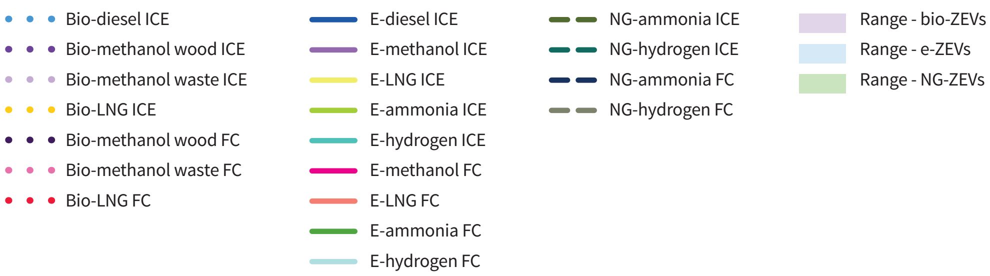


Figure 3a – Scenario 1; low-price scenario; TCO trends for a bulk carrier.



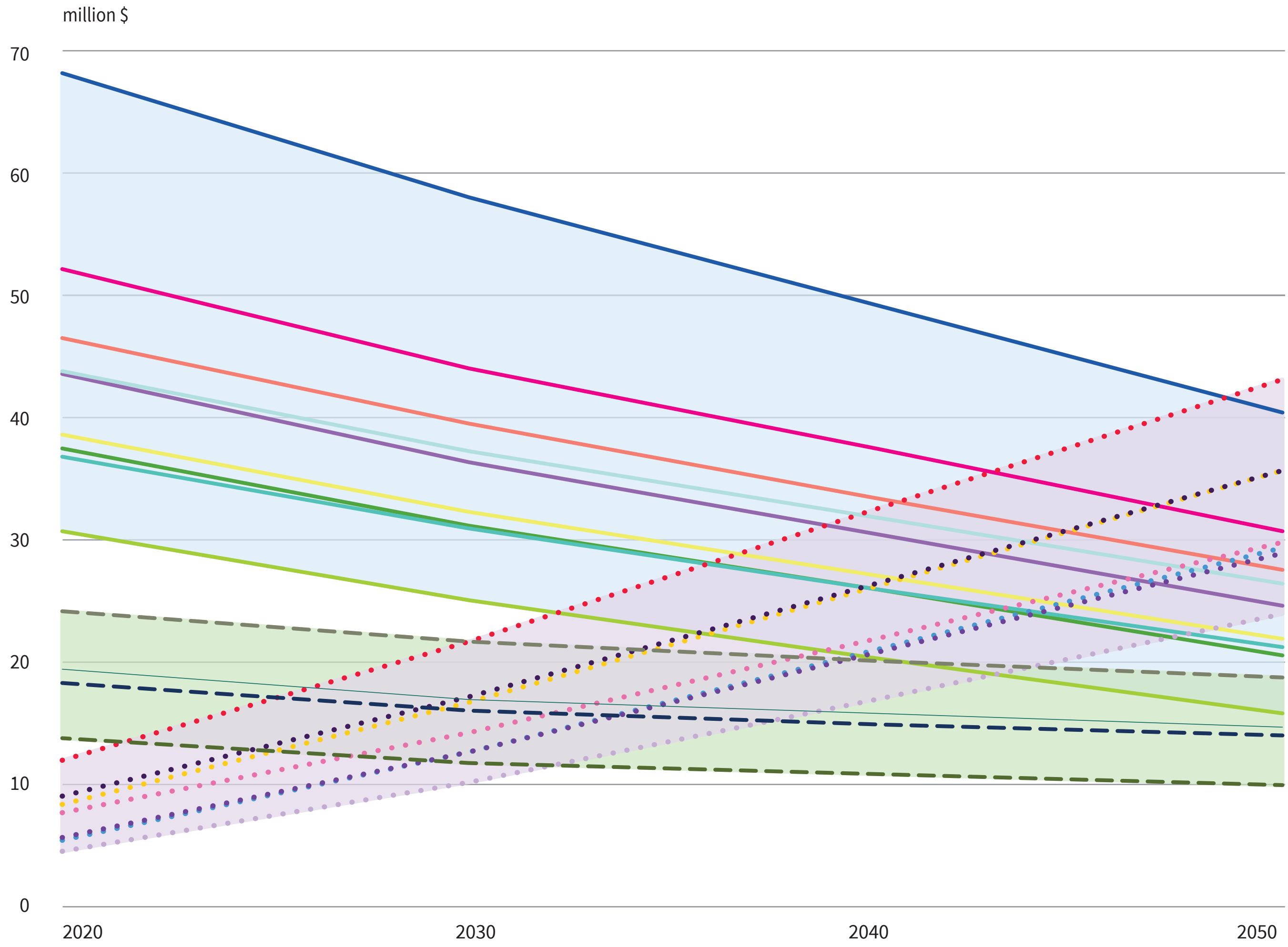
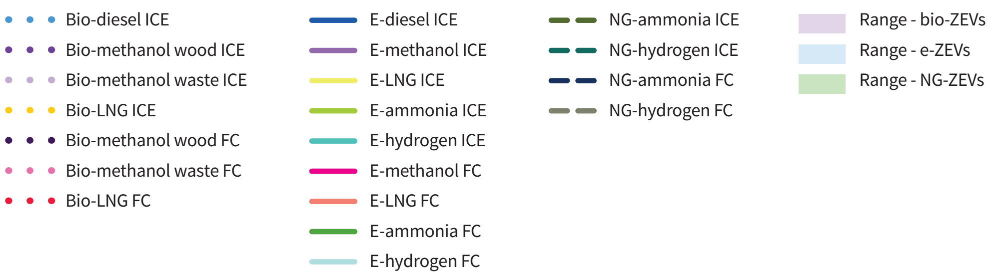


Figure 3b – Scenario 3; high-price scenario; TCO trends for a bulk carrier.



Notes for Figures 3a and 3b:

- ZEVs which are entirely battery powered are not included within these Figures 3a and 3b as the TCO is significantly higher in comparison with the other ZEV options.

The costs of e-ZEV options have a decreasing trend over time driven by the assumed reduction in the renewable electricity price, whereas in contrast the bio-ZEV options have an increasing trend over time driven by the assumed increase in biofuel prices.

The crossover point between the cheapest e-ZEV (NG-ammonia) and highest bio-ZEV (bio-LNG) occurs around the early 2030s in the high-price scenario, whereas fuels produced from NG with CCS (ammonia, hydrogen) are more comparable to bio-ZEVs (bio-LNG) today with a crossover point occurring in the 2020s.

In both scenarios, the ZEVs using FCs always have a higher TCO than their equivalent with an ICE due to the assumption of a high capital cost for FC technology, making FC ZEVs less competitive than ICE ZEVs. Therefore, to address the TCO deficit and become the preferred ZEV propulsion option, the capital cost of FCs will need to decrease significantly and/or the FC efficiency needs to improve over and above an equivalent ICE.

Given the consistently lower TCO of the ICE ZEVs, Figures 3c and 3d below have had the FC scenarios removed, allowing a deeper dive into the fuels in combinations with ICE only.

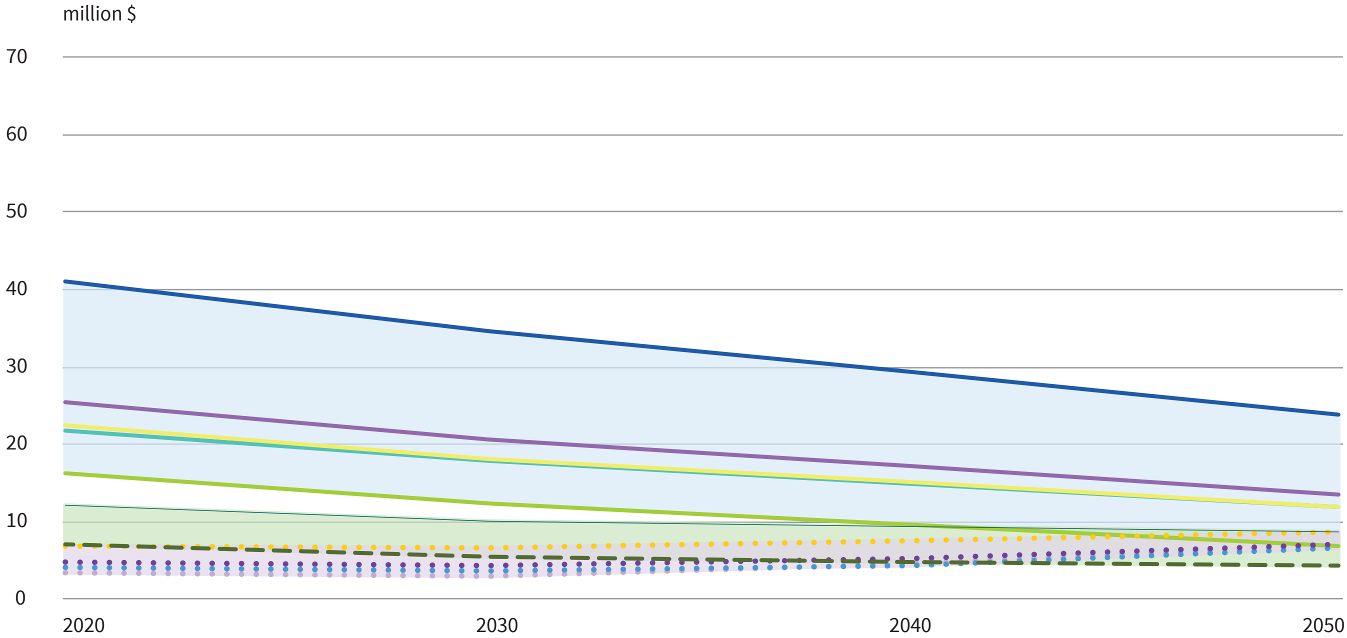


Figure 3c – Scenario 1; low-price scenario; TCO Trends for a Bulk Carrier (only ZEVs with ICE).

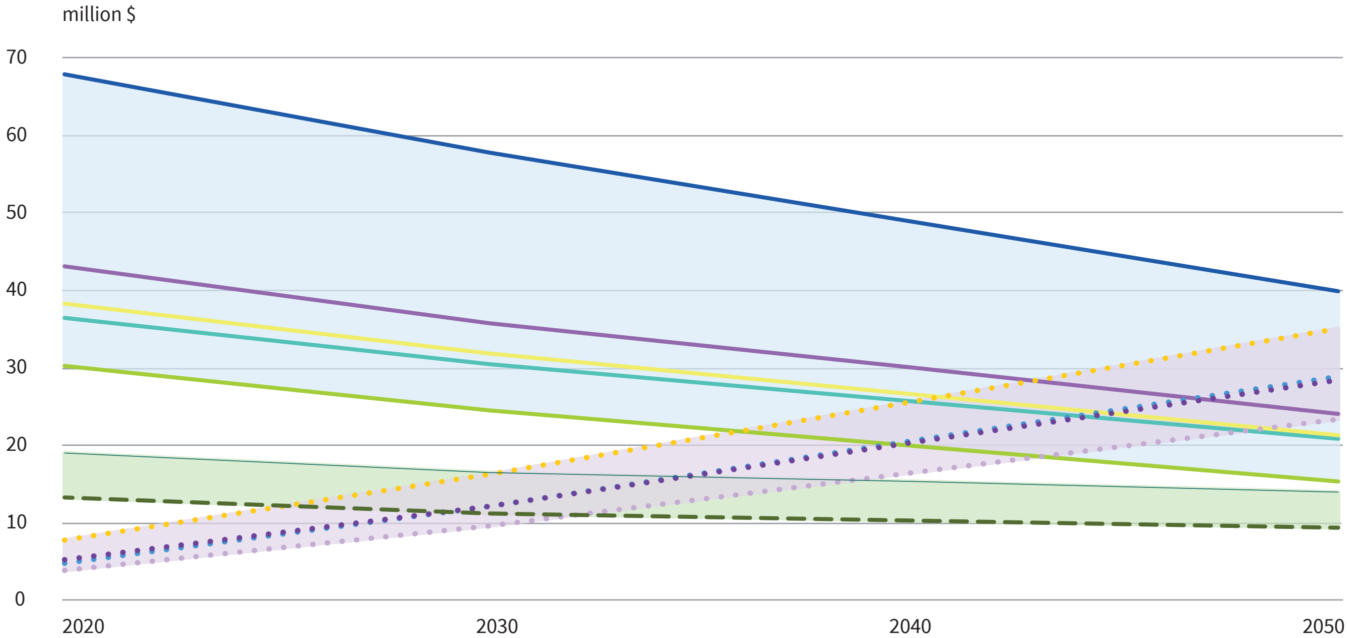
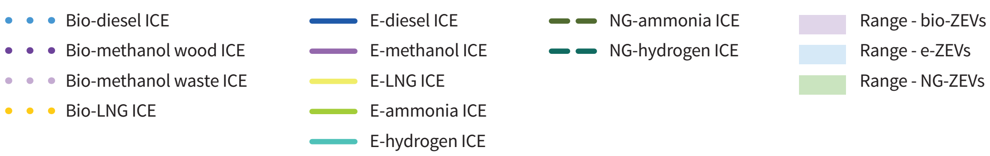


Figure 3d – Scenario 3; high-price scenario; TCO Trends for a Bulk Carrier (only ZEVs with ICE).



Figures 3c and 3d demonstrate that under these fuel price scenarios, although biofuels may be considered to be more competitive than other ZEV solutions in the short term, over time they will lose this advantage as prices are expected to increase. This occurs by the mid-2030s in the lower bound price scenario and even earlier in the upper bound price scenario. NG-ammonia is as competitive today as the most expensive biofuel. Even when compared to the cheapest biofuel (bio-methanol), NG-ammonia becomes more competitive in the early 2030s. Overall, e-fuels become more competitive in the 2040s.

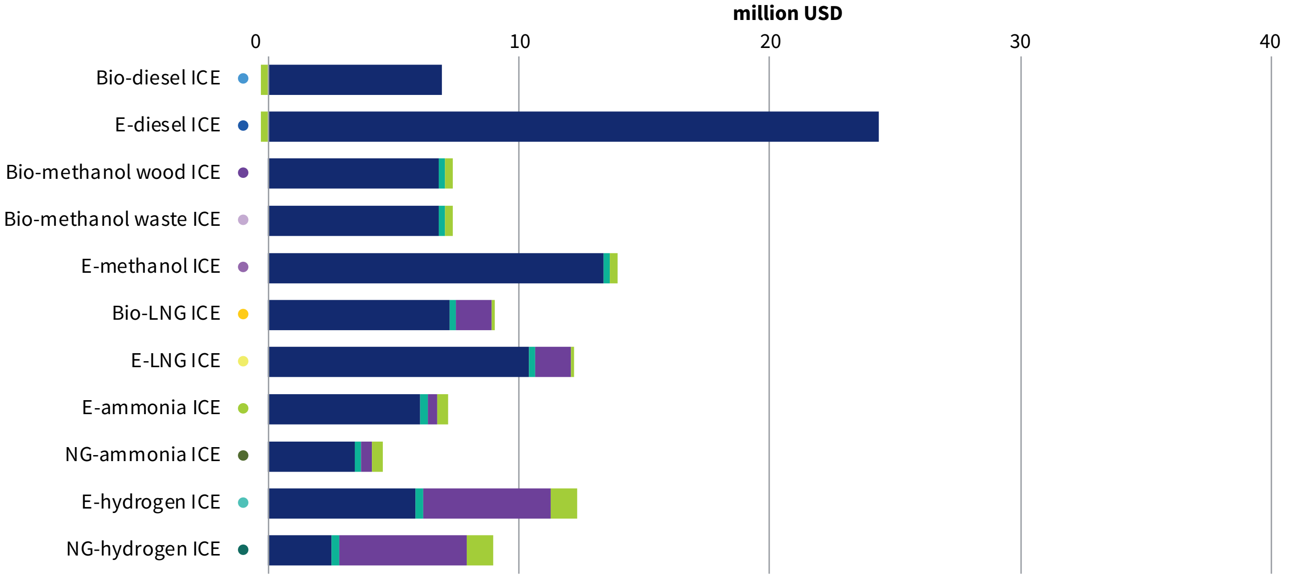
3.4. Fuel-related voyage costs.

When prices are high, the fuel-related voyage cost represents a significant share of the TCO, meaning ZEVs using more expensive fuels are penalised relative to the ones using less expensive fuels. This can be observed in Figures 4a and 4b below, which demonstrate the breakdown of the TCO for both low-and high-price scenarios in 2050.

Notes for Figures 4a and 4b:

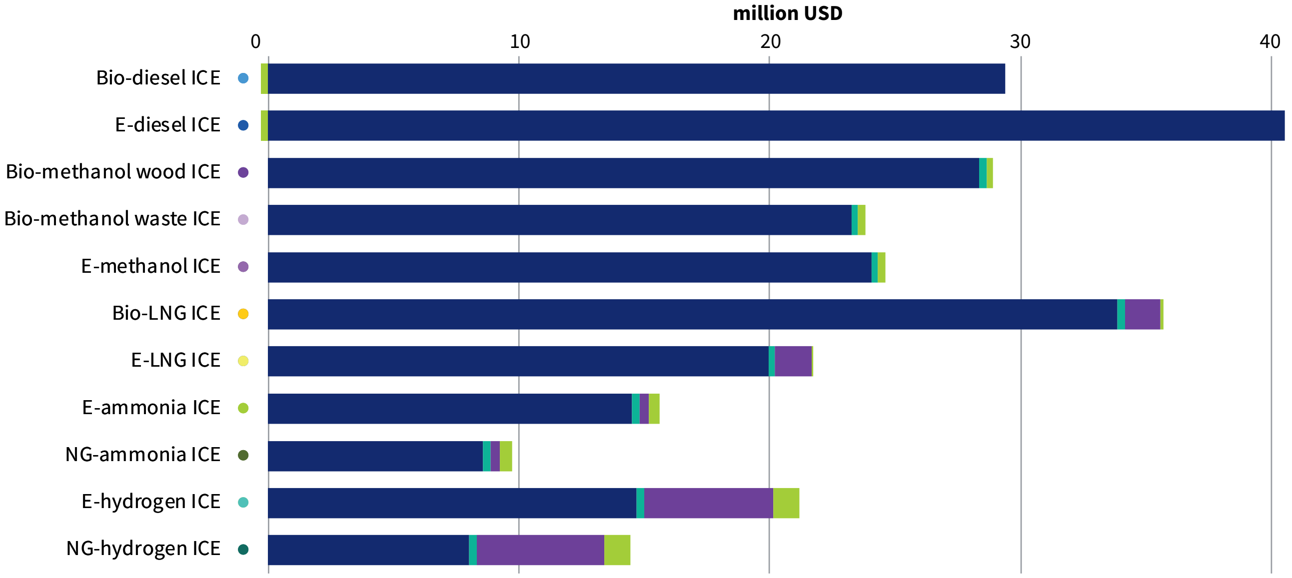
- Storage means capital cost of fuel storage system.
- Storage impact means revenue impact due to loss of cargo capacity.
- Hydrogen storage is as liquid.

2050 (low price scenario)



Figures 4a – Relative cost implications of ZEV technologies for bulk carrier under low-price scenario and no carbon price.

2050 (high price scenario)



Figures 4b – Relative cost implications of ZEV technologies for bulk carrier under high-price scenario and no carbon price.

Voyage Engine Storage Storage impact

ZEVs using hydrogen have a high capital cost of storage as well as a loss of cargo-carrying capacity due to the energy density of hydrogen, which ultimately impacts the revenue, represented by the storage impact in Figures 4a and 4b above. Significant improvements are required in terms of capital cost reduction and higher volumetric energy density of hydrogen storage systems to make this option more viable for the case study vessel presented.

In the high-price scenario, the ZEV using NG-ammonia has the lowest TCO in 2050 due to NG price predictions and the moderate assumption of capex cost of CCS, even when compared to e-ammonia. However, in both cases, ammonia has the lowest TCO of all the fuels considered in this paper. This is primarily due to the fact that the technology and production processes which are required for e-hydrocarbons (e-LNG, e-methanol and e-diesel) are still in development and consume large amounts of energy, making the future price predictions uncertain.

In the low-price scenario, the ZEV using bio-methanol has a very competitive TCO, very close to bio-diesel and e-ammonia. Among the ZEVs using biofuels, the ZEV using bio-diesel is the one with the lowest TCO as it has the advantage of being able to use the existing machinery and fuel system onboard, therefore demonstrating savings from storage and storage impact.

Among the ZEVs using e-fuels, the ZEV using NG-ammonia appears to be the one with the lowest TCO, followed by the e-hydrocarbons.

In terms of voyage costs, hydrogen has the lowest cost due to its low price of production when compared with other fuels such as ammonia. For details of production and cost assumptions, please refer to Appendix B.

The ZEVs using e-methanol and e-diesel have a higher TCO than the ZEVs using e-LNG because e-LNG is cheaper under the assumptions of the scenarios covered in this paper.

The energy content of methanol is lower than LNG (5.53 kWh/kg methanol versus 15.3 kWh/kg LNG) even though it has a better volumetric density (~789 kg/m^3 methanol versus ~428 kg/m^3 LNG); this results in a volumetric energy density of 4,363 kWh/m^3 for methanol and a 6,548 kWh/m^3 for LNG. This means that more space is needed in the ZEVs using methanol compared to LNG to meet the same energy requirements. This also means that there will be a higher loss of cargo capacity and revenue for the ZEVs using methanol compared to LNG. The analysis reported in this paper is based on the volume of tank storage (m^3) alone and does not take into account any related equipment necessary for handling or maintaining the fuels, or any fuel tank topology constraints. Further consideration of the storage tank design and optimal engineering architecture would be needed on a case-by-case basis. In addition, variations in actual energy density and exact composition may also alter the outcome.

It should be mentioned that the extra capital cost for the storage of e-LNG is higher than the one required for e-methanol, but the TCO for a ZEV using e-LNG will still be less than e-methanol under the assumptions of the scenarios covered in this paper.

The TCO of e-hydrocarbons will depend on the evolution of key carbon capture technologies such as direct air capture (DAC). These fuels rely on DAC becoming more available; at present, it is still in the concept stage. For this paper, the capex of DAC was assumed to be 1.5 \$/kg CO_2, derived from [Ref (05, 2018)], while the energy requirement for DAC was assumed to be 2.6 kWh/kg CO_2, derived from [Ref (06, 2015)]. It should also be mentioned that the literature referenced in this section provides greater cost reduction potentials for DAC; however, this has not been included in this paper due to lack of robust evidence.

Results for Scenarios 2 and 4 include an increasing carbon price. The carbon price has a significant impact on the fuel-related voyage cost of the reference ship which implies that the extra cost of voyage per year (CVpa) is smaller than the one in scenarios without carbon prices (Scenarios 1 and 3). The trends are essentially the same, but the overall TCO reduces at a different degree and eventual crossover with the x-axis for the price scenario (zero TCO which means no extra costs relative to the reference ship). This indicates that the introduction of carbon prices is essential to close the gap with the ships using traditional fossil-based fuels.

The results also suggest that when prices of zero-carbon fuels are high, higher carbon price is needed to make ZEVs more competitive in comparison with the reference ship. This paper does not take into account that part of the revenue generated from the introduction of carbon price may be used as a potential recycling mechanism. Such revenue can fund the development of zero-carbon fuel infrastructure, therefore reducing its price.

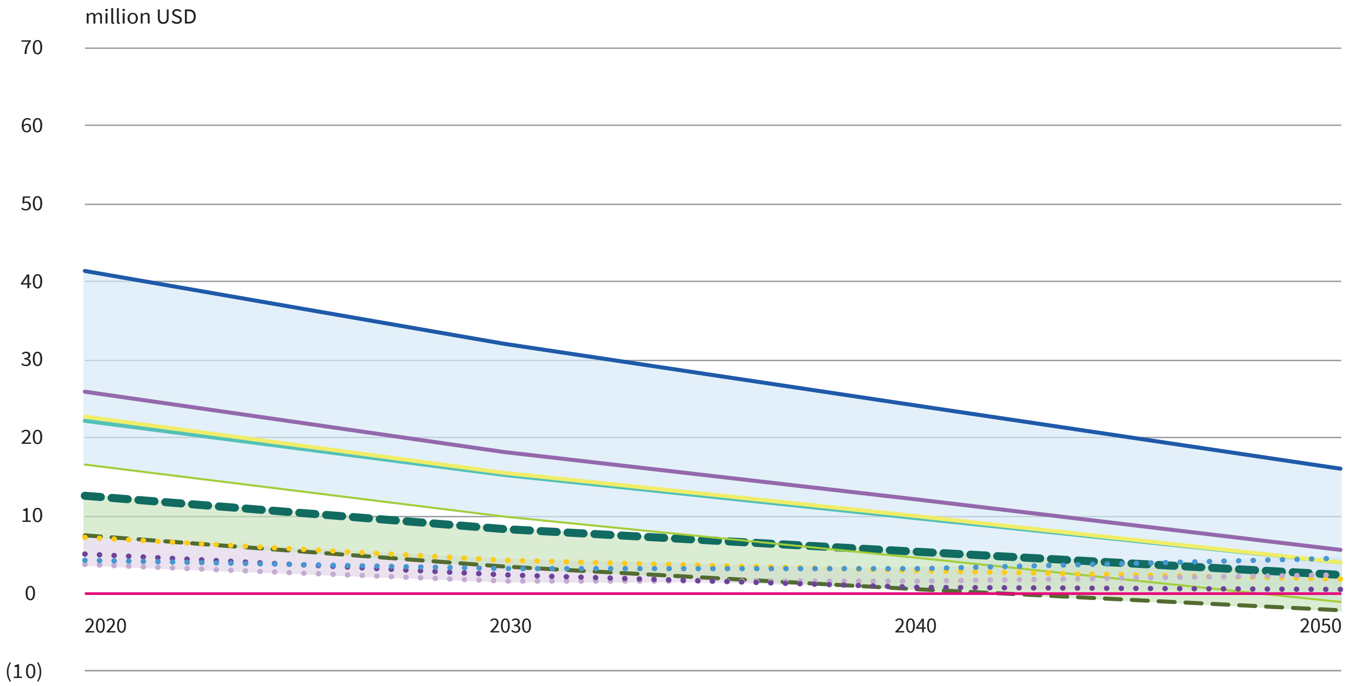


Figure 5a – Scenario 2; low-price scenario; TCO trends for a bulk carrier (only ZEVs with ICE).

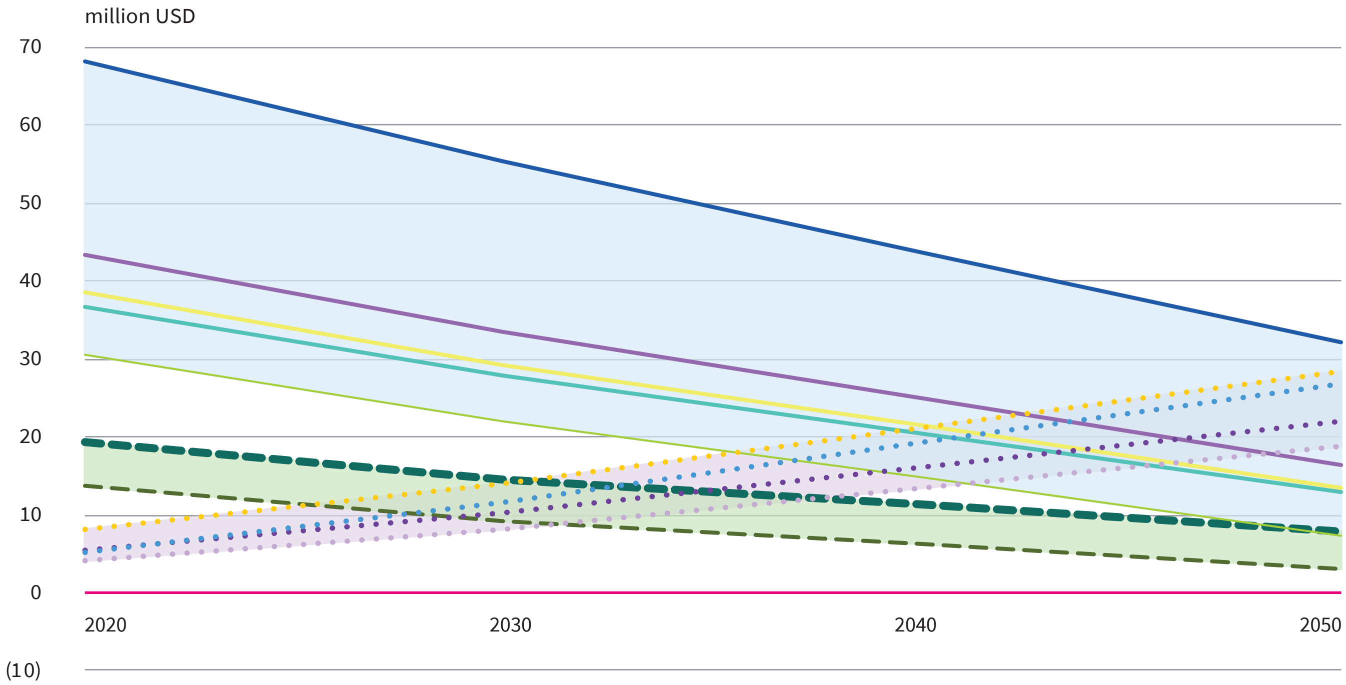
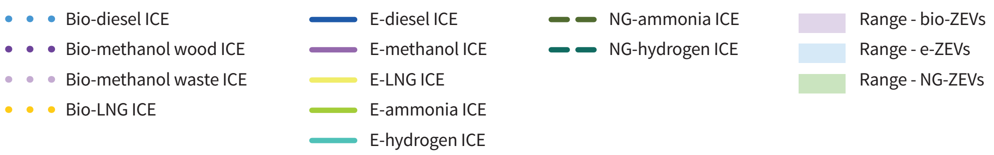


Figure 5b – Scenario 4; high-price scenario; TCO Trends for a Bulk Carrier (only ZEVs with ICE).



3.5. Impact of cargo-carrying capacity.

The cargo capacity of a ship storing zero-carbon fuel onboard could change. This is due to the different energy densities of these fuels relative to the conventional fossil fuels such as LSHFO. However, space requirements of the storage system of the zero-carbon fuel depends also on the amount of fuel stored onboard due to voyage requirements of that ship.

Figure 6 shows the impact on cargo-carrying capacity for the ZEVs considered in this paper. Results are provided for our case study ship (~82,000 DWT bulk carrier) for each ZEV option. We have also applied the assumption of a reduction of 80% in range (nm) relative to the reference ship. This 80% reduction in range explains the negative value presented for the ZEVs using diesel (both bio-diesel and e-diesel). As the energy density of diesel for LSHFO and bio-diesel and e-diesel are very similar, the storage required remains the same. Therefore, bio-diesel and e-diesel ZEVs gain a 20% saving on cargo capacity compared to other ZEV options.

A tailored investigation is recommended for each size and ship type because of the different technical and operational specifications that may lead to different conclusions. For very small bulk carriers, the impact on cargo capacity may have a more significant contribution to the overall TCO; therefore, other solutions may become more appropriate (e.g. batteries for very small vessels). Bulk carriers can be considered similar to oil tankers in their technical specifications, so it is expected that the results are very similar to the bulk carriers. Container ships have different key characteristics, which can lead to different results.

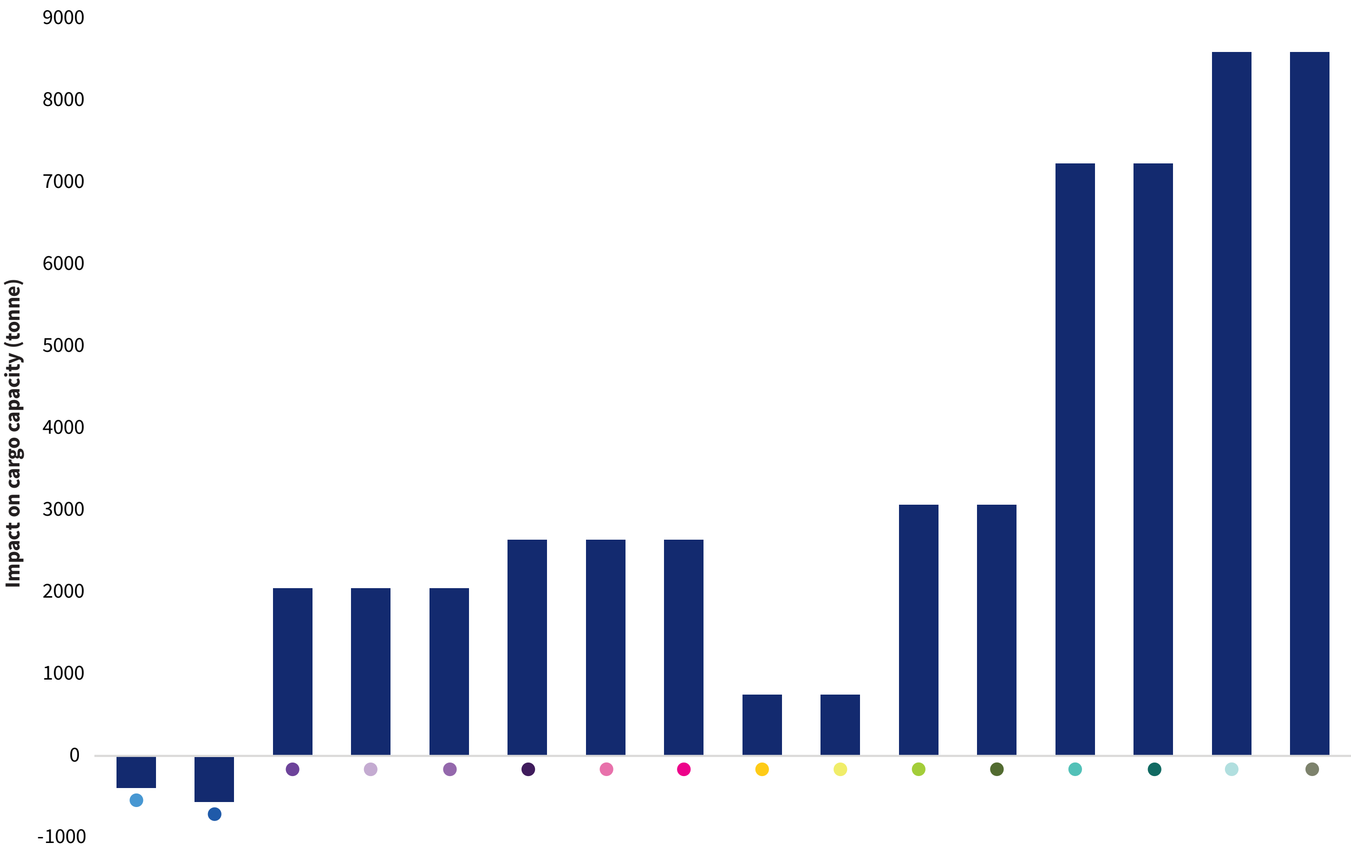


Figure 6 – Space requirements impact on cargo capacity for the case study ship, bulk carrier (~82,000 DWT).

- Bio-diesel ICE
- E-diesel ICE
- Bio-methanol wood ICE
- Bio-methanol waste ICE
- E-methanol ICE
- Bio-methanol wood FC
- Bio-methanol waste FC
- E-methanol FC
- Bio-LNG ICE
- E-LNG ICE
- E-ammonia ICE
- NG-ammonia ICE
- E-hydrogen ICE
- NG-hydrogen ICE
- E-hydrogen FC
- NG-hydrogen FC

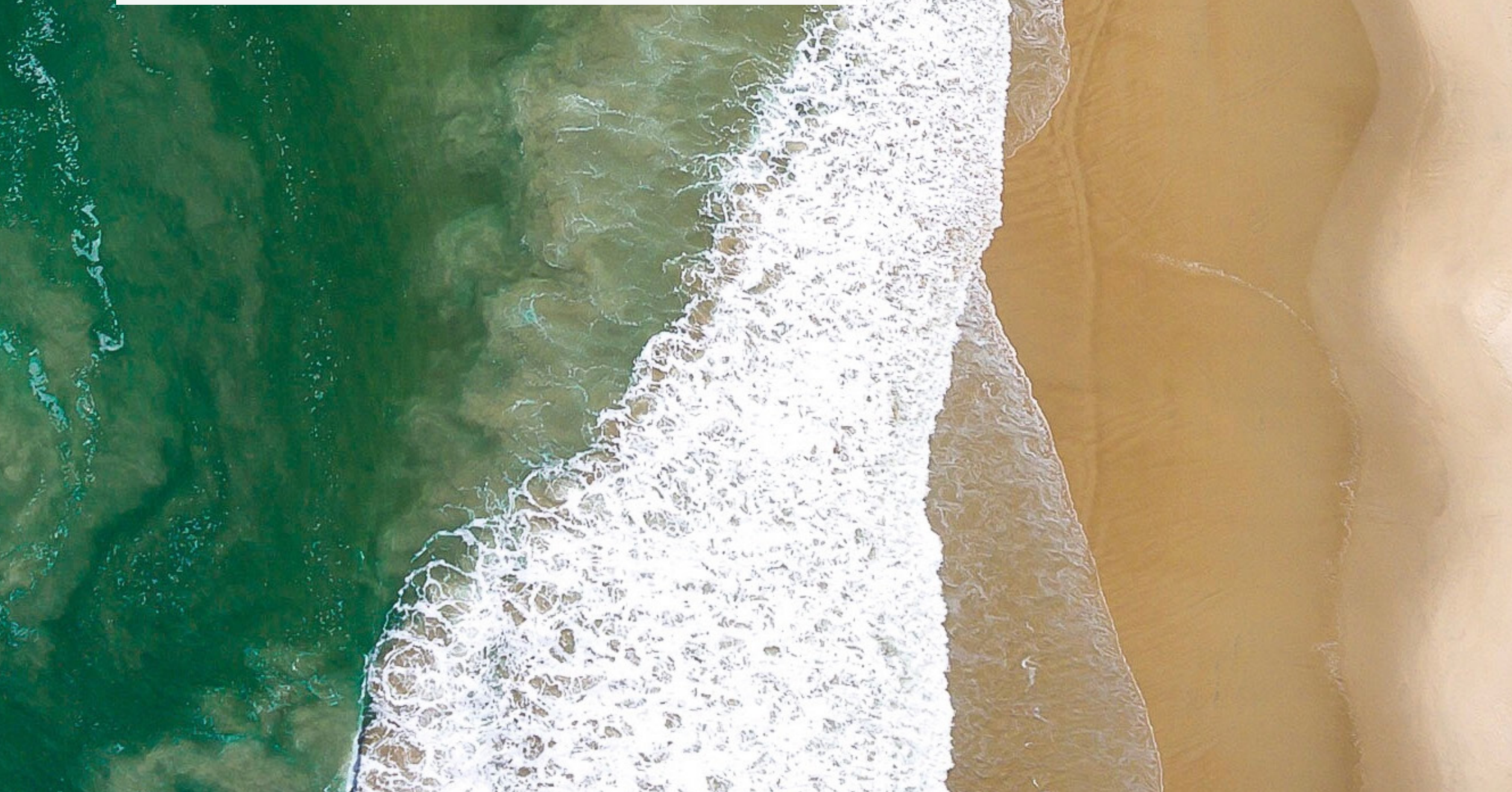
3.6. Sensitivity analysis.

This section provides sensitivity analysis of TCO against changes in renewable electricity and biofuel prices.

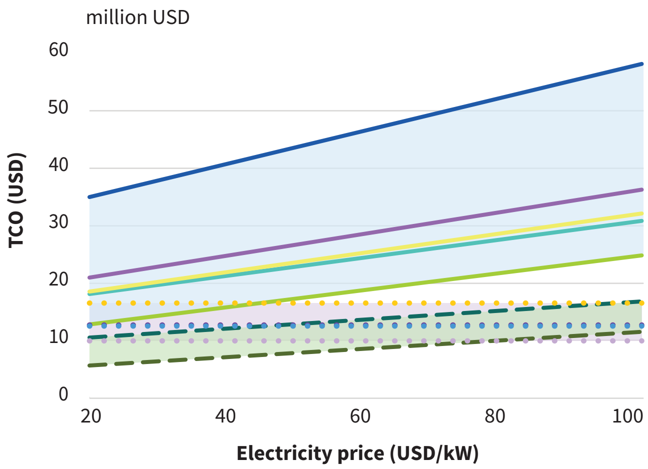
The first sensitivity is to electricity price. Fuels derived from NG are sensitive to the electricity prices because the processes involved in the supply chain would also require electricity as an input, although this may be negligible compared to e-fuels (demonstrated in Figure 7a). In this figure, the increase in electricity price for different ZEV options is demonstrated and it is apparent that the effect of electricity price on e-ZEVs is a lot more than NG-ZEVs (slope for range e-ZEV is steeper than range NG-ZEV).

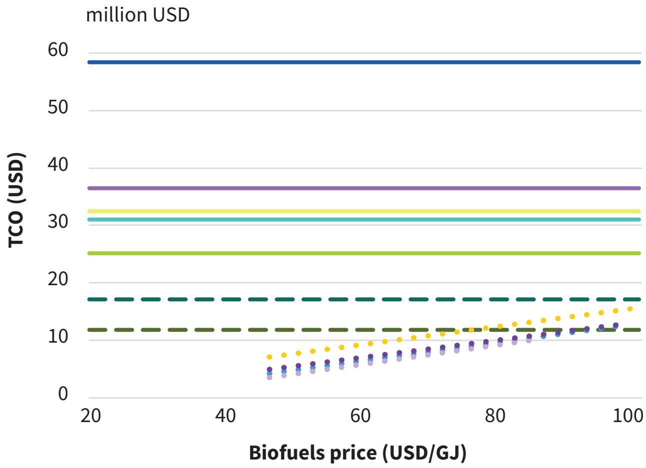
As the major energy input for the production of e-fuels, lower electricity prices lead to lower TCOs for these fuel types. Figure 7a shows that in 2030, the crossover point with the most expensive biofuels occurs for the cheapest electricity price of 0.04 $/kWh. In 2040, the crossover point of the cheapest e-fuels ZEV with the cheapest biofuel ZEV occurs for an electricity price of 0.07 $/kWh.

The second sensitivity varies the biofuel price. The TCO with a changing biofuel price can highlight indicative thresholds for the competitiveness of biofuels. Based on these scenarios, the results shown in Figure 7b indicate that when biofuels become more expensive (e.g. more than 70 $/GJ in 2030, 40-60 $/GJ in 2040, 30 $/GJ in 2050), other ZEVs start to be as competitive as the ZEVs using biofuels.

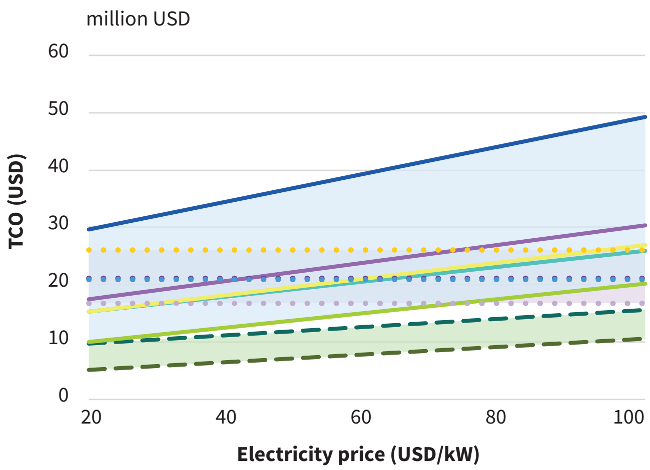


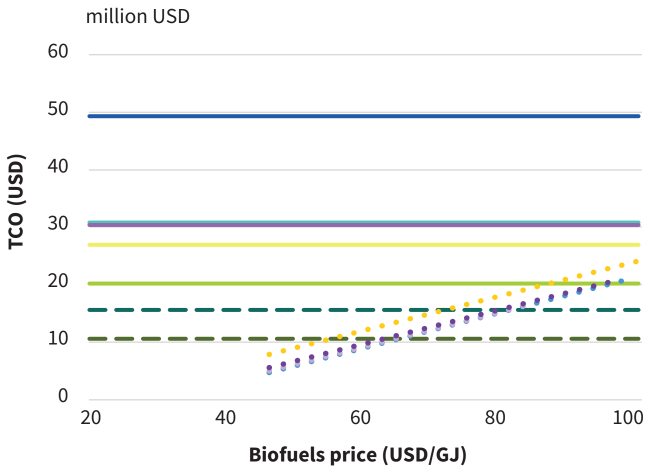
2030



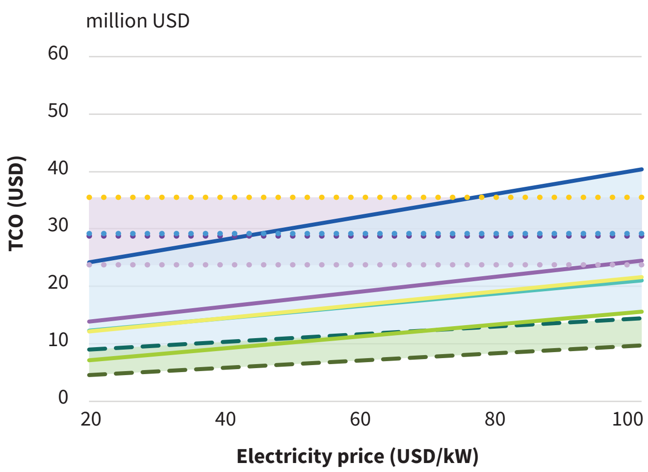


2040





2050



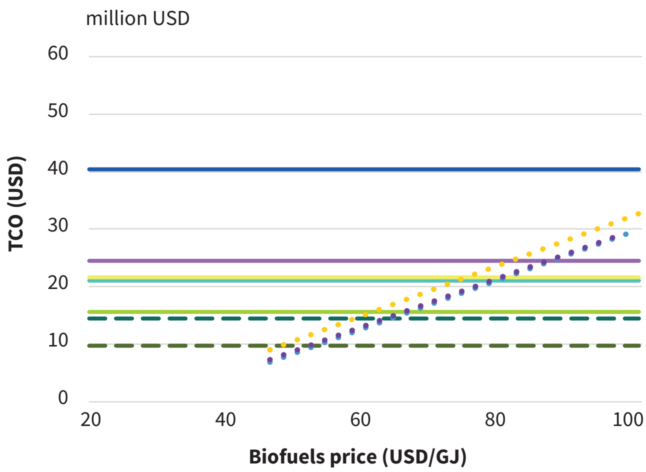


Figure 7a – Sensitivity analysis with electricity prices.

Figure 7b – Sensitivity analysis with biofuels prices.

Bio-diesel ICE
Bio-methanol wood ICE
Bio-methanol waste ICE
Bio-LNG ICE
E-diesel ICE
E-methanol ICE
E-LNG ICE
E-ammonia ICE
E-hydrogen ICE
NG-ammonia ICE
NG-hydrogen ICE
Range - bio-ZEVs
Range - e-ZEVs
Range - NG-ZEVs

4. Technology readiness of zero-carbon solutions.

In this section, we assess the technology feasibility for zero-carbon solutions and provide an insight into the current barriers to market.

The objective of the assessment is to establish the current 'readiness' of technologies considered to be critical in the application of zero-carbon fuels for shipping. The screening and assessment process is fuel-agnostic and ultimately assigns a TRL to indicate the development status of a technology on a scale ranging from 'basic principles observed' to 'product and production fully operational'. The allocation of a TRL is defined by the Research & Innovation Policy Tool 'EARTO' scale which is intended for the planning of innovation management. An overview of definitions and descriptions of TRLs by EARTO is shown in Figure 8, [Ref (07, 2014)]. The method has been applied to the technologies in question as it stands in 2020.

Figure 8 – EARTO TRL definitions and descriptions, [Ref (07, 2014)].

We examined the technology readiness of zero-carbon fuels and their usage in terms of onboard procedures of bunkering, vessel storage, processing, conversion onboard and propulsion. These are exampled below:

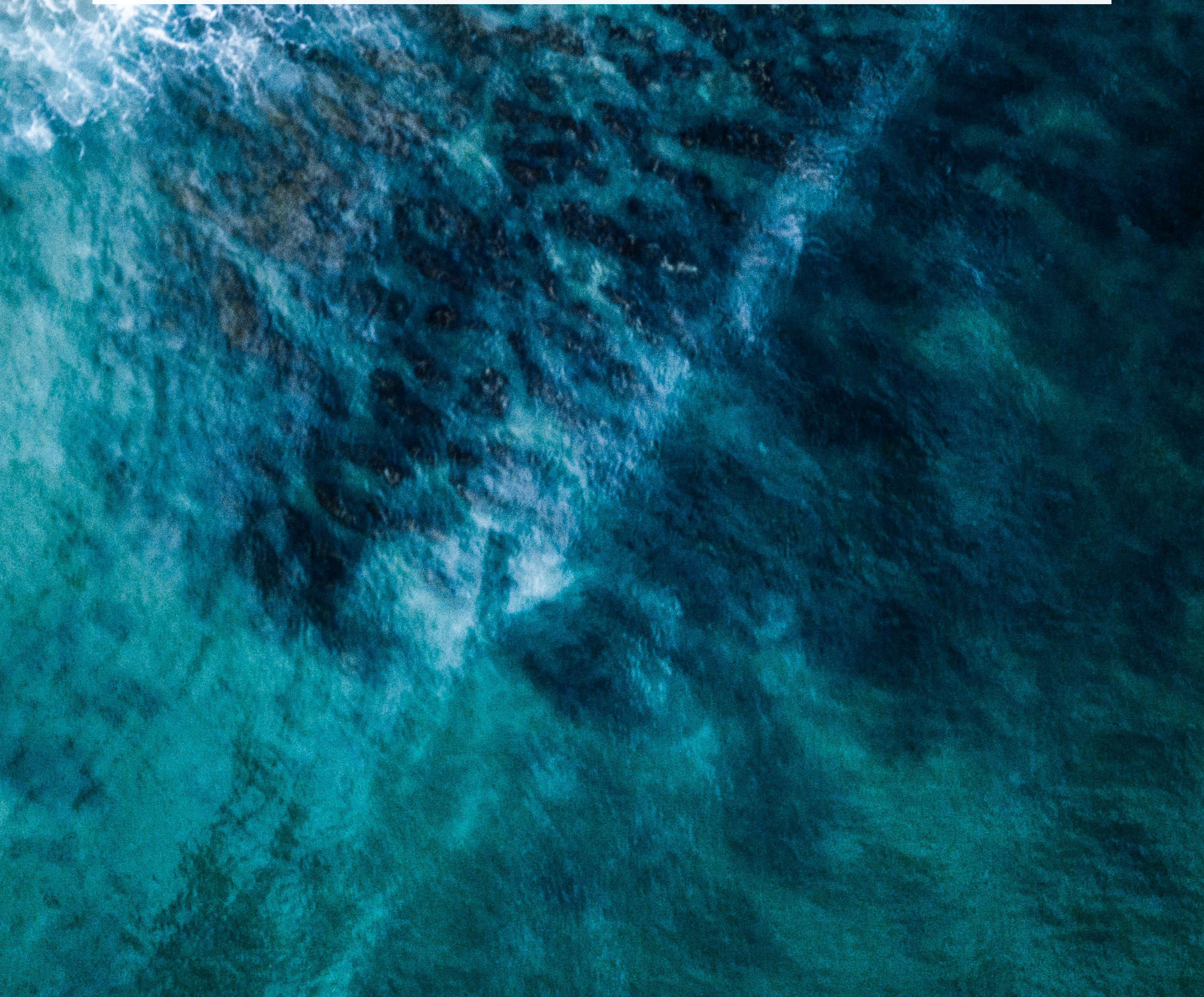
Bunkering: this includes technologies and arrangement of forced ventilation, leakage detection, airlocks, spray shields, temperature sensor, liquid bunkering hose, vapour discharge hose, dry break-away coupling, purging system (inert gas), secure sockets layer and emergency shutdown communication, transfer system: loading-arm-fuel and flexible hoses, fuel bunkering procedures, and fuel bunkering standard.

Storage onboard: this includes technologies and arrangement of piping, piping insulation, valves, pressure relief valves (PRV), pumps, inerting system, containment system thermal insulation, leak detection system, PRV emergency isolation, tank pressure/temperature control, thermal oxidation systems, gas sampling and monitoring system, tank type.

Processing and conversion: this includes technologies and arrangement of double walled piping, automatic "master gas fuel valve", gas heater, double-block-and-bleed valves, pipe rupture detection, double piping or duct inerting system, venting system, compressor or pump bulkhead shaft penetrations, compressors or pump, submerged pump, and liquefied fuel gas pump.

Propulsion: this includes ICE 2-stroke, ICE 4-stroke, main/auxiliary boilers, gasification, reformers.

The outcomes are demonstrated in Table 3.



TRL	Bunkering			Storage onboard					Processing and conversion			Propulsion			
	Equipment	Procedures	Fuel quality standards	Structural tank	Membrane containment system	IMO type A tank	IMO type B tank	IMO type C tank	Venting system	Fuel supply system	Reformer	2-Stroke ICE	4-Stroke ICE	FC	Boiler
LSHFO ICE reference ship	9	9	9	9					9	9		9	9		9
Bio-diesel ICE	9	9	9	9					9	9		9	9		9
E-diesel ICE	9	9	9	9					9	9		9	9		9
Bio-methanol ICE	7	6	3	7					7	7		7	6		2
E-methanol ICE	7	6	3	7					7	7		7	6		2
Bio-methanol FC	7	6	3	7					7	7	3		6	7	2
E-methanol FC	7	6	3	7					7	7	3		6	7	2
Bio-LNG ICE	9	9	9		8		9	9	9	9		9	9		9
E-LNG ICE	9	9	9		8		9	9	9	9		9	9		9
Bio-LNG FC	9	9	9		8		9	9	9	9	4			7	
E-LNG FC	9	9	9		8		9	9	9	9	4			7	
E-ammonia ICE	7	2	2			7	7	7	3	7		3	2		2
NG-ammonia ICE	7	2	2			7	7	7	3	7		3	2		2
E-ammonia FC	7	2	2			7	7	7	3	7	2		2	7	2
NG-ammonia FC	7	2	2			7	7	7	3	7	2		2	7	2
E-hydrogen ICE	4	2	3				3	6	2	2		2	5		2
NG-hydrogen ICE	4	2	3				3	6	2	2		2	5		2
E-hydrogen FC	4	2	3				3	6	2	2			5	7	2
NG-hydrogen FC	4	2	3				3	6	2	2			5	7	2
Batteries	4	2	3				3	6	2	2			5	7	

Table 3 – TRL ranking for ZEV technologies.

Notes for Table 3:

- Zero-carbon fuels are considered in combination with either a 2-stroke or 4-stroke ICE.
- Only Proton Exchange Membrane (PEM) FCs are considered.
- PEM FCs do not currently have enough transient power, therefore a secondary source such as an ICE or batteries would be needed.
- Cargo loading experience for ammonia is used as basis for TRL value for ammonia bunkering equipment.

This assessment has not considered or recognised the most optimal propulsion architecture. Therefore, it should not be considered in isolation or without critical engineering judgment. From an onboard technology perspective, the more technology ready (greater than TRL 6) ZEVs are technologically possible in the next two years. However, to have confidence around future investments, we also require confidence around the fuel supply chain, both in the availability of the quantities required and the land-based infrastructure in place.

4.1. Actors and barriers.

In the early 2020s, to enable the transition, we will need to see the number of zero-carbon fuel producers grow. A key milestone to enable the transition is the formation of alliances between fuel producers, equipment manufacturers and associated technology providers, with the aim of increasing the uptake of zero-carbon fuels against the use of conventional fossil-based fuels in shipping. This is expected to begin by focusing on ship type markets and geographical regions where they see potential for the different zero-carbon fuels to compete with conventional fossil-based fuels. More specialised alliances would evolve for the purpose of promoting the use of e-, bio- and NG -fuels. In the late 2020s, these different alliances and networks will need to continue to grow as more actors enter the market. The alliances between actors promoting the same final energy carriers could grow particularly strong. In the 2030s, as the acceptance, availability and uptake of zero-carbon fuels in shipping grows and competition among the different zero-carbon fuel options increases, these actor groups would redirect their attention towards promoting their respective solution as the best and most viable one.

In the early 2020s, the role of civil society actors in enabling the transition will increase by advocating zero-carbon shipping and increasing the pressure on policymakers at the national, regional and international level. Expectations will be high for measures already outlined in the IMO Initial GHG Strategy to be implemented through such measures as command and control regulations, market-based measures and establishing a supportive policy environment for guidelines and best practice, e.g. safe handling of zero-carbon fuel options to achieve the milestone of ZEVs to enter the world fleet in 2030.

Regulatory Bodies	Port Authorities	Classification Societies	Shipowners
• Methanol • Hydrogen • Ammonia • Batteries • Biofuels • NG	• Methanol • Hydrogen • Ammonia • Batteries • Biofuels • NG	• Methanol • Hydrogen • Ammonia • Batteries • Biofuels • NG	• Methanol • Hydrogen • Ammonia

Equipment Manufacturers	R&D Bodies	NGOs
• Methanol • Hydrogen • Ammonia • Batteries • Biofuels • NG	• Hydrogen • Ammonia • Batteries	• Methanol • Hydrogen • Ammonia

Table 4 – Actors that can Improve TRL of ZEVs.

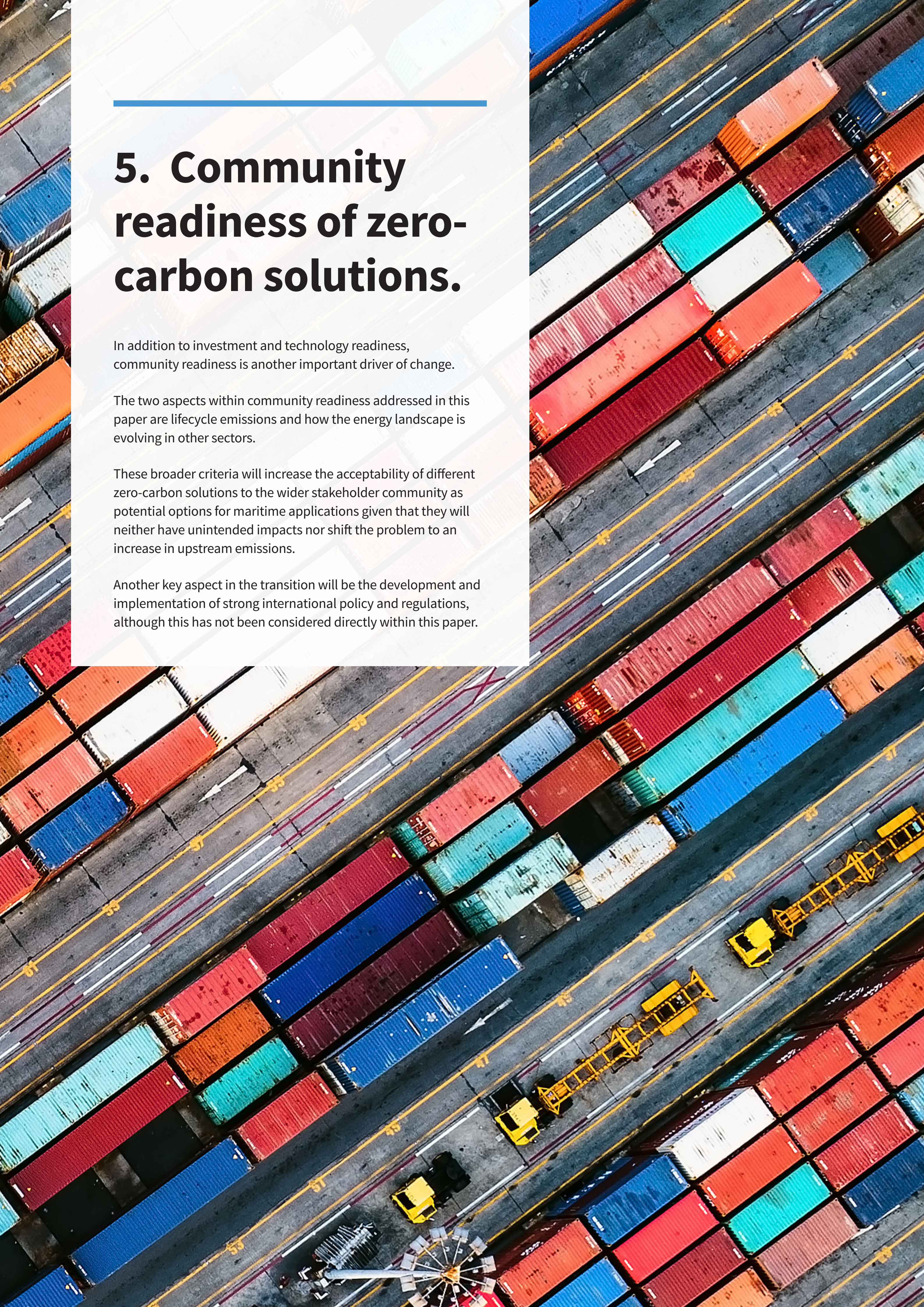
Barriers are elements that need to be removed to enable the zero-carbon fuels to reach higher TRLs. For each zero-carbon fuel, there are a number of barriers and some of these are common for others. Understanding the limitations and how influence can be exerted in overcoming them will shape the development of the technology best suited to the industry. Barriers for zero-carbon fuels are listed overleaf.

Barriers for zero-carbon fuels:

- Further development of IGF Code to include detailed safety requirements
- Development of fuel bunkering procedures
- Development of fuel bunkering standards
- Development of fuel quality standards
- Improvement on application
- Development of auxiliary equipment
- Research & Development on thermodynamics and fluid dynamics
- Development of onboard storage
- Development of bunkering infrastructure
- Development of conversion equipment

Lack of bunkering procedures and fuel quality standards are common barriers across the zero-carbon fuels. The actors, such as regulatory bodies and NGOs (e.g. the ISO), would need to work together to produce procedures and standards to improve TRLs. This is a good demonstration of how actors and barriers are linked to each other for the improvement of TRLs.

The additional price to build a ship with new fuel tanks, modified engines and fuel supply systems is a small element of the TCO. The design should be flexible enough to be able to run on one fuel today, to be adapted for an in-life retrofit to run on alternative fuels, and to ensure resilience to further adapt should something affect the supply chain. Although ships and engines will have to be flexible and adaptable, this part of the challenge is insignificant compared with ensuring the right fuel is ready, as well as the required supporting infrastructure on land. Therefore, the bulk of the technology challenge is in land infrastructure and in the energy sector.



5. Community readiness of zero-carbon solutions.

In addition to investment and technology readiness, community readiness is another important driver of change.

The two aspects within community readiness addressed in this paper are lifecycle emissions and how the energy landscape is evolving in other sectors.

These broader criteria will increase the acceptability of different zero-carbon solutions to the wider stakeholder community as potential options for maritime applications given that they will neither have unintended impacts nor shift the problem to an increase in upstream emissions.

Another key aspect in the transition will be the development and implementation of strong international policy and regulations, although this has not been considered directly within this paper.

5.1. Lifecycle emissions.

One of the concerns from shipowners and operators is in relation to the upstream emissions in production of different energy sources. They do not want to address emissions in the marine industry only for the problem to be shifted upstream, [Ref (02, 2017)]. Therefore, we have considered the full lifecycle of emissions for each fuel. Figure 9 below shows both upstream, operational and net CO_2 emissions for each fuel included in this paper. The data represented in Figure 9 does not include any indirect emissions, e.g. those from the construction of the production of the plant, and they are mid-values identified through research.

We have focused on upstream emissions of CO_2 because it is the dominant GHG in existing processes. However, there are several other GHGs that may be significant (such as methane and nitrous oxide) and the impacts of these need to be considered in making decisions on the direction for the shipping sector.

Figure 9 demonstrates that the best net-CO_2 performers are fuels that are e-fuels, i.e. fuels that are produced from renewable electricity such as e-methanol, NG-ammonia, e-diesel, e-hydrogen and batteries that are charged by renewable electricity.

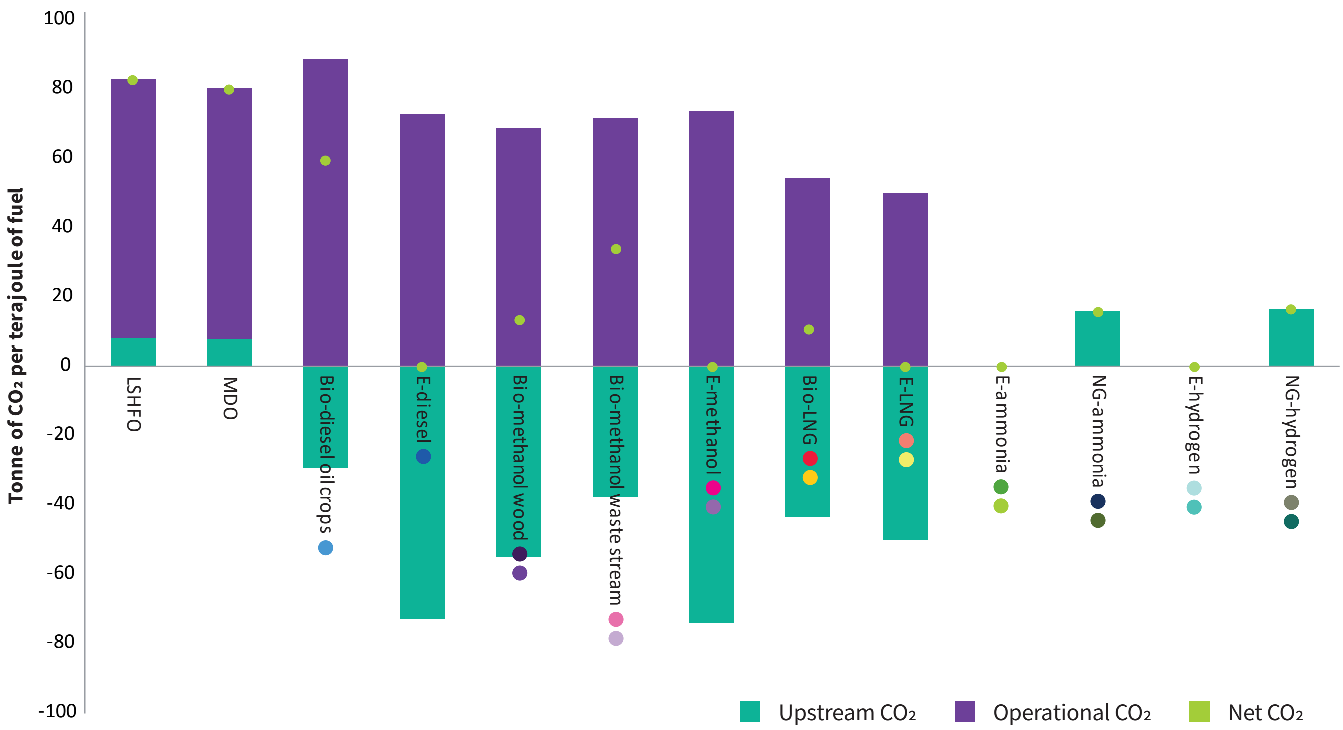


Figure 9 – Upstream, operational and net CO_2 emissions for each fuel.

However, the majority of fuels considered have very low CO_2 emissions across their lifecycle and may have the potential to become zero or net zero CO_2 emissions, although in some biofuel cases, dependent upon the bio-feedstock used, they have the same carbon credentials as fossil fuels.

The IMO Initial GHG Strategy and any future subsequent IMO regulation is likely to be constrained to operational emissions from shipping. There are several energy sources that might be zero GHG in operation/combustion on a ship but have significant upstream emissions in production. Therefore, there is a material risk that by addressing the emissions from shipping, the problem is moved upstream to another sector. Whilst there are transitions happening in the upstream fuel production sector, this takes time and the supply of zero-carbon energy may not develop in line with shipping's demand at appropriate volume and price levels, so during the transition, it may be necessary to use non-zero GHG upstream emission energy sources.

In practice, as the global economy decarbonises in line with the Paris Agreement, chemical manufacturing and energy generation will also need to decarbonise. This process of upstream decarbonisation will happen 'naturally' over time; however, to have a significant impact on global CO_2 reduction, the timing of shipping's move to zero-emission options may need careful management.

5.2. How the energy landscape is evolving in other sectors.

Shipping has a number of technology and zero-carbon fuel choices but there is no doubt that how shipping decarbonises will be closely linked to how the wider energy system decarbonises and the implications this has for the shipping sector.

There are some underlying challenges in relation to production or process technology for many fuels such as hydrogen and biomass feedstock. There are also challenges associated with key enabling technologies such as CCS and DAC. These are explained in more detail below:

- In order to have clean hydrogen, other production processes need to come into play. Steam Methane Reforming (SMR) and CCS is a potential solution; however, it would not ensure 100% of CO_2 emissions are captured, whereas fuel production through an electrolyser using only renewable electricity would have the potential to create virtually zero-CO_2 fuels.
- Biomass has some underlying issues in terms of availability and sustainability. Studies ([Ref 10, 2019)]) show that some purpose-grown energy crops (e.g. palm and soy) have significant implications for land-use change and, in some cases, may have worse carbon credentials than the fossil-based fuels they are looking to replace. There is also a lack of consensus across industry experts over the amount of available biomass feedstocks and which sectors this limited supply would be directed to.
- CCS technologies' biggest challenges are cost, reputational risks of having an association with the fossil industry, and the insurance/legal risks associated with CO_2 leakage from a geological store.
- DAC technologies are still under development and there is uncertainty about how this technology will develop and its associated costs.

How other sectors decarbonise may have an effect on selecting a resilient transition pathway for the shipping sector. With the aim of giving a brief overview of other sectors' decarbonisation plans, we give a summary below which provides the evolution of other sectors at a global level from the Intergovernmental Panel on Climate Change (IPCC 2019) and it is expected that there will be regional and national variation.

Aviation

Aviation emits around 2% of global CO_2 emissions, and emissions are expected to rise significantly. For emissions to decrease, sustainable aviation fuels (SAF) need to be used. SAF generally refers to biomass feedstock aviation fuels with lower GHG emissions than conventional aviation fuels. There are six certified SAFs. However, only one of these is commercially mature, which has a significant cost premium being almost two to three times higher than conventional jet fuel.

There is significant progress on developing SAF derived from biomass, but the use of SAF is still minimal and will remain limited in the short term. In the long term, we believe that it will be restricted by biomass availability and competition from other sectors.

There is a lot of interest in e-fuels in aviation and electric aircraft are a potential option for short-distance flights. However, due to non-activity in this field, the future of electric aircraft and potentially other SAFs that are not derived from biomass is still uncertain.

The International Civil Aviation Organization (ICAO) targets are fuel efficiency and carbon-neutral growth from 2020, which are not aligned with Paris Agreement temperature goals. Considering limited availability of SAF, achievement of 2020 carbon neutrality will likely rely heavily on offsetting.

It is surprising to see that the EU and individual countries have put in place targets and policy measures that are more ambitious than ICAO. The aircraft industry target is not aligned with the Paris Agreement temperature goal but it is more ambitious than the ICAO target.

To source sufficient supplies of SAF, airlines and biofuel producers have concluded long-term off-take agreements, but delivery on agreed quantity and timeline appear to be challenging.

Across most stakeholders and initiatives, strong focus on SAFs derived from biomass and offsetting seem to be likely to the detriment of finding lower-carbon alternatives.

Lessons learned from aviation that are applicable to shipping may be summarised below:

- Biomass feedstock SAF has become aviation's 'preferred fuel' and we may investigate whether shipping can also have a 'preferred fuel'.
- As biomass feedstock SAF will not be sufficient for decarbonisation of the aviation industry, we may need to investigate carefully when selecting our 'preferred fuel'.
- IMO policy alone may not address our challenges; therefore, we may also need to complement our policy with different industry initiatives.
- Offtake agreements for biofuels could be mirrored for shipping's 'preferred fuel'.

Transport

The potential for reduced energy consumption and CO_2 emissions, and strategies to achieve this, differ significantly among transport modes. For example, there is rapid growth of electric vehicle sales in passenger cars, so we see more attention towards structural changes such as consumer behavioural choices within this sector. However, there are also regional strategies such as the EU investigating specific areas for their decarbonisation pathways, [Ref (08, 2019)]. Some of these areas are listed below and may affect shipping's decarbonisation:

- Shift passengers from private cars to public transport services
- Shift more freight off the road and onto railways or waterways
- Improve/introduce regulations during the transition period to decrease consumer demand for oversized vehicles and oversized engines
- Improve/reduce the average emissions of all passenger cars and light duty vehicles
- Improve/increase the rate of market penetration of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) for passenger transport
- Improve/increase the penetration rate of low-carbon electricity generation into the grid urgently
- Improve and adapt the design and regulation of electricity markets and tariffs that apply to electric vehicles, so that costs are minimised for all consumers
- Improve and simplify guidance on use of biofuels, biogas, natural gas and methane for transport
- Improve/increase resources for the development of technologies for producing synthetic fuels
- Improve/increase the levels of investments in information and communication technologies and autonomous vehicles
- Improve/strengthen preparations for long-term emission reductions by making long-term policy commitments to invest in innovation, jobs, skills and interdisciplinary research

Power

The power sector is expected to be decarbonised by mid-century in both 1.5°C and well below 2°C pathways in line with Paris Agreement.

It is recognised by the power sector that rapid decarbonisation is needed, particularly as heat and transport sectors are electrified, creating an increase in demand for electric power. Decarbonisation is being achieved by increasing the share of low-carbon energy sources, particularly renewables, and a corresponding reduction in the use of fossil-based fuels. Worldwide, renewables now produce a third of the global power capacity. Capping GHG from fossil-based fuel power stations by installing CCS technology is also expected to play an increasing role, [Ref (09, 2018)].

In the short term, there is a shift from coal to NG to reduce power plant emissions. However, as far as possible, fossil-based fuel combustion will need to be replaced, primarily with renewables such as wind and solar power, and where fossil-based fuel power stations continue to operate, CCS will be required.

Industry

The industry sector accounted for about 28% of global GHG emissions in 2014, so the targets set by the Paris Agreement cannot be reached without decarbonising industrial activities. Industrial sites have long lifetimes; therefore, upgrading or replacing these facilities to lower carbon emissions requires that planning and investments start well in advance.

The industrial sector is a vital source of wealth, prosperity and social value on a global scale. Industrial companies produce about one-quarter of global gross domestic product (GDP) and employment, and make materials and goods that are integral to our daily lives, such as fertiliser to feed the growing global population, steel and plastics for the cars we drive, and cement for the buildings we live and work in.

In 2014, direct GHG emissions from industrial processes and indirect GHG emissions from generating the electricity used in industry made up ~15 Gton CO_2 (~28% of global GHG emissions). CO_2 makes up over 90% of direct and indirect GHG emissions from industrial processes. Between 1990 and 2014, GHG emissions from the industrial sector increased by 69% (2.2% per year), while emissions from other sectors such as power, transport and buildings increased by 23% (0.9% per year), Ref [(11, 2018)].

The industry sector's mitigation measures include energy efficiency, reducing demand, increasing electrification of energy demand, reducing the carbon content of non-electric fuels, and deploying innovative processes and application of CCS.

Overall, industrial companies are planning to reduce CO_2 emissions in various ways, with the optimum local mix depending on the availability of biomass, carbon-storage capacity and low-cost zero-carbon electricity and hydrogen, as well as projected changes in production capacity. A combination of decarbonisation technologies could bring industry emissions close to zero, namely demand-side measures, energy efficiency improvements, electrification of heat, using hydrogen (made with zero-carbon electricity) as feedstock or fuel, using biomass as feedstock or fuel, CCS, and other innovations, Ref [(12, 2018)].

There are some key areas which could affect the shipping industry based on how other sectors decarbonise:

- Important to identify and drive implementation for a specific fuel by creating the right conditions. For example, in the case of ammonia and methanol, which are currently only used as industrial commodities:
  1. Work with associations and potential fuel producers to show demand particularly for the industrial commodities as a transport fuel
  2. Improve production efficiency and evaluate decarbonisation pathway options with stakeholders
  3. Leverage existing supply chain to identify geographically best-suited areas for early adoption
  4. Work with regulators to influence policy to create the right conditions

6. Conclusions.

All ZEV options show a strong link between the evolution of the fuel production and therefore price and the overall economic case of a ZEV. The way that this evolves over time, through the 2020s, 2030s and up to the 2050s, means that different zero-carbon fuel options are more economically viable in different decades and there is not one option that is more economically viable from today through to 2050.

6.1. Investment readiness.

The primary driver for the competitiveness of different ZEVs when compared to a reference ship running on fossil-based fuel is the fuel price. Although it is difficult to have absolute certainty about how costs will evolve, an understanding of potential upper and lower ranges and how sensitive the TCO is to changes in fuel prices will help in managing any risks and exposure from an economic perspective.

For the case study ship selected for this paper, battery technology is simply not competitive and still requires significant development in terms of size, weight and cost of operation before it could be a viable technology as a main propulsion. Batteries are not likely to be part of ZEVs for deep sea shipping but have a role to play in integration in power systems in the short term.

Physical characteristics in fuels (e.g. a lower volumetric energy density) will mean changes to how we store and handle fuels onboard, which may in turn impact cargo-carrying capacity for some ship types.

ZEVs using hydrogen have a high capital cost of storage and loss of cargo-carrying capacity. Therefore, significant improvements are needed to reduce capital cost and to resolve the onboard storage issues in order to improve the competitiveness of hydrogen compared to other options.

E-hydrocarbons with a better ratio of energy versus volume required to store the fuel would have a more competitive advantage, assuming similar fuel prices.

Between now and 2030, from the perspective taken in this paper, biofuels look more competitive than NG-fuels in the short term. However, over time, biofuels will lose that competitive advantage in the lower bound fuel price scenarios by the mid-2030s. In the upper bound scenario, all biofuels become uncompetitive more quickly, in the late 2020s/early 2030s, with NG-fuels taking the competitive lead for a longer period of time, given the expected amount of time required for renewable electricity prices to fall to competitive levels. Although biofuels can be used as 'drop-ins' or blends today, the use of biofuels in the short term should not hinder efforts for a longer-term solution. Due to significant concerns regarding their sustainability and availability, this solution may need to be bound by time and ship type/routes, limiting its impact as a viable long-term solution.

In 2020, fuels derived from NG are the next lowest TCO after biofuels, primarily NG-ammonia . This means that such NG-fuels could be an attractive alternative to biofuels from today. Over time, the production and supply would transition from NG to renewable electricity. With the price assumptions used in this paper, this could occur around the early 2040s. This could occur sooner in specific geographical locations where there is access to cheap renewable electricity.

Applying a carbon price to the end fuel means that the economic case is more viable earlier. For the fossil-based fuelled ships, this is less attractive, making zero-carbon fuels cheaper earlier, which could occur around 2040.

Under the scenarios in this paper, ammonia looks to be the most promising. Although e-hydrocarbons appear to be more expensive, this might be affected by the uncertainty linked to the development of key technologies needed for their production.

Overall, the TCO for e-fuels is trending towards a continuous reduction every decade, whereas biofuels are not showing as consistent a trend. The trend shows that under the high-price scenario for biofuels, the TCO is increasing, and under the low-price scenarios, the TCO is either staying level or slightly decreasing.

6.2. Technology readiness.

Regardless of which zero-carbon fuels emerge as favoured from an economic perspective, from an onboard technology perspective, ZEVs are likely to be technologically possible in the next two years. However, to be confident about future investment, we will also require confidence about the fuel supply chain, both in the availability of the quantities required and the land-based infrastructure in place.

From a technology readiness perspective, methanol, LNG and diesel are more mature than hydrogen and ammonia as rules and regulations currently exist and there are vessels already using these fuels. From an onboard technology perspective, there are minimal differences, for example, between using bio-methanol, e-methanol or NG-methanol; the same applies to LNG (bio-LNG, fossil-LNG and e-LNG). The main technical barrier for new fuels such as ammonia and hydrogen is the storage and bunkering infrastructure. This means regulatory actors need to collaborate with OEMs to enable the uptake.

The additional price to build a ship with new fuel tanks and modified engines and fuel supply systems is a small element of the TCO. The design should be flexible enough to be able to run on one fuel today, to be adapted for an in-life retrofit to run on alternative fuels and to ensure resilience to further adapt should something affect the supply chain. Although ships and engines will have to be flexible and adaptable, this part of the challenge is insignificant compared with ensuring the right fuel is ready, as well as the required supporting infrastructure on land. Therefore, the bulk of the technology challenge is in land infrastructure and in the energy sector.

These uncertainties play into viewing technology readiness from a flexibility perspective to ensure resilience should something effect the supply chain.

6.3. Community readiness.

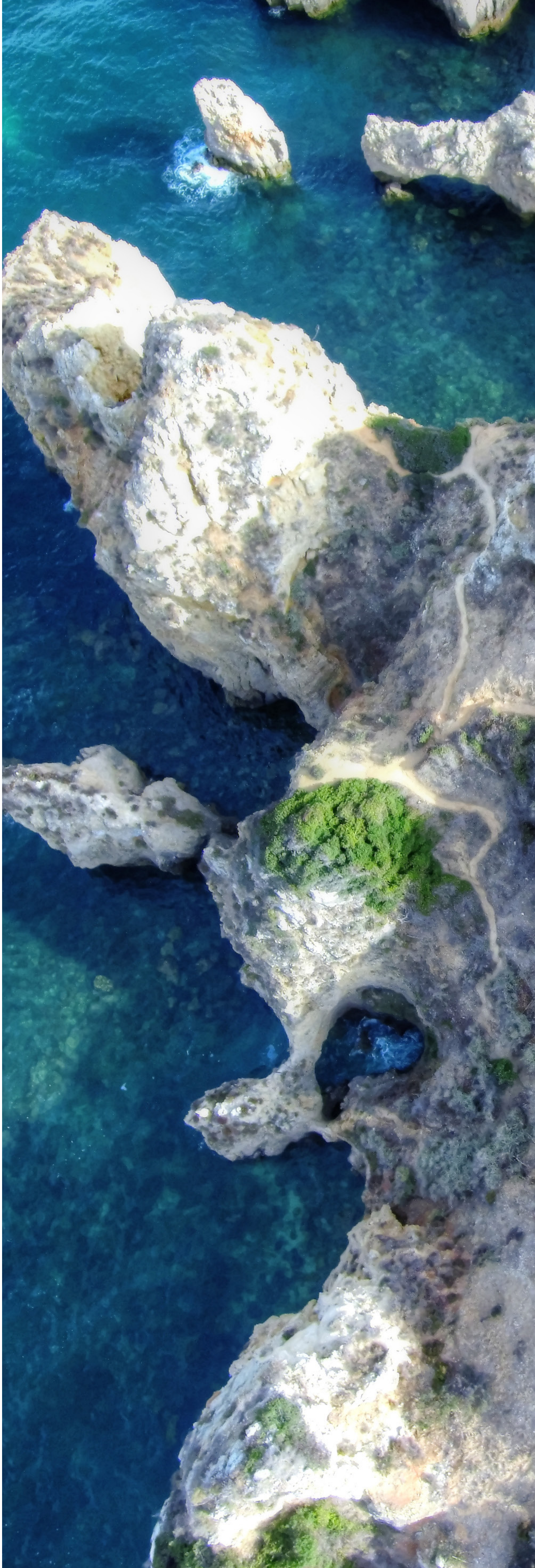
In addition to investment and technology readiness, community readiness is an important driver of change – what may be ready from an investment and technology perspective may not be ready from other stakeholders' perspectives. Future fuels will be expected to meet not only GHG emission criteria, but also other air pollutant standards (e.g. NOx and particulates) as well as contribute to broader sustainability criteria at regional and national levels. These broader criteria will increase acceptability to stakeholders as potential options for maritime applications given that they will neither have unintended impacts on local air quality, nor shift the problem to an increase in upstream emissions.

Another key aspect in the transition will be the development and implementation of strong international policy and regulations, although this has not been specifically covered in this paper. Irrespective of the price uncertainties, the market will not drive the transition to zero as the price spread across the different fuels is too large.

The choices made in the next decade will be critical. This action relies on understanding the dynamics and interactions between technology, investment and community readiness within the wider range of ship types, sizes and operational profiles. Decarbonising the shipping sector requires substantial and collaborative effort across maritime and energy stakeholders and beyond into the wider system.

Although certain pathways look more resilient than others from the perspective of asset longevity, fuel price is the predominant factor that impacts the TCO. Any biofuel pathway appears uncompetitive in the long term and prone to restrictions or higher prices resulting from supply constraints and does not necessarily lead to more resilient options such as hydrogen or ammonia derived from NG or renewable electricity. In anticipation of the impacts of the evolution of the global energy demands and the associated uncertainty of biofuels being available at competitive prices, the most resilient options of a fuel that can be produced from NG or renewable electricity may offer commercial advantages that are not seen in the very short term. In order to have clean hydrogen, other production processes need to come into play. SMR and CCS is a potential solution; however, it would not ensure 100% of CO_2 emissions are captured, whereas a production through the electrolyser using only renewable electricity would have the potential to have virtually zero CO_2 emissions associated.

Looking into how the energy landscape is evolving in other sectors, we should draw similarities and understand how we can work together to meet one goal. Actions may include policy development, investing in innovation, undertaking research and development, energy efficiency and change in consumer behaviour.



Acronyms and definitions.

Biofuel - Types of fuels derived from biomass feedstock

BTU LHV - British thermal unit lower heating value

Capex - Capital expenditure

CCS - Carbon capture and storage

CO_2 - Carbon dioxide

CVpa - Cost of voyage per year calculated as fuel consumption per year multiplied by the fuel price of that year

DAC - Direct air capture is a process of capturing carbon dioxide directly from the ambient air and generating a concentrated stream of CO_2 for sequestration or utilisation

DWT - Deadweight tonnage

EARTO - European Association of Research and Technology Organisations

ECA - Emission control area

E-fuel (electro fuels) - Fuels produced from renewable electricity

E-hydrocarbons - e-LNG, e-methanol, e-diesel

EU - European Union

Fossil-based fuel - Fuels formed by natural processes, such as anaerobic decomposition of buried dead organisms

FC - Fuel cell

GHG - Greenhouse gas

GJ - Gigajoule

HFO - Heavy fuel oil

H_2 - Hydrogen

ICAO - International Civil Aviation Organization

ICE - Internal combustion engine

IGF - IMO's International Code of Safety for Ships using Gas or other Low-flashpoint Fuels

IMO - International Maritime Organization

ISO - International Organization for Standardization

kg - Kilogram

Acronyms and definitions cont.

kW - Kilowatt

Knot - A unit of speed equal to one nautical mile per hour

LCP - Levelised cost of production

LR - Lloyd's Register

LNG - Liquefied natural gas

LSHFO - Low sulphur heavy fuel oil

MDO - Marine diesel oil

MeOH - Methanol

N_2 - Nitrogen

NG - Natural gas

NG with CCS-fuels - Fuels produced from natural gas with carbon capture and storage

NGO - Non-governmental organisation

NH_3 - Ammonia

NOx - Nitrogen oxides

Paris Agreement - An agreement within the United Nations Framework Convention on Climate Change, dealing with greenhouse-gas-emissions mitigation, adaptation and finance, signed in 2016

PEM - Proton Exchange Membrane

R&D - Research and development

SAF - Sustainable aviation fuel

SFOC - Specific fuel oil consumption

SMR - Steam methane reformer is the technology for hydrogen production from natural gas

TCO - Total cost of operation which is the sum of the additional costs relative to the reference ship

TJ - Terajoule

TRL - Technology readiness level

UMAS - University Maritime Advisory Services

$ - United States Dollars

ZEV - Zero-emission vessel

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Appendix A: ZEVs considered in this paper.

No	Reference ships
1	Bio-diesel ICE
2	Bio-methanol wood ICE
3	Bio-methanol waste ICE
4	Bio-LNG ICE
5	Bio-methanol wood FC
6	Bio-methanol waste FC
7	Bio-LNG FC
8	E-diesel ICE
9	E-methanol ICE
10	E-LNG ICE
11	E-ammonia ICE
12	E-hydrogen ICE
13	E-methanol FC
14	E-LNG FC
15	E-ammonia FC
16	E-hydrogen FC
17	NG-ammonia ICE
18	NG-hydrogen ICE
19	NG-ammonia FC
20	NG-hydrogen FC
21	Batteries

Appendix B: Assumptions.

We made some assumptions for fuel price projections and the values are provided in this appendix.

For e-fuels and NG-fuels, we looked at their potential supply pathways and estimated the levelised cost of production over time, which is used as proxy for fuel prices.

In addition to the future prices of LSHFO, the price projections of several zero-carbon fuels have been estimated as detailed in this appendix. They are distinguished as biofuels, e-fuels and NG with CCS-derived fuels.

The renewable electricity price and natural gas projections provided in Section B1 are used to estimate the levelised cost of production projections of several zero-carbon fuels. The levelised cost of production is used as a proxy of future fuel price projections; Section B2 provides the underlying assumptions of these estimates (including the cost assumptions of key technologies such as CCS, DAC and electrolyser) as well as the biofuel price projections and conventional marine fuels projections. Section B3 provides the assumption on carbon prices, while from Sections B4 to B8, several input assumptions are reported, including assumed fuel emissions factors, fuel densities, onboard technology costs, and ships' technical and operational specifications. These do not change across scenarios.

B1 Scenarios.

The scenarios are detailed in Table 2 in Section 3.1.

B2 Energy price projections.

B2.1 Renewable electricity price projections.

Renewable electricity price projections are derived from the IRENA 2017 Power Costs Study [31]. Upper and lower cases are assumed to linearly decrease, as described in Table B1 below.

Description	Unit	2020	2030	2040	2050
Upper case	$/kWh	0.1	0.083	0.066	0.05
Lower case	$/kWh	0.05	0.04	0.03	0.02

Table B1 – Assumed renewable electricity prices.

B2.2 Natural gas price projections.

The assumptions on natural gas price projections are provided below in Table B2 and were derived from World Bank and IEA 2016[1].

Description	Unit	2020	2030	2040	2050
Upper case	$/MWh	41	41	41	41
Lower case	$/MWh	17	17	17	17

Table B2 – Assumed natural gas prices.

[1] Atradius Economic Research Gas Prices Jan_2017 https://group.atradius.com/publications/gas-price-update-2017.html

B3 Fuel price projections.

Table B3 summarises the fuel price projections for each fuel considered in this paper.

Fuel price projections									
		Lower bound				Upper bound			
		$/GJ				$/GJ			
Primary energy source	**Fuel**	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Oil	LSHFO	8	11	11	11	8	11	11	11
Biomass	Bio-diesel	22	24	27	29	25	49	74	98
Biomass	Bio-methanol wood	23	25	27	30	24	48	72	96
Biomass	Bio-methanol waste stream	19	21	23	25	20	40	61	81
Substitution price for biofuels		9	19	26	33				
Renewable electricity	E-diesel	130	114	99	83	208	182	156	130
Renewable electricity	E-methanol	84	73	63	52	136	118	101	83
Renewable electricity	E-LNG	69	60	51	42	113	98	84	69
Renewable electricity	E-ammonia	55	47	39	30	96	82	68	55
Renewable electricity	E-hydrogen	52	44	36	28	92	79	65	52
Natural gas	NG-ammonia	28	26	24	23	46	43	40	38
Natural gas	NG-hydrogen	25	23	21	19	44	40	37	34

Table B3 – Assumed fuel prices.

B3.1 Hydrogen.

Hydrogen is a key ingredient for a number of zero-carbon fuels. Two different pathways are assumed to produce hydrogen, as shown in Figure B1. The first pathway uses the electrolysis of water using renewable electricity; the second pathway uses the steam methane reforming with carbon capture and storage (SMR & CCS).

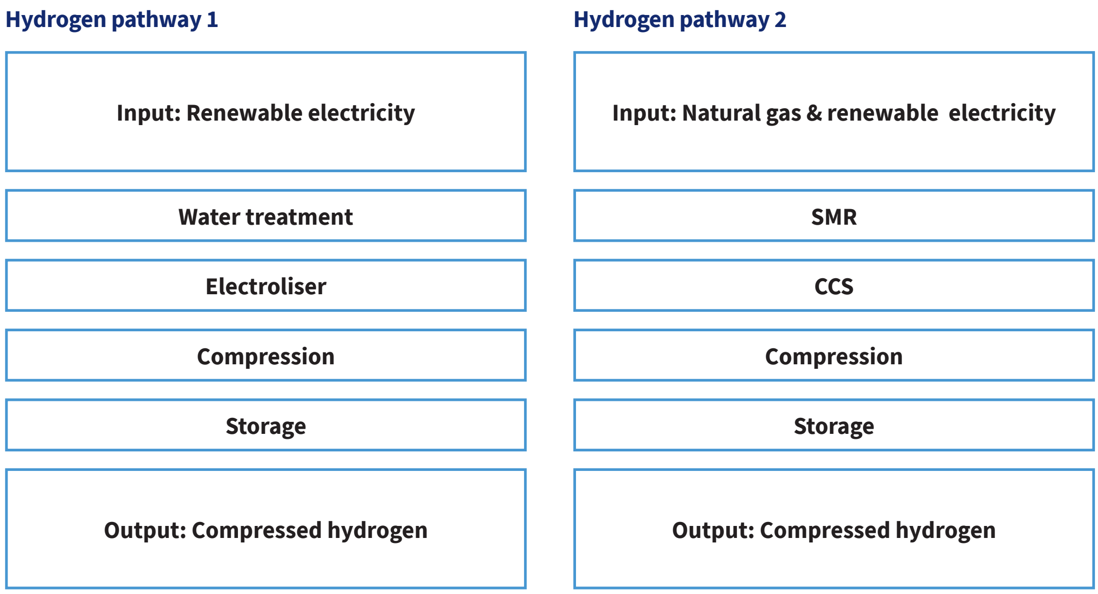

Figure B1 – Hydrogen pathway diagram.

Assumptions were also made for the hydrogen production plant[2], as provided in Table B4 below.

Hydrogen plant assumptions	Unit	Value
Availability	%	90%
Utilisation rate	%	80%
Annual production	tonne/yr	360,000
Days active	days	292
Daily production	tonne/day	1,233
Plant capacity	tonne/yr	500,000

Table B4 – Hydrogen production plant assumptions.

The interest rate is assumed constant at 10%. Other indirect costs include local taxes equal to 3% of annual capex and insurance equal to 1% of annual capex. The detailed assumptions for each component for both pathways are provided in Tables B5 and B6.

[2] It is assumed in this study that the capacity of all liquefaction plants is at a constant, large centralised production-level scale. Decentralised smaller liquefaction and storage plant would have increased costs due to smaller scale infrastructure

Hydrogen pathway 1 (renewable electricity)	2020	2030	2040	2050
Water treatment				
Capital costs ($/m^3)	2.6314	2.6314	2.6314	2.6314
Operational costs (% of capex)	4.3%	4.3%	4.3%	4.3%
Efficiency (%)	45%	45%	45%	45%
Energy requirement (kWh/m^3)	3	3	3	3
Lifetime (year)	30	30	30	30
Electrolysers				
Capital costs ($/kWe)	472	472	472	472
Operational costs (% of capex)	3%	3%	3%	3%
Efficiency (%)	0.7	0.7	0.7	0.7
Energy requirement (kWh/kg)	56	56	56	56
Lifetime (year)	10.7	10.7	10.7	10.7
Operating hours	75,000	75,000	75,000	75,000
Compression				
Capital costs ($/kg)	0.965	0.965	0.965	0.965
Operational costs (% of capex)	3%	3%	3%	3%
Efficiency (%)	94%	94%	94%	94%
Energy requirement (kWh/kg)	2.85	2.85	2.85	2.85
Storage				
Capital costs ($/kWh)	0.02	0.02	0.02	0.02
Operational costs (% of capex)	3%	3%	3%	3%

Table B5 – Detailed assumptions for hydrogen pathway 1.

Hydrogen pathway 2 (SMR & CCS)	2020	2030	2040	2050
Steam methane reforming				
Capital costs ($/kg H_2)	2.10	2.10	2.10	2.10
Operational costs (% of capex)	4.3%	4.3%	4.3%	4.3%
Electricity requirement (kWh/kg H_2)	8	8	8	8
NG consumption (million BTU NG/kg H_2)	0.165	0.165	0.165	0.165
Efficiency (%)	72%	72%	72%	72%
Compression				
Capital costs ($/kg)	0.965	0.965	0.965	0.965
Operational costs (% of capex)	3%	3%	3%	3%
Efficiency (%)	94%	94%	94%	94%
Energy requirement (kWh/kg)	2.85	2.85	2.85	2.85
Storage				
Capital costs ($/kWh)	0.02	0.02	0.02	0.02
Operational costs (% of capex)	3%	3%	3%	3%

Table B6 – Detailed assumptions for hydrogen pathway 2.

B3.2 Liquid hydrogen.

Liquid hydrogen is assumed to be used on board ships, therefore the levelised cost of production is estimated for liquid hydrogen. This means that compressed hydrogen from both hydrogen production pathways is liquified and stored at bunkering ports. Figure B2 provides the schematic representation of the pathways; Table B7 provides the detailed assumptions as well as the resulting levelised cost of production (LCP) under the upper and lower cases.

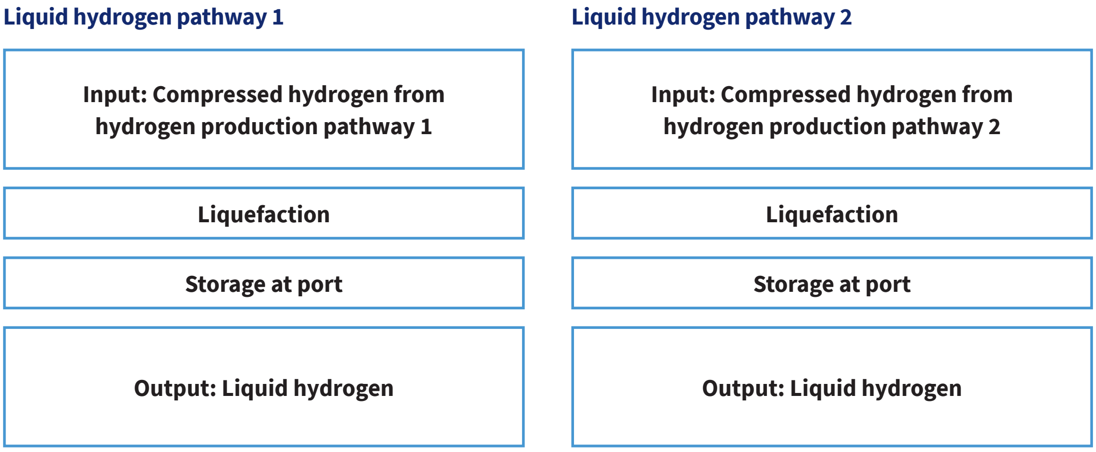

Figure B2 – Liquid hydrogen pathway diagram.

Liquid hydrogen pathway		2020	2030	2040	2050
Liquefaction					
Capital costs ($/kg H_2)		0.94	0.94	0.94	0.94
Operational costs (% of capex)		5%	5%	5%	5%
Electricity requirement (kWh/kg H_2)		10.18	10.18	10.18	10.18
Efficiency (%)		77%	77%	77%	77%
Liquid storage at port and dispensing					
Capital costs ($/kg H_2)		18	18	18	18
Operational costs (% of capex)		5%	5%	5%	5%
Energy requirement (% boil off per day)		0.1	0.1	0.1	0.1
LCP pathway 1					
Upper case	$/GJ	92.0	78.7	65.3	52.0
Lower case	$/GJ	52.0	44.0	36.0	28.0
LCP pathway 2					
Upper case	$/GJ	44.4	40.4	37.0	33.6
Lower case	$/GJ	25.4	22.9	20.8	18.8

Table B7 – Detailed pathway assumptions for liquid hydrogen.

B3.3 Ammonia.

Hydrogen from either of the two pathways described previously can be used to manufacture liquid ammonia through the Haber-Bosch process. Figure B3 and Tables B8 and B9 below outline the main assumptions of these processes.

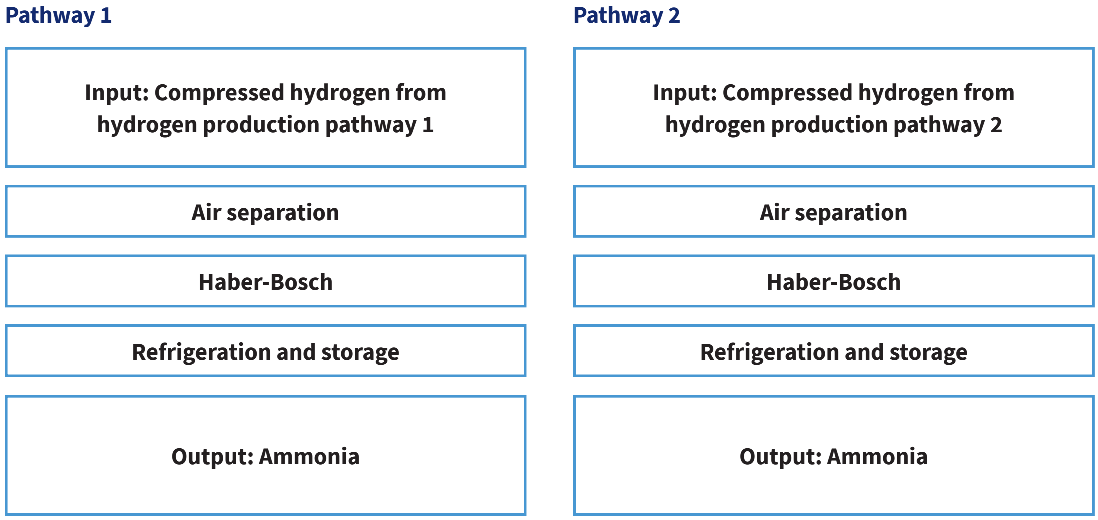

Figure B3 – Ammonia pathway diagram.

Ammonia plant assumptions	Unit	Value
Hydrogen to ammonia	kg NH_3/kg H_2	5.632
Hydrogen to nitrogen	kg N_2/kg H_2	4.632
Annual production of ammonia	tonne/yr	2,027,500
Annual production of nitrogen	tonne/yr	1,667,500
Daily ammonia production	tonne/day	6,943

Table B8 – Ammonia plant assumptions.

Ammonia pathway		2020	2030	2040	2050
Air separation					
Capital costs ($/kg N_2)		0.16	0.16	0.16	0.16
Operational costs (% of capex)		4%	4%	4%	4%
Efficiency (%)		71.25%	71.25%	71.25%	71.25%
Electricity requirement (kWh/kg N_2)		0.108	0.108	0.108	0.108
Haber-Bosch					
Capital costs ($/kg NH_3)		0.51	0.51	0.51	0.51
Operational costs (% of capex)		2%	2%	2%	2%
Efficiency (%)		78%	78%	78%	78%
Energy requirement (kWh/kg NH_3)		0.44	0.44	0.44	0.44
Energy density (kWh/kg NH_3)		5.22	5.22	5.22	5.22
Refrigeration and storage					
Capital costs ($/kg ammonia)		1.06	1.06	1.06	1.06
Operational costs (% of capex)		3%	3%	3%	3%
Efficiency (%)		85%	85%	85%	85%
Energy requirement (kWh/kg/NH_3)		0.0378	0.0378	0.0378	0.0378
% boil off per day		0.1%	0.1%	0.1%	0.1%
LCP pathway 1					
Upper case	$/GJ	96.0	82.0	68.0	55.0
Lower case	$/GJ	55.0	47.0	39.0	30.0
LCP pathway 2					
Upper case	$/GJ	46.0	43.0	40.0	38.0
Lower case	$/GJ	28.0	26.0	24.0	23.0

Table B9 – Detailed pathway assumptions for ammonia.

B3.4 Synthetic methanol.

Methanol (MeOH) can also be manufactured through chemical synthesis using CO_2 harvested from the atmosphere alongside hydrogen produced through renewable electricity. Note that the pathway below described in Figure B4 assumes that CO_2 has been sequestered directly from the air.

Pathway 1

Input: Compressed hydrogen from hydrogen production pathway 1

Direct air capture

MeOH synthesis

Storage

Output: Synthetic methanol

Figure B4 – Synthetic methanol pathway diagram.

Synthetic methanol plant assumptions	Unit	Value
Hydrogen and methanol ratio	kg MeOH/kg H_2	5.000
Hydrogen and CO_2 ratio	kg CO_2/kg H_2	7.300
Annual production of methanol	tonne/yr	1,800,000
Annual production of CO_2	tonne/yr	2,628,000
Daily methanol production	tonne/day	6,164

Table B10 - Synthetic methanol plant assumptions.

Synthetic methanol pathway		2020	2030	2040	2050
Carbon capture (DAC)					
Capital costs ($/kg CO_2)		1.50	1.50	1.50	1.50
Operational costs (% of capex)		4%	4%	4%	4%
Energy requirement (kWh/kg CO_2)		2.631	2.631	2.631	2.631
MeOH synthesis					
Capital costs ($/kW)		857	857	857	857
Operational costs (% of capex)		4%	4%	4%	4%
Efficiency (%)		80%	80%	80%	80%
Energy requirement (kWh/kg/MeOH)		0.216	0.216	0.216	0.216
Energy density (kWh/kg)		5.53	5.53	5.53	5.53
Storage					
Capital costs ($/kg)		0.14	0.14	0.14	0.14
Operational costs (% of capex)		3%	3%	3%	3%
LCP pathway 1					
Upper case	$/GJ	135.8	117.9	100.6	83.3
Lower case	$/GJ	84.0	72.9	62.5	52.2

Table B11 – Detailed pathway assumptions for synthetic methanol.

B3.5 Synthetic diesel (e-diesel).

Likewise, a range of fossil fuels can also be synthesised artificially using CO_2 as feedstock, as well as hydrogen manufactured from renewable electricity. This process is described in Figure B5 below.

Pathway 1

Input: Compressed hydrogen from hydrogen production pathway 1

Direct air capture

Diesel synthesis

Storage

Output: Synthetic diesel

Figure B5 – Synthetic diesel pathway diagram.

Synthetic diesel plant assumptions	Unit	Value
Hydrogen to diesel ratio	kg Diesel/kg H_2	1.554
Hydrogen to CO_2 ratio	kg CO_2/kg H_2	7.406
Hydrogen to kerosene ratio	kg KER/kg H_2	0.282
Hydrogen to naptha ratio	kg NAP/kg H_2	0.311
Annual production of diesel	tonne/yr	559,441
Annual production of carbon dioxide	tonne/yr	2,666,282
Annual production of kerosene	tonne/yr	101,555
Annual production of naptha	tonne/yr	111,788
Daily diesel production	tonne/day	1,916

Table B12 – Synthetic diesel plan assumptions.

Synthetic diesel pathway		2020	2030	2040	2050
Carbon capture (DAC)					
Capital costs ($/kg CO_2)		1.50	1.50	1.50	1.50
Operational costs (% of capex)		4%	4%	4%	4%
Energy requirement (kWh/kg CO_2)		2.631	2.631	2.631	2.631
Diesel synthesis					
Capital costs ($/kW)					
Diesel ($/kg)		1.80	1.80	1.80	1.80
Kerosene ($/kg)		0.05	0.05	0.05	0.05
Naptha ($/kg)		0.06	0.06	0.06	0.06
Operational costs (% of capex)		3%	3%	3%	3%
Efficiency (%)		58%	58%	58%	58%
Energy requirement (kWh/kg)		0.258	0.258	0.258	0.258
Energy density (kWh/kg)					
Diesel		11.84	11.84	11.84	11.84
Kerosene		11.94	11.94	11.94	11.94
Naptha		13.36	13.36	13.36	13.36
Storage					
Capital costs ($/kg)		0.31	0.31	0.31	0.31
Operational costs (% of capex)		3%	3%	3%	3%
LCP pathway 1					
Upper case	$/GJ	207.7	181.8	155.8	129.9
Lower case	$/GJ	129.9	114.4	98.8	83.3

Table B13 – Detailed pathway assumptions for synthetic diesel.

B3.6 Synthetic LNG (e-LNG).

Unlike the previous two pathways, the synthesis of LNG requires an additional liquefaction process, as illustrated below in Figure B6.

Pathway 1

Input: Compressed hydrogen from hydrogen production pathway 1

Direct air capture

Methanation

Methane liquefaction

Storage

Output: Synthetic LNG

Figure B6 – Synthetic LNG pathway diagram.

Synthetic methane plant assumptions	Unit	Value
Hydrogen to methane ratio	kg CH_4/kg H_2	1.990
Hydrogen to CO_2 ratio	kg CO_2/kg H_2	7.261
Annual production of methane	tonne/yr	715,099
Annual production of CO_2	tonne/yr	1,960,841
Daily methane production	tonne/day	2,453

Table B14 – Synthetic LNG plant assumptions.

Synthetic LNG pathway		2020	2030	2040	2050
Carbon capture (DAC)					
Capital costs ($/kg CO_2)		1.50	1.50	1.50	1.50
Operational costs (% of capex)		4%	4%	4%	4%
Energy requirement (kWh/kg CO_2)		2.631	2.631	2.631	2.631
Methanation					
Capital costs ($/kW)		300	300	300	300
Operational costs (% of capex)		2%	2%	2%	2%
Efficiency (%)		78%	78%	78%	78%
Energy requirement (kWh/kg)		0.299	0.299	0.299	0.299
Energy density (kWh/kg)		15.3	15.3	15.3	15.3
Liquefaction					
Capital costs ($/kg)		0.85	0.85	0.85	0.85
Operational costs (% of capex)		2%	2%	2%	2%
Efficiency (%)		77%	77%	77%	77%
Storage					
Capital costs ($/kg)		0.50	0.50	0.50	0.50
Operational costs (% of capex)		2%	2%	2%	2%
LCP pathway 1					
Upper case	$/GJ	113.4	98.5	83.5	68.6
Lower case	$/GJ	68.6	59.7	50.7	41.8

Table B15 – Detailed pathway assumptions for synthetic LNG.

B3.7 Cost assumptions of key technologies.

This section provides the cost assumptions of key technologies for the supply of the fuels considered in this analysis.

B3.7.1 Steam Methane Reformer (SMR) with Carbon Capture and Storage (CCS).

SMR is a mature technology with a wide range of reported prices for construction in 2020 [1 – 11]. However, there is very little evidence in the literature suggesting how these prices may change beyond 2020. We have therefore used the mean of the reported costs. These costs are assumed constant to 2050, justified by the maturity of the technology and the scale at which it is currently deployed [12 – 16]. Table B16 provides the capital costs for SMR plants in combination with the costs of the accompanying CCS processing facilities.

The overall CCS cost is assumed to be 50 \$/tonne CO_2. On top of this cost there is an assumed cost of transportation of 10 \$/tonne CO_2 and storage cost of 10 \$/tonne CO_2 taken from Fasihi et al (2019).

Unit	2020	2030	2040	2050
\$/kg H_2	2.10	2.10	2.10	2.10

Table B16 – Assumed capex of SMR.

B3.7.2 Direct air capture (DAC).

Broehm (2015) points out that estimates for the energy needs of DAC processes are a point of contention. While the process of separating CO_2 from ambient air is calculated to require very little energy theoretically, these energy requirements in practice become much higher. The author discusses the theoretical minimum energy requirement. However, he declares that the theoretical energy needs do not determine DAC's success; it is the practical amount and, most critically, the source of this energy that influence this. With the lack of an actual, operating, full-scale system to study, a number of studies have attempted to quantify these values through thermodynamic calculations, comparisons with similar existing systems, informed estimations, and the construction of prototype systems and system parts. The author selected a number of publications with the “best attempt to select scientifically credible sources that analyse DAC systems specifically”.

Broehm (2015) also provides a table (see Table B17) broken down into electrical and thermal energy (first and second rows of each source respectively), and into use by three different parts of the process: the contactor, regeneration, and compression. At the bottom of the table are the ranges for secondary electrical and thermal energy selected.

Broehm (2015) states that most of the systems operate with high heats of over 800°C, which is high quality heat energy that is not usually obtained as secondary heat from another process.

Finally, Broehm (2015) declares that most of the systems reviewed require energy at scales of around 10 GJ/tCO_2 total without energy conversion from primary energy efficiencies of real-world energy systems considered.

Source	Contactor	Regeneration	Compression (max temp. of process)	Total
(Baciocchi et al., 2006)	0.69 GJ/tCO_2	0.53-0.74 GJ/tCO_2	0.36-0.42 GJ/tCO_2	1.58-1.79GJ/tCO_2
		6.04-8.8 GJ/tCO_2	900-1000 °C	6.04-8.8 GJ/tCO_2
(Stolaroff, 2006)	0.6-1.3 GJ/tCO_2	0.12-0.4 GJ/tCO_2	0.4 GJ/tCO_2	1.12-2.1 GJ/tCO_2
		8-11 GJ/tCO_2		8-11 GJ/tCO_2
(Keith et al., 2006)	0.27-0.33 GJ/tCO_2	0 GJ/tCO_2	0.44 GJ/tCO_2	0.71-0.77 GJ/tCO_2
		10.9 GJ/ tCO_2		10.9 GJ/tCO_2
(Stolaroff et al., 2008)	1.73 GJ/ tCO_2			
(Zeman, 2007)	0-2 GJ/ tCO_2	0.36 GJ/ tCO_2	0.43 GJ/ tCO_2	2.79 GJ/ tCO_2
		3.58-7.25 GJ/ tCO_2	900 °C	3.58-7.25 GJ/ tCO_2
(Mahmoundkhani et al., 2009)	0.68 GJ/ tCO_2			
			800 °C	
(Lackner, 2009)				1.14 GJ/ tCO_2
(Socolow et al., 2011)	0.70 GJ/ tCO_2	0.66 GJ/ tCO_2	0.42 GJ/ tCO_2	1.78 GJ/ tCO_2
		6.1 GJ/ tCO_2	900 °C	8.1 GJ/ tCO_2
(Holmes et al, 2013)	< 0.69 GJ/ tCO_2			
(Veselovskaya et al, 2013)				
		7.3 GJ/ tCO_2	150-300 °C	
Average: (lower & single & upper values)	0.82 GJ/ tCO_2	0.41 GJ/ tCO_2 7.67 GJ/ tCO_2	0.41 GJ/ tCO_2	
Ranges as described in text		Electrical Range	Lower Middle Upper	1.1 GJ/ tCO_2 1.5 GJ/ tCO_2 1.9 GJ/ tCO_2
		Thermal Range	Lower Middle Upper	6 GJ/ tCO_2 8 GJ/ tCO_2 10 GJ/ tCO_2

Table B17 – Energy values from literature broken down by portion of process and energy type.

Key: White + Blank = No value reported by source; White + Value = Energy value; Grey = Electrical energy value; Dark Grey = Thermal energy value. Source: Taken directly from Broehm (2015).

More recent studies have also been considered, in particular Fasihi [17], which provides a similar range of 5.5 to 10 GJ/tCO_2, which is equal to 1.5 to 2.7 kWh/tCO_2. The assumption taken in this study of 2.6 kWh/tCO_2 appears to be within the range found in the literature.

A wide range of capital cost figures can be found in the literature for DAC [17 – 23]; this study takes the capital cost proposed in Fasihi et al. (2019), a figure on the more conservative end compared to other studies. Where specified, prices of high-temperature DAC systems with a predominantly electric-powered heating capability have been selected [17, 18].

Unit	2020	2030	2040	2050
$/kg CO_2	1.5	1.5	1.5	1.5

Table B18 – Assumed capex of DAC.

B3.7.3 Electrolyser.

For simplicity, it is assumed that electrolysers continue to use Alkaline Electrolysis Cell (AEC) technology, a very mature technique whose price will likely remain stable [30]. Prices are taken from [27] and are on the competitive end of prices cited in supporting studies [1, 7, 24 – 30].

Unit	2020	2030	2040	2050
$/kWe	472	472	472	472

Table B19 – Assumed capex of electrolyser.

B3.8 Biofuels fuel price projections.

Marine biofuels fuel price projections are uncertain and current literature is poor. The approach of calculating the levelised cost of production and using it as proxy of future fuel prices (as applied for the other fuels) is not appropriate for biofuels because it does not take into account the supply constraint on bioenergy. The supply/demand balance for these fuels implies that growth in demand for bioenergy could push the supply to its limit and therefore cause a significant increase in price.

We failed to find any evidence that biofuels prices will decrease in the future. The consensus mirrors what was said in SCAB (2017) report [32], stating that biofuels (with some rare exceptions) will remain more expensive than fossil fuels in almost all cases.

The report by IRENA [33] provides evidence of a potential decrease in costs of production but it does not take into account any elements on bioenergy supply constraint or future competition among different sectors. For this reason, it cannot be considered a reliable source of data for this analysis.

The approach taken in this analysis uses the averages of the current estimates of costs of production from existing studies; the range found for each fuel is used as a starting point in 2020 for the upper and lower bounds.

To identify the lower bound up to 2050 (upper scenario), a first guess was made assuming prices will increase by 0.5% every year, in line with current literature describing how each biofuel price may change in the future due to future availability as well as due to the future feedstock and fuel competition with other sectors. We then overlaid the potential cost of substitution (as opposed to the cost of production) to the estimated biofuel prices. The cost of substitution is estimated as the LSHFO with an assumed carbon price ($/tonne 101, 194, 288 respectively in 2030, 2040, 2050) taken from a UK government report authored by the department for Business, Energy and Industrial Strategy (BEIS) in December 2017.

As detailed in Table B3, the estimated cost of substitution is generally in line with the first guess of 0.5% annual increase. In 2020, the estimated cost of production is higher than the cost of substitution, whereas from 2030 onwards they are of the same order of magnitude. Where the cost of production is lower than the cost of substitution, we have used the cost of substitution.

The upper bound for these fuels is theoretically infinite (except algal) because of the supply/demand balance and bioenergy availability issues. For illustrative purpose only, a first guess of higher biofuels prices was estimated assuming they will be four times higher than their values in the baseline year. Table B3 also details the biofuel price projections for high-price and low-price scenarios.

B3.9 Conventional marine fuel price projections.

The historical relationship between the price of LSHFO and MDO fuels and the crude oil price was estimated; starting from the current average prices of these fuels, they were projected up to 2050 using the BEIS oil price projection published in December 2017 and the identified historical relationship. The resulting prices are also shown in Table B3.

B4 Carbon prices.

Carbon price, when used, is assumed to be 101, 194 and 288 $/tonne respectively in 2030, 2040 and 2050 [54].

B5 Fuel emissions factors.

Figure 9 from Section 5.1 illustrates the emissions factors assumed for the upstream and operational processes of each fuel considered in this study. Reference figures are taken from [36 – 40].

B6 Fuel densities.

Table B20 outlines the pertinent physical and chemical properties of each fuel considered in this study.

ID	Name	MJ/tonne	kg/m³	Note
1	**LSHFO**	40,500	991	
2	**MDO**	42,624	837	
3	**Bio-diesel oil crops**	39,333	859	
4	**Methanol**	19,908	789	
5	**Synthetic LNG**	55,000	428	
6	**Ammonia**	18,800	603	Compressed liquid, 25 temp, 1,030 pressure
7	**Hydrogen**	119,988	71	Compressed liquid, -253 temp, 102 pressure

Table B20 – Fuel densities.

B7 On board technology costs.

Tables B21 and B22 provide the assumed costs of on board technologies on a per-kW basis, extrapolated to 2050.

Description	Unit	2020	2030	2040	2050
2 stroke diesel engine (ICE)	$/kW	400	400	400	400
Gas injection engine. ME-GI, XFD	$/kW	590	590	590	590
Liquid gas/low flash injection engine ME-LGI	$/kW	590	590	590	590
Fuel Cells (PEM)	$/kW	1,500	1,500	1,500	1,500
Electric motor	$/kW	116	116	116	116
Reformer	$/kW	300	300	300	300
Gasificator	$/kW	100	100	100	100
4 stroke auxiliary engine	$/kW	250	250	250	250

Table B21 – Engine capex costs.

Description	Unit	2020	2030	2040	2050
LNG tank IMO Type C	$/kg	7.14	7.14	7.14	7.14
Ammonia storage IMO Type B	$/kg	0.7	0.7	0.7	0.7
Liquid hydrogen tank IMO Type A	$/kg	56	56	56	56
Batteries	$/kWh	177	177	177	177

Table B22 – Engine storage capex costs.

B8 Ship technical and operational specifications.

Table B23 provides the detailed technical, operational and economic specifications of the archetypal case study ship used in this study.

Ship type	Bulk carrier
Size category	**60,000 – 99,999**
Capacity (DWT)	81,911
Average capacity (DWT) fleet 2016	76,869
Power main engine (kW)	10,840
Power auxiliary engine (kW)	542
Design speed (kts)	14.30
Design engine load	0.8
SFOC main engine (gm/kWh)	178
SFOC auxiliary engine (gm/kWh)	225
Boiler year (t/y)	236
Fuel type in ECA	MDO
Total bunker capacity reference ship HFO (m^3)	2,760
Days active per year (operational)	355
Days spent at port per year	125
Days spent at port per nautical mile	0.0023
Utilisation rate	0.9
% Time spent in ECA	0.2
Laden / Ballast ratio	0.6
Days at sea per year	230
Operational speed (kts)	12.8
Operational main engine load (laden)	0.7
Operational main engine load (ballast)	0.7
Operational auxiliary engine load (laden)	0.8
Operational auxiliary engine load (ballast)	0.8
Ship density (cap/m^3)	0.8

Table B23 – Ship technical, operational, and economic parameters.

B9 References in Appendix B.

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