H2SHIPS

System-Based Solutions for H2-Fuelled Water Transport in North-West Europe

Comparative report on alternative fuels for ship propulsion

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List of Abbreviations

AF	Application Form
CM	Communication Manager

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DAC	Direct Air Capture
DWT	Dead Weight Tonnage
FC	Fuel Cell
FCEV	Fuel Cell Electric Vehicle
FM	Financial Manager
FLC	First Level Control
GHG	Green House Gas
GT	Gross Tonnage
HHV	Higher Heating Value
ICE	Internal Combustion Engine
IMO	International Maritime Organisation
JS	Joint Secretariat
LHV	Lower Heating Value
LOHC	Liquid Organic Hydrogen Carrier
LP	Lead Partner
MGO	Marine Gas Oil
NWE	North West Europe
PA	Partnership Agreement
PP	(Full) Project Partners)
SMR	Steam Methane Reforming
TRL	Technology Readiness Level
TTW	Tank-To-Wheel
VLBC	Very Large Bulk Carrier
VLCC	Very Large Crude Carrier
WP	Work Package
WTW	Well-to-Wheels (or Well-to-Wake)
ZEV	Zero Emission Vehicle (Vessel)

1 Executive Summary

The total cost of ownership analysis done separately for 34 different ship types has demonstrated that the most promising options for decarbonisation of regional shipping, using hydrogen as a fuel are:

- **Compressed hydrogen with PEM FC** for relatively small ships with an operational profile that allows for frequent refuelling, limiting the required amount of fuel that needs to be stored onboard, or for larger ships but ones which can more easily accommodate the extra volume of fuel needed.
- **Liquefied hydrogen with PEM FC** for ships with more energy storage requirements, where storing energy in the form of compressed hydrogen is not viable (even if the fuel itself is cheaper).

Furthermore, the sensitivity analysis shows that even a significant change in hydrogen production costs does not make any of the synthetic fuel options a more viable decarbonisation pathway for regional shipping.

The results of this study show that, for the following value chain analysis, should focus primarily on the compressed and liquified hydrogen value chains.

2 Introduction

The following paper contains a techno-economic analysis of various shipping business models relevant for the North-West Europe (NWE) area.

The analysis is made on the basis of total cost of ownership comparison and covers all relevant types of vessels - from inland ships, through vessels operating within port areas like tugs and pushers, to sea-going vessels used exclusively for short sea application e.g. ferries, ro-ro ships, general cargo ships and small containerships.

Because the project is focusing exclusively on the NWE area, the analysis doesn’t include ships used in deep sea shipping applications – as introduction of alternative fuels to those ships would require a coordinated international effort and cannot be achieved by any region alone. Among others the ships excluded from this analysis are cruise ships and all types of ships used mostly on intercontinental voyages, e.g. VLCCs, VLBCs and large containerships.

The purpose of this analysis is to assess the long-term viability of various hydrogen-based solutions for the full decarbonization of NWE shipping. More specifically, the goal was to see what role can hydrogen technologies and hydrogen itself play in reducing the GHG footprint of shipping in the NEW region, which solutions work best for which ship types and applications and what are the techno-economic barriers for a wide adoption of hydrogen as marine fuel.

As a next step the results of this analysis will feed future work planned in the H2SHIPS Project, related with identification of key stakeholders and the value chain analysis.

Given the stated purpose, the analysis has a forward-looking outlook, not only assessing options based on their current technology readiness level but also taking into account their expected development over the coming years. Consequently, the results of this report should not be seen as a recommendation of best available solutions today but rather as a projection of long-term viability of different hydrogen-based options.

In line with the scope of the H2SHIPS project the analysis focuses exclusively on hydrogen. As a result some alternative solutions that might also be a viable option for decarbonisation of shipping – like battery electric propulsion and biofuels - have been omitted.

This does not however mean that the analysis covers only hydrogen as a fuel. While using hydrogen directly is the most energy-efficient option, it is also possible to use it as an ingredient to produce synthetic e-fuels, which are particularly attractive for applications where energy density of the fuel is key for its financial viability. The synthetic e-fuels, produced from hydrogen, included in this analysis are ammonia, LNG, methanol and diesel.

Although there are many pathways to produce clean hydrogen, this analysis includes exclusively hydrogen produced from renewable energy.

Due to inability to include the results of the concurrent work done by project partners on metal hydride storage option for hydrogen, this option is not included in this version of the analysis – but as the techno-economic information from the WP I1 work package becomes available, the report will be updated accordingly.

3 Scope and methodology

The economic comparison of different options has been evaluated using an approach similar to the metric known as Levelized Cost of Electricity – in the sense that the final costs borne by the shipowners include actualized investment (CAPEX) and operating (OPEX) costs of different options and are put in relation to the amount of fuel consumed. To ensure comparability of options the fuel consumption has been expressed in kWh of the energy content of the fuel (based on LHV) instead of its mass (in kg or tonnes). The discount rate used to actualize investments costs has been fixed at 5% p.a. in real terms.

The model includes the following elements:

- **Hydrogen production costs –** Levelized costs of producing renewable hydrogen via water electrolysis.
- **Transformation and conditioning costs** – costs of transforming pure hydrogen into the final fuel. Includes compression or liquefaction for pure

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hydrogen options, hydrogenation for LOHC and N2/CO2 supply and synthesis for e-fuels.[1]

- **Fuel logistics costs -** costs of transporting the fuel from its production site to the storage facility in the port. Together with hydrogen production costs and transformation and conditioning costs, these three categories combined represent the total cost of fuel to be paid by the shipowner[2].
- **Storage costs –** costs of fuel onboard storage system, including also impact of the extra volume of space needed on the revenue-generating potential of the ship.[3]
- **Onboard reforming costs -** costs of additional equipment (if needed) for treatment and cleaning of the fuel before it can be burned or used in a fuel cell.[4]
- **Energy conversion costs –** costs related to the final energy converter (marine engine or a fuel cell), converting the fuel into useful energy for propulsion or electric energy supply.[5]

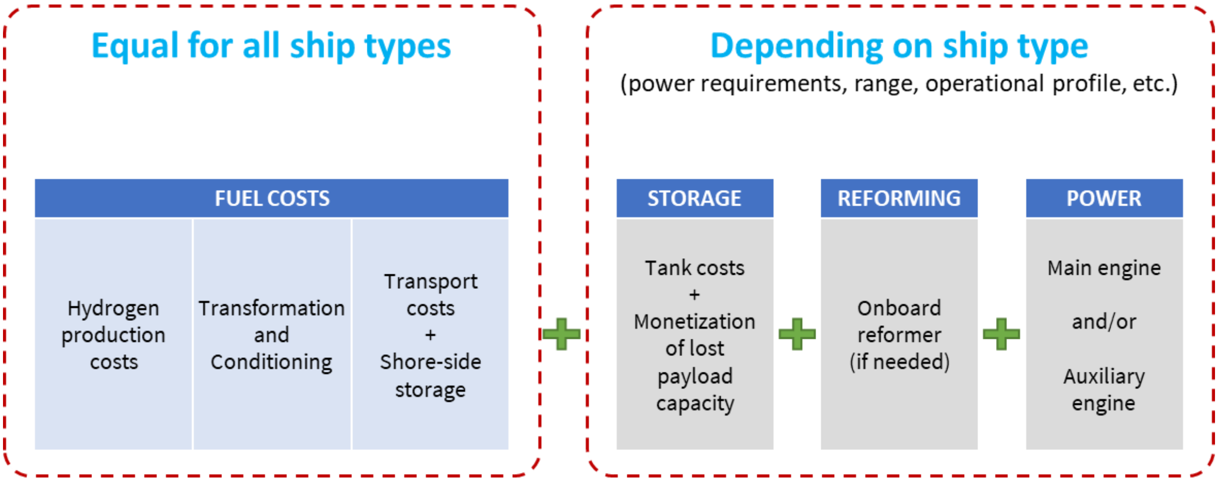

Figure 1. Techno-economic analysis model structure

Source: own elaboration.

[1] Details about the assumed pathways for production of various fuels are presented in Annex 1 and detailed techno-economic assumptions are presented in Annex 2.

[2] Detailed techno-economic assumptions are presented in Annex 3.

[3] Detailed techno-economic assumptions are presented in Annex 4.

[4] Detailed techno-economic assumptions are presented in Annex 5.

[5] Detailed techno-economic assumptions are presented in Annex 6.

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4 Powertrain options

While using hydrogen directly is the most energy-efficient option, it is also possible to use it as an ingredient to produce synthetic e-fuels, which are particularly attractive for deep-sea shipping applications, where energy density of the fuel is key for its financial viability. The synthetic e-fuels, produced from hydrogen, included in this paper are ammonia, LNG, methanol and diesel.

It's obvious that using hydrogen as its predominantly produced today, i.e. via steam methane reforming (SMR), would not bring any decarbonization benefits, and its manufacturing from fossil fuels needs to be replaced by renewable or low-carbon alternatives. **Consequently, for the purpose of this analysis, we have assumed that hydrogen used for all analysed options will be exclusively of renewable origin.**

This does not mean that other low-carbon hydrogen production pathways are not suitable for decarbonization of shipping, but as this analysis is based on a techno-economic comparison, there is little added value in expanding the analysis to other hydrogen production methods, as they mostly impact hydrogen production costs and those have been analysed in detail as part of the sensitivity analysis.

When it comes to energy use onboard it's also important to stress that it's possible to partially decarbonise shipping also by using hydrogen only as fuel for generating auxiliary power or co-combustion of hydrogen together with fossil marine fuel[6]. While those options present genuine opportunity for shipping, they are out of the scope of this analysis, which focuses only on options allowing for total decarbonization of shipping.

Another important disclaimer that needs to be stressed concerns the technology readiness level (TRL) of various technologies. As, because of its purpose, the analysis is forward-looking, for **various technologies we have assumed the technology readiness level will be market ready as of 2030 and not how it is currently**. This has the most profound impact on technologies like solid oxide fuel cells, which are still relatively immature and require significant further development in order for to be a viable solution for large ships, requiring multi-MW powertrains. Because of this assumption, **the results of this paper should not be seen as an assessment of best available solutions today but rather a projection of long-term viability of different hydrogen-based shipping decarbonization options.**

[6] E.g. https://www.internationales-verkehrswesen.de/hydroville-vessel-cmb/

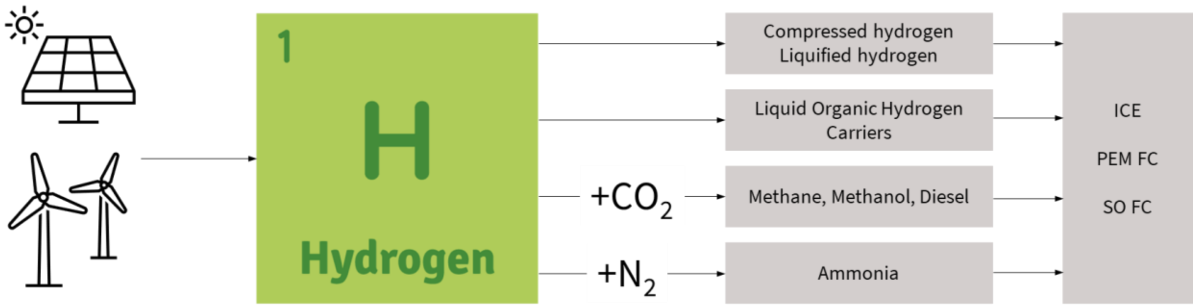

Figure 2. Analysed fuel options

Source: own elaboration.

4.1 Compressed and liquified hydrogen

The two "pure hydrogen" options covered in this analysis include compressed hydrogen (at 350 bar) and liquefied hydrogen. The advantage of those options lies with the less complicated fuel production process, as in both of those cases, in order to arrive at the final fuel, only one additional step is needed (compression or liquefaction respectively). Usually, this translates into lower costs of production compared to the alternatives.

On the other hand, the energy density of those two options is lower that is the case for e-fuels. As a result, the "pure" hydrogen options make the most sense for short sea shipping application, where the amount of fuel that needs to be stored onboard is lowest and therefore also the amount of lost payload capacity of ships, resulting from extra volume needed for fuel, is also relatively low. For deep-sea shipping, the implications of lower energy densities vs synthetic fuels are far more significant.

Another advantage of pure hydrogen options is the fact that neither requires any onboard reforming or cleaning before being used as a fuel in a fuel cell or an internal combustion engine (ICE).

It should also be mentioned that it's also possible to use compressed hydrogen at different pressures – for example, 700 bar, as is the standard for passenger FCEV's, yet because of substantially higher costs than 350 bar, without high enough difference in energy density, this option was not included at this stage.

Another possible method cryo-compressed hydrogen storage, which is a mixture of compressed and liquid storage. The pressurized hydrogen is stored at temperatures above the boiling temperature at elevated pressure. It reaches its highest density at temperatures below -200 °C at pressures up to 1000 bar [1]. Since its currently only in the prototype stage it has not been included in the paper but will be considered in future updates of the analysis.

It's possible to use hydrogen in both fuel cells as well as combust it in an engine. From the energy efficiency point of view, PEM FC is the best option, they are also more mature and thus cheaper than the SOFC. SOFC's might still be a good option if the vessel has substantial heat requirements, e.g. for cruise ships. One of the advantages of fuel cells over combustion engines is the fact that the energy efficiency of fuel cells increases in partial load and can reach 60+%. Furthermore, the combustion of hydrogen in the air might result in the formation of NOx, which does not occur in fuel cells.

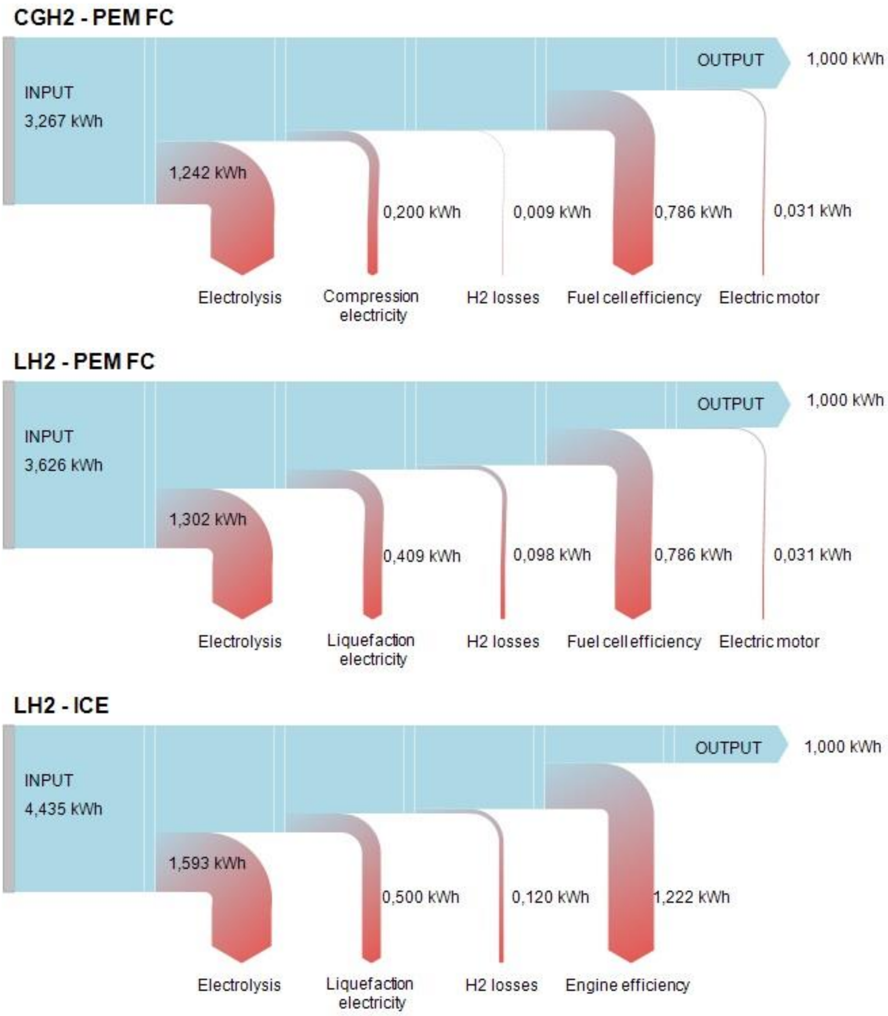

Figure 3. The energy efficiency of pure hydrogen options

Source: own elaboration.

4.2 Hydrogen carriers

Hydrogen is one of the most energy-dense fuels by mass, but it is extremely light and so the volumetric energy density in standard conditions is very low. Conventional hydrogen delivery solutions solve this problem by either compressing and delivering a pressurised gas, or by liquefaction and delivery of a liquid. Alternative solutions include using hydrogen carriers.

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Hydrogen carriers store hydrogen by hydrogenating a chemical compound at the site of production or onboard and then possibly dehydrogenating either at the point of delivery or potentially onboard the fuel cell vehicle for transport applications. They are largely at the research stage and have yet to be proven to be cost, energy/roundtrip efficient. They may include for example liquid organic hydrogen carriers (**LOHCs**) or inorganic hydrogen carriers (e.g. borohydrides, polysilane).

LOHCs are typically hydrogen-rich aromatic and alicyclic molecules, with high hydrogen absorption capacities. They include, in particular, the carbazole derivative N-ethylcarbazole, but also toluene, which is converted to methylcyclohexane by hydrogenation, dibenzyltoluene, and others [2].

The hydrogenation reaction occurs at elevated hydrogen pressures of 10-50 bar and is exothermic, releasing about 9 kWh_{th}/kg H2, which can be used locally for heating or process purposes or must be otherwise dissipated.

Dehydrogenation is endothermic and occurs at low pressures between 1 and 3 bar. The unloaded carrier is returned to the production site for reloading with possible degradation of the carrier happening depending on chemistries, operating conditions and the number of cycles. Dehydrogenation plays a key role in deciding the suitability of using LOHC as a fuel carrier for shipping applications. The necessity to extract hydrogen from LOHC before it can be used as a fuel requires additional equipment (dehydrogenation unit) to be carried on board, which diminished somewhat the energy density properties of the fuel itself. In addition to dehydrogenation, for use in PEM Fuel Cells (PEMFC), hydrogen extracted from LOHC would require additional purification step – although, when used with high-temperature solid oxide fuel cells (SOFC) or in an ICE, purification is not needed.

A further complication is related to the endothermic characteristic of the dehydrogenation process itself. If one would recover heat from the dehydrogenated liquid with an additional gas heater, about one-third of the energy stored in LOHC would be required to sustain the dehydrogenation reaction - further increasing the amount of fuel that would need to be stored onboard. This is less of a problem if LOHC would be used in combination with an ICE or SOFC, which could provide enough waste heat to maintain the dehydrogenation process.

In terms of volumetric energy density, one litre of LOHC contains around 1,32 kWh of hydrogen, which is higher than compressed hydrogen (0,81 kWh/l at 350 bar) but lower than liquefied hydrogen (2,359 kWh/l).

Its advantages come mostly from the ease of transport and storage. The hydrogenated carbazole derivative has comparable physicochemical properties to diesel fuel and can be stored and transported accordingly [2]. No pressurization or low temperature is needed. There are also no losses during storing. LOHC (both hydrogenated and dehydrogenated) is also non-toxic and inflammable. It can also be stored at ambient conditions in standard steel tanks used today to store other

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marine fuels. This opens up the potential for LOHC to use existing bunkering infrastructure in ports.

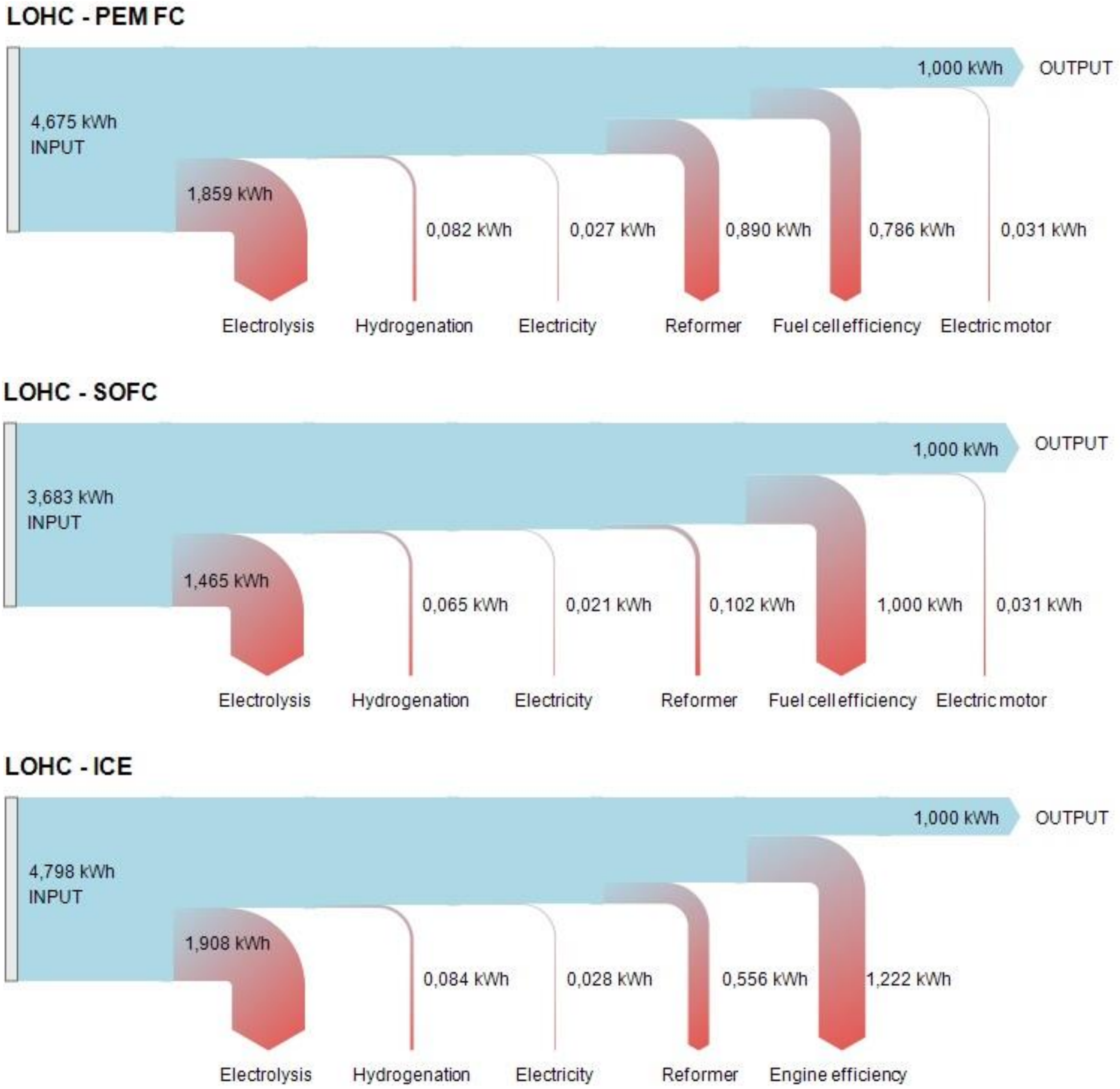

Figure 4. The energy efficiency of LOHC options

Source: own elaboration.

Another group of hydrogen carriers, which are getting increased attention for maritime applications are **metal hydrides**. In metal hydride storage systems the hydrogen forms interstitial compounds with metals. Generally, similarly to LOHC, the "loading" of hydrogen onto the metal hydride is an exothermic process (releasing heat), while heat needs to be supplied to keep the dehydrogenation process going. Metal hydrides are based on elemental metals such as palladium, magnesium and lanthanum, intermetallic compounds, light metals such as aluminium, or certain

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alloys. Although this may differ depending on the specific metal hydride solution chosen. Palladium, for example, can absorb a hydrogen gas volume up to 900 times its own volume [2] [1].

Two of the most promising solutions are based on using sodium borohydride (NaBH4) or Mg-Al alloys as hydrogen carriers. Using metal hydrides for hydrogen storage can achieve volumetric density matching that of liquefied hydrogen.

The challenges are related with the low gravimetric energy density (hydrogen is only accounting for around 1-2% of the mass of the carrier) and the fact that the regeneration of the carrier after the dehydrogenation reaction is often extremely complex and costly[7].

Advantages include the filter effect of metallic storage, allowing high-purity hydrogen to be discharged, and the low potential of accidental release [2].

Even though metal hydrides are potentially a very promising solution, as **metal hydride storages are not yet available as a commercial product, they have been omitted from this analysis at this stage but will be included in future updates.**

4.3 Ammonia

NH_3 is a colourless inorganic compound, that can be used in fuel cells or as a fuel for direct combustion in an ICE. It has a high hydrogen content but does not contain any carbon or sulphur molecules. As a result, combustion of ammonia doesn't emit any carbon dioxide (CO_2) or sulphur oxide (SOx). It is s a technically feasible solution for decarbonizing international shipping.

It has been estimated that depending on the used propulsion type and specific ammonia production method, ammonia fuelled ships could reduce GHG emissions by approximately 83.7–92.1% [3].

The exact emissions of NOx, as well as the global warming potential of ammonia slip and N_2O emissions from ammonia combustion, require further research. Especially N_2O requires significant attention as it is a GHG with almost 300 x higher global warming potential than CO2.

Ammonia is an interesting case among the synthetic e-fuels options not only because it is the only fuel that doesn't contain a carbon molecule but also because it is already produced globally in large volumes, which makes a fast transition towards decarbonization easier than with some alternatives.

Given ammonia's use as a fertilizer, it is a widely traded commodity with a volume of international trade of up to 20 million tonnes with 17 Mt of that being sea trade. As a result, there are operating transportation and storage infrastructures as well as

[7] For more information on metal hydrides, their prospects and ongoing research see e.g.**Invalid source specified.**.

port infrastructure for shore-to-ship loading/unloading, handling experience, and safety know-how in the current supply chain.

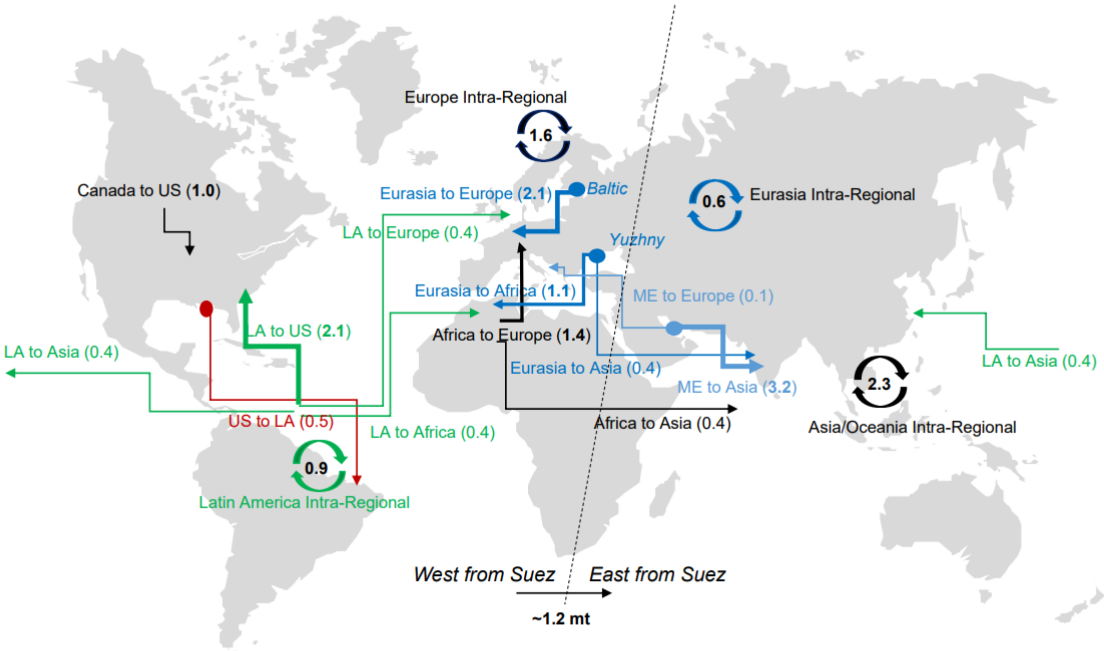

Figure 5. International trade flows of ammonia

Source: Fertecon.

The Norwegian ammonia producer – Yara alone, has 4 ammonia export plants in Europe with an export capacity of around 1 Mt and 2.7 Mt worldwide, together with ammonia maritime transport capacity of more than 200 kt and 17 terminals with a storage capacity of 580 kt.

Furthermore, as ammonia can be stored under similar conditions as LPG it can also utilize existing LPG fleet and LPG storage facilities.

Very much like hydrogen, the deployment of ammonia as a marine fuel is still in the research and development phase. It is currently being tested for use in ships by various companies including Wartsila and a consortium of Samsung Heavy Industries, MISC, Lloyd's Register (LR) and MAN Energy Solutions. [4], [5], [6].

Liquid ammonia's volumetric hydrogen content, at 14,500 MJ/kg is 70% greater than liquid hydrogen's at 8500 MJ/kg. Liquid ammonia thus allows more energy storage per cubic meter than in liquid hydrogen and without the need for cryogenic temperature storage as it is the case of liquid hydrogen. This represents cost savings as storing ammonia at -33.4 C is technologically easier and cheaper than storing hydrogen at -252.9 C. [7]

Ammonias advantage also lies with the fact that its synthesis (via the Haber-Bosch process) is relatively energy efficient (around 14% energy loss) and contrary to hydrogen carriers it can be used directly in a high-temperature fuel cell or burned in

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an ICE without the need for costly dehydrogenation step onboard (although this would not be possible for a low-temperature PEM fuel cell, which would require ammonia cracking and hydrogen purification).[8]

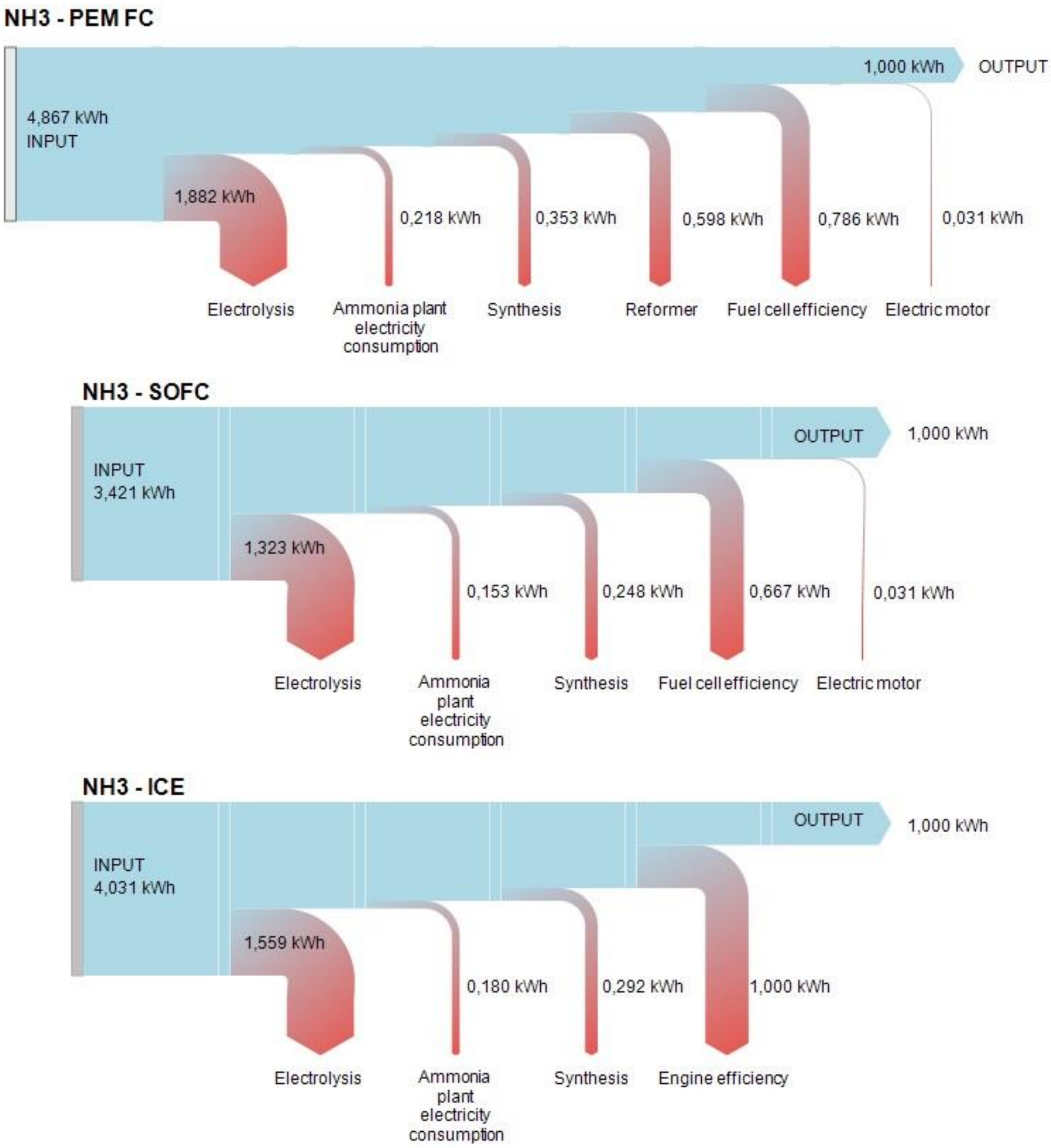

Figure 6. The energy efficiency of ammonia options
Source: own elaboration.

[8] More information on ammonia as a fuel available at: (De Vries, N., 2019), **Invalid source specified.**.

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In terms of risk of fire or explosion its safer than hydrogen or hydrocarbons, as it requires both higher ignition temperature and higher concentration in the air before the Air-NH_3 mixture becomes flammable. Ammonia main disadvantage is related to its toxicity, which makes its use on passenger ships especially challenging.

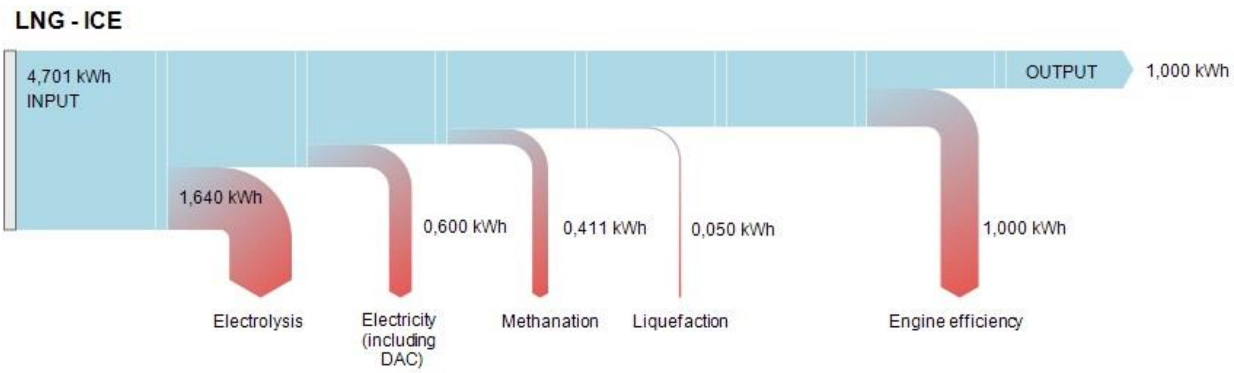
Although at the same time, the fertilizer industry has been working with ammonia for many decades and has developed standards and guidelines that can be followed to ensure safe usage of this chemical. Ammonia's strong smell makes it also easy to detect well before it reaches dangerous concentration levels.

It should also be mentioned that there already exists an IGC Code with requirements for carrying anhydrous ammonia in bulk, which can be used to provide guidance for non-gas carriers (IGF Code).

4.4 Other e-fuels

Synthetic e-fuels like methane, methanol or other hydrocarbons have higher energy density and are generally simpler to handle than ammonia or liquefied hydrogen. They also benefit from the fact that there is already storage and transportation infrastructure in place. This is, of course, most valid for synthetic diesel, but it's also the case for both LNG as well as methanol, which is already available at around 100 ports around the globe.

However, the production of those fuels is both more energy-intensive as well as more capital intensive than the previously mentioned alternatives.



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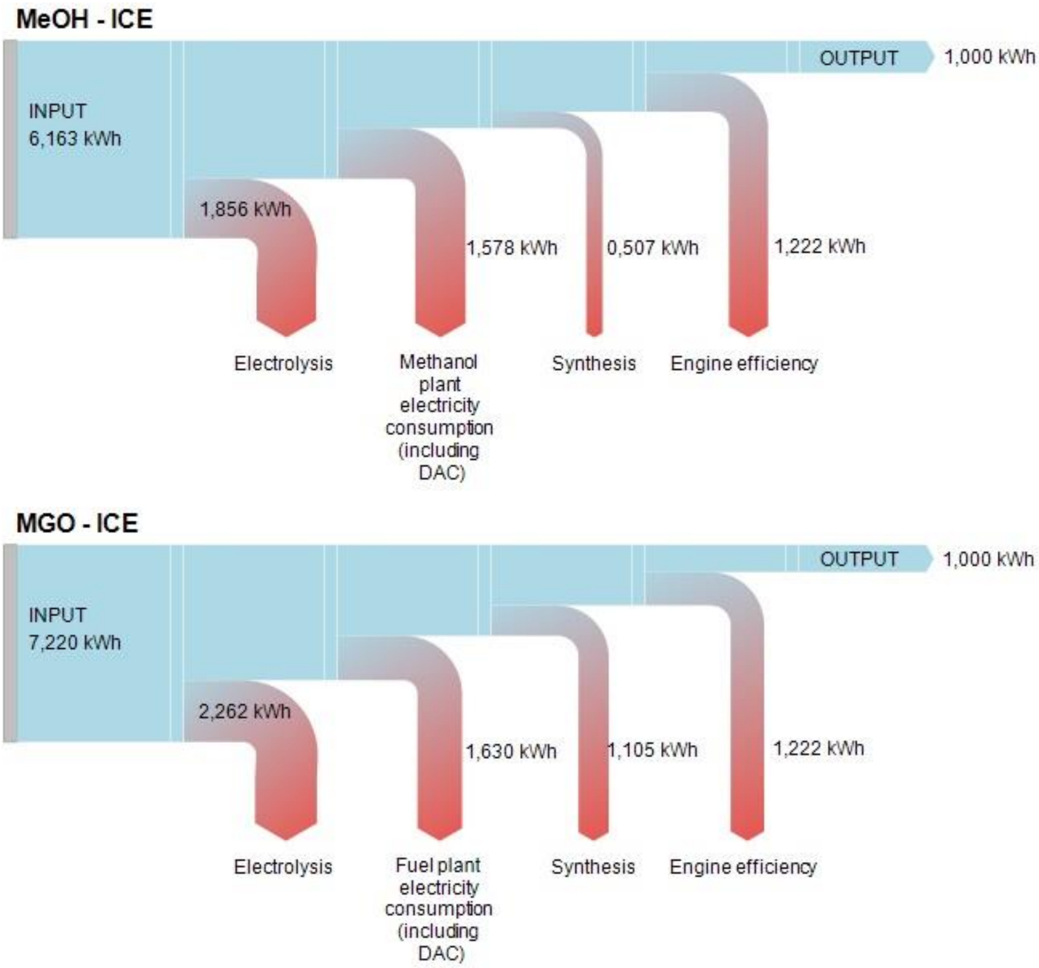

Figure 7. The energy efficiency of various e-fuel options

Source: own elaboration.

Furthermore, production of such carbon-based e-fuels will require a source of CO2, which will not only drive costs further up but has implications for the overall sustainability of those fuels.

By far the cheapest source of CO2 would be to use the CO2 point captured from industrial processes or power plants, yet the long-term sustainability of this pathway is questionable. The CO2 saving credit can go either to the industry, which has captured it or to the end-user (in this case a ship), it can never go to both.

If it stays with the industry then, from the point of view of GHG emissions such synthetic fuel would be no better than its fossil fuel equivalent. If however the CO2 credit is attached to the e-fuel, then, while the fuel itself is climate neutral, the long term availability of CO2 is uncertain. If the ultimate goal of the EU is to become a fully decarbonized economy, the industry would have to decarbonize as well, meaning that, at some point, either the captured CO2 would have to be destined for permanent storage or the industry will transition to another zero-emission solution - either way, limiting the availability of CO2 for CCU. Furthermore, the use CCU from fossil sources might potentially lead to lock-in of fossil sources of CO2.

The use of point captured CO2 for production of e-fuels, can therefore be seen only as a transitional solution at best. For this reason, for this analysis, we have assumed that all CO2 used for e-fuels synthesis would come from Direct Air Capture (DAC).

4.5 Other alternatives

Although this report focuses exclusively on hydrogen and hydrogen-made synthetic fuels, it should be noted that there are potentially also other options being considered for decarbonization of the shipping sector.

The most commonly considered alternative fuels/propulsions systems in shipping are LNG, batteries, and biofuels, but each of them comes with their own set of advantages and challenges.

4.5.1 Electrification

Similarly to using hydrogen as a fuel, battery technology offer a TTW zero-emission solution. Well-to-Wake emissions on the other hand depend on the carbon footprint of the national/regional electricity grids that are used to charge the batteries.

Because of high energy efficiency of electric motors (up to 99%), high efficiency of energy storage in batteries and relatively low energy losses for AD/DC and DC/AC conversions, the biggest advantage of direct electrification of waterborne transport is certainly the fact that it is by far the most energy-efficient option.

The first fully electric vessel, MF Ampère, has been in service between Lavik and Oppedal on the west coast of Norway since 2015 [8]. According to Clarksons Research, as of June 2020, there were 16 vessels in operation with battery-electric propulsion. All of them were small ferries or catamarans below 3,000 GT. There are also 29 further battery-electric vessels on order with current building date between 2020 and 2023. Besides pure battery-electric ships, there were also 101 hybrid battery-electric vessels (with further 68 on order), which are using batteries only as a power source for manoeuvring in ports or peak load shaving.[9]

Yet, despite these initial deployments, batteries face a number of important challenges, that are limiting their usefulness for shipping decarbonization, especially when it comes to larger vessels.

One issue faced by the direct electrification option is related with the fact that while there are no TTW emissions, the overall carbon footprint of battery-powered vessels is depending on the carbon intensity of the grid electricity used for battery charging. While there are some countries in the EU where the carbon intensity of the grid is low enough for that not to be an issue, there is still quite a number of those, most notably Estonia and Poland, where battery-electric vessels would result in a net

[9] Clarksons Research, World Fleet Register, Accessed 03/06/2020

increase in GHG emissions. More long term, this issue should solve itself by the expected decarbonisation of power generation in the EU, but in the meanwhile, the climate benefit would be limited.

Another key challenge is the extremely low energy density of batteries. As a recent study by the US Sandia National Laboratory has shown [9], for most ship types, space and mass requirements are so large that it is impossible to fit a required battery storage system that would be enough even for a single one-way voyage.

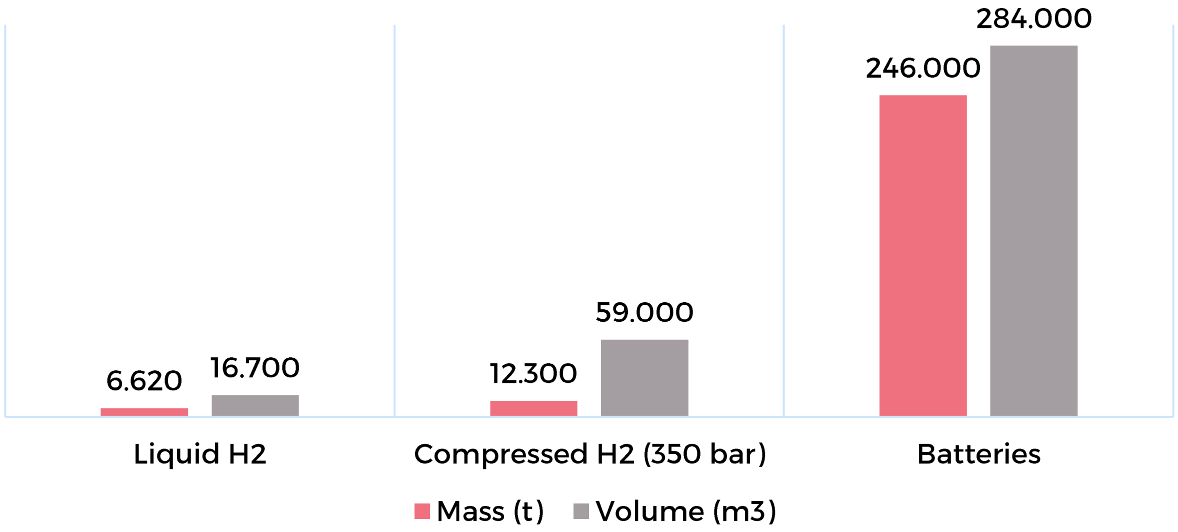

Figure 8. Comparison of space and weight requirements of different zero-emission systems for a large containership (example of Emma Maersk)

Source: own elaboration based on: [9].

Finally, even if, through some future technological breakthrough, the energy density problem could be overcome, there would still be an issue with the provision of the required charging infrastructure in ports. The size of the challenge can be best seen on the example of Ro-Pax ferries. A vessel of this type operating on a line like Gdynia (PL) – Karlskrona (SE) would need around 200 MWh of energy for a single one-way trip. Considering the fact that ferries usually are unloaded/loaded within 1.5 – 2.0 hours, to charge the batteries within the available time, the onshore power supply (OPS) system would need a power of at least 100 MW. There are not many ports in the EU capable of doing that. Furthermore, taking into account that this is just power required for a single ship, it becomes clear that **while batteries are likely to be adopted for some use cases, especially short sea shipping, their low energy density, high requirements for onshore power supply, and charging times will continue to limit their proliferation among other medium-to-long distance applications.**

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4.5.2 Biofuels

In terms of technology readiness and cost, biofuels appear as one of the most attractive ZEV solution and flexible alternative to current marine fuels. Biofuels can be either blended with conventional fuels or used as a drop-in fuel without changes to the existing infrastructure and assets, requiring minimal adjustments to machinery and storage. As a result, they are often touted as the ideal replacement of fossil-based marine fuels. However, biofuels face at least two significant challenges related to their sustainability and availability.

In the case of the most commonly used first generation, it is clear that **many types of crop-based biofuels are worse from a climate impact perspective than the fossil fuels they are replacing.** This is mostly due to indirect land-use change (ILUC).

When existing agricultural land is turned over to biofuel production, agriculture has to expand elsewhere to meet the existing (and growing) demand for crops for food and animal feed. This happens at the expense of forests, grasslands, peatlands, wetlands, and other carbon-rich ecosystems and in turn results in substantial increases in greenhouse gas emissions. ILUC is a key factor that shows why crop biofuels are not a decarbonisation option for transport. Issues relating to impacts on biodiversity, water use, local communities and food prices are also considerable. Then, even ignoring the ILUC effects the area needed to cultivate crops required to decarbonize the maritime sector would be enormous and would run counter to the efforts to increase negative emissions and carbon sinks, which will be required as part of the Paris Agreement. [10]

Advanced biofuels[10], from waste or residues, could still play a positive role in decarbonising the maritime sector, but while there is no question about sustainability, their availability is limited due to wastes and residues being incidental to other processes. Their availability for the shipping sector will be further reduced by the high demand for advanced biofuels from other transport sectors (like aviation) and non-transport industries, which will not only limits their availability but likely also increase their cost. **Because of the limited availability of feedstock and demand from other sectors, the supply of advanced biofuels won't be sufficient to reach decarbonization targets.**

Moreover, the use of biofuels in shipping would create unique sustainability and enforcement challenges, which do not arise in other transport modes and would appear to be insurmountable from a regulatory point of view. Ocean-going ships usually bunker in specific ports where fuel is cheap; hence, they do not need to refuel

[10] IEA defines advanced biofuels as "sustainable fuels produced from non-food crop feedstocks, capable of delivering significant lifecycle GHG emissions reductions compared with fossil fuel alternatives, and which do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts."

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every time they make a port call to take up or discharge cargo. Such a unique refuelling pattern of shipping makes the application of strict sustainability criteria for biofuels - in order to prevent the use of crop-based biofuels extremely challenging. [11]

A global and uniform application of sufficiently strict sustainability criteria - via for example the IMO or another framework - would require a global consensus agreement, which is improbable because of the interests of large bio-energy producing countries such as Brazil, Argentina, the US, Colombia, Indonesia, Malaysia, etc. Even if such a global consensus on applying strict environmental criteria was reached uniform enforcement would be an additional and equally insurmountable challenge. [11]

4.5.3 Liquefied Natural Gas (LNG)

LNG became the most adopted alternative marine fuel as of 2020. Its initial adoption has been facilitated by increasing SOx and NOx emission standards as well as increasing world trade of LNG and proliferation of LNG liquefaction facilities and LNG terminals.

While LNG currently dominates the alternative fuel vessel infrastructure, its importance in a low carbon maritime shipping sector is uncertain. It's certainly true that LNG provides significant opportunities for reducing air pollution from shipping. Compared to heavy fuel oil (HFO) and marine diesel oil (MDO), LNG propulsion produces only trace amounts of SOx and particulate matters while NOx emissions can be reduced by 91.4% [12]. Unfortunately, in terms of CO2 emissions, the potential GHG savings are limited.

Taking into account LNG combustion only, total CO2 reductions from using LNG might reach around 25% compared to MGO or HFO [13]. However, relatively large Well-to-Tank (WTT) emissions of the LNG supply chain [14] as well as methane slip from the ship's engines, more or less offset any GHG savings from LNG combustion [15].

As a result, multiple studies ([15], [16], [17], [18]) have recently shown that the only LNG option which can realistically have a positive contribution towards GHG reduction is the 2–stroke high-pressure dual fuel option, and even there the total GHG reductions are only around 15% compared to MGO.

It is therefore clear that, while LNG enables air pollution reduction, it is certainly not an option for decarbonization of shipping.

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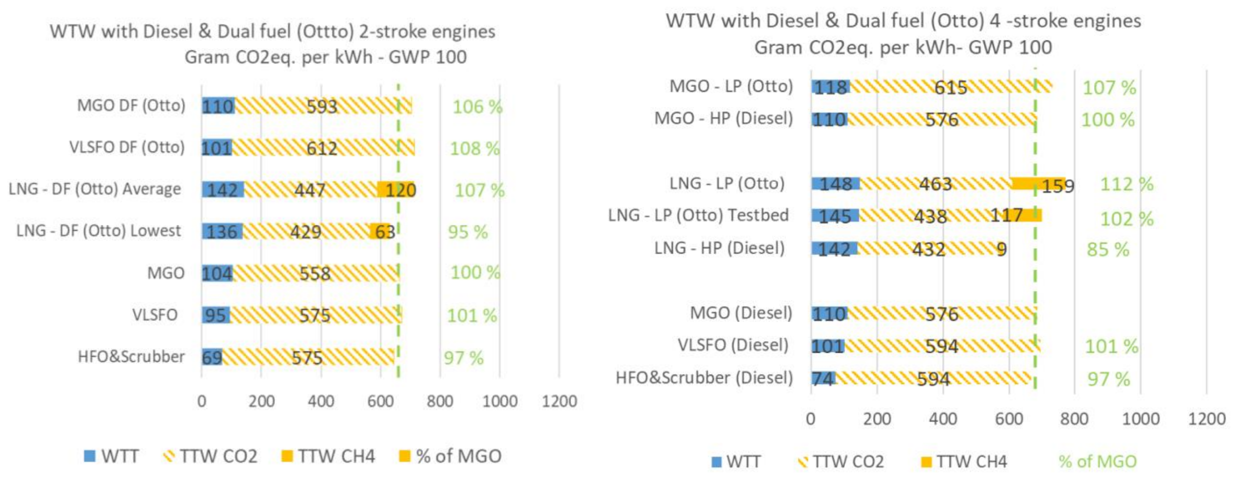

Figure 9. Comparison of LNG WTW GHG emissions with other fossil fuel options Source: [18].

5 Ship types

The maritime sector is very diverse and encompasses a wide variety of ship types, which differ not only by size and cargo but also have vastly different power requirements and operational profiles. As a result, it's rather unlikely there will be a single one-size-fits-all solution to decarbonize the entire sector.

To tackle this diversity the techno-economic analysis was performed separately for 34 different ship-types covering:

- 8 inland ship types (mostly various types of barges and also inland oil and product tankers, cruise ships and small ferries),
- Tugs
- Offshore vessels (PSV, ATHS and CTVs)
- Several other sea going vessels – but ones that are exclusively (or at least can be) exclusively used on short sea applications – including feeder vessels, small passenger ships, ro-ro and ro-pax ferries and small oil tankers (and bunker vessels).

The parameters of the sea-going vessels were adopted as defined in the recent IMO GHG Study [1]. The parameters of offshore vessels and inland ships were adopted based on own analysis of the Clarkson Research World Fleet Register database.

Table 1. Ship types included in the analysis

Ship type	Size	Size unit	Avg. DWT (tonnes)	Avg. GT	Average main engine power (kW)
Inland Bulk cargo barge	0–+	dwt	4.371	2.550	3.715
Inland Cruise	0–+	dwt	411	3.782	1.916
Inland Tow/pusher barge	0–+	dwt	367	240	1.717
Inland product tanker	0–+	dwt	3.304	1.155	440
Inland RoRo cargo	0–+	dwt	1.919	5.591	1.564
Inland ferry – ro-pax	0–+	dwt	613	2.206	1.130
Inland Ferry - pax only	0–+	dwt	299	731	700
Bulk carrier	0–9,999	dwt	4.271	2.104	1.796
Container	0–999	TEU	8.438	6.452	5.077
Container	1,000–1,999	TEU	19.051	15.019	12.083
General cargo	0–4,999	dwt	2.104	1.206	1.454
General cargo	5,000–9,999	dwt	6.985	4.894	3.150
Oil tanker	0–4,999	dwt	3.158	1.181	966
Ferry-pax only	0-299	GT	65	185	1.152
Ferry-pax only	300-999	GT	102	543	3.182
Ferry-pax only	1,000-1,999	GT	354	1.421	2.623
Ferry-pax only	2000-+	GT	1.730	6.443	6.539
Cruise	0–1,999	GT	241	906	911
Cruise	2,000–9,999	GT	867	5.008	3.232
Ferry – ro-pax	0–1,999	GT	309	669	1.383
Ferry – ro-pax	2,000-4,999	GT	832	3.053	5.668
Ferry – ro-pax	5,000-9,999	GT	1.891	7.171	12.024
Ferry – ro-pax	10,000-19,999	GT	3.952	14.123	15.780
Ferry – ro-pax	20,000-+	GT	6.364	31.985	28.255
Ro-ro	0–4,999	dwt	1.406	3.847	1.618
Ro-ro	5,000-9,999	dwt	6.955	11.524	9.909
Ro-ro	10,000-14,999	dwt	12.101	25.131	15.939
Ro-ro	15,000-+	dwt	27.488	51.780	19.505
Tug	0–+	GT	168	292	2.900
AHTS	0–+	GT	1.460	1.733	6.000
CTV	0–+	GT	200	280	3.010
PSV	0-3000	dwt	1.761	1.372	3.190
PSV	3000+	dwt	4.200	3.388	6.500

Source: [19].

One other key assumption which has a huge impact on the overall results is the minimum distance that a ship needs to be able to cover on a single tank.

The larger the required range the bigger the impact from low energy density of hydrogen on the business case (as more and more of the ships payload capacity needs to be dedicated to additional fuel storage). For the purpose of this analysis we have assumed as a base case that the minimum distance between bunkering for each ship type is 200 nautical miles.

The sensitivity analysis performed at the end of this report shows the impact of this assumption on the overall results.

6 Scenario analysis

6.1 Fuel production costs

Fuel production costs consist of combined costs of renewable hydrogen production and its transformation and conditioning required for it to reach its final form, which can be used as an energy carrier on board of ships.

Taking into account average solar irradiation and average wind conditions in the EU Member States, as well as Norway and the UK, estimated renewable hydrogen production costs with direct connection vary from €3.5/kg (from solar PV in Portugal) to €6.5/kg (from onshore wind in Luxemburg). In southern European countries the cheapest pathway to green hydrogen production is solar PV, while for northern European countries in most cases the cheapest option is onshore wind, except for Belgium and Germany, where on average offshore wind is the cheapest option [20].

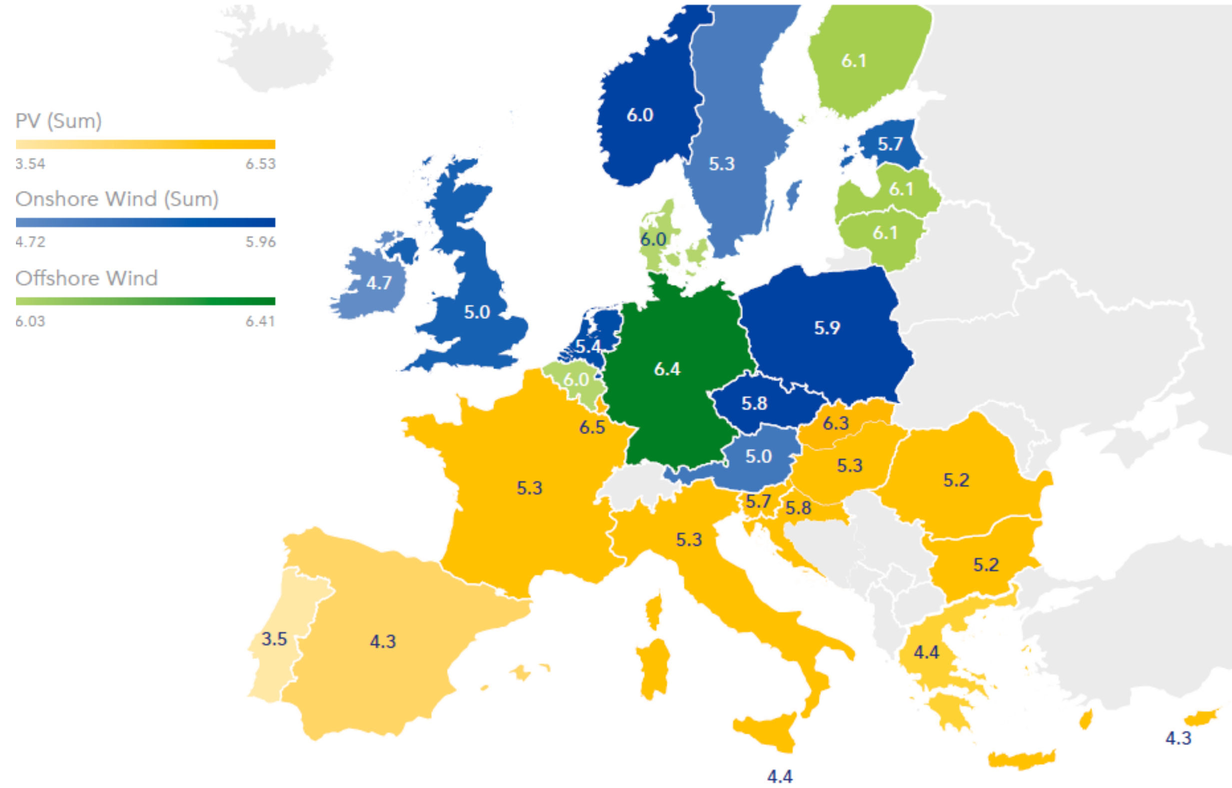

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Figure 10. Lowest available green hydrogen production costs given average wind and solar conditions in the EU in 2019 (in € per kg)

Source: [20].

Since this analysis is forward-oriented, we have decided to estimate the costs of hydrogen production also based on expected future electrolysis CAPEX as well as based on future renewable energy LCOE (40 EUR/MWh). Detailed techno-economic assumptions adopted to estimate different cost elements have been presented in detail in Annex 2. Based on those assumptions, renewable hydrogen production costs for all options were estimated at **2.4 EUR/kg**.

Such a price level, while below current production costs is well within the range projected by McKinsey (see below) or the IEA (see [21]), IRENA and BNEF who project that by 2030 renewable hydrogen production costs will fall to **1.1-2.4 EUR/kg**. Such renewable hydrogen production costs are also in line with the EU Hydrogen Strategy goal of green hydrogen becoming cost-competitive with other forms of hydrogen production, including hydrogen from fossil fuels, which currently costs around 1.5 EUR/kg.

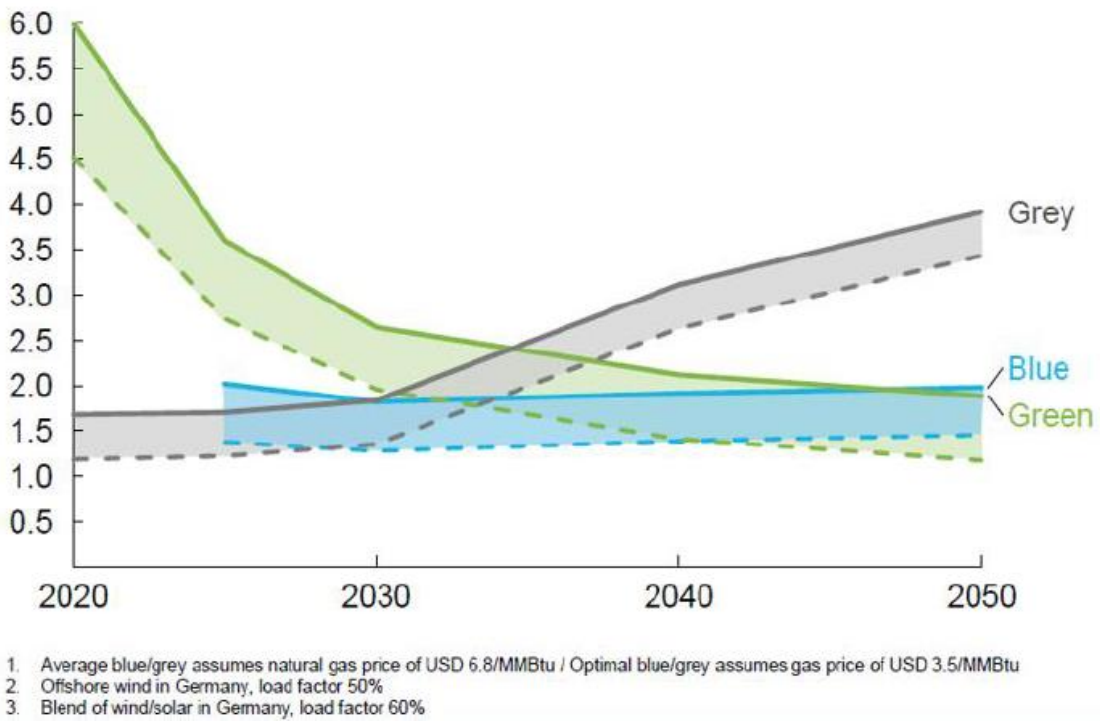

Figure 11. Production of hydrogen across different types of locations (in USD/kg)

Source: McKinsey.

Even with such relatively low hydrogen production costs, assuming a marine gas oil (MGO) price of 500 USD/t, all analysed alternative fuels would be significantly more expensive than the fossil fuel reference.

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The two most low-cost options in terms of fuel production costs would be compressed hydrogen (CGH2) and LOHC, with total estimated production costs at around 91 EUR/MWh, which more than twice that of MGO at around 38 EUR/MWh. Liquefied hydrogen is as expected a more expensive option compared to compressed hydrogen and LOHC with total estimated costs at 104 EUR/MWh (around 15% more than compressed hydrogen).

Yet, even so, both hydrogen options as well as LOHC, are substantially cheaper than all e-fuels, which is also not surprising considering the additional synthesis processes required to produce these fuels. The most expensive out of all the e-fuels is the synthetic MGO, which, at 211 EUR/MWh is 5.6 times more expensive than its fossil bases equivalent.

Because of the lack of carbon molecule, green ammonia is significantly less expensive to produce than all other synthetic fuels. With production costs estimated at 123 EUR/MWh, it's 14% less expensive than its closer carbon-based e-fuel (e-LNG) and around 18% more expensive than liquefied hydrogen.

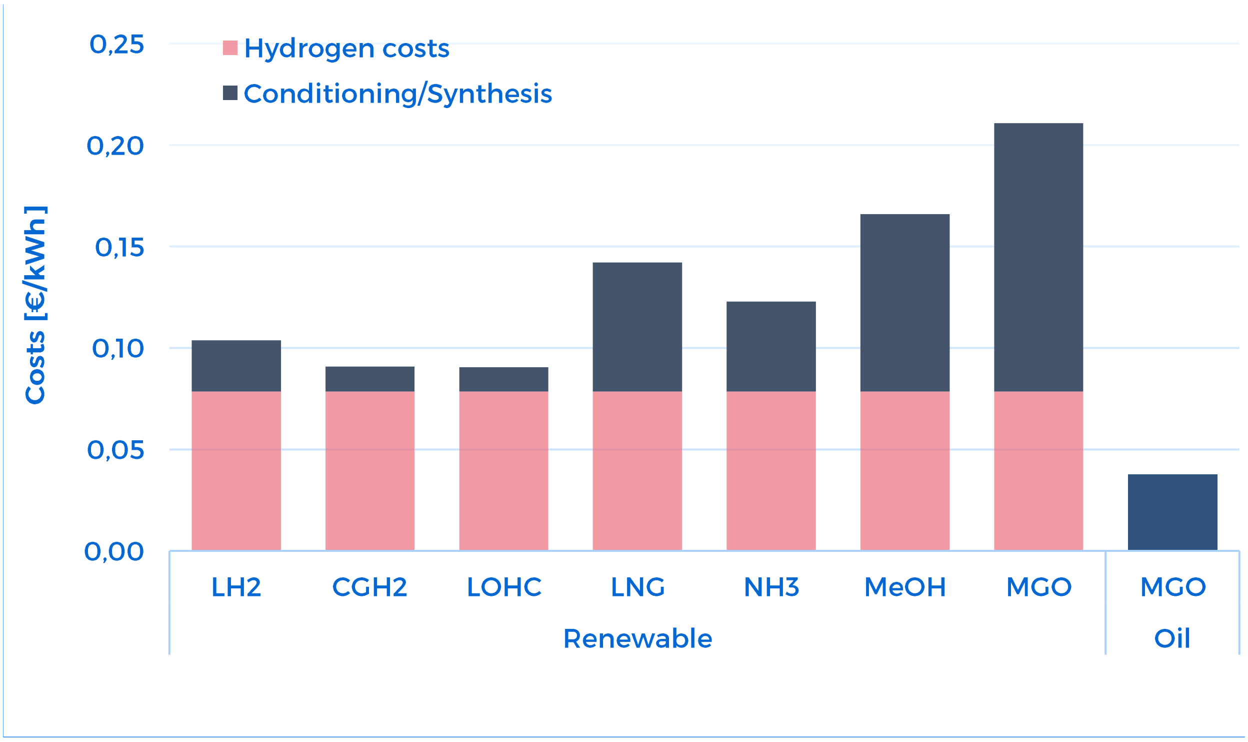

Figure 12. Estimated fuels production costs

Source: own elaboration.

6.2 Logistics costs

Logistics of alternative fuels pose a significant challenge, which would need to be overcome before any of the analysed options becomes universally adopted. For options like the LOHC or synthetic diesel, the challenges are less profound, as both

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of those options can use existing marine fuels transport, storage and bunkering infrastructures.

For synthetic LNG, ammonia and methanol the challenges are greater but still, all of these options benefit from the fact that, as those are internationally traded commodities, there already is some infrastructure in place, which can be built upon. Due to similar storage requirements, ammonia could also use existing LPG storage facilities and transport ships.

By far the biggest challenge in the area fuel logistics is faced by the pure hydrogen options. H_2 presents unique challenges for transportation and distribution due to its low volumetric density. Furthermore, neither compressed nor liquefied hydrogen can benefit from any existing dedicated infrastructure of the same scale as some of the other options. On the other hand, in both of those cases, it's possible to reduce the time and cost necessary to put the transportation and storage infrastructure in place by retrofitting existing natural gas and LNG assets.[11]

Currently, the most commonly used hydrogen transportation methods include:

- **Road transport of gaseous hydrogen**. Most tube trailers in operation today deliver small quantities of compressed H_2 gas at relatively low pressure (<200bar). At 200 bar, the density of hydrogen, under standard conditions is around 15.6 kg hydrogen per cubic meter, meaning that a single tube trailer can carry only around 300 – 400 kg of hydrogen. The latest state of the art solution for road transport is 500 bar tube trailers. Under such pressure, hydrogen density would reach around 33 kgH2/m3, allowing to increase the capacity of a single truck up to 1,100kg H_2. The ambition is the development of a 700 bar tube trailers (c. 1,500kg) in the coming years. [12]
  Because of low amounts of hydrogen carried per truck, this option is relatively expensive for high quantities of hydrogen and long distances of transport. However, in comparison to liquefaction or a pipeline network, there are virtually no fixed costs, so this is the best option for small amounts and short distances. It is also flexible since it is available for any route and at any time and is easily scalable. [2] [22]

- **Road transport of liquid hydrogen** – H_2 in liquid form is the most conventional means of transporting bulk hydrogen on the road. The H_2 is stored at -253°C in super-insulated 'cryogenic' tanks and can be safely

[11] For more information on retrofitting natural gas infrastructure to hydrogen see the recent European Hydrogen Backbone report: [26].

[12] See: Multiannual Work Programme of the Fuel Cell and Hydrogen Joint Undertaking (https://www.fch.europa.eu/) and the Strategic Research and Innovation Agenda of the proposed Clean Hydrogen for Europe partnership (available at https://hydrogeneurope.eu/clean-hydrogen-europe.eu).

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transported by trucks over a distance of 4,000 km. However, liquefaction is energy-intensive and storage/transport of the LH_2 results in heat ingress and losses due to evaporation. “Boil-off” losses can be reduced by improved insulation concepts or, as demonstrated by NASA, by an integrated refrigeration and storage system. It should be noted that most of the boil-off happens during transfer phase (Storage to Trailer, Trailer to local storage), far above the vaporisation inside storage tanks.
Over the journey time, the cryogenic hydrogen heats up, causing the pressure in the container to rise. The evaporated hydrogen is extracted from the container, normally at the filling station, and supplied for another use or re-liquefied. Similarly to lorry transport, LH2 can also be transported by ship or by rail, provided that suitable waterways, railway lines and loading terminals are available.
In comparison to pressure gas vessels, more hydrogen can be carried with an LH2 trailer, as the density of liquid hydrogen is higher than that of gaseous hydrogen. At a density of 70.8 kg/m^3, around 3,500 kg of liquid hydrogen or almost 40,000 Nm^3 can be carried at a loading volume of 50 m^3. Over longer distances, it is usually more cost-effective than transporting hydrogen in compressed in gaseous form. The additional cost for hydrogen liquefaction is then offset by the lower trucking cost.

- **Pipelines** – for delivering large volumes of hydrogen over land, pipelines are by far the cheapest option. A pipeline network would be the best option for the comprehensive and largescale use of hydrogen as an energy source. However, pipelines require high levels of initial investment, which may pay off, but only with correspondingly large volumes of hydrogen. Nevertheless, one possibility for developing pipeline networks for hydrogen distribution is local or regional networks, known as micro-networks. These could subsequently be combined into transregional networks.
  Worldwide there are already more than 4,500 km of hydrogen pipelines in total, the vast majority of which are operated by hydrogen producers. The longest pipelines are operated in the USA, in the states of Louisiana and Texas, followed by Belgium and Germany. In Europe, there is already >1000 km dedicated hydrogen pipelines serving the industry. This network should be expanded by new build pure H_2 pipelines.
  For the transport of very large hydrogen volumes, a comprehensive pipeline network is ideal. This option is dominated by the costs of building the pipeline infrastructure. Once it has been built, the increase in specific transport costs for larger volumes is negligible. A pipeline is thus the most cost-effective choice for large transport volumes, whereas for small amounts the fixed costs are very difficult to recover [2], [22], [23].

There also exists an option of blending hydrogen with natural gas. Blending hydrogen into natural gas pipeline networks has also been proposed as a means of delivering pure hydrogen to markets, using separation and purification technologies downstream to extract hydrogen from the natural gas blend close to the point of end-use. As a hydrogen delivery method, blending can defray the cost of building dedicated hydrogen pipelines or other costly delivery infrastructure during the early market development phase. Until well into the 20th century, hydrogen-rich town gas or coke-oven gas with a hydrogen content above 50 vol% was distributed to households in e.g. Germany, the USA and England via gas pipelines – although not over long distances. Infrastructure elements that were installed at the time, such as pipelines, gas installations, seals, gas appliances etc., were designed for the hydrogen-rich gas and were later modified with the switch to natural gas. Many countries have looked at adding hydrogen into the existing natural gas networks. For the USA, it would be possible to introduce amounts from 5 vol% to 15 vol% hydrogen without substantial negative impact on end-users or the pipeline infrastructure.

At the same time, the larger additions of hydrogen would in some cases require expensive conversions of appliances. In Germany, this limit has been set somewhat lower, at up to 10 vol%. In principle, gas at concentrations of up to 10 vol% hydrogen can be transported in the existing natural gas network without the risk of damage to gas installations, distribution infrastructure, etc. However, a number of components have been listed that are still considered to be critical and to be generally unsuitable for operation with these hydrogen concentrations. For CNG vehicles, the currently authorized limit value for the proportion of hydrogen used is only 2 vol%, depending on the materials built-in.

The different hydrogen transport options each require specific infrastructure and also involve a different combination of fixed and operating costs as well as varying levels of transport capacity. Depending on the amount of hydrogen to be transported and the distance over which it needs to be delivered, the most suitable option might change case by case.

As is demonstrated in the following chart, because of the lowest investment cost and high variable costs, road transport of gaseous hydrogen is the cheapest option only for short distances and low amounts of hydrogen. The opposite is true for pipelines – fixed costs are driven by high investment costs. Once the pipeline is fully utilised, the variable costs are low. The road transport of liquid hydrogen option is optimal whenever the transportations distances are high but the volume of hydrogen is not sufficient to ensure high utilization of a pipeline.

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Quantity in kg per year / Distance in km	10	50	100	200	300	400	500	600	700	800	900	1,000	1,250	2,000	2,500
100,000	CH2	CH2	CH2	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
200,000	CH2	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
500,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
1,000,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
2,000,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
3,000,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
4,000,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
5,000,000	CH2	P	P	P	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
10,000,000	CH2	P	P	P	P	P	P	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
15,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	LH2	LH2	LH2
20,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	LH2
25,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
30,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
50,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
100,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
250,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
500,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
1,000,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
2,000,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P

Figure 13. The cheapest option for hydrogen transportation depending on distance and quantity

Source: own elaboration based on [21] [22] [23] [24] [25] [26].

NOTE: CH2 - Road transport of gaseous hydrogen, LH2 - Road transport of liquid hydrogen, P – pipelines.

Translating those values into costs, one can see that for low amounts of hydrogen the costs of transportation alone can easily double the cost of hydrogen itself. On the other hand transportation costs of large quantities over large capacity pipelines can be as cheap as 0.1-0.3 EUR/kg, i.e. even up to 10 times cheaper than transporting energy via electric cables.

Its also clear from the analysis that for the liquified hydrogen option, especially for large quantities, it might be more cost-effective to transport it from production site to port via hydrogen pipelines in gaseous form, and liquefy it in port, potentially limiting the storage requirements as well.

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Quantity in kg per year \ Distance in km	10	50	100	200	300	400	500	600	700	800	900	1,000	1,250	2,000	2,500
100,000	2.021	2.021	2.021	2.021	2.021	2.335	2.817	3.299	3.299	3.299	3.299	3.299	3.299	3.299	3.633
200,000	1.213	1.213	1.213	1.370	1.852	2.273	2.273	2.273	2.273	2.273	2.273	2.273	2.440	3.156	3.633
500,000	0.728	0.728	0.888	1.370	1.658	1.658	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
1,000,000	0.567	0.646	0.888	1.370	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
2,000,000	0.486	0.646	0.888	1.370	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
3,000,000	0.459	0.646	0.888	1.370	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
4,000,000	0.453	0.646	0.888	1.370	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
5,000,000	0.453	0.613	0.765	1.299	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
10,000,000	0.453	0.461	0.459	0.688	0.968	1.260	1.558	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
15,000,000	0.453	0.410	0.358	0.484	0.662	0.853	1.049	1.247	1.447	1.648	1.849	2.051	2.440	3.156	3.633
20,000,000	0.453	0.384	0.307	0.382	0.509	0.649	0.794	0.942	1.091	1.241	1.391	1.542	1.924	3.069	3.633
25,000,000	0.453	0.369	0.276	0.321	0.418	0.527	0.642	0.759	0.877	0.997	1.117	1.237	1.542	2.459	3.069
30,000,000	0.453	0.359	0.256	0.281	0.357	0.446	0.540	0.636	0.735	0.834	0.933	1.033	1.288	2.051	2.560
50,000,000	0.453	0.348	0.234	0.238	0.292	0.360	0.433	0.508	0.585	0.662	0.740	0.819	1.020	1.623	2.025
100,000,000	0.453	0.345	0.228	0.225	0.273	0.334	0.400	0.469	0.539	0.611	0.682	0.754	0.939	1.494	1.863
250,000,000	0.453	0.323	0.184	0.136	0.140	0.157	0.179	0.203	0.229	0.256	0.283	0.311	0.385	0.607	0.754
500,000,000	0.453	0.319	0.176	0.120	0.117	0.125	0.139	0.156	0.174	0.193	0.213	0.233	0.287	0.450	0.559
1,000,000,000	0.453	0.319	0.176	0.120	0.117	0.125	0.139	0.156	0.174	0.193	0.213	0.233	0.287	0.450	0.559
2,000,000,000	0.453	0.315	0.168	0.104	0.092	0.092	0.098	0.106	0.116	0.127	0.138	0.150	0.184	0.285	0.352

Figure 14. Costs of hydrogen transportation in EUR per kg as a function of quantity and distance

Source: own elaboration based on [21] [22] [23] [24] [25] [26].

In this study, due to its long term outlook, we have calculated the transportation and storage costs with the assumption that the quantity of transported hydrogen (and other fuels as well) will be big enough to optimize the utilization of assets and reduce the costs. Furthermore, as has been mentioned before already, we expect that marine ports are very well suited as a potential location for local renewable hydrogen production – especially from offshore wind. This would greatly reduce the costs of hydrogen transportation. On average we have assumed around a 50 km distance from fuel production site to port.[13]

Costs of storage were estimated with an assumption that the storage facilities in port would need to be able to hold an amount of fuel sufficient for 5 days of operation.

As can be seen in the graph below, compressed hydrogen is by far the most expensive option both from the point of view of transportation as well as storage and are around 42x higher than for MGO and 6x higher than for LNG. Liquid hydrogen logistics costs are around 15x higher than for MGO and twice as high as for LNG. On the other hand, these costs are a rather small part of the total costs of fuels and are not enough to reduce to the overall cost advantage of pure hydrogen option versus synthetic fuels.

[13] Detailed assumptions available in the annexes.

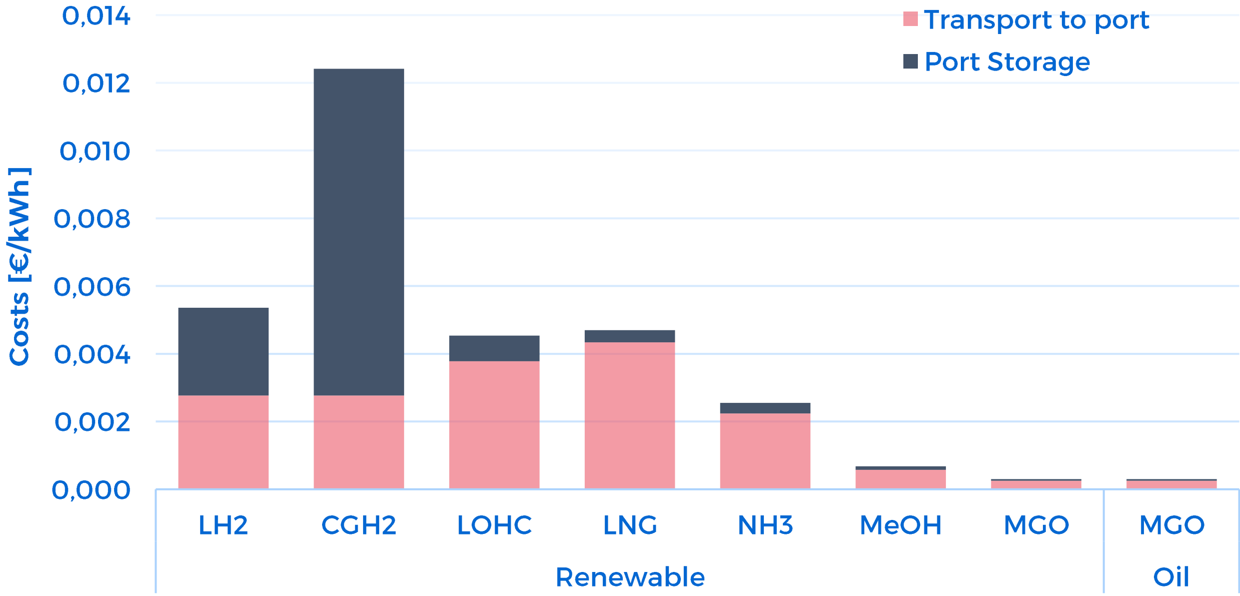

Figure 15. Costs of fuel logistics

Source: own elaboration based on [21] [22] [23] [24] [25] [26].

Note: Note that the costs of transportation in the chart below don't include costs of compression or liquefaction of hydrogen, as these costs were already accounted for in the previous step (but are shown in figure 33 for better depiction of total costs).

6.3 Volume and weight considerations

Other than fuel production costs, the energy density properties of various fuels are the most important factor determining the viability of different options for any given ship type. While the specific energy of hydrogen is almost 3 times higher than MGO's, in terms of energy density per unit of volume pure hydrogen has considerably worse properties than e-fuels.

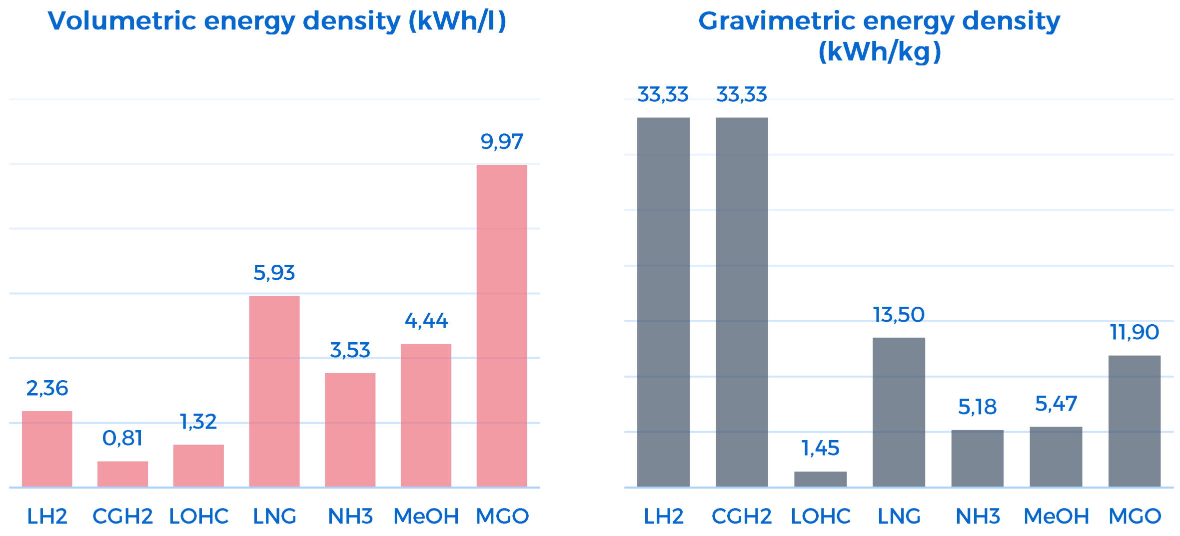

Figure 16. Volumetric and gravimetric energy densities

Source: own elaboration.

With a volumetric energy density of around 0,81 kWh/l, one cubic meter of hydrogen compressed at 350 bar contains 12 times less energy than a comparable volume of MGO and 7 times less than LNG. One cubic meter of liquid hydrogen contains over 4 times less energy than MGO and 2.5 times less than LNG. In the case of LOHC, while its volumetric energy density is higher than hydrogen at 350 bar, its specific energy is lower than that of all the other options.

Yet, just looking at energy densities of various fuels does not give the complete picture.

For example, compressed hydrogen is usually stored in cylindrical containers, with relatively thick walls, required to withstand the high pressure, adding around 20% to the fuel volume. If one would consider storing compressed hydrogen in 40-foot containers, then the space lost in between multiple containers as well as the container frame itself would add further space requirements.

In the case of cryogenic fuels like LH2 or LNG, the tanks generally have a double hull design, with a vacuum between the inner and outer container. Besides that, the tanks are rarely filled-up completely in order to leave space for the boil-off gas.

LOHC comes with its own, unique challenges. It can be stored in standard marine fuel tanks but the "spent" carrier, once the hydrogen has been extracted, needs to be also stored onboard. In case of metal hydrides depending on the reaction needed to extract hydrogen, the spent carrier can require even more space than the "loaded" one (e.g. sodium borohydride). Furthermore, as hydrogen needs to be extracted before it can be used, additional dehydrogenation equipment and hydrogen purification equipment needs to be accommodated as well. Similarly, to be able to

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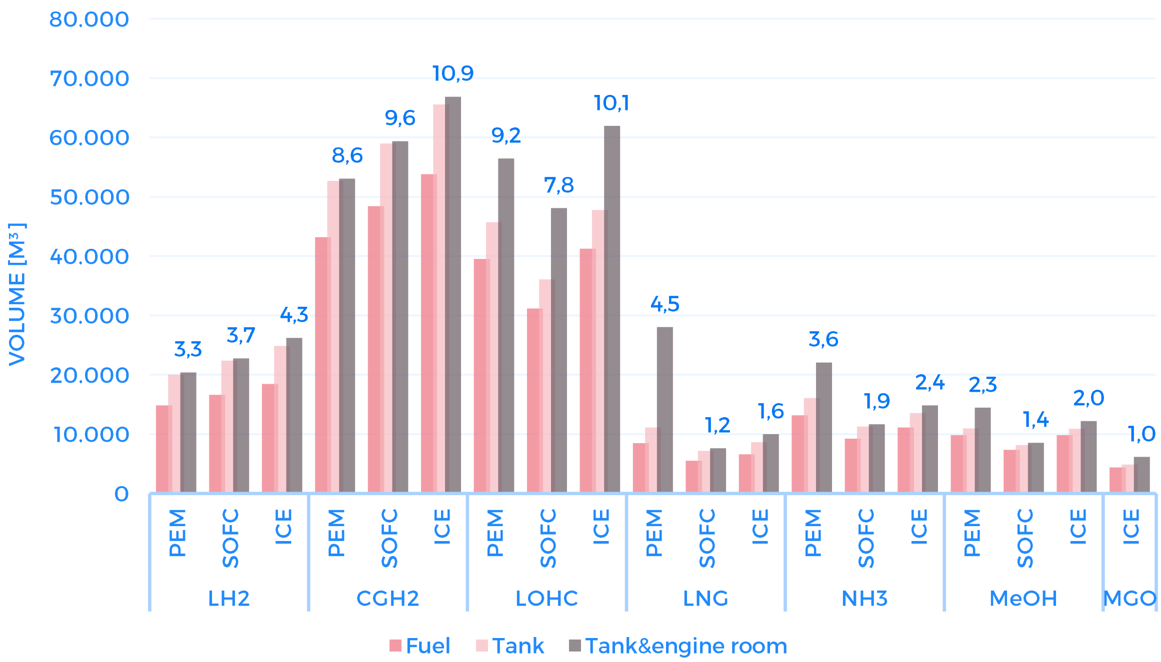
use PEM FC in combination with any of the e-fuels, additional fuel reforming/cracking equipment would have to be included in the powertrain setup, increasing the overall space requirements of the system.

On the other hand, there are also potential gains from using fuel cells. Firstly, fuel cells themselves take-up less space than an ICE of comparable power output. Furthermore, using hydrogen in combination with fuel cells allows to eliminate the exhaust treatment system, which - especially in multi-deck vessels - might free up a substantial amount of space. Fuel cells are also more energy-efficient than an ICE, making it possible to carry less fuel on board, for the same final energy output. This effect would be further strengthened by the fact, that the efficiency of fuel cells increases in partial load.

All things considered, the exact impact of using alternative fuels on commercial space available on any given ship would need careful examination on a case-by-case basis. For the purpose of this analysis, however, we have applied several general assumptions to take into account the different requirements of various technologies with regards to the fuel storage system and energy system (fuel reforming and engine or fuel cell) space requirements[14]. The following figure presents the results of the calculations done for a 8,000–11,999 TEU Containership. The figure shows total space requirements for fuel both in terms of cubic meters as well as relative to an MGO + ICE.



[14] See Annex 4 for details.

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Figure 17. Fuel volume (absolute & relative factor to MGO), example calculation for 8,000–11,999 TEU Containership

Source: own elaboration.

As can be seen, in some cases the additional space requirements are quite significant. For LOHC one can see that, although the energy density of the LOHC itself is higher than that of hydrogen compressed to 350 bar, considering the additional buffer tank for dehydrogenated liquid as well as space for the dehydrogenation system, the final space demands are in fact not much better than that of compressed hydrogen. On the other hand, when combining the LOHC with a SOFC, which allows for the possibility of using the fuel cell waste heat to maintain the dehydrogenation process, total space requirements for a system based on LOHC can be greatly reduced.

All options combining synthetic fuels with a PEMFC suffer from similar negative impact from extra space needed for the necessary fuel cracking/reforming/purification step – which is not necessary for a combustion engine or a high-temperature SOFC, where it's possible to use those fuels directly without prior reforming. In addition to that, in the case of SOFC, using e-fuels, instead of pure hydrogen has also benefits in the form of increased efficiency.

All things considered, it is clear though that for all options a switch to alternative fuels will require more space dedicated to the fuel and energy systems that were the case with standard marine fuel oils. This will not only translate into costs of storage tanks and extra equipment but will also impact on the ship’s capacity to carry passengers and/or cargo.

The severity of the impact will of course vary and will depend not only on the chosen technology but will also greatly depend on the ship’s operational profile. It will be most felt for business models which require high operational flexibility and cannot be refuelled often. On the other hand, when ships operate on fixed and relatively short routes, then - even for quite large vessels, like ro-pax ferries – it's possible to use even compressed hydrogen as a solution.

Consequently, the economic impact of the fuel storage on the total cost of ownership of various ship types will also differ dramatically – especially if one looks not only at the cost of equipment and tanks but also on the economic value of lost revenue generation potential.

Taking into account current freight rates per TEU on certain most common routes or charter rates per day per ship, for each ship type we have estimated the potential revenue generation capacity per year. With that estimations, the next step was to translate the lost payload capacity into lost revenues. The results of this analysis have shown that for most of the ships, the economic impact from lost revenues outweigh costs of the tanks – even in cases where the storage system is expensive (e.g. compressed and liquefied hydrogen).

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At the same time, the analysis has also shown that, while the relative "position" of various options against each other remains the same, the monetary impact for short sea applications is much smaller. In other words, while the costs of storage for compressed hydrogen are always the highest for short sea shipping applications the additional costs versus other options are much more manageable and don't outweigh lower production costs of compressed hydrogen.

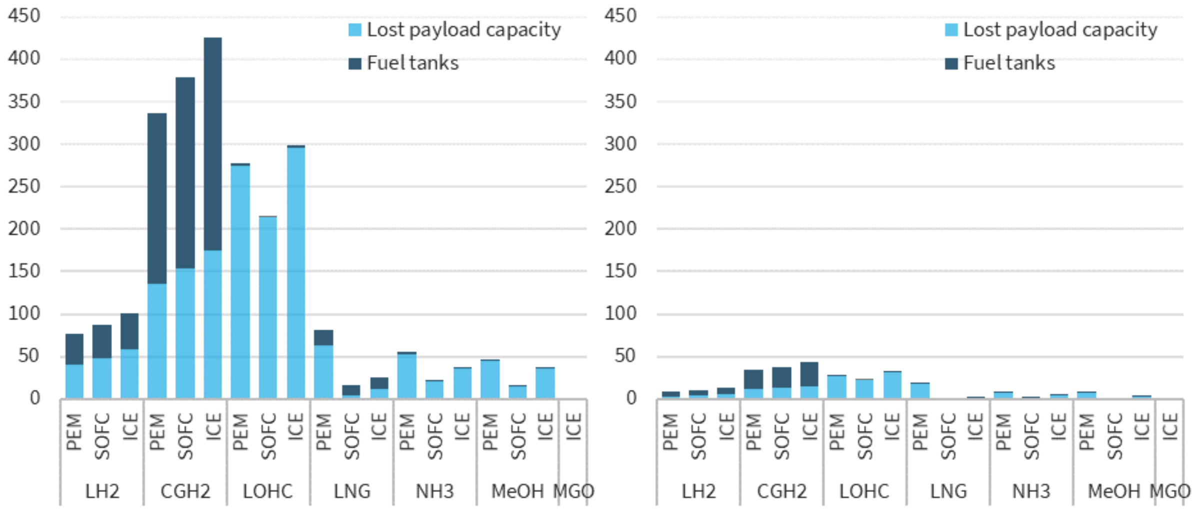

Figure 18. Estimated economic costs of the onboard energy storage system (in EUR/nm/ship), for an 8,000–11,999 TEU containership (left graph) and a 2000 – 2,999 TEU feeder vessel (right graph)

Source: own elaboration.

It should also be mentioned that there are still plenty of opportunities in the shipping sector to increase the energy efficiency of ships thus reducing the amount of fuel that needs to be stored on board and reduce the economic importance of fuel energy density. Technical and operational measures like:

- hull shape optimization,
- use of lightweight materials,
- air lubrication,
- hull resistance reduction devices,
- ballast water reduction,
- hull coating improvements,
- speed and voyage route optimization,

can increase the energy efficiency of ships by 20-30%. Combined with other alternative power solutions like e.g. wind assistance, these measures can be therefore seen as enablers for clean sustainable fuels uptake in the maritime sector.

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6.4 Energy conversion

The energy conversion step includes both the fuel transformation/conditioning onboard (if needed) and the power generation.

Using LOHC (as well as metal hydrides) for energy storage onboard will require dehydrogenation equipment to first 'extract' hydrogen from the hydrogen carrier. This, of course, adds to overall costs but also contributes to higher space requirements – not only for the dehydrogenation unit but, in case of no waste heat being available, also for the extra fuel needed to maintain the dehydrogenation process. Similar problems occur for all synthetic fuel options if coupled with PEMFC, which require high purity grade hydrogen as a fuel. This makes high-temperature SOFC a more preferable option for use with ammonia and other synthetic fuels.

On the other hand, with their higher electrical efficiency when running on pure hydrogen, coupled with lower CAPEX, faster start and ramp-up time, PEMFC look set to be the optimal solution to be used with compressed and liquefied hydrogen.

For power generation, we include an internal combustion engine and two types of fuel cells: Polymer electrolyte membrane fuel cells (PEMFC) and Solid oxide fuel cells (SOFC). Fuel cells use the chemical energy of fuels such as hydrogen, ammonia or hydrocarbon gas to produce electricity and thermal energy. If fuel cells use hydrogen directly, the only emitted by-product is water, i.e. there are no emissions of GHG or any air pollutants, such as NOx, SO2 or PM.

Fuel cells have a high electrical generation efficiency compared to most other generator technologies (reciprocating engines, gas turbines without combined condensing cycles). The efficiency of a gas-fueled internal combustion engine is around 42-45% for small units and up to 48-50% for large multi-MW engines, with a couple of percentage points lower efficiencies, when fuelled with liquid fuel oils. Electrical efficiency of PEMFC is usually around 50-56% and in the case of SOFCs electrical efficiencies of over 70%[15] on a stack level and over 60% on a system level have been demonstrated.

It should also be noted that, while internal combustion engine technology is mature and expected future efficiency improvements are limited, the efficiency of fuel cells is expected to go up considerably. According to the Strategic Research and Innovation Agenda of the foreseen Clean Hydrogen for Europe Partnership[16],

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[15] https://www.fch.europa.eu/news/performance-sofc-stack-breaks-record-thanks-project-nellhi

[16] The third EU public-private partnership, continuation of the FCH2JU. The Strategic Research and Innovation Agenda is made of a set of 21 roadmaps. This SRIA represents the view of the private partner and will be used as a basis to develop the Multi Annual Work Plan (MAWP) of the Clean Hydrogen for Europe partnership. The current version (July 2020) is the final draft that has been submitted to the European Commission and is available at https://hydrogeneurope.eu/clean-hydrogen-europe.

prepared by Hydrogen Europe and Hydrogen Europe Research, the target of research is to reach electrical efficiencies of 58% for PEMFCs and 65% for SOFCs by 2030. [27]

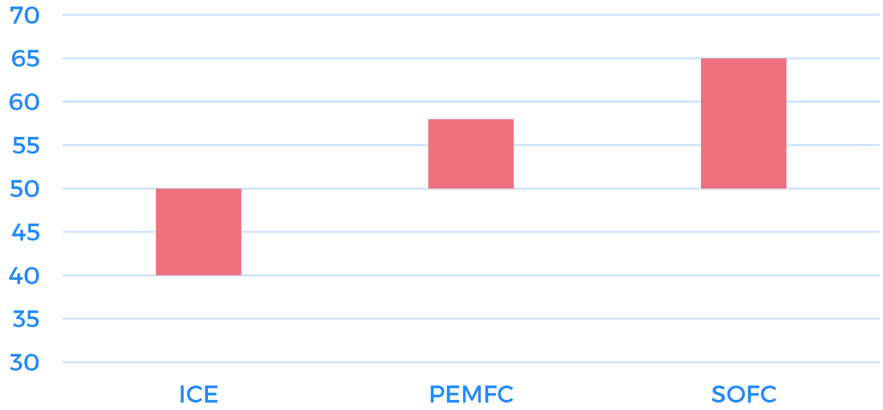

Figure 19. Electrical efficiency comparison of an internal combustion engine with PEMFCs and SOFCs

Source: own elaboration.

Yet, it needs to be remembered that fuel cells generate electricity directly, while internal combustion engines generate primarily mechanical energy. Therefore whenever electricity is needed ICE has to convert the energy in the fuel first into mechanical energy and then into electrical energy, further reducing the efficiency. This increases the efficiency advantage of fuel cells for use as a source of auxiliary power or as main power for large ships, which use diesel-electric powertrains (e.g. large ferries). Conversely, for propulsion needs, the advantage of fuel cells would be slightly diminished by the need to convert electrical energy to mechanical energy via an electric motor.

Another difference in favour of fuel cells is the shape of the load-efficiency curve. For internal combustion engines, the maximum efficiency is usually reached at around 0,7 – 0,85 of rated power but at loads below 50%, the ICE efficiency starts to drop sharply.

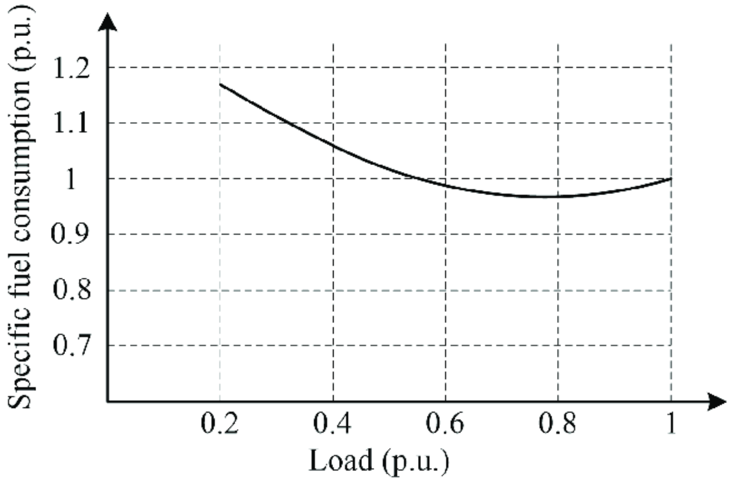

Figure 20. Typical specific fuel consumption curve of a marine diesel-engine

Source: [28].

This is not the case with fuel cells, which have a much flatter efficiency curve, which starts to drop below its level at maximum power only below 10% of load. Furthermore, within the entire load range between 20%-90% of rated power, the efficiency of a fuel cell is higher than at maximum power, which gives higher operational flexibility than an internal combustion engine.

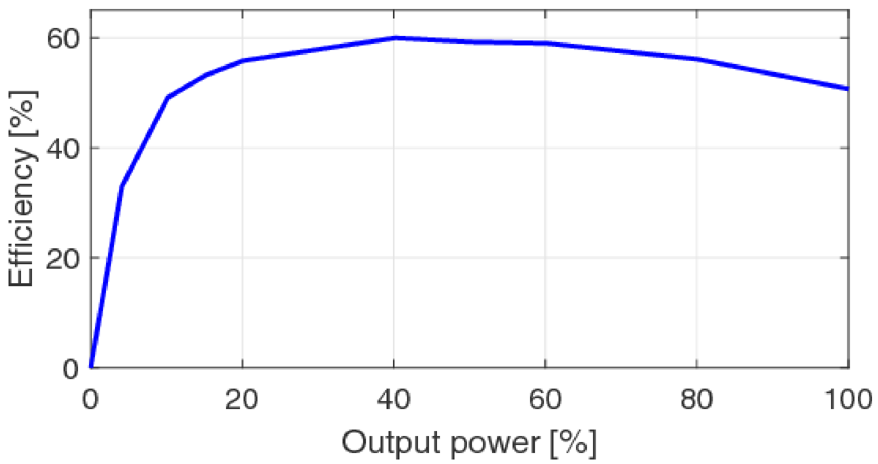

Figure 21. Typical efficiency curve of a PEMFC

Source: [29].

Fuel cells have also other advantages over combustion engines: they have no moving parts – as a result, they are quiet, require no oil changes and minimal maintenance. Fuel cells are also easily scalable, as individual cells can be stacked together to provide a wide range of power.

Another consideration is the heat supply. PEMFC typically operate at about 80°C, which isn't high enough to provide a meaningful source of thermal energy. As a result, ships with significant heat demand would need an additional hydrogen boiler.

SOFCs operate at much higher temperatures - typically 800°C to 1,000°C – and, as such, can cover the heating demand as well. On the other hand, high temperatures make rapid start-up challenging, while PEMFC can respond quickly to changing loads.

So far fuel cells have been deployed mostly as small scale CHP or in road mobility applications. Researchers have developed these components to the point where they have the operational reliability to allow them to be deployed in small series production to mainstream vehicle customers (1,000s of units in the US and Asia); the main driver for fuel cell technology in Europe is heavy-duty applications (over 1,600 buses to be deployed). The fuel cell stacks operating in London's buses since 2010 have lasted for over 25,000 hours, thereby proving their possible longevity in a heavy-duty vehicle at least for this specific usage.

The challenge now is to reduce cost through a combination of increased production volume as well as technology development to improve and automate production techniques, reduce material costs per unit of output (specifically, costs of precious metals used as catalysts in fuel cells and carbon fibre in tanks) and improve designs at stack (e.g. catalyst layers) and system BoP components level (e.g. air loop). Although, as demonstrated in the graph below, **the impact of fuel cell / ICE cost in the Total Cost of Ownership is rather small** in comparison to other elements, like fuel costs and cost of storage (including impact on ships payload capacity).

The onboard fuel reforming system has a much higher impact on TCO than the engine/fuel cell. Even though the costs of those systems are likely to fall following an increase in production volume, they are likely going to remain relatively expensive because, unlike fuel cells, the demand for those systems outside of maritime sector will most likely remain limited and because of fuel cell losses, the fuel reforming system needs to have twice the power output than the fuel cell it's is used to supply fuel to.

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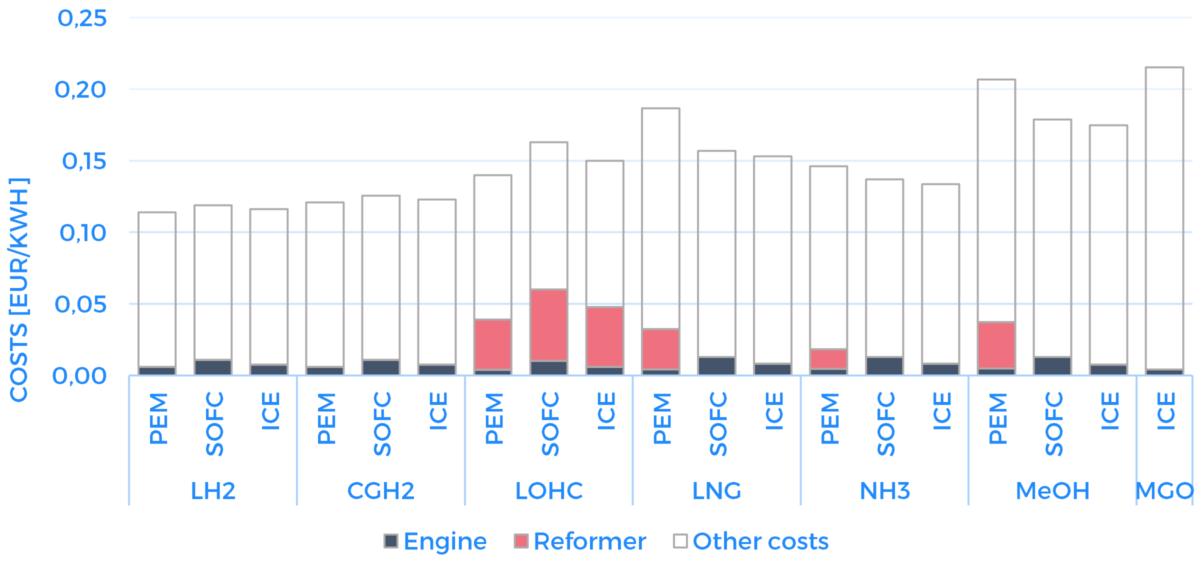

Figure 22. Energy conversion system cost comparison.

Source: own elaboration.

6.5 Total costs of ownership comparison

AS mentioned the shipping sector involves a wide range of use cases, with both the power requirements and onboard fuel storage of vessels differing by multiple orders of magnitude. This highlights the importance of defining different strategies for zero-emission propulsion for each vessel type.

To illustrate this, on the following pages we have presented results of the analysis for three various cases:

- **Inland passenger ship** – with both low power requirements and many bunkering opportunities, resulting in low onboard energy storage demand.
- **Ro-pax ferries** – large vessels with substantial power requirements but operated on short routes with frequent refuelling possibilities.
- **PSV** – Medium size vessels but with relatively high power requirements and medium range requirements.

6.5.1 Inland passenger ships

The analysis shows that **for these types of ships compressed hydrogen option is the most cost-competitive**. This is not surprising as those are usually small ships navigating on fixed routes with the possibility of relying on fixed bunkering points along their routes. Onboard, storage will not be an issue because of shorter/fixed routes. In many cases, onshore fuel cell technology and Hydrogen Refuelling Stations (HRS) can be used or adapted.

It should also be noted, that although compressed hydrogen is the cheapest option, its lower production costs are somewhat reduced by higher than in other options costs of fuel logistics and as a result, the costs of liquefied hydrogen are only slightly higher. Ammonia option is 12% more expensive and the cheapest of e-fuels. Even the cheapest hydrogen option is more than twice as expensive as MGO (at 500 USD/t).

As neither compressed nor liquefied hydrogen needs any reforming, PEMFC is the preferred energy converter due to its lower price.

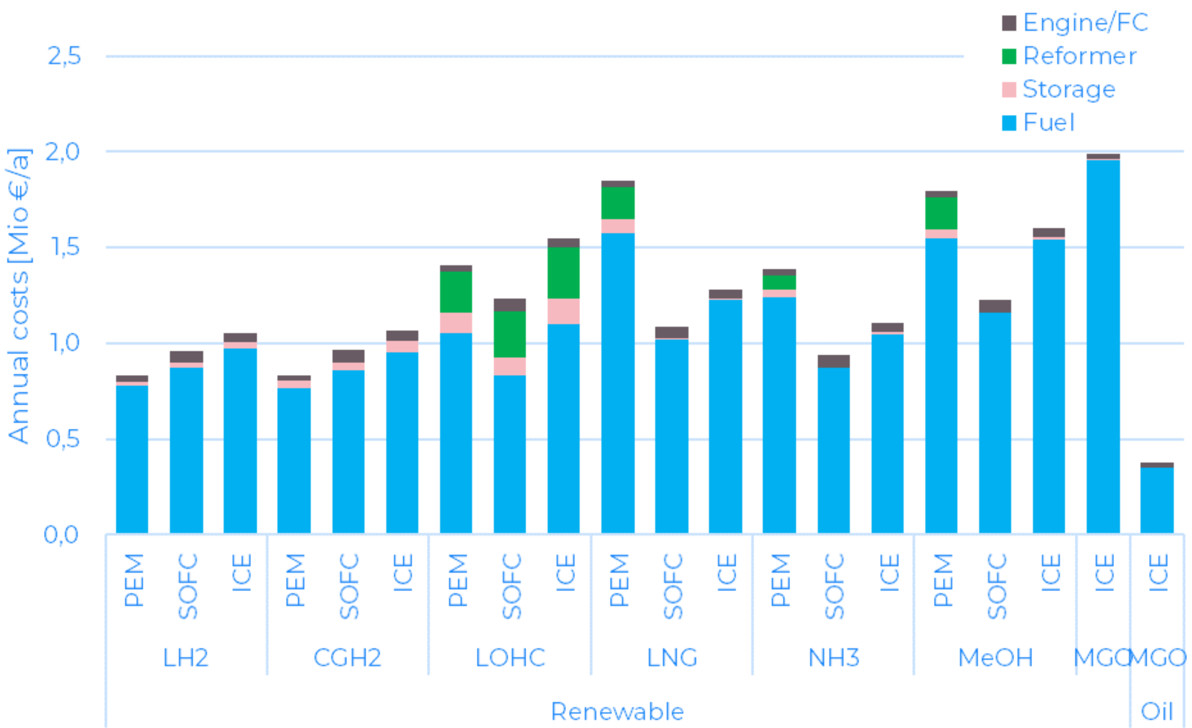

Figure 23. TCO analysis (in M€ p.a.) for inland passenger ferry

Source: own elaboration.

6.5.2 Ro-pax ferry

For these vessels, liquefied hydrogen is the most cost-competitive option by a significant margin. This category includes among others ROPAX (roll-on/roll-off passenger)[17] ships. Larger power generation units will be required (from 1MW to 15-25MW), however with limited autonomy, as these ships usually operate on a sea link between fixed two ports. This makes it relatively easy to provide the necessary bunkering infrastructure and will make these ships the likely first adopters (along with type 1 vessels), especially for liquefied hydrogen solutions.

In an example 10,000 – 19,999 GT Ro-Pax ferry, liquefied hydrogen is around 12% less expensive than the next best option (ammonia), and 14% less expensive than compressed hydrogen. On the other hand, its still twice as expensive as MGO.

[17] a RORO vessel built for freight vehicle transport along with passenger accommodation

For this sector to start adopting hydrogen as a fuel, important regulatory issues still need to be addressed and upscaling to these high-power generation units will require new technology developments.

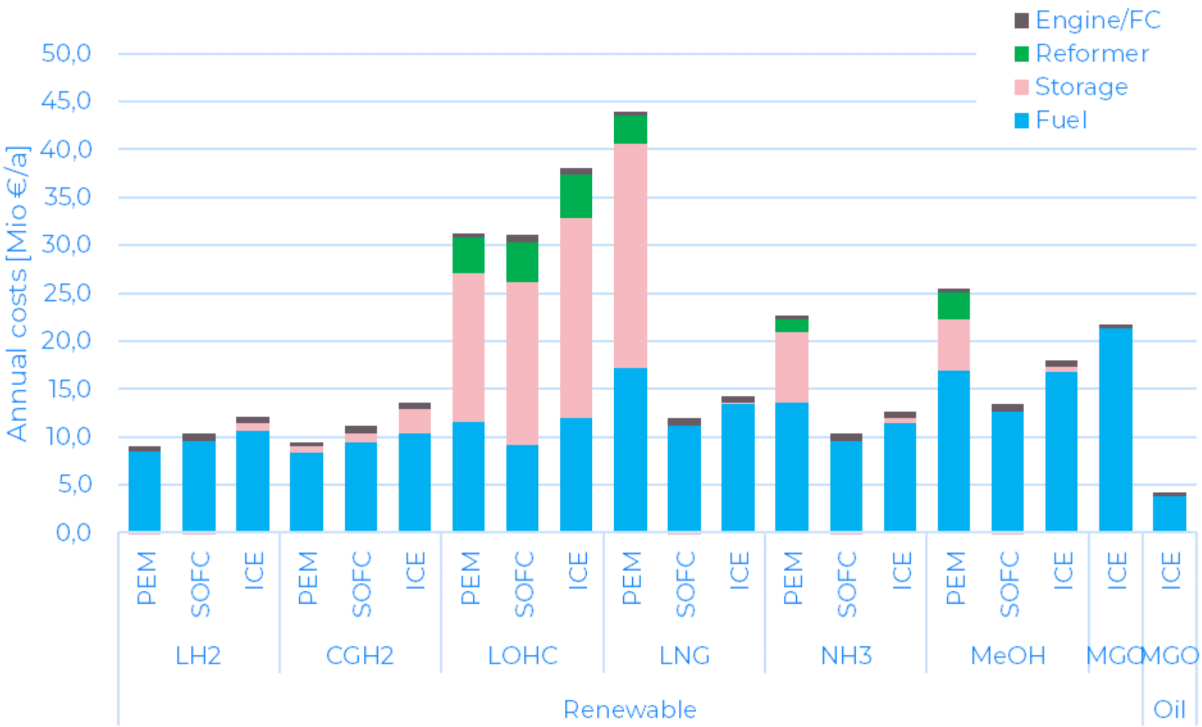

Figure 24. TCO analysis (in M€ p.a.) for a 10,000-19,999 GT RO-PAX ferry

Source: own elaboration.

6.5.3 PSV

The results for a PSV vessel are not much different than for a ro-pax ferry, with liquefied hydrogen the most cost-competitive zero-emission option. The analysis shows LH2 being 5% less expensive than compressed hydrogen, 18% than ammonia, and more than 31% than e-LNG.

Although it should be noted that this category is quite diverse. These ships are generally characterized by reduced hull dimensions and a very high number of systems and equipment on-board. Power needs are therefore dominated by propulsion and the operation of on-board equipment. These vessels could be served in distinct clusters (e.g. from a fishing port) to minimize infrastructure costs. Nevertheless, these ships will still require considerable onboard energy storage, which – combined with limited space available for extra fuel storage, makes energy dense synthetic fuels an option – even if more expensive. Much will therefore depend on the distance from the offshore wind farm to the ship's base port.

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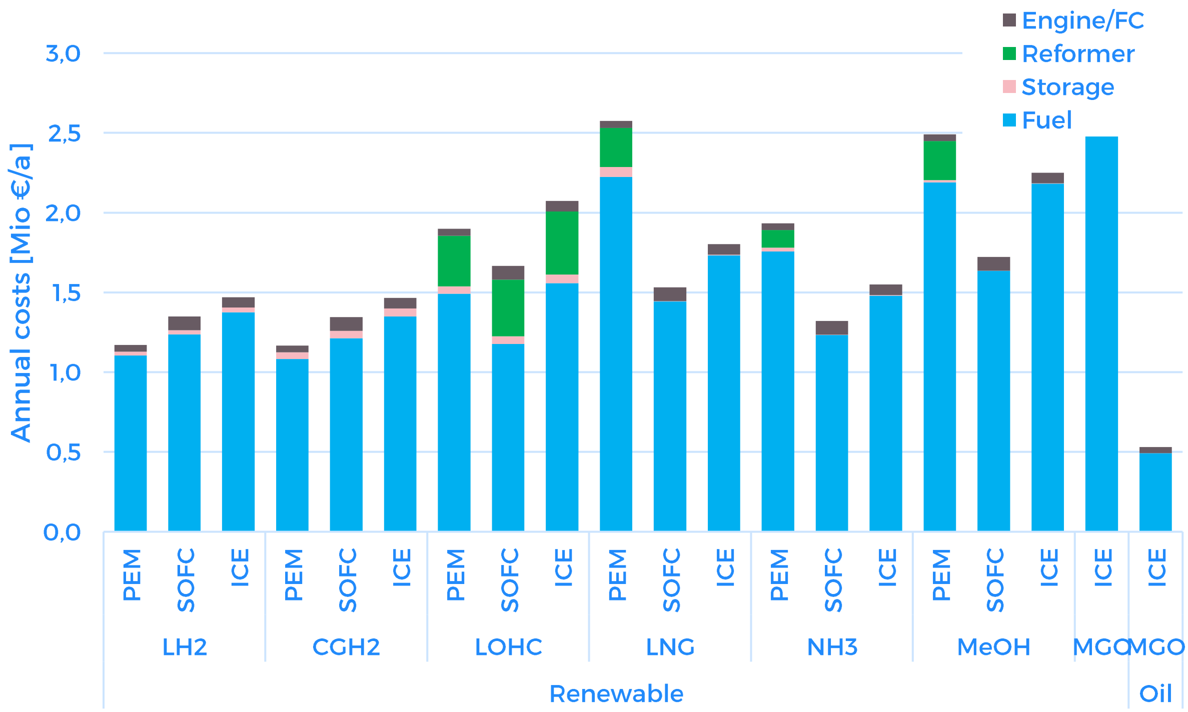

Figure 25. TCO analysis (in M€ p.a.) for a PSV vessel
Source: own elaboration.

6.5.4 Summary

When repeating the exercise for all 34 ship types, what the results show is that out of all analysed options it's **only two that ever come out as the most cost-efficient**:

- **Compressed hydrogen with PEM FC** for relatively small ships with an operational profile that allows for frequent refuelling, limiting the required amount of fuel that needs to be stored onboard, or for larger ships but ones which can more easily accommodate the extra volume of fuel needed.
- **Liquefied hydrogen with PEMFC** for ships with more energy storage requirements, where storing energy in the form of compressed hydrogen is not viable (even if the fuel itself is cheaper).

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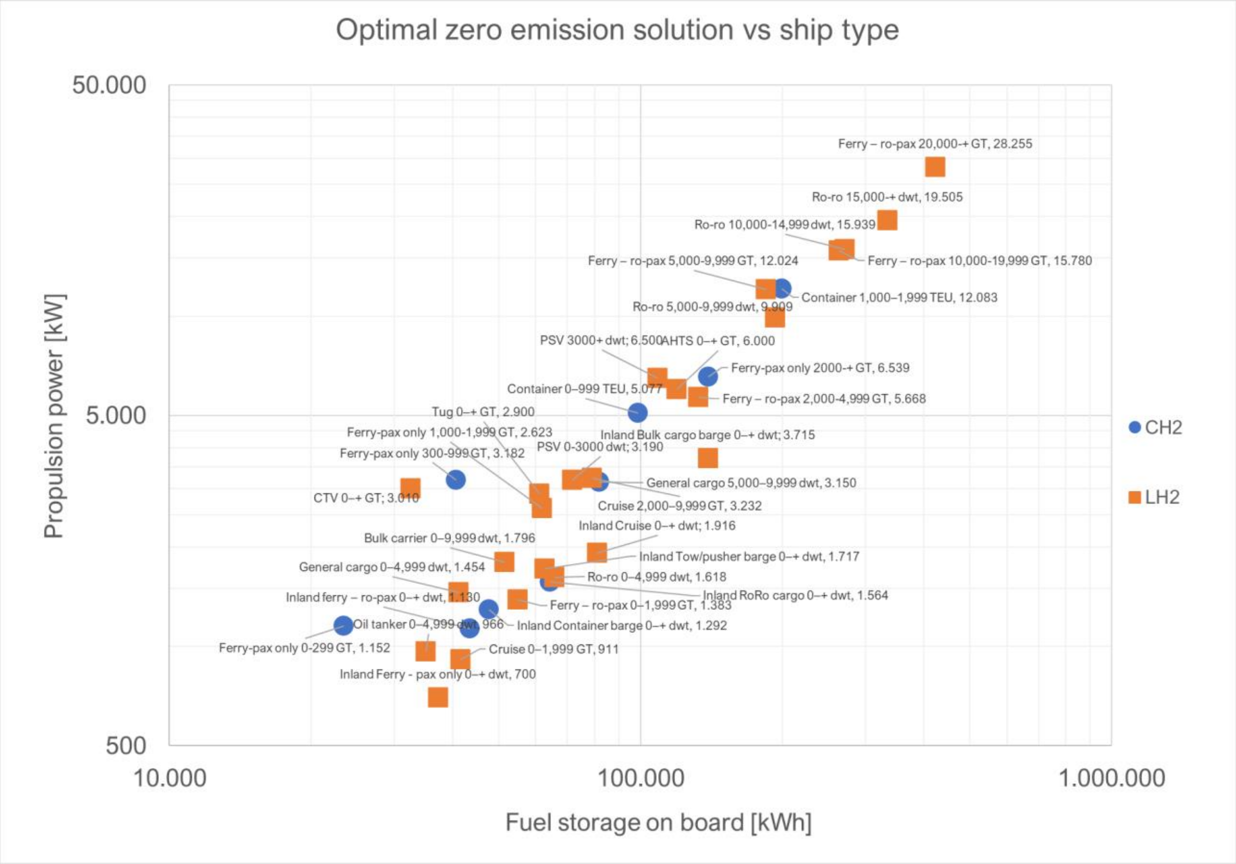

Figure 26. Optimum zero-emission option for various ship types
Source: own elaboration.

The overall costs of all options for every ship type are well above the fossil fuel option (MGO at 500 USD/t). This is of course not unexpected, given the low fossil fuels costs, supported by low, to non-existent taxation put on marine fuel oils. The cost difference is one of the key barriers that need to be tackled in order to see a real uptake of zero-emission fuels in the maritime sector, which would go beyond just demonstration projects and which could have a real impact on reducing the sector's GHG emissions. Some of the ways of overcoming the cost difference, currently under consideration in the EU is to on one hand to impose zero-emission obligation quota on ship operators or to impose a carbon price on marine fuels.

An analysis of the required CO2 cost break-even point (i.e. a CO2 price at which the cheapest zero-emission, hydrogen based option would reach cost parity with MGO) shows that, depending on ship type, for the CO2 price to provide a sufficient incentive to switch from fossil fuel oils to zero-emission fuels, it would have to be between EUR 115 per tonne of CO2 to EUR 150 per tonne of CO2.

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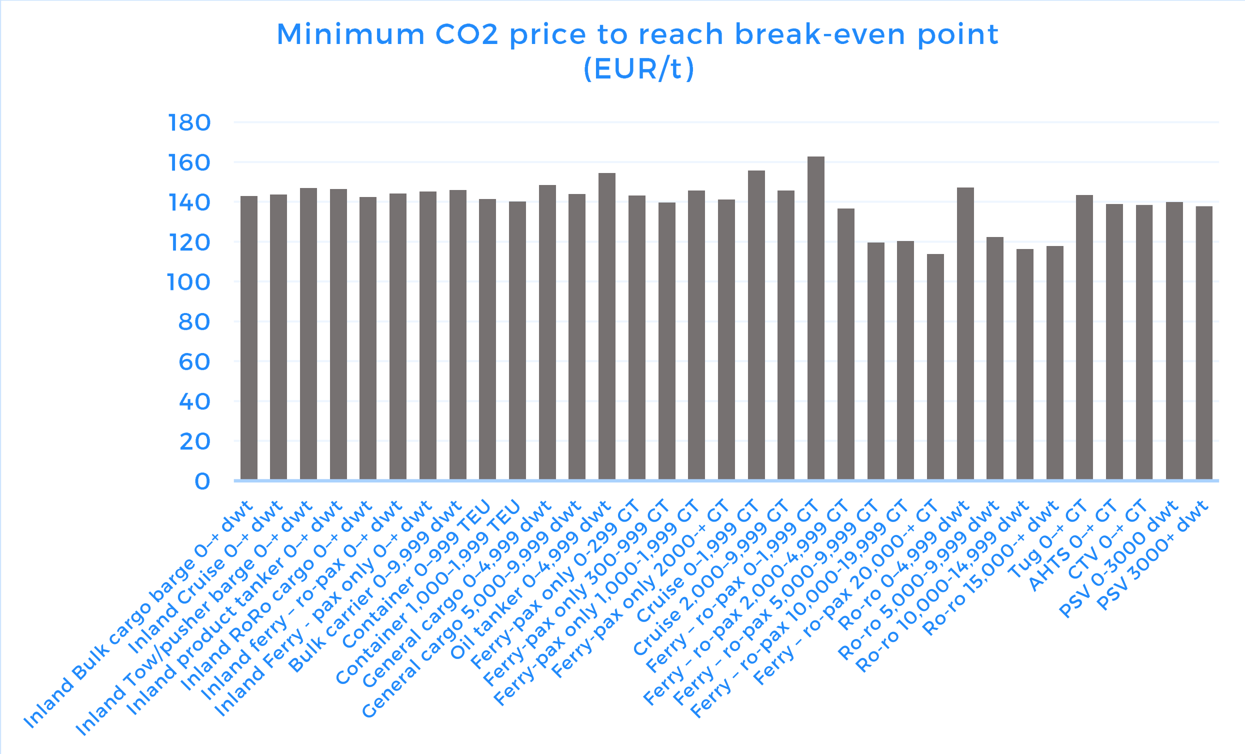

Figure 27. Minimum CO2 price to reach a break-even point

Source: own elaboration.

This is of course well above the current EU ETS CO2 emission allowance price of around EUR 30-35 per tonne of CO2. As a result, it is clear that if the inclusion of the maritime sector in the ETS alone would not be a sufficient measure.

On the other hand, the EU ETS carbon price would still impose around a 40x higher carbon tax on fuels than the proposed R&D fund proposed by the International Council of Shipping, which assumes contributions of USD 2 per tonne of fuel consumed by every ship.

7 Results sensitivity analysis

As is the case with every analysis of this kind, it is heavily influenced by a number of key assumptions, which bring a considerable amount of uncertainty to the end results. To reduce this uncertainty, in the following chapter, we have analysed the extent that those key assumptions can influence the results. The identified key risk factors include:

- Hydrogen production costs;
- Hydrogen liquefaction costs;
- Minimum required bunkering frequency;

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7.1 Hydrogen production costs

As mentioned before, this analysis assumes that hydrogen used as a fuel or as feedstock to produce e-fuels would be of renewable origin - produced via water electrolysis using renewable electricity, at a cost of around **2.4 EUR/kg**. While this is a level that would be hard to achieve today in Europe, at least outside of a limited number of location in the South of Europe with extremely good solar irradiation, by 2030 we expect that due to continuous technology developments leading to reduction of electrolyser CAPEX coupled with a continuation of the downwards renewable energy costs trend, we expect this cost level to be attainable in most of the EU. More long-term, renewable hydrogen is expected to be cost-competitive with even fossil fuel-based hydrogen reaching production costs of around 1.0 – 1.2 EUR/kg. The graph below shows the impact of a fall of electrolyser CAPEX and reduction of renewable energy LCOE would have on the production costs of hydrogen.

< USD 2/kg | USD 2-3/kg | USD 3-4/kg | > USD 4/kg | Viable medium-term (<2030)

LCOE \ Capex electrolyser	USD 750/kW					USD 500/kW					USD 250/kW				
UDD 0/MWh	5.7	2.8	1.9	1.4	1.1	4.2	2.1	1.4	1.1	0.9	2.8	1.4	0.9	0.7	0.6
USD 10/MWh	6.1	3.3	2.4	1.9	1.6	4.7	2.6	1.9	1.5	1.3	3.2	1.9	1.4	1.2	1.0
USD 20/MWh	6.6	3.8	2.8	2.4	2.1	5.2	3.0	2.3	2.0	1.8	3.7	2.3	1.9	1.6	1.5
USD 30/MWh	7.1	4.2	3.3	2.8	2.5	5.6	3.5	2.8	2.5	2.2	4.2	2.8	2.3	2.1	2.0
USD 40/MWh	7.5	4.7	3.8	3.3	3.0	6.1	4.0	3.3	2.9	2.7	4.6	3.2	2.8	2.6	2.4
USD 50/MWh	8.0	5.2	4.2	3.7	3.5	6.5	4.4	3.7	3.4	3.2	5.1	3.7	3.2	3.0	2.9
USD 100/MWh	10.3	7.5	6.5	6.1	5.8	8.9	6.7	6.0	5.7	5.5	7.4	6.0	5.6	5.3	5.2
Load factor	10%	20%	30%	40%	50%	10%	20%	30%	40%	50%	10%	20%	30%	40%	50%

Figure 28. Renewable hydrogen production costs (in USD/kg) depending on CAPEX, electrolyser load factor and renewable energy LCOE

Source: [30].

Furthermore, there are many more ways of producing clean hydrogen, including among others, steam or autothermal reforming of natural gas with carbon capture and storage, reforming of biogas/biomethane, gasification of biomass or waste, or water electrolysis using nuclear electricity. All those pathways have their own cost dynamic and may prove to provide an even cheaper hydrogen supply opportunity.

Considering all of the above, we have done an analysis showing what would the results of the analysis be if hydrogen production costs would significantly differ from the one assumed in the base analysis.

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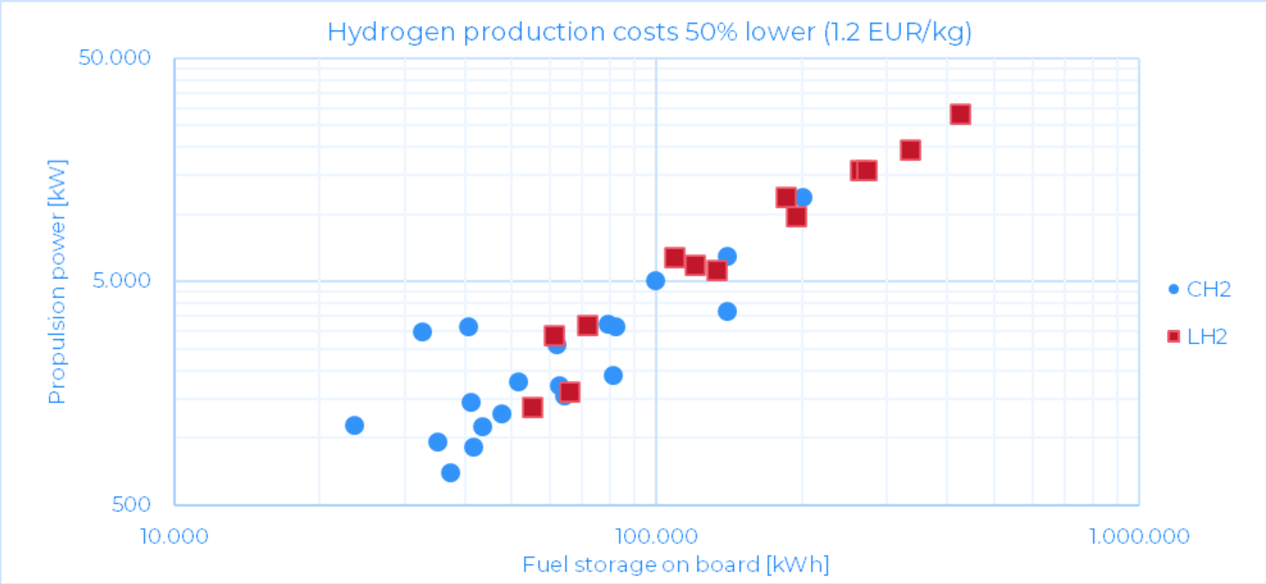

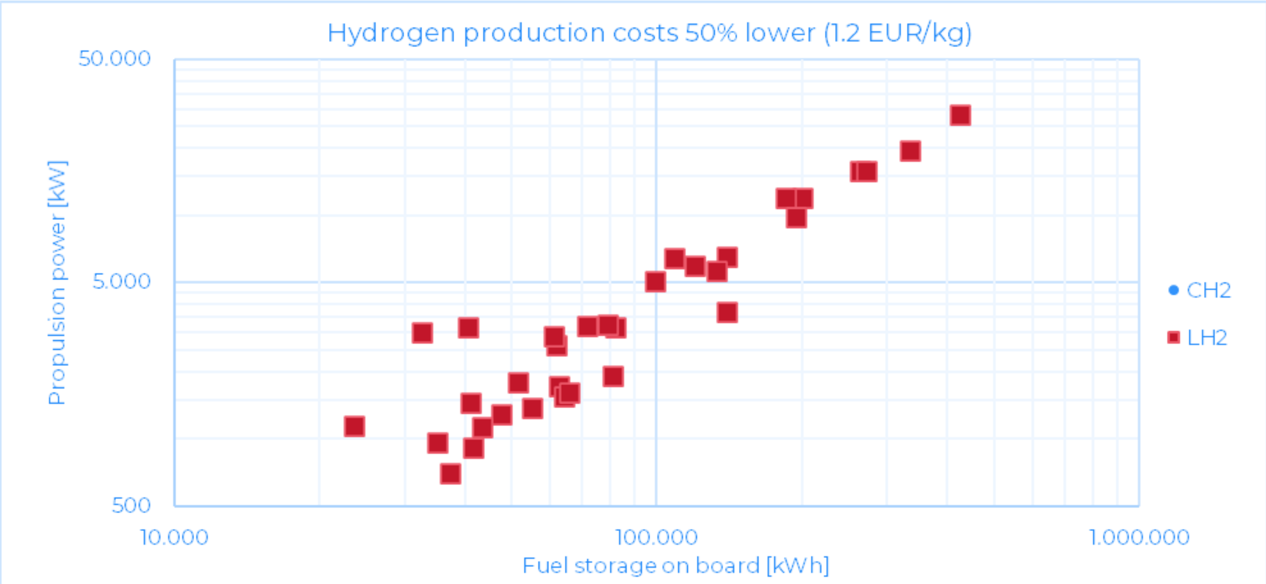

Figure 29. The sensitivity of results to changes in hydrogen production costs

Source: own elaboration

As can be seen in the graphs above a dramatic fall of clean hydrogen production costs would make liquefied hydrogen the preferred option for all ship types. This is because as hydrogen would get cheaper, the energy losses from the liquefaction process would have a less significant impact on overall costs and hence the superior energy density of liquefied hydrogen would make it the most attractive option.

7.2 Hydrogen liquefaction costs

As the market for liquefied hydrogen in the EU today is limited to a number of niche applications, all the hydrogen liquefaction facilities in Europe are rather small scale with a capacity of 5 – 10 tonnes per day (TPD). If there would be a large scale demand for liquefied hydrogen from the maritime sector it would make it viable to construct liquefaction facilities with capacities of an order of magnitude larger. This would enable to not only reduce the CAPEX per unit of production but also would lead to a significant reduction in energy intensity of the liquefaction process bringing it down from around 10 kWh per kg of hydrogen to even 6 kWh per kg – leading to a decrease of specific liquefaction costs even by 2/3 compared to current state-of-art.

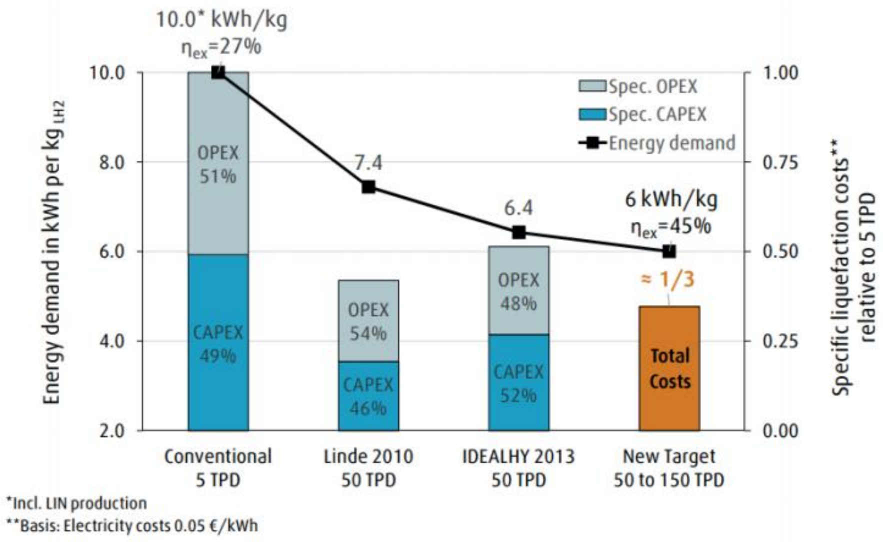

Figure 30. Current and projected liquefaction costs and efficiencies.

Source: [31].

As the market for liquefied hydrogen in the EU today is limited to a number of niche applications, all the hydrogen liquefaction facilities in Europe are rather small scale, with a capacity of 5 – 10 tonnes per day (TPD). If there would be a large scale demand for liquefied hydrogen from the maritime sector it would make it viable to construct liquefaction facilities with capacities of an order of magnitude larger. This would enable to not only reduce the CAPEX per unit of production but also would lead to a significant reduction in energy intensity of the liquefaction process bringing it down from around 10 kWh per kg of hydrogen to even 6 kWh per kg – leading to a decrease of specific liquefaction costs even by 2/3 compared to current state-of-art.

As is shown on the graphs below, this would also make liquefied hydrogen the most cost-efficient option for all analysed ship types.

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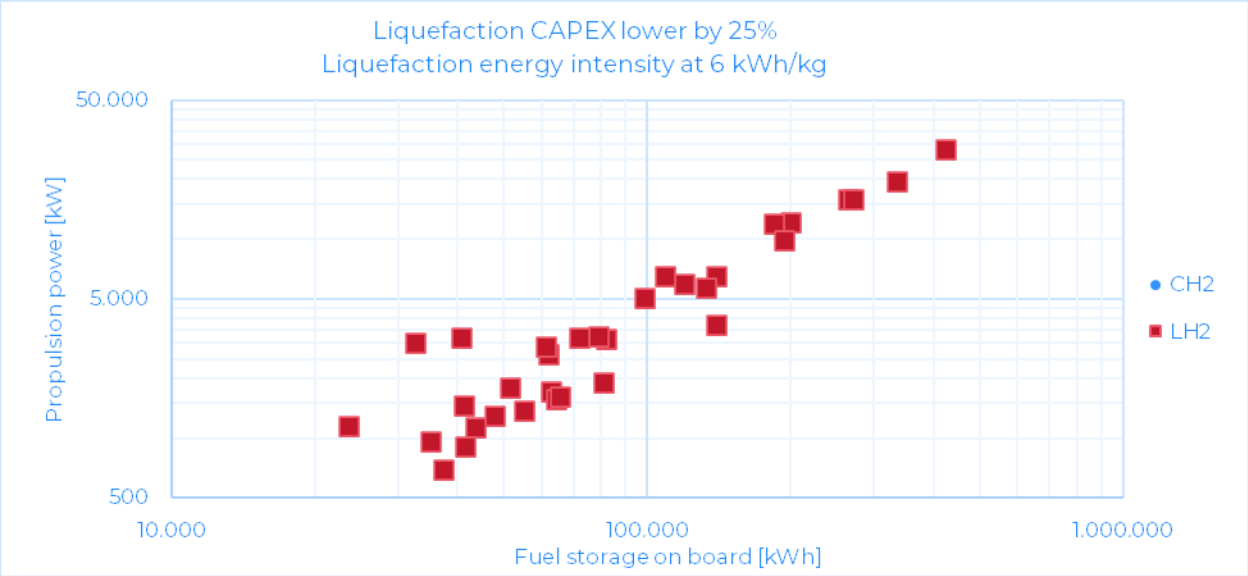

Figure 31. The sensitivity of results to changes in hydrogen liquefaction costs
Source: own elaboration.

7.3 Refuelling frequency

As mentioned the refuelling frequency is one of the key factors in the analysis. Depending on the minimum distance a ship needs to be able to travel on a single tank, the impact of low energy density of hydrogen changes significantly.

For the assumed 200 nm of minimum distance, the compressed and liquefied hydrogen options between them cover all analysed ship types. If the minimum refuelling distance would be increased twice to 400 nm, then compressed hydrogen is never the cheapest option – losing out in each case to liquefied hydrogen or even to synthetic fuel for tugs. Increasing the minimum distance to 1000 nm makes synthetic fuels (ammonia) the optimal option for most sea going vessels.

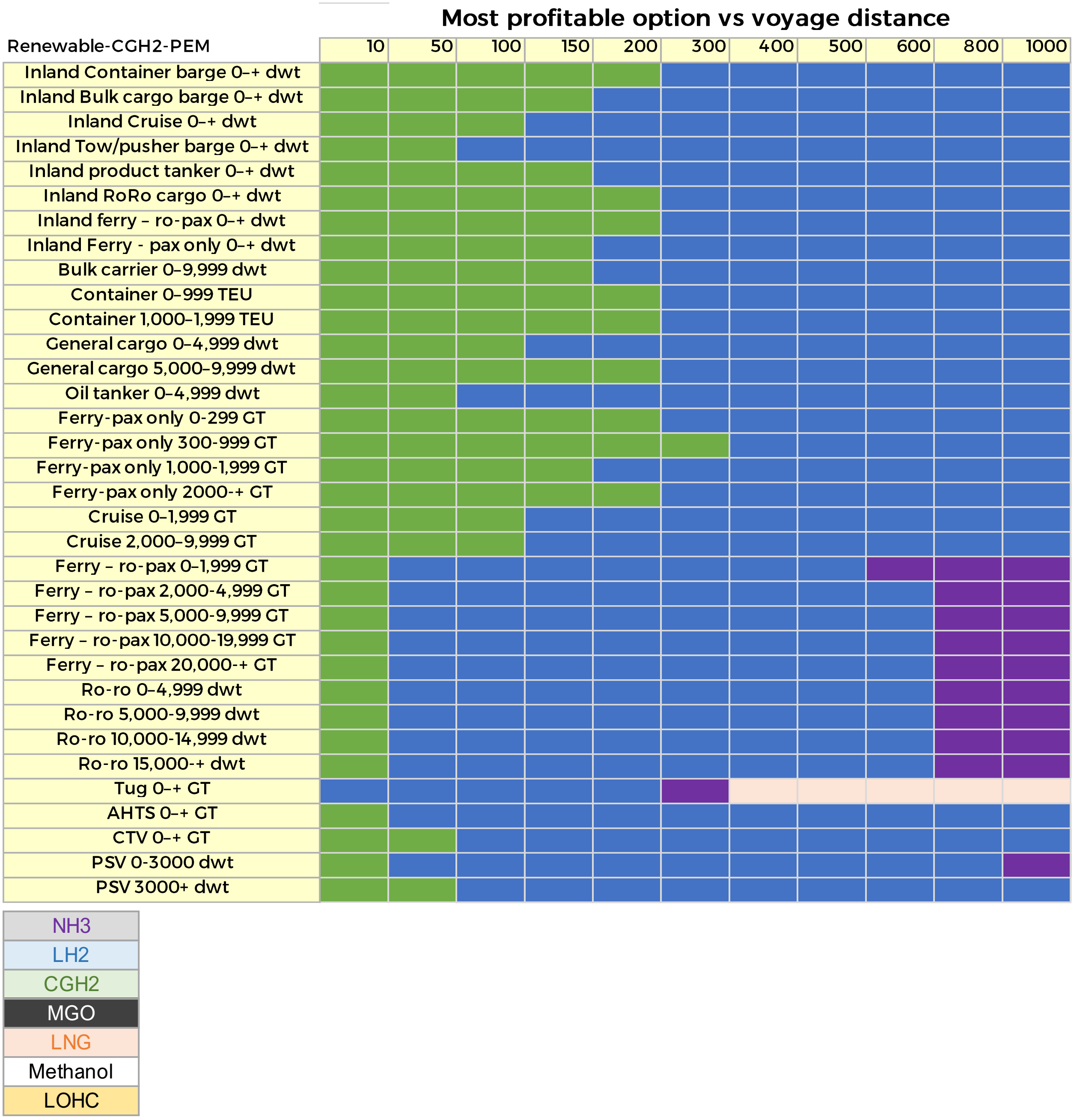

Figure 32. The sensitivity of results to changes in refuelling frequency

Source: own elaboration.

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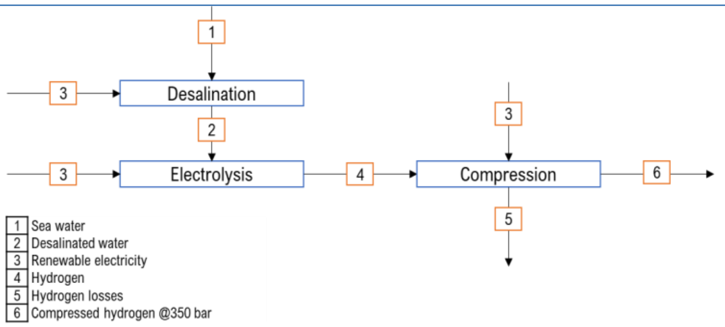
9 Annex I – Detailed assumptions

9.1 Fuel production pathways

Table 2. Fuel production process

#	Option	Process
1	Renewable compressed hydrogen	

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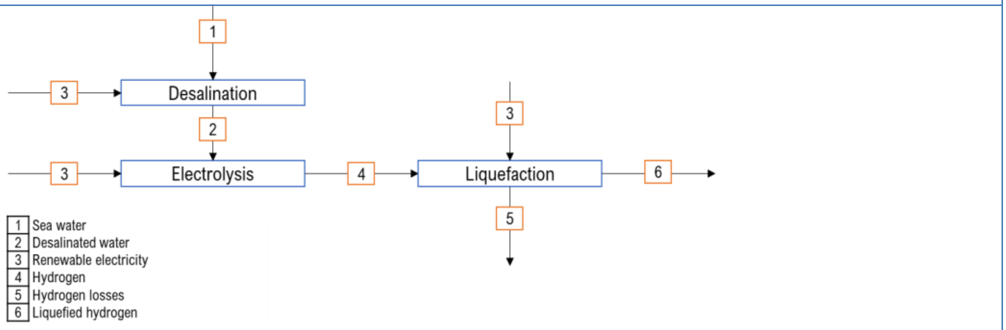
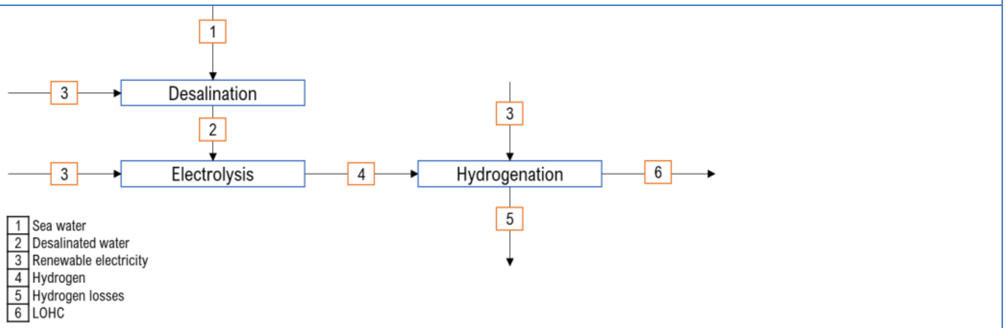
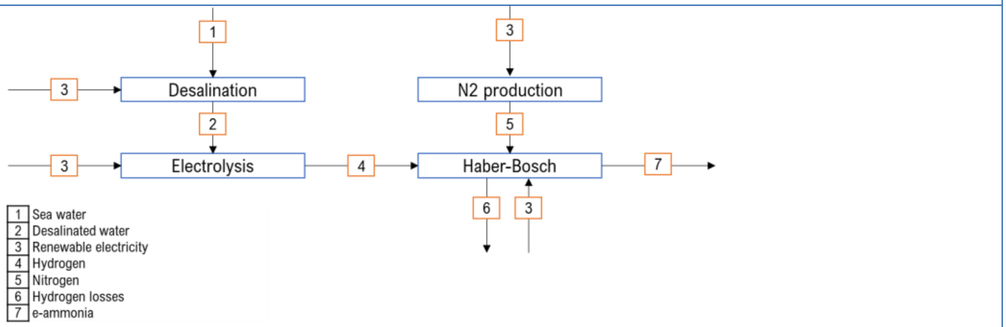
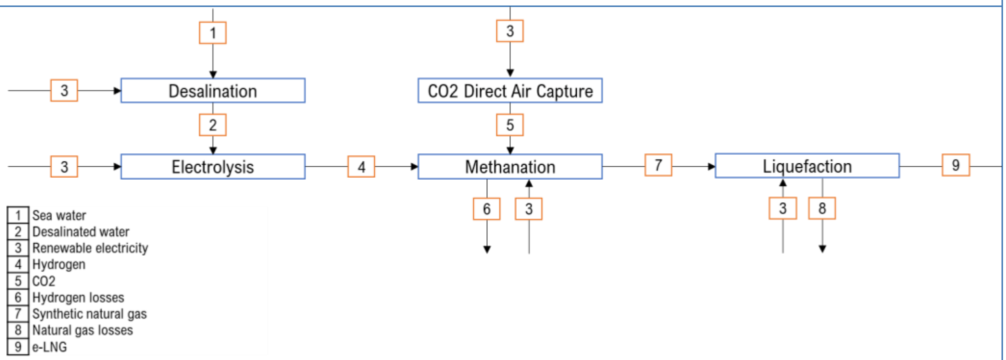
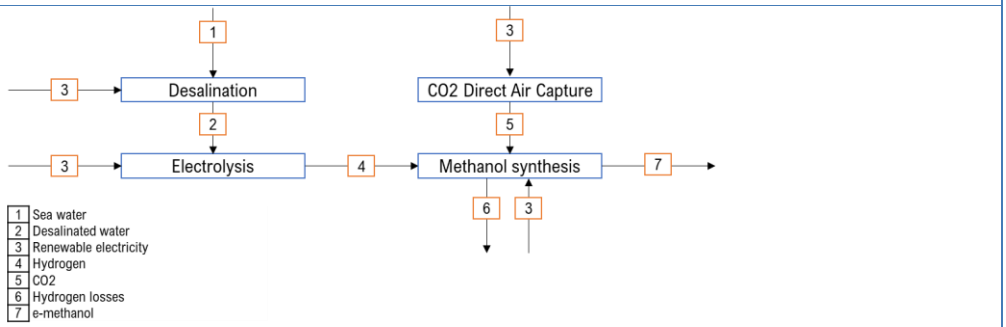
#	Option	Process
2	Renewable liquified hydrogen	
3	Renewable hydrogen stored in LOHC	
4	Renewable e-ammonia	
5	Renewable e-LNG	
6	Renewable e-methanol	

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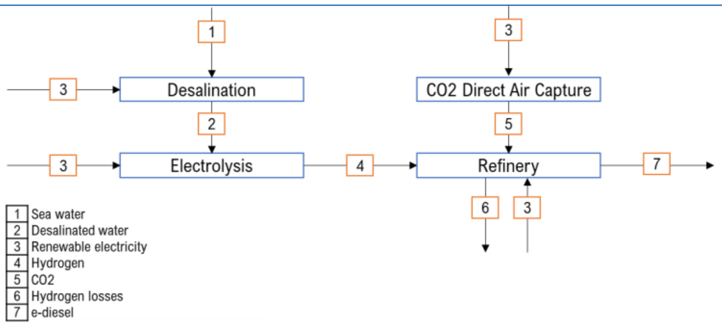
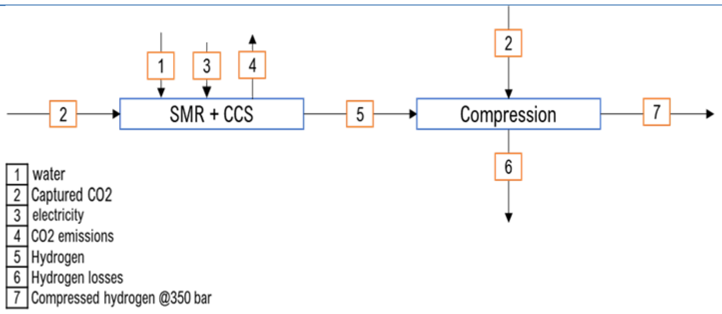
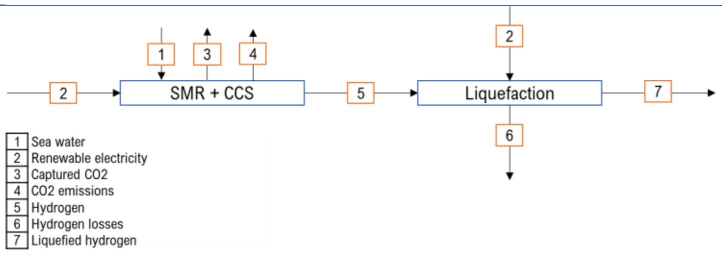
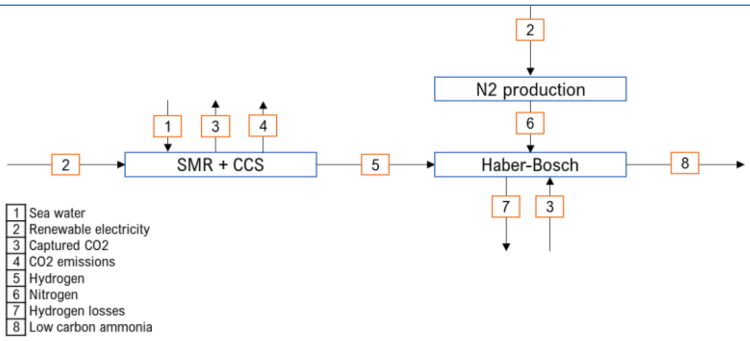
#	Option	Process
7	Renewable e-diesel	
8	Low carbon compressed hydrogen	
9	Low carbon liquified hydrogen	
10	Low carbon ammonia	

9.2 Fuel production costs

Table 3. Assumptions for water desalination

Item	Value	Unit	Literature references
CAPEX	1,243	€/(m³/d)	[32]
OPEX	0.08	%/a of CAPEX	based on [32]
Lifetime	20	a	[32]
Annual full load hours	7,008	h/a	[33]
Electricity consumption per water output	3.00	kWh_e/m^3_{H2O}	[33]

Table 4. Assumptions for H2 production via water electrolysis

Item	Value	Unit	Literature references
CAPEX	400	€/$kW_{H2\ output}$	[33]
OPEX	0.03	%/a of CAPEX	[33]
Lifetime	20	a	[33]
Annual full load hours	4000	h/a	Own assumption
GHG emissions of fuel production	0	g_{CO2}/kWh_{fuel}	
Electricity consumption per hydrogen output	1.68	kWh_e/kWh_{H2}	[33]
Water consumption	0.270	kg_{H2O}/kWh_{H2}	Theoretical value

Table 5. Assumptions for H2 production via steam methane reforming

Item	Value	Unit	Literature references
CAPEX	913	€/$kW_{H2\ output}$	based on [34], p.387
OPEX	0.031	%/a of CAPEX	based on [34], p. 405
Lifetime	25	a	[35]
Annual full load hours	8000	h/a	
GHG emissions of fuel production	103.0	g_{CO2}/kWh_{fuel}	
Natural gas consumption per hydrogen output	1.365	kWh_{NG}/kWh_{H2}	[35]
CO_2 emission factor NG upstream only	45.7	g/kWh_{NG}	[36](NG pipeline for transport into the EU: 4000 km)
CO_2 emission factor NG incl. upstream	244.0	g/kWh_{NG}	[36] (NG pipeline for transport into the EU: 4000 km)
CO_2 capture rate	0.85		[35]

Table 6. Assumptions for H2 liquefaction

Item	Value	Unit	Literature references
CAPEX	1000	€/kW_{H2}	[37] based on [38], [39], [40]
OPEX	0.019	%/a of CAPEX	[37] based on [41]
Lifetime	30	a	[33]
Annual full load hours	7008	h/a	[33]
GHG emissions of fuel production	0	g_{CO2}/kWh_{fuel}	
Electricity consumption	0.225	kWh_e/kWh_{H2}	[33]
Hydrogen input per LH2 output	1.0541	kWh/kWh_{fuel}	[38]

Table 7. Assumptions for H2 compression

Item	Value	Unit	Literature references
CAPEX	250	€/kW_{H2}	based on [42]
OPEX	0.04	%/a of CAPEX	[42]
Lifetime	20	a	
Annual full load hours	4000	h/a	
GHG emissions of fuel production	0	g_{CO2}/kWh_{fuel}	

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Electricity consumption	0.11	kWh_e/kWh_{H2}	LBST calculation based on [42]
Hydrogen input per CGH2 output	1.005	kWh/kWh_{fuel}	[43]

Table 8. Assumptions for LOHC production

Item	Value	Unit	Literature references
CAPEX	500	€/kW	[44]
OPEX	0.015	%/a of CAPEX	[44]
Lifetime	30	a	[44]
Annual full load hours	4000	h/a	Equal to electrolyser
GHG emissions of fuel production	0	g_{CO2eq}/kWh_{fuel}	
Electricity consumption	0.03	kWh_e/kWh_{fuel}	[44]
Hydrogen input per LOHC output	1.01	kWh/kWh_{fuel}	[44]

Table 9. Assumptions for e-LNG production

Item	Value	Unit	Literature references
Methanation			
CAPEX	1100	$€/kW_{CH4}$	[37] based on [45], [46], [47], [48], [39], [40]
OPEX	0.024	%/a of CAPEX	[37] based on [49], [45], [46], [47], [48], [39], [40]
Lifetime	20	a	
Annual full load hours	4000	h/a	
Electricity consumption	0.25	kWh_e/kWh_{fuel}	[37] based on [46]
Hydrogen input per CH_4 output	1.21	kWh/kWh_{fuel}	Based on chemical reaction
NG liquefaction			
CAPEX	300	$€/kW_{CH4}$	[50]
OPEX	0.04	%/a of CAPEX	[51]
Lifetime	30	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.025	kWh_e/kWh_{fuel}	[52]

Table 10. Assumptions for e-ammonia production

Item	Value	Unit	Literature references
N2 production			
CAPEX	53.6	€/(kg/d)	[53]
OPEX	0.04	%/a of CAPEX	[33]
Lifetime	20	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.108	kWh_e/kg_{N2}	based on [53]
Haber-Bosch			
CAPEX	762	$€/kW_{NH3}$	based on [53]
OPEX	0.04	%/a of CAPEX	[33]

Lifetime	20	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.0786	kWh_e/kWh_{fuel}	LBST calculation
Hydrogen input per fuel output	1.146	kWh/kWh_{fuel}	Theoretical values
Nitrogen input per fuel output	0.16	kg/kWh_{fuel}	Theoretical values

Table 11. Assumptions for e-methanol production

Item	Value	Unit	Literature references
CAPEX	1800	€/kW_{MeOH}	[37] based on [54], [46], [47], [48], [39] [40], [55]
OPEX	0.023	%/a of CAPEX	[37] based on [49], [54], [46], [47], [48], [39], [40], [55]
Lifetime	20	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.578	kWh_e/kWh_{fuel}	[37] based [54], [46], [47], [48]
Hydrogen input per fuel output	1.2283	kWh/kWh_{fuel}	[54]

Table 12. Assumptions for e-diesel production

Item	Value	Unit	Literature references
CAPEX	3000	€/kW	[37] based on [47], [48], [56], [57], [39], [40]
OPEX	1.8%	%/a of CAPEX	[37] based on [49], [47], [48], [56], [57], [39], [40]
Lifetime	20	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.49	kWh_e/kWh_{fuel}	[37] based on [57], [46], [48]
Hydrogen input per fuel output	1.4972	kWh/kWh_{fuel}	[57]

9.3 Fuel logistics costs

Table 13. Assumptions for fuel logistics costs calculation

Category	Item	Value	Unit	Literature references
Trucks	Lifetime	12	years	[21]
	Truck CAPEX	165	kEUR	[21]
	Truck Annual OPEX	12	% CAPEX	[21]
	Driver cost	20.6	EUR/h	[21]
	Speed	50	km/h	[21]
	Effective working hours	2000	h/year	own calculation based on [21]
Trailers	CAPEX - CH_2 trailer	581	kEUR	[21]
	Net capacity - CH_2 trailer	670	kgH2	[21]
	CAPEX - LH_2 trailer	894	kEUR	[21]
	Net capacity - LH_2 trailer	4300	kgH2	[21]
	LH2 trailer boiloff rate	0.3	%/day	[24]
	CAPEX - LNG	235	kEUR	[25]
	Capacity - LNG	44	m3	own assumption

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Category	Item	Value	Unit	Literature references
	LNG trailer boiloff rate	0.3	%/day	own assumption
	CAPEX - LOHC, MeOH, MGO	152	kEUR	[21]
	CAPEX - NH3	197	kEUR	[21]
	Capacity	55	m3	standard volume
	Annual OPEX - trailer	2	% CAPEX	[21]
CH2 pipeline – transmission pipeline	Lifetime	40	years	[21]
	Design throughput (large)	1,952	ktH2/y	[23]
	CAPEX	2.75	mEUR/km	[23]
	Utilization	5.000	h	[23]
	Annual OPEX	5	% CAPEX	[22]
CH2 pipeline – medium diameter	Lifetime	40	years	[21]
	Design throughput (large)	340	ktH2/y	[21]
	CAPEX	1.08	mEUR/km	[21]
	Utilization	0.75		[21]
	Annual OPEX	5	% CAPEX	[22]
	Mass losses	0.5	%	[26]
CH2 pipeline – Small diameter	Design throughput (small)	38	ktH2/y	[21]
	CAPEX	0.45	mEUR/km	[21]
	Annual OPEX	5	% CAPEX	[22]
	Mass losses	0.5	%	[26]
NG pipeline	Natural gas network costs in EU	0.00649	EUR/kWh	Eurostat
NH3 pipeline - transmission	Lifetime	40	years	[21]
	Design throughput (large)	1932	kt/y	[21]
	CAPEX	0.49	mEUR/km	[21]
	Utilization	0.75		[21]
	Annual OPEX	5	% CAPEX	own assumption
	Mass losses	0.5	%	own assumption
NH3 pipeline - distribution	Design throughput (large)	216	kt/y	[21]
	CAPEX	0.22	mEUR/km	[21]
	Annual OPEX	5	% CAPEX	own assumption
	Mass losses	0.5	%	own assumption
Other pipeline - transmission	Lifetime	40	years	[21]
	Design throughput (large)	12810	kt/y	[21]
	CAPEX	1.08	mEUR/km	[21]
	Utilization	0.75		[21]
	Annual OPEX	5	% CAPEX	own assumption
	Mass losses	0.5	%	own assumption
Other pipeline - distribution	Design throughput (large)	608	kt/y	[21]
	CAPEX	0.45	mEUR/km	[21]
	Annual OPEX	5	% CAPEX	own assumption

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Category	Item	Value	Unit	Literature references
	Mass losses	0.5	%	own assumption
Stor\age	Capacity	5	days of storage	own assumption based on [22]
	Lifetime	40	years	own assumption
	CH2 CAPEX	9	EUR/kWhH2	[21]
	LH2 CAPEX	80.6	EUR/kgH2	[21]
	LNG CAPEX	4.6	EUR/kgLNG	[25]
	NH3 CAPEX	1.5	EUR/kgNH3	[21]
	Others CAPEX	0.5	EUR/kgfuel	[21]
	OPEX	2	% CAPEX	own assumption

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9.4 Fuel onboard storage costs

Category	Item	Value	Unit	Literature references	Comments
LH_2	CAPEX	x	€/kWh	[58], [59], [60]	*f(y) = 13,974*storage(kg)^-0,206 + 100% markup for fuel handling system similar to LNG (crypumps, vaporizers, BOG handling system)*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	2.359	kWh/l		
	Fuel energy density by weight	33.333	kWh/kg		
	Fuel density	0.071	kg/l		
	Tank: volumetric storage density	1.75	kWh/l	[37]	*Cylinder: approx. 30 m outer length, 6 m outer diameter; filling level: 90%; superinsulation*
	Tank (rectangular room): voluminentric storage density	0.976	kWh/l	[37]	*Module of several cylinders*
	Tank: specific weight	x	kg/m3	[60]	*f(y) = 976 x volume ^-0,164 [kg/m3]*
CH2	CAPEX	9	€/kWh	[21]	
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	0.81	kWh/l		
	Fuel energy density by weight	33.333	kWh/kg		
	Fuel density	0.024	kg/l		
	Tank: volumetric storage density	0.66	kWh/l	[37]	*Cylinder: approx. 10,975 m outer length, 0.59 m outer diameter*
	Tank (rectangular room): voluminentric storage density	0.34	kWh/l	[37]	*Module of several cylinders inside a container frame*
	Tank: specific weight	433	kg/m3	[60]	
LOHC	CAPEX	3.00	€/kg_{tank}		*same as standard marine fuel tank*

Category	Item	Value	Unit	Literature references	Comments
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	1.32	kWh/l	[44]	*LOHC unloaded: C21H20; loaded C21H38*
	Fuel energy density by weight	1.45	kWh/kg	[44]	
	Fuel density (H_2 loaded)	0.91	kg/l	[44]	*H2 content: 0.06245 kgH2/kgLOHC, loaded*
	Tank: volumetric storage density	1.14	kWh/l	[37]	*10 chambers (9 chambers for loaded LOHC at start of trip, one chamber empty; all chambers used for loaded and unloaded LOHC separately); assumption (4% space losses for piping etc.)*
	Tank (rectangular room): volumentric storage density	1.03	kWh/l	[37]	*Assumption*
	Tank: specific weight	47	kg/m3	[44] Engineeringtoolbox.com	*same as standard marine fuel tank*
LNG	CAPEX	x	€/kWh	[61] + own market analysis	*3385 EUR/m3 (tanks + fuel handling system)*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	5.925	kWh/l		
	Fuel energy density by weight	13.5	kWh/kg	Engineeringtoolbox.com	
	Fuel density	0.44	kg/l		*@ 100 K; 0.1 MPa; https://www.engineeringtoolbox.com/methane-density-specific-weight-temperature-pressure-d_2020.html*
	Tank: volumetric storage density	4.525	kWh/l	[37]	*Same ratio as for LH2*
	Tank (rectangular room): volumentric storage density	2.524	kWh/l	[37]	*Same ratio as for LH2*
	Tank: specific weight	x	kg/m3	own market research	*weight = 1192*Volume^(-0,303)*
Ammonia	CAPEX	3.00	€/kg_{tank}		*Same as MGO per kg of tank mass*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		

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Category	Item	Value	Unit	Literature references	Comments
	Fuel energy density by volume	3.532	kWh/l		*Density liquid (-33.3°C (239.85 K): 681.9 kg/m³; gaseous at STP (Standard Temperature and Pressure - 0°C (273.15 K) and 1 atm (101.325 kPa)): 0.769 kg/m3*
	Fuel energy density by weight	5.18	kWh/kg		
	Fuel density	0.6819	kg/l		
	Tank: volumetric storage density	2.891	kWh/l	[37]	*Assumption: cryogenic storage (-33°C @ 1 bar); similar to LH2 cylinder, but thinner insulation*
	Tank (rectangular room): voluментric storage density	1.613	kWh/l	[37]	
	Tank: specific weight	x	kg/m3	[own research]	*weight = 559,49*Volume^(-0,207)*
Methanol	CAPEX	3.00	€/kg_{tank}		*Same as MGO per kg of tank mass*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	4.44	kWh/l		
	Fuel energy density by weight	5.47	kWh/kg		
	Fuel density	1.232	kg/l		
	Tank: volumetric storage density	4.00	kWh/l	[37]	*Assumption*
	Tank (rectangular room): voluментric storage density	3.60	kWh/l	[37]	*Assumption*
	Tank: specific weight	x	kg/m3	Engineeringtoolbox.com	*Assumption - same as for fuel oil (374,27*volume$^{-0,226}$)*
MGO	CAPEX	3.00	€/kg_{tank}		*[CRIST 2019]*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	9.97	kWh/l		*based on lower heating value (Hl)*
	Fuel energy density by weight	11.9	kWh/kg		*based on lower heating value (Hl)*

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Category	Item	Value	Unit	Literature references	Comments
	Fuel density	**0.838**	kg/l		
	Tank: volumetric storage density	**8.973**	kWh/l	[37]	*Assumption*
	Tank (rectangular room): volumentric storage density	**8.0757**	kWh/l	[37]	*Assumption*
	Tank: specific weight	**x**	kg/m3	Engineeringtoolbox.com	*(374,27*volume$^{-0,226}$)*

9.5 Onboard reforming costs

Table 14. Assumptions for onboard fuel reforming

Category	Item	Value	Unit	Reference	*Comments*
LOHC dehydrogenation & cleaning	CAPEX (per kW output)	1100	€/kW	[62]	
	OPEX	0,03	%/a of CAPEX	[62]	
	Lifetime	20	a	[62]	
	GHG emissions per hydrogen output		kg_{CO2}/kWh_{H2}		
	LOHC input per hydrogen output - LT FC	1,49	kWh/kWh_{H2}	[62]	*Without heat integration*
	LOHC input per hydrogen output - ICE	1,25	kWh/kWh_{H2}	[62]	*With engine heat integration*
	LOHC input per hydrogen output - HT FC	1,05	kWh/kWh_{H2}	[62]	*With FC heat integration*
	PM emissions	0,000	g/kWh_{H2}		*Heated with H2 which has hydrocarbon content except traces of HC from side reactions*
	NOx emissions	0,005	g/kWh_{H2}	[63], [64], [65]	*From hydrogen combustion for heat supply; NOx* [64] [65] *Heat input* [63],
	SOx emissions	0,000	g/kWh_{H2}		*Heated with tailgas without sulfur*
	NMVOC emissions	0,000	g/kWh_{H2}		*Heated with H2 which has hydrocarbon content except traces of HC from side reactions*

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Category	Item	Value	Unit	Reference	Comments
	CO emissions	0,000	g/kWh_{H2}		*Heated with H2 which has hydrocarbon content except traces of HC from side reactions*
	LOHC reformer specific weight	17,000	kg/kW_{output}	[62]	
	LOHC reformer specific volume	0,100	m^3/kW_{H2}	[62]	
LNG reformer	CAPEX (per kW output)	935,9	€/kW	[66]	*exchange rate GBP EUR: 1.10*
	OPEX	0,02	%/a of CAPEX	assumption	
	Lifetime	20	a	assumption	
	GHG emissions per hydrogen output		kg_{CO2}/kWh_{H2}		
	LNG input per hydrogen output	1,44	kWh/kWh_{H2}	[66] + [67]	*79.5% related to the HHV => 1.1/1.182*79.5% = 74.0% related to the LHV*
	PM emissions	0,000	g/kWh_{H2}	[68]	*Derived from PAFC with steam reformer*
	NOx emissions	0,005	g/kWh_{H2}	[68]	*Derived from PAFC with steam reformer (0.9 mg per MJ of NG input)*
	SOx emissions	0,000	g/kWh_{H2}	[68]	*Derived from PAFC with steam reformer*
	NMVOC emissions	0,002	g/kWh_{H2}	[68]	*Derived from PAFC with steam reformer (0.3 mg per MJ of NG input)*
	CO emissions	0,009	g/kWh_{H2}	[68]	*Derived from PAFC with steam reformer (1.7 mg per MJ of NG input)*
	LNG reformer specific weight	27,3	kg/kW_{output}	[67]	
	LNG reformer specific volume	0,16	m^3/kW_{H2}	[67]	
Ammonia cracker	CAPEX (per kW output)	423,5	€/kW	[66], [69]	*exchange rate GBP EUR: 1.10 cracker + evaporator (@110 EUR/kW_{NH3})*
	OPEX	0,02	%/a of CAPEX	assumption	
	Lifetime	20	a	assumption	
	GHG emissions per hydrogen output		kg_{CO2}/kWh_{H2}		
	NH_3 input per hydrogen output	1,329	kWh/kWh_{H2}	[70]	*Calculation base on inputs and outputs indicated in* [70]

Category	Item	Value	Unit	Reference	Comments
	PM emissions	0,000	g/kWh_{H2}		*Heated with tailgas without hydrocarbons*
	NOx emissions	0,004	g/kWh_{H2}	[68]	*Derived from PAFC with steam reformer (0.9 mg per MJ of NG input)*
	SOx emissions	0,000	g/kWh_{H2}		*Heated with tailgas without sulfur*
	NMVOC emissions	0,000	g/kWh_{H2}		*Heated with tailgas without hydrocarbons*
	CO emissions	0,000	g/kWh_{H2}		*Heated with tailgas without hydrocarbons*
	NH_3 cracker specific weight	11,2	kg/kW_{output}	[71]	
	NH_3 cracker specific volume	0,05	m^3/kW_{H2}	[71]	
Methanol reformer	CAPEX (per kW output)	936	$€/kW_{H2}$		*Assumption: equal to LNG reformer*
	OPEX	0,02	%/a of CAPEX		
	Lifetime	20	a		
	GHG emissions per hydrogen output		kg_{CO2}/kWh_{H2}		
	MeOH input per hydrogen output	1,2500	kWh/kWh_{H2}	[72]	*Onboard methanol reformer for low temperature PEMFC*
	PM emissions	0,0000	g/kWh_{H2}	[68]	*Derived from PAFC with steam reformer*
	NOx emissions	0,0001	g/kWh_{H2}	[73]	*Catalytic burner, traced back to H2 output*
	SOx emissions	0,0000	g/kWh_{H2}		*No sulfur in the fuel*
	NMVOC emissions	0,0060	g/kWh_{H2}	[73]	*Catalytic burner, traced back to H2 output*
	CO emissions	0,0057	g/kWh_{H2}	[73]	*Catalytic burner, traced back to H2 output*
	MeOH reformer specific weight	16,8	kg/kW_{output}	own estimation based on [74] and [75]	
	MeOH reformer specific volume	0,03	m^3/kW_{H2}	own estimation based on [74] and [75]	

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9.6 Fuel cells and engines

Table 15. Assumptions for fuel cells and engines

Category	Item	Value	Unit	Literature references	*Comments*
PEM	CAPEX	250	€/kW	[76], [77]	
	OPEX	2%	%/a of CAPEX	[76], [78]	
	Lifetime	20	a	[76]	
	Efficiency	56%	%	[76], [79]	
	PM emissions	0	g/kWh_e		
	NOx emissions	0	g/kWh_e		
	SOx emissions	0	g/kWh_e		
	NMVOC emissions	0	g/kWh_e		
	CO emissions	0	g/kWh_e		
SOFC-H2	CAPEX	500	€/kW	[76], [78]	*SOFC using H2*
	OPEX	2%	%/a of CAPEX	[76], [78]	
	Lifetime	20	a	[76]	
	Efficiency	50%	%	[76], [80]	
	PM emissions	0	g/kWh_e		
	NOx emissions	0	g/kWh_e		
	SOx emissions	0	g/kWh_e		
	NMVOC emissions	0	g/kWh_e		
	CO emissions	0	g/kWh_e		
SOFC-ir	CAPEX	500	€/kW	[76], [78]	*SOFC with internal reforming (MeOH, LNG, NH3)*
	OPEX	2%	%/a of CAPEX	[76], [78]	

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Category	Item	Value	Unit	Literature references	*Comments*
	Lifetime	20	a	[76]	
	Efficiency	60%	%	[80]	
	PM emissions	0	g/kWh_e		*Air pollutant emissions for NG SOFC with internal reforming (assumption: same emissions as for NG MCFC); Methanol SOFC probably similar, no NMVOC and CO in case of NH3, maybe NH3 slip and different NOx in case of NH3*
	NOx emissions	0.0017	g/kWh_e	[81]	
	SOx emissions	0	g/kWh_e		*No SOx because no sulfur in the fuel*
	NMVOC emissions	0.0008	g/kWh_e	[81]	
	CO emissions	0.0017	g/kWh_e	[81]	
ICE-H2	CAPEX	425	€/kW	assumptions: equal to LNG	*ICE running on hydrogen*
	OPEX	1%	%/a of CAPEX	assumption: equal to LNG	
	Lifetime	20	a	assumption	
	GHG emissions per mechanical output		g_{CO2}/kWh_{mech}		*see calculation in "Calculation engine"*
	Efficiency	45%	%	assumption: equal to MGO	
	PM emissions	0	g/kWh_{mech}		
	NOx emissions	2.6	g/kWh_{mech}	[82]	*Assumption: H2-ICE equal to LNG-ICE; IMO Tier III: 1 January 2016 and operating in the North American ECA and the United States Caribbean Sea ECA, 1 January 2021 and operating in the Baltic Sea ECA or the North Sea ECA; engins with n < 130 rounds/min*
	SOx emissions	0	g/kWh_{mech}		
	NMVOC emissions	0	g/kWh_{mech}		
	CO emissions	0	g/kWh_{mech}		
ICE-LNG	CAPEX	425	€/kW	[25]	*ICE running on methane incl. SCR*

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Category	Item	Value	Unit	Literature references	*Comments*
	OPEX	1%	%/a of CAPEX	[83]	
	Lifetime	20	a		
	GHG emissions per mechanical output		g_{CO2}/kWh_{mech}		*see calculation in "Calculation engine"*
	Efficiency	50%	%	[84]	
	S content pilot diesel fuel	0.001			
	Share pilot diesel fuel	0.06		[85]	
	PM emissions	0.1	g/kWh_{mech}	[85]	*Air pollutant emissions (2-stroke, dual fuel)*
	NOx emissions	2.6	g/kWh_{mech}	[T&E 2016], [85], [82]	*IMO Tier III: 1 January 2016 and operating in the North American ECA and the United States Caribbean Sea ECA, 1 January 2021 and operating in the Baltic Sea ECA or the North Sea ECA; engins with n < 130 rounds/min*
	SOx emissions	0.020	g/kWh_{mech}	[85]	*No sulfur in the (main) fuel, but sulfur in pilot diesel fuel*
	NMVOC emissions	0.1	g/kWh_{mech}	[85]	*Assumption: 80% fo VOC consists of CH4*
	CO emissions	0.3	g/kWh_{mech}	[85]	
ICE-NH3	CAPEX	425	€/kW	assumptions: equal to LNG	*ICE running on ammonia*
	OPEX	1%	%/a of CAPEX	assumptions: equal to LNG	
	Lifetime	20	a	assumptions	
	GHG emissions per mechanical output		g_{CO2}/kWh_{mech}		*see calculation in "Calculation engine"*
	Efficiency	50%	%	[84]	
	S content pilot diesel fuel	0.001			
	Share pilot diesel fuel	0.06			
	PM emissions	0	g/kWh_{mech}		*Air pollutant emissions (2-stroke, dual fuel)*
	NOx emissions	3.4	g/kWh_{mech}	[82]	*IMO Tier III: 1 January 2016 and operating in the North American ECA and the United*

Category	Item	Value	Unit	Literature references	Comments
					States Caribbean Sea ECA, 1 January 2021 and operating in the Baltic Sea ECA or the North Sea ECA; engins with n < 130 rounds/min
	SOx emissions	0.0200	g/kWh_{mech}	[85]	*No sulfur in the (main) fuel, but sulfur in pilot diesel fuel*
	NMVOC emissions	0	g/kWh_{mech}		
	CO emissions	0	g/kWh_{mech}		
ICE-MeOH	CAPEX	425	€/kW	assumptions: equal to LNG	*ICE running on methanol*
	OPEX	1%	%/a of CAPEX	assumptions: equal to LNG	
	Lifetime	20	a		
	GHG emissions per mechanical output		g_{CO2}/kWh_{mech}		*see calculation in "Calculation engine"*
	Efficiency	45%	%	assumptions: equal to MGO	
	S content pilot diesel fuel	0.001			
	Share pilot diesel fuel	0.06			
	PM emissions	0.01	g/kWh_{mech}	[83]	*Air pollutant emissions (2-stroke, dual fuel)*
	NOx emissions	3.4	g/kWh_{mech}	[83] [82]	*IMO Tier III: 1 January 2016 and operating in the North American ECA and the United States Caribbean Sea ECA, 1 January 2021 and operating in the Baltic Sea ECA or the North Sea ECA; engins with n < 130 rounds/min*
	SOx emissions	0.022	g/kWh_{mech}		*No sulfur in the (main) fuel, but sulfur in pilot diesel fuel*
	NMVOC emissions	0.5	g/kWh_{mech}	assumption: equal to diesel (VOC has low CH4 content)	
	CO emissions	0.3	g/kWh_{mech}	assumption: equal to LNG	
ICE-MGO	CAPEX	244	€/kW	[25]	*ICE running on MGO*
	OPEX	1%	%/a of CAPEX	assumption	

Category	Item	Value	Unit	Literature references	Comments
	Lifetime	20	a	assumption	
	GHG emissions per mechanical output		g_{CO2}/kWh_{mech}		*see calculation in "Calculation engine"*
	Efficiency	45%	%	[84]	
	S content	0.001		[82]	*IMO: Sulfur content of fuel in SECA areas: max. 0.1% S or SO2 scrubbers required*
	PM emissions	0.269	g/kWh_{mech}	[85]	*Air pollutant emissions (2-stroke); PM emissions partly depend on the S content of the fuel (see equation)*
	NOx emissions	3.400	g/kWh_{mech}	[85] [82]	*Similar to diesel according to: [de Vries 2019]*
	SOx emissions	0.371	g/kWh_{mech}	[85]	*IMO: Sulfur content of uel in SECA areas: max. 0.1% S; sulfur content of PtL is 0!*
	NMVOC emissions	0.500	g/kWh_{mech}	[85]	*VOC mainly consists of NMVOC in case of diesel engines*
	CO emissions	0.350	g/kWh_{mech}	[85]	*2-stroke: 0.35 g/kWh; 4-stroke: 0.5 g/kWh*

Table 16. Assumptions for fuel cells and engines mass and space requirements

Category	Item	Value	Unit	Reference
Fuel cell	Mass (in kg) - slope	3.7871	x power [kW]	[86]
	Mass (in kg) - intercept	-29.147		[86]
	Calculated mass of the FC system	F(x)	kg	Calculated F(x) = ax + b no less than 1 tonne
	Volume (in m3) - slope	0.0067	x power [kW]	[86]
	Volume (in m3) - intercept	-0.0714		[86]
	Calculated volume of the FC system	F(x)	m3	Calculated F(x) = ax + b no less than 20m3
ICE	Mass (in kg) - slope	13.783	x power [kW]	[Wartsila, MAN product catalogues]
	Mass (in kg) - intercept	-5865.4		[Wartsila, MAN product catalogues]

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Category	Item	Value	Unit	Reference
	Calculated mass (in kg) of the ICE System	F(x)	kg	Calculated F(x) = ax + b no less than 1 tonne
	Volume (in m3) - slope	0.0229	x power [kW]	[Wartsila, MAN product catalogues]
	Volume (in m3) - intercept	-20.628		[Wartsila, MAN product catalogues]
	Calculated volume (in m3)) of the ICE System	F(x)	m3	Calculated F(x) = ax + b no less than 20m3

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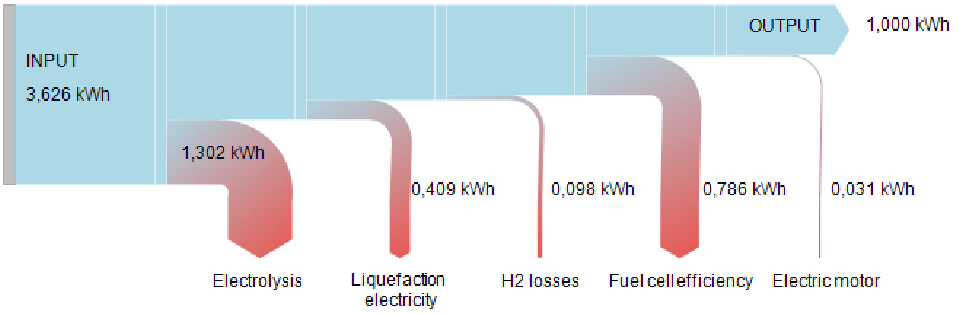
9.7 Energy efficiency comparison

Table 17. Fuel production process

<table>
<tr><th>#</th><th>Option</th><th>Energy efficiency</th></tr>
<tr><td>1</td><td>LH2 - PEM FC</td><td>


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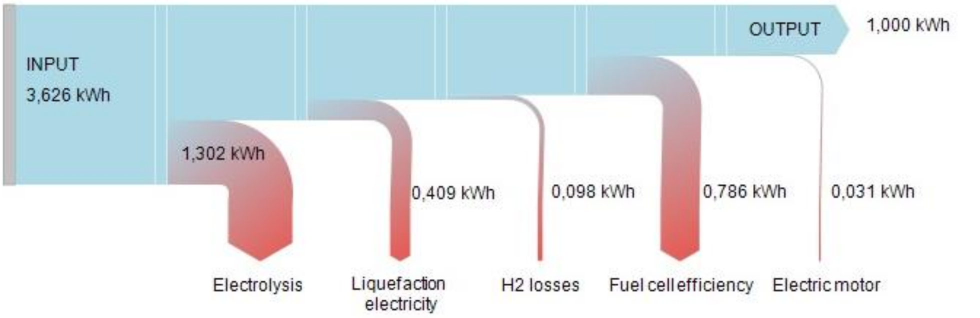

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<tr><td>3</td><td>LH2 - ICE</td><td>


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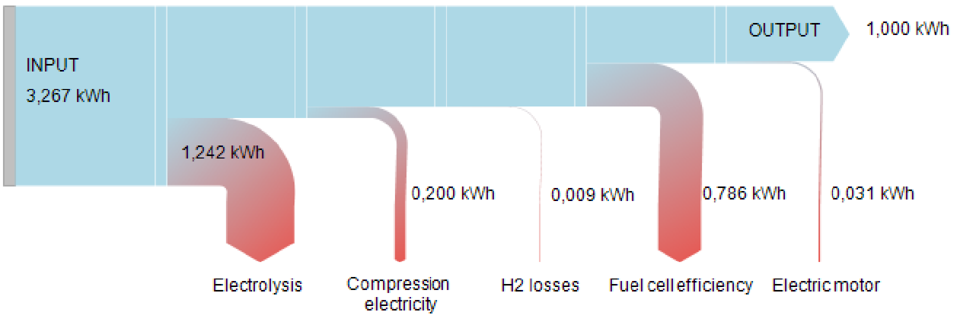
<tr><td>4</td><td>CGH2 - PEM FC</td><td>


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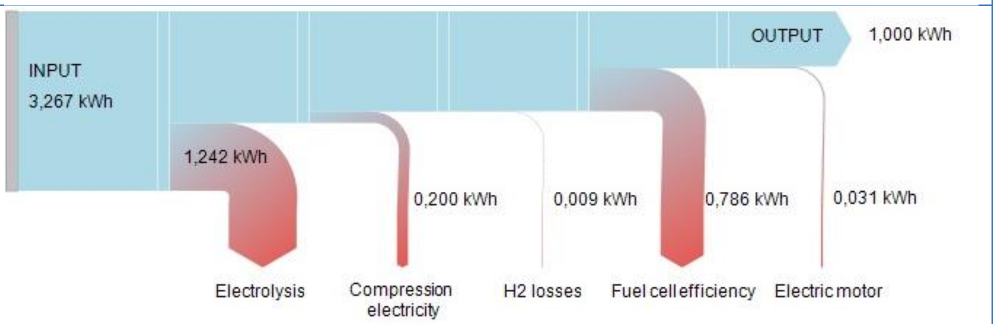
<tr><td>5</td><td>CGH2 - SOFC</td><td>


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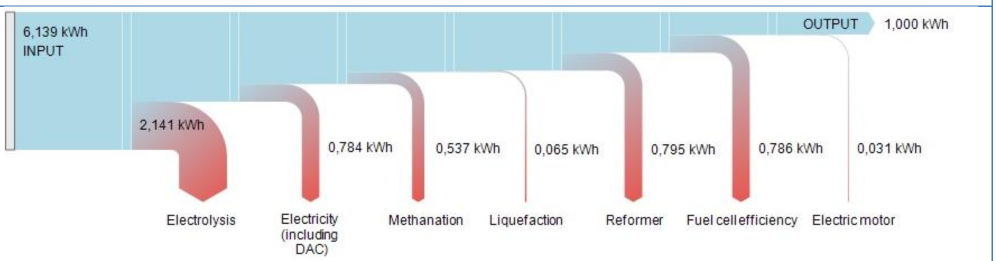
<table>
<tr><th>#</th><th>Option</th><th>Energy efficiency</th></tr>
<tr><td>6</td><td>CGH2 - ICE</td><td>
</td></tr>
<tr><td>7</td><td>LOHC - PEM FC</td><td>
</td></tr>
<tr><td>8</td><td>LOHC - SOFC</td><td>
</td></tr>
<tr><td>9</td><td>LOHC - ICE</td><td>
</td></tr>
<tr><td>10</td><td>LNG - PEM FC</td><td>
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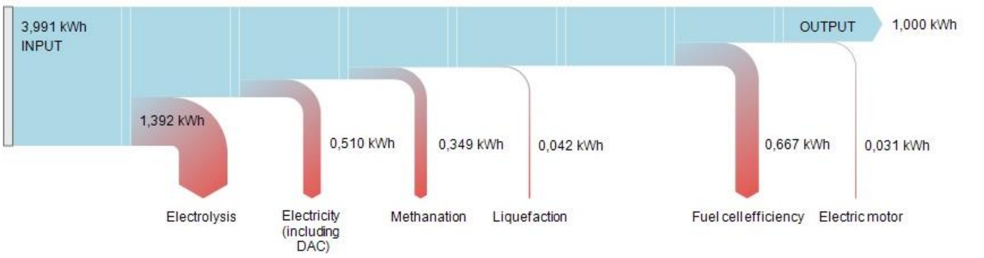
<tr><td>11</td><td>LNG - SOFC</td><td>
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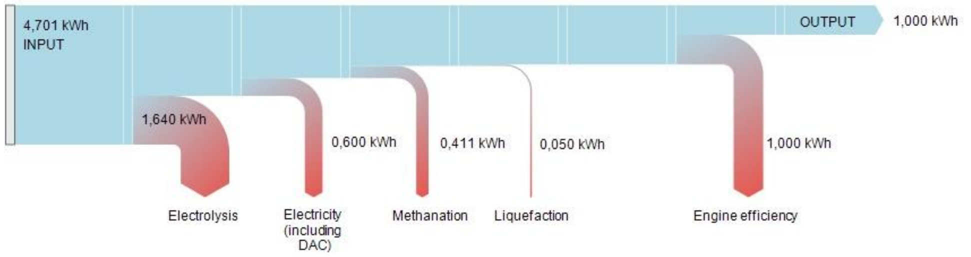
<table>
<tr><th>#</th><th>Option</th><th>Energy efficiency</th></tr>
<tr><td>12</td><td>LNG - ICE</td><td>
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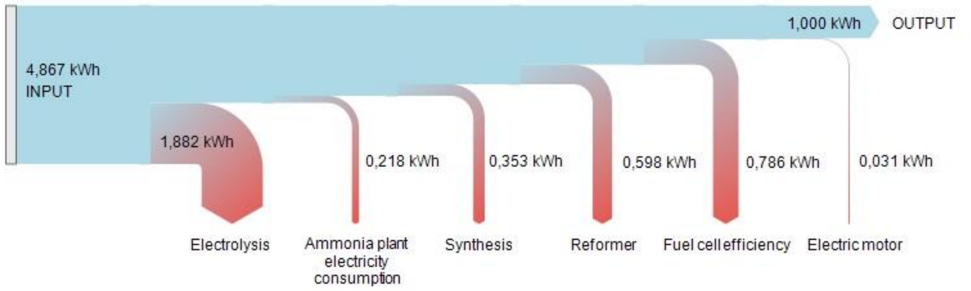
<tr><td>13</td><td>NH3 - PEM FC</td><td>
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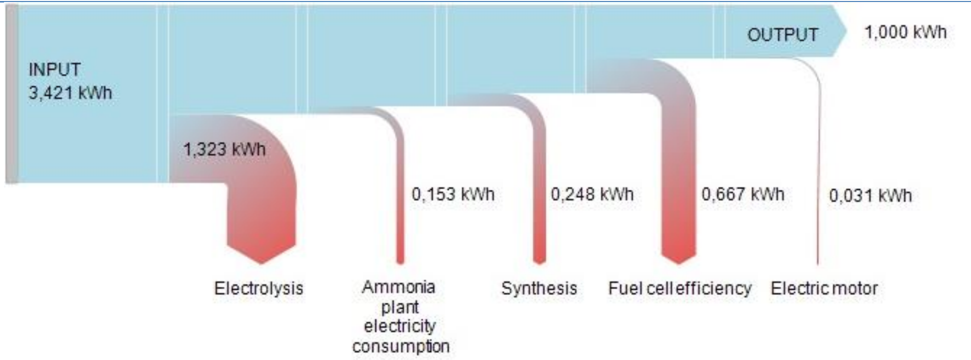
<tr><td>14</td><td>NH3 - SOFC</td><td>
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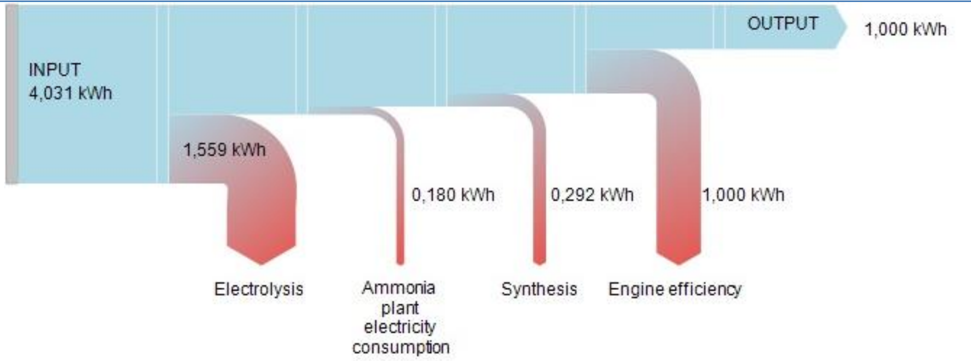
<tr><td>15</td><td>NH3 - ICE</td><td>
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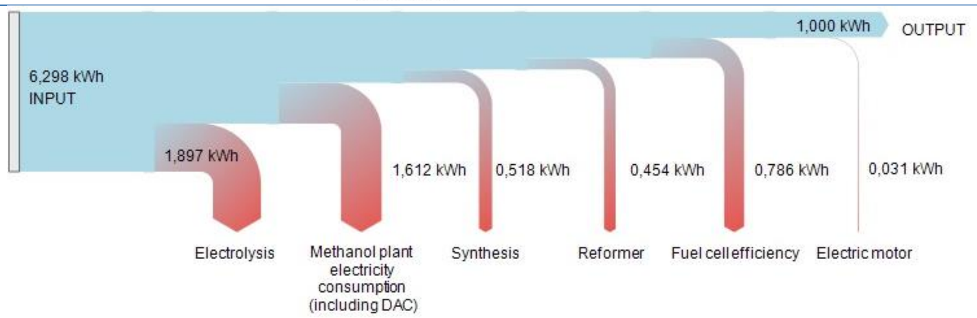
<tr><td>16</td><td>MeOH - PEM FC</td><td>
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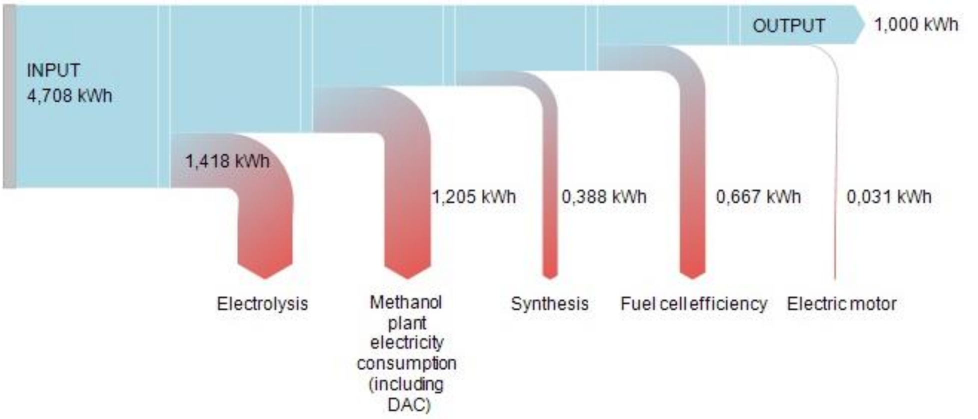
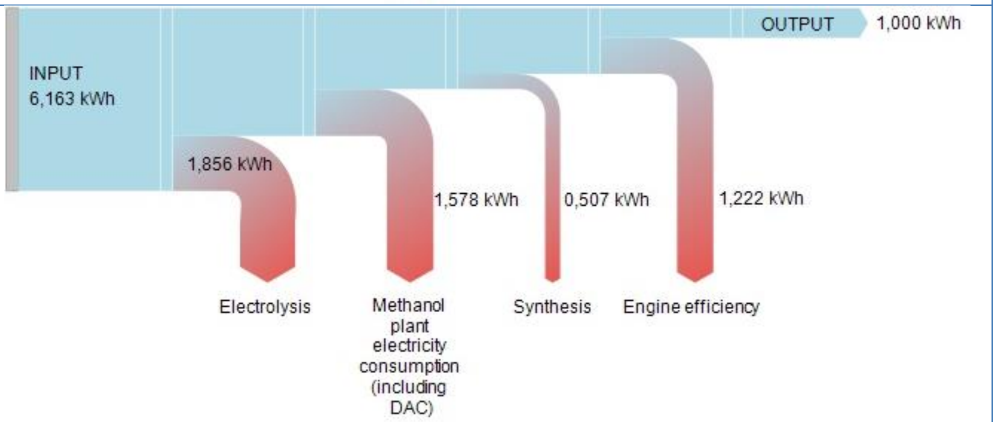
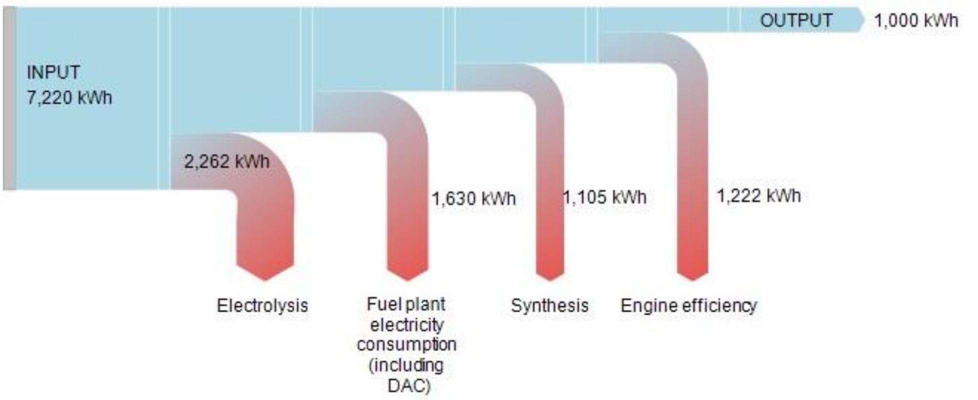
#	Option	Energy efficiency
17	MeOH - SOFC	
18	MeOH - ICE	
19	MGO - ICE	

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