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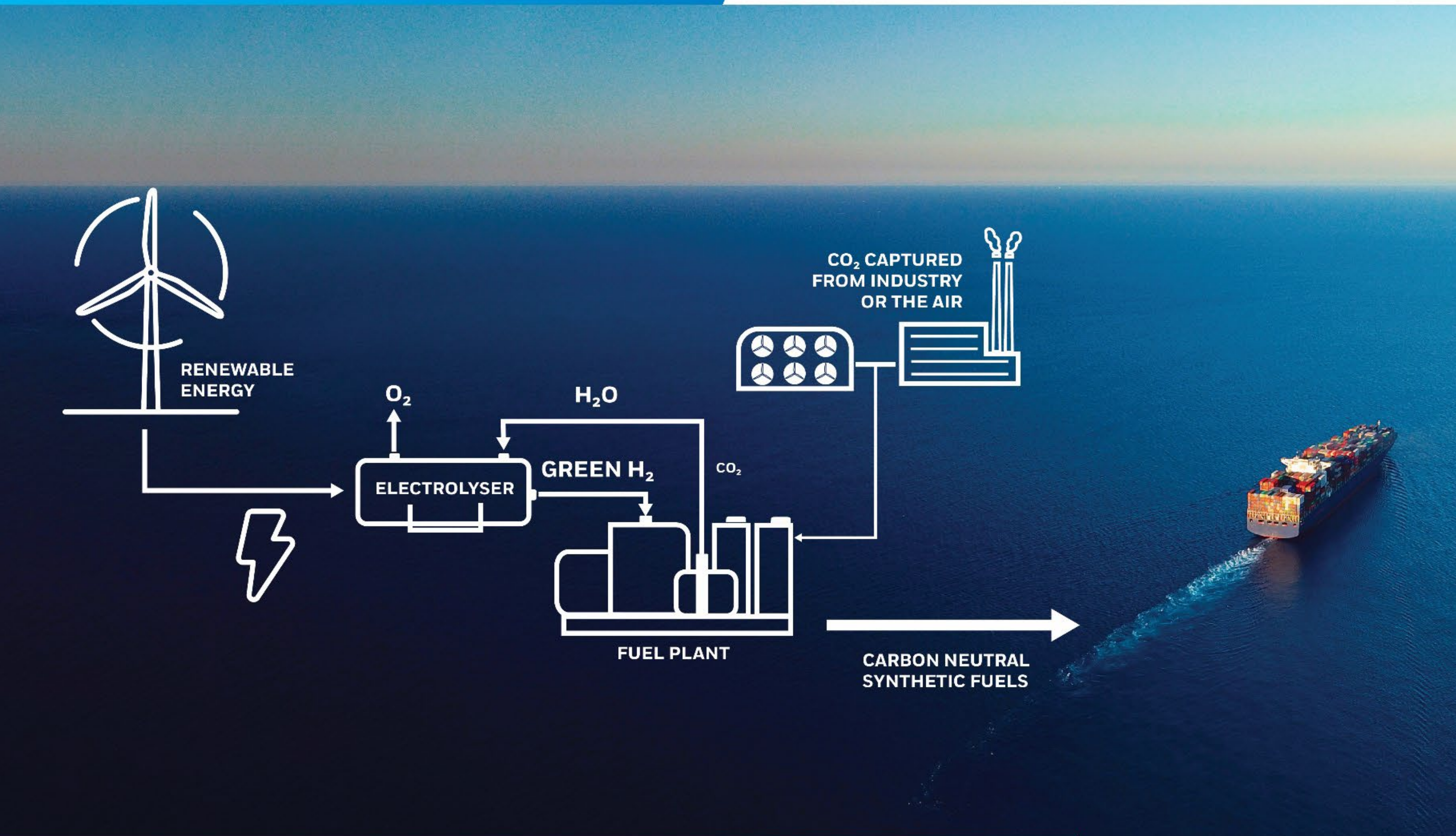


# SYNTHETIC FUELS FOR SHIPPING

by ABS & CE Delft

EMSA/Synthetic Fuels - 2023/2024

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# Executive Summary

The maritime industry is facing several substantive challenges, mostly driven by increasingly strict air emissions and climate legislation. Among the broad spectrum of technology and fuel solution pathways presently available to ship designers, builders, owners and operators – synthetic fuels or, more specifically, renewable e-fuels (to be referred as e-fuels in this study) – offer medium and long-term alternatives that can enter the market relatively quickly. On a Well-to-Tank basis, they also offer the potential to reduce the carbon output of their fleets to zero, or very close to it. Among the synthetic fuels, e-ammonia, e-hydrogen, e-diesel, e-methane and e-methanol are expected to see the largest uptake by the shipping industry. The first two have been extensively analysed in previous EMSA studies – '*Update on Potential of Biofuels for Shipping'* (EMSA, 2022b) and '*Potential of Hydrogen as Fuel for Shipping*' (EMSA, 2023) – so the focus of this study will be on the remaining three, namely e-diesel, e-methane and e-methanol.

**Production**

In this section, the reader will find an overview of the technologies, energy efficiency and technology-readiness levels. For the three e-fuels direct air capture (DAC) is required for all the production pathways. Since DAC is an immature technology, none of the e-fuel production pathways is currently technologically advanced enough to enter the market. In addition, some of the production routes for the three e-fuels under consideration require further technological advancements to enter the market.

**Sustainability**

The volume of life cycle greenhouse gas (GHG) and air-pollutant emissions generated by using e-fuels for shipping is considered significantly lower than those produced by fossil fuels. However, to produce e-fuels on a significant scale, large amounts of land are needed for wind and solar parks; this is becoming a challenge as it competes with agriculture and biodiversity conservation efforts. In parallel, the construction and operation of wind farms may adversely affect the habitats of birds and bats. Areas with large amounts of sun, wind and water resources, and large areas with deserts are therefore seen to be suitable locations to establish large production of e-fuels. Lastly, materials for manufacturing wind and solar parks, electrolysers and other systems will also be required to produce e-fuels, potentially also generating negative environmental impacts.

**Availability**

To ensure the large-scale production of e-fuels for the maritime industry, a tremendous expansion in the number of renewable-electricity plants, electrolysers, direct air capture plants and e-fuel synthesis plants will be needed. Whereas the projected global growth in renewable-electricity production could prove large enough to serve the demand for e-fuels of the commercial fleet in 2030, electrolysis capacity, e-fuels synthesis capacity and DAC capacity are not expected to keep pace. Furthermore, the shipping sector will need to compete with all other sectors for the renewable electricity, green hydrogen and renewable carbon dioxide ($CO_2$) required for e-fuels production.

The full transition of the global maritime sector to e-fuels will require a significant expansion of industry's capacity to produce renewable electricity, electrolysers, DAC and e-fuels synthesis plants. An analysis of the required and available capacity for the different e-fuel production segments indicates that the largest restraint on expanding e-fuel production capacity is the development of DAC capacity. Subsection 2.1.5 shows that DAC is the least developed technology and is likely to offer the longest delay before being ready for mass deployment. In addition, the costs of producing $CO_2$ from DAC are still prohibitively high. In the short to medium term, however, this restraint could be eased by using biogenic $CO_2$, another form of renewable $CO_2$.

**Suitability**

The suitability of the three e-fuels is covered by the EMSA study *'Update on Potential of Biofuels for Shipping'* (EMSA, 2022b)

**Techno-economic aspects**

The Total Cost of Ownership (TCO) has been calculated for e-methanol-, e-diesel- and e-methane-powered newly built vessels.

- In 2030, a low-cost estimate appears to be approximately 45-85% higher than ships running on conventional fuel oils, with the use of e-diesel representing the upper end and e-methane the lower end of the cost range.
- In 2050, the TCO of newly built e-fuel-powered ships ultimately could reach a lower cost level than those powered by conventional fuel oil. This is because the cost of e-fuels is expected to decrease significantly, and carbon costs will be applicable.

This means that e-fuels have the potential to play a major role in shipping in the long term, especially since the production varied inputs for e-fuels are not scarce if production techniques are deployed at large-scale.

The results of a retrofitting cost case for a small containership show that, depending on the fuel prices and the investment time, the shipowner may benefit from retrofitting some existing ships to using (a blend of) e-fuel.

Without global policy measures to either bridge the price gap or to encourage ships to use green fuels, a transition towards e-fuels with zero-$CO_2$ impact is unlikely to accelerate at the desired speed and scale in the next decade. Stimulation of market demand for carbon-free maritime transportation could be a complementary or an alternative way to achieve a transition towards green fuels.

The business case for e-fuel-powered vessels also will be dependent on developments in the global price of fuel oil. If fossil fuel prices continue to rise, the cost gap between the TCOs for using conventional fuels and e-fuels may be closed.

**Regulations**

Synthetic fuels, including e-fuels, can be considered *'drop-in'* fuels, and are expected to replace fossil fuels in the future. The existing standards and regulations, as well as ongoing regulatory developments, industry guidance and best-practice publications are, to some extent, expected to facilitate their adoption as marine fuels. However, for wide adoption of these fuels to be realised, further developments will be needed.

At the same time, the basket of measures introduced by the European Commission under its *'Fit for 55'* initiative sets, among others, specific targets for renewable fuels of non-biological origin (RFNBO)[2]. At the same time, the International Maritime Organization (IMO) has set new levels of ambition based on Well-to-Wake emissions. Among others, there is an ambition at the IMO to increase the uptake of zero or near-zero GHG emission technologies, fuels and/or energy sources, until they will represent at least 5% (striving for 10%) of the energy used by international shipping in 2030. All these developments are expected to support the uptake of synthetic fuels.

2 Considered synonym to e-fuels. Refer to Section 1.2.

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# 1. Introduction

## 1.1 Background

The marine industry is facing significant challenges. Stringent environmental regulations, uncertainties about the impact of globalisation, geopolitical influences, digitalisation and cyber risks are multiplying an already complex operating landscape. At the same time, shipping's stakeholders are trying to identify and deploy the most suitable decarbonisation strategies by investigating propulsion efficiencies and fuel options. Aside from the pressure human activities have put on biodiversity, the most important threat to the planet is the increase in global temperatures, mainly caused by anthropogenic emissions. Deforestation continues, adding pressure on biodiversity and accelerating global warming; lately, fires are causing rapid changes to forested areas, adding to the impact of global warming. Prompt and impactful action is required to steer our society towards a more sustainable future.

The shipping industry is responsible for approximately 3% of the global $CO_2$ emissions caused by human activities. In April 2018, the International Maritime Organization (IMO) agreed to align its regulations with the goals of the UN's Paris Agreement, thereby reducing the greenhouse gas (GHG) emissions from shipping. The *'Initial IMO Strategy on Reduction of GHG Emissions from Ships'* (Resolution MEPC.304(72)), included the ambition to reduce annual emissions by at least 50% by 2050 compared to 2008, beginning a massive and international shift towards the adoption of zero- and low-carbon fuels for the industry. This strategy was revised in 2023 during Marine Environment Protection Committee (MEPC) 80, increasing significantly the levels of ambition to reaching net-zero GHG emissions by or around 2050.

At the same time, the European Union through the European Green Deal and the 2030 Climate Target Plan aimed to reduce GHG emissions by at least 55% by 2030, relative to 1990, and achieve climate neutrality in 2050. All sectors should contribute to these targets, including maritime transport. The EU's *'Fit for 55'* package of measures has, for the most part, been adopted, including the extension of the EU Emissions Trading Scheme to maritime transport and the FuelEU Maritime Regulation.

Achieving these targets will require a transition from fossil fuels to renewable energy sources, potentially requiring different engines and fuel systems onboard ships. With the average commercial ship having a lifetime of more than 20 years, owners' uncertainty about which investments to make has put a hold on many decisions for building new ships. As such, pressure is building for the transition to begin as soon as possible. At the same time, regulatory developments in the EU indicate that a quicker response is needed from shipping.

## 1.2 Definitions

Industry literature and the various regulatory frameworks apply different terms for and the classification of renewable fuels. These are discussed below.

- ***Synthetic fuels*** are commonly known to be a mixture of carbon monoxide and hydrogen. These can be produced from fossil or renewable-energy resources.[3] An alternative definition of synthetic fuels is that they are chemically synthesised fuels designed to mimic the chemical and physical properties of fossil fuels, which are typically made from renewable or non-fossil feedstocks (Ram & Salkuti, 2023). In practice, however, the term *'synthetic fuels'* is also used to refer specifically to fuels that are synthetically made using renewable energy sources.

- ***Renewable fuels*** are those made from renewable energy sources, i.e., renewable electricity and renewable $CO_2$, if required.

- ***Renewable fuels of non-biological origin (RFNBO)*** are liquid and gaseous fuels, the energy content of which is derived from renewable sources other than biomass (EU, 2018). This definition from the Renewable Energy Directive (RED) is also applied in the FuelEU Maritime Regulation.

3 The European Commission (EC) and the International Energy Agency (IEA) apply a similar definition of synthetic fuels (https://knowledge4policy.ec.europa.eu/glossary-item/synthetic-fuels_en).

- ***Renewable e-fuels*** are fuels made from renewable hydrogen, which is produced using renewable electricity and water electrolysis, and renewable $CO_2$, if required.

Based on the above, RFNBOs can be considered a synonym of renewable e-fuels, if renewable $CO_2$ of non-biological origin is used to produce these fuels.

In parallel, in the *'2023 IMO Strategy on Reduction of GHG Emissions from Ships'* (Resolution MEPC.377(80)) and *'2024 Guidelines on Life Cycle GHG Intensity of Marine Fuels'* (IMO LCA Guidelines - Resolution MEPC.391(81)), there are three more terms used:

- Zero or near-zero GHG emission fuels
- Low- and zero-carbon fuels
- Sustainable marine fuels

Similar to the definition of *'synthetic fuels'*, these terms, or categories, are used to include a large variety of fuels and have not unequivocally been defined. Notably, the first two terms are used to also include fossil fuels such as liquified natural gas (LNG).

The focus of this study is renewable e-fuels. So-called *'blue fuels'* are produced using *'blue hydrogen'* from steam-reformed natural gas with the $CO_2$ emissions from the process being captured and permanently stored geologically. Blue fuels are neither e-fuels nor can blue fuels, due to the use of fossil fuels, be considered renewable fuels. Therefore, blue fuels fall outside the scope of this report.

In this study the term *'e-fuels'* will be used as a shorter version of RNFBOs, i.e., e-fuels that are produced using renewable electricity for hydrogen production and renewable $CO_2$ production not stemming from a biogenic source, if required. Although a third Delegated Act under the EU Taxonomy labels some specific nuclear energy activities as sustainable under strict conditions, nuclear energy is generally not considered renewable, as it currently depends on a finite supply of uranium and causes radioactive waste. Moreover, nuclear energy does not count as renewable energy under the EU Renewable Energy Directive[4]. Therefore, electricity produced from nuclear energy is not considered part of this scope. In addition, work is progressing for the review and revision of the Gas Directive (Directive 2009/73/EC) and Gas Regulation (EC) No 715/2009 which may include relevant definitions and certification rules in this context[5].

Regarding the type of e-fuel, in Appendix 1 of the IMO LCA Guidelines references are made to diesel, methanol, ammonia ($NH_3$), hydrogen ($H_2$), liquified petroleum gas (LPG), dimethyl ether (DME), compressed natural gas (CNG), ethane and ethanol produced by renewable sources other than biomass (next to production methods in which biomass or fossil fuels are used). Similarly, the FuelEU Maritime Initiative (EU, 2023) mentions e-diesel, e-methanol, liquefied e-methane, e-hydrogen, e-ammonia, e-LPG and e-DME.

From the fuels listed above, ammonia and hydrogen are e-fuels that have been covered in previous EMSA studies – '*Potential of Hydrogen as Fuel for Shipping*' (EMSA, 2023) and '*Potential of Ammonia as Fuel for Shipping*' (EMSA, 2022b). Next to these e-fuels, e-diesel, e-methane and e-methanol are considered promising options, while the rest of the fuels mentioned above are not expected to be used widely in shipping.

- ***E-methanol*** is the simplest primary alcohol, relatively easy to produce, but its production requires more energy per megajoule (MJ) of fuel compared to hydrogen, ammonia and methane (Concawe, 2022). It is easy to store, cheap to transport because it is a liquid at ambient temperature and can be stored in non–pressurised tanks.

4 The Renewable Energy Directive does allow for nuclear-derived hydrogen, but under conditions that are so challenging that some industry experts say they are impossible to meet (EurActiv, 2023).

5 https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/hydrogen-and-decarbonised-gas-market-package_en

- ***Liquefied e-methane*** (*'e-methane'* in short) is also a simple molecule, relatively easy to produce; the production of the gas requires less energy per MJ fuel than e-methanol and e-diesel. However, it must be cooled and stored at -160C° as a liquid, which requires some energy. The low cryogenic storage temperature requires both cryogenic equipment and tank materials that can withstand these conditions. Transporting e-methane is also more expensive than e-methanol. As e-methane is stored as a liquid, there is some loss of energy from e-methane evaporation, known as boil-off gas (BOG). This BOG can be reliquefied or used as fuel. Another issue is the methane slip. Nowadays, LNG-ships can run on e-methane and the current LNG fuel infrastructure (i.e., LNG terminals, storage tanks, carriers, bunkering systems, etc.) also can be used. Contrary to e-methane, LNG can contain up to 10% of other gases, such as ethane, propane, butane and traces of heavier hydrocarbons. E-methane will be almost 100% methane, except for traces of nitrogen.

- ***E-CNG*** is e-methane that is compressed to reduce the storage space it needs. One unit of e-CNG requires three times more volume than one unit of liquefied e-methane (Clarke Energy, 2023). Therefore, liquefied e-methane is the preferred form of e-methane storage for maritime shipping.

- ***E-diesel*** is expected to be a more complex fuel to produce, requiring more energy than e-methanol. Therefore, it is also expected that the cost of e-diesel will be higher than e-methanol. On the other hand, e-diesel is a drop-in fuel for the current maritime fleet, which mainly runs on diesel. Therefore, for many users, together with bio-based diesel fuel, e-diesel would be the only option that does not require a ship to be retrofitted.

- ***E-ammonia*** is expected to be produced on a larger scale in the future. It is being widely considered as a carrier for hydrogen energy: Renewable hydrogen could be efficiently shipped after its conversion to ammonia. While a large number of ships is ordered today that specify to be fuelled by ammonia – primarily LPG carrier design to carry ammonia and a number of bulk carriers – ammonia is not currently used as a fuel by ocean-going ships. However, analysis of the requirements for land storage and distribution, onboard storage and conversion to energy – in either an internal combustion engine or a fuel cell – have also revealed no insurmountable barriers to the use of ammonia as a marine fuel. Although it is toxic and harmful to the environment, the related health, safety and environmental challenges can be managed. Several research and development projects are in progress, and standards for the use of ammonia as a marine fuel are being developed. For more details see EMSA study '*Potential of Ammonia as Fuel for Shipping'* (EMSA, 2022b).

- ***E-hydrogen*** is also expected to be produced on a larger scale. Currently, hydrogen is not used by ocean-going ships, and is used by just a handful of coastal ships for propulsion purposes. However, e-hydrogen is considered as a fuel of the future for short-sea shipping. As described in the EMSA study *'Potential of Hydrogen as Fuel for Shipping'* (EMSA, 2023), the storage and distribution on land and the deployment in internal combustion engines or fuel cells have not revealed insurmountable barriers to its use as a fuel. However, storing hydrogen onboard appears to be an obstacle, with compressed gas suffering from low storage densities even at high pressures and limited space onboard ships; liquid hydrogen would need to be stored in specialised, highly insulated or vacuum-insulated tanks.

- ***E-LPG*** is a mixture of hydrocarbon gases, notably propane and butane. It is gaseous at ambient temperature and needs to be stored in pressurised tanks or cooled to -42°C (propane). When e-distillates are produced using low-temperature Fischer-Tropsch synthesis combined with hydrocracking, the product mix consists of 37% e-gasoline, 28% e-diesel, 32% e-kerosine and 3% e-LPG (Concawe, 2022). A niche market could develop using e-LPG onboard LPG carriers (it is currently used on 92 vessels); for other ship types, there are more attractive options, such as e-methanol, available.

- ***E-DME*** is a complex molecule. It is gaseous at ambient temperature and needs to be stored under pressure which is a disadvantage compared to e-methanol and e-diesel. For reference, there are no vessels currently burning fossil DME. Onboard conversion from methanol to DME has been tested and appears to work but is associated with extra costs. Also, high-molecular, liquid ethers that can be produced from methanol are being considered. As per Concawe (2022), typically poly(oxymethylene)dimethyl ether (PODE) or more commonly $OME_X$ are oxygenates of the general structure $CH_3$-O-$(CH_2O)_X$-$CH_3$, where x is typically 3 to 5 for fuel applications ($OME_{3-5}$). $OME_{3-5}$ is a longer diether than DME, with a higher number of carbon atoms. Its chemical formula is $CH_3O$-$(CH_2O)_X$-

$CH_3$ (compared to $CH_3OCH_3$ for DME). It is produced from methanol and oxygen using formaldehyde. Its production is complex and there are different production routes. It requires more energy to produce than e-diesel. If blended with e-diesel, it reduces soot and $NO_x$ emissions compared to pure e-diesel.

- ***E-ethane*** is expected only to be used onboard ethane carriers; there are currently only a few ethane gas carriers that are using ethane as fuel. Fossil ethane is only available in special gas terminals. For reference, there are 26 (Jan. 2024) ethane/ethylene/LPG carriers, burning fossil ethane and another 30 to 40 ships are on order. It is noted that e-ethane is not included in the long list of fuel production pathways in the IMO LCA Guidelines. At the same time, it is not listed among the e-fuels that have been analysed by Concawe (2022). The reason for this might be that there is no widely available ethane fuel infrastructure. Also, e-methane is expected to be cheaper to produce.

- ***E-ethanol*** has similar physical properties to (e-)methanol. According to a study (Verhelst, Turner, Sileghem, & Vancoillie, 2019), ethanol and methanol have similar octane numbers, very high heat of vapourisation values and low stoichiometric air-fuel ratios, with the latter two differing more than the former. This indicates that a methanol engine/system could use ethanol directly or with limited modifications; however, this needs to be proven in practice. However, ethanol's molecules are more complex and require a more complex process to produce. In terms of production cost, methanol is expected to be significantly cheaper. Currently, there is no vessel burning ethanol. Blending of conventional fossil bunker fuel with ethanol is technically possible, but it is not considered to be a way forward. This is confirmed by the fact that e-ethanol is not included in the IMO LCA Guidelines. Therefore, e-ethanol is not expected to play a role in shipping.

To conclude, from the above list of fuels, e-ammonia, e-hydrogen, e-diesel, (liquified) e-methane and e-methanol are considered to have the highest potential for shipping. Since e-ammonia and e-hydrogen have already been analysed in the previous EMSA studies – '*Potential of Ammonia as Fuel for Shipping'* (EMSA, 2022b) and '*Potential of Hydrogen as Fuel for Shipping'* (EMSA, 2023) – the focus of this study will be on e-diesel, (liquified) e-methane and e-methanol.

### 1.2.1 Drop-in fuels

The International Energy Agency (IEA) defines *'drop-in'* fuels as *'liquid hydrocarbons that are functionally equivalent to petroleum fuels and are fully compatible with existing petroleum infrastructure'*. In this definition, *'infrastructure'* relates both to petroleum distribution and refining, and to the applicable fuel specifications, i.e., for using these fuels in engines (IEA, 2019). The definition of drop-in fuels that will be used in this study is *'fuels that can be used as alternatives to conventional petroleum-refined hydrocarbon fuels without substantial modifications to the engines, fuel tanks, fuel pumps and the overall fuel-supply systems currently in use'*.

Most liquid e-fuels are generally considered *'drop-in'* fuels, although Concawe (2022) adds that this should be validated to a varying degree, depending on the e-fuel. E-diesel is a drop-in fuel that can replace fossil diesel in diesel-fuelled ships. E-methane is a drop-in fuel for LNG-fuelled ships. Similarly, e-methanol is a drop-in fuel for ships designed to operate on fossil-derived methanol. Thus, all three e-fuels are considered drop-in fuels for their fossil counterparts. Different blends could be produced using different blend percentages. Their use may require confirmation by engine designers regarding their applicability. Fuel quality standards will be developed that will regulate permissible fuel blends (mixed fuels and percentages).

## 1.3 Scope and Objectives

This study examines three e-fuels: e-methanol, e-methane and e-diesel. As per the definitions in Section 1.2, they are assumed to be produced using renewable electricity for hydrogen production and renewable captured $CO_2$. *'Renewable captured $CO_2$'* refers to $CO_2$ extracted from the natural environment. Although $CO_2$ captured from a biomass-combustion process also can be considered renewable, this source is out of the scope, as its availability is much more limited. $CO_2$ captured from fossil-fuel based processes is not considered renewable, so it is not considered.

The scope and objectives of this study contain the technical issues, regulatory frameworks and states of play for applying e-fuels. It addresses the potential of e-fuels to be used as fuel in shipping as part of EMSA tender EMSA/OP/43/2020 for *'Studies on Alternative Fuels/Power for shipping'*.

The study specifically addresses the following:

- it provides information on the properties, production, suitability and sustainability of e-diesel, e-methane and e-methanol, as well as a techno-economic analysis of the use of the fuels in the shipping sector (refer to Section 2);

- it also supplements the study previously carried out covering the potential of biofuels (including bio-diesel, bio-methane, bio-methanol) for the shipping industry (EMSA (2022a)) in relation to safety and environmental standards, regulations and guidelines on the production, transport, bunkering, onboard storage, handling and use of e-fuels for shipping (refer to Section 3);

- the safety implications of using these e-fuels as marine fuels are covered by the Hazard Identification (HAZID) assessments included in Section 4 of the previous studies (EMSA, 2022a), (EMSA, 2022b) and (EMSA, 2023).

## 1.4 Acronym List

Used acronyms can be found in Appendix D – Symbols, Abbreviations and Acronyms.

# 2. Use of e-Fuels in the Shipping Sector

E-fuels from renewable electricity and renewable $CO_2$ have the potential to almost eliminate the Well-to-Wake GHG emissions from the marine sector, while also meeting the industry requirements for sulphur emissions. E-fuels emit low levels of particulate matter during their combustion due to the absence of sulphur. $NO_X$ emissions from e-fuels will be the same or lower than those from biofuels. It is noted that bio-oils, which have more oxygen content than both e-fuels and fossil-based fuels, might have higher $NO_X$ emissions, as these increase approximately linearly with the fuel's oxygen content. Thus, e-fuels have multiple environmental benefits.

The most practical way to introduce e-fuels in shipping is either by fully replacing fuel oils or by blending them with compatible fossil-based marine fuels in quantities verified by equipment suppliers and engine designers. The introduction of drop-in e-fuels such as e-diesel and e-methane would allow the current fuel infrastructure and ship engines to continue being used.

This chapter analyses the state of play for the current and projected use of e-fuels in the shipping sector. Section 2.1 presents the different fuels and production pathways. Section 2.2 analyses the sustainability of e-fuels for maritime ships and Section 2.3 discusses their availability in Europe and globally. The fuels' suitability for use in existing ships is analysed in Section 2.4, together with any required modifications to engines and fuel systems. Section 2.5 presents an analysis of the cost impact of replacing conventional fuels with e-fuels.

## 2.1 Production Technologies

### 2.1.1 Introduction

The main e-fuels relevant to maritime shipping identified in Section 1.2 that were not covered in previous EMSA studies are e-methanol, e-methane (which is used in this study as a short version of 'liquefied e-methane) and e-diesel. Renewable electricity and renewable $CO_2$ are needed for all production pathways of these fuel types. The required renewable $CO_2$ is assumed to be extracted from the natural environment (see Section 1.3). Not all pathways require renewable hydrogen as a primary input. The routes for producing renewable hydrogen and renewable $CO_2$ are shown in Figure 1 the e-fuel production pathways are visualised in Figure 2.

The use of electrolysis will be covered in Subsection 2.1.2 and renewable $CO_2$ capture in Subsection 2.1.3. The production pathways are presented in Subsection 2.1.4. In Subsection 2.1.5, the technological readiness of the technical options is examined more closely, followed by an investigation of developments in production capacity in Subsection 2.1.6. Conclusions on e-fuel production technologies are drawn in Subsection 2.1.7.

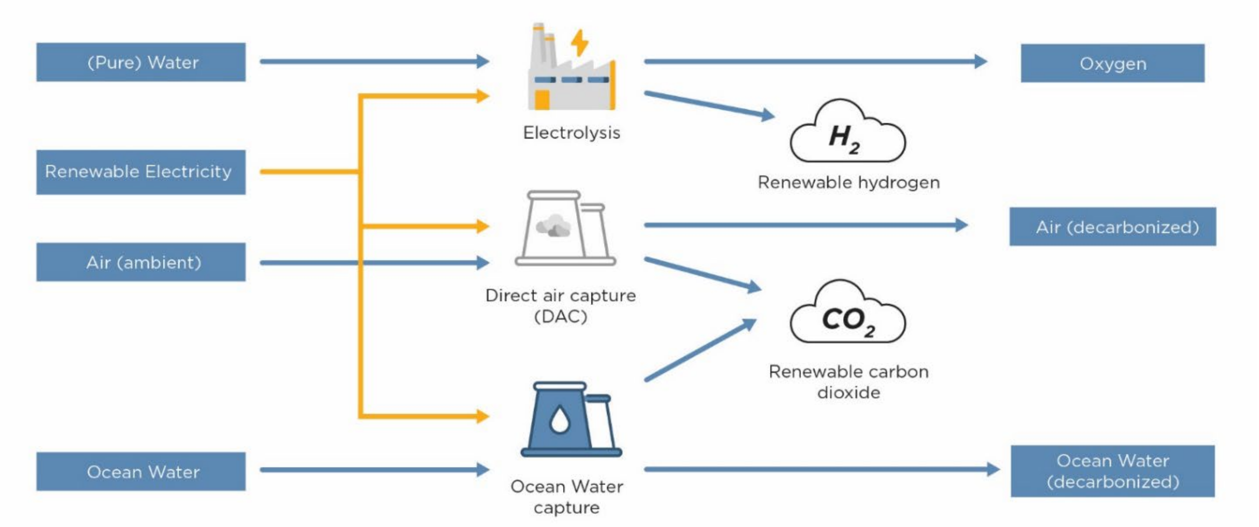


*Figure 1. Renewable hydrogen and $CO_2$ production routes.*

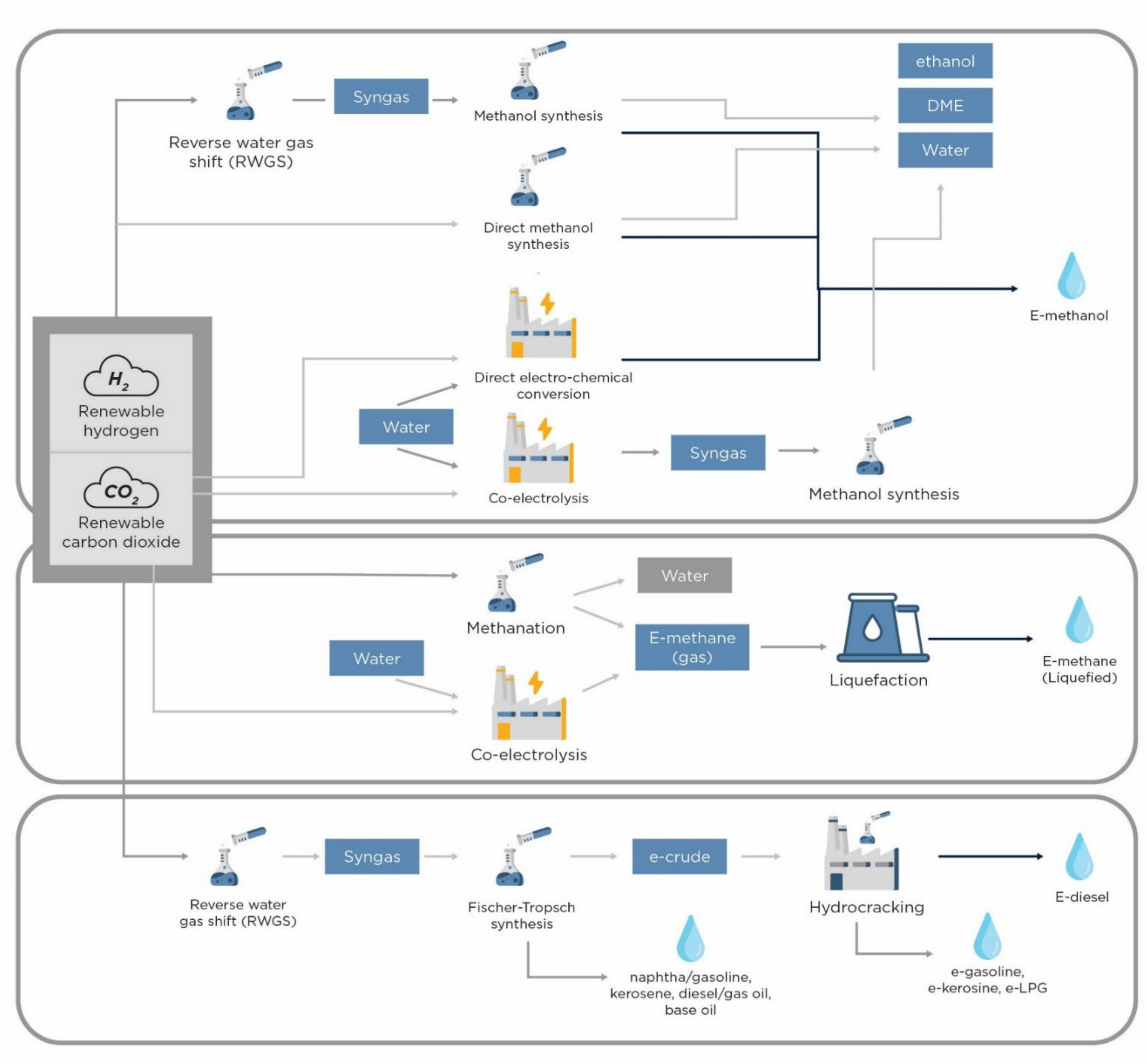


*Figure 2. E-fuel production pathways.*

## 2.1.2 Electrolysis

To produce the renewable hydrogen used to make e-fuels, the process of water electrolysis is used. In principle, this is a well-known process. Until the 1960s, most fertilisers sold in Europe were made from ammonia based on hydrogen produced with hydropower-based electrolysis. However, different electrolyser technologies exist and many of the newer technologies are still under development.

Currently, there are two main electrolyser technologies to consider: alkaline and proton-exchange membrane (PEM). The alkaline technology is the most advanced and cheapest option; it has a relatively high electricity-to-hydrogen efficiency of 63-70% (IEA, 2019). The PEM electrolyser is less developed, more expensive and has a lower efficiency (56-60% (IEA, 2019)). However, this type of electrolyser is expected to be more operationally flexible (i.e., its load factor can be better adjusted to fluctuating power output from wind and solar parks) than the alkaline version.

The solid oxide electrolyser cell (SOEC) is another technology, which is not commercially available at this point of time and thus far from being implemented on a large-scale. This technology works at a high temperature and has the potential to offer a greater energy efficiency than alkaline and PEM (74-81%, according to the IEA (2019)), especially when integrated with concentrated solar plants, which enable heat utilisation (IEA, 2017). These three electrolyser technologies are illustrated in Figure 3 and summarised and compared in Table 1.

PEM electrolysers use a proton-exchange membrane and a solid polymer electrolyte. When electric current is applied, the water splits into hydrogen and oxygen and the hydrogen protons pass through the proton-exchange membrane to form gas on the cathode side. Increasing the density of the current enables a faster system response to fluctuations in energy input, which can be a great benefit when working with renewable-energy sources that are intermittent.

PEM electrolysers operate at temperatures between 50-80°C, but at higher pressures than alkaline electrolysers. Typical PEM electrolysers are constructed using a higher quantity of rare-earth metals than alkaline electrolysers and require more precise construction techniques for their catalysts, which makes them more expensive to produce and maintain. In 2021, about 25% of the installed electrolyser capacity worldwide was based on PEM technology (IEA, 2022).

Alkaline electrolysers use a liquid-electrolyte solution, such as potassium hydroxide or sodium hydroxide and water. When current is applied, the hydroxide ions move through the electrolyte from the cathode to the anode of each cell, generating hydrogen-gas bubbles on the cathode side of the electrolyser and oxygen gas at the anode, as represented in Figure 3.

Alkaline electrolysers can be unipolar or bipolar in design. Unipolar designs (also known as monopolar or tank designs) have their electrodes suspended, in parallel, in tanks separated by thin membranes that allow the ions to be transferred, while restricting the movement of the gases that are produced. Bipolar designs position the electrodes very close to each other, separated by a thin non-conductive membrane. Unipolar designs have the advantage of being cheaper and easier to build and maintain. Nevertheless, they are usually less efficient than bipolar designs.

Alkaline electrolysers operate best near their design loads; they experience a drop-in efficiency when operating under lower loads. Both designs for alkaline electrolysers are more durable and contain fewer expensive rare-earth metals than PEM and solid oxide electrolysers. In 2021, almost 70% of the installed electrolyser capacity was based on alkaline technology (IEA, 2022).

Solid oxide electrolysers use solid ceramic material for the electrolyte. Electrons from the external circuit react with water at the cathode to form hydrogen gas and negatively charge ions. Oxygen then passes through the solid ceramic membrane and reacts at the anode to form oxygen gas and generate electrons for the external circuit. Solid oxide electrolysers, being in an early stage of development and requiring temperatures of more than 700°C to operate, are less likely to be used anytime soon.

All electrolyser technologies require pure, deionised water to be split into hydrogen and oxygen. To produce this kind of water, freshwater can be purified, using filtration, deionisation or reverse-osmosis processes. If access to freshwater is a challenge, seawater can be desalinated and then purified. Water-purification technologies such as mechanical vapour compression and reverse osmosis are available commercially. Water desalination and purification typically represent less than 1-2% of the total cost of hydrogen production. It is important to purify the water to demineralised water quality before it is used by the electrolysers, as their lifetime and performance are severely affected by the water impurities. For example, a PEM electrolyser – which is possibly the most stringent when it comes to water purity – requires water with a resistivity of minimum 1MΩ-cm.

During the electrolysis process, impurities that need to be removed may appear. Often, oxygenates (oxygen and water) need to be removed from the hydrogen, as these can have detrimental effects on the synthesis catalyst if hydrogen is used for production of other chemicals. Deoxidisers are required for this task. The purity of the hydrogen that is produced could be further increased by removing argon, which will improve the efficiency of downstream production. However, this provides only a minor improvement. No further impurities are expected.

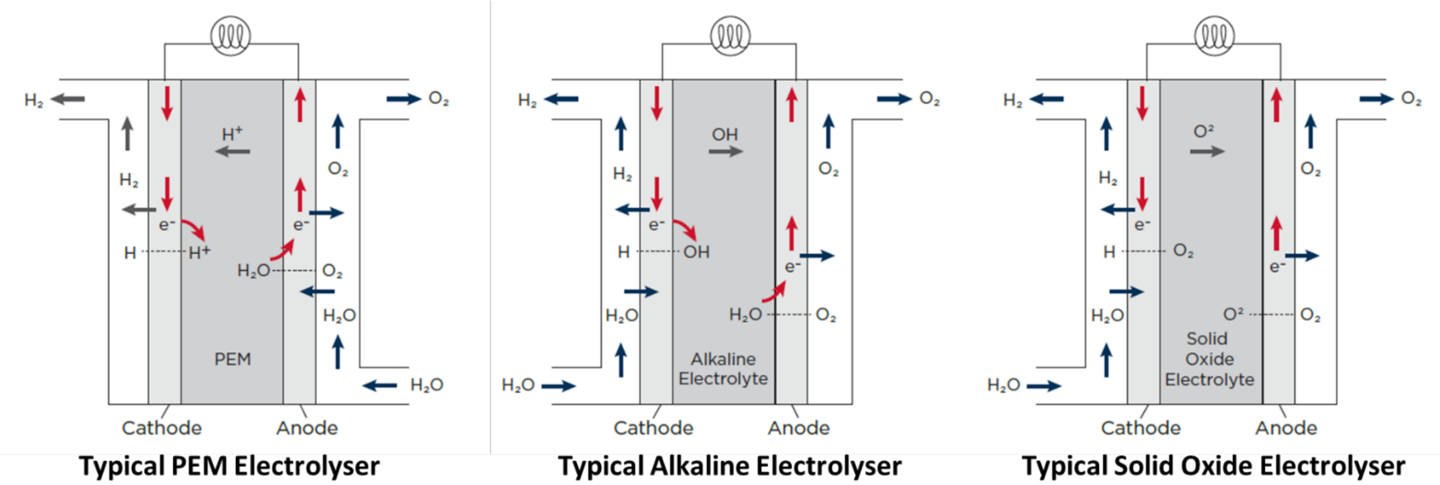


*Figure 3. Electrolyser technologies currently available or under development (ABS).*

*Table 1. Summary comparing the different types of electrolysers.*

| Name | PEM Electrolyser | Alkaline Electrolyser | Solid Oxide Electrolyser |
|---|---|---|---|
| Electrolyte | Solid Polymer | Aqueous Alkaline Solution (KOH or NaOH) | Solid Oxide, Yttria-stabilised Zirconium Oxide |
| Electrical efficiency (based on lower heating value) | 56-60% | 63-70% | 74-81% |
| Current Density [A/m²] | 10,000-20,000 | 2,000-4,000 | 3,500-5,500 |
| Operating Temperature [°C] | 50-80 | 60-90 | 500-850 |
| Input Component(s) | Deionised Water | Deionised Water and Alkali Material | Deionised Water (Steam) |

### 2.1.3 Renewable $CO_2$ capture

#### *Direct air capture (DAC)*

As the name suggests, direct air capture (DAC) technology is used to capture $CO_2$ directly from the air. This is more energy intensive than $CO_2$ capture from a point source such as a coal power plant, because the $CO_2$ concentration in the atmosphere is much lower than in the flue gas of industrial plants. The most energy-intensive process in DAC operation is the release of $CO_2$ after capture. To date, 27 small-scale DAC plants have been commissioned worldwide to demonstrate the technology. They have been successfully operated in different climates, mostly in Europe and North America (IEA, 2024).

Main components of a DAC system are the contact area (filter), the solvent or sorbent and the regeneration module (to regenerate the filter). The contact area exposes the sorbent to ambient air and facilitates airflow through the system, increasing the absorption or adsorption of $CO_2$ molecules (Fasihi, Efimova, & Breyer, 2019). DAC technology is at an early development stage and costs of $CO_2$ capture are still very high. Since the $CO_2$ concentration in the atmosphere is only 0.04% huge blowers are needed to generate enough airflow. It requires a large amount of energy to operate the fans, and this is a big obstacle.

Two main DAC categories are high temperature aqueous solution (HT DAC) and low temperature solid sorbent (LT DAC) systems (Fasihi, Efimova, & Breyer, 2019). LT DAC, which is the most technologically advanced, uses an adsorption/desorption cycling process and a solid sorbent to extract the $CO_2$. The adsorption of $CO_2$ takes place at ambient temperature, whereas the desorption occurs through a temperature-vacuum swing process, where $CO_2$ is released at low pressure and lower temperatures (80-100°C). Various LT DAC technologies have been developed, which differ in energy intensity and operating temperature. HT DAC makes use of two closed chemical loops, higher temperatures and an aqueous solution to extract the $CO_2$ from the air. In the first loop, air is brought into contact with an aqueous-basic solution, such as potassium hydroxide, capturing the $CO_2$. In the second loop, the captured $CO_2$ is released from the solution at temperatures between 300°C and 900°C (IEA, 2022).

The technological differences between LT DAC and HT DAC have various effects on performance. First, the energy consumption of DAC, which consists of roughly 20% electricity and 80% heat, is about 30% lower for HT DAC than for LT DAC (IEA, 2024). Secondly, HT DAC requires three to four times less surface area than LT DAC per megatonne of captured $CO_2$. HT DAC is more suitable for a large-scale operation, whereas LT DAC is modular and scalable. Theoretically, HT DAC can operate continuously at steady state, whereas LT DAC is a batch process, with some units capturing $CO_2$ while others regenerate and release the captured $CO_2$ from the filters. Finally, HT DAC can produce the water required by extracting it from the air, whereas LT DAC needs an external water supply (IEA, 2022). Despite their higher energy and land requirements and batch operation, Fasihi, Efimova & Breyer (2019) conclude that LT DAC systems are the cheapest type of DAC technology due to the lower cost of heat supply and the potential to use waste heat from other systems.

Different adsorption processes are considered for DAC by researchers. The main and most mature is temperature swing adsorption (TSA), where the captured $CO_2$ is released in its concentrated form (up to 100%) by heating the sorbent to a temperature high enough to liberate the $CO_2$ (~100°C). The purity of the $CO_2$ that is obtained is higher than 99.5%. Another advanced method is moisture swing adsorption (MSA), in which the regeneration happens by moisturising the $CO_2$-rich sorbent.

Furthermore, some innovative DAC methods have been suggested by some researchers, including electrochemical $CO_2$ capture, membrane-based DAC, nano-factory-based molecular filter, zeolites, passive DAC and crystallisation of $CO_2$ molecules with a guanidine sorbent (Fasihi, Efimova, & Breyer, 2019) (IEA, 2022) (IEA, 2024). Zeolites have a porous structure that can absorb $CO_2$, while passive DAC accelerates the natural conversion of calcium hydroxide and $CO_2$ into limestone. Electrochemical $CO_2$ capture, also called electro-swing adsorption, makes use of an electrochemical cell where a solid electrode absorbs $CO_2$ when negatively charged, and releases it when positively charged. This technology has a relatively low space requirement, because the cells are theoretically stackable. Also, it operates without conditioning or pumping equipment, unlike HT DAC (IEA, 2022). However, electrochemical $CO_2$ capture is not yet capable of removing $CO_2$ from atmospheric air due to the low $CO_2$ concentration in air. The technology has been tested at lab scale (TRL 4) for $CO_2$ concentrations down to 0.6% (IEA, 2022).

### *Oceanwater capture*

Oceanwater capture is an even newer category of $CO_2$ capture from the environment. Although this category gained some attention only recently, there are two reasons to justify further research: The $CO_2$ concentration in oceanwater is more than 100 times higher than in ambient air and the first step in DAC systems of adsorption or absorption of the $CO_2$ is not needed (Kim, et al., 2023).

Kim et al. (2023) have carried out a *'proof-of-concept'* study about an asymmetric-electrochemical system that can capture and release chloride ions and create a chloride-mediated electrochemical swing in the pH-value of oceanwater. The $CO_2$ is dissolved in oceanwater as carbonic acid and the carbon that is dissolved can be converted back to molecular $CO_2$ by lowering the pH of the oceanwater. With one subsystem that acidifies the oceanwater and one subsystem that regenerates the electrodes through the alkalisation of the treated stream, $CO_2$ can be continuously removed from simulated oceanwater. The pH of the treated water should be raised before it is returned to the ocean, which has the benefit of countering the acidification of the oceans and fostering the further absorption of $CO_2$ from the atmosphere. The technology needs to be developed further before it is ready to leave the laboratory stage.

Another technology is proposed by Straatman & van Sark (2021), who have described a concept in which $CO_2$ from oceanwater is captured by means of an open-cycle ocean thermal energy conversion (OC-OTEC) system. This system uses large quantities of oceanwater to generate electricity from temperature differences between different oceanwater layers. $CO_2$ and other gases dissolved in oceanwater are extracted from oceanwater by a vacuum compressor that is used in the OC-OTEC system for heat transfer. The extracted gas mixture contains up to 14% $CO_2$, which can be refined to 80-90% purity with a water-absorption process.

A third $CO_2$-extraction technology, developed by Eisaman et al (2012), is based on the process of electrodialysis. This technology makes use of an electrochemical $CO_2$-extraction cell. The oceanwater flows through parallel channels, which are separated by alternating bipolar and anion-exchange membranes. The applied electrical potential drives OH- and Cl- anions toward the anode and moves H+ cations from the 'base' channels to the *'acid'* channels. By reducing the channel's pH to below 5, $CO_2$ is separated and is collected using membrane contactors. In the contactors, the acidified oceanwater flows along an array of hollow fibers. The $CO_2$ gas diffuses into the fibers and is collected by a vacuum pump. Finally, the acid and base water flows are recombined to obtain a neutral effluent. A prototype cell extracted 59% of the dissolved $CO_2$ (Patterson, et al., 2019).

### 2.1.4 E-fuel Production Pathways

In this subsection different production pathways are considered for each of the e-fuels being examined. Consecutively, e-methanol, e-methane and e-diesel are discussed.

#### 2.1.4.1 E-methanol

Four production pathways to produce e-methanol have been found in the literature.

The first production method is to produce hydrogen through the electrolysis of water using renewable electricity to subsequently pre-treat $H_2$ and $CO_2$ and produce a syngas – which contains a high share of $H_2$ and CO – using the reverse water gas shift (RWGS) reaction; the syngas is then used for methanol synthesis. The (exothermic) syngas-to-methanol process is applied in the conventional fossil-fuel-based methanol-production process. The by-products of the synthesis step are ethanol, dimethyl ether (DME) and water, which must be separated from the methanol. So far, the syngas-production step (RWGS) has been only demonstrated in small-scale plants (UBA, 2023).

In a second production pathway, methanol is produced by a direct-synthesis process of $CO_2$ and $H_2$ produced from electrolysis. This single-step process is also described as the *'hydrogenation'* of $CO_2$. The result of direct-methanol synthesis is a mixture of methanol and water which then needs to be separated by distillation. This production pathway can achieve a higher methanol yield (approx. 70% has been reported) and a methanol purity of 99.9%. It also has a higher thermodynamic efficiency compared to the previous pathway due to the lower operating temperature. However, more hydrogen is needed for methanol production than in the first pathway. Direct-methanol synthesis has been classified in academic literature as a proven technology that has been demonstrated at a small industrial scale (UBA, 2023).

A third pathway consists of direct electrochemical conversion of $CO_2$ and water to methanol. So far, obtained energy efficiencies and yields are limited and only obtained at a laboratory scale (IRENA and Methanol Institute, 2021). It is operated in a fixed-bed catalytic reactor at 250-300°C and 50-100 bar (Sollai, Porcu, Tola, Ferrara, & Pettinau, 2023).

A fourth pathway is to produce syngas, i.e., CO and $H_2$, through high-temperature co-electrolysis of water and $CO_2$, followed by a conversion of the syngas to e-methanol. While this pathway could achieve a higher conversion efficiency, it is less developed than the first. Where conventional water electrolysis is used in the first pathways, the co-electrolysis process is in the laboratory stage and only tested at kilowatt scale (IRENA and Methanol Institute, 2021) (Mebrahtu, et al., 2021).

#### 2.1.4.2 E-methane

The main production pathway for e-methane uses methanation, also known as the Sabatier reaction, which combines $CO_2$ and $H_2$ at a temperature of up to 400°C, a pressure of 30 bar and the presence of a nickel or ruthenium catalyst to produce methane and water (Concawe, 2022). This single-stage process is exothermic. It has been demonstrated and operated on a MW scale but has not been applied on an industrial scale. A possible synergy in this production pathway is that the waste heat that is released could be used in the direct air capture process (UBA, 2023).

A novel system that is studied is the co-electrolysis of water and $CO_2$ in high-temperature SOECs. In this system, water and $CO_2$ are converted by the SOEC to syngas ($H_2$ and CO), which then undergoes a methane-synthesis step. There are different configurations for the combination of co-electrolysis and methane synthesis:

the hydrogen or syngas from the SOEC could be supplied to a conventional Sabatier reactor; or the methanation could take place in the SOEC. In the latter configuration, the cathode of the SOEC also acts as a catalyst for the methanation reaction. The highest methane yield obtained in experimental studies was 29%. A round-trip energy efficiency of 62% was found to be possible with in-situ synthesis of methane, against 48% of the conventional Sabatier process. Although the technology of in-situ synthesis is promising, large investigations of the reaction mechanisms, kinetics and the behaviour of cell materials under various process conditions are needed (Biswas, Kulkarni, Giddey, & Bhattacharya, 2020).

Syngas methanation is the process of methanation using syngas ($CO + H_2$) as an input. Although this pathway is briefly mentioned by Concawe in its report on e-fuels as another possible production pathway (Concawe, 2022), it is not discussed further. This is probably because the production of syngas would include another production step compared to the methanation process using hydrogen and $CO_2$. Indeed, experimental research papers and feasibility studies focus on the syngas resulting from biomass gasification, where syngas methanation is a logical consecutive step. Because syngas methanation using only renewable electricity as a renewable energy source is meaningless, this production route is not discussed further in this study.

#### 2.1.4.3 E-diesel

There is only one main production pathway to produce e-diesel described in the literature, consisting of three consecutive steps: the RWGS reaction, the Fischer-Tropsch (FT) synthesis process and hydrocracking.

First, the RWGS reaction converts $CO_2$ and $H_2$ into syngas at an operating temperature of around 1,000°C. The RWGS plant is a net electricity and heat consumer. Next, the syngas is converted into a mix of fuel gases, naphtha/gasoline, kerosene, diesel/gas oil, base oil and waxes (e-crude) in the FT synthesis process (Concawe, 2019). FT synthesis is an exothermic process. Finally, the e-crude that is produced can be converted into hydrocarbon products in a hydrocracking unit, which could be a unit from a conventional (fossil) refinery.

To maximise the yield of transport fuels (gasoline, diesel, kerosene), the FT synthesis process could be designed and operated at a low temperature[6], resulting in a product slate of 37% gasoline, 28% diesel, 32% kerosene and 3% LPG (Concawe, 2022). The e-diesel yield is thus much lower than the e-distillates yield. However, with post-processing, it may be possible to increase the yield of e-diesel production at the expense of other e-distillates, although this has not yet been demonstrated.

The FT process is an established process that has been used on an industrial scale to produce fossil hydrocarbons such as synthetic diesel and kerosene from coals and natural gas. However, the syngas production (RWGS reaction) has only been demonstrated in small-scale plants (UBA, 2023).

### 2.1.5 Levels of Maturity of Technologies

The technology readiness levels (TRL) of the hydrogen and $CO_2$ production technologies are presented in Table 2, while the TRLs of the e-fuel production technologies are shown in Table 3.

Hydrogen production and $CO_2$ production technologies are relevant for all production pathways.

Whereas alkaline and PEM electrolyser technologies are operational in the market, DAC is still in the demonstration phase. As DAC is required for all e-fuel production pathways, this immediately shows that none of the e-fuel production pathways are technologically advanced enough to enter the market.

In addition, the syngas production route for e-methanol production and the Fischer-Tropsch route for e-diesel production require the RWGS reactor to advance past the demonstration phase. The methanation process (Sabatier reaction) for e-methane production also remains at the demonstration phase.

6 The product mix is influenced by the temperature and the catalyst of the FT reaction, resulting in lighter hydrocarbons for high temperatures (320-350°C) and heavier hydrocarbons for low temperatures (190-250°C) (Concawe, 2022).

*Table 2. TRL of hydrogen and $CO_2$ production technologies.*

| Production segment | Production pathway | Technologies | Remarks | Technology readiness level (TRL) | Sources |
|---|---|---|---|---|---|
| Hydrogen production (most pathways*) | Electrolysis | Alkaline electrolyser | Alternative technologies to split pure water into hydrogen and oxygen using electricity | 9 | (Rouwenhorst, Van der Ham, Mul, & Kersten, 2019), (Smith, Hill, & Torrente-Murciano, 2020) |
| | | PEM electrolyser | | 8-9 | (Smith, Hill, & Torrente-Murciano, 2020) |
| | | SOEC electrolyser | | 3-5 | (Rouwenhorst, Van der Ham, Mul, & Kersten, 2019), (Smith, Hill, & Torrente-Murciano, 2020) |
| $CO_2$ production (all pathways) | Direct air capture (DAC) | High temperature aqueous solution | | 5-6 | (IRENA and Methanol Institute, 2021) |
| | | Low temperature solid sorbent | The most advanced adsorption process is that of temperature swing adsorption (TSA). | 7 | (UBA, 2023) (IRENA and Methanol Institute, 2021) |
| | | Innovative DAC technologies | | 1-4 | (Fasihi, Efimova, & Breyer, 2019) (IEA, 2022) (IEA, 2024) |
| | Oceanwater capture | Asymmetric electrochemical system | | 3 | (Kim, et al., 2023) |
| | | Integrated in open-cycle thermal energy conversion system | | 2 | (Straatman & van Sark, 2021) |
| | | Electrodialysis | | 5-6 | (Eisaman, et al., 2012) (Patterson, et al., 2019) |

*Notes: TRL 1 = Basic principles observed; TRL 2 = Concept formulated; TRL 3 = Experimental proof of concept; TRL 4 = Validated in lab; TRL 5 = Validated in relevant environment; TRL 6 = Demonstrated in relevant environment; TRL 7 = System prototype demonstrated in operational environment; TRL 8 = System complete and qualified; TRL 9 = System proven in operational environment.*
** Except for the two co-electrolysis routes and direct electrochemical conversion.*

*Table 3. TRL of e-fuel production technologies*

| Production segment | Production pathway | Technologies | Remarks | Technology readiness level (TRL) | Sources |
|---|---|---|---|---|---|
| E-methanol production | Syngas production route | Reverse water gas shift (RWGS) | | 7 | (Concawe, 2022) (UBA, 2023) |
| | | Methanol synthesis | | 9 | (IRENA and Methanol Institute, 2021) |
| | Direct methanol synthesis | Direct methanol synthesis | Also called hydrogenation process | 7 | (Sollai, Porcu, Tola, Ferrara, & Pettinau, 2023) (UBA, 2023) |
| | Direct electrochemical conversion | Direct electrochemical conversion | | 3-4 | (IRENA and Methanol Institute, 2021) |
| | High-temperature co-electrolysis | Co-electrolysis | Produces syngas | 3-4 | (IRENA and Methanol Institute, 2021) (Mebrahtu, et al., 2021) |
| | | Methanol synthesis | | 9 | (IRENA and Methanol Institute, 2021) |
| E-methane production | Sabatier reaction | Methanation | Also called methanation process | 6 | (ENTEC, 2022) |
| | Co-electrolysis in solid oxide electrolyser cell (SOEC) | Co-electrolysis | Methane production with co-electrolysis | 3-4 | (Biswas, Kulkarni, Giddey, & Bhattacharya, 2020) |
| | Both e-methane pathways | Liquefaction | Same technology as for LNG production | 9 | |
| E-diesel production | Fischer-Tropsch (FT) route | RWGS | | 7 | (Concawe, 2022) (UBA, 2023) |
| | | FT synthesis | Used on an industrial scale | 9 | (UBA, 2023) |
| | | Hydrocracking | | | |

*Notes: TRL 1 = Basic principles observed; TRL 2 = Concept formulated; TRL 3 = Experimental proof of concept; TRL 4 = Validated in lab; TRL 5 = Validated in relevant environment; TRL 6 = Demonstrated in relevant environment; TRL 7 = System prototype demonstration in operational environment; TRL 8 = System complete and qualified; TRL 9 = System proven in operational environment.*

#### *Vessel technology*

Because e-diesel, e-methane and e-methanol can be used as drop-in fuels in ships powered by fossil diesel, LNG and methanol, respectively, the number of current and planned vessels that could run on e-fuels is significant, as shown in Appendix A – Current and planned vessels.

### 2.1.6 Developments in Production Capacity

Table 4 presents a global overview of projects to produce e-methanol, e-methane and e-diesel. The projects rely on biogenic $CO_2$ or industrial $CO_2$ sources rather than $CO_2$ captured from air. Nevertheless, to date, 27 DAC plants have been commissioned worldwide and there are plans for at least 130 more DAC facilities at various stages of development (IEA, 2024). These plants and facilities are still small-scale: The 27 DAC plants add up to 0.01 megatonne of captured $CO_2$ per year, from which only 7,140 tonnes of e-methanol could be produced per year.

*Table 4. Large e-fuel projects worldwide*

| Project | | | | | |
|---|---|---|---|---|---|
| **Project** | **Country** | **E-fuel production** | **Phase** | **Start of operation** | **Remarks** |
| **E-methanol** | | | | | |
| Bell Bay Powerfuels (ABEL Energy, 2023) | Australia | 300,000 tonne/year | Design phase (FEED) | 2027 | Uses a 240 MW electrolysis plant with syngas from a biomass gasifier |
| HIF Tasmania eFuels Facility (HIF Global, 2023) | Australia | Unknown | Design phase (FEED) | 2028 | Primary product is expected to be e-gasoline initially. Uses biogenic $CO_2$. |
| Haru Oni plant (HIF Global, 2022) | Chile | 350 tonne/year (methanol) | Operational | 2022 | Produces e-methanol, e-gasoline and e-LPG. Uses wind energy, 1.2 MW of electrolyser capacity and biogenic $CO_2$. |
| Dalian Institute of Chemical Physics plant (IRENA and Methanol Institute, 2021) | China | 1,000 tonne/year | Pilot project | 2020 | Uses electrolysis and solar energy (PV). |
| Kassø plant (Mitsui, 2023) | Denmark | 42,000 tonne/year | Construction phase | 2024 | One of the customers is shipping company A.P. Moller-Maersk. Use of biogenic $CO_2$. |
| George Olah plant (Carbon Recycling International, 2023) | Iceland | 4,000 tonne/year | Operational | 2012 | Uses electrolysis and $CO_2$ capture from a geothermal power plant. World's first industrial scale production of e-fuel, according to developer. |
| Finnfjord plant (Carbon Recycling International, 2023) | Norway | 100,000 tonne/year | Design phase (FEED) | Unknown | Use of industrial $CO_2$. FID expected in 2024. |
| FlagshipONE (H2 Energy News, 2023) | Sweden | 50,000 tonne/year | Construction phase | 2025 (upscaling by 2030) | Uses electrolysis and industrial $CO_2$. |
| FlagshipTWO (Liquid Wind, 2023) | Sweden | 100,000 tonne/year | Announced | 2025-2026 | Uses electrolysis, renewable electricity and biogenic $CO_2$. |
| Matagorda plant (Collins, 2023) | United States | 750 million litres/year (methanol) | Permit issued | 2027 | Produces e-methanol and e-gasoline. 1.4 Mtonnes of methanol could be produced but will partly be refined into e-gasoline. |
| **E-methane** | | | | | |
| Santos Cooper Basin project (Santos, 2023) (Santos, 2023b) | Australia | 60,000 tonne/year | Feasibility study | 2030 | For export to Japan. Focus on the Cooper Basin. Feed entry in 2024 and FID in 2026. |
| Columbus project (Engie, Carmeuse and John Cockerill, 2023) | Belgium | 330 GWh/year | Design phase (FEED) | Unknown | Use of industrial $CO_2$ and a 100 MW electrolyser. The e-methane will be suitable for injection into the natural gas grid. |
| Project Mauricie | Canada | 70,000 tonne/year (hydrogen) | Announced | 2030 | About two-thirds of the hydrogen will be converted to e-methane. Use of wind, solar and hydropower. |
| Kristinestad plant (ESG Review, 2023) | Finland | 50,000 tonne/year | Design phase (FEED) | After 2024 | Use of wind and solar power. |
| Werlte e-gas plant (Audi, 2021) | Germany | 1,000 tonne/year | Operational | 2013 | Production of synthetic natural gas (*'Audi e-gas'*) that is distributed to CNG filling stations |

| Project | | | | | |
|---|---|---|---|---|---|
| **Project** | **Country** | **E-fuel production** | **Phase** | **Start of operation** | **Remarks** |
| Osaka Gas project (Osaka Gas and ENEOS, 2023) | Japan | 60 million $m^3$/year | Feasibility study | 2030 | Use of imported green hydrogen. |
| Peru LNG plant (Parkes, 2023) | Peru | 60,000 tonne/year | Announced | 2030 | FID by 2025. Use of solar, wind and hydropower. |
| US Gulf Coast plant (Mitsubishi, 2023) | United States | 130,000 tonne/year | Feasibility study | Unknown | Production for export to Japan. |
| TotalEnergies and TES project (TotalEnergies, 2023) | United States | 100,000-200,000 tonne/year | Feasibility study | After 2024 | Use of 1 GW electrolyser, 2 GW of wind and solar energy and biogenic $CO_2$. Aim to take FID in 2024. |
| **E-diesel** | | | | | |
| Vordingborg plant (Arcadia eFuels, 2023) | Denmark | Unknown | Design phase (FEED) | 2026 | The primary product is e-kerosene, but e-diesel can also be produced. Uses biogenic $CO_2$. |
| INERATEC Frankfurt plant (INERATEC, 2023) | Germany | 2,500 tonne/year (e-fuels) | Construction phase | 2024 | The aim of the plant is to produce e-kerosine on a mass scale, but other fuels will be produced as well. Use of biogenic $CO_2$ and $CO_2$ captured from air. |
| DAWN plant (Synhelion, 2022) | Germany | Several thousand litres/year (e-fuels) | Construction phase | 2024 | Production of e-kerosine and other e-fuels. Demonstration plant using concentrated solar power. Use of biogenic $CO_2$. |
| INERATEC Amsterdam plant (INERATEC, 2023) | Netherlands | 35,000 tonne/year (e-fuels) | Memorandum signed | 2027 | Production of e-fuels, including kerosene, diesel and gasoline. Use of $CO_2$ captured from industry. |
| Mosjøen plant (Norsk e-Fuel, 2023) | Norway | Unknown | Announced | 2026 | E-kerosene is the primary product. Use of biogenic $CO_2$. |
| Nordic Electrofuel plant (Nordic Electrofuel, 2023) | Norway | 8,000 tonne/year (e-liquids) | Design phase (FEED) | 2026 | Use of electrolysis and renewable electricity. |

### 2.1.7 Production Conclusions

Table 5 provides a summary of the hydrogen and $CO_2$ production technologies, while Table 6 presents a summary of e-fuel production pathways. Both tables include the technologies, energy efficiencies and technology readiness levels identified in this subsection. Because DAC is required for all e-fuel production pathways, none of the e-fuel production pathways are technologically advanced enough to enter the market. In addition, all three e-fuel production routes require the advancement of some of the required technologies from the demonstration phase to market entry.

*Table 5. Summary of hydrogen and $CO_2$ production technologies.*

| Production segment | Production pathway | Technology | Energy efficiency | Technology readiness level (TRL) |
|---|---|---|---|---|
| Hydrogen production (most pathways**) | Electrolysis | Alkaline electrolyser | 63-70% * | 9 |
| | | PEM electrolyser | 56-60% * | 8-9 |
| | | SOEC electrolyser | 74-81% * | 3-5 |
| $CO_2$ production (all pathways) | Direct air capture (DAC) | High temperature aqueous solution | - | 5-6 |
| | | Low temperature solid sorbent | - | 7 |
| | | Other technologies | - | 1-4 |
| | Oceanwater capture | Asymmetric electrochemical system | - | 3 |
| | | Integrated in open-cycle thermal energy conversion system | - | 2 |
| | | Electrodialysis | - | 5-6 |

** Power-to-hydrogen*
*** Except for the two co-electrolysis routes and direct electrochemical conversion*

*Table 6. Summary of e-fuel production pathways.*

| Production segment | Production pathway | Technology | Energy efficiency | Technology readiness level (TRL) |
|---|---|---|---|---|
| E-methanol production | Syngas production route | Reverse water gas shift (RWGS) | 45-65%* | 7 |
| | | Methanol synthesis | | 9 |
| | Direct methanol synthesis | Direct methanol synthesis | | 7 |
| | Direct electrochemical conversion | Direct electrochemical conversion | | 3-4 |
| | High-temperature co-electrolysis | Co-electrolysis | | 3-4 |
| | | Methanol synthesis | | 9 |
| E-methane production | Sabatier reaction | Methanation | 48-57%* | 6 |
| | Co-electrolysis in SOEC | Co-electrolysis | 62% | 3-4 |
| E-diesel production | Fischer-Tropsch (FT) route | RWGS | 13-15% (45-53%) ** | 7 |
| | | FT synthesis | | 9 |
| | | Hydrocracking | | |

** Power-to-fuel*
*** Power to e-diesel. The energy efficiency between brackets is the power-to-e-distillate efficiency. Assumed e-diesel share is 28%* (Concawe, 2022).

## 2.2 Sustainability

### 2.2.1 GHG Emissions

The life cycle GHG emission factor of a fuel includes direct and indirect GHG emissions as well as any emissions of $CO_2$, $CH_4$ and $N_2O$ which are converted to $CO_2$-equivalents using global warming potential (GWP) factors. In Table 7, the GHG performances of the e-fuels under consideration are summarised in comparison to conventional marine fuels.

If renewable electricity and renewable $CO_2$ are used to produce the e-fuels (which is assumed in this study), the combustion of e-fuels does not lead to a net emission of $CO_2$. If the GHG emissions from manufacturing and construction of the production systems (i.e., wind turbines, solar panels, electrolysers, DAC systems and synthesis plants) are included[7], the GHG emission factors are higher than zero. Even then, however, the e-fuel emission factors are minor compared to those for conventional marine fuels, as shown in Table 7. The use of a fossil-fuel-based pilot fuel[8] may add to GHG emissions, but if a net-zero carbon fuel is used, it will not. If e-fuels are used as a blend, the GHG impact is proportional to the blend rate.

The comparison between life cycle GHG emissions factors of e-fuels and fossil fuels for maritime shipping from Table 7 shows that the switch to e-fuels will reduce GHG emissions by 99% when manufacturing emissions are excluded and by 94% when manufacturing emissions are included. Therefore, these e-fuels comply with the RED III, the revised Renewable Energy Directive that is part of the EU's *'Fit for 55'* Package, which mandates a 70% reduction in GHG emissions for RFNBOs compared to the fossil reference.

*Table 7. Life cycle GHG emission factors for e-fuels vs. marine fossil fuels.*

| Fuel | GHG emission factor excl. manufacturing (g $CO_2$eq./MJ fuel) | GHG emission factor incl. manufacturing (g $CO_2$eq./MJ fuel) | Source | Remarks |
|---|---|---|---|---|
| E-methanol | 0.5 | 5.1 | (Concawe, 2022) | Main production pathways assumed. Use of renewable electricity assumed. The use of grid electricity could lead to GHG emissions that are even higher than those of VLSFO and MGO, depending on the grid mix (Concawe, 2022). |
| E-methane | 0.3 | 5.1 | | |
| E-diesel | 0.5 | 5.6 | | |
| VLSFO | 92 | | (CE Delft, 2021) FuelEU Maritime proposal | Upstream emissions depend on the source of the crude oil and its refinery. |
| MGO | 91 | | | |

*Notes: VLSFO = very low sulphur fuel oil; MGO = marine gasoil.*

In the case of e-methane, the storage of liquid e-methane leads to additional GHG emissions: Some of the liquid methane in the storage tanks evaporates (boil-off), resulting in a methane loss rate of 0.1%-0.15% per day. The evaporated methane must be captured to avoid a strong increase in the GHG impact (UBA, 2023).

Furthermore, hydrogen leakage also may contribute to the GHG impact of e-fuels, because hydrogen is an indirect GHG. Electrolysers make use of venting during start up, shutdown and purging during operations to remove impurities. In the worst-case scenario, this may lead to hydrogen emissions up to 9.2% of the volume produced. Assuming that all the purged and vented hydrogen is captured and used, preventing its release into the atmosphere, hydrogen emissions from electrolysis would be less than 0.52% (Frazer-Nash Consultancy, 2022). The global warming potential of hydrogen over a period of 100 years ($GWP_{100}$) is estimated in the literature at 1.9-16 (EMSA, 2023)[9]. This shows that it is important to prevent hydrogen leakage, as it could have a large effect on GHG performance. However, even with hydrogen leakage, the switch from fossil fuels to e-fuels can be expected to result in a substantial GHG emissions reduction (EMSA, 2023).

### 2.2.2 Air Pollutant Emissions

The different air-pollutant emissions from ships have unique determinants that materialise from the production pathway of a specific fuel type. Table 8 provides an overview of the main determinants of Tank-to-Wake (TtW) air pollutant emissions and the degree to which the volume of these emissions depends on the specific production pathway (i.e., fossil vs bio vs e-fuel types). The focus is on $SO_X$, $NO_X$ and PM emissions.

7 In literature, the life cycle GHG emission factors of renewable electricity and hydrogen often include the emissions associated with the manufacturing and construction of wind turbines, solar panels and electrolysers.
8 Pilot fuel refers to the small amount of liquid fuel needed when operating a gas engine, for the safe ignition of the gaseous fuel.
9 The $GWP_{100}$ is 1 for $CO_2$, 29.8 ± 11 for fossil $CH_4$ and 27 for non-fossil $CH_4$ and 273 ± 130 for $N_2O$ (IPCC, 2021).

*Table 8. Main determinants of the Tank-to-Wake air pollutant emissions and degree of dependency on production pathway of a specific fuel type.*

| Air pollutant emissions | Main determinants of the TtW emissions | Degree of dependency of TtW emissions on production pathway of a specific fuel type (i.e., fossil vs bio vs e-fuel) |
|---|---|---|
| $SO_X$ | Sulphur content of fuel | High degree. |
| PM | 1. Sulphur content of fuel: Parts of sulphur are not converted to $SO_X$, but to sulphate/sulphite aerosols (part of PM).<br>2. Feed rate of cylinder oil<br>2. Ash content of fuel | Medium degree. |
| $NO_X$ | Fuel type (i.e., diesel vs methanol vs methane)<br>Combustion process<br>Engine load | Low degree |

In addition, the following general statements can be made on air pollutant emissions:

- $SO_X$ emissions
  - Methanol as such is sulphur free, independent of the specific production pathway (e-methanol/bio-methanol/fossil methanol;
  - In general, the sulphur content of e-fuels can be expected to be zero;
  - (The sulphur content of biofuels is, in general, much lower compared to the fossil counterpart of a fuel and compared to fossil VLSFO.)

- $NO_X$ emissions
  - Without extra measures (e.g., aftertreatment), $NO_X$-Tier III requirements cannot be met by
    - using VLSFO;
    - using methanol in an internal combustion engine (ICE), independent of the specific methanol production pathway;
    - using methane in a diesel cycle engine, independent of the specific methane production pathway;
  - Aside from aftertreatment systems, the application of a methanol-water fuel mixture also would meet $NO_X$-Tier III requirements;
  - Combustion of methane in diesel-cycle engines will generate higher $NO_X$ emissions than combustion in an Otto-cycle engines, independent of specific methane-production pathway;
  - Since the molecule is the same, $NO_X$ emissions are the same for:
    - E-methanol and fossil methanol;
    - E-methane and fossil methane.

- PM emissions
  - The use of lubrication for cylinder liners leads to PM emissions. These emissions cannot be avoided even if a fuel type is not associated with PM emissions; therefore, the lubricants determine the lowest possible PM emissions level, a base level that does not depend on the production pathway of a specific fuel (fossil/bio/e-fuel).

One side effect of reducing $NO_X$ in a selective catalytic reduction (SCR) system is the potential risk of forming $N_2O$ emissions. $N_2O$ is a strong GHG, 265 times stronger than the GHG impact from $CO_2$. The chemical reaction in the SCR is well understood and there is specific SCR catalysts that form more $N_2O$ than others. As an example, using Fe-SCR only forms small amounts of $N_2O$. Another source of $N_2O$ emission may come from the reaction between $NO_2$ and $NH_3$ in the SCR; this reaction is less likely when the amount of NO emission in the exhaust is higher than the $NO_2$ emission. In a conventional diesel process, NO emissions comprise 70-90% of the $NO_X$.

To ignite methanol and methane it requires an ignition source, in dual fuel engines pilot fuel is usually used. In single fuel engines ignition coils have also been used for ignition of methane gas. For methanol and methane, in dual fuel engines, the overall emission reduction depends on the pilot fuel use:

- Use of methanol in an ICE requires the use of pilot fuels (3-5% for 2-stroke engines, higher for marine 4-stroke engines);
- Use of methane in an ICE requires the use of pilot fuels (with 1-3% being the highest level for high pressure/diesel-cycle engines), at least if a spark-ignition engine is not used.

It is noted that limited e-fuels – as defined for the purpose of this study – have been produced, which is why no emission-measurement data is available. E-diesel, however, can be expected to be identical with gas-to-liquid fuel (GTL-fuel) produced via the Fischer-Tropsch (FT) process, which is already available on the market.

The air-pollutant emissions of different marine biofuels compared to VLSFO were analysed in a previous study (EMSA, 2022a). The following table summarises these outcomes.

*Table 9. TtW air pollutant emissions: Biofuel versus conventional fossil liquid bunker fuel), not considering pilot fuels.*

| Fuel | $NO_X$ emissions | $SO_X$ emissions | PM emissions |
|---|---|---|---|
| Bio-diesel | 0-30% reduction, depending on specific fuel type.<br><br>For bio-diesel containing oxygen, $NO_X$ can be higher than for fossil diesel (Maersk McKinney Moller Center For Zero Carbon Shipping, 2023). | 89-100% reduction, depending on specific fuel type | 30-90% reduction, depending on specific fuel type |
| Bio-methanol | 30-82% reduction<br>(diesel engine cycle) | 100% reduction | 60-100% reduction |
| Bio-methane | Can contribute to a reduction of $NO_X$ emissions, mainly if combusted in Otto-cycle engines.<br><br>Diesel-cycle engines: may result in 20-30% reduction compared to distillate fuels.<br><br>SGC can be improved if $NO_X$ is allowed to be increased to reach tier II level by means of re-calibration of engine and not by aftertreatment. | | |

Table 10 shows the expected reduction in TtW air pollutant emissions for the three e-fuel types considered in this study.

*Table 10. TtW air pollutant emissions: E-fuel versus conventional liquid bunker fuel.*

| Fuel | $NO_X$ emissions | $SO_X$ emissions | PM emissions |
|---|---|---|---|
| E-diesel | Average reductions of 15-19% compared to MGO (Ushakov, Halvorsen, Valland, Williksen, & Æsøy, 2013) | 100% reduction | Particulate number concentrations* - increase in average by 21% particulates mass* - up to 16% decrease at medium and high loads (Ushakov, Halvorsen, Valland, Williksen, & Æsøy, 2013) - increase by 12-15% under lower load conditions (Ushakov, Halvorsen, Valland, Williksen, & Æsøy, 2013) |
| E-methanol | 30-40% reduction, compared to diesel/ HFO (Sustainable Ships, 2023) | Only pilot fuel related emissions. | 85-95% reduction compared to MGO/HFO (Green Maritime Methanol consortium, 2021) |
| E-methane | 20-80% depending on engine technology (DNV, 2021) | Only pilot fuel related emissions. | Almost eliminated (DNV, 2021) Approx 40-60% reduction (ISO) (MAN Diesel & Turbo, 2014) |

** Particle number concentration is the total number of particles per unit volume of air (for example, cm-3), whereas particle mass concentration is the total mass of particles per unit volume of air (for example, µg m-3). Particle mass concentrations are typically dominated by larger particles.* (DEFRA, 2024)

The comparison of e-diesel with conventional liquid bunker fuel is based on Ushakov et al. (2013), which compared the emissions of fossil gas-to-liquid (GTL) fuel with marine gas oil for turbocharged heavy-duty diesel engines. The study also analysed the impact of the use of GTL fuel on other air pollutants and concluded that GTL fuel compared to MGO leads, on average, to a 25% decrease of CO and a 30% decrease of smoke, while unburned hydrocarbon emissions slightly increase. Ushakov et al. (2013) is not conclusive on the average impact on PM. Shell, a supplier of GTL fuel, however, specifies a PM reduction of up 59% for marine engines compared to conventional diesel (Shell, 2023).

### 2.2.3 Other Environmental Impacts

#### *Renewable electricity generation*

Generating renewable electricity to produce green hydrogen requires significant land or sea surface areas. The amount varies widely across regions, depending on the incoming solar radiation and prevailing wind speeds. To realise large-scale green hydrogen production, solar-energy plants and wind farms also would need to be built on a large-scale. If solar energy parks and onshore wind parks are located where the cultivation of food crops is not possible, their creation will not interfere with food production, preventing indirect changes in land use and the related environmental damage. There are arid regions around the world where this is the case (e.g., northern Chile, western Australia, northeast Brazil, northern Africa, parts of the U.S. and China). Some regions (e.g., northern Europe, the eastern U.S. and western Africa) have seas that are suitable for offshore wind farms. However, these may have an impact on marine ecosystems.

#### *Wind parks*

Chowdhury et al (2022) have examined the environmental impacts of wind parks. Manufacturing is the main source of environmental impact from wind turbines; operation has the lowest impact. The impact of the end-of-life stage (decommissioning) can be significantly reduced by recycling the steel and fibre glass from the turbines.

Residual copper, which is a main element in the wind turbine generator, can accumulate in plants and animals, create metabolic disturbances and inhibit plant growth.

During operations, wind turbines can harm birds and bats. However, there is not enough evidence on the potential impact on those species. Moreover, during the construction phase for wind turbines, wildlife may be harmed, and the breeding of birds and bats could be hampered. The noise from the construction and operation of wind turbines may cause birds and bats to relocate their habitats. To reduce these negative impacts, the location of bird and bat habitats should be considered when selecting a location for a wind park.

Offshore wind turbines also may affect marine mammals. For example, there is evidence that Minke whales have been stranded due to noise from wind turbines. Additionally, the noise at wind turbine sites could cause nearby residents and wind-turbine workers to suffer from sleep disorders, and the change in landscape may influence the residents' mental health.

Finally, wind parks have the potential to reduce the kinetic energy of local winds so dramatically that it may have a local impact similar to the greenhouse effect, because the turbulence in the wake of the turbines can alter the direction of the high-speed wind near the ground and thereby increase local moisture evaporation. However, research suggests that spatial and temporal impacts such as these are relatively minor (Chowdhury, et al., 2022).

### *Solar parks*

For solar parks, there are negative environmental effects associated with the manufacturing, construction and disposal of photovoltaic panels, and other technologies used to generate solar electricity, but the negative effects from operations are less prevalent than for wind parks.

In one study (Armstrong, Ostle, & Whitaker, 2016), analysis of photovoltaic arrays at a solar park located in a species-rich grassland in the U.K. found that the arrays caused seasonal and diurnal variation to air and soil microclimates, including plant diversity and fluxes in $CO_2$ within the ecosystem. During the summer, a cooling of up to 5.2°C was observed and the diurnal variation in temperature and humidity was reduced under the photovoltaic arrays. Photosynthesis and net ecosystem exchange in spring and winter also were lower under the photovoltaic arrays.

More research is needed to better understand the environmental effects, but the authors concluded that optimising the design and management of the solar park could minimise the environmental costs.

### *Hydrogen production (electrolysers)*

Although there is limited information on the environmental impact of the large-scale electrolysers used to produce green hydrogen, a recent study by Delpierre, Quist, Mertens, Prieur-Vernat, & Cucurachi (2021) offered some insight. The authors compared the environmental performance of green hydrogen production using alkaline electrolysers, PEM electrolysers and steam methane reforming (SMR), using ex-ante Life Cycle Assessment (LCA) for a 2050 scenario in the Netherlands.

The contribution of the electrolyser to the environmental impact was limited to 10% in all categories of impact, including acidification, climate change, land use, eutrophication, resource depletion, ozone depletion and the formation of photochemical ozone. More than 80% of the environmental impact came from the production of electricity in the Dutch system.

Secondly, when the electricity used by the electrolysers came from wind energy, SMR performed better than large-scale electrolysers in terms of the depletion of water resources, minerals, fossil and renewable-resources, but worse for other categories.

The production of green hydrogen by means of electrolysis requires pure, de-ionised water. The amount of water needed to produce green hydrogen can increase the scarcity of water, if freshwater is used. On the other hand, if seawater is used to produce de-ionised water, the intake of seawater and the rejection of brines can be detrimental to ocean biodiversity and marine life (Ghavam, Vahdati, Grant Wilson, & Styring, 2021).

### *Renewable $CO_2$ capture*

An environmental concern specific to direct air capture (DAC) plants is local $CO_2$ depletion, which may affect the environment and vegetation. Local $CO_2$ depletion in the local ambient air might occur if large-scale DAC systems operate in a relatively small area. However, researchers have concluded that DAC systems do not lead to local $CO_2$ depletion (Fasihi, Efimova, & Breyer, 2019).

Another concern is the need for land area. Researchers arrived at a land footprint of 1.5 $km^2$/Mt $CO_2$, if DAC units are located 250 metres apart to prevent dual depleted air intake. The Climeworks DAC plant has a footprint of 0.4 $km^2$/megatonne $CO_2$ (Fasihi, Efimova, & Breyer, 2019).

Furthermore, HT aqueous solution DAC systems require water. The water loss in these systems could be 0-50 tonnes per tonne of captured $CO_2$, depending on the temperature, air humidity and concentration of the solution. The Carbon Engineering DAC design requires 4.7 tonnes of water per tonnes of capture $CO_2$. This could be problematic in regions with water stress. In contrast, LT DAC systems can capture water as a by-product, which could be used in a nearby electrolyser system (Fasihi, Efimova, & Breyer, 2019).

Kim et al. (2023) state that a potential benefit of oceanwater capture would be that the capture of $CO_2$ from oceanwater could help to mitigate the acidification of oceans, lowering the adverse effects on coral reefs, shellfish and other marine life. However, improper treatment of the by-products of the capture process also could increase ocean acidification. Moreover, oceanwater capture could lead to an increase in ocean noise pollution, disruption of benthic ecosystems and pollution resulting from of high concentrations of chlorine and $CO_2$ (Meyer & Spalding, 2021). Finally, oceanwater capture systems introduce risks of toxic redox couples leaking into the ocean (Kim, et al., 2023).

In general, the research and development of oceanwater carbon capture technologies are still in a very early phase, so the environmental impacts of these technologies are largely unknown and require further investigation.

### *Production of e-fuels*

The manufacturing and installation of e-methanol, e-methane and e-diesel production systems are not expected to have a negative impact on resource depletion.

### *Spillage of e-fuels*

E-methanol has the same chemical composition as fossil methanol so the environmental effects of any spillage would be the same. If spilt, methanol spreads on the ocean surface, partly dissolving into the water and partly evaporating into the atmosphere. The methanol that is dissolved has the potential to have a toxic impact on the immediate surroundings, but the methanol concentration will rapidly shrink, and long-term impacts are thought to be negligible. Dissolution of methanol to non-toxic levels (<1%) will happen significantly faster than with petroleum-based fuels. Because of the short residence time of toxic methanol in the ocean, traditional spill response is most likely unnecessary (NorthStandard, 2024).

E-methane spillage will have the same effects as LNG spillage, as the two fuels have the same chemical composition. When e-methane is spilt, it warms and vaporises. At higher concentrations, the vaporised methane causes an asphyxiation hazard to those who are exposed. If the methane contacts water, the vapourisation may accelerate. If spilt e-methane ignites, it results in a rapid burn-off of natural gas vapors, rather than an explosion. Thus, e-methane spillage at sea causes both safety hazards and GHG emissions, but environmental hazards would be smaller than for fuel oils (Lehr & Simecek-Beatty, 2017). No impacts on marine ecosystems were found in the literature examined.

Diesel (both fossil diesel and e-diesel) that is spilt into the ocean will initially form a slick on the ocean surface. If limited amounts of diesel are spilt (less than 5,000 gallons, or 19,000 litres), most of the diesel will evaporate or naturally disperse. It can be completely degraded by microbes within two months, if there is sufficient oxygen. Although fish and invertebrates that come in direct contact with diesel may be killed, small spills in open water are so rapidly diluted that fish kills have never been reported.

Near the shore, diesel can damage sensitive benthic habitats, such as seagrass beds and coral reefs. Also, marine birds could be killed if they came into direct contact with diesel on the water surface before the diesel is sufficiently diluted (National Oceanic and Atmospheric Administration, 2023).

### 2.2.4 Sustainability Conclusions

Table 11 summarises the levels of life cycle GHG and air pollutant emissions generated by using e-fuels as marine fuels compared to fossil fuels.

*Table 11. Life cycle GHG emissions and air pollutant emissions from e-fuels vs fossil marine fuels.*

<table>
<tr><th></th><th>HFO, MGO*</th><th>LNG*</th><th>E-methanol</th><th>E-methane</th><th>E-diesel</th></tr>
<tr><td colspan="6">Life cycle GHG emissions</td></tr>
<tr><td>$N_2O$</td><td>Present</td><td>Present</td><td colspan="3">Present</td></tr>
<tr><td>$CH_4$</td><td>Low</td><td>Present at Otto engines</td><td>Not present</td><td>Present in Otto cycle engines</td><td>Not present</td></tr>
<tr><td>$CO_2$</td><td>Present</td><td>Present</td><td colspan="3">Mainly from manufacturing production systems.</td></tr>
<tr><td>$H_2$ (indirect)</td><td>Not present</td><td>Not present</td><td colspan="3">From venting and purging for electrolysers.</td></tr>
<tr><td colspan="6">Air pollutant emissions</td></tr>
<tr><td>$SO_X$</td><td>Present</td><td>Not present (limited to pilot fuel)</td><td>Not present (limited to pilot fuel)</td><td>Not present (limited to pilot fuel)</td><td>Not present</td></tr>
<tr><td>$NO_X$</td><td>Needs SCR for ECA</td><td>Otto engines meet ECA requirements without SCR, diesel engines do not</td><td>Reduced compared to HFO/MGO, but needs SCR for ECA</td><td>Otto engines meet ECA requirements without SCR, diesel engines do not</td><td>Needs SCR for ECA</td></tr>
<tr><td>Direct particulate matter</td><td>Present</td><td>Reduced</td><td colspan="2">Likely reduction compared to HFO/MGO</td><td>Present</td></tr>
<tr><td>Carbon monoxide and hydrocarbons</td><td>Present</td><td>Present or increased</td><td colspan="2">Present or increased (for Otto cycle engines, CO emissions are higher)</td><td>Present</td></tr>
<tr><td>VOCs and PAHs</td><td>Present</td><td>Reduced</td><td colspan="3">Not present</td></tr>
</table>

*Notes: HFO = heavy fuel oil; LNG = liquefied natural gas; MGO = marine gas oil; SCR = selective catalytic reduction.*
** Adapted from* (Ash & Scarbrough, 2019). *Pilot fuel is not considered in this table.*

To produce e-fuels on a significant scale, large amounts of land are needed for wind and solar parks. It is becoming increasingly challenging to find enough land for onshore wind and solar energy projects. Eligible land is often also useful for agriculture and biodiversity conservation (McKinsey and Company, 2023). Thus, indirect land use change and related environmental damage, such as biodiversity loss, may occur if wind and solar capacity is expanded at the expense of agriculture or nature conservation. Manufacturing wind and solar parks, electrolysers and other systems that are required to produce e-fuels generate negative environmental impacts. The construction and operation of wind farms may affect the habitats of birds and bats. Finally, the spillage of e-diesel into the ocean has larger negative impacts on the marine environment than e-methanol and e-methane and may cause fish and bird kills, although e-diesel will disperse and dissolve and could be completely degraded within two months.

Areas with large amounts of sun, wind and water resources, and large areas with deserts are therefore seen to be suitable locations to establish large production of e-fuels. These areas are found in Western Australia, the Middle East, Africa, Southern America, and the United States.

## 2.3 Availability

### 2.3.1 Introduction

To produce enough e-fuels to power the entire global maritime fleet, the production capacity of all segments of the production chain would need to be massively expanded: this includes renewable electricity capacity; renewable $CO_2$ capacity; electrolyser capacity; and e-fuel production capacity. Renewable electricity is required for the renewable hydrogen production, renewable $CO_2$ capture and e-fuel synthesis processes. Renewable hydrogen production, using electrolysis, takes up about 90% of the total electricity demand for e-fuels production[10].

The current global capacity of wind and solar parks is relatively low; and this holds even more true for global electrolyser capacity[11]. It also should be noted that the demand for renewable electricity, renewable hydrogen and e-fuels is expected to rise across virtually all economic sectors; so, production capacity would need to increase far beyond the levels required for the maritime sector alone.

The size of global electrolyser capacity relative to the capacity of wind and solar parks will have an impact on the operational schemes and profitability of the overall power system. In cases where electrolysers are directly connected to a wind or solar park, for example, customising them to the maximum power output of the wind/solar park would create a system with a low load factor and hydrogen output.

However, by connecting the electrolyser to the grid and using the grid's electricity when winds and solar irradiation are low, the electrolyser's load factor can be increased, reducing the capacity required to obtain the same amount of hydrogen. An alternative way to increase the load factor is to *'over-dimension'* the wind/solar park and feed excess electricity into the grid (see Figure 4).

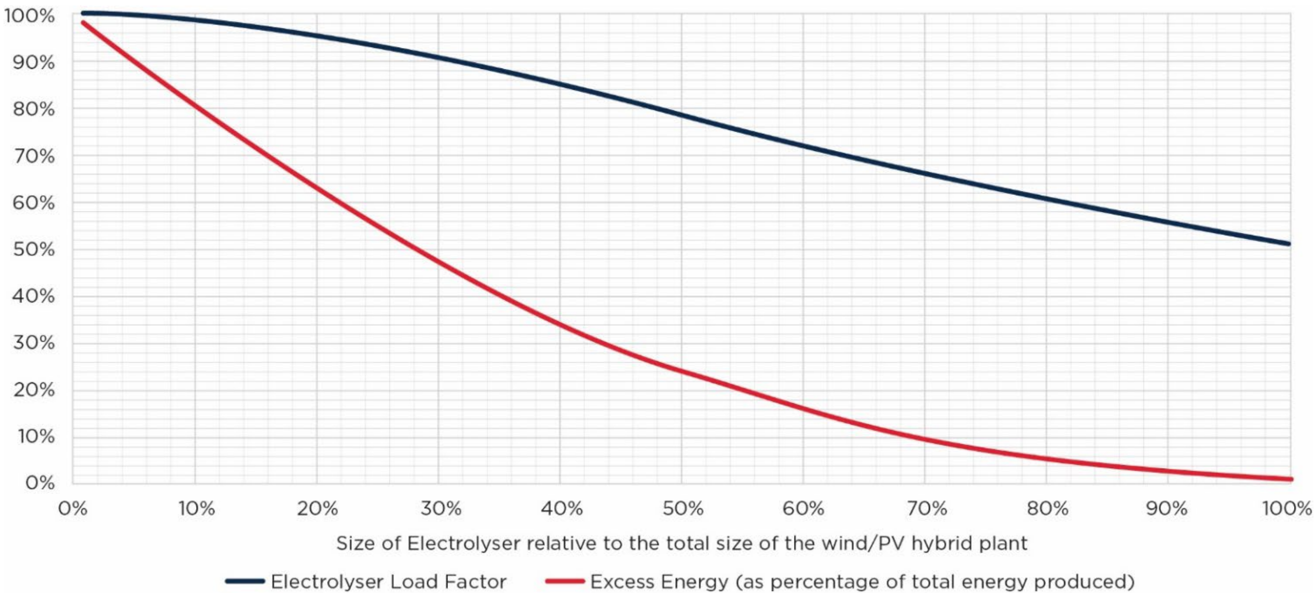


*Figure 4. The relationship between the electrolyser's load factor and excess renewable electricity, given the sizes of the system and wind/solar park (IEA, 2017).*

The need for grid connectivity to achieve competitive price levels for e-fuels was demonstrated in a recent study by Nami et al. (2021). According to the authors, the electrolyser needs to be continuously operated at maximum capacity to encourage a profitable business case. However, it is noted that profitability will largely depend on the electrolyser operator's electricity costs and the market price for green hydrogen.

The use of grid-connected electrolysers creates the need for reliable certification schemes to ensure that the electricity used, and hydrogen produced, can be considered *'green'*. The European Commission (EC) published a Delegated Act in June 2023, which includes rules on when hydrogen produced via electrolysis

10 Using figures from Concawe (2022), it is estimated that the electricity demand shares for production of the considered e-fuels are roughly 91% for electrolysis, 7% for direct air capture, and 2% for e-fuel synthesis.
11 The installed global renewable electricity capacity in 2020 was 2,800 GW (with more than 1,200 GW from hydropower), and the current installed global electrolyser capacity is about 200 MW (Aurora, 2021).

can be called *'green'*. The CertifHy initiative developed a green and low-carbon hydrogen certification system, which aims to enable the cross-border trade of green hydrogen within the EU.

When the green hydrogen is used for e-fuels production, a similar certificate system would be needed for e-fuels so that purchasers can be assured the fuels were made from renewable energy sources.

If the renewable hydrogen for e-fuels production is produced at large and remote wind and solar parks, it is likely that the e-fuel production plants would be located near the electrolysis plant. This is because e-fuels have a higher volumetric energy density than hydrogen and can thus be transported more efficiently across the globe.

### 2.3.2 European Availability

It is theoretically possible to develop the capacity to produce e-fuels all over the world. Renewable electricity could be produced at most locations with favourable conditions for wind and solar irradiation. The cost savings from production at these locations would easily outweigh the additional costs associated with the intercontinental transport of e-fuels, so it is better to examine the potential worldwide capacity for e-fuels production than to look solely at the availability in Europe.

Nonetheless, in 2019, Europe had a capacity of 475 GW for renewable electricity, with wind, solar and hydro each having a large share (Errard, Diaz-Alonso, & Goll, 2021). Given the provisional agreement between the European Parliament and the Council to raise the EU's renewable energy target from 32% to at least 42.5% by 2030, the development of wind and solar power will need to be accelerated. Also, the FuelEU Maritime Regulation incentivises the use of RFNBOs.

In addition, the EU has the ambition to develop 40 GW of electrolyser capacity by 2030. So far, its member states have pledged 34 GW (Aurora, 2021).

Regarding e-fuels, the EU's Renewable Energy Directive (RED) mandates that at least 1% of energy consumption in mobility in 2030 should be met by RFNBOs. And, according to REDIII, Member States with maritime ports should ensure that as of 2030 the share of RFNBOs in the total amount of energy supplied to the maritime transport sector is at least 1.2% (refer to Section 3.3). It should be noted that these targets also can be met by using renewable hydrogen, so they will not necessarily boost the production of e-methanol, e-methane and e-diesel. A non-exhaustive list of e-fuel production projects worldwide is given in Table 4.

### 2.3.3 Worldwide Availability

The amount of e-fuels that may become available for the global maritime shipping industry is difficult to estimate, because it is subject to market developments, such as industry investment plans, changes in demand for renewable electricity and hydrogen, technological advances in wind and solar parks, electrolysers, renewable $CO_2$ capture and e-fuel production processes.

Some insight, however, arises from calculating the global capacity that would be needed to supply enough e-fuels to meet the final energy demand of the entire maritime shipping fleet in 2030 and 2050, and then comparing that to projected developments in production capacity. This exercise is described below and summarised in Table 13. For this exercise, it has been assumed that the global maritime shipping demand is met by 33.3% e-methanol, 33.3% e-methane and 33.3% e-diesel.

#### *Maritime shipping demand*

The final energy demand of the entire global maritime shipping sector is projected to be 12.1-14.2 EJ in 2030, and 10.2-23.2 EJ by 2050 (CE Delft, Dallan Maritime University, ClassNK, Purdue University, Krannert School of Management, Fudan University et al., 2020) (CE Delft, 2020).

### *Renewable electricity capacity*

Assuming an electrolyser efficiency of 65% (based on a lower heating value), 9,549-11,206 terawatt hours (TWh) of renewable electricity would be needed in 2030 to enable a full global switch of maritime shipping to e-fuels. For 2050, this volume would be 6,649-15,123 TWh. Today's production capacity is already significant: The worldwide production of renewable electricity in 2022 was about 8,500 TWh, 51% of which was from hydropower, 25% from wind, 8% from bioenergy, 15% from solar and 1% from other renewables (Ember, 2023). Some projections for the global production of renewable electricity in 2030 and 2050 are listed in Table 12.

*Table 12. Projections of global renewable electricity production from various scenarios (TWh/year) (CE Delft, 2020).*

| Scenario | 2030 | | 2050 | |
|---|---|---|---|---|
| | Min | Max | Min | Max |
| IEA, 2°C Scenario | 14,500 | | 28,700 | |
| IPCC RCP2.6 scenarios | 6,300 | 13,100 | 22,200 | 28,100 |
| IRENA REmap Case | 20,400 | | 47,400 | |
| IEA, Beyond 2°C Scenario | 14,500 | | 31,800 | |
| IPCC RCP 1.9 scenarios | 8,100 | 14,700 | 31,200 | 49,100 |

Summarising these volumes into a range, the projected global production of renewable electricity is estimated at 7,500-15,000 TWh in 2030, and 25,000-50,000 TWh in 2050. This shows that in 2030 the production capacity for renewable electricity already could be high enough in 2030 to meet the entire global demand for maritime e-fuels; the global production of renewable electricity in 2050 would be three to four times higher than what is needed for a complete switch of maritime shipping to e-fuels.

Although these projected volumes of renewable electricity theoretically would support a full switch for the maritime sector, in practice, a large share of the renewable electricity produced will feed into the power grids to supply worldwide demand in other industries. As a result, the estimated volumes of renewable electricity may prove insufficient to satisfy the demand for all sectors, and thus restrict its availability for shipping.

### *Electrolyser capacity*

To estimate the electrolyser capacity required to enable a complete switch of maritime shipping to green hydrogen, an energy efficiency of 65% (based on lower heating value) and 4,000-5,000 full-load hours from the electrolysers is assumed. Under those conditions, 1,300-1,900 GW of electrolyser capacity would be needed to produce enough e-fuels to supply the entire maritime sector in 2030. For 2050, this is 1,100-3,100 GW.

If all the announced electrolyser projects worldwide are realised, this would lead to an installed electrolyser capacity of 170-365 GW by 2030 (IEA, 2023). In the Net-Zero Emissions (NZE) scenario of the IEA, the electrolyser capacity reaches 3,670 GW in 2050 (Odenweller & Ueckerdt, 2023). The 170-365 GW of announced electrolyser capacity for 2030 is much higher than the worldwide capacity in 2020, which was 0.3 GW. It is also higher than the sum of the electrolyser projects planned for the 2021-2026 period, which is 16.7 GW. About 85% of these projects are in China, Chile, Spain and Australia. However, the largest part of the announced electrolyser projects is slated for Europe, a result of the EU's ambitions and policies aimed at reducing GHG emissions (IEA, 2021).

Assuming that these announced and projected electrolyser capacity volumes are realised, the amount of electrolyser capacity available globally in 2030 only would produce e-fuels for 13-19% of the global maritime fleet. However, the available electrolyser capacity in 2050 would be sufficient for a full switch.

### *Direct air capture (DAC) capacity*

The required DAC capacity to enable a complete switch of maritime shipping to e-fuels has been estimated in this study by using the average of the $CO_2$ consumption rates from the e-methanol, e-methane and e-diesel production processes from Concawe (2022). It was found that the required DAC capacity will be 873-1,024 Mt $CO_2$ in 2030 and 736-1,673 Mt $CO_2$ in 2050.

The lower value of the range of available DAC capacity in 2030 is based on the planned DAC production capacity, which is 4.7 Mt $CO_2$. This is more than 500 times today's carbon capture capacity, which is less than 0.01 Mt $CO_2$/year. The higher value of the 2030 range was set as equal to the volume that would be needed to realise the IEA's NZE scenario, which is 75 Mt $CO_2$ (IEA, 2024). The higher value of the range of available DAC capacity in 2050 has been set equal to the value from the NZE scenario for 2050, which is 980 Mt $CO_2$/year (IEA, 2022). The lower value has been set at 500 Mt $CO_2$/year.

Comparing the required DAC capacity with the available capacity, the amount of e-fuels that could be produced with the available DAC capacity would satisfy only about 0.5-7.3% of maritime shipping demand in 2030, and 59-68% in 2050. This makes DAC capacity a more important barrier to the development of e-fuel production than electrolyser or renewable electricity capacity.

### *E-fuel synthesis capacity*

To produce e-fuels for the entire global maritime fleet, the required e-fuel synthesis capacity, expressed in exajoules (EJ) of e-fuels, equals the fuel demand for the global maritime fleet: 12.1-14.2 EJ in 2030, and 10.2-23.2 EJ by 2050 (CE Delft, Dallan Maritime University, ClassNK, Purdue University, Krannert School of Management, Fudan University et al., 2020) (CE Delft, 2020)[12].

In a scenario analysis, Concawe (2021) projected the available production volume of e-fuels in Europe to be 0.063 EJ in 2030, and 3.3 EJ in 2050. Assuming that the European share of global mobility sector demand is 25% (Tzeiranaki, et al., 2023), the global available e-fuels production capacity can be estimated at 0.25 EJ in 2030, and 13.4 EJ in 2050.

Comparing the required e-fuel synthesis capacity with the estimated available capacity, the amount of e-fuels that could be produced with the available e-fuels synthesis capacity would satisfy only 2.1% of maritime shipping demand in 2030, but 100% by 2050 (see Table 14).

*Table 13. Comparison of required and available production volumes for e-fuels production that would fully supply global maritime shipping in 2030 and 2050.*

| | 2030 | | | | 2050 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Required* | | Available | | Required* | | Available | | Unit | Remarks |
| | Min | Max | Min | Max | Min | Max | Min | Max | | |
| Renewable electricity capacity | 9,549 | 11,206 | 7,500 | 15,000 | 6,649 | 15,123 | 25,000 | 50,000 | TWh/ year | Estimated based on global scenario values shown in Table 12. |
| Electrolyser capacity | 1,300 | 1,900 | 170 | 365 | 1,100 | 3,100 | 1,800 | 3,670 | GW | Required volume calculated assuming 4,000-5,000 full-load hours. |
| DAC capacity | 873 | 1,024 | 4.7 | 75.0 | 736 | 1,673 | 500 | 980 | Mt $CO_2$/ year | |
| E-fuels synthesis capacity | 12.1 | 14.2 | 0.25 | 0.30 | 10.2 | 13.4 | 13.4 | 15.0 | EJ/ year | |

** 'Required' refers to the quantity needed to supply 100% of global maritime shipping with e-fuels.*

12 No more recent projections of global fleet demand in 2030 and 2050 have been found in literature. The used projections are in our view still valid.

*Table 14. Percentage of global maritime demand that could be met by e-fuels, when considering the estimated available production capacity of different segments required for e-fuel production.*

| | 2030 | | 2050 | |
|---|---|---|---|---|
| | Min | Max | Min | Max |
| Renewable electricity capacity | 79% | 100% | 100% | 100% |
| Electrolyser capacity | 13% | 19% | 100% | 100% |
| DAC capacity | 0.5% | 7.3% | 68% | 100% |
| E-fuels synthesis capacity | 2.1% | 2.1% | 100% | 100% |

### *Findings*

The complete switch of the global maritime sector to e-fuels requires a large expansion of renewable electricity capacity, electrolyser capacity, as well as DAC plants and e-fuels synthesis plants. A comparison of required and available capacity for the different e-fuel production segments indicates that the largest bottleneck for the expansion of e-fuel production capacity is the development of DAC capacity. This is in line with the findings from Subsection 2.1.5, which show that DAC is the least developed technology, and thus is likely to take the most time before the technology is technically ready for mass deployment. In addition, the costs of $CO_2$ from DAC are still prohibitively high. In the short to medium term, this bottleneck may be relieved by using biogenic $CO_2$, which is another form of renewable $CO_2$. However, biogenic $CO_2$, which is already difficult to source for the production of methanol for the ships planning to operate on green methanol, will continue to be a scarce resource as it will also be needed to produce bio-based chemical products.

Furthermore, from an availability perspective, the comparison points out that e-fuels cannot be expected to play a major role in global shipping by 2030. The costs of e-fuels form another barrier, which is further analysed in Section 2.5. In the medium to long term, however, e-fuels are expected to be the dominant carbon neutral fuels.

## 2.3.4 Links with Other Sectors

Maritime shipping's share of global energy consumption is limited (about 1.5% in 2022); its global energy demand was about 9.2 EJ/year in 2022 (IEA, 2023), whereas global primary energy consumption in 2022 was 604 EJ/year (Ritchie, Rosado, & Roser, 2024). If only global oil consumption is considered, the maritime sector has a higher share: In 2018, 6.8% of global final consumption was from navigation (IEA, 2020).

All sectors are facing the challenging task of transitioning towards net-zero GHG emissions by 2050, with renewable electricity from wind, solar, hydro and geothermal energy being important alternatives to fossil fuels.

Renewable electricity could be directly used, for example, by electric road vehicles or electric boilers and furnaces across industry; or indirectly, it could be used to produce e-fuels such as ammonia, methane, methanol, diesel and kerosene. Therefore, it is certain that shipping will face fierce competition with other sectors for the use of renewable electricity and renewable hydrogen.

Theoretically, there are more than enough suitable locations to produce renewable electricity to meet global energy consumption. However, there is a limit to the speed at which economies can build solar and wind parks, conversion systems, and transport and distribution infrastructure. Workforces, construction equipment, available capital, and the minimum duration for permitting and project development processes all presently constrain the speed at which the capacity can be increased.

If the growth of renewable electricity production does not keep pace with the increasing demand for it, scarcity will raise electricity prices, potentially making the production of e-fuels too expensive for maritime shipping in comparison to sustainable alternatives. In addition, other sectors may be willing to pay more to ensure their share of the available renewable electricity.

Moreover, competition for renewable $CO_2$ may rise. Many studies have shown the need for *'negative $CO_2$ emissions'*, or carbon removal, to achieve 2040 and 2050 climate goals. The use of $CO_2$ captured from the natural environment for the production of e-fuels is not a form of long-term $CO_2$ storage, whereas such storage would be preferable from a climate perspective. Given the expected limited availability of DAC capacity (see Subsection 2.3.3), renewable $CO_2$ may be prohibitively expensive for maritime shipping.

### 2.3.5 Availability Conclusions

To enable the large-scale production of e-fuels for the maritime industry, the capacity of all segments – renewable electricity plants, electrolysers, DAC plants and e-fuel synthesis plants – will need to grow tremendously. Whereas the anticipated worldwide availability of renewable electricity appears sufficiently large to enable the global maritime fleet to fully switch to e-fuels as early as 2030, e-fuels cannot be expected to play a major role in global shipping by 2030. The technical development and implementation speed of DAC capacity is expected to be the main inhibitor to the growth of e-fuel production capacity. This is especially true for the year 2030. Furthermore, the shipping sector will need to compete with most other industry sectors for the renewable electricity, green hydrogen and renewable $CO_2$ required for e-fuels production.

## 2.4 Suitability

Analysing the suitability, e-methanol and e-methane return an identical result to the fossil fuels they would replace. They can directly replace the fossil fuels without having to modify the engine system, fuel supply and tank system. More information can be found in the EMSA study '*Update on Potential of Biofuels for Shipping'* (EMSA, 2022b).

Similarly, e-diesel will be produced using the FT process. This fuel is expected to be identical to the FT diesel produced from biofuels. The biofuel counterpart is produced using a gasification process in combination with the FT synthesis. The main difference in producing e-diesel is that the $CO_2$ comes from the DAC process. This process may result in insignificant impurities, and there also might be minor quantities leftover from the solvent. These impurities are not expected to change the physical properties, compared to the FT bio-diesel, which has slightly lower calorific value of about 37 MJ/kg. FT bio-diesel is a drop-in fuel, which has analysed in the previously mentioned EMSA study (EMSA, 2022b).

## 2.5 Cost Developments and Techno-Economic Analysis

This section provides an overview of the cost development for e-fuel marine-propulsion systems. The techno-economic analysis provides a forward outlook that spans decades. The analysis also shows how the total cost of ownership (TCO) for using e-fuels will evolve for newly built ships and outlines a TCO case for an indicative retrofit. The TCO analysis covers specific vessel types and compares them to fossil-fuelled references. The cost of e-fuel applications is a major obstacle that needs to be overcome, since e-fuel production technology is currently unavailable at large-scale or competitive prices compared to conventional fuel-oil production systems.

### 2.5.1 General considerations

This analysis presents an estimate of the TCO for vessels powered by e-methanol, e-diesel and e-methane. It represents the total cost to the shipowner[13], assuming that e-fuel bunker facilities are available at major ports. The cost for developing the supporting infrastructure is not included in the analysis.

The TCO is comprised of the sum of yearly capital expenditures (CAPEX), annual fuel costs and other annual operational expenditures (aggregated in OPEX). It is calculated for the ship types and size categories defined in the '*Fourth IMO Greenhouse Gas Study 2020*' (Faber, et al., 2020) for the years 2030 and 2050[14]. The specifics of all the cost elements are outlined below.

13 While some cost components may be in practice be passed on to the charterer (e.g., fuel cost, carbon cost), the aim here is to present a complete overview of all cost components for the acquisition and operation of vessels using the e-fuels under consideration.
14 The ship types and sizes which have to report to the EU MRV are considered. See Appendix B – Overview of data of the economic analysis for an extensive list of all ship types and sizes considered.

The CAPEX represents the investment costs for the propulsion and auxiliary systems, which are fixed and independent of the operation of the vessel. The OPEX is dependent on the frequency and intensity of the vessels' operation. The assumptions and input for the TCO model calculations are outlined in Appendix B – Overview of data of the economic analysis.

The economic analysis is performed for newly built vessels and a TCO-retrofit case. The retrofit cost case covers the conversion of an existing ship powered by VLSFO to a propulsion system suitable for the alternative fuels e-methanol and e-methane. The e-fuels analysed in this study are considered drop-in fuels to some extent; they are fully compatible with conventional fuels in that e-methane can replace LNG without engine modifications and e-diesel can be used in fuel oil engines. If the fuel properties fall outside of the scope of fuel standards, minor modifications in engine management may be required. But these would not have a substantial impact on the TCO.

The next two sections define the items included in capital and operational costs to indicate ship-specific TCOs. They then compare the TCO of ships running on different types of e-fuels to the TCO of ships sailing on conventional fuels. In the subsequent section, the retrofit TCO case is outlined for a small containership. The final subsection includes the techno-economic conclusions.

### 2.5.2 CAPEX

CAPEX are the fixed costs for the propulsion system on a newly built vessel, including the cost of the engine, aftertreatment, storage tanks and the fuel supply system (FSS). Only the fixed-cost items for e-fuels that are different by design than those of conventionally-fuelled ships are included in the analysis. The ship's hull structure is not considered, since the cost for the raw structure of a ship is assumed to be the same[15].

The e-fuels under consideration – i.e., e-methanol, e-diesel and e-methane – are, at a molecular level, equal to the structure of biofuels such as bio-methanol, bio-diesel and bio-methane, even though they are produced by using a different production process. Therefore, it can be assumed that the cost for the propulsion and auxiliary systems are equal. The cost of the propulsion system, storage tanks and FSS are equal to the cost indicated for their biofuel counterparts, just as in the analysis of the EMSA study '*Update on Potential of Biofuels in Shipping*' (EMSA, 2022a).

#### *Propulsion-system costs*

The propulsion system is the main item in which an e-fuel-powered vessel differs from a conventional fuel oil-powered vessel, except in the case of e-diesel used in a conventional propulsion system. As a reference, the internal combustion engine (ICE) using conventional fuel oil is considered. The cost of engine systems is examined for newbuilding perspectives and depends on the amount of installed-power capacity of the ship (given in kW).

The average installed power by ship type and size from the IMO fleet database (Faber, et al., 2020) was used to define the power capacity for the vessels. CAPEX is expressed as an annual cost over a 25-year lifetime with the weighted average cost of capital (WACC) at 7%, based on ranges of WACC reported by several maritime freight operators[16].

For e-methanol and e-diesel, a 2-stroke, low-speed diesel ICE is considered. For vessels powered by e-methane, a natural gas Otto 2-stroke ICE is considered. For the use of e-methane in an LNG-powered ship, there is no additional cost.

No improvements in ICE technology are assumed over the timeframe of the analysis, because the propulsion-system technology is considered fully mature. This means that no cost decrease for the CAPEX is assumed over time.

15 It is noted that in practice it may be needed to adjust ship design to fit alternative fuel storage and other system components to fit in the vessel. These cases are out of scope in this analysis.
16 Considering WACC of different maritime freight operators (Faber, Kleijn, Király, & Geun, 2021).

The authors are aware of the costs of inflation that is currently applied for resources for the manufacturing of propulsion systems and FSS. But as the main aim of the economic analysis is to identify the differences between a conventionally-powered ship and an e-fuel-powered ship, and due to uncertainty about the related cost increases and a lack of trustworthy data, the projections are not adjusted for CAPEX price fluctuations. It is considered that given that relative cost increases apply similarly for the conventional and alternative-propulsion systems, the difference in cost will be similar.

Total CAPEX depends on the average installed power of a vessel. Engine cost ranges from €190/kW for conventional fuel ICE to €330/kW for methanol engines. An indication of cost per kW is presented in Figure 5. The shaded area indicates the cost range. The high range is for the smallest ships with a relatively low power capacity. The low end of the cost range is for propulsion systems with a high-power capacity and for containerships, due to economies of scale.

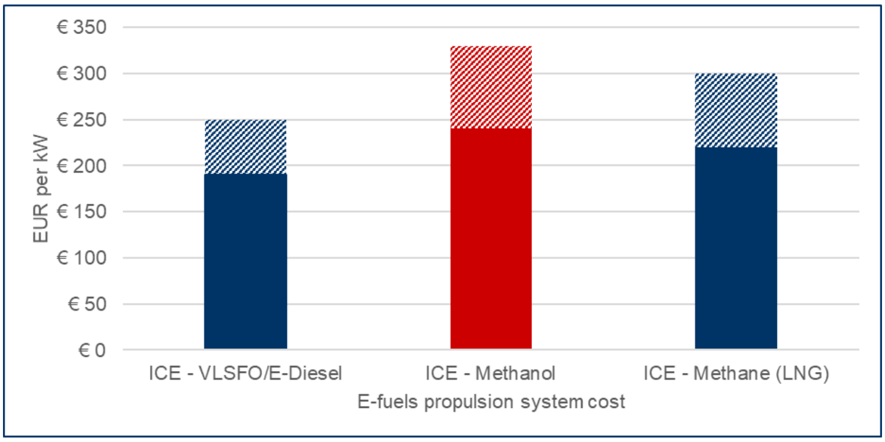


*Figure 5. Engine cost input for alternative suitable ICE (Hendriksen, Sørensen, & Münster, 2021 ; Horvath, 2017).*

### *Aftertreatment system costs*

Aftertreatment costs are those borne by the shipowner for the system and the treatment of harmful substances or elements that regulation prohibits the release of into the environment (air or ocean waters). An example of aftertreatment cost is the cost of a selective catalytic system (SCR), required to bring $NO_X$ emissions in line with regulatory limits.

As mentioned earlier, the combustion of e-fuels is not expected to produce sulphur emissions. However, $NO_X$ emissions can be emitted when the e-fuels are used, due to the requirement for a comparatively small amount of pilot fuel for the combustion of e-methanol and e-methane. The pilot fuel would be bio-diesel, which does not lead to $SO_X$ or much higher $NO_X$ emissions.

The reference ship is sailing on very low sulphur fuel oil (VLSFO), for which it has been assumed that almost no $SO_X$ emissions and $NO_X$ are emitted, and therefore no aftertreatment is necessary to comply with Tier II limits. So, no aftertreatment costs are considered in the analysis.

If the vessels need to comply with IMO Tier III $NO_X$ limits, $NO_X$ aftertreatment systems would be necessary for the referenced VLSFO use, as well as the use of e-diesel, e-methanol and e-methane if a diesel-cycle engine is used. This would thus not lead to a difference in the relative costs of the options.

### *Onboard storage and fuel tanks and piping*

For the supply and storage of the fuels, dedicated onboard tanks and piping systems are needed as part of the FSS. System costs for the storage tanks and FSS vary by fuel type. The vessels' power capacity is considered as a determining factor for the sailing range of the vessel. The range is directly related to the fuel storage capacity. Therefore, the ships power capacity is used to calculate the cost of fuel storage. The storage and FSS costs are included with the cost of the propulsion system (see Figure 6). Both storage tanks and the FSS are assumed to have a lifetime of 25 years. Systems-maintenance costs will be covered in the OPEX section.

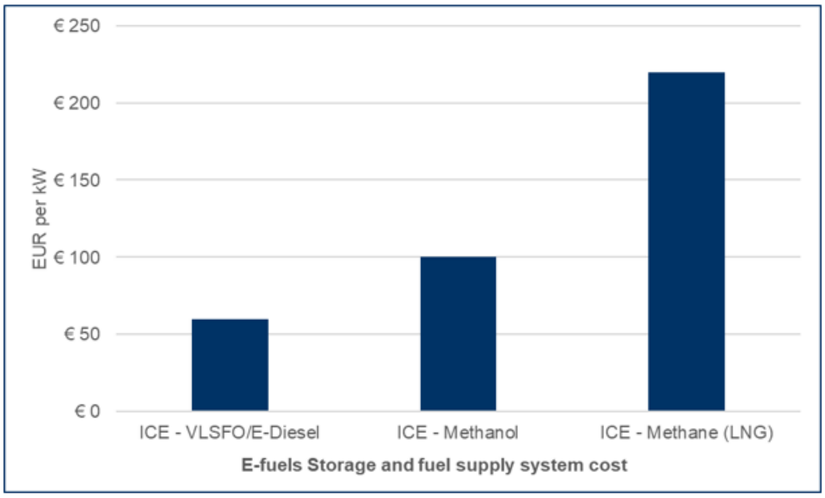


*Figure 6. Storage and fuel supply system cost input for e-fuels suitable ICE (Horvath, 2017).*

### 2.5.3 OPEX

The shipowners' OPEX is comprised of cost items that are variable, meaning they depend on the use of the vessel. The OPEX comprise fuel expenditures, carbon costs (see below) and the costs for bunkering, maintenance and repair, and crew training. There are other operational expenditures, such as seafarer costs, which are not considered in the cost analysis, as it is assumed that they will be similar for the referenced fuel oil-powered and e-fuel-powered vessels.

#### *Carbon costs*

The maritime shipping sector that is active in Europe has been included in the European Emissions Trading System (EU ETS). This means that, from 2024, shipping companies are obliged to surrender allowances for the $CO_2$ emissions that their ships emit on voyages to and from ports in the European Economic Area (EEA), as well as for activities inside EEA ports. Next to the fuel costs, carbon costs also will accrue if, within the geographical scope of the EU ETS, fossil fuels are combusted onboard ships (refer to Section 3.3).

E-fuels such as e-methanol, e-methane and e-diesel have a carbon content, so carbon emissions are released during the combustion process. However, this analysis only considers green e-fuels. This implies that the $CO_2$ in the e-fuels will be extracted from the atmosphere by DAC techniques, sequestered in the e-fuels and then emitted again when used in marine engines. Therefore, on balance, the $CO_2$ in the atmosphere will not increase in the long term.

Given this carbon cycle, it is assumed that the Tank-to-Wake $CO_2$ emissions of the e-fuels can be accounted for as zero and no carbon costs will accrue[17]. The authors are aware that, in EU legislation, the exact treatment of the air captured and used (combusted) carbon has yet to be fully determined. Still, for the purpose of providing a logical cost analysis, the assumption is made that for this type of carbon no carbon cost applies. Besides, there might be methane slip from the e-methane used in the production and transportation chain. This is, however, not accounted for in this analysis to avoid over-complicating it.

For the calculation of the carbon costs related to the use of VLSFO, as part of the TCO analysis, an ETS price of €46/tonne $CO_2$ in 2030 and €150/tonne $CO_2$ in 2050 (EC, 2021) are considered. In Figure 7 the carbon cost for the use of VLSFO is indicated. The carbon cost is expressed in EUR per tonne VLSFO using aforementioned prices[18]. In addition, it is assumed that carbon costs accrue for each tonne of $CO_2$ emitted, meaning it has been implicitly assumed that vessels sail on routes between EEA ports only.

17 According secondary legislation still needs to be developed. Implementing acts will specify how to account for emissions from renewable fuels of non-biological origin and recycled carbon fuels, ensuring that such emissions are accounted for and that double counting is avoided. (see Article 14 of the amended EU ETS Directive).
18 Considering the ETS price is 46 EUR per tonne CO2 in 2030 and 150 EUR per tonne CO2 in 2050; combustion of one tonne VLSFO emits about 3.26 tonne CO2. This result in total carbon cost per tonne VLSFO amounts in 2030 to 148 EUR and in 2050 to 480 EUR.

For the CO2 emitted on voyages between EEA and non-EEA ports, allowances will have to be submitted only for 50% of the emissions, leading to lower carbon costs on these voyages. And if vessels do not call at EEA ports at all, the baseline carbon costs for VLSFO will be lower than assumed here, at least provided that no other policy measures implementing a carbon cost were adopted at the international level/in other regions.

Figure 7 illustrates the 2030 and 2050 carbon costs per tonne of VLSFO for the ETS prices above.

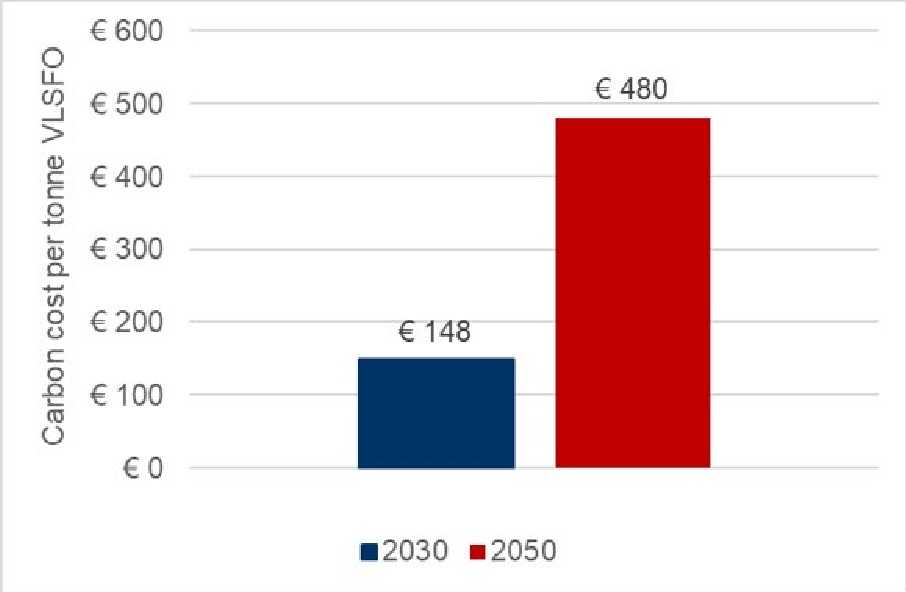


*Figure 7. Carbon cost per tonne of VLSFO.*

### Fuel cost

Fuel costs are another major cost item for the shipowner operating a vessel. The fuel cost includes the cost for production, transportation, storage and reconversion of the fuels. For the TCO analysis, the total yearly fuel cost for a specific vessel type is calculated by the yearly average of fuel used per ship category based on the average yearly energy demand (in GJ) as given by the IMO fleet data by ship type and size.

The fuel types considered in the analysis include the currently conventional VLSFO (EC, 2021; Shipandbunker, 2024) and three e-fuels: e-methanol, e-diesel and e-methane. In line with the previous sections on e-fuels production, green e-fuels are assumed to have been produced in pathways that use renewable energy input (green hydrogen as a feedstock) and DAC to provide the renewable carbon for their production.

In line with the previous studies of this series, the main analysis assumes that, apart from pilot fuel if required, the fuel used is 100% e-fuel[19]. In addition, Subsection 2.5.5 also discusses a *'blending'* scenario.

To be consistent with previous studies on e-ammonia and e-methanol, the production cost for e-fuels is calculated using the HyChain model (Kalavasta, 2019), which provides an overview of synthetic fuels from renewable-energy sources and carbon input from DAC. To reflect the uncertainty on the cost of carbon sourced by DAC techniques, the cost presented by the IEA are used (IEA, 2022). These figures were considered with published cost data for DAC and e-fuels production cost (based on hydrogen production), conversion and transportation cost to Europe (TNO, 2023); (Cazzola, Gérard, Gorner, Gibbs, & Young, 2023)). These sources present comparable costs to produce e-fuels. In the appendix, an overview of the cost ranges in the literature and the applied cost range for DAC and production cost of the e-fuels are indicated. See Appendix B – Overview of data of the economic analysis.

In Figure 8 the expected cost range of fuels in euros per GJ is given. Each fuel under consideration has a different energy content per tonne (or litre). For a fair comparison of fuel cost between them, all costs are indicated by a unit of energy. For the conversion, the gravimetric energy density (in MJ/kg) of the fuels has been used (Table 15).

19 Ships that have to comply with the FuelEU Maritime Regulation and do not make use of the pooling option will probably use a blend, at least in the short and medium run. The additional TCO will therefore be lower compared to the outcomes as presented in Subsection 2.5.4.

The indicated production costs should be perceived as a minimum level of cost, because fuel producers and merchants will probably charge a mark-up. The shaded areas indicate the range of the fuel in terms of minimum and maximum fuel prices. The ranges indicating the minimum and maximum fuel cost represent the uncertainty about the development in the production and conversion technologies and increased competition for the fuel if a larger part of the shipping sector and other sectors increase demand for the fuels.

Because these e-fuels, aside from e-diesel, need a pilot fuel for ignition, bio-diesel fuel prices are indicated. In the analysis, a 3% blend (by energy content) of bio-diesel is assumed necessary for the e-fuel, which is thus 97% of the blend.

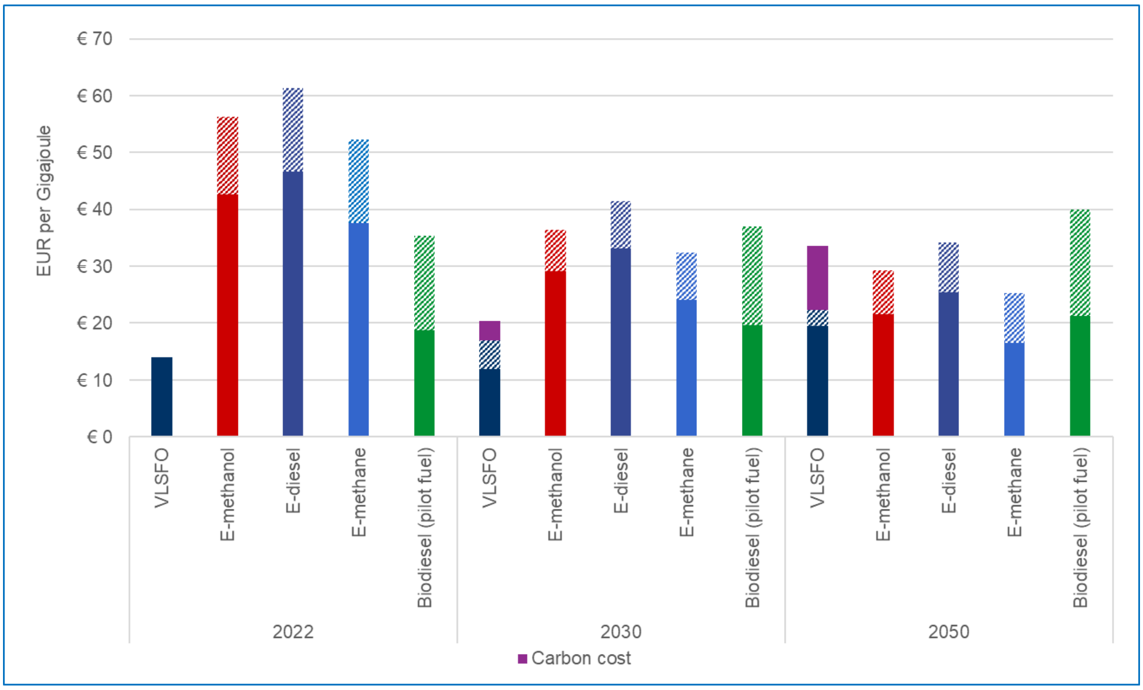


*Figure 8. Projected fuel cost of e-fuels and VLSFO (including carbon cost).*

In analysing the fuel cost, the authors assume the e-fuels are sourced from the countries where renewable-hydrogen production will be the most cost-effective. E-fuel production takes place in the same country where hydrogen production facilities are installed.

Average minimum and maximum prices for fuel costs are used. Fuel prices may vary, depending on the future production locations. See Appendix B – Overview of data of the economic analysis for the projected ranges of fuel cost in 2030 and 2050. The estimated impact of a carbon cost in the EEA (EU ETS) on the use of VLSFO is indicated by a purple bar and is additional to the market price of the VLSFO.

A 20% improvement in ship-energy efficiency is factored in for 2030, in line with recent regulations from the IMO's Carbon Intensity Indicator. This is an estimation of the anticipated efficiency gains from the recent introduction or emergence of several energy-saving technologies and operational measures, partly stimulated by regulations in the energy-efficiency index. No further improvements in energy efficiency are assumed after 2030, so 2050 projections also reflect a 20% improvement in efficiency compared to 2020.

### *Bunkering cost*

Bunkering costs are derived from storing fuels at a port and delivery to the ships. They are levied for handling the bunkering process, not for the fuel bunkered. They vary by fuel type and are estimated proportional to the yearly energy consumption. The bunkering costs are derived using the methodology provided by the Netherlands Organisation for Applied Scientific Research (TNO, 2020a) (TNO, 2020b).

Some e-fuels have a lower volumetric energy density compared with VLSFO (e.g., e-methanol); this has cost implications for bunkering. For example, a vessel powered by e-methanol would have to increase the number of bunkering stops compared to a VLSFO-fuelled vessel to fulfil equal energy demand for similar transport work.

If onboard space for fuel storage is similar, an e-fuel-powered vessel would have to increase its bunkering frequency by a factor of the fuel's volumetric energy density relative to the energy density of the VLSFO. This leads to higher bunkering costs per tonne or litre. The increased bunkering factor of e-fuels is displayed in Table 15. In practice, the additional bunkering may become an obstacle to operating vessels powered by e-fuels, depending on the type of e-fuel and the route of the vessel.

*Table 15. Energy density of e-fuels (DNV GL, 2019).*

| Fuel type | MJ/L | Volumetric density % of VLSFO | Factor increased bunkering |
|---|---|---|---|
| VLSFO | 36 | 100.0% | 1.00 |
| e-methanol | 15 | 41.7% | 2.40 |
| e-diesel | 32 | 88.9% | 1.13 |
| e-methane (e-LNG) | 13 | 36.1% | 2.77 |

### *Maintenance and repair*

Maintenance and repair (M&R) costs occur annually for every ship. A factor of the ships' CAPEX is assumed for the M&R costs. The M&R costs are assumed to be 1.5% of the CAPEX based on several public economic analyses and expert judgements (Kim, Roh, Kim, & Chun, 2020). This is valid for all types of e-fuel propulsion systems, and for the VLSFO reference.

### *Training costs*

Using alternative fuels brings different risks associated with fuel handling. For example, e-methanol is a corrosive substance with a low-flashpoint, so it requires specialised handling during bunkering, system maintenance and its use as a fuel. For this, additional training is necessary to ensure safe and adequate handling by the crew. However, this cost is very small compared to other cost components and is therefore not quantified here.

## 2.5.4 TCO newbuilding estimation

This section presents the results of the TCO analysis for e-fuel-powered vessels. It aims to provide an indication of the shipowners' TCO for a newly built ship powered by the e-fuels under consideration – in 2030 and 2050 – and to show the cost difference to the reference vessels powered by VLSFO.

The TCO for the reference vessel powered by VLSFO and the vessels operating on e-fuels are calculated for different vessel types and sizes. The results are outlined in detail for two vessel categories that are assumed to operate on the intra-EU trades, for which an EU ETS carbon cost would apply to the (VLSFO) reference ship.

For consistency and ease of comparison, the TCO for vessels powered by e-fuels is presented for the same vessel types in the EMSA study '*Update on Potential of Biofuels in Shipping'* (EMSA, 2022a). The two vessel categories are a bulk carrier 35,000-60,000 deadweight tonnes (DWT) and a containership 14,500-19,999 TEU.

### *Bulk Carrier*

The TCO for bulk carriers in the 35,000-60,000 DWT category sailing on e-fuels is indicated in Figure 9. The graph on the left presents the absolute cost differences per item compared to the TCO of the VLSFO reference bulk carrier. The right side of the graph indicates the TCO as a percentage of the VLSFO[11].

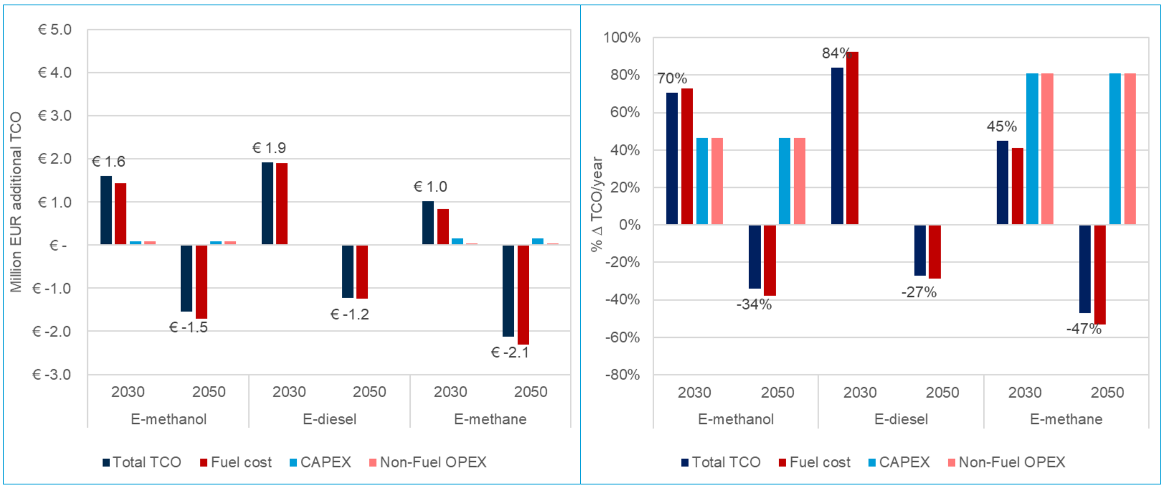


*Figure 9. Annual difference in TCO of e-fuel-powered bulk ships (35,000-60,000 DWT).*

Figure 9 (above) indicates the TCO increase for a bulk carrier running on synthetic e-fuels. The highest cost component of the TCO for all alternative-fuelled ships is the fuel. The results show an approximately 50% higher CAPEX for e-methanol-powered ships; the CAPEX for e-methane-powered bulk carrier is about 80% higher compared to the VLSFO-powered bulk carrier. The higher CAPEX for the e-methane ship is due to the higher comparative fuel storage and FSS costs (refer to Subsection 2.5.2 on storage cost).

These are some of the more significant comparative cost findings for alternative-fuelled bulk carriers projected for 2030:

- The estimated TCO for e-methanol is approximately 70% higher than the VLSFO reference bulk carrier;
- E-diesel-powered ships are not expected to feature additional CAPEX but using this fuel is expected to be the most expensive of the three e-fuels in the analysis, due to the more extensive production process for e-diesel which involves additional conversion steps;
- The estimated TCO for e-methane in a bulk carrier is about 45% higher than for the VLSFO bulk carrier;
- For all e-fuel types, the fuel cost is the largest component of the TCO.

For 2050:

- The TCO estimations for all e-fuels applied in bulk carriers are lower than the TCO of a VLSFO bulk carrier. This is partly caused by the steep decline in the cost of e-fuel production cost due to lower cost of renewable hydrogen production and expected lower cost of carbon input from a wide scale deployment of DAC by 2050. Moreover, the TCO for the VLSFO reference ship increased, mainly due to an expected rise in the market price of fuel oil, and an increased carbon cost by 2050;
- The TCO estimation for e-methanol is 34% lower than VLSFO; the TCO for e-diesel is 27% lower; and the estimated TCO for e-methane is almost half (-47%) the TCO for the VLSFO reference bulk carrier;
- Even though the CAPEX and non-fuel OPEX are still significantly higher for e-fuel-powered ships, the expected fall in the cost of e-fuel production cost weighs heavily on TCO outcomes. As fuel costs are the largest cost item in the TCO, a lower TCO for all e-fuels-powered bulk carriers operating on intra-EU voyages is projected.

The above cost comparisons are *'low-fuel price'* scenarios, which suggests that the differences between the TCO for e-fuels and VLSFO-powered vessels ultimately could be more pronounced. For the outcomes of the *'high-fuel price'* scenarios, see Appendix B – Overview of data of the economic analysis. The difference in the

TCO between the VLSFO reference and e-fuel-powered vessels may be lower or higher in 2030 and 2050, depending on developments in global bunker prices for fuel oil, the carbon cost and technological developments in the production process for e-fuels.

### *Containership*

The TCO for containerships in the 14,500-20,000 TEU range is indicated in Figure 10. The annual TCO difference is indicated in % for each cost item.

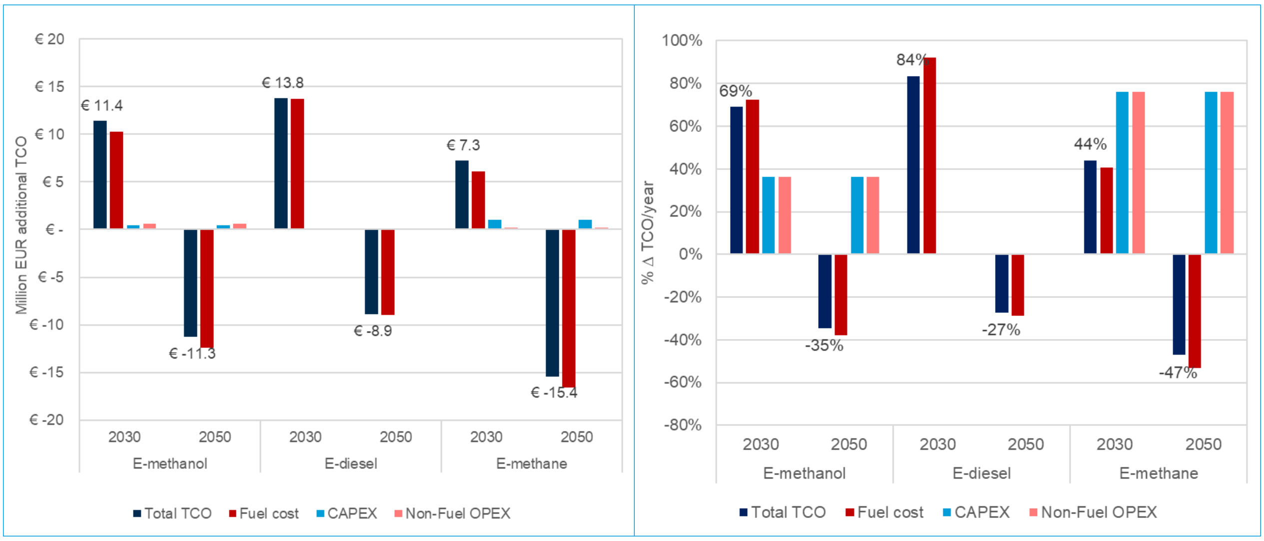


*Figure 10. Annual difference in TCO of e-fuel-powered containerships (14,500-20,000 TEU).*

Below are the significant outcomes from comparing the yearly TCO of containerships powered by e-fuels and VLSFO:

- General notes:
  - The minimum fuel cost scenario is presented, meaning the cost differences may be larger depending on the price scenario;
  - The higher CAPEX for the e-methane ship is due to higher fuel storage and FFS costs when using methane.
- In 2030:
  - The TCO estimation of e-methanol and e-diesel containerships presents similar figures to the bulk carriers (+69% and +84% accordingly) compared to the VLSFO-reference containership;
  - The TCO estimation for an e-methane-powered containership is at least 44% higher than for the VLSFO-fuelled ship;
  - Again, the fuel cost is the largest cost component of the TCO for all e-fuel types.
- In 2050:
  - The TCO estimates for all e-fuels used in containerships may be lower than for VLSFO-powered ships. As with the bulk carriers, a decline in e-fuel costs is projected between 2030 and 2050 due to lower hydrogen-production costs, which is the main energy input for e-fuels, and a lower cost of producing carbon from using DAC techniques. Moreover, the carbon cost of using fuel oil is expected to have increased, contributing to higher fuel costs in the TCO of the VLSFO container ship;
  - The TCO estimation for e-methanol is 35% lower than for VLSFO; the TCO for e-diesel is 27% lower; and the TCO estimate for e-methane is almost a half (-47%) than that projected for the VLSFO-reference bulk carrier.

Above is a cost comparison for scenarios with low fuel prices, so it is possible that the TCO differential between e-fuels and VLSFO-powered vessels may be higher. The difference in TCO between VLSFO-reference and e-fuel-powered vessels in 2030 and 2050 may deviate, based on future developments in fuel oil prices, carbon costs and the production costs for e-fuels.

Even though the TCO may be lower for e-fuels than for the conventional fuel oil reference, other factors may also come into play to hinder or promote the large-scale deployment of e-fuels in shipping. These include:

- High upfront capital costs for the fuel system;
- Whether adequate infrastructure is available for bunkering;
- Safe handling of the fuels by the ships' crews.

These factors all could be barriers to the adoption of e-fuels on vessels, even if the TCO of e-fuels is significantly lower than conventional powertrains. However, given the lower absolute cost of e-fuel propulsion systems for smaller sized ships, an earlier transition might be feasible for that category.

### 2.5.5 Discussion on blending of e-fuels

At molecular level, e-fuels are equal to their biofuel counterparts. However, their production processes are different. This means that e-fuels are suited for blending with their biofuel counterparts. A brief recap of the fuels which are technically feasible for blending is shown in Table 16. E-diesel can be used as a drop-in fuel for conventional fuel-oil propulsion systems.

*Table 16. Overview of fuel variants suitable for the same propulsion system type.*

| Propulsion system type | Fossil fuel variant | Biofuel variant | E-fuel variant |
|---|---|---|---|
| Fuel oil engine | VLSFO | Bio-diesel | E -diesel |
| Methanol engine | Methanol (grey) | Bio-methanol | E -methanol |
| LNG/methane engine | LNG | Bio-methane | E-methane |

Due to several factors, any expectations for a 100% uptake of e-fuel is unrealistic during shipping's adoption phase, the first years that e-fuels become commercially available and shipping companies gradually begin to use them. Because green e-fuels are expected to be commercially available at a competitive price later than biofuels, it is more likely that a blend of biofuels and e-fuels will be used in suitable propulsion systems. The exact blending ratio for bio- and e-fuel variants for a specific ship will depend on their availability at ports and the prevailing market price for the fuels. Therefore, performing an analysis with specific blending ratios may not, by definition, be representative of common practice in future. The fuel cost for the blend will be directly linked to the prices of the fuel types and each blending ratio.

To provide an insight into the cost differences of blending e-fuels and biofuels, the TCO was compared for blending e-diesel with VLSFO, and for blending bio-diesel with VLSFO, in a bulk carrier. All data for the cost calculations were from the cost inputs presented in the sections (above) on CAPEX and OPEX.

In Figure 11, the yearly difference in the TCO between an e-diesel blend and a bio-diesel blend is indicated for the years 2030 and 2050, according to the *'low fuel cost'* scenario. For indicative purposes (and given that cost parity of e-fuels is not probable in 2030), a blend of 10% is chosen. This means that 10% of the yearly fuel used is from a renewable source (either bio- or e-diesel) and the other 90% of the fuel is VLSFO.

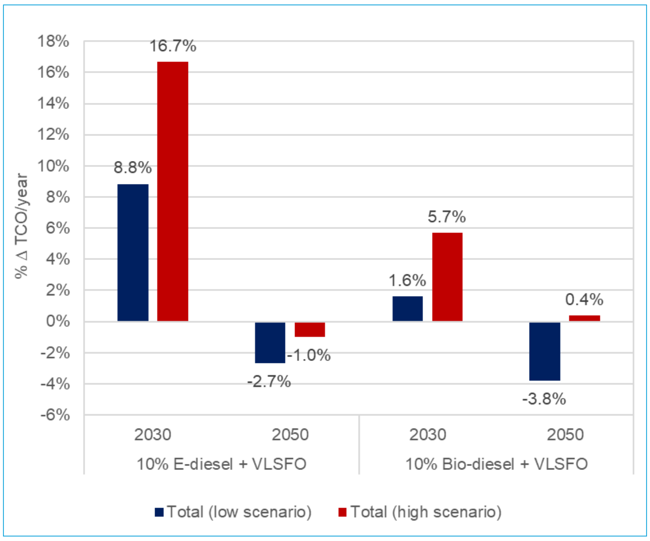


*Figure 11. Cost comparison for ships using a blend of renewable diesel and VLSFO in an existing powertrain.*

In 2030, the cost for blending 10% e-diesel was found to be at least 9% higher compared to sailing on 100% VLSFO. Sailing on a blend of 10% bio-diesel and 90% VLSFO may be only a few percentages more costly on a yearly basis compared to using pure VLFSO. By 2050, blending may become cost effective, depending on developments in fuel and carbon costs. The blend with bio-diesel shows a lower total cost in 2050; However, the cost for blending e-diesel at that point ultimately may result in similar cost figures. Moreover, in the scenario where a lower TCO is shown for the 10% blend than the (100%) VLSFO reference case, a higher blending percentage of the bio- or e-diesel may lead to even lower yearly TCO than using only VLSFO. This is because no item of CAPEX cost is at play, only the difference in the fuel cost is the determining factor.

The availability and the market price of the fuels are driven by supply and demand factors, including:

- Demand factors: competition for fuels with other sectors (e.g., e-methane can be used in existing gas grid and gas fired power plants), which drive developments in market price;
- Supply factors: developments in and availability of e-fuels production capacity, production cost developments, and the availability of port storage and bunkering infrastructure.

### 2.5.6 TCO retrofit estimation

So far, the TCO analysis has focused on the comparison between the costs for newly built VLSFO-fuelled vessels and newly built e-fuels-powered vessels.

In this subsection, the cost is examined for retrofitting current conventional VLSFO-fuelled vessels to equip them with internal combustion engines suitable for e-fuels. This would require the engines, the FSS and the tanks to all be replaced, incurring significant CAPEX, except if e-diesel is used. At the same time, the costs for the planning and execution of the retrofit and the gaining the required approvals would also need to be considered. Finally, the comparative cost of using e-fuel instead of VLSFO would be necessary to complete the analysis. The fuel cost for e-fuels from the above results of the newbuild TCO analysis is considered.

An estimation of the retrofit cost for the internal combustion systems that are suitable for bio-methanol, bio-diesels and bio-methane was provided in the EMSA study '*Update on Potential of Biofuels in Shipping*' (EMSA, 2022a). Given the physical properties of the fuels, the application and use of the onboard engine and fuel system is similar to biofuels and the e-fuels variants (e.g., bio-methanol and e-methanol are equal at the molecular level). Therefore, it is assumed that VLSFO-fuelled ships require the same retrofit-CAPEX for e-fuels as for the biofuel counterpart of the respective e-fuel. The outcome for the CAPEX part of the biofuels retrofitting analysis is used. Only the fuel cost is different between biofuels and e-fuels.

The retrofitting analysis on the CAPEX items shows indicative cost for retrofitting a medium-sized containership from fuel oil to both methanol- and methane-suitable systems.

*Table 17. Indicative ship retrofit costs for a medium sized containership (5,000-8,000 TEU) (EMSA, 2022a).*

| Fuel type conversion | Additional cost to newbuild CAPEX | Indicative ship conversion cost* (million USD) | Indicative ship conversion cost* (million EUR) |
|---|---|---|---|
| Fuel oil to e-methanol | ~13-17% | 19.0 – 25.0 | 16.6 – 21.8 |
| Fuel oil to e-methane | ~15-20% | 22.0 – 30.0 | 19.2 – 26.2 |

For this ship type, the yearly operational expenditures (i.e., fuel cost, carbon cost, bunkering cost, M&R cost) were taken from the newbuild TCO analysis, assuming using 100% e-fuels and sailing on intra-EU routes. The retrofit CAPEX was annualised in similar way to the newbuild TCO analysis. This allows all cost items to be expressed in yearly cost. Finally, the difference in percentage of total yearly cost of retrofit CAPEX and OPEX between the use of e-methanol, e-diesel and e-methanol compared to VLSFO was calculated.

In the reference case, the VLSFO-powered containership, to which the TCO of retrofitted containership is compared, no CAPEX applies. Only the operational cost during the period for the use of VLSFO in the existing ship is considered. For the e-methanol and e-methane cases, the CAPEX for retrofitting the propulsion system and the OPEX apply. The TCO for the use of e-diesel in the existing ship is also presented, for comparison, even though this would not require a full retrofitting process, meaning there is no additional CAPEX in the TCO of e-diesel compared to the TCO of the VLSFO ship.

In 2030, the estimated differences in yearly TCO for retrofitting the ship and using the applicable e-fuels are significantly higher than the VLSFO reference, including carbon cost. However, considering a 5-year investment period (or the ship's remaining service life), depending on the fuel price scenario, the use of (100%) e-diesel may be the most cost-effective option among the sustainable e-fuels. For 10- and 15-year investment periods (remaining service life), retrofitting the ship to be e-methane suitable may be more cost-effective, compared to retrofitting for e-methanol or directly using e-diesel as a drop-in fuel.

In 2050, overall, the cost difference for retrofits decreases significantly. Retrofitting the containership to an e-methanol propulsion system appears to be the most expensive of the e-fuels for both 5-year and 10-year investment periods. In most cases, retrofitting the ship to use e-methane appears to be the cost-effective option for sailing on e-fuels. The result is given in Figure 12.

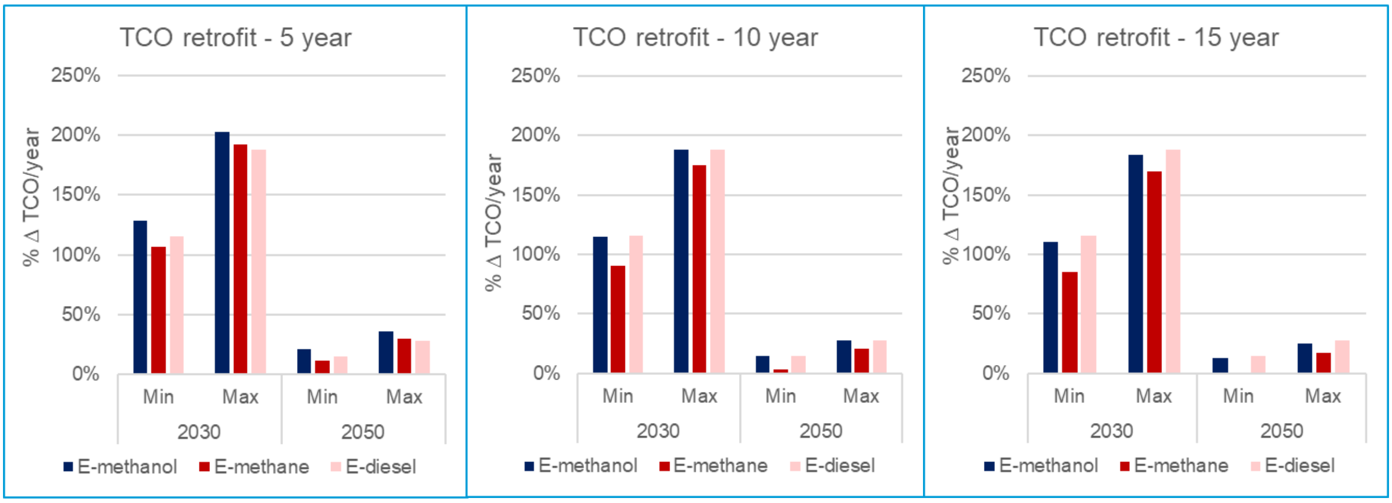


*Figure 12. Difference in yearly cost of a retrofitted containership sailing on e-fuels, for varying investment periods – compared to a reference VLSFO powered container ship.*

For a longer investment period such as 15 years, the difference to the VLSFO reference only may be a few percentages, in a *'low fuel cost'* scenario. The outcomes for using e-diesel as a drop-in for existing fuel-oil propulsion system may be a cost-effective option for ships with a relatively short service lives remaining. The cost-saving benefits of retrofitting (CAPEX) outweigh the higher fuel cost; in some cases, this leads to lower total costs compared to the retrofitting and use of the other e-fuels.

### 2.5.7 Techno-economic Conclusions

The yearly TCO for e-methanol-, e-diesel- and e-methane-powered vessels was analysed for new-build vessels to provide an insight into the cost development of these alternative fuels and to compare this to conventional fuel oil-powered vessels. A retrofitting case for a small containership was examined in addition to the newbuild cases.

In 2030, the minimum-cost estimates for the TCO of newbuild e-fuelled vessels appears to be 45%-85% higher compared ships running on conventional fuel oils, with using e-diesel representing the upper and e-methane the lower end of the scale.

In the decades thereafter, the fuel cost of e-fuels is expected to decrease substantially, leading to the potential for cost parity with fuel-oil ships. If carbon costs are applied to using fossil marine fuels, cost parity may be reached at earlier stage of the e-fuel production scale up. In 2050, the TCO for newbuild e-fuel-powered ships is estimated to reach a lower cost level than those powered by conventional fuel oils. This means e-fuels have the potential to fulfil a major role in shipping in the long term, especially because the production inputs for e-fuels will be less scarce when production techniques are deployed at large-scale.

The retrofitting cost analysis showed that the (CAPEX) investments required to adjust the ships' propulsion system and, to a larger extent, fuel costs determine the TCO outcome. Depending on the fuel prices and the investment time, and given the remaining service life of the ship, the shipowner may benefit from retrofitting the ship and using (a blend of) e-fuels. However, this is again dependent on the development of the production costs for e-fuels, the development of the fossil fuel price and the carbon cost for its use.

Without global policy measures to either bridge the price gap or oblige ships to use green fuels, a transition to e-fuels with zero-$CO_2$ impact is unlikely to accelerate at desired speed and scale in the next decade. Stimulation of market demand for carbon-free maritime transportation could be a complementary or alternative way to achieve a better and faster transition to green fuels.

However, the business case for e-fuel-powered vessels also will be dependent on developments in the global price of fuel oil. If fossil fuel prices continue to rise, the cost gap between the TCO for using conventional fuels and the TCO for e-fuels may be tightened.

The storage of e-methanol can be a challenge for ships on long routes as its volumetric energy density is less than half of the energy density of conventional fuel oils. The storage of e-diesel does not seem to pose substantial limitations, since this fuel type can be used as a drop-in next to fossil variants. The storage of e-methane still poses a challenge in shipping, although these systems are already currently used in shipping. Specifically, the drop-in variants of e-diesel and e-methane can use existing bunkering infrastructure. To make e-methanol ready for widescale use by shipping, there is a need for additional development of storage and bunker infrastructure in ports.

# 3. Safety and Environmental Regulations, Standard and Guidelines

In the realm of environmental regulations, standards and guidelines, most do not mention e-fuels specifically; rather they address synthetic fuels. Because synthetic fuels cover e-fuels, this section covers the synthetic varietal (i.e. mixtures of carbon monoxide and hydrogen, which can be produced from fossil or renewable-energy resources), as well as the regulations for the *'electro'*-variants of the fuels.

However, the EU approach is more detailed than overall regulations in that it defines a specific regulatory framework for RFNBOs, which are produced from renewable energy sources other than biomass. Gaseous renewable hydrogen produced by feeding renewables-based electricity into an electrolyser is considered an RFNBO. Liquid fuels, such as ammonia, methanol or e-fuels, also are considered RFNBOs when produced from renewable hydrogen and renewable CO2 not stemming from a biogenic source, if required.

## 3.1 Bunkering, onboard storage, handling and use of synthetic fuels - Introduction

Like biofuels, synthetic fuels (including e-fuels) are often considered advantageous from the technical perspective due to their potential to *'drop-in'* and replace fossil-derived fuels, ability to take advantage of existing infrastructure and equipment, and reduce carbon emissions.

Furthermore, adoption is encouraged by regulatory regimes for synthetic fuels often referring to existing standards, rules, or codes of practice for handling the corresponding petroleum or fossil-based fuel types.

However, the practice of including synthetic fuels in petroleum fuels as blends has been limited.

Also, the regulatory development of quality standards for marine synthetic fuels relies on the limited experience gained with synthetic fuel blends across multiple applications, together with experience from the use of fossil fuel equivalents and is typically facilitated by performance testing on land or at sea.

Shipping's advantage over other sectors is that marine engines, particularly slow speed 2-stroke engines and large medium-speed engines, are specifically designed to handle residual and distillate fuels with a wide range of properties and a growing portfolio of dual-fuel capabilities. They are therefore better suited to accommodate drop-in synthetic fuels without having to change hardware.

This section provides an overview of the current safety standards, regulations and guidelines related to synthetic fuels, together with an overview of the policies driving demand for renewable fuels and including requirements for bunkering, onboard storage, handling and their use for propulsion or power generation on vessels.

## 3.2 International

The following subsections discuss current global regulations, standards and guidelines related to the use of synthetic fuels in marine applications.

### 3.2.1 International Organization for Standardization (ISO)

***ISO Marine Fuel Oil Quality Standard***

The most widely used fuel standard in the marine industry, which covers the conventional residual or distillate fuel grades, is ISO 8217:2017. The standard – *Petroleum products – Fuels (class F) – 'Specifications of Marine Fuels'* – specifies the requirements for fuel oils for use in marine diesel engines and boilers prior to conventional onboard treatment. There are seven categories of distillate fuels and six for residual fuels.

The ISO standard defines fuel as hydrocarbons from petroleum crude oil, oil sands and shale and hydrocarbons from synthetic or renewable sources similar in composition to petroleum distillate fuels. It also includes blends of these with FAME, where permitted.

The ISO standard also clarifies that the fuel composition is to consist predominantly of hydrocarbons primarily derived from petroleum sources while it may also contain hydrocarbons from the following sources:

- synthetic or renewable sources such as Hydrotreated Vegetable Oil (HVO), Gas-to-Liquid (GTL) or Biomass-to-Liquid (BTL);
- co-processing of renewable feedstock at refineries with petroleum feedstock.

The ISO 8217 standard was prepared by the ISO Technical Committee, ISO/TC 28, '*Petroleum and Related Products, Fuels and Lubricants from Natural or Synthetic Sources'.*

### *ISO Marine LNG Fuel Quality Standard*

In response to growing industry interest and applications for LNG and demand for an internationally recognised standard for marine fuels, the ISO developed 23306:2020, a standard for the '*Specification of Liquefied Natural Gas as a Fuel for Marine Applications'*.

While it was formed from industry experiences with the application of fossil-derived LNG, the standard also applies to LNG derived from other sources, including shale gas, coalbed methane, bio-methane or synthetic methane. It therefore can be applied to both LNG derived from fossil fuels or other renewable sources.

Other ISO Standards applicable to LNG as fuel for ships, include:

- ISO/TS 18683:2021 – *Guidelines for Safety and Risk Assessment of LNG Fuel Bunkering Operations*
- ISO 20519:2021 – *Ships and Marine Technology – Specifications for Bunkering of Liquefied Natural Gas-Fuelled Vessels*
- ISO 28460:2010 – *Petroleum and natural gas industries – Installation and Equipment for Liquefied Natural Gas – Ship-to-Shore Interface and Port Operations*
- ISO 21593:2019 – *Ships and marine technology – Technical Requirements for Dry-Disconnect/Connect Couplings for Bunkering Liquefied Natural Gas*
- ISO 22548:2021 – *Ships and marine technology – Performance Test Procedures for LNG Fuel Gas Supply Systems (FGSS) for Ships*
- ISO 22547:2021 – *Ships and marine technology – Performance Test Procedures for High-Pressure Pumps in LNG Fuel Gas Supply Systems (FGSS) for Ships*
- ISO/TS 16901:2022 – *Guidance on Performing Risk Assessment in the Design of Onshore LNG Installations Including the Ship/Shore Interface*
- ISO 16904:2016 – *Petroleum and Natural Gas Industries – Design and Testing of LNG Marine Transfer Arms for Conventional Onshore Terminals*
- ISO/TS 18683:2021 – *Guidelines for Safety and Risk Assessment of LNG Fuel Bunkering Operations*
- ISO/TR 17177:2015. *Petroleum and Natural Gas Industries – Guidelines for the Marine Interfaces of Hybrid LNG Terminals*
- ISO/AWI 22238 [Under Development] – *Design, Construction and Testing of High-Pressure Gas Transfer Systems*

### *ISO Marine Methyl/Ethyl Alcohol Fuel Quality Standard*

During the development of IMO's safety requirements for the use of methyl/ethyl alcohols as marine fuels, it was recognised that the marine industry would benefit from the development of a marine fuel standard such as those that apply to conventional distillate and residual fuels and LNG. Following the request from IMO, the ISO's standard for marine applications of methanol fuel – ISO/CD 6583 '*Specification of Methanol as a Fuel for Marine Applications'* – is currently being prepared. It is not clear if this will also cover ethanol, or if a separate standard will be developed. However, the standard is expected to follow the approach of LNG ISO 23306 standard and cover methanol derived from fossil and renewables.

Methanol is synthesised, commercially traded and transported at high levels of purity, and it therefore does not face the same challenges as LNG, which has wide range of properties, depending on the origin of the fossil fuel. However, the lack of an ISO methanol marine fuel standard remains one of the barriers to take up.

## 3.2.2 ASTM International

The ASTM International D2069-91(1998) '*Standard Specification for Marine Fuels'* was withdrawn in 2003 with no other standard replacing it. Thus, in the absence of standards covering specific marine fuels, particularly marine synthetic fuels standards, it is typical that compliance with existing land-based diesel fuel standards such as ASTME D975-21 are used to benchmark the fuels at the commercial level. For European countries this is the EN 590 diesel fuel standard.

## 3.2.3 International Maritime Organization Requirements

### 3.2.3.1 Strategy on Reduction of GHG Emissions

Since the adoption of the *'Initial IMO Strategy on Reduction of GHG Emissions from Ships'* in 2018, the IMO has continued to assess emerging technologies and the availability of alternative fuels to remain current with the options that could support the decarbonisation in shipping. In that time, the will among member States grew to increase the level of ambition in the IMO's GHG reduction goals; by adopting the *'2023 IMO Strategy on Reduction of GHG Emissions from Ships'*, the shipping industry committed to achieving net-zero emissions 50 years sooner than previously agreed.

The *'2023 IMO Strategy on Reduction of GHG Emissions from Ships'* is a comprehensive work package consisting of targets, workplans, reviews and impact studies all aimed at achieving decarbonisation by or around 2050: the GHG reduction targets set levels of ambition for overall emissions and carbon intensity, and they set indicative checkpoints along the way.

Achieving these targets will require a basket of mid-term measures to be developed to steer the maritime industry towards full decarbonisation by 2050. However, to get the balance of the proposed measures right, a comprehensive impact assessment will be carried out in parallel.

In July of 2023, the IMO's 80th meeting of the Marine Environment Protection Committee (MEPC 80) adopted the following levels of ambition for the international shipping in the *'2023 IMO Strategy on Reduction of GHG Emissions from Ships'* (all reductions below refer to the 2008 levels):

- ***carbon intensity of the ship to decline through further improvement of the energy efficiency for new ships***

  *to review with the aim of strengthening the energy efficiency design requirements for ships;*

- ***carbon intensity of international shipping to decline***

  *to reduce CO2 emissions per transport work, as an average across international shipping, by at least 40% by 2030, compared to 2008;*

- ***uptake of zero or near-zero GHG emission technologies, fuels and/or energy sources to increase***

  *uptake of zero or near-zero GHG emission technologies, fuels and/or energy sources to represent at least 5%, striving for 10%, of the energy used by international shipping by 2030; and*

- ***GHG emissions from international shipping to reach net-zero***

*to peak GHG emissions from international shipping as soon as possible and to reach net-zero GHG emissions by or around, i.e., close to 2050, taking into account different national circumstances, whilst pursuing efforts towards phasing them out as called for in the Vision consistent with the long-term temperature goal set out in Article 2 of the Paris Agreement.*

Also, indicative checkpoints were set:

- *Total annual GHG emissions reduction by 20%, striving for 30%, by 2030*
- *Total annual GHG emissions reduction by 70%, striving for 80%, by 2040*

Several of the levels of ambition leave leeway for the exact date or amount of implementation, such as the targets that strive for a higher value, or the net-zero target on or around 2050. Nevertheless, the revised targets are ambitious and will be challenging to achieve.

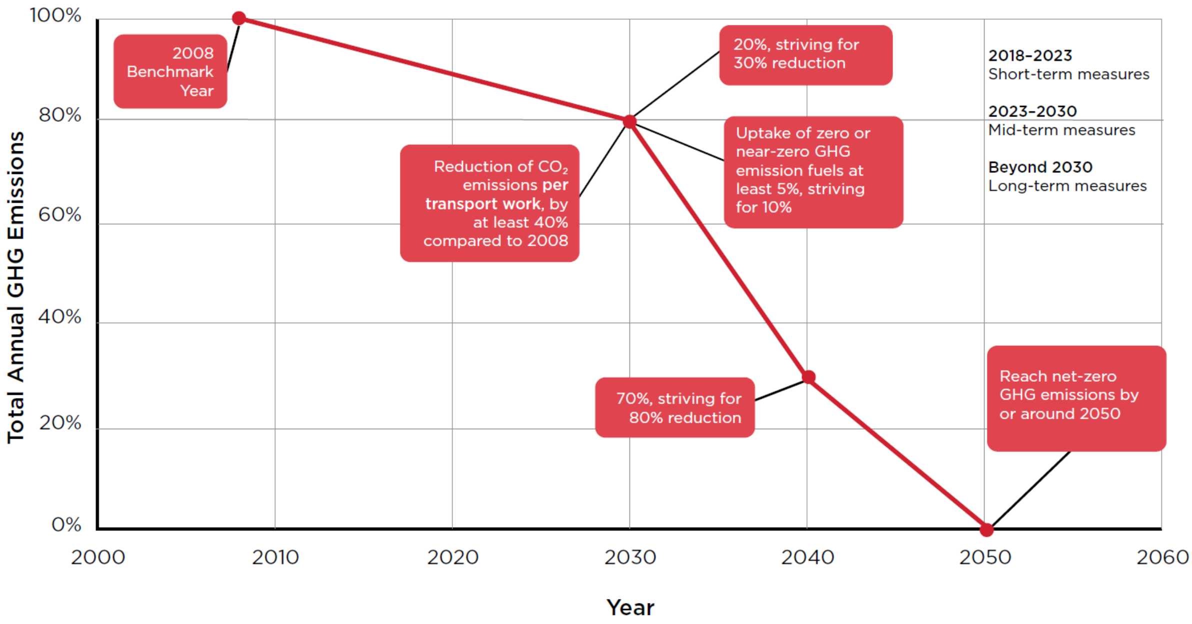


*Figure 13. IMO GHG reduction targets.*

### 3.2.3.2 LCA Guidelines

IMO MEPC adopted the *'2024 Guidelines on Life Cycle GHG Intensity of Marine Fuels'* (IMO LCA Guidelines - Resolution MEPC.391(81)), building on the initial guidelines (Resolution MEPC.376(80)). Though initially synthetic fuels were considered, it was ultimately recommended that in order to establish the methodology for the emission credits from the use of captured $CO_2$ as carbon stock to produce synthetic fuels in the fuel production process, further consideration is needed. For now, fuel pathway codes are established which include renewable electricity processes.

The scope of these guidelines is to address Well-to-Tank (WtT), Tank-to Wake (TtW), and Well-to-Wake (WtW) GHG intensity and sustainability themes/aspects related to marine fuels/energy carriers (e.g., electricity for shore power) used for ship propulsion and power generation onboard.

The relevant Greenhouse Gases (GHG) included are:

- carbon dioxide ($CO_2$)
- methane ($CH_4$) and
- nitrous oxide ($N_2O$)

The guidelines aim at covering the whole fuel life cycle (with specific boundaries), from feedstock, extraction/cultivation/recovery, feedstock conversion to a fuel product, transportation as well as distribution/bunkering, and fuel utilisation onboard a ship.

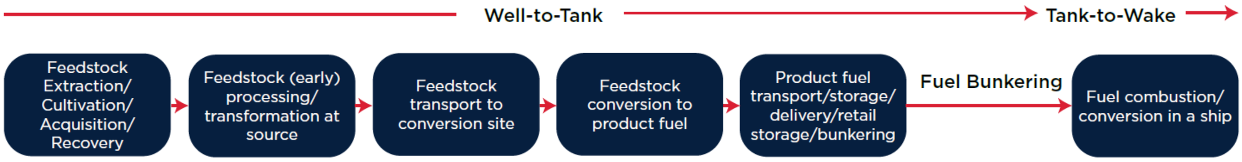


*Figure 14. Well-to-Wake approach to emissions.*

In addition, the guidelines also specify sustainability themes/aspects for marine fuels and define a Fuel Lifecycle Label (FLL), which carries information about fuel type, feedstock (feedstock type and feedstock nature/carbon source), conversion/production process (process type and energy used in the process), GHG emission factors, information on fuel blends and sustainability themes/aspects. The guidelines will specify the elements of FLL subject to verification/certification and include a general procedure on how the certification scheme/standards could be identified.

The Committee agreed on the establishment of the Joint Group of Experts on the Scientific Aspects of Marine Environmental Protection (GESAMP) Working Group on Life Cycle GHG Intensity of Marine Fuels (GESAMP-LCA WG) to review scientific and technical issues with the following Terms of Reference (ToR) (as per MEPC 81/WP.8):

- *Methodological refinement of the emission quantification in the LCA Guidelines, with a view to ensuring the integrity of all information provided*
  - *Scientific review of the LCA methodology*
  - *Scientific review of the WtT GHG default emission factors of fuel production pathways and technologies*
  - *Scientific review of the TtW GHG default emission factors of fuel usage and onboard technology (explicitly mentioning OCCS boundaries), and*
  - *Sample calculations on LCA and reflecting the output into the existing Fuel Lifecycle Label (FLL)*

- *Sustainability themes/aspects*
  - *Refining and further exploring indicators and metrics under the sustainability themes/aspects in the LCA Guidelines, and*
  - *Approaches to Indirect Land Use Change (ILUC) risk classification*

- *Methodological requirements of the LCA Guidelines with regard to certification*
  - *Provide external experience, and further information for the development and/or identification of possible requirements for fuel pathway certification, including WtT and TtW actual values*

The Committee also agreed on the establishment of the LCA Correspondence Group, to further consider *'other social and economic sustainability themes/aspects of marine fuels'.*

IMO will continue the scientific review and enhancement of the LCA Guidelines.

#### 3.2.3.3 MARPOL

The IMO's International Convention for the Prevention of Pollution from Ships (MARPOL 73/78, as amended) sets out international requirements to prevent pollution from ships travelling internationally or between two member states. The MARPOL convention is divided into these annexes covering specific pollution controls:

- Annex I – *Regulations for the Prevention of Pollution by Oil*
- Annex II – *Regulations for the Control of Noxious Liquid Substances in Bulk*
- Annex III – *Regulations for Prevention of Pollution by Harmful Substances Carried by Sea in Packaged Form*
- Annex IV – *Regulations for the Prevention of Pollution by Sewage from Ships*

- Annex V – *Regulations for the Prevention of Pollution by Garbage from Ships*

The last annex to be added to the convention, Annex VI – Regulations for the prevention of air pollution from ships, was adopted by the Protocol of 1997 to MARPOL. It introduced the IMO's regulatory framework for air pollution and some key air-pollutant controls for shipping, including ozone-depleting substances, nitrogen oxides ($NO_X$), sulphur oxides ($SO_X$), volatile organic compounds (VOCs), shipboard incineration and fuel oil quality. By later amendment, the IMO introduced additional regulations for energy efficiency and more recently carbon intensity.

The following topics under MARPOL Annex VI are considered to be important regarding the use of synthetic fuels (or e-fuels) as marine fuel.

They are:

- Nitrogen Oxides (NOX)
- Sulphur Oxides (SOX) and Particulate Matter (PM)
- Fuel Oil Availability and Quality
- EEDI, EEXI and CII
- Data Collection System (DCS)

#### 3.2.3.3.1 Nitrogen Oxides ($NO_X$)

To reduce the harmful effects of $NO_X$ emissions on human health and the environment, regulation 13 of Annex VI set the limits for $NO_X$ emissions from ships' diesel engines. It mandates compliance for all marine diesel engines greater than 130 kW installed on vessels subject to MARPOL Annex VI with the applicable emission limit, except for engines used solely for emergencies.

Marine diesel engines are defined by the IMO as any reciprocating internal combustion engine operating on liquid or gaseous or dual fuels, including engines operating on the Diesel or Otto combustion cycles.

The regulation's $NO_X$ limits are based on engine rated speed (see Figure 15), with the lowest limits applicable to medium and high-speed engines. The application is tied to the date the ship was built.

When Annex VI entered into force on 19 May 2005, the Tier I $NO_X$ limit was retrospectively applied to engines fitted on ships with keels laid on or after 1 January 2000. Further $NO_X$ limits were introduced in 2008, when Annex VI and its $NO_X$ Technical Code was amended. Those amendments introduced the global Tier II limit from 1 January 2011.

The amendments also introduced the Tier III limit, which is only applicable in Emission Control Areas (ECAs) and reduced $NO_X$ emissions approximately 80% compared to the Tier I limit. The Tier III limits are applicable to $NO_X$ ECAs only after those regimes are recognised at the IMO.

Currently, the only active $NO_X$ ECAs are the North American coasts and United States Caribbean Sea, which entered into force on 1 January 2016, and the Baltic and North Sea ECAs, which were originally only designated $SO_X$ ECAs and became $NO_X$ ECAs from 1 January 2021.

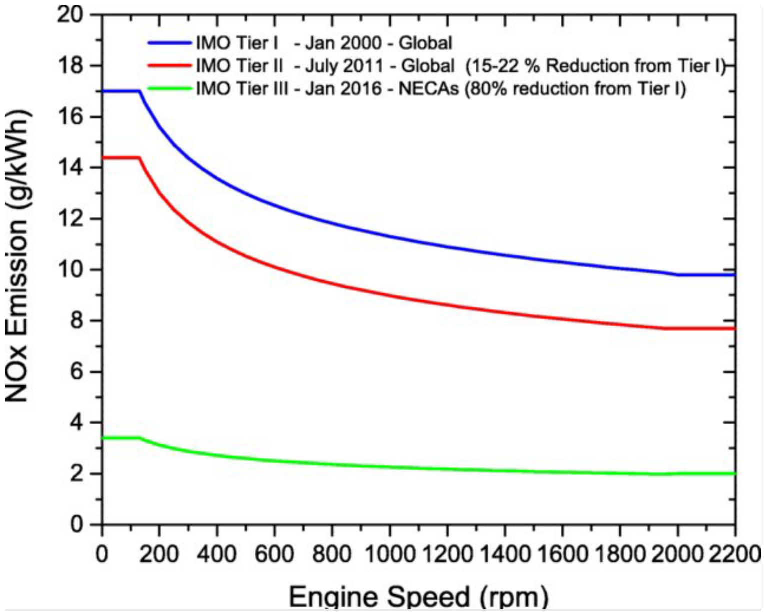


*Figure 15. MARPOL 73/78 Annex VI Reg 13 - $NO_X$ emission limits with respect to engine speed.*

The key instrument supporting Regulation 13 is the $NO_X$ Technical Code (NTC), which is in large parts based on the ISO 8178 series of standards *'Reciprocating Internal Combustion Engines – Exhaust Emission Measurement'*, specifically the following parts (showing current revision dates):

- ISO 8178-1:2020 Part 1 – *Test-Bed Measurement Systems of Gaseous and Particulate Emissions*
- ISO 8178-4:2020 Part 4 – *Steady State and Transient Test Cycles for Different Engine Applications*
- ISO 8178-5:2021 Part 5 – *Test Fuels*
- ISO 8178-6:2018 Part 6 – *Report of Measuring Results and Test*
- ISO 8178-7:2015 Part 7 – *Engine Family Determination*
- ISO 8178-8:2015 Part 8 – *Engine Group Determination*

As required by Annex VI, the NTC is applicable to the reference testing and certification of all marine diesel engines subject to the requirements of Regulation 13. The NTC sets the application-specific test cycles from which the cycle-weighted $NO_X$ emission value is determined for that group or family of engines, in accordance with the provisions of chapter 5 of the NTC.

As part of those provisions, the NTC requires the *'parent'* engine test to be undertaken on a DM grade (distillate) marine fuel, in accordance with ISO 8217:2005, if a suitable reference fuel is not available. Furthermore, if a DM grade fuel is not available, the emissions testing for the parent engine is to use a RM-grade (residual) fuel oil.

In all cases, the fuel oil used during the parent engine test is sampled and analysed for use in the calculation of the $NO_X$ emissions. Most marine certifications of $NO_X$ emissions have used a DM grade fuel oil.

Marine engines, particularly the larger medium-speed and slow-speed engines, operate on many ISO 8217 distillate and residual fuel oils and have adjustable features that compensate for variations in fuel quality and ignition properties. This is the basis for defined engine group (rather than engine family) certification. The operating ranges are covered by the engine group's certification and an individual engine's technical file.

While the range of marine fuel oils varies significantly, including fuel-bound nitrogen and oxygen content, the IMO's regime for $NO_X$ certification is based on defined testbed testing on DM- or RM-grade fuels. It accepts that $NO_X$ emissions from operations will vary from the certified values, depending on the fuel oil.

This recognition is confirmed by the allowance of 10% $NO_X$ emissions for testing onboard using RM-grade fuel oils (refer to 6.3.11.2 of the NTC). This foundation comes from a knowledge base of RM- and DM-grade fuel oils and blends derived from petroleum refining.

There is limited emissions data from burning synthetic fuels in marine engines. No clear trend exists, and $NO_X$ emissions are very dependent on engine load, adjustable features and fuel properties.

To an extent, Annex VI addresses this with provisions for the quality of fuel oil under regulation 18 of Annex VI where 18.3.2.2 restricts an engine from exceeding the applicable $NO_X$ emission limit when consuming fuels derived by methods other than petroleum refining.

There are also the Annex VI regulation 4 *'Equivalents'* provisions which allow equivalent '… *fitting, material, appliance or apparatus or other procedures, alternative fuel oils, or compliance methods* …' to be applied under flag Administration agreement on a ship-specific basis.

#### 3.2.3.3.2 Sulphur Oxides ($SO_X$) and Particulate Matter

MARPOL Annex VI Regulation 14 restricts the amount of $SO_X$ and associated sulphate-based particulate matter (PM) emitted by all fuel oil-consuming equipment onboard ships by limiting the sulphur content of the marine fuels.

In line with Regulation 13 limits for $NO_X$, the IMO adopted initial fuel sulphur content limits that were later updated with the 2008 revisions of Annex VI, and also provided separate fuel sulphur content limits to be applied globally and within ECAs. Starting initially with limits of 4.50% sulphur globally and 1.50% in ECAs, these limits were lowered to 0.50% for all ships and 0.10% for ships in ECAs on 1 January 2020 (see Figure 16).

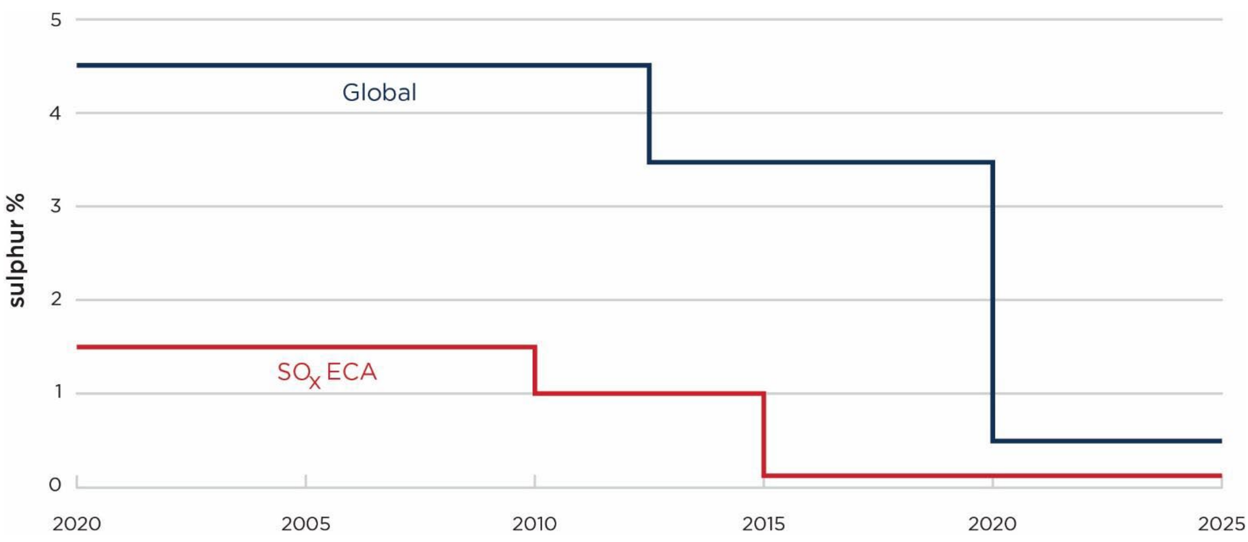


*Figure 16. MARPOL 73/78 Annex VI Reg 14 – % Sulphur content in fuel limits.*

Synthetic fuels, due to their production process, are inherently low in sulphur, or are sulphur-free, so compliance with Regulation 14 is easily reached for many liquid or gaseous synthetic fuels. However, the IMO's most stringent fuel sulphur limit of 0.10% in ECAs, which is 1,000 ppm, remains considerably higher than other land-based regulations, for which those limits may be as low as 10 ppm. Synthetic fuels therefore provide a way to comply with the IMO's regulations, but they also offer a way to reduce the quantities of $SO_X$ emitted by the marine industry to levels significantly below the IMO's most stringent limits.

Further reductions in IMO's regulation 14 fuel sulphur limits would provide significant air quality benefits, but also encourage application of inherently low sulphur synthetic fuels.

#### 3.2.3.3.3 Fuel Oil Availability and Quality

Regulation 18 in MARPOL Annex VI outlines requirements for the availability and quality of fuels to administrations, fuel suppliers and owner/operators. As defined by Annex VI, fuel oil is any fuel delivered to and intended for combustion purposes for the propulsion or operation onboard a ship, including gas, distillate and residual fuels.

These requirements include obligations on the fuel supplier to document the sulphur content and other parameters in the BDN, which must be accompanied by a sealed sample of the fuel. Regulation 18.4 states, however, that the requirements for the BDN and fuel sample do not apply to gaseous fuels such as LNG or LPG. Similar exemptions are also therefore applicable to the equivalent gaseous synthetic fuels.

Regulation 18.3 states the general fuel properties required for hydrocarbon fuel oils derived largely from petroleum refining, as well as fuel oil for combustion purposes derived by methods other than petroleum refining. Synthetic fuels fall into the latter category, but many of the high-level fuel requirements are applicable to fuels derived from both methods. The regulation restricts the fuels from:

- Containing inorganic acid;
- Jeopardising the safety of ships or adversely affect machinery performance;
- Harming or being harmful to personnel;
- Contributing to additional air pollution.

It can be argued that the Annex VI $NO_X$ certification regime accepts $NO_X$ emissions will vary in operation depending on the fuel, giving some width to interpret the regulation's application for synthetic fuels. Generally, most synthetic fuels and synthetic fuel blends can be used in marine $NO_X$-certified engines without any changes to the $NO_X$-critical components or settings and limits to operating values provided in the engine's related technical file.

If settings need to be adjusted, these usually could be covered by the flexibility provided in the engine group concepts; as given by 4.4.7.1 of the NTC, minor adjustments or modifications are allowed after pre-certification or final measurement of the test bed – in particular for onboard adjustments of *'… injection timing for compensation of fuel-property differences …'* – as per the example offered in NTC Regulation 4.4.7.2.

While Annex VI has robust provisions for undertaking trials under the agreement of the flag Administration on a case-by-case basis, this regulatory uncertainty could hamper the widespread adoption of synthetic fuels.

#### 3.2.3.3.4 Required EEDI, EEXI and CII

At the IMO MEPC 62nd session in July 2011, further amendments to MARPOL annex VI were made with the adoption of MEPC.203(62), which introduced a new Chapter 4 that included energy-efficiency measures for ships. This chapter introduced new design and operational requirements for energy efficiency via the Energy Efficiency Design Index (EEDI) and the Ship Energy Efficiency Management Plan (SEEMP).

Regulation 22 of MARPOL Annex VI requires that the attained EEDI shall be calculated for each new ship, each new ship that undergoes a major conversion, or existing ships that undergo so many changes that, in the Administration's judgement, they are considered a new ship. The 2014 Guidelines on the method of calculation for the EEDI and MEPC.308(73) as amended, is to be used for related calculations. Similarly, there is a new requirement for the existing ships, the attained EEXI as per Regulation 23 which entered into force in 1st of January 2023.

Regulation 24 of MARPOL Annex VI provides the required EEDI which is made up of two parts, a reference line and reduction factors for the EEDI relative to the reference line. These depend on the ship types and sizes (MARPOL ANNEX VI and NTC 2008, 2017). Similarly, there is a new Regulation 25 defining the required EEXI.

While the calculation principles are the same for EEDI and EEXI, some reduction factors are different.

The attained EEDI and EEXI values are considered a measure of the ships' energy efficiency, expressed in $CO_2$ emissions per cargo tonnage and distance carried (in g $CO_2$/t nm). The formula includes many parameters, including the fuel consumed by the main and auxiliary engines. The amount of $CO_2$ emitted during the consumption of that fuel is determined by multiplying the main and auxiliary engine powers, specific fuel consumption and the default fuel-specific conversion factors, $C_F$ (conversion factor between fuel consumption and $CO_2$ emissions – which originate from Intergovernmental Panel on Climate Change (IPCC) values). It is noted that the EEDI reference lines were constructed using ships built between 1999 and 2008, assuming the use of HFO and a Tank-to-Wake carbon factor of 3.114.

For the time being, the $C_F$ conversion factors used for EEDI, EEXI and CII take into account only the Tank-to-Wake $CO_2$ emissions as shown in Table 18.

*Table 18. CF nondimensional conversion factors as per Resolution MEPC.364(79).*

| Type of Fuel | Reference | Lower Calorific Value (LCV) | Carbon Content | Cf (t-$CO_2$/t-Fuel) |
|---|---|---|---|---|
| MDO/MGO | ISO 8217 Grades DMX through DMB | 42,700 | 0.8744 | 3.206 |
| LFO | ISO 8217 Grades RMA through RMD | 41,200 | 0.8594 | 3.151 |
| HFO | ISO 8217 Grades RME through RMK | 40,200 | 0.8493 | 3.114 |
| LPG | Propane | 46,300 | 0.8182 | 3.000 |
| | Butane | 45,700 | 0.8264 | 3.030 |
| Ethane | - | 46,400 | 0.7989 | 2.927 |
| LNG | - | 48,000 | 0.7500 | 2.750 |
| Methanol | - | 19,900 | 0.3750 | 1.375 |
| Ethanol | - | 26,800 | 0.5217 | 1.913 |

Synthetic fuels can contribute to reducing carbon emissions, and an agreed $C_F$ factor, or certified carbon content, value provided by the fuel supplier could account for the $CO_2$ reductions that may be applicable to that particular synthetic fuel. This provision could account for the Well-to-Tank, as well as Tank-to-Wake, emissions resulting from synthetic fuel feedstock extraction, production and transportation to end-use and provide an easy tool to apply within existing and developing instruments. Certification to the ISCC (International Sustainability and Carbon Certification) system is an example of how this can be recognised, and it is understood that it has already been applied in certain cases.

However, there is uncertainty on how to apply the above concept within the EEDI framework since the choice of the fuel (synthetic instead of fossil) used is more frequently considered as an operational measure that may be captured under IMO's Energy Efficiency Operational Indicator (EEOI), Carbon Intensity Indicator (CII) and/or Data Collection System (DCS) regulations. This is considered a gap in the EEDI requirements, since it is not possible to indicate the lower $CO_2$ footprint of a ship that is designed and intended to operate on lower carbon, or carbon-neutral, synthetic fuels in service. It is noted that this index is recognised as an indicator of design performance and is critical for charterers and managers.

Another related issue is that the EEDI framework and through-life monitoring does not obligate verifying ships to operate on the EEDI fuels for which they have been certified. This is captured to an extent by other operational fuel reporting requirements, but it remains disconnected from other parts of Annex VI. It also fails to recognise the significant differences in $CO_2$ footprints that may exist between different modes of ship operation: Tier II vs Tier III, oil mode vs gas mode, for example. Historically, Annex VI air pollution control regimes required compliance with the applied limit on all fuels, and all modes of operation, on a worst-case (i.e., highest emissions) basis. Therefore, these remain gaps that may need further discussion at IMO level.

Another recent addition in MARPOL Annex VI is the CII. CII entered into force on the 1 January 2023, under Regulation 28, and is a metric of operational carbon intensity based on the actual fuel consumption reported by the vessel under the Fuel Oil Data Collection System (DCS). Apart from the reported data under DCS, some correction factors and voyage adjustments are also applicable (Resolution MEPC.355(78)). Again, this index should be below certain limits which depend on ship type and size and get stringent every year. While the whole CII concept is under IMO's plan for revision and amendments, the carbon factor, as defined under the EEDI (Table 18) is currently to be used for CII calculation. It is noted that, at MEPC 80, IMO approved the '*Interim Guidance on the Use of Biofuels under Regulations 26, 27 and 28 of MARPOL ANNEX VI (DCS and CII)'* (MEPC.1/Circ.905). However, it is noticed that synthetic fuels are not included in this, or similar, Guidance. Therefore, this does not allow for a harmonised approach among the various Flag Administrations.

Additionally, while IMO has already adopted the LCA guidelines which account for the life cycle emissions of marine fuels, default emission factors for synthetic fuels have not been included yet. It is also a topic of discussion whether and how the LCA Guidelines (i.e., considering the Well-to-Wake emissions, instead of Tank-to-Wake) can be taken into account in the CII calculation, as well to upcoming mid-term measures which are expected to be decided at future MEPC meetings. At the same time, there have been discussions for the inclusion of LCA Guidelines into EEDI and EEXI, however, this is less probable to happen due to the reasons described above.

##### 3.2.3.3.5 Data Collection System (DCS)

The IMO DCS requires ships with a size of 5,000 GT or more to report their fuel oil consumption, by fuel oil type, to their Administration on an annual basis (Resolution MEPC.278(70)). The fuel oil types are the same as for the EEDI. The DCS does not currently explicitly require ships to report the nature of the fuel. For example, when using methanol, there is no requirement to report whether the fuel is fossil, biological or synthetic.

Therefore, there remains uncertainty as to how to capture all fuels that are in use, and considered for future use, within the DCS reporting, particularly those from lower carbon and bio sources. This has been recognised but remains an area requiring regulatory clarification.

#### 3.2.3.4 SOLAS

The IMO's International Convention for the Safety of Life at Sea, as amended (SOLAS 1974 as amended), lays out the basic safety regulations for most ships travelling internationally. While synthetic fuels are not explicitly discussed, aspects such as overall structure, layout, fire protection, firefighting measures, ship subdivision, machinery space and equipment requirements are included, and are applicable to fuel systems and equipment using synthetic fuels or their blends.

The SOLAS convention comes from a time when coal-powered ships were in operation, and it was the start of the transition to oil-fuelled ships. As such, most of its requirements for fuels are based on the distillate and residual fuels derived from petroleum refining.

Historically, SOLAS has prohibited the use of fuel oils with less than a 60˚C flashpoint, except for use in emergency generators (where the flashpoint limit is 43˚C) and subject to other requirements detailed in SOLAS Chapter II-2 Regulation 4.2.1.

To accommodate growing interest in the application of gaseous and liquid fuels with flashpoints under 60˚C, the IMO adopted the '*International Code of Safety for Ships using Gases or Other Low-Flashpoint Fuels'* (IGF Code) by including a new Part G to SOLAS II-1. See Subsection 3.2.3.4 for more information on the IGF Code.

All liquid biofuels, or biofuel blends, intended as *'drop-in'* fuels to replace conventional residual or distillate fuel oils must meet the SOLAS requirements for a flashpoint (closed cup test) of not less than 60˚C.

In the years preceding the adoption of the IMO global fuel sulphur limit of 0.50% in 2020, concerns were raised on the availability of sufficient quantities of fuel to meet the switch in fuel demand. Those concerns proved largely unfounded, but it was suggested that the marine industry may see more blending of fuel oils derived from the land-based supply chain, which are subject to lower regulatory limits on flashpoints (typically 52-55˚C).

Acceptance of lower SOLAS flashpoints for fuel oils has proven to be a contentious issue. Currently, the IMO has asked the CCC Sub-committee to consider how best to proceed with developing draft amendments to the IGF Code that will address new safety provisions for ships using low-flashpoint oil fuels (see Subsection 3.2.3.4.1).

There is recognition of the need for IMO requirements for such fuels, and it has been suggested that these provisions should cover an increased range of oil-based fossil fuels, liquid biofuels, synthetic fuels – and any mixture thereof – with flashpoints under 60˚C. However, this topic is one of a number within a heavy CCC work programme, and the way ahead has yet to be finalised.

The lack of current regulation for fuel oils with a flashpoint between 52˚ and 60˚C is not seen as a significant barrier to synthetic fuels uptake (since many have flashpoints above 60˚C), however this is a gap in the current IMO instruments.

Under SOLAS II-1/Regulation 3-1 there is also a requirement that '… *ships shall be designed, constructed and maintained in compliance with the structural, mechanical and electrical requirements of a classification society which is recognized by the Administration …*'.

In the context of the application of fuel oils under SOLAS it has to be recognised that the instrument is deliberately limited in requirements. This is to recognise the wide specifications of residual and distillate and blended fuels that are utilised in the maritime sector. IMO also does not mandate fuel supply in accordance with the ISO 8217 standard, and that standard itself does not preclude additional fuel handling and cleaning onboard required to enable use in the machinery and equipment onboard.

#### 3.2.3.4.1 Draft Interim Guidelines for the Safety of Ships using Low-Flashpoint Oil Fuels

The purpose of these [Draft] '*Interim Guidelines for the Safety of Ships Using Low-Flashpoint Oil Fuels'* is to provide an international standard for ships using oil-based fossil fuels, synthetic fuels, biofuels and any mixture thereof with a flashpoint between 52°C and 60°C.

This work is being undertaken by IMO Sub-Committee on Carriage of Cargo and Containers (CCC) and the draft interim guidelines are publicly available through IMO CCC 9/3 and CCC 9/3/Add.1. Annex 2. These interim guidelines are expected to be further developed in CCC 10 being held in September 2024.

The basic philosophy of these Interim Guidelines is to provide provisions for the arrangement, installation, control and monitoring of machinery, equipment and systems using low-flashpoint oil fuels to minimise the risk to the ship, its crew and the environment, having regard to the nature of the fuels involved.

These Interim Guidelines follow the '*Generic Guidelines for Developing IMO Goal-Based Standards'* (MSC.1/Circ.1394/Rev.2) by specifying goals and functional requirements for each section forming the basis for the design, construction and operation of ships using low-flashpoint oil fuels. Ship design and arrangement, fuel containment system, material and general pipe design, bunkering, fuel supply to consumers, power generation including propulsion and other fuel consumers, fire safety, explosion prevention, ventilation, electrical installations, control, monitoring and safety systems and other general requirements are covered within these draft interim guidelines.

#### 3.2.3.4.2 ISM Code

The IMO's '*International Safety Management Code'* (ISM Code) provides an international standard for the safe management and operation of ships and to prevent pollution. Intended to have a widespread application, based on general principles and objectives, this Code requires operators to assess all risks to a specific company's ships, personnel, and the environment, and to establish appropriate safeguards.

With respect to biofuels, the fuel supplier's fuel specifications and Bunker Delivery Note (BDN), Material Safety Data Sheet (MSDS), equipment manufacturer's recommendations and industry stakeholder guidelines would provide the basis for operators to undertake their ISM Code obligations. While there are some potential risks to equipment and operation with synthetic fuels, the *'drop-in'* nature and similarity to conventional residual or distillate fuels makes application relatively straightforward.

The deep-sea fleet particularly are experienced with application of fuels with a wide range of properties and the operational practices for tank cleaning, separation, stability and compatibility checks, fuel changeover procedures, and machinery adjustments for the range of density, viscosity and combustion characteristics that are normal in marine fuel supplies.

Synthetic fuel trials need to be conducted and data needs to be reported publicly to advance their use under the provisions of IMO's MARPOL Annex VI regulations 3.2 or regulation 4 as *'Equivalent'*. For the safety side, there are similarities to the guidance on the development of a ship implementation plan provided by IMO's MEPC.1/Circ.878 for the consistent implementation of the 0.50% fuel sulphur limit; the so called 2020 fuels.

That instrument considers that a ship implementation plan is not mandatory and could cover various items relevant for the specific ship, including the below items, as may be also interpreted as applicable for the application of biofuels:

- Risk assessment and mitigation plan (impact of new fuels);
- Fuel system modifications and tank cleaning (if needed);
- Fuel capacity and segregation capability;
- Fuel changeover procedures;
- Documentation and reporting.

MEPC.1/Circ.878 contains other useful information that may be relevant for application to synthetic fuels and therefore the lack of a synthetic fuel specific recommendations is not seen as a barrier to take up, however industry may benefit from a similar synthetic fuel publication to facilitate a harmonised approach and that can support the ISM Code obligations.

#### 3.2.3.5 IGC Code

Historically, the gas carrier regulations for burning cargo products as fuel, IMO's '*International Code for the* Construction *and Equipment of Ships Carrying Liquefied Gases in Bulk'* (IGC Code), only permitted burning natural gas (methane) as fuel. The adoption of the revised (2016) IGC Code by IMO Resolution MSC.370(93) in May 2014 introduced the option to burn other non-toxic cargoes as fuel.

For gas carriers, the use of natural gas as fuel is permitted under Chapter 16 of the IGC Code. With the adoption of the revised IGC Code in 2014, a new section 16.9 for *'Alternative Fuels and Technologies'* was introduced to permit combustion of other non-toxic cargoes, provided that the same levels of safety as methane are ensured.

Dialogue with the flag Administration is required to develop the roadmap for approval, and the criteria that will demonstrate equivalency. This often includes a risk-based assessment, such as Hazard Identification study (HAZID), and the application of 1.3 of the IGC Code for *'Equivalents'*. When completed, the flag must notify the IMO through the Global Integrated Shipping Information System (GISIS) database.

It is this new provision in the IGC Code that has allowed ethane and LPG cargoes to be burned on the dedicated VLEC and LPG carrier fleets. Nothing within the IMO's statutory safety requirements would prevent gas carriers from transporting synthetic fuel variants of these products, from burning those products as fuel if the demand is established to transport them.

#### 3.2.3.6 IGF Code

In June 2015, by resolution MSC.391(95), the IMO adopted the '*International Code of Safety for Ships using Gases or Other Low-*Flashpoint *Fuels'*, the IGF Code. This introduced the regulatory safety requirements and framework for fuels with a flashpoint less than 60˚C, creating mandatory provisions for the use of natural gas and other low-flashpoint fuels and gases.

At the same time as adopting the IGF Code, the IMO adopted Resolution MSC.392(95), amendments to SOLAS making the IGF Code mandatory by including a new Part G to SOLAS II-1. Under the *'one-ship, one code'* policy, the IMO clarified that, excluding ships that are subject to the IGC Code for burning cargoes as fuel, the IGF Code is applicable to all new ships, and ship conversions, over 500 GT that use low-flashpoint fuels and for which the building contract was placed on or after 1 January 2017.

In the absence of a building contract, the IGF Code is applicable to all ships with a keel laid on or after 1 July 2017, or which were delivered on or after 1 January 2021.

The main structure of the IGF Code is detailed below, but it only includes detailed prescriptive requirements for natural gas (methane) under Parts A-1, B-1 and C-1. In the longer term, additional parts will be added as industry applications and experience grows. Prior to that, it is anticipated that the IMO will issue *'interim guidelines'* to cover other low-flashpoint fuels and gases.

- Part A
  - General
  - Goal and Functional Requirements
  - General Requirements

- Part A-1 - *Specific Requirements for Ships Using Natural Gas as Fuel*

- Part B-1 - *Manufacture, Workmanship and Testing*

- Part C-1 - *Drills and Emergency Exercises*

- Part D - *Training*

The application of all low-flashpoint fuels and gases under the IGF Code includes a risk assessment, which is detailed under Part A *'General Requirements'*. For natural-gas (methane) applications this only needs to be applied when specifically identified in the prescriptive requirements, but all other fuels require a full risk assessment to be conducted using acceptable and recognised techniques for risk analysis.

Other low-flashpoint fuels and gases may be applied, provided they meet the goals and functional requirements of Part A of the IGF Code and an equivalent level of safety. This approval process is met by applying the *'Alternative Design'* criteria referenced under the *'General'* section of part A of the IGF Code.

The equivalency is to be demonstrated as specified in SOLAS II-1/55 for *'Alternative Design and Arrangements'*, which refers to the application of guidelines in MSC.1/Circ.1212. It requires dialogue and approval from the flag administration, with engagement of all stakeholders to develop the roadmap for risk-based approval and the supporting documentation.

Although detailed prescriptive requirements are not given in the IGF Code for all the low-flashpoint fuels and gases under consideration, including their synthetic fuel variants, the goal and risk-based provisions provide a way to apply and to get approval for these fuels. Furthermore, with no significant differences from the safety perspective between methane and e-methane, or methanol and e-methanol, there are no barriers to adoption of synthetic fuels under this IMO instrument.

#### 3.2.3.7 Interim Guidelines for the Safety of Ships Using Methyl/Ethyl Alcohol as Fuel

The IMO's requirements for using methyl/ethyl alcohol fuels were developed under the CCC Sub-committee and approved in principle at the CCC 5 meeting held 10-14 September 2018. Unfortunately, due to workload and COVID delays, these were not approved until MSC 102 in 2020 when MSC.1/Circ.1621 the '*Interim Guidelines for the Safety of Ships Using Methyl/Ethyl Alcohol as Fuel'* was approved.

These interim guidelines adopted the same basic structure and layout as the IGF Code, including the detailed prescriptive requirements, but they were adapted to the specific fuel characteristics of methanol and ethanol. The provisions still include the option to apply the *'Alternative Design'* process if deviating from the prescriptive requirements or applying novel arrangements. In all cases, this will require a risk-assessment.

As indicated above, under the adopting SOLAS amendments for the IGF Code it was clarified that only IGC Code gas carriers that are exempt from the application of the IGF Code. Therefore, ships falling under the IBC Code are also subject to the IGF Code when burning cargoes as fuel. The MSC.1/Circ.1621 interim guidelines facilitate the burning of methyl alcohol cargoes, including e-methanol, on IBC Code ships. These interim guidelines are one of the factors driving increased interest in the application of methanol as fuel, demonstrated by recent construction orders for methanol-fuelled containerships and related projects in supplying e-methanol (Maersk, 2022).

As with all the low-flashpoint fuels and gases, there are additional safety requirements compared to conventionally-fuelled ships. However, because methyl/ethyl fuels are liquid at ambient temperatures and pressures, these are simpler to store and distribute than cryogenic or gaseous fuels. The guidelines include requiring protective cofferdams to integral fuel tanks and nitrogen blanketing of fuel-tank vapour spaces but allow fuel to be stored next to the shell plating below the lowest possible waterline.

#### 3.2.3.8 Development of a safety regulatory framework to support the reduction of GHG emissions from ships using new technologies and alternative fuels (MSC)

IMO's Maritime Safety Committee (MSC) has recognised the need to ensure that there are suitable provisions for the safe operation of the new technologies and alternative fuels on ships that will support to achieve the IMO ambition for net zero GHG emissions.

In MSC 107 a Correspondence Group has been established to prepare a report for MSC 108 on the Development of a Safety Regulatory Framework to Support the Reduction of GHG Emissions from Ships Using New Technologies and Alternative Fuels. In this report, a list of fuels and technologies that could enable the reduction of GHG emissions from ships has been summarized. For each of those, the report contained an assessment of technical aspects, hazards, and risks to ships and shoreside, while the obstacles related to safety and gaps in existing regulations were also discussed.

The analysis revealed that the use of alternative fuels and new technologies will add new complexities and risks to the onboard ship systems. Therefore, further consideration should be given to the human element, crew training and ship-specific familiarization to ensure a safe operation.

The Correspondence Group is going to continue the work and submit an interim report to MSC 109 with recommendations to address each of the identified barriers as well as gaps in the current IMO instruments that may hinder the safe use of those alternative fuels and or new technologies.

It is noted that in this analysis, there has not been a distinction related to the production pathway of a fuel (unless this presents unique safety issues that need to be addressed) since it is expected that this will not impact the risks and hazards from its use.

### 3.2.4 International Bunker Industry Association

The International Bunker Industry Association (IBIA) is based in the United Kingdom, with branches in Africa and Asia, representing industry stakeholders. Its membership is broad and includes owner/operators, bunker suppliers, traders, brokers and port authorities. IBIA has consultative status at the IMO as a non-governmental organisation and is an important and active player in providing technical information to the IMO on marine fuel specifications, fuel sampling, etc.

IBIA develops positions on IMO regulations and industry guidance or best practice publications, both directly and as contributors. The joint-industry guidance document '*The supply and use of 0.50% sulphur marine fuel*' is an example.

To support industry adoption of alternative marine bunker fuels, IBIA has created the Future Fuels Working Group, which has been undertaking an assessment of the associated technologies and fuels. As the results of this ongoing assessment become final, they will be available to IBIA members (IBIA, 2022).

### 3.2.5 International Methanol Producers and Consumers Association

The International Methanol Producers and Consumers Association (IMPCA) is active in supporting the handling and transport of methanol. The IMPCA '*Procedures for Methanol Cargo Handling on Shore and Ship*' intends to provide a standardised process for sampling that may be applied in the movement of methanol from producer to end user. Developed in consideration of other established standards and best practices from IMO, ISGOTT and others, these procedures can facilitate take up of e-methanol as a marine fuel.

The IMPCA methanol specification is also incorporated in the Methanol Institute sponsored study by Lloyd's Register, '*Introduction to Methanol Bunkering Technical Reference'*, which provides a checklist and process flow approach to safely handle methanol bunkering transfers. This document also fills some of the regulatory and best practice gaps for supply of marine methanol and e-methanol.

### 3.2.6 IACS Classification Societies

Classification societies play an active maritime role in assuring the safety of life, property, and the environment. The members of IACS collectively make a unique contribution to maritime safety and regulation by providing technical support, compliance verification (of statutory instruments in their role as Recognised Organizations) and research and development. The collaborative effort of multiple class societies in IACS leads to the implementation of common rules, unified requirements (UR) for typical Class Rules, unified interpretations (UI) of statutory instruments and other recommendations that are applied consistently by IACS members.

With reference to the application of classification society requirements under SOLAS II-1/3-1 given under 3.2.3.1 above, it is typical for Class societies to require demonstration onboard of the suitability of residual fuel oils, or other special fuel oils (which may be considered to include synthetic fuels) to validate operation on such fuels. This is given in IACS members rules and originates from IACS UR M51, '*Factory Acceptance Test and Shipboard Trials of I.C. Engines*', which requires that '*the suitability of the engine to operate on fuels intended for use is to be demonstrated*'.

This requirement supports the type-approval of engines; however, e-diesels are not a type defining parameter under IACS UR M71, '*Type Testing of I.C. Engines*', and are grouped under the liquid fuels category. This means a repeat of the type test and engine recertification is not required. The verification of liquid fuels other than those used at type test (typically DM grade) is through the shipboard demonstration. For other synthetic fuels, the application of further shipboard trials is on a case-by-case basis in consideration of the specific synthetic fuel to be applied. Clarification of this under UR M51, or other IACS instrument, would facilitate harmonised application.

For synthetic fuels such as e-methanol or e-methane, additional rules and guidance may be available from class to standardise the use and handling of low-flashpoint fuel on vessels. While these may not be specific to synthetic fuels, e-derived fuels with similar chemical makeups to petroleum-based low-flashpoint fuels may fall under the scope of the same rules and guides. The shipboard trials referenced above would be applied for application of the fossil derived methanol or LNG during construction or conversion to the low-flashpoint fuel and would not be required when that installation switches to the chemically consistent e-methanol or e-LNG products.

Low-flashpoint and gaseous fuels are often handled and used very differently than conventional liquid petroleum marine fuels, so additional provisions and safety measures should be established onboard vessels. Class societies include these provisions in their rules or guides covering alternative, low-flashpoint, or gaseous fuels.

Some class rules and guides follow or take after IMO codes or guidelines, while others may preclude the adoption of such international instruments. In the latter case, after IMO requirements are adopted, adaptation of class rules and guides is usually required. Where IACS have adopted URs, these must be uniformly applied by IACS members in their rules. Similarly, where IACS UIs exist to statutory requirements, these are, by purpose, to facilitate harmonised application of the regulations. Currently no such IACS publications related to synthetic fuels exist.

Where no class rules or guides exist for a synthetic fuel, class societies may offer advisory or consultancy services regarding the adoption of synthetic fuels and synthetic fuel blends for use on vessels, including risk assessments, review of statutory requirements or international standards and recommendations for approval on a trial basis or as *'equivalent'* arrangements.

## 3.3 Regulations for EU member states

On 14 July 2021, the European Commission presented *'Fit for 55'* (see Figure 17), a package of measures that seeks to align EU policies on climate, energy, land use, transport and taxation in such a way that the net GHG emissions can be reduced at least 55% by 2030, compared to 1990. It contains proposals for revising regulations and directives and some new policy initiatives.

### *AFIR*

The alternative fuels infrastructure regulation (AFIR) is part of the *'Fit for 55'* package. On 14 July 2021, the Commission submitted to the European Parliament and to the Council the proposal for a Regulation on the deployment of AFIR, as part of the *'Fit for 55'* package. The objective of the AFIR proposal is threefold:

- first, to ensure that there is a sufficient infrastructure network for the (re)charging or (re)fuelling of road vehicles or vessels with alternative fuels;
- second to provide alternatives to the use of onboard engines (powered by fossil fuels) for vessels at berth or stationary aircraft, and
- third to ensure full interoperability and user friendliness of the infrastructure.


*Figure 17. The European Commission 'Fit for 55' package.*

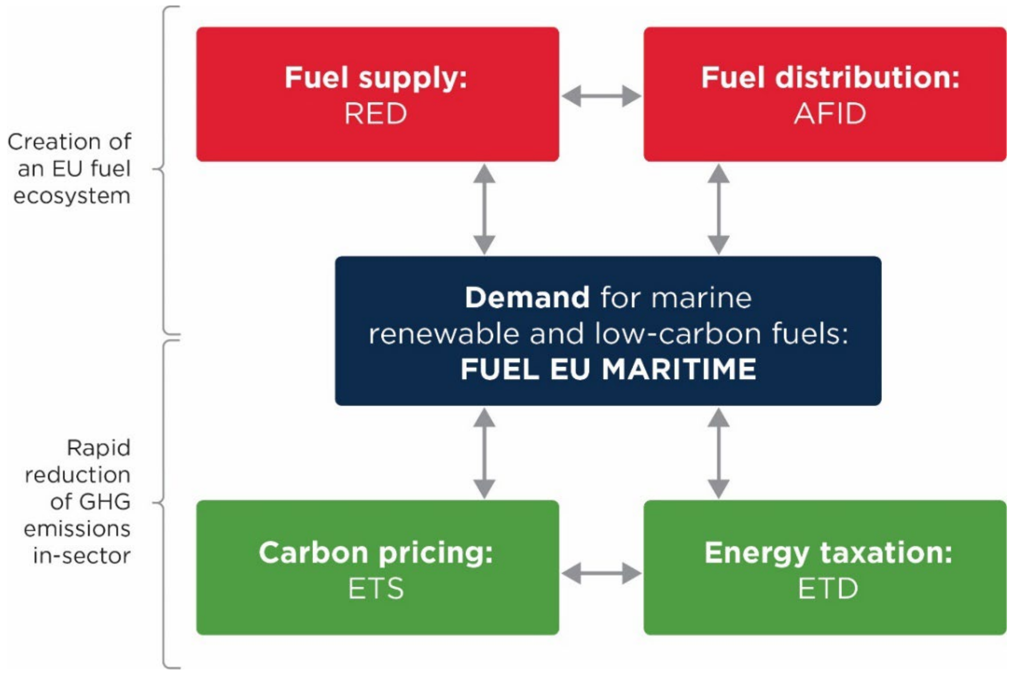


*Figure 18. EU policies related to maritime transport.*

### *FuelEU Maritime*

As part of the *'Fit for 55'* package, the EC launched the FuelEU Maritime Initiative to increase demand for renewable and low-carbon fuels (RLF) for ships sailing to and from EU ports. It also sought to reduce the emissions from navigation and at berth, and to support EU and international climate objectives.

FuelEU Maritime sets a harmonised regulatory framework in the EU and aims to increase the share of renewable and low-carbon fuels used in the fuel mix for international maritime transport, including: liquid biofuels, e-liquids, decarbonised gas (including bio-LNG and e-gas), decarbonised hydrogen and its derived fuels (including methanol and ammonia) and electricity.

The initiative will contribute to wider goals by pursuing specific objectives to:

- Enhance predictability by setting a clear regulatory environment for the use of RLF in maritime transport;
- Stimulate technology development;
- Stimulate production on a larger scale of RLF with high technology readiness levels (TRLs) and reduce the price gap with current fuels and technologies;
- Create demand from ship operators to bunker RLF or connect to electric grid while at berth;
- Avoid carbon leakage.

FuelEU Maritime will require ships of 5,000 GT and above to gradually reduce the GHG intensity limits of energy used onboard against the 2020 benchmark average value by:

- 2% as of 2025
- 6% as of 2030
- 14.5% as of 2035
- 31% as of 2040
- 62% as of 2045
- 80% as of 2050

This will cover 100% of the energy used on intra-EU voyages and 50% of the energy on extra-EU voyages. It is also notes that in 2028 the Commission will review whether the 5,000 GT threshold should be lowered and if the requirements of the Regulation should be tightened.

Depending on the actual GHG intensity of a vessel compared to the target GHG intensity, a compliance balance will be calculated. If the compliance balance is negative, then a penalty in Euro will be calculated for each vessel. Positive compliance balance will create a surplus.

To incentivise the use of RFNBOs FuelEU has included a provision for a multiplier of 2 (RWDi) in the calculation of GHG intensity to reward the ships using such fuels until the end of 2033, allowing their energy to count twice. This will result in a reduction in the potential penalty, aiming to compensate for the expected higher price of those fuels.

It is worth noting that to further incentivise the use of RFNBOs the European Commission will be monitoring the uptake of RFNBOs and if the share of RFNBOs for the reporting period 2031 is less than 1%, then a 2% target will be set in the yearly energy used onboard as of 2034. In case this 2% target is not met, ships that will be required to pay a remedial penalty. This will be equivalent to the compliance balance of RFNBOs, calculated as the difference between the 2 percent of the total energy used onboard minus the total energy that comes from RFNBOs, multiplied with the price difference between RFNBOs and fossil fuel compatible per tonne VLSFO. For ships that have compliance deficits for either GHG intensity or RFNBOs target for two or more consecutive years penalties will be increased.

It is noted that in case that a ship has a compliance surplus (either on the GHG intensity or the sub-target for RFNBOs), the company may use it for the same ship in the following reporting period.

Regarding emission factors, default values are given in Annex II of FuelEU Maritime Regulation for fossil fuels, biofuels and RFNBOs. Particularly for biofuels and RFNBOs, FuelEU Regulation refers to RED Directive. These fuels shall meet the sustainability and GHG savings criteria. The default or actual values certified under a scheme that is recognised by the commission can be used.

### *EU Emission Trading Scheme (EU ETS)*

Another important part of the *'Fit for 55'* package, the EC decided under Directive 2023/959 to extend to maritime transport the scope of the EU Emissions Trading System (EU ETS), which was established by Directive 2003/87/EC of the European Parliament. This system has two principles: setting a ceiling on the yearly maximum amount of GHG emissions; and enabling the trading of EU emission allowances. These principles aim to contribute to the wider EU goal to eliminate at least 55% of the continent's net GHG emissions by 2030, compared to 1990.

From 2025, shipping companies will have to surrender sufficient EU emission allowances based on the EU Monitoring, Reporting and Verification (MRV) data of the previous year. If the allowances prove insufficient, additional allowances can be acquired, or a reduction of the carbon emissions will be needed. For each tonne of $CO_2$-equivalent that has been emitted without surrendering allowances, shipping companies will have to pay a penalty of €100.

To ensure a smooth transition of the shipping industry to the EU ETS scheme, companies will have to surrender allowances for 40% of the verified emissions in 2024 and 70% in 2025. From 2026 onwards, 100% of the verified emissions will be considered.

Since shipping companies will be paying for the $CO_2$ they emit, this system can stimulate lower output; it will be up to them to determine the method by which that is achieved. Although renewable fuels can reduce GHG emissions, the adoption of renewable fuels would not be directly stimulated by the shipping industry implementing EU ETS (EC, 2021).

As of now, emissions due to combustion of sustainable biomass which is meeting the sustainability criteria set by EU RED has a zero $CO_2$ emission factor under EU ETS. The final determination of this allowance for RFNBO and Recycled Carbon Fuels (RCF) is yet to be finalised with the implementation of legislation which is expected to be developed and adopted under Article 14 of EU ETS. However, it can be expected that the $CO_2$ emission factor of such fuels will be less compared to the fossil counterparts, resulting in reduced carbon cost.

### *Renewable Energy Directive (RED)*

The Renewable Energy Directive (RED) is an EU instrument aiming to promote the use of energy from renewable sources. The second phase of RED (RED II – Directive EU/2018/2001) set an overall target to use at least 32% renewable energy by 2030, including a specific *'RES-T'* target of at least 14% renewable energy in the final energy consumption (level of energy consumed after losses) from transport (road and rail) by 2030.

The renewable energies in transport could consist of biofuels, RFNBOs and include recycled carbon fuels meeting the sustainability requirements. For biofuels and RFNBOs, FuelEU Regulation refers to RED II Directive. Biofuels and RFNBOs shall meet the sustainability and GHG savings criteria contained in Article 29 of RED II. With respect to renewable fuels in maritime shipping, the RED II has been allowing member states to apply those fuels towards their RES-T target.

The RED II's impact assessment identified an additional challenge specific to the maritime sector: the juxtaposition of the shipowners' and operators' incentives does not work to stimulate the deployment of renewable fuels.

In response, and to introduce incentives for the maritime and aviation sectors, fuels supplied to either are measured at 1.2 times their energy content (except for fuels produced from food and feed crops) when demonstrating compliance with the renewable-energy target. By this 20% extra counting, there are implications for fuel volumes; as lower fuel volumes are required to meet the target, the amount by which GHG emissions will be reduced may be adversely impacted.

Because of the higher ambitions of the European Green Deal for reducing net GHG emissions by at least 55% by 2030, the RED has been revised. The new RED III (Directive EU/2023/2413) entered into force on the 20th of November 2023. This is to be implemented by all Member States in their national law by the 21st of May 2025. To achieve the 2030 target, RED III increased the overall binding target for renewables in the EU energy mix to 42.5%, aiming for 45%, from the previous 32%.

Regarding the transport sector, Member States will need to set an obligation to fuel suppliers so that the amount of renewable fuels and renewable electricity supplied to the whole sector (including shipping and aviation) will lead to either a share of at least 29% of renewables within the final consumption of energy in the transport sector by 2030 or a 14.5% reduction of greenhouse gas intensity in transport from the use of renewables by 2030. At the same time, an additional sub-target is set for 1% in 2025 and 5.5% by 2030 for advanced biofuels, biogas and RFNBOs in the energy supplied to the transport sector, including a 1% target for RFNBOs.

To ensure that RFNBOs contribute to the GHG reduction, electricity from renewable origins should be used to produce fuels. RED is supplemented by the RFNBO delegated regulation (EU) 2023/1184, which dictates the rules to produce such fuels, and (EU) 2023/1185, which sets a methodology for assessing their GHG emissions.

To be noted that the energy from RFNBOs shall be counted towards Member States' shares of renewable energy and the targets only if the greenhouse gas emissions savings from the use of those fuels are at least 70% compared to their fossil counterparts. Three other criteria also apply related to temporal correlation, geographical correlation and additionality.

There are already several EU approved voluntary and national certification schemes that will certify RFNBOs as produced in a sustainable way, complying with the above criteria and relevant methodologies. As of April 2024, the Commission has recognised 15 different voluntary and national certification schemes. These are:

- *Biomass Biofuels Voluntary Scheme (2BSvs)*
- *Better Biomass*
- *Bonsucro EU*
- *International Sustainability and Carbon Certification (ISCC EU)*
- *KZR INiG system*
- *REDcert*
- *Red Tractor Farm Assurance Combinable Crops & Sugar Beet Scheme (Red Tractor)*
- *Roundtable of Sustainable Biofuels EU RED (RSB EU RED)*
- *Round Table on Responsible Soy EU RED (RTRS EU RED)*
- *Scottish Quality Farm Assured Combinable Crops (SQC)*
- *Trade Assurance Scheme for Combinable Crops (TASCC)*
- *Universal Feed Assurance Scheme (UFAS)*

- *Sustainable Resources (SURE) voluntary scheme*
- *Sustainable Biomass Program (SBP)*
- *Austrian Agricultural Certification Scheme (AACS)*

Sustainable biofuels and RFNBOs can either use the default values as provided in Annex II and RED II Directive or actual values certified under a scheme that is recognised by the commission.

Considering the regulatory and technological constraints for the use of such fuels from the maritime sector, for the purpose of the calculation of the GHG intensity reduction and the renewable energy share in transport, the energy supplied to the maritime transport sector will be capped at 13% of the gross final consumption of energy in a Member State.

Additionally, to enable the shift to renewable energy in maritime sector, RED III stipulates that Member States having maritime ports shall endeavour to ensure that the share of RFNBOs supplied to the maritime transport are at least 1.2% of the total amount of energy by 2030.

#### *Fuel Quality Directive (FQD)*

The EU's Fuel Quality Directive (FQD) had a reduction target for the average GHG intensity of transport fuels by at least 6% by 2020. With the RED III, the GHG intensity target has been replaced by the 2030 target for transport.

#### *Energy Taxation Directive (ETD)*

Taxation initiatives at the EU and member-state level help industries to reach the climate-policy goals by encouraging a switch to cleaner energy. The EU's ETD entered into force in 2003, offering structural rules and minimum rates for excise duties to tax the energy products that are used as motor and heating fuels, and for electricity.

Individual member states are free to set their own rates provided the directive's minimum rates are respected.

Some sectors, such as aviation and maritime transport, until now have been fully exempt from energy taxation in the EU. However, a revision of the ETD was proposed in the EU's *'Fit for 55'* package under which these sectors would no longer be fully exempted. It introduces a new structure of tax rates based on the energy content and the environmental performance of fuels and electricity. This will help the system to ensure the most polluting fuels are taxed at the highest levels.

The revision also broadens the taxable base by including more products into the scope and removing some of the current exemptions and reductions (EC, 2020). However, it is noted that the revision of the ETD has not been adopted yet.

### 3.3.1 CEN/CENELEC Standards

CEN, the European Committee for Standardization, is one of three European standardisation organisations (together with CENELEC and ETSI) that bring together the national standardisation bodies of 34 European countries.

CWA 17540:2020 – *Ships and marine technology – 'Specification for bunkering of methanol-fuelled vessels'*. This CEN Workshop Agreement (CWA) was drafted and approved by a workshop of interested parties and submitted for approval in April 2020. Produced to meet an industry need for methanol bunkering standards, it can be applied to e-methanol bunkers and acts as a guideline for requirements for bunkering methanol to vessels. This CWA covers four main elements:

- Guidelines for usage of hardware and transfer system
- Operational procedures
- Requirement for the methanol provider to provide a BDN, and
- Training and qualification of personnel involved.

In the absence of standards covering specific synthetic fuels, particularly marine standards, it is typical that compliance with existing land-based diesel fuel standards are used to benchmark the fuels at the commercial level. For European countries this is the EN 590 standard detailed by EU Directive 2009/30/EC, which establishes minimum specifications for petrol and diesel fuels for use in road and non-road mobile applications. For example, the so- called *'drop-in renewable diesels'* such as HVO meet the EN 590 and ASTM D975 diesel fuel standards.

## 3.4 Other relevant regulation from other Nations

### 3.4.1 Canada

The Regulations for the Prevention of Pollution from Ships and for Dangerous Chemicals (SOR/2007-86, 30 March 2012) under the Canada shipping act are aligned with MARPOL Annex VI and require limits to ozone-depleting substances and offers fuel-quality specifications. In 2013, the country's *'Regulations Amending the Vessel Pollution and Dangerous Chemicals Regulations'* implemented MARPOL Annex VI rules to reduce air pollution and the greenhouse gas emissions from vessels.

### 3.4.2 China

The Chinese government has initiated plans to reduce emissions from shipping, first with restrictions of residual fuel oils at and near ports and by reducing the allowable $SO_X$ and particulate matter emissions from ships.

The introduction of domestic emission control areas (DECAs) intends to reduce the sulphur content in the marine fuels consumed in those areas, originally three major coastal regions: the Pearl River Delta; the Yangtze River Delta; and the Bohai Rim; the DECA was later extended to 12 nautical miles off the coast of mainland China (Song, 2017).

China also has intent to increase the number of domestically owned LNG-fuelled vessels plying its waters to reduce the volumes of heavy marine residual fuels. While the initiative is in place, there are current difficulties identifying a consistent way to evaluate the DECA policies nationwide. Therefore, guidance on further ship-emission controls is not clear.

Overall, the initial DECA policies reduced $SO_2$ and particulate-matter emissions between 2016 and 2019 by 29.6% and 26.4%, respectively, within China's 200 nm control zone[1]. The uptake of biofuels in these areas could continue to contribute to reduced $SO_X$ and particulate matter emissions.

However, $NO_X$ emissions from ships appear to have increased during the four years of the evaluation, likely due to the common use of older ships and low engine standards for the new ones. $NO_X$ emissions may be of concern when using some synthetic fuels, so stringent limits on $NO_X$ may not encourage synthetic fuel use. More clarity on government policy for ship emissions and fuels may appear if China's coastal waters receive international status as environmental control areas.

### 3.4.3 Japan

Japan's *'Roadmap to Zero Emission from International Shipping (March 2020)'* was jointly published by the Japan Ship Technology Research Association, The Nippon Foundation and the Japan Ministry of Land, Infrastructure, Transport and Tourism as a part of the Shipping Zero Emission Project. Aligned with the *'Initial IMO Strategy on Reduction of GHG Emissions from Ships'* to phase out greenhouse gases as soon as possible this century, the roadmap highlights two emission pathways for achieving the 2050 target and beyond.

- Emission Pathway I: *'a fuel shift from LNG to carbon-recycled methane'*
- Emission Pathway II: *'the expansion of hydrogen and/or ammonia fuels'*

Pathway I detailed the transition from petroleum-based LNG fuels to bio-methane from 2025 and increased use of carbon-recycled methane from 2030. It assumes that carbon-recycled bio-methane will account for approximately 40% of the energy consumption within international shipping in 2050, that carbon-recycled methane and biofuels will be become available in sufficient volumes and that they will be recognised by the IMO or other bodies as carbon-neutral fuels.

For this pathway to be realised, the report recognises that emerging regulatory measures from the IMO that promise guidelines for the life cycle GHG and carbon-intensity of fuels also may need to address cross-border issues for carbon-recycled fuels and biofuels (JSTRA, 2020).

For coastal ships, Japan is discussing developing a decarbonisation roadmap. This may be a complicated process due to Japanese coastal marine industry being dominated by small enterprises and limited capital for change.

### 3.4.4 South Korea

The recent adoption of domestic emission control areas for Korean ports – including Incheon, Pyeongtaek-Dangjin, Yeosu-Gwangyang, Busan and Ulsan – has encouraged the adoption of alternative marine fuels to meet more stringent fuel sulphur limits.

From September 2020, ships anchored or at berth in those ECAs must use fuel with sulphur content limit of 0.10%; from January 2022, ships anywhere in the ECAs must adhere to the limits at all times.

Other methods of compliance include the use of scrubbers for cleaning exhaust gases; using clean fuel (e.g., LNG) also will be accepted by South Korean authorities to meet the sulphur limits. In general, these limits could contribute to the to near-shore adoption and use of marine biofuels (Gard, 2020) and e-fuels.

### 3.4.5 Canal Requirements in Panama (Panama Canal) & Egypt (Suez Canal)

***Panama Canal***

According to the January 2020 NT Notice to Shipping No. N-1-2020 from the Panama Canal Authority (ACP), which acknowledges that the IMO MARPOL Annex VI regulation 14 ECAs do not include Panama, vessels entering the Panama Canal are required to use *'lighter'* fuels.

Mainly, this is expected to involve switching from residual to marine distillate fuels, while recording the changeover and verifying proper engine operation with the lighter fuel. Using distillate manoeuvring fuel can reduce the particulate matter from stacks and improve the air quality around the canal.

***Suez Canal***

The Suez Canal Authority (SCA) Circular No. 8/2019 does not explicitly restrict fuel oils from being used during transits through the Suez Canal. It states that there are no restrictions on open-loop exhaust gas cleaning systems, except that the wash water cannot be discharged into canal waters.

In other words, a vessel may have an open-loop exhaust gas cleaning system, but it may not operate when transiting. Operators are free to turn the systems off and release exhaust gases from heavy marine fuel oils. This also appears to be the case until the Arab Republic of Egypt ratifies MARPOL Annex VI, which will likely impose restrictions on manoeuvring fuel in ships transiting through the canal.

However, most transiting vessels are under the authority of flag administrations who are signatories to MARPOL Annex VI, and therefore would be required to use low-sulphur fuel oil when an onboard open-loop exhaust gas cleaning system cannot be operated with heavy marine fuel oil.

The current fuel requirements for the canal do not contribute to the uptake of marine synthetic fuels or encourage a switch to alternative marine fuels.

## 3.5 Gap Analysis

The regulatory framework for rules, standards, guidelines, recommendations and best practices, etc., for synthetic fuels is tabulated in detail in Appendix C – Detailed Regulatory Gap Analysis of this study. This highlights where the existing publications contribute to or restrain industry adoption of the synthetic fuels under review.

As referenced throughout this section of the study, there are ‘gaps’ that will restrain adoption of synthetic fuels. Notably, these gaps are within IMO safety and environmental regulation and international standards.

Discussion and recommendations are provided to encourage further consideration about developing policy to improve the adoption of synthetic fuels. A synopsis of the key findings is presented in Table 19 and Table 20.

*Table 19. Gap Analysis Legend.*

| |
|---|
| No Gap or Changes needed to address synthetic fuels |
| Small Gap or Minor Change to address synthetic fuels |
| Medium Gap or Some Challenging Change to address synthetic fuels |
| Large Gap or Many Challenging Changes to address synthetic fuels |

*Table 20. Synopsis on Regulatory Gap Analysis for Synthetic Fuels.*

| Subject | Rule/Guidance | Comment on Code/Standard - Gaps |
|---|---|---|
| Sustainability and Emissions Regulations | MARPOL Regulations 13 – Nitrogen Oxides ($NO_X$) and Regulation 18 – Fuel oil availability and quality | There are variations in $NO_X$ emissions from the use of synthetic fuels and synthetic fuel blends (it depends on the engine, load and specific fuel). The $NO_X$ Technical Code has limited provisions for the certification of $NO_X$ with synthetic fuels and there is uncertainty about the application of Regulation 18.3.2.2. |
| | MARPOL Regulation 14 – Sulphur Oxides (SOX) and Particulate matter | IMO's ECA fuel-sulphur limit of 0.1% (1,000 ppm) is less stringent than land-based regulations. Synthetic fuels have less sulphur than what is required by the regulation but are not directly encouraged or incentivised for adoption by the IMO’s fuel sulphur limits. |
| | MARPOL Chapter 4 – Regulations on the Carbon Intensity of International Shipping | Required calculations for ships energy efficiency and carbon intensity using various methods, including EEDI, EEXI or CII are based on limited current fuel carbon factors. Clarification of how to incorporate synthetic fuels into these calculations to meet EEDI, EEXI, or CII values and DCS reporting is needed. The ability to certify ships with alternative (certified) fuel carbon factors, at design and during operation, may encourage the uptake of synthetic fuels as shipowners look for ways to reduce their carbon footprint and increase efficiency. It is noted that IMO LCA Guidelines have been adopted but they will be under technical review and further development can be expected. Synthetic fuels are expected to be included and may close the gap in the future. |
| | EU Renewable Energy Directive (RED) 2009/28/EC | Could be more effective if provisions within the directive were officially recognised and/or adopted in non-member states and international governance policy. This would expand the applicability of the directive beyond the scope of the EU. |
| | EU Fuel-Quality Directive (FQD) 2009/30/EC | The EU’s Fuel Quality Directive (FQD) had a reduction target for the average GHG intensity of transport fuels by at least 6% by 2020. With the RED III, the GHG intensity target has been replaced by the ambitions 2030 target for transport. |
| | FuelEU Maritime | To further incentivise the use of RFNBOs FuelEU has included a provision for a multiplier of 2 (RWDi) until the end of 2033. This will be used in the calculation of GHG intensity to reward the ships using such fuels, allowing their energy to count twice. |

| Subject | Rule/Guidance | Comment on Code/Standard - Gaps |
|---|---|---|
| Storage | American Petroleum Institute API RP 1640Product Quality in Light Product Storage | Although covering gasoline, kerosene, diesel, heating oil and their blend components (i.e., ethanol, bio-diesel/FAME, and butane), could be more useful if it covered other synthetic fuel types. |
| Transportation & Handling | IMO Code for Construction and Equipment of Ships Carrying Liquefied Gases (IGC Code) | Could benefit from clarifying current Code covers transport of synthetic equivalents such as e-LNG or updated as necessary. |
| | International Code for the Construction and Equipment of Ships Carrying Dangerous Chemicals in Bulk (IBC Code) | Covers carriage of biofuel equivalents such as bio-methanol in association with other IMO instruments covering energy-rich fuels and application of MARPOL Annexes I and II, however, synthetic fuels are not directly addressed. |
| | Guidelines for the Carriage of Energy-Rich Fuels and their Blends (MEPC.1/Circ.879) and Guidelines for the Carriage of Blends of Biofuels and MARPOL Annex I Cargoes (MSC-MEPC.2/Circ.17) | Considered covers carriage in bulk of biofuel blends and energy-rich fuels in bulk, however, synthetic fuels are not directly addressed. |
| | IBIA, IMPCA, Methanol Institute | Could include dedicated marine bunkering guidance for synthetic fuels or add clarification that there is no change in bunkering for synthetics as compared to traditional fuels. |
| Use & Consumption | IMO International Code of Safety for Ships using Gases or other Low-Flashpoint Fuels (IGF Code) | Future amendments should include detailed prescriptive requirements for other gaseous and low-flashpoint fuels, including the synthetic-derived variants, and prior to amendments can support take- up through the development of interim guidelines similar to the methyl/ethyl alcohol precedent. |
| | IMO International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) | Some differences between IGC Code and IGF Code hamper harmonised requirements. |
| | IMO MSC.1/Circ.1621 – Interim Guidelines for the Safety of Ships Using Methyl/Ethyl Alcohol as Fuel | No significant gaps for supporting application of synthetic methanol as a marine fuel. |
| | SOLAS and IMO International Code of Safety for Ships using Gases or other Low- Flashpoint Fuels (IGF Code) | Fuel oils (which may include synthetic fuels) with lower than 60˚C flashpoint currently not covered within SOLAS or IGF Code. That said, work is ongoing at IMO CCC on Draft Interim Guidelines for the Safety of Ships using Low-Flashpoint Oil Fuels. These will cover synthetic fuels with a flashpoint between 52ºC and 60ºC. |
| | SOLAS ISM Code, SOLAS II-1/Regulation 3-1 and classification society requirements | SOLAS ISM Code requires operators to assess all risks to a company's ships. SOLAS also requires equipment compliance with classification society rules. Synthetic fuels are not an engine type defining parameter, but onboard demonstration of suitability typically required. IMO guidance similar to MEPC.1/Circ.878 for bio-diesels and clarification on application via IACS UR missing. |

| Subject | Rule/Guidance | Comment on Code/Standard - Gaps |
|---|---|---|
| | ISO 22548:2021. Ships and marine technology – Performance test procedures for LNG fuel gas supply systems (FGSS) for ships | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic-derived alternative fuels or used as basis for development of new standard(s). |
| | ISO 22547:2021. Ships and marine technology – Performance test procedures for high-pressure pumps in LNG fuel gas supply systems (FGSS) for ships | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic-derived alternative fuels or used as basis for development of new standard(s). |
| Quality | ISO 8217:2017 Petroleum products – Fuels (class F) – Specifications of marine fuels | Limits allowed liquid biofuel blends to de minimis or only up to 7% FAME in the DFA, DFZ and DFB grades. Industry experience indicates the specific energy calculation is not accurate for synthetic fuels. Standard could be revised to allow higher blend percentages of qualified synthetic fuels in marine fuels. |
| | ISO/PAS 23263 Petroleum Products – Fuels (class F) – Considerations for fuel suppliers and users regarding marine fuel quality in view of the implementation of maximum 0,50% sulphur in 2020 | Could incorporate these considerations into the next ISO 8217 revision. |
| | IMO Prevention of Pollution from Ships (MARPOL) Convention – Regulation 18 – Fuel Oil Availability and Quality | There is uncertainty on the application of regulation 18.3.2.2 for $NO_X$. Annex VI should add required clarifications for suppliers of synthetic fuels regarding the $NO_X$ emissions resulting from the synthetic fuel and other relevant synthetic specific requirements such as BDNs and CF factors that may be applicable. |
| | ISO 23306:2020 Specification of liquefied natural gas as a fuel for marine applications | Standard does not define a minimum MN value (requires the minimum to be agreed between supplier and user) or a limit on debris, therefore could benefit from including limits for those characteristics. |
| | ISO/CD 6583 Specification of methanol as a fuel for marine applications | Ongoing standard development should ensure coverage of fuels derived from renewable sources (i.e., e-methanol). |
| Bunkering | ISO/TS 18683:2021 Guidelines for safety and risk assessment of LNG fuel bunkering operations | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic-derived alternative fuels or used as basis for development of new standard(s). |
| | ISO 20519:2021 Ships and marine technology – Specifications for bunkering of liquefied natural gas-fuelled vessels. | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standard(s), where similar low-flashpoint, gaseous or toxicity risks to ports exist. |
| | ISO 28460:2010 Petroleum and natural gas industries – Installation and equipment for liquefied natural | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standard(s), where similar low-flashpoint, gaseous or toxicity |

| Subject | Rule/Guidance | Comment on Code/Standard - Gaps |
|---|---|---|
| | gas – Ship-to-shore interface and port operations | risks to ports exist. |
| | ISO 21593:2019 Ships and marine technology. Technical requirements for dry- disconnect/connect couplings for bunkering liquefied natural gas | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). |
| | ISO/TS 16901:2022 – Guidance on performing risk assessment in the design of onshore LNG installations including the ship/shore interface | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). |
| | ISO 16904:2016. Petroleum and natural gas industries - Design and testing of LNG marine transfer arms for conventional onshore terminals | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). |
| | ISO/TS 18683:2021 - Guidelines for safety and risk assessment of LNG fuel bunkering operations | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). |
| | ISO/TR 17177:2015. Petroleum and natural gas industries - Guidelines for the marine interfaces of hybrid LNG terminals | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). |
| | ISO/AWI 22238 [Under Development] - Design, construction and testing of high-pressure gas transfer systems | This document addresses requirements for design, construction and testing of high-pressure transfer systems for FSRU/ FRU/ FSU applications. High-pressure transfer systems are considered to be ship-to-shore systems transferring pressurised gas from floating units to any part of a gas grid. This document could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). |
| | MI/LR – Introduction to Methanol Bunkering Technical Reference | Supports the adoption of methanol and e-methanol as marine fuels. |
| IACS Classification Societies Rules, Guides and Guidance | | More could be done to encourage industry adoption of synthetic fuels. Currently no IACS publications related to synthetic fuels exist. |
| Regional and National Rules for Marine Fuel, including Synthetic Fuels as Marine Fuel | | Regional and national regulations can lead developments at IMO level. Wider adoption of IMO (or regional or national regulations) in those locations lacking all such instruments, could uniformly support the adoption of synthetic fuels. |

## 3.6 Marine regulation conclusions

The *‘drop-in’* nature of synthetic fuels often can be considered advantageous from the technical perspective, in that they facilitate the adoption and replacement of fossil-derived fuels in suitable applications. Furthermore, the use of existing regulatory instruments, which in many cases are transferrable to the synthetic-fuel equivalents, supports the adoption of synthetic fuels.

The ongoing revision of regulations and publication of new standards, industry guidance and best-practice are further facilitating the adoption of synthetic fuels, including e-fuels, for marine applications.

The basket of measures introduced by the European Commission under its *'Fit for 55'* initiative, which includes revising regulations, directives and new policy initiatives, signals a strong commitment to a decarbonised and sustainable future for shipping. However, further initiatives and regulatory developments are required to facilitate the widespread use of synthetic fuels, and to fill some of the gaps that have been identified.

Specifically, the following need to be considered:

- To finalise and publish the ISO/AWI 6583 Specification of methanol as a fuel for marine applications to support the use of renewable methanol;
- The lack of current regulation under the IGF Code for fuel oils with a flashpoint between 52˚-60˚C is not seen as a significant barrier to synthetic uptake; however, this is a gap in the current IMO instruments;
- The lack of IMO specific guidance for application of synthetic fuels, similar to that issued for the 2020 fuels under MEPC.1/Circ.878, is not seen as a barrier to synthetic fuel uptake, however such a publication could support harmonised application under the ISM Code obligations and support application of classification society requirements called out by SOLAS II-1/Regulation 3-1;
- Further reductions in IMO's regulation 14 fuel sulphur limits would provide significant air quality benefits, but also encourage application of inherently low sulphur synthetic fuels;
- The uncertainty on application of regulation 18.3.2.2 of Annex VI regarding engines exceeding the applicable regulation 13 $NO_X$ emission limit when consuming fuels derived by methods other than petroleum refining remains a significant barrier to widespread adoption. However, workarounds exist by application of regulation 3.2 for trials onboard or regulation 4 for *'equivalents'*, and the publication of UI MEPC.1/Circ.795/Rev.6 provides pragmatic interpretation for the application of fuels derived from methods other than petroleum refining. However, there is an urgent need to update Annex VI and the $NO_X$ Technical Code to provide further clarity and harmonised application for burning synthetic fuels;
- While IMO LCA Guidelines have been adopted, further work is expected. Upon finalisation of IMO LCA Guidelines, the recognition of certified lower carbon factors for synthetic fuels is expected to be accounted for in upcoming IMO measures. The inclusion of LCA Guidelines under CII and DCS framework may be considered. On the other hand, there are some barriers for synthetic fuels to be considered under the EEDI and EEXI;
- Considering the challenges in developing and implementing changes to regulations in a timely manner, industry stakeholders such as IACS may facilitate synthetic fuel take up and harmonised application by the development of Unified Requirements, Unified Interpretations and Recommendations, this should be encouraged;
- Development of industry best practice and guidance publications for synthetic fuel handling, specifically bunkering and transfers, together with engine manufacturer design and operational guidance should be supported or clarification needs to be added to existing instruments stating synthetics are similar to traditional fuels;
- In general, the existing and developing international fuel standards and regulations are leading the maritime industry to contribute to the adoption of alternative fuels, including liquid and gaseous synthetic fuels, for decarbonisation and emissions reductions, albeit at present uptake is currently relatively small.

# 4. Conclusions of Synthetic Fuels Study

This study supplements the previous study developed for EMSA that covered the potential of biofuels (EMSA (2022a), including an overview of the *'state of play'* on the use of synthetic fuels in the shipping sector. The focus of this study is on e-methanol, e-methane and e-diesel, produced by renewable electricity and renewable $CO_2$ from non-biological origin. These three fuels are thought to have the highest potential for use as maritime fuels, together with e-ammonia and e-hydrogen, which have been analysed in previous studies (EMSA, 2022b) and (EMSA, 2023).

The main production routes for those fuels, namely, methanol synthesis for e-methanol, methanation for e-methane, and Fischer-Tropsch synthesis for e-diesel, require renewable hydrogen. This is mainly produced by using electrolysis, a process where pure water is split into hydrogen and oxygen using renewable electricity.

The main route for (non-biogenic) $CO_2$ production is direct air capture (DAC). DAC plants require (renewable) electricity to operate, and the process makes use of a solvent or sorbent to capture $CO_2$ from atmospheric air. In fact, DAC is required for all e-fuel production pathways analysed in this study. However, since DAC technology is still in the demonstration phase, none of the e-fuel production pathways are technologically advanced enough to enter the market. Although being in a much earlier stage of the development, oceanwater carbon capture can be considered an alternative for DAC.

Overall, it is observed that all three e-fuel production routes need some of their required technologies to advance from the demonstration phase to market entry. In the short term, it is more feasible to rely on the most advanced technologies and processes to produce e-fuels, including electrolysis being used to produce renewable hydrogen and DAC technology to obtain renewable $CO_2$. Biogenic residual $CO_2$ (e.g., from bio-methane production) may be used as a cheaper way to scale up the production of e-fuels production. But, in parallel, DAC systems or alternative systems have to be further developed to enable capturing of $CO_2$ on a large-scale in the longer term. Further research is needed to develop less advanced technologies (i.e., the technologies with a low TRL, as indicated in Table 2 and Table 3) and alternative production pathways, in order to improve technical performance, reduce costs and minimise environmental impacts.

As e-fuels production has been very limited to this point, emission measurement data is unavailable. In general, the sulphur content of e-fuels can be expected to be zero; only the emissions from pilot fuels may remain (although e-diesel can also be used as pilot fuel). The $NO_X$ emissions may be reduced by up to 80% compared to the fossil maritime fuel oils, depending on the e-fuel, fossil fuel and engine technology. Particulate matter (PM) emissions from e-fuels are identical to their biofuel counterpart. Some PM reduction can be seen if the e-fuels are compared to VLSFO containing sulphur.

Indirect land use change and related causes of environmental damage, such as loss of biodiversity, may occur if wind and solar capacity is expanded at the expense of agriculture or nature conservation. Areas with high wind, solar, water resources and large desert area are better suited for large production of e-fuels. DAC plants may also have a significant land footprint of 1.5 $km^2$/Mt of captured $CO_2$. However, it is expected that technological development can reduce this footprint. The manufacturing of wind and solar parks, electrolysers and the other systems required for e-fuel production is associated with negative environmental impacts as well. Electrolysers and DAC systems using aqueous solutions require fresh water, which may contribute to water scarcity in certain regions. Desalination of seawater is an alternative option to generate fresh water but requires a plan for dealing with the brine as it can have a devastating impact on the local marine environment if it is returned to the sea.

Concerning spill, it should be also noted that although e-diesel will disperse and dissolve and could be completely degraded within two months, spilling it into the ocean has larger negative impacts on the marine environment than both e-methanol and e-methane, and may kill fish and birds. The impact on marine environment from ocean water carbon capture still needs further research.

To enable the large-scale production of e-fuels for the maritime industry, the capacity of all production segments – renewable electricity plants, electrolysers, DAC and e-fuel synthesis plant – will need to grow tremendously. The limited expansion rates found in the availability analysis indicate that the role of e-fuels cannot be expected to play a major role in global shipping by 2030. The technical development and implementation speed of DAC need to be scaled up to reduce costs. As the lower production costs spur the adoption of e-fuels, an expansion in supporting infrastructure (such as bunkering) can be expected to lower the price of e-fuels further. The development of dedicated e-fuel projects – in which renewable electricity production, electrolysis capacity, e-fuels production capacity and DAC are developed simultaneously – should be supported to enable expansion and avoid any part of the required technical systems from lagging behind. Overall, policy support for financial measures, carbon taxes and mechanisms for carbon emissions trading are expected to facilitate such developments. At the same time, it needs to be recognised that the shipping sector will need to compete with all other industrial sectors for the renewable electricity, green hydrogen and renewable $CO_2$ required to produce e-fuels.

In terms of the total cost of ownership (TCO), the cost gap between e-fuel-powered and conventional fossil-fuelled vessels may close by 2050, provided that e-fuel production costs decrease, while the cost for using fossil fuels increases along with the carbon costs. In terms of carbon costs, dedicated bulk carrier and containership analyses present cases in this study for the TCO for e-fuels being about 45-85% higher than vessels powered by conventional (fossil) fuels in 2030; however, that TCO range could drop to 20-50% lower in 2050. If no carbon costs are accounted for, the TCO for the e-fuels-powered vessels in the high-price scenario for 2050 were projected to reman 20-50% higher than conventional vessels. This illustrates how the carbon costs incentivise the use of e-fuels. Aside from renewable green ammonia, these e-fuels and their biofuel counterparts are the alternative fuels associated with a lower additional TCO that will support the transition to zero-carbon shipping. However, to ensure the adoption of e-fuels, global market-based measures may be needed to bridge the price gap between e-fuels and conventional fuels. Due to the high production costs, e-diesel is, in the short and medium term, not a cheaper option for a newbuild, although no additional capital expenditures have to be incurred. This holds for the case in which you compare the e-fuels considered in this study on the basis that a ship is fully powered by the according e-fuel. If, however, compliance with a regulation could be achieved by using significantly less e-diesel compared to the other e-fuels, then e-diesel could become a more attractive option.

The existing standards and regulations, as well as ongoing regulatory developments, industry guidance and best-practice publications are, to some extent, expected to facilitate their adoption as marine fuels. However, for wide adoption of these fuels to be realised, further developments will be needed. The International Maritime Organization (IMO) has set new levels of ambition based on Well-to-Wake emissions. Among others, there is an ambition at the IMO to increase the uptake of zero or near-zero GHG emission technologies, fuels and/or energy sources, until they will represent at least 5% (striving for 10%) of the energy used by international shipping in 2030. Also, in 2023, IMO adopted the '*Guidelines on Life Cycle GHG Intensity of Marine Fuels'* (IMO LCA Guidelines), which have been amended in 2024 and there is still work in progress. Further development of the IMO LCA Guidelines and standards to support a complete assessment of the GHG impacts of alternative fuels, including e-fuels, would allow a fair comparison of the carbon footprints from the different production pathways. In parallel, the development of the '*Interim Guidelines for the Safety of Ships Using Low-Flashpoint Oil Fuel*s' to provide an international standard for ships using oil-based fossil fuels, synthetic fuels, biofuels and any mixture thereof with a flashpoint between 52°C and 60°C is a step in the right direction for widespread adoption of synthetics. At the same time, in a regional level, European Commission has introduced a basket of measures under its *'Fit for 55'* initiative. This sets, among others, specific targets for renewable fuels of non-biological origin (RFNBO)[20]. All these developments are expected to support the uptake of synthetic fuels.

To conclude, e-fuels are seen viable solution to support the decarbonisation of shipping. This is mainly due to their lower carbon contents and *'drop-in'* nature, which allow their direct use onboard existing ships without substantial retrofitting or unsurmountable risk-related implications. Regulations could be updated and improved to better support e-fuels, as many of the current regulations on fossil fuels can be directly or indirectly applied to e-fuels. Some remaining barriers are preventing a wider adoption of e-fuels, mainly related to cost and availability. However, existing regulations, such as the EC's *'Fit for 55'* package are providing incentives, and the IMO's upcoming Market Based Measures are expected to further incentivise adoption on a global scale. On medium-to-long term, sufficient amounts of renewable carbon are going to be needed for production of carbon neutral fuel for shipping, including e-fuels. However, it is noted that biogenic $CO_2$ is a scarce resource and will be needed for renewable production of chemicals and other products we take for granted today. Finally, replacing biogenic $CO_2$ with $CO_2$ from DAC may reduce the pressure on biodiversity, provided that the DAC plants do not take up land used for agriculture. Also, in case fresh water is produced, this should be taken from a sustainable source. In case of desalinated water, a plan has to be developed in order to deal with the brine in an environmentally friendly way, to avoid negative impact on the marine environment.

20 Considered synonym to e-fuels. Refer to Section 1.2.

*Table 21. Summary of the Observations*

| Subject | Observation/Mitigations/Suggestions |
|---|---|
| Production | **Observations**<br>• The e-fuels relevant to maritime shipping considered in this study are e-methanol, (liquefied) e-methane and e-diesel (ammonia and hydrogen have been treated in previous EMSA studies). In the scope of this study, e-fuels are made from renewable electricity and renewable $CO_2$ from a non-biological origin.<br>• The main production routes are methanol synthesis for e-methanol, methanation for e-methane, and Fischer-Tropsch synthesis for e-diesel production.<br>• The main, most advanced production technology for the production of renewable hydrogen is electrolysis, where pure water is split into hydrogen and oxygen using renewable electricity.<br>• The main route for (non-biogenic) $CO_2$ production is direct air capture (DAC). This technology makes use of a solvent or sorbent to capture $CO_2$ from atmospheric air and requires (renewable) electricity to operate. DAC technologies are still in the demonstration phase.<br>• Oceanwater carbon capture is in a much earlier stage of development than DAC.<br>• As DAC is required for all e-fuel production pathways, none of the e-fuel production pathways are technologically advanced enough to enter the market. In addition, all three main e-fuel production routes require the advancement of some of the needed technologies from the demonstration phase to market entry.<br><br>**Mitigations and Suggestions**<br>• In the short term, it is more feasible to rely on the most advanced technologies and processes for producing e-fuels, with electrolysis being used to produce renewable hydrogen and DAC to obtain renewable $CO_2$.<br>• In the short term, biogenic residual $CO_2$ (e.g., from bio-methane production) may be used as a cheaper alternative to scale up the production of e-fuels, but DAC systems should be developed in parallel to enable the switch to atmospheric and/or oceanic $CO_2$ in the long term.<br>• Further R&D should focus on developing less advanced technologies and alternative-production pathways to improve technical performance, reduce costs and uncover and minimise environmental impacts. |
| Sustainability | **Observations**<br>• As e-fuels production has been very limited so far, no emission-measurement data is available. In general, the sulphur content of e-fuels can be expected to be zero; only pilot-fuel emissions may remain. The $NO_X$ emissions may be reduced by 20%-80% compared to fossil maritime fuels, depending on the e-fuel, fossil fuel and engine technology. Particulate matter (PM) emissions are reduced for both e-methanol and e-methane. In the case of e-diesel, the effects on PM emissions will also be improved, but the PM emissions will be higher than for both e-methanol and e-methane.<br>• Indirect land use change and related environmental damage such as biodiversity loss may occur if wind and solar capacity is expanded at the expense of agriculture or nature conservation. DAC systems may also have a significant land footprint of 1.5 $km^2$/Mt of captured $CO_2$, but technological development can result in a reduction of this footprint.<br>• The manufacturing of wind and solar parks, electrolysers and other systems required for e-fuel production generates negative environmental impacts. The construction and operation of wind farms may affect the habitats of birds and bats.<br>• Electrolysers and DAC systems using aqueous solutions require water, which may contribute to water scarcity in certain regions.<br>• The spillage of e-diesel into the ocean has larger negative impacts on the marine environment than e-methanol and e-methane and may cause fish and bird kills, although e-diesel will disperse and dissolve and could be completely degraded within two months.<br><br>**Mitigations and Suggestions**<br>• The IMO and members states could further develop the already adopted international LCA Guidelines and standards to allow for a complete assessment of the GHG impacts of alternative fuels, including e-fuels. This is to allow a fair carbon footprint comparison between the different production pathways for the different types of fuels.<br>• Large desert areas are probably better suited for large e-fuels production facilities than areas with a higher nature value, as the use of these areas will result in lower environmental damage;<br>• Standards, reporting.<br>• Particular attention should be given to the use of water to produce hydrogen. Seawater desalination could be a better option than freshwater use in areas with water scarcity.<br>• More R&D is needed to identify and reduce the environmental impacts of oceanwater carbon |

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| | capture technologies. |
| Availability | **Observations**<br>• To enable the large-scale production of e-fuels for the maritime industry, the capacity of all segments required for e-fuel production – renewable-electricity plants, electrolysers, DAC and e-fuel-synthesis plants – will need to grow tremendously.<br>• Whereas the anticipated worldwide availability of renewable electricity appears sufficiently large to enable the global maritime fleet to fully switch to e-fuels perhaps as early as in 2030, especially the technical development and implementation speed of DAC capacity is estimated to form a main bottleneck in the growth of e-fuel production capacity.<br>• The shipping sector will need to compete with all other sectors for the renewable electricity, green hydrogen and renewable $CO_2$ required for e-fuels production.<br><br>**Mitigations and Suggestions**<br>• Support the development of dedicated e-fuel projects in which renewable electricity production, electrolysis capacity, e-fuels production capacity and DAC are developed simultaneously. This enables simultaneous technological development and scale-up, prevents parts of the required technical systems from lagging in production capacity, and makes renewable electricity available for e-fuels production.<br>• Stakeholders in the shipping sector could contribute to the expansion of e-fuels availability by co-investing in e-fuels production projects and signing e-fuel supply agreements or provisional contracts. This would reduce investment uncertainty for the project developers and increase the availability of e-fuels for the stakeholders involved. Governments could implement financial support instruments to create a viable business case for e-fuel projects.<br>• Direct air capture needs to be scaled up to bring down costs, which can be facilitated by financial policy support measures and by carbon taxes and carbon emissions trading mechanisms. |
| Techno-economical | **Observations**<br>• The cost of the application of three types of e-fuel in different ship types has been evaluated.<br>• In terms of TCO (total cost of ownership), the cost gap between e-fuel-powered and conventional fossil-fuelled vessels may close by 2050, if e-fuel production costs fall, while the cost for fossil fuels increases along with the carbon costs.<br>• Considering carbon costs, the example cases of a bulk carrier and containership present a TCO for e-fuels that is about 45-85% higher than vessels powered by conventional (fossil) fuels in 2030 and could range to about 20-50% lower TCO compared to the VLSFO reference ship in 2050.<br>• If no carbon costs accrue, the TCO for the e-fuels-powered vessels analysed might, however, in a high-price scenario in 2050, remain 20-50% higher than the TCO of the conventional vessels.<br>• Overall, it seems that these e-fuels, in tandem with their biofuel variant, besides renewable green ammonia, are the alternative fuels associated with lower additional TCO to support the transition to zero-carbon shipping.<br><br>**Mitigations and Suggestions**<br>• To ensure the adoption of e-fuels, global regulations may need to be put in place to bridge the price gap between these renewable fuels and conventional fuels.<br>• Market pressure may also play an equivalent or support role in the transition towards e-fuels: in case shipping companies desire to accelerate decarbonisation due to demand for zero carbon shipping from their customers.<br>• It is important for the industry to focus on initiatives to lower the cost of production of e-fuels, by switching from technology demonstration to technology maturisation.<br>• As e-fuels uptake develops, the accompanying infrastructure (such as bunkering) and availability will increase which is expected to drive the prices of the e-fuels downwards. Therefore, it is important to continue to incentivise the uptake of e-fuels as it may support lowering the TCO values as presented in this study. However, competition for the use of the same renewable electricity in other sectors may have an opposite effect on the cost, with the extent remaining of unknown size. |
| | **Observations**<br>• As synthetic fuels are drop-in by nature, they can likely take advantage of the existing regulatory framework and regulations can be easily modified to include synthetics.<br>• The adoption of synthetic blends has been limited.<br>• Synthetic blends can be easily integrated into marine engines as those engines are large and designed to handle a wide range of residual and distillate fuels.<br>• ISO fuel standards exist for marine fuel oil and marine LNG fuel.<br>• E-fuels need to comply with the same MARPOL Annex VI regulations for air pollution.<br>• Synthetic fuels have an advantage in lowering $SO_X$ as they are inherently low in sulphur or are sulphur-free.<br>• Synthetic fuels fare better in the FuelEU scheme but have no advantage in CII yet. |

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| Rules and Regulation | • FuelEU regulations cover e-liquids and incentivise RFNBO's.<br>• There are several EU approved voluntary and national certification schemes to certify RFNBO's.<br><br>**Mitigations and Suggestions**<br>• Adoption of synthetics can be encouraged by referring to existing codes and standards by regulators.<br>• The quality of synthetics needs standardisation as the blends may be produced from a wide variety of sources.<br>• ISO marine methanol fuel standards when developed can promote the use of e-methanol.<br>• While the IMO LCA Guidelines have been adopted, they are still under technical review and further work is expected to promote all low and zero carbon fuels, including synthetics, and place them on an even playing field as the current scheme only accounts for Tank-to-Wake emissions on an international level.<br>• More engine testing needs to be done on synthetic fuels as there is scant emission testing data available from combustion of synthetic fuels. This will provide a greater degree of confidence on the criteria air pollutant values.<br>• As synthetic fuels have the potential to lower carbon emission, this needs to be recognised in the CII framework and a lower carbon factor could be possibly embedded into the CII regulation for synthetics.<br>• IMO DCS does not currently require ships to report the nature of fuel and there is a degree of uncertainty on how to capture all fuels in-use and in consideration for future use within the DCS reporting system. This area requires regulatory clarification.<br>• The development of interim guidelines for the use of oil fuels with a flashpoint between 52°C and 60°C, covering oil-based fossil fuels, synthetic fuels, biofuels and any mixture thereof is being done intersessionally and will further develop through CCC 10 but this needs to be fast-tracked for the widespread adoption of synthetics.<br>• National regulations beyond the EU can be strengthened by including incentives for the use of synthetics as marine fuel. |

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# Appendix A – Current and planned vessels

Although the current e-fuel production capacity is very low (see Subsection 2.1.6), the number of current and planned vessels that could utilise the e-fuels considered in this study – e-diesel, (liquefied) e-methane and e-methanol – is significant. After all, e-diesel, e-methane and e-methanol are drop-in fuels for diesel-powered ships, LNG-fuelled ships and methanol-powered ships, respectively. Diesel is one of the main shipping fuels in current use. An overview of the current and planned LNG and methanol vessels is given in table below.

*Table 22. Current and planned LNG and methanol vessels (DNV, 2023).*

| Fuel | Vessels in operation | Vessels on order | Remarks |
|---|---|---|---|
| LNG | 1,079 | 829 | E-methane is a drop-in fuel for LNG-powered ships. |
| Methanol | 27 | 151 | E-methanol is a drop-in fuel for methanol-powered ships. |

# Appendix B – Overview of data of the economic analysis

In the following sections of this annex, the input variables of the TCO analysis are presented followed by a list of the considered ship types and sizes. Also, the TCO of alternative-fuelled ships for the maximum fuel cost scenario is shown. The TCO comprises all cost aspects in a minimum and maximum fuel cost case. CAPEX, bunkering and maintenance and repair costs are similar in both cases; only the fuel costs differ between lower and upper limits as found in different sources. Considering the different energy density of fuels, the figures include the cost for increased bunkering as a ratio of difference in energy content of the fuel considered. All TCO figures are rounded to the next thousand.

## Input variables

*Table 23. Input cost of propulsion systems based on (Hendriksen, Sørensen, & Münster, 2021 ; Horvath, 2017)*

| Ship category | Fuel type | Ship size | Engine Cost per kW (USD) | Engine Cost per kW (EUR) |
|---|---|---|---|---|
| Small vessels | Fuel Oil*/ E-Diesel | All vessel types* with size up to 15,000 DWT | 290 | 250 |
| Large vessels | Fuel Oil*/ E-Diesel | All vessel types* with size above 15,000 DWT | 230 | 200 |
| Containerships | Fuel Oil*/ E-Diesel | All sizes containerships | 220 | 190 |
| Short sea vessels | E-methane | All vessel type with size up to 15,000 DWT | 340 | 300 |
| Deep sea vessels | E-methane | All vessel types with size above 15,000 DWT | 290 | 250 |
| Containerships | E-methane | All sizes containerships | 250 | 220 |
| Short sea vessels | E-methanol | All vessel type with size up to 15,000 DWT | 380 | 330 |
| Deep sea vessels | E-methanol | All vessel types with size above 15,000 DWT | 320 | 280 |
| Containerships | E-methanol | All sizes containerships | 270 | 240 |

** Fuel oil includes the fuel types: ULSFO, VLSFO, HFO, MGO, e-diesel*

*Table 24. Bunkering cost per GJ (CE Delft, 2020).*

| Fuel type | Bunkering cost (USD/GJ) | Bunkering cost (EUR/GJ) |
|---|---|---|
| VLSFO | 0.07 | 0.06 |
| E-methanol | 0.21 | 0.18 |
| E-diesel | 0.07 | 0.06 |
| E-methane | 0.29 | 0.25 |

*Table 25. Increased bunkering factor of alternative fuels, based on DNV GL (DNV GL, 2019).*

| Fuel type | MJ/L | Volumetric density % of VLSFO | Factor increased bunkering |
|---|---|---|---|
| VLSFO | 36 | 100.0% | 1.00 |
| E-methanol | 15 | 41.7% | 2.40 |
| E-diesel | 32 | 88.9% | 1.13 |
| E-methane (LNG) | 13 | 36.1% | 2.77 |

Direct air capture cost by EUR/t$CO_2$ found in the literature are presented in Table 26.The figures by IEA, 2022 used in the analysis for constructing the e-fuel production cost are marked **bold**.

*Table 26. Overview of literature direct air capture cost in EUR/t$CO_2$.*

| Source | Value | 2020 | 2030 | 2050 |
|---|---|---|---|---|
| HyChain model (Kalavasta, 2019) | Min | € 590.00 | € 150.00 | € 60.00 |
| | Max | € 590.00 | € 340.00 | € 220.00 |
| (IEA, 2022) | **Min** | **€ 110.00** | **€ 90.00** | **€ 80.00** |
| | **Max** | **€ 300.00** | **€ 110.00** | **€ 90.00** |
| (Agora Verkehrswende, Agora Energiewende and Frontier Economics, 2018) | Mid | € 150.00 | € 100.00 | € 100.00 |
| (ENTEC, 2022) | Mid | € 500.00 | n/a | n/a |

Fuel production cost found in the literature are presented in the tables below. Production cost figures for e-methanol are presented in Table 27. The cost figures used for the economic analysis in this study are outlined in **bold**.

*Table 27. E-methanol production cost in EUR/GJ from various literature sources.*

| Source | Value | 2020 | 2030 | 2050 |
|---|---|---|---|---|
| (Concawe, 2021) | Min | € 49.0 | € 42.1 | € 42.8 |
| | Max | € 91.1 | € 63.6 | € 65.3 |
| (ENTEC, 2022) | Min | € 47.3 | € 24.5 | € 12.2 |
| | Max | € 100.4 | € 49.8 | € 26.6 |
| (IRENA, 2021) | Min | € 61.1 | n/a | € 13.0 |
| | Max | € 107.6 | n/a | € 28.5 |
| (Öko-Institut; Ce Delft; DLR, 2021) | Min | n/a | € 26.6 | € 20.0 |
| | Max | n/a | € 52.3 | € 36.1 |
| Mar-E-fuel, 2021 | Min | € 56.6 | € 42.8 | € 29.4 |
| | Max | € 61.8 | € 48.6 | € 34.5 |
| (Kalavasta, 2019) | Min | € 69.5 | € 35.3 | € 21.5 |
| | Max | € 69.5 | € 50.0 | € 38.6 |
| **Authors calculation based on IEA** (IEA, 2022) **(carbon input by DAC) and HyChain model** (Kalavasta, 2019)**(renewable H2 feedstock)** | **Min** | **€ 42.6** | **€ 29.1** | **€ 21.5** |
| | **Max** | **€ 56.3** | **€ 36.4** | **€ 29.2** |

Production cost figures for e-diesel are presented in Table 28. The cost figures used for the economic analysis in this study are outlined in **bold**.

*Table 28. E-diesel production cost in EUR/GJ from various literature sources.*

| Source | Value | 2020 | 2030 | 2050 |
|---|---|---|---|---|
| (ENTEC, 2022) | Min | € 51.3 | € 28.5 | € 16.2 |
| | Max | € 105.4 | € 54.8 | € 31.6 |
| HyChain model (Kalavasta, 2019) | Min | € 73.5 | € 39.3 | € 25.5 |
| | Max | € 74.5 | € 55.0 | € 43.6 |
| **Authors calculation based on IEA** (IEA, 2022) **(carbon input by DAC) and HyChain model** (Kalavasta, 2019) **(renewable H2 feedstock)** | **Min** | **€ 46.6** | **€ 33.1** | **€ 25.5** |
| | **Max** | **€ 61.3** | **€ 41.4** | **€ 34.2** |

Production cost figures for e-methane are presented in Table 29.The cost figures used for the economic analysis in this study are outlined in **bold**.

*Table 29. E-methane production cost in EUR/GJ from various literature sources.*

| Source | Value | 2020 | 2030 | 2050 |
|---|---|---|---|---|
| (CE Delft, 2021) | Min | n/a | € 24.4 | € 20.3 |
| | Max | n/a | € 54.4 | € 38.1 |
| (ENTEC, 2022) | Min | € 42.3 | € 19.5 | € 7.2 |
| | Max | € 96.4 | € 45.8 | € 22.6 |
| (Kalavasta, 2019) | Min | € 64.5 | € 30.3 | € 16.5 |
| | Max | € 65.5 | € 46.0 | € 34.6 |
| **Authors calculation based on IEA** (IEA, 2022) **(carbon input by DAC) and HyChain model** (Kalavasta, 2019) | **Min** | **€ 37.6** | **€ 24.1** | **€ 16.5** |
| | **Max** | **€ 52.3** | **€ 32.4** | **€ 25.2** |

## List of considered ship types and sizes

*Table 30. List of considered ship types and sizes (CE Delft, Dallan Maritime University, ClassNK, Purdue University, Krannert School of Management, Fudan University et al., 2020)*

| Ship type | Size category | Unit | Average Deadweight | Avg. installed power (kW) | Yearly total average fuel consumption (GJ) |
|---|---|---|---|---|---|
| Bulk carrier | 0-9999 | DWT | 4271 | 1,796 | 56,280 |
| Bulk carrier | 10000-34999 | DWT | 27303 | 5,941 | 128,640 |
| Bulk carrier | 35000-59999 | DWT | 49487 | 8,177 | 172,860 |
| Bulk carrier | 60000-99999 | DWT | 76147 | 9,748 | 237,180 |
| Bulk carrier | 100000-199999 | DWT | 169868 | 16,741 | 406,020 |
| Bulk carrier | 200000-+ | DWT | 251667 | 20,094 | 546,720 |
| Chemical tanker | 0-4999 | DWT | 4080 | 987 | 80,400 |
| Chemical tanker | 5000-9999 | DWT | 7276 | 3,109 | 124,620 |
| Chemical tanker | 10000-19999 | DWT | 15324 | 5,101 | 180,900 |
| Chemical tanker | 20000-39999 | DWT | 32492 | 8,107 | 281,400 |
| Chemical tanker | 40000-+ | DWT | 48796 | 8,929 | 285,420 |
| Container | 0-9999 | TEU | 8438 | 5,077 | 148,740 |
| Container | 1000-1999 | TEU | 19051 | 12,083 | 281,400 |
| Container | 2000-2999 | TEU | 34894 | 20,630 | 402,000 |
| Container | 3000-4999 | TEU | 52372 | 34,559 | 627,120 |
| Container | 5000-7999 | TEU | 74661 | 52,566 | 932,640 |
| Container | 8000-11999 | TEU | 110782 | 57,901 | 1,197,960 |
| Container | 12000-14499 | TEU | 149023 | 61,231 | 1,250,220 |
| Container | 14500-19999 | TEU | 179871 | 60,202 | 1,246,200 |
| Container | 20000-+ | TEU | 195615 | 60,210 | 1,025,100 |
| General cargo | 0-4999 | DWT | 2104 | 1,454 | 28,140 |
| General cargo | 5000-9999 | DWT | 6985 | 3,150 | 76,380 |
| General cargo | 10000-19999 | DWT | 13423 | 5,280 | 152,760 |
| General cargo | 20000-+ | DWT | 36980 | 9,189 | 221,100 |
| Liquefied gas tanker | 0-49999 | cbm | 8603 | 2,236 | 156,780 |
| Liquefied gas tanker | 50000-99999 | cbm | 52974 | 12,832 | 510,540 |
| Liquefied gas tanker | 100000-199999 | cbm | 83661 | 30,996 | 1,109,520 |
| Liquefied gas tanker | 200000-+ | cbm | 121977 | 36,735 | 1,603,980 |
| Oil tanker | 0-4999 | DWT | 3158 | 966 | 64,320 |
| Oil tanker | 5000-9999 | DWT | 6789 | 2,761 | 96,480 |
| Oil tanker | 10000-19999 | DWT | 14733 | 4,417 | 148,740 |
| Oil tanker | 20000-59999 | DWT | 43750 | 8,975 | 289,440 |
| Oil tanker | 60000-79999 | DWT | 72826 | 11,837 | 361,800 |
| Oil tanker | 80000-119999 | DWT | 109262 | 13,319 | 389,940 |
| Oil tanker | 120000-199999 | DWT | 155878 | 17,446 | 534,660 |
| Oil tanker | 200000-+ | DWT | 307866 | 27,159 | 775,860 |
| Other liquids tankers | 0-999 | DWT | 3450 | 687 | 112,560 |
| Other liquids tankers | 1000-+ | DWT | 10813 | 2,034 | 277,380 |
| Ferry-pax only | 0-299 | GT | 4034 | 1,152 | 28,140 |
| Ferry-pax only | 300-999 | GT | 102 | 3,182 | 40,200 |
| Ferry-pax only | 1000-1999 | GT | 354 | 2,623 | 36,180 |

| Ship type | Size category | Unit | Average Deadweight | Avg. installed power (kW) | Yearly total average fuel consumption (GJ) |
|---|---|---|---|---|---|
| Ferry-pax only | 2000-+ | GT | 1730 | 6,539 | 176,880 |
| Cruise | 0-1999 | GT | 3115 | 911 | 108,540 |
| Cruise | 2000-9999 | GT | 867 | 3,232 | 124,620 |
| Cruise | 10000-59999 | GT | 4018 | 19,378 | 514,560 |
| Cruise | 60000-99999 | GT | 8249 | 51,518 | 1,503,480 |
| Cruise | 100000-149999 | GT | 10935 | 67,456 | 1,825,080 |
| Cruise | 150000-+ | GT | 13499 | 73,442 | 1,776,840 |
| Ferry-RoPax | 0-1999 | GT | 2720 | 1,383 | 52,260 |
| Ferry-RoPax | 2000-4999 | GT | 832 | 5,668 | 112,560 |
| Ferry-RoPax | 5000-9999 | GT | 1891 | 12,024 | 196,980 |
| Ferry-RoPax | 10000-19999 | GT | 3952 | 15,780 | 418,080 |
| Ferry-RoPax | 20000-+ | GT | 6364 | 28,255 | 763,800 |
| Refrigerated bulk | 0-1999 | DWT | 2409 | 793 | 76,380 |
| Refrigerated bulk | 2000-5999 | DWT | 3986 | 3,223 | 152,760 |
| Refrigerated bulk | 6000-9999 | DWT | 7476 | 6,206 | 237,180 |
| Refrigerated bulk | 10000-+ | DWT | 12612 | 11,505 | 510,540 |
| Ro-Ro | 0-4999 | DWT | 1406 | 1,618 | 84,420 |
| Ro-Ro | 5000-9999 | DWT | 6955 | 9,909 | 317,580 |
| Ro-Ro | 10000-14999 | DWT | 12101 | 15,939 | 498,480 |
| Ro-Ro | 15000-+ | DWT | 27488 | 19,505 | 538,680 |
| Vehicle | 0-29999 | GT | 5151 | 7,264 | 237,180 |
| Vehicle | 30000-49999 | GT | 13571 | 11,831 | 337,680 |
| Vehicle | 50000-+ | GT | 20947 | 14,588 | 462,300 |
| Yacht | 0-+ | GT | 1077 | 1,116 | 16,080 |
| Service - tug | 0-+ | GT | 1218 | 1,086 | 20,100 |
| Miscellaneous - fishing | 0-+ | GT | 468 | 983 | 24,120 |
| Offshore | 0-+ | GT | 4765 | 2,010 | 44,220 |
| Service - other | 0-+ | GT | 2496 | 1,620 | 40,200 |
| Miscellaneous - other | 0-+ | GT | 11496 | 15,301 | 108,540 |

## Detailed results cost analysis

In this section the results of the cost analyses are presented in further detail.

### Bulk Carrier (35,000-60,000 DWT)

Detailed results of the TCO for a bulk carrier (size category 35,000-60,000 DWT) in the low- and high fuel cost scenario are presented in Table 31. The TCO for the reference ships considers carbon cost (as applicable at intra-EU voyages).

*Table 31. Delta yearly TCO of a bulk carrier (35,000-60,000 DWT) powered by e-fuels. For the TCO of the VLSFO reference ship carbon cost apply.*

| Fuel type | Year | Low | High |
|---|---|---|---|
| E-methanol | 2020 | 189% | 279% |
| E-methanol | 2030 | 73% | 149% |
| E-methanol | 2050 | -34% | -18% |
| E-diesel | 2020 | 207% | 303% |
| E-diesel | 2030 | 86% | 163% |
| E-diesel | 2050 | -27% | -10% |
| E-methane | 2020 | 158% | 254% |

| Fuel type | Year | Low | High |
|---|---|---|---|
| E-methane | 2030 | 47% | 132% |
| E-methane | 2050 | -47% | -28% |

Detailed results of the TCO for a bulk carrier (35,000-60,000 DWT) in the low- and high fuel cost scenario are presented inTable 32. The TCO for the reference ships does not consider carbon cost (as applicable to non-EU related voyages).

*Table 32. Delta yearly TCO of a bulk carrier (35,000-60,000 DWT) powered by e-fuels. For the TCO of the VLSFO reference ship carbon cost do not apply.*

| Fuel type | Year | Low | High |
|---|---|---|---|
| E-methanol | 2020 | 189% | 279% |
| E-methanol | 2030 | 135% | 214% |
| E-methanol | 2050 | 16% | 36% |
| E-diesel | 2020 | 207% | 303% |
| E-diesel | 2030 | 153% | 233% |
| E-diesel | 2050 | 28% | 51% |
| E-methane | 2020 | 158% | 254% |
| E-methane | 2030 | 100% | 194% |
| E-methane | 2050 | -7% | 20% |

### Containership (14,500-20,000 TEU)

Detailed results of the TCO for a containership (14,500-20,000 TEU) in the low- and high fuel cost scenario are presented in Table 33. The TCO for the reference ships considers carbon cost (as applicable at intra-EU voyages).

*Table 33. Delta yearly TCO of a containership (14,500-20,000 TEU) powered by e-fuels. For the TCO of the VLSFO reference ship carbon cost apply.*

| Fuel type | Year | Low | High |
|---|---|---|---|
| E-methanol | 2020 | 188% | 278% |
| E-methanol | 2030 | 72% | 148% |
| E-methanol | 2050 | -34% | -19% |
| E-diesel | 2020 | 208% | 304% |
| E-diesel | 2030 | 86% | 164% |
| E-diesel | 2050 | -27% | -10% |
| E-methane | 2020 | 157% | 254% |
| E-methane | 2030 | 46% | 132% |
| E-methane | 2050 | -47% | -28% |

Detailed results of the TCO for a containership (14,500-20,000 TEU) in the low- and high fuel cost scenario are presented in Table 34. The TCO for the reference ships does not consider carbon cost (as applicable to non-EU related voyages).

*Table 34. Delta yearly TCO of a containership (14,500-20,000 TEU) powered by e-fuels. For the TCO of the VLSFO reference ship carbon cost do not apply.*

| Fuel type | Year | Low | High |
|---|---|---|---|
| E-methanol | 2020 | 188% | 278% |
| E-methanol | 2030 | 134% | 213% |
| E-methanol | 2050 | 15% | 35% |
| E-diesel | 2020 | 208% | 304% |
| E-diesel | 2030 | 154% | 233% |
| E-diesel | 2050 | 28% | 51% |
| E-methane | 2020 | 157% | 254% |
| E-methane | 2030 | 99% | 193% |
| E-methane | 2050 | -7% | 20% |

## Retrofitting TCO containership (5,000-8,000 TEU)

The figures of the TCO analysis for the retrofit case of a small containership (size category 5,000-8,000 TEU) are presented in Table 35, Table 36 and Table 37, for an investment period of 5 years, 10 years and 15 years respectively.

*Table 35. TCO retrofit for a containership (5,000-8,000 TEU) over a 5-year investment term.*

| Fuel type | 2020 Min | 2020 Max | 2030 Min | 2030 Max | 2050 Min | 2050 Max |
|---|---|---|---|---|---|---|
| E-methanol | 239% | 346% | 129% | 203% | 21% | 36% |
| E-methane | 208% | 327% | 106% | 192% | 11% | 30% |
| E-diesel | 230% | 334% | 115% | 188% | 15% | 28% |

*Table 36. TCO retrofit for a containership (5,000-8,000 TEU) over a 10-year investment term.*

| Fuel type | 2020 Min | 2020 Max | 2030 Min | 2030 Max | 2050 Min | 2050 Max |
|---|---|---|---|---|---|---|
| E-methanol | 224% | 327% | 115% | 188% | 15% | 28% |
| E-methane | 191% | 304% | 90% | 175% | 3% | 21% |
| E-diesel | 230% | 334% | 115% | 188% | 15% | 28% |

*Table 37. TCO retrofit for a containership (5,000-8,000 TEU) over a 15-year investment term.*

| Fuel type | 2020 Min | 2020 Max | 2030 Min | 2030 Max | 2050 Min | 2050 Max |
|---|---|---|---|---|---|---|
| E-methanol | 219% | 321% | 110% | 184% | 13% | 25% |
| E-methane | 186% | 296% | 85% | 169% | 1% | 18% |

# Appendix C – Detailed Regulatory Gap Analysis

| |
|---|
| No Gap or Changes needed to address synthetic fuels |
| Small Gap or Minor Change to address synthetic fuels |
| Medium Gap or Some Challenging Change to address synthetic fuels |
| Large Gap or Many Challenging Changes to address synthetic fuels |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| Sustainability and Emissions Regulations | MARPOL Annex VI Regulation 13 – Nitrogen Oxides (NOX) and Regulation 18 – Fuel Oil Availability and Quality | Applies the $NO_X$ Technical Code (NTC) to reference testing and certification of all subject marine diesel engines | There are variations in $NO_X$ emissions from the use of synthetic fuels and synthetic fuel blends (it depends on the engine, load and specific fuel). The $NO_X$ Technical Code has limited provisions for the certification of $NO_X$ with synthetic fuels and there is uncertainty about the application of Regulation 18.3.2.2. Amendment of Annex VI and the NTC will contribute to the uptake of synthetic fuels within the global marine industry. | Further discussion and encouragement to amend Annex VI and the $NO_X$ Technical Code to account for synthetic fuels will encourage the uptake of synthetic fuels. |
| | MARPOL Annex VI Regulation 14 – Sulphur Oxides (SOX) and Particulate matter | Restricts the amount of $SO_X$ and (sulphate) particulate matter emitted by all fuel oil-consuming equipment onboard ships by limiting the sulphur content in the fuel. | IMO's ECA fuel-sulphur limit of 0.1% (1,000 ppm) is less stringent than land-based regulations. Synthetic fuels are below the limits emposed by the regulation but are not directly encouraged/incentivised for adoption by the IMO's fuel sulphur limits. | Timely update of international IMO MARPOL emissions and air pollution limits, to accommodate industry needs and development, is a strong driver to support adopting of alternative fuels such as synthetic fuels. Supporting international technical and regional/national standards and requirements can continue to support the prevention of pollution from ships and contribute to the adoption of synthetic (including e-) fuels as marine fuel. |
| | MARPOL Annex VI Chapter 4 – Regulations on the Carbon Intensity of International Shipping | Required calculations for ships energy efficiency and carbon intensity using various methods, including EEDI, EEXI or CII are based on limited current fuel carbon factors. Ability to certify ships with alternative (certified) fuel carbon factors, at design and during operation, may encourage the uptake of synthetic fuels as shipowners | Required calculations for ships energy efficiency and carbon intensity using various methods, including EEDI, EEXI or CII are based on limited current fuel carbon factors on the basis of tank-to wake emissions. Clarification of how to incorporate synthetic fuels into calculations to meet EEDI, EEXI, or CII values and DCS reporting is needed, taking into account the | IMO LCA Guidelines are expected to be further developed and may close the gap in the future. |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| | | look for ways to reduce their carbon footprint and increase efficiency. | sustainability of the fuel over its life cycle of production to use. | |
| | EU Renewable Energy Directive (RED) 2009/28/EC | This European Commission Directive directly contributes to the uptake of biofuels in EU Member states, specifically requiring the integration of at least 32% biofuels in energy by 2030. | Due to the regional nature of this directive, issues may arise when biofuels are traded across non-member borders.<br>This directive could be more effective if its provisions within the directive were officially recognised, adopted, or incorporated in non-member states and international reporting schemes for sustainable energy sources. | The EU is taking the initiative with the EU RED to require the uptake of biofuels through policy and economic principles, including the qualification of biofuel sustainability through supply chain validation. A clear directive or incorporation of synthetic fuels may be needed to promote the use of synthetic fuels. |
| | EU Fuel Quality Directive (FQD) 2009/30/EC | European Commission directives such as the FQD provide ship owners guidance and instruction of how to implement and account for decarbonisation and reduced emissions initiatives through alternative marine fuel schemes. | The EU's Fuel Quality Directive (FQD) had a reduction target for the average GHG intensity of transport fuels by at least 6% by 2020. With the RED III, the GHG intensity target has been replaced by the ambitions 2030 target for transport. | Directives such as these can contribute to the uptake of synthetic fuels. |
| Storage | American Petroleum Institute API RP 1640<br>Product Quality in Light Product Storage | This Recommended Practice provides guidance for light liquid biofuel (bio-diesel/FAME) handling and storage for bunkering and ship facilities. Guidance documents that cover various applications, uses, and processes for other synthetic fuels can contribute to its uptake. | Similar to other guidance documents and fuel quality rules, this RP covers only gasoline, kerosene, diesel, heating oil and their blend components (i.e., ethanol, bio-diesel/FAME, and butane).<br>Modifications to this or the creation of further guidance covering other commonly used synthetic fuel types may be more useful | Guidelines such as these can contribute to the uptake of synthetic fuels as it is used by ship designers, owners, regulators, and operators as an informational resource when addressing alternative or new types of fuels. |
| Transportation & Handling | IMO Code for Construction and Equipment of Ships Carrying Liquefied Gases (IGC Code) | Adequately deals with the transport in bulk of liquefied gases. Gas carrier fleet is focused on transport of LNG, LPG, ethane, ethylene and ammonia with bulk of experience with burning LNG as cargo and evolving trend to burn other cargoes such as ethane and LPG. | Could benefit from clarifying current Code covering transport of bio equivalents such as e-LNG or updated as necessary | As synthetic fuels continue to grow in the industry, addressing their specific needs as a cargo (if any) is equally as important as addressing provisions in use. Further experience and developments regarding the trade and transport of synthetic fuels can contribute to the uptake of those types of alternative fuels. |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| | International Code for the Construction and Equipment of Ships Carrying Dangerous Chemicals in Bulk (IBC Code) | Adequately deals with the transport in bulk of chemicals. Methanol carrying fleet emerged as early adopters of methanol as fuel. | Covers carriage of biofuel equivalents such as bio-methanol in association with other IMO instruments covering energy-rich fuels and application of MARPOL Annexes I and II, however, synthetic fuels are not directly addressed. | |
| | Guidelines for the Carriage of Energy-Rich Fuels and their Blends (MEPC.1/Circ.879) and Guidelines for the Carriage of Blends of Biofuels and MARPOL Annex I Cargoes (MSC MEPC.2/Circ17) | Provides important information to the marine industry about the handling and carriage of biofuels and energy-rich fuels. | Considered covers carriage in bulk of biofuel blends and energy- rich fuels in bulk, however, synthetic fuels are not directly addressed. | Internationally published guidelines such as these can contribute to the uptake of synthetic fuels as it is used by ship designers, owners, regulators, and operators as an informational resource when addressing alternative or new types of fuels. |
| | IBIA, IMPCA, Methanol Institute | IMPCA and Methanol Institute are active in developing methanol specifications and methanol handling guidance, including bunkering. IBIA are undertaking future fuels assessments, including biofuels. | Could include dedicated marine bunkering guidance for synthetic fuels, or add clarification that there is no change in bunkering for synthetics as compared to traditional fuels. | Development of industry best practice and guidance publications for synthetic fuel handling, specifically bunkering and transfers, should be supported. |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| Use & Consumption | IMO International Code of Safety for Ships using Gases or other Low-Flashpoint Fuels (IGF Code) | Provides requirements for ships using fuels with low-flashpoint (i.e., below 60°C), prescriptively covers LNG but can apply to other low-flashpoint or gaseous fuels, including e-methanol (applies MSC.21/Circ.1621) or e-LNG. | Future amendments should include detailed prescriptive requirements for other gaseous and low-flashpoint fuels, including the synthetic-derived variants, and prior to amendments can support take- up through the development of interim guidelines similar to the methyl/ethyl alcohol precedent. | The origin of the IGF Code was initially to support the adoption of LNG as marine fuel but contains provisions to approve other low-flashpoint fuels and gases under the *'Alternative Design'* process. In the absence of amendments, publication of interim guidelines (as already implemented for methyl/ethyl alcohol fuels with MSC.1/Circ.1621) would facilitate uptake of those fuels, and their synthetic fuel equivalents. |
| | IMO International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) | 2014 Update introduced the option to burn non-toxic cargoes as fuel other than natural gas (methane). These can include synthetic fuel cargo variants, such as e-methane. | The 2014 update facilitates burning of other cargoes such as ethane and LPG. On basis of no significant differences between e - variants of IGC Code cargoes to their synthetic equivalents, the Code adequately covers potential burning of those cargoes as fuel. Some differences between IGC Code and IGF Code hamper harmonised requirements for effectively the same equipment and systems. | Future work at the IMO Sub-Committee on Carriage of Cargoes and Containers (CCC) plans to undertake a complete review of the IGC Code. These changes seek to fix implementation problems with the 2014 Code, harmonise further with the IGF Code where practicable and to consider widening the range of allowed cargoes to be burnt. Earliest implementation is expected to enter into force 1 January 2028. |
| | IMO MSC.1 /Circ.1621 – Interim Guidelines for the Safety of Ships Using Methyl/Ethyl Alcohol as Fuel | Applicable to methyl/ethyl alcohol fuels and supports application under the IGF Code. Landmark publication supporting application of methanol as a marine fuel beyond the early adopters. | No significant gaps for supporting application of synthetic methanol (including e-methanol) as a marine fuel. | Further updates expected based on industry experience. |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| | SOLAS and IMO International Code of Safety for Ships using Gases or other Low-Flashpoint Fuels (IGF Code) | Historically, SOLAS has prohibited the use of fuel oils with less than a 60˚C flashpoint, except for use in emergency generators (where the flashpoint limit is 43˚C) and subject to other requirements detailed in SOLAS Chapter II-2 Regulation 4.2.1. Currently this work item being considered by CCC to develop requirements for fuel oils with a flashpoint between 52˚ and 60˚C. | Fuel oils (which may include biofuels) with lower than 60°C flashpoint currently not covered within SOLAS or IGF Code. That said, work is ongoing at IMO CCC on Draft Interim Guidelines for the Safety of Ships using Low-Flashpoint Oil Fuels. These will cover synthetic fuels with a flashpoint between 52ºC and 60ºC. | The lack of current regulation for fuel oils with a flashpoint between 52˚ and 60˚C is not seen as a significant barrier to synthetic fuel take- up (since some have flashpoints above 60˚C), however this gap is being addressed in the current IMO instruments. |
| | SOLAS ISM Code, SOLAS II – 1/Regulation 3-1 and classification society requirements | SOLAS ISM Code requires operators to assess all risks to a company's ships. SOLAS also requires equipment compliance with classification society rules. Synthetic diesels are not an engine type defining parameter, but onboard demonstration of suitability typically required. | IMO guidance similar to MEPC.1/Circ.878 for bio-diesels and clarification on application via IACS UR missing. | IMO guidance similar to MEPC.1/Circ.878 for bio-diesels would facilitate owners and operators' obligations under the ISM Code. Together with clarification on application of classification society requirements via IACS URs or similar instruments would support harmonised application of class society requirements, as called out by SOLAS II-1/Regulation 3-1. |
| | ISO 22548:2021. Ships and marine technology – Performance test procedures for LNG fuel gas supply systems (FGSS) for ships | This document specifies evaluation methods of characteristics such as pressure, flow rate, temperature and system stability of fuel gas supply systems (FGSS), which are manufactured to use vapourised liquefied natural gas (LNG) or boil-off gas as fuel gas supply to the vessel's gas consumers. It is applicable to evaluate the performance of the LNG FGSS: prior to delivery or after installation onboard a ship, and to assure the system characteristics are taken into account for the entire gas consumers during ship's gas trial or sea trial. | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standard(s) | Existing standards that cover performance test procedures for LNG FGSS or other quality standard can ease the adoption of fuel alternatives using the existing infrastructure, such as e-LNG as the testing is expected to be similar. |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| | ISO 22547:2021. Ships and marine technology – Performance test procedures for high-pressure pumps in LNG fuel gas supply systems (FGSS) for ships | This document specifies performance and additional tests for high-pressure pumps in marine fuel gas supply systems (FGSS) supplying liquefied natural gas (LNG) to ships.<br><br>This document is applicable to positive displacement pumps to assess the mechanical features of the pumps and their auxiliary devices. | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standard(s) | Existing standards that cover performance test procedures for high-pressure pumps in LNG FGSS or other quality standard can ease the adoption of fuel alternatives using the existing infrastructure, such as e-LNG as the testing is expected to be similar. |
| Quality | ISO 8217:2017<br><br>Petroleum products – Fuels (class F) – Specifications of marine fuels | Limits allow liquid biofuel blends to de minimis or 7%, depending on the grade of marine fuel. | Standard could be revised to allow blend percentages of qualified synthetic fuels in marine fuels | Additional types of synthetic fuels can be used in marine fuel blends to meet sulphur limit regulations, but do not exactly conform to the fuel grades defined in this or other quality standards. Future updates of this standard intend to cover other fuels as industry experience grows. Including the 0.50% S fuel guidance, additional synthetic fuels, higher % of blend fuels and updating the specific energy calculator in the next ISO 8217 revision can contribute to the uptake of synthetic fuels. |
| | ISO/PAS 23263<br><br>Petroleum Products - Fuels (class F) – Considerations for fuel suppliers and users regarding marine fuel quality in view of the implementation of maximum 0,50% sulphur in 2020 | Addresses quality considerations that apply to marine fuels, defining general requirements that apply to all 0,50 mass% sulphur fuels and confirms the applicability of ISO 8217 for those fuels. | Incorporation of these considerations to the next ISO 8217 revision would consolidate the requirements and explicitly apply to synthetic fuels to be blended with petroleum fuels. | |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| | IMO Prevention of Pollution from Ships (MARPOL) Convention – Regulation 18 – Fuel Oil Availability and Quality | Provides recognised MARPOL fuel quality and availability regulations for marine fuel supply. | There is uncertainty on application of regulation 18.3.2.2 for $NO_X$. Annex VI Should add required clarifications for suppliers of e-fuels regarding the $NO_X$ emissions resulting from the synthetic fuel and other relevant synthetic fuel specific requirements such as BDNs and CF factors that may be applicable. | While a workaround exists by application of regulation 3.2 for trials onboard or regulation 4 for *'equivalents'*, there is a need to update Annex VI and the $NO_X$ Technical Code to provide clarity and harmonised application for burning synthetic fuels. |
| | ISO 23306:2020<br><br>Specification of liquefied natural gas as a fuel for marine applications | The standard applies to LNG derived from sources other than fossil petroleum, including shale gas, coalbed methane, bio-methane or synthetic methane. | The limiting facet of this standard is the method to calculate the Methane Number (MN) of the fuel and the potential for particles or debris, which is based on the fuel composition.<br><br>Standard does not set quality limits or defines a minimum MN value (requires the minimum to be agreed between supplier and user). It could benefit from including limits for those characteristics. | The inclusion of synthetic methane in this standard, and therefore bio-LNG, encourages the uptake of these fuels derived from synthetic materials. |
| | ISO/CD 6583<br><br>Specification of methanol as a fuel for marine applications | While this standard is under development, it is expected to follow the ISO 23306 approach to cover fuels derived from both fossil and renewable sources. | Ongoing standard development should ensure coverage of fuels derived from renewable sources (i.e., e-methanol) | The adoption of this standard into international marine regimes can contribute to the uptake of e-derived methanol (and possibly e-derived ethanol). |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| Bunkering | ISO/TS 18683:2015 – Guidelines for systems and installations for supply of LNG as fuel to ships | Where LNG is derived from bio-methane, this guideline applies to fuel supply systems to ships | This is applicable to LNG (and therefore to bio-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). | Existing standards that cover equipment requirements and bunkering procedures for a qualified type of fuel such as LNG as per ISO 23306 or other quality standard can ease the adoption of fuel alternatives using the existing infrastructure, such as e-LNG. |
| | ISO 20519:2017 Ships and marine technology – Specifications for bunkering of liquefied natural gas - fuelled vessels. | Where LNG is derived from bio-methane, this guideline applies to fuel bunkering | This is applicable to LNG (and therefore to bio-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). | |
| | ISO 28460:2010 Petroleum and natural gas industries – Installation and equipment for liquefied natural gas – Ship-to-shore interface and port operations | This document applies only to conventional onshore LNG terminals and to the handling of LNGC's in international trade. However, it can provide guidance for offshore and coastal operations. | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standard(s), where similar low-flashpoint, gaseous or toxicity risks to ports exist. | |
| | ISO 21593:2019 – Ships and marine technology. Technical requirements for dry-disconnect/connect couplings for bunkering liquefied natural gas. | This document specifies the design, minimum safety, functional and marking requirements, as well as the interface types and dimensions and testing procedures for dry-disconnect/connect couplings for LNG hose bunkering systems intended for use on LNG bunkering ships, tank trucks and shore-based facilities and other bunkering infrastructures. It is not applicable to hydraulically operated quick connect/disconnect couplers (QCDC) used for hard loading arms, which is covered in ISO 16904.<br><br>Based on the technology used in industrial manufacturing at the time of | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). | |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| | | development of this document, it is applicable to sizes of couplings ranging from DN 25 to DN 200. | | |
| | ISO/TS 16901:2022 – Guidance on performing risk assessment in the design of onshore LNG installations including the ship/shore interface | This document provides a common approach and guidance to those undertaking assessment of the major safety hazards as part of the planning, design, and operation of LNG facilities onshore and at shoreline using risk-based methods and standards, to enable a safe design and operation of LNG facilities. | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). | |
| | ISO 16904:2016 – Petroleum and natural gas industries – Design and testing of LNG marine transfer arms for conventional onshore terminals | ISO 16904:2016 specifies the design, minimum safety requirements and inspection and testing procedures for liquefied natural gas (LNG) marine transfer arms intended for use on conventional onshore LNG terminals, handling LNG carriers engaged in international trade. It also covers the minimum requirements for safe LNG transfer between ship and shore. | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). | |
| | ISO/TS 18683:2021 – Guidelines for safety and risk assessment of LNG fuel bunkering operations | Gives guidance on the risk-based approach to follow for the design and operation of the LNG bunker transfer system, including the interface between the LNG bunkering supply facilities and receiving LNG - fuelled vessels. | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). | |
| | ISO/TR 17177:2015 – Petroleum and natural gas industries - Guidelines for the marine interfaces of hybrid LNG terminals | ISO/TR 17177:2015 provides guidance for installations, equipment and operation at the ship to terminal and ship to ship interface for hybrid floating and fixed LNG terminals that might not comply with the description of *'Conventional* | This is applicable to LNG (and therefore e-LNG) but could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). | |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
|---|---|---|---|---|
| | | *LNG Terminal'* included in ISO 28460.<br><br>ISO/TR 17177:2015 is intended to be read in conjunction with ISO 28460 to ensure the safe and efficient LNG transfer operation at these marine facilities. | | |
| | ISO/AWI 22238 [Under Development] – Design, construction and testing of high-pressure gas transfer systems | This document addresses requirements for design, construction and testing of high-pressure transfer systems for FSRU/ FRU/ FSU applications. High-pressure transfer systems are considered to be ship-to-shore systems transferring pressurised gas from floating units to any part of a gas grid. | This document addresses requirements for design, construction and testing of high-pressure transfer systems for FSRU/ FRU/ FSU applications. High-pressure transfer systems are considered to be ship-to-shore systems transferring pressurised gas from floating units to any part of a gas grid. This document could be revised to include specific guidance for other synthetic derived alternative fuels or used as basis for development of new standards(s). | |
| | MI/LR Introduction to Methanol Bunkering Technical Reference | MI/LR: publication provides a checklist and process flow approach to safely handle methanol bunkering transfers. | Supports take up of methanol and e-methanol as a marine fuel. | |
| IACS Classification Societies Rules, Guides and Guidance | | Classification Societies participate in international committees and regulatory bodies regarding ship design, construction, and safety requirements. IACS collectively make a unique contribution to maritime safety and regulation by providing technical support, compliance verification (of statutory instruments in their role as Recognised Organizations) and research and development. The collaborative effort of multiple class societies in IACS leads to the implementation of common rules, unified requirements | While Class Societies are engaging with synthetic fuel stakeholders to contribute to the safe uptake of synthetic fuels, more could be done to encourage industry adoption of synthetic fuels. Where IACS have adopted URs, these must be uniformly applied by IACS members in their rules. Similarly, where IACS UIs exist to statutory requirements, these are, by purpose, to facilitate harmonised application of the regulations. Currently no such IACS publications related to synthetic fuels exist. | Considering the challenges in developing and implementing changes to regulations in a timely manner, industry stakeholders such as IACS can facilitate synthetic fuel take up and harmonised application by the development of Unified Requirements, Unified Interpretations and Recommendations, this should be encouraged. |

| Subject | Rule/Guidance | Comment on Code/Standard - Benefits | Comment on Code/Standard - Gaps | Discussion and Recommendations |
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| | | (UR) for typical Class Rules, unified interpretations (UI) of statutory instruments and other recommendations that are applied consistently by IACS members. They are participating with ship owners and engine manufacturers to guide safety practices, as well as to gain experience on the use of synthetic fuels as marine fuel. | | |
| Regional and National Rules for Marine Fuel, including Synthetic fuels as Marine Fuel | | In general, when regions, nations, and local authorities adopt rules, standards, or regulations regarding the decarbonisation and reduced emission limits of marine fuels, they are contributing to the uptake of synthetic fuels as marine fuels. | Regional and national regulations can lead developments at IMO level. Wider adoption of IMO (or regional or national regulations) in those locations lacking all such instruments could uniformly support the adoption of synthetic fuels. When local marine authorities do not implement emissions reductions limits similar to those of IMO MARPOL Annex VI, the uptake of synthetic fuels for marine fuel is generally restrained. Specifically, without the required emissions limits (or economic incentive), shipowners and operators will continue to purchase and use the less costly options for fuel, which are typically the conventional petroleum heavy fuel oils. | The selected regional or national authorities in the sections above can be seen by the industry as the leaders in regional maritime authority, and therefore the policy and regulations put in place regarding alternative fuels may or may not lead others to implement similar measures. When these authorities incorporate emission limits on emissions from local, domestic and international shipping, contributions to the uptake of alternative fuels including synthetic fuels are being made. |

# Appendix D – Symbols, Abbreviations and Acronyms

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|---|---|
| **ABS** | American Bureau of Shipping |
| **AFIR** | Alternative Fuels Infrastructure Regulation |
| **ASTM** | American Society for Testing of Materials |
| **BDN** | Bunker Delivery Note |
| **BOG** | Boil Off Gas |
| **BTL** | Biomass-to-Liquid |
| **CAPEX** | Capital Expenditure |
| **CCC** | Carriage of Cargoes and Containers Sub-Committee (IMO) |
| **$C_F$** | Fuel-Conversion Factor (IMO - EEDI) |
| **$CH_4$** | Methane |
| **CII** | Carbon Intensity Indicator (IMO) |
| **CNG** | Compressed Natural Gas |
| **CO** | Carbon Monoxide |
| **$CO_2$** | Carbon Dioxide |
| **DAC** | Direct Air Capture |
| **DCS** | Data Collection System (IMO) |
| **DECA** | Domestic Emission Control Areas |
| **DME** | Dimethyl Ether |
| **DWT** | Deadweight Tonnage |
| **ECA** | Emission Control Area |
| **EEA** | European Economic Area |
| **EEDI** | Energy Efficiency Design Index (IMO) |
| **EEOI** | Energy Efficiency Operational Index (IMO) |
| **EEXI** | Energy Efficiency Existing Ship Index (IMO) |
| **EMSA** | European Maritime Safety Agency |
| **EU** | European Union |
| **ETD** | Energy Taxation Directive (EU) |
| **ETS** | Emissions Trading Scheme (EU) |
| **FAT** | Factory Acceptance Test |
| **FGSS** | Fuel Gas Supply System |
| **FLL** | Fuel Lifecycle Label |
| **FOC** | Fuel Oil Consumption |
| **FOG** | Fat Oil and Greases |
| **FQD** | Fuel Quality Directive (EU) |
| **FSS** | Fuel Supply System |
| **FT** | Fischer-Tropsch |
| **GHG** | Greenhouse Gas |
| **GISIS** | Global Integrated Ship Information System (IMO) |
| **GTL** | Gas-To-Liquid |
| **GWP** | Global Warming Potential |
| **HAZID** | Hazard Identification Studies |
| **HC** | Hydrocarbon |

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|---|---|
| **HFO** | Heavy Fuel Oil |
| **HT** | High-Temperature |
| **HVO** | Hydrotreated Vegetable Oil |
| **IACS** | International Association of Classification Societies |
| **IBIA** | International Bunker Industry Association |
| **ICE** | Internal Combustion Engine |
| **IEA** | International Energy Agency |
| **IEC** | International Electrotechnical Commission |
| **IGC** | International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IMO) |
| **IGF** | International Code of Safety for Ships Using Gases or other Low-Flashpoint Fuels (IMO) |
| **IMO** | International Maritime Organization |
| **IPCC** | Intergovernmental Panel on Climate Change |
| **IRENA** | International Renewable Energy Agency |
| **ISM** | International Safety Management Code |
| **ISO** | International Organization for Standardization |
| **IFO** | Intermediate Fuel Oil |
| **LCA** | Life Cycle Assessment |
| **LCV** | Lower calorific value |
| **LFO** | Light Fuel Oil |
| **LHV** | Lower Heating Value |
| **LNG** | Liquified Natural Gas |
| **LNGC** | Liquified Natural Gas Carrier |
| **LPG** | Liquified Petroleum Gas |
| **LT** | Low-Temperature |
| **MARPOL** | Marine Pollution (IMO) |
| **MDO** | Marine Diesel Oil |
| **MEPC** | Marine Environment Protection Committee (IMO) |
| **MGO** | Marine Gas Oil |
| **MRV** | Monitoring Reporting Verification (EU) |
| **MSC** | Maritime Safety Committee (IMO) |
| **MSDS** | Material Safety Data Sheet |
| **$NH_3$** | Ammonia |
| **NO** | Nitrogen Oxide |
| **$NO_2$** | Nitrogen Dioxide |
| **$NO_X$** | Nitrogen Oxides |
| **$N_2O$** | Nitrous Oxide |
| **NTC** | $NO_X$ Technical Code |
| **OC-OTEC** | Open-Cycle Ocean Thermal Energy Conversion |
| **OECD** | Organization for Economic Co-operation and Development |
| **OPEX** | Operating Expenditure |

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|---|---|
| **PEM** | Proton Exchange Membrane |
| **PM** | Particulate Matter |
| **PPM** | Parts Per Million |
| **RCF** | Recycled Carbon Fuels |
| **RED** | Renewable Energy Directive (EU) |
| **RFNBO** | Renewable Fuel of Non-Biological Origin |
| **RLF** | Renewable and Low-carbon Fuel |
| **RO** | Recognised Organization |
| **RWGS** | Reverse Water Gas Shift |
| **SCR** | Selective Catalytic Reduction |
| **SDS** | Safety Data Sheet |
| **SECA** | $SO_X$ Emission Control Area |
| **SFOC** | Specific Fuel Oil Consumption |
| **SGC** | Specific Gas Consumption |
| **SMR** | Steam Methane Reforming |
| **SOLAS** | International Convention for the Safety of Life at Sea, 1974, as amended (IMO) |
| **SOEC** | Solid Oxide Electrolyser Cell |
| **SO2** | Sulphur Dioxide |
| **SO3** | Sulphur Trioxide |
| **$SO_X$** | Sulphur Oxides |
| **SVO** | Straight Vegetable Oil |
| **TCO** | Total Cost of Ownership |
| **TEU** | Twenty Foot Equivalent (Container) |
| **TRL** | Technology Readiness Level |
| **TSA** | Temperature Swing Adsorption |
| **TTW** | Tank-To-Wake |
| **UI** | Unified Interpretation |
| **ULSFO** | Ultra Low Sulphur Fuel Oil |
| **UR** | Unified Requirement |
| **VOC** | Volatile Organic Compound |
| **VLSFO** | Very Low Sulphur Fuel Oil |
| **WTT** | Well-To-Tank |
| **WTW** | Well-To-Wake |

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