Review Alternative Fuels for Shipping

Verkenning Alternatieve Brandstoffen voor de Scheepvaart (VABS)

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Contents

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Uitgangspunten

De internationale druk op het reduceren van scheepsemissies is groot Er worden maatregelen genomen voor de reductie van CO2, NOx, SOx en roet (PM). LNG (Liquefied Natural Gas) biedt perspectieven voor grotere zeeschepen, maar is niet haalbaar voor kleinere schepen, vanwege het ruimtebeslag aan boord en de hoge investeringskosten.

Ook (hernieuwbare) waterstof en (bio)methanol kunnen gebruikt worden voor de scheepvaart. Waterstof is een aantrekkelijke brandstof vanuit emissie perspectief, maar heeft een zeer lage energiedichtheid per volume-eenheid. Voor de scheepvaart lijkt het daarom beter om waterstof te binden aan methanol. Methanol is een schone brandstof en kan eenvoudiger opgeslagen worden aan boord met een kleiner ruimtebeslag dan LNG tegen lagere investeringskosten.

Er zijn diverse uitdagingen om varen op waterstof of methanol mogelijk te maken. De technologie is beschikbaar, maar er dienen, naast de bunkerinfrastructuur, geïntegreerde oplossingen ontwikkeld te worden die voldoen aan regelgeving en maatschappelijk en economisch aantrekkelijk zijn.

Doelstelling van het project

Doel van de verkenning is te onderzoeken in welke situatie waterstof en/of methanol kan worden ingezet vanuit het perspectief van operationele inzet, techniek, veiligheid en rentabiliteit.

Er dient bepaald te worden welke configuraties (op termijn) economisch aantrekkelijk zijn voor welke vaartuigen en welke bunkerinstallaties aan de wal nodig zijn. Configuraties omvatten zowel de ontvangstinstallatie, de opslag, het distributienetwerk en de installatie aan boord als aan de wal. Er wordt een vergelijking gemaakt van (hernieuwbare) waterstof en (bio)methanol met (bio)LNG en de huidige fossiele Marine Gas Oil (MGO) op de aspecten ontwerp, bedrijfseconomie en veiligheid.

Daarnaast gaat het om te bepalen welke doorontwikkeling van architectuur, componenten en deelsystemen nodig zijn om kosten en risico's te verlagen en te voldoen aan de stringente regelgeving voor brandstoffen met een laag vlampunt. Het project creëert daarmee randvoorwaarden voor verdere ontwikkeling van componenten en deelsystemen en levert informatie op voor eventuele toespitsing van de regelgeving.

Spin off binnen en buiten de sector

Dit project is mede aanleiding geweest voor een vervolgproject genaamd Green Maritime Methanol, waarin een groot aantal bedrijven en onderzoeksinstellingen de mogelijkheden van groene methanol voor de scheepvaart onderzoekt. (zie ook www.greenmaritimemethanol.eu)

Overige informatie

Dit rapport is kosteloos te downloaden op www.koersenvaart.nl.
Voor meer informatie kunt u contact opnemen met Koers & Vaart B.V. - dhr. P. 't Hart.

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Introduction

There is an growing international consensus to substantially reduce air emissions in shipping. Policy measures are being taken on a global scale to reduce emissions from NOx, SOx, Particulate Matters (PM), and greenhouse gasses such as CO2.

Alternative fuels offer opportunities to meet new international regulations and ambitions set out by the International Maritime Organisation (IMO). However, each of these fuels have their own hurdles and challenges that must be overcome, both in financial and technical terms. This study sets out to define these hurdles and determine the most preferable alternative fuels. Alternative fuels covered within this study are; (bio-)LNG, biodiesel, (bio-)methanol and (green) hydrogen and will be compared to a reference fuel; MGO. These fuels were chosen because of their promising potential to reduce both local pollutants and greenhouse gas emissions.

Hydrogen has regained popularity due to its reputation as a zero-emission fuel. Nevertheless the energy density is very low, complicating its storage onboard of vessels. Methanol is another appealing alternative fuel configuration as is can be stored more easily taking up less volume in comparison to both hydrogen and LNG. Although the fuels are mostly considered technologically ready, challenges regarding bunkering infrastructure, safety and ship design must be overcome. Furthermore, alternative fuels must be economically viable.

The aim of this study is to first determine whether alternative fuel configurations are feasible from a technical and economic perspective. The configurations discussed cover the receiving installation, storage, distribution, and the installation onboard as ashore. A comparison is made between conventional MGO and Biodiesel, (bio) LNG, (bio)methanol and (renewable or green) hydrogen in terms of design, economic feasible and safety. The properties of the alternative fuels will be thoroughly considered identifying any challenges and opportunities inherent to each alternative fuel. Various properties result in differing safety regulations and technical configurations for both the vessel and the fuel system. Fuel availability, bunkering and scalability also play a vital role in whether alternative fuels are feasible. Moreover, the economic viability of the different fuel configurations will be assessed according to a return on investment calculation model. This model in combination with a scenario approach predicated on historic price data then outlines 325 different scenarios, aiming to illustrate under which conditions alternative fuels will achieve a return on investment. The scenarios clearly show where the risks of various alternative fuels lie and give an indication on where fuel prices ought to be in order to be profitable. From here recommendations are given as to how national and international air emission regulations may be met and which fuel(s) form a realistic alternative.

This study is useful for shipowners and larger shipping companies that consider to adopt an alternative fuel system. Furthermore, the study may provide policy makers with useful insights and could aid in policy adjustments needed in order to achieve ambitions regarding local pollution and greenhouse gases articulated by the IMO. Furthermore, the study will aid further development of the architecture of alternative fuel configurations, components and subsystems needed to reduce costs and comply with stringent regulations applied to low-flashpoint fuels.

1. State of the art technology

In order to get a comprehensive view of the technical feasibility of the alternative fuels researched it is important to outline the main characterises of these various fuel types. This chapter will elaborate on the fuel properties and their (life-cycle) air emissions. In the following chapters a clear distinction is made between 'green', 'blue' and 'grey' fuels. The difference lies not in the physical or chemical components of the fuel, but rather in the amount of greenhouse gasses (GHG) emitted over the life-cycle. Grey fuels are fossil fuels and do emit extra GHG's into the atmosphere. While blue fuels have similar emissions rates, carbon is captured and sequestered. Green fuels do not emit extra GHG's in the atmosphere at all, with the one exception of biofuels. Biofuels are considered to be renewable as no fossil fuel are extracted from the earth's crust and can be grown back at the same rate as used. Nevertheless biofuels have been subject to criticism as its production can lead to indirect land use change as its production competes with cropland or natural areas that contain high carbon stocks. However, because biofuel is created from seemingly inexhaustible sources it also considered to be green or renewable energy (European Commission , 2018) (World Energy Council, 2019).

1.1 Marine Gas Oil (MGO)

Marine gasoil (MGO) comprises all the marine fuels that consist of distillates which are derived from crude oil often containing a blend of various distillates. Marine gasoil should not be confused with Marine Diesel Oil (MDO) which consists of a blend between distillates and heavy fuel oils. Marine gasoil is similar to diesel, although it has higher density (E4tech , 2018).

In contrast to HFO, MGO does not require heated storage, due to the lower viscosity allowing the fuel to be pumped into the engine at approximately 20*°C.* Furthermore, marine gasoil is considered to be a clean fossil fuel especially when compared to heavy fuel oil (HFO) and marine diesel oil (MDO). Both greenhouse gas (GHG), particulate matter, and soot emissions of marine gasoil are significantly less when compared to the more commonly used HFO (Marguard & Bahls AG, 2019).

MGO is more expensive than HFO. However, it is expected by industry insiders that the maritime industry will start using more MGO, mainly due to the optimization of production processes of refineries producing less residual fuel because of the falling price of HFO caused by stricter regulations (Wankhede, 2019). Besides, McKinsey & Company expects that due to the IMO 2020 lower sulphur requirements shippers will switch to MGO (BIlling, Fitzgibbon, & Shankar, 2018).

1.2 Liquified Natural Gas (LNG)

LNG is natural gas that has been converted to liquid, by means of cooling, for ease of storage and transport. Like MGO, natural gas is a fossil fuel consisting of hydrocarbons, because the chemical composition consists of hydrogen and carbon atoms. Natural gas may be derived directly from gas/oil fields, or from the industrial distillation process from refineries. By cooling the natural gas to -162 *°C* it becomes a cryogenic liquid. LNG consists mainly out of methane (87%-99%), ethane (<1%-10%), propane(>1%- 5%) and butane (1%) and therefore is a non-toxic gas.

Bio-LNG can also be produced from biogas, which is mainly produced by anaerobic digestion of organic waste materials. Moreover, bio-LNG is considered to be the cheapest and cleanest biofuel available (Bakker, Langerak, Lems, & Dirkse, 2012).

Storage of (bio-)LNG is more complex in comparison to MGO, as the liquid must be stored in heat insulated tanks. Besides, the energy density of LNG is approximately half of that of MGO and therefore requires more storage room with additional installation and arrangements of the system. If any LNG leaks from these tanks the cryogenic temperature will instantly freeze any tissue or cause other solid materials to become brittle. The flammability of natural gas makes it desirable as an energy source but can also form a safety hazard. LNG in liquid form is not flammable, and a small leak in a tank within a well ventilated area will swiftly mix with air so that methane concentrations will be below 5%. Therefore, only a small area close to the leak would allow the gas to ignite. LNG is colour and odourless, although the cold liquid causes water in the air to freeze creating a white cloud. This cloud does not define the boundaries of combustible gas in the air. Furthermore, LNG vaporizes completely in air and does so rapidly leaving no residues behind and not harming any aquatic life if a spill occurs, which is in stark contrast to heavy fuel oil (HFO) or MGO.

Despite safety hazards such as the high energy content of the LNG tank, the explosion hazard in case of leakage and the extremely low temperatures, LNG has become a proven and available commercial fuel for the maritime industry. Currently, the LNG fleet consists of approximately 600 vessels and is arguably safer as opposed to MGO and HFO shipping as insurance rates are considerably lower (Dodge, 2014).

Additionally, when compared to oil-based marine fuel LNG shows significant GHG benefits. Upon ignition LNG produces mainly carbon dioxide and water vapour. A recent study conducted for SEA\LNG SGMF by Thinkstep (2019) indicates that it could potentially reduce shipping GHG up to 21%. Because of this the importance of using LNG as a marine fuel is increasing, not only for LNG tankers transporting the liquid gas but also other ship types, such as large container ships, ferries or other carriers. Nevertheless, LNG engines often do experience methane slip to an extent that is depended on combustion cycle, either Diesel (high pressure) or Otto cycle (low pressure). (Trakakis, 2018).

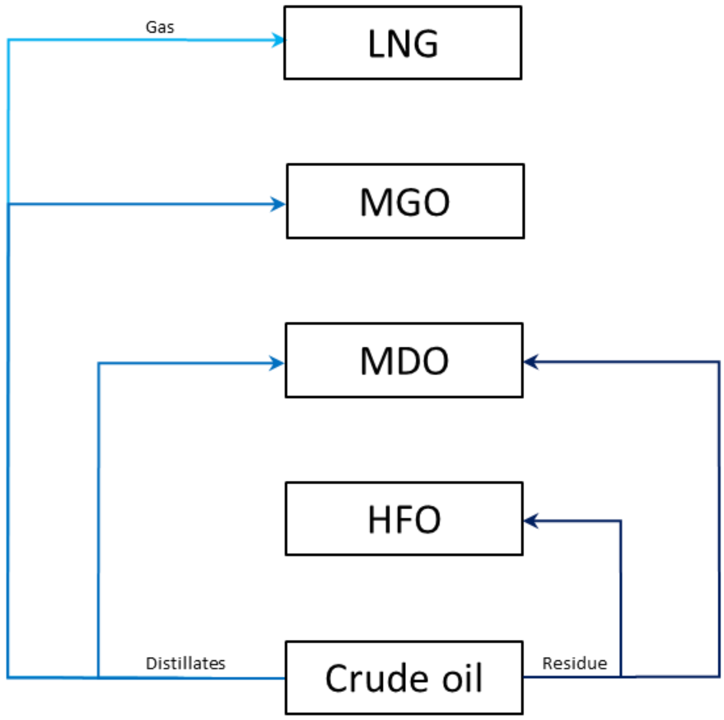


Figure 1: Fossil fuels for the maritime industry

1.3 Biodiesel

Generally, there are three types of biodiesel. The first type of biofuel comprises of long-chain fatty acid methyl esters (FAMEs) derived either from biomass or biomass residues made into liquid fuel, through the process of esterification using methanol as a catalyst. Different raw materials may be used for the production of FAMEs, such as palm, coconut, rapeseed, soya, tallow or even cooking oils. Currently, the use of FAME is more widespread and is almost always blended and sold with mineral diesel fuel. Biodiesel is also produced by transesterification of vegetable oils, which in principle are suitable for the operation of diesel engines. However, energy content per kg is lower when compared to diesel. Other than that fuel properties as defined in European Norms (EU 14214) for FAME are similar to those of diesel fuels. In practice the chemical composition of different FAMEs often vary significantly due to the wide variety of feedstocks from which the fuels are produced. In principle FAMEs are suitable for diesel engines, although it is most often blended with other diesel fuels. FAMEs are known to reduce depreciation of the combustion system due to the higher lubricity, although esters are more polar which attracts debris thereby polluting the fuel and plugging the filters. Therefore FAME biodiesel in vehicle engines has a B7 blend wall meaning that diesel engines should be compatible with up to 7% biofuel contained in the fuel blend (Giakoumis & Sarakatsanis, 2018; Martinez, Sanchez, Encinar, & Gonzalez, 2014; Merkisz, Fuc, Lijewski, & Kozak, 2016).

The second one is produced by hydro-treating vegetable oils or waste oil and fats (HVO). In this process hydrogen is used to remove oxygen from the vegetable oil in order to create hydrocarbons. Although the technique is relatively new its use has matured swiftly and is already a commercial option. In contrast to FAME, HVO is a hydrocarbon, with an almost identical chemical composition to that of diesel fuels, making it compliant with diesel fuel specifications. HVO is a drop-in fuel and is functional equivalent to its fossil counterparts in the marine combustion engines, and thus fully functional within the existing infrastructure. HVO is very much like DMA(MGO) and therefore subject to the same regulations and norms. For this reason HVO need not to be blended with MGO. Heating values are the highest of existing biofuels and HVO often requires less maintenance as the fuel has a low tendency to form deposits in the fuel injection system. Also, when compared to FAME, HVO has no issues operating in severe cold circumstances (Aatola, Larmi, Sarjovaara, & Mikkonen, 2008).

The newest type of biofuels are biomass-to-liquid or BtL fuels, in which lignocellulosic biomass is converted into synthetic liquid hydrocarbons. BtL has very good fuel characteristics and is low in sulphur and aromatic contents. Furthermore, like HVO it meets all the standards for normal diesel fuels. BtL is produced in two steps, first , synthesis gas is produced from biomass feedstock, after which the synthesis gas is converted into a liquid fuel. Conversion of the latter step is done by using a catalytic process known as the Fischer-Tropsch process. Currently BtL is still in the research and development phase and is yet to be commercialized (Tyrovola, Dodos, Kalligeros, & Zannikos, 2017).

Biodiesels (FAME, HVO & BtL) offer an alternative to the earlier discussed fossil fuels or can be added as a drop-in fuel. The main advantages of biodiesel are that the fuels are nontoxic, biodegradable, and renewable with the potential to reduce greenhouse gas emissions. However, traditional FAMEs are considered controversial as it often competes with the food industry. Besides, biodiesel fuel is still more expensive when compared to the fossil fuels (DNV-GL, 2019).

1.4 Methanol (MEOH)

Methanol (MEOH), also known as methyl alcohol or wood alcohol is the simplest alcohol and is widely used in the chemical industry. Recently, methanol has made its way into the energy sector in which its application is growing. The fuel itself is light, volatile, colourless and flammable (non-luminous), has a distinctive odour, is toxic, and (unlike ethanol) is unfit for consumption. Methanol is produced mainly from natural gas, but can also be produced from biomass (bio-methanol), coal, waste and even CO2 produced by power plants. Methanol is also used to produce biofuels through the process of transesterification. When produced from natural gas a combination of steam reforming and partial oxidation is applied, with an energy efficiency of approximately 70% when compared to the energy provided from the natural gas. Another widely applied approach to produce methanol is through the process of gasification of coal, which is cheap and widely available. However, this produces twice as much GHG emissions as methanol produced from natural gas. When methanol is produced from green hydrogen and CO2 it is considered to be a renewable energy source making it a green ship fuel (Maritime Knowledge Centre, 2017; SSPA, 2014)

The fuel can be used for internal combustion engines or fuel cells and can be injected independently or as a mixture. In the maritime industry methanol is most often mixed with other fuels (MGO) (Marguard & Bahls AG, 2019). Once mixed with a diesel blend it becomes suitable for use in diesel combustion engines. Due to the lower density of the fuel, methanol requires larger storage volumes (factor 2.5) when compared to MGO. Prices for methanol per unit of energy content are highly depended on the natural gas prices as it is most often produced from natural gas (Andersson & Salazar, 2015).

1.5 Hydrogen

Hydrogen (H2) is the most common element in the universe, accounting for approximately 90% of the universe by weight, although it is rarely found in its pure form. Hydrogen is a colourless, odourless, and non-toxic gas under atmospheric conditions. Compared to MGO, hydrogen has a high energy content per weight (approximately factor 3), although it is quite low per volume at standard temperatures and under atmospheric pressure. Like with natural gas this problem may be solved by storing the hydrogen under increased pressure or by storing it at extremely low temperatures (-254°C) so that it becomes a liquid, thereby increasing the density of hydrogen by a factor 800. Another important feature to consider is its extraordinary high dispensability, passing through a porous material or even metals. This can cause materials to become brittle, which is why storage containers must be equipped with a diffusion coating layer. Besides, it must be noted that hydrogen is highly flammable, has an extremely high flammability range, and burns in a flame that is pale blue making the fire difficult to see. The combustion properties of hydrogen make it an interesting combustion fuel

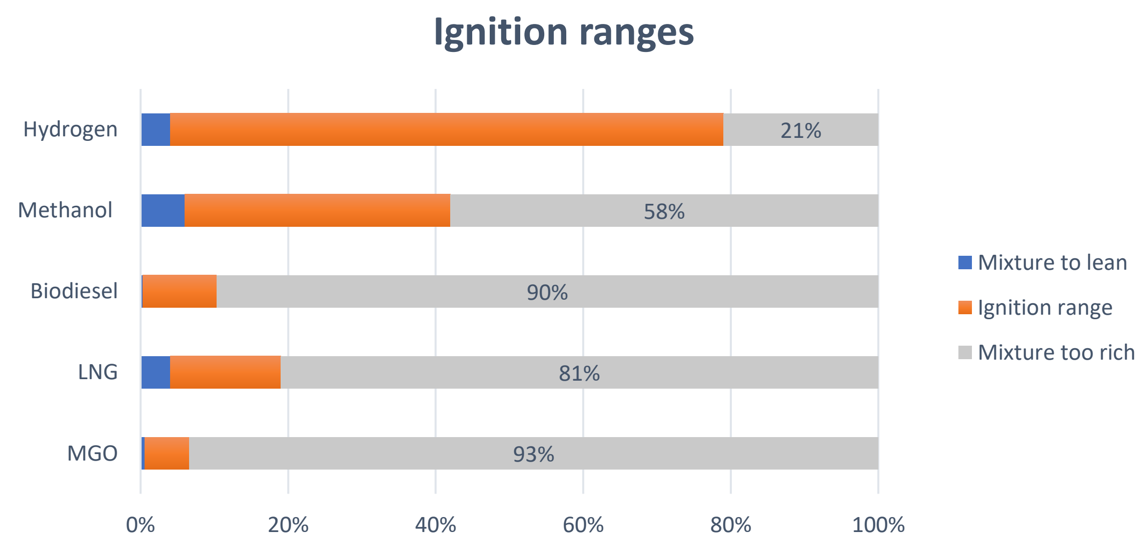


Figure 2: Ignition ranges of various alternative fuels

as it can be used in internal combustion engines while allowing for extremely lean air/hydrogen gas mixtures. Lean-burn engines emit far less hydrocarbons and can also be used to reduce throttling losses. (Rinebold, 2016; Shell, 2017).

As hydrogen is the most common element it can be produced from numerous resources, such as fossil fuels, biomass, nuclear energy and renewable energy resources. This diversity of potential supply resources make that hydrogen is considered to be such a promising energy carrier. The use of hydrogen in shipping is mainly considered to happen through the use of fuel cells, although it may also be injected with a pilot fuel in a gas powered turbine or diesel engine to provide propulsion. The marine application of fuel cells requires new electrical propulsion systems, a fuel cell and new storage capabilities.

Since hydrogen does not produce CO2 upon combustion, its GHG emissions depend on the production method used. Currently most hydrogen is produced from fossil resources (95%) which includes methane steam reforming and coal gasification, which produce high GHG emission rates (grey hydrogen), although smart carbon capture and sequestration (CCS) systems may significantly reduce these emissions (blue hydrogen). Hydrogen can also be produced through electrolysis in which water (H2O) is split by running an electrical current through the water. If the electricity used is renewable and subsequently is used in a fuel cell the entire process (well-to-propeller) is without GHG emissions (green hydrogen).

The chemical properties of hydrogen make it an excellent combustion fuel. Nevertheless, in order to be compatible in terms of energy/volume, the fuel must be stored at extremely low temperatures, which would require additional infrastructure on board and onshore. Moreover, green hydrogen is not readily available yet due to difficulties with transport and storage. Besides, production of green hydrogen is considered to be expensive, up to 2 or 3 times as high as MGO.

The following table provides an overview of relevant physical and chemical properties of the fuels discussed in this study.

Table 1 Fuel properties

Fuel properties	**MGO**	**LNG**	**bio diesel**			**CH3OH**	**H2**
			FAME (EN 14214)	**HVO**	**BTL (R&D phase)**		
Liquid density (kg/m3)	*820-890 (ISO 3675) default 850 (15°C)*	*430-470 default 450 (-162°C)*	*860-900 (15 °C)*	*770-790*	*760*	*790-800 (20 °C)*	*70.96 (-254 °C)*
Lower heating value (MJ/kg)	*42.7*	*42-55*	*36.5-38.6*	*≈ 44.0*	*43.9*	*20.1*	*120*
Lower explosive limit (% vol)	*0.60*	*4*	*0.3*	*0.5*	-	*6*	*4*

Upper explosive limit (% vol)	*6.5*	*15*	*10*	*5*	-	*36*	*75*
Flashpoint (°C)	*60 (ISO 1523)*	-*188*	*>120*	*55*	-	*12*	*-252.9*
Viscosity /40 (mm2/s)	*2-6 (ISO 3104)*	*n.v.t.*	*3.5-5*	*2.5-3.5*	*3.2-4.5*	*0.45*	*n.v.t*
	Definition of properties						
Liquid density			Measures the mass density of the liquid fuel in a given volume. Density is used to calculate the quantity of fuel delivered and gives an indication of the ignition quality of the fuel.				
Lower heating value			Heating value is the amount of heat released during combustion of the liquid fuel. The lower heating value (or calorific value) of a fuel is defined as the amount of heat liberated (MJ) by the complete combustion of a unit volume or weight of a fuel assuming that the produced water remains as a vapor and the heat of the vapor is not recovered (UNFCC, 1996).				
Lower explosive limit			Lowest concentration of gas or vaporized fuel in air capable of producing fire or an explosion in the presence of an ignition source (Werner Sölken, 2018).				
Upper explosive limit			Highest concentration of gas or vaporized fuel in air capable of producing fire or an explosion in the presence of an ignition source. Within the lower and the upper explosive limit gases and vapour are capable of producing fire or an explosion (Werner Sölken, 2018).				
Flashpoint			The lowest temperature at which a liquid fuel will form a vapour in the air near its surface that will ignite. This gives an indication of the flammability or combustibility of a fuel. Fuel with a flashpoint lower than 37.8°C are considered flammable, whereas fuels above are called combustible (Encyclopaedia Britannica , 2019).				
Viscosity			The resistance of a fluid to a change in shape, or a movement of neighbouring portions relative to one another. Viscosity denotes the opposition to flow of the fluid and can be seen as the internal friction between molecules,, opposing the development of velocity. Viscosities may vary greatly amongst different fuel types. Viscosity of fuel strongly depends on the temperature, the higher the temperature the lower the viscosity (Enceclopaedia Britannica , 2019).				

1.6 Air emissions alternative fuels

There are two main leading motivations that drive the shipping industry to use alternative fuels: to reduce local pollutants that are known to cause health issues; and to mitigate the effects of climate change by reducing greenhouse gas emissions. Emissions can be measured over the entire life-cycle of the fuel from Well-to-Propeller (WTP), including emissions associated with generating a fuel Well-to-

Tank (WTT)) and those associated with the combustion of the fuel itself (Tank-to-Propeller (TTP)). A key requirement for the alternative fuels is that it can deliver air emission reductions over its entire life-cycle. However, strict monitoring is needed to ensure that fuel generation is done sustainably.

Table 2 Air emissions related to shipping transport

Local pollutants	**Greenhouse gases**
Sulphur Oxide - SOx	Carbon Dioxide - CO2
Nitrogen Oxide - NOx	Methane – CH4
Particular Matter - PM	Nitrous Oxide – N2O

Many studies currently suggest that no widely available fuel exists to deliver on both the motivations, although research does suggest that some have the potential to do so. Green hydrogen, green LNG and green methanol are such fuels with the potential of being carbon neutral fuels. Many scientists and governments now point to hydrogen or other synthetic fuels to rely on decarbonisation of both energy input to the final production. However, hydrogen produced from natural gas emits almost twice as much CO2 in comparison to MGO. Likewise, biofuels are viewed as a sustainable short to medium-term solution for shipowners to comply with local pollutant regulations and GHG ambitions set by IMO.

At current regulations regarding local pollutants have focussed on reducing NOx, SOx, and PM emissions of ships. Regarding greenhouse gas emission reductions, policies have mainly focussed on reducing CO2 emissions as these are most common within the maritime industry. When looking at hydrogen it is often referred to as a clean and carbon free fuel, however this is only true in the case of green hydrogen production. Unfortunately, most government policies only look at emissions in the tank-to-propeller phase, thereby overlooking upstream emissions caused e.g. by grey hydrogen production. In the case of hydrogen, if produced from natural gas or coal refineries, CO2 emissions produced upstream are 1.5x as high (see figure 4), when compared to the well-to-propeller emissions of MGO.

As demonstrated in figure 3 in an overview of Well to Propeller NOx, PM, and SOx emissions it becomes evident that the fuel options MGO, Biodiesel and Methanol both have significantly higher NOx emission rates when compared to the other fuels. According to Gilbert el al (2017), in contrast to fossil fuels, hydrogen emissions mostly occur upstream within the fuel life cycle, although its reduction potential is significant. Furthermore, it is interesting to note that although some local pollutants are emitted upstream for hydrogen these are nowhere near the total of emitted pollutants from other alternative or conventional fuels. Besides it is worth mentioning that Tier III which will take effect from 2020 onward also only looks at local pollutants emitted during operations, or from Tank-To-Propeller (Gilbert, et al., 2017).

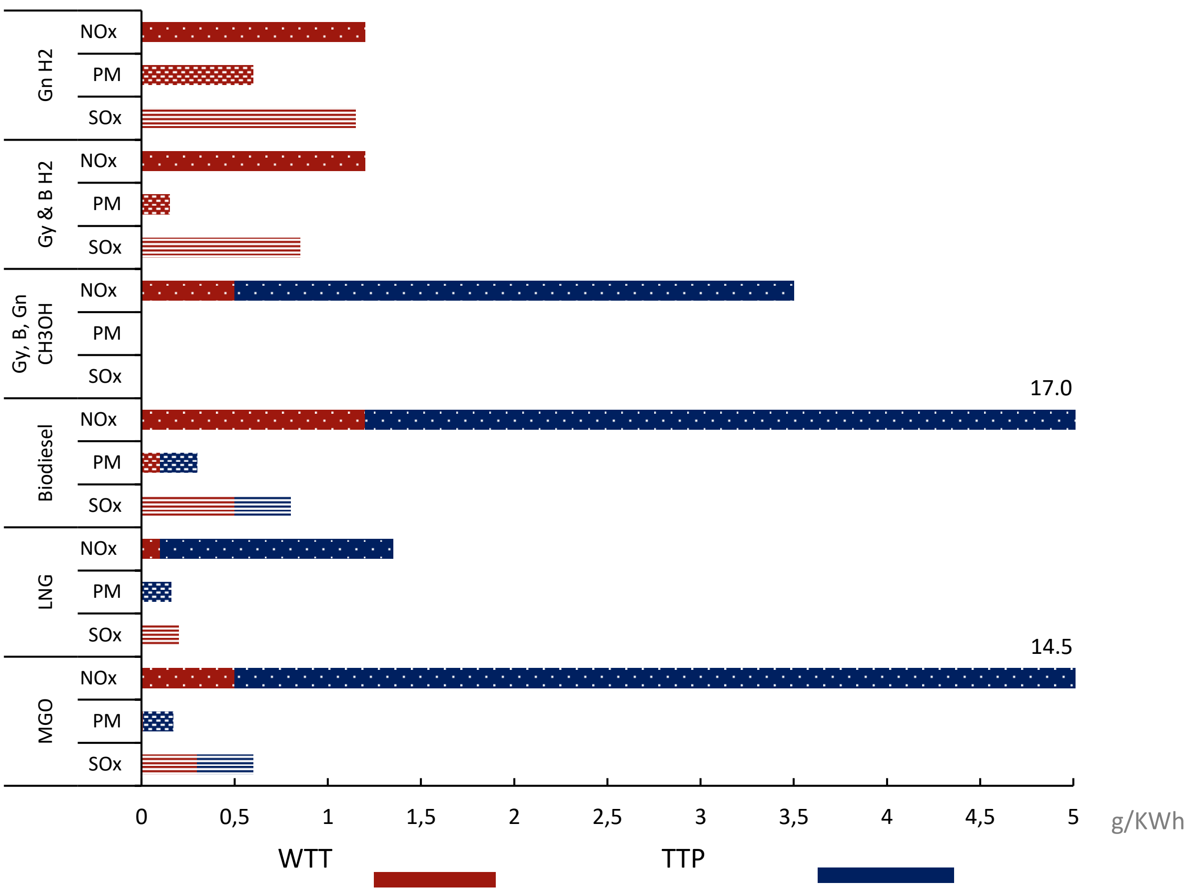


Figure 3: Local pollutants (Gilbert, et al., 2017)

Figure 4 depicts the CO2 emissions of the fuels relevant to the research from well-to-propeller. It becomes evident when looking at the graph that both fossil fuels, and grey methanol and grey hydrogen produce significant amounts of CO2 emissions. The cleanest fuel is hydrogen produced from renewable energy. Of all relevant fossil fuels, LNG produces the lowest CO2 emissions. However, unburnt methane (methane-slip) could lead to reduced benefits over MGO as methane has greenhouse gas effect that is 25-30 times greater than CO2 (DNV GL , 2018).

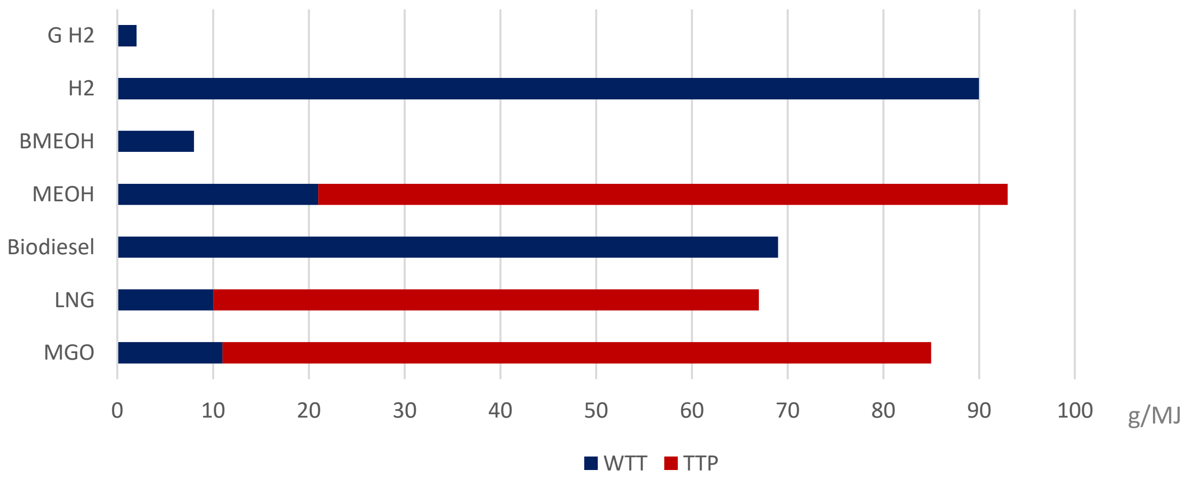


Figure 4: WTP CO2 emissions (DNV GL , 2018)

Tank-To-Propeller (TTP)

TTP emissions are solely related to fuel combustion in the main engine only. CO2 from combusted bio-methanol is considered to be climate neutral. In the case of bio-methanol it is assumed that the CO2 emitted from biomass-based fuel is removed from the atmosphere as new biomass grows to replace formerly delved biomass. Merely looking at the TTP emissions presented in table 3 it becomes evident that LNG is the most future-proof fossil-fuel, although CO2 reductions aren't compliant with IMO's ambitions to reduce CO2 emissions for shipping with 50% . Grey methanol also does not meet this target. Hydrogen, whether renewable or not in principle would meet this target, as this target only applies to what comes out of exhaust pipe at the end of the chain. However, in reality this would only shift the problem further upstream in the life cycle. Thus, to meet both local pollutant regulations and the 50% reduction target set by the IMO only green hydrogen and green methanol remain.

Table 3 TTP emissions (Gilbert, et al., 2017)

Fuel types	**Operational fuel emissions g/kWh**					
	Greenhouse gases			**Local pollutants**		
	CO2	**CH4**	**N2O**	**SOx**	**NOx**	**PM**
MGO	524	0.010	0.027	0.32	14.8	0.16
Biodiesel	---*	0.0064	0.13	0.37	17.1	0.19
LNG	412	3	0.016	0.003	1.17	0.027
(grey) Methanol	522	0	0	0	3.05	0
Hydrogen	0	0	0	0	0	0

** Biodiesel is regarded as carbon neutral fuel*

Concluding remarks on air emissions

From a life-cycle perspective there seems to be no readily available alternative fuel option which could deliver on both local pollutant reduction and greenhouse gas emissions. Although LNG appears very promising in meeting regulations regarding local pollutants, it does not suffice in meeting the ambitious goals set out by the IMO. On the other hand green methanol is promising due to its low CO2, SOx, and PM emissions, although Selective Catalytic Reduction (SCR) is required to reduce NOx pollutants.

2. State of the art regulations

This chapter discusses the goals and ambitions set out by the IMO to reduce air emissions (local pollutants and GHG's). In order to achieve these goals and ambitions alternative fuels will need to be adopted by the shipping industry. These novel fuel configurations will have very different safety norms and regulations. Ships operating on conventional fuels will have different designs and operational aspects then those operating on alternative fuels. These design outlines and operational aspects will also be discussed in this chapter.

2.1 Air emissions

Up until now, most sea going vessels have relied mainly on heavy fuel oil (HFO) as a low cost fuel that provides high energy efficiency. However, in recent years environmental and human health considerations have initiated a paradigm shift towards a preference for low sulphur, nitrogen oxides and particulates, which are known to have negative impacts on both humans and the environment. Although international shipping is not included in the Paris Agreement (2017) the International Maritime Organisation IMO will be held responsible for the GHG reductions. In April 2018 IMO adopted an initial strategy in an effort to reduce GHG emission in the coming years (IMO, 2019).

2.1.1 NOx, SOx and PM emissions

The international Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI establishes international standards limiting the emissions of NOx, SOx and PM from ships. Under MARPOL and the NOx Technical Code specific engine design standards and testing protocols are stipulated. SOx and PM emissions are also restricted under MARPOL Annex VI by limiting the maximum amount of sulphur content in fuels used on board of ships, or through the use of exhaust gas cleaning systems. From January 1st 2020 the sulphur limit for all marine fuels used across the world will drop from 3.5% to 0.5%, thereby significantly reducing SOx emissions (IMO, 2019).

In effort to reduce the SOx and NOx emissions close to shore and populated regions Emission Control Areas have been mandated by the IMO in 2015. The four ECA's established under Annex VI are in the Baltic Sea, the North Sea, North America and US Caribbean, allowing for a maximum fuel sulphur content of 0.1% within these ECA's (see figure 5). Although these ECA's have initiated great steps forward in reducing SOx emissions from ships, it has impacted only a small area of the global shipping fleet. Therefore, new and stricter regulations will be implemented as of January 2020 with a new global reduction cap allowing a 0.5% maximum sulphur content in marine fuels affecting far more ships than the current ECAs. In addition to the global cap on SOx, the permitted sulphur content within ECA's will remain in place (World Shipping Council, 2019)

Figure 5: IMO Emissions Control Areas (Hall, 2015)

Regulations regarding NOx emission have been mandated in Tier I, II, and III. NOx emission limits are set for diesel engines depending on the engines maximum operating speed, the year they were build and whether or not they are operational within ECA's. Tier I is operational on a global scale for ships constructed on or after January 1st 1990, but prior to January 1st 2000. Tier II is also operational at a global scale, although it only applies to engines installed on or after January 1st 2011. Tier III standards apply to new ships that are 500 GT and above, with a length of a least 24m, built after January 1st , 2016, and sailing within the North American and U.S. Caribbean ECAs. In the Baltic and North Sea Tier III will only apply to ships built after January 2021. In doing so the NOx Tier III aims to cut back NOx emissions with 80% compared to Tier I (IMO , 2019).

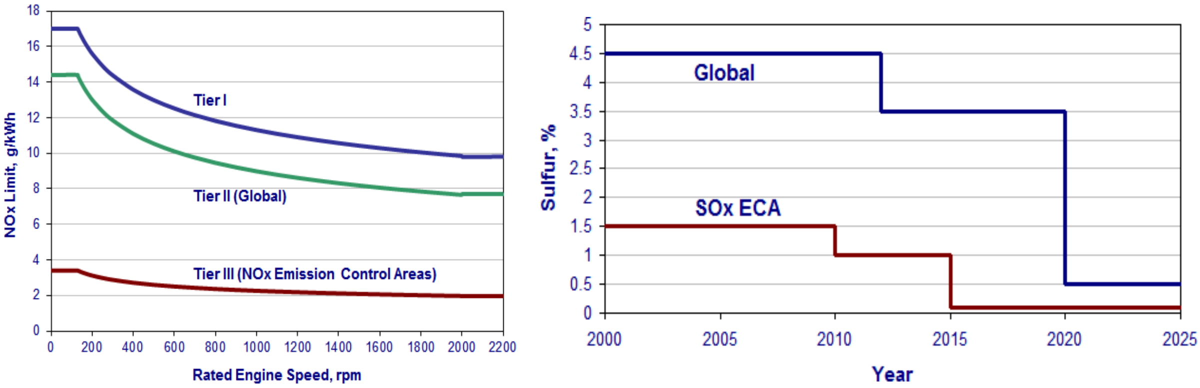


Figure 6: SOx and NOx regulations set by IMO (Fagerholt, Gausel, Rakke, & Saraftis, 2015)

Seagoing vessels operating diesel engines must comply with MARPOL Annex regulations as well as with the NOx Technical Code. NOx Compliance with these new regulations may be met by the use of alternative fuels, energy efficiency measures, Selective Catalytic Reduction (SCR), or Exhaust Gas Recirculation (EGR) (Inoue & Yokoyama, 2018).

2.1.2 Greenhouse Gas emissions

The international shipping industry emitted approximately 800 million tonnes of CO2 in 2012, accounting for about 2.2% of the total global anthropogenic CO2 emission of that year. It is expected that emission from international shipping will grow by 50-250% by 2050 due to the growth of maritime trade. In 2013 the IMO mandated a new set of regulations regarding energy efficiency for ships, in which new ships are required to comply with the Energy Efficiency Design Index (EEDI), a minimum mandatory energy efficiency performance level. Furthermore, the Ship Energy Efficiency Plan (SEEMP), will serve as tool for shipowners to improve the energy efficiency of both new and existing ships using measures such as weather routing and speed optimization. These new regulation were added in a new chapter of the MARPOL Annex VI, titled ''Regulations on energy efficiency for ships''. In 2016 the Marine Environment Protection Committee (MEPC) 70 adopted amendments requiring ships to record and report their fuel oil consumption. Besides, the MEPC also approved of a roadmap for developing a comprehensive strategy on reducing GHG emissions from shipping (IMO, 2018).

In April 2018 IMO adopted an Initial IMO strategy on the reduction of GHG emissions from ships. The strategy is highly ambitious and aims to reduce CO2 emission by at least 40% by 2030, and pursuing the goal of 100% by 2050 as of 2008 if possible. Furthermore, it outlines how GHG emissions from international shipping should peak as soon as possible and to reduce the total annual GHG emission by at least 50% by 2050 which equates to 85% reduction in carbon intensity (Palmer, 2018).

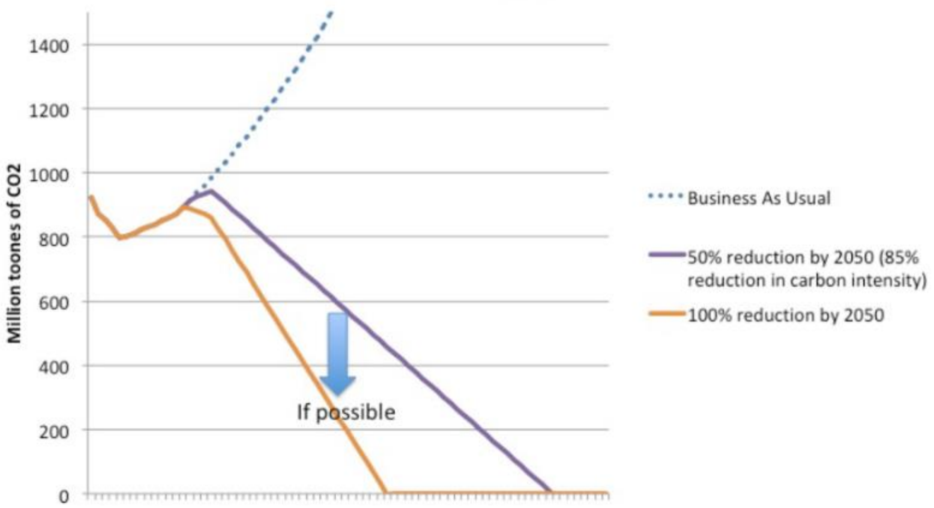


Figure 7: IMO CO2 emission reduction pathways (Palmer, 2018)

This initial strategy set out a framework for future actions, setting high goals and ambitions relating to GHG emission reductions and therefore providing merit for alternative fuel research and development. Moreover, this strategy provides a clear signal to the industry that the overarching aim is to end the use of fossil fuels all together. In order for this to be achieved zero emission vessels need to start entering into service by 2030. Therefore, anyone designing or building a new ship after 2020 should carefully consider how their vessel should be able to switch to green fuels.

2.1.3 Meeting carbon intensity decline

Significant efforts are necessary to reduce CO2 emissions per transport work, as an average across international shipping by at least 40% by 2030 as of 2008 and by at least 50% by 2050. Currently, some alternative fuels potentially can meet this target, i.e. biodiesel, green LNG, green methanol, and green hydrogen. Unfortunately none of these fuels and technologies are readily available on a large enough scale that it can provide for the entire shipping industry, further elaboration to this topic is given in paragraph 3.1.3.

In the Initial strategy of the IMO it isn't explicitly stated that this target concerns WTP or TTP CO2 emissions. However, in chapter 3 Levels of Ambition and Guiding Principles it is stated that carbon intensity of the ship must decline through the implementation of further phases of the Energy Efficiency Design Index (EEDI), which implies that one is talking about tank-to-propeller reduction values (Lindstad, et al., 2019).

The Initial Strategy on GHG Reduction states that CO2 emissions are to be reduced by at least 50% as of 2008. Up until now the main fuel for mode of transport in the shipping industry has been HFO, which contains approximately 541 g/kWh CO2. Thus for a conventional vessel to comply with this target this number must be brought back to approximately 270 g/kWh CO2. This may be done through either full

CO_2 elimination or by choosing a fuel blend that allows for this CO_2 reduction. Shipowners would have a mixture containing approximately 50% of alternative carbon neutral or zero carbon fuel.

Another option often proposed is to introduce speed restrictions or the so called slow steaming concept. In order for the shipping industry to be able to meet this absolute reduction of 50% as of 2008 it is thought that slow steaming can be a valuable tool.

2.2 Operational aspects

Rules and regulations regarding the fuel system onboard seagoing vessels depend mainly on the type of fuel that is used during operations. Ships that sail on gas have different safety regulations than those operating on traditional oil fuels. The following paragraph will define design outline and safety regulations of the alternative fuels. Norms/codes set out by the IMO are used by various Classification Societies and class rules have been developed by e.g. Lloyd's Register, Bureau Veritas and DNV GL. These were used as main guiding sources to determine onboard system arrangements. LNG, methanol and hydrogen are (partially) covered by the IGF Code set by the IMO, while biodiesels are not separately regulated and fall under normal diesel fuel regulations. Even though hydrogen falls under the IGF Code, it is still considered to be a novel fuel configuration which is why there are still regulatory gaps existent regarding the bunkering and storage of hydrogen. The IGF has at least opened up for approval of hydrogen fuel storage and fuel supply systems (PART A, Annex Standard for the use of limit state methodologies in the design of fuel containment systems of novel configuration). IMO has also announced that requirements for fuel cell installations will be added as a new part E to the Code in 2024 (Haugom, 2019). This chapter will shortly cover the PART A, which is quite general and applicable for all low-flashpoint fuels (LFF). PART A-1 is also discussed as these regulations are applicable to vessels operating on natural gas. From there the requirements set for biofuels, methanol and hydrogen are discussed respectively.

International Code of Safety for Ships Using Gases or Other Low-flashpoint fuels (IGF Code)

The goal of IGF code is to provide an international safety standard for ships that operate on gas or low-flashpoint liquids as a fuel. The code provides mandatory criteria for the ship design (installation of machinery, equipment and other systems for operation), in order to minimize safety hazards onboard the ship and its environment. The code discusses all those areas which deserve extra attention for the usage of the gas or low-flashpoint fuels. The goals set out in the IGF Code form the basis of every ships design, construction and operation and will allow for equivalent levels of integrity in terms of safety, reliability and dependability as those achieved through the use of comparable conventional oil fuelled vessels.

The IGF regulations are applicable to all new build ships that fall into its category, its application for existing vessels is determined by the flag under which the ship sails. The IGF Code covers the following chapters:

1. Preamble

PART A

2. General
3. Goal and functional requirements
4. General requirements

PART A-1 SPECIFIC REQUIREMENTS FOR SHIPS USING NATURAL GAS AS FUEL

5. Ship Design and arrangement

6. <u>Fuel containment system</u>
7. <u>Material and general pipe design</u>
8. <u>Bunkering</u>
9. <u>Fuel supply to consumers (distribution)</u>
10. <u>Power generation including propulsion and other gas consumers</u>
11. <u>Fire safety</u>
12. <u>Explosion prevention</u>
13. <u>Ventilation</u>
14. <u>Electrical installations</u>
15. <u>Control, monitoring and safety systems</u>

PART B-1

16. Manufacture, workmanship and testing

PART C-1

17. Drills and emergency exercises
18. Operation

PART D

19. Training

2.2.1 Requirements for ships using natural gas as a fuel

Without going into too much details on rules and regulation the above chapters that are underlined will be covered as these are critical when it comes to the system design of vessels using LNG. Part B-1 specifies functional requirements and regulations for manufacture, workmanship and testing. Functional requirements are not hard design rules, but instead are up for interpretation by the designers. Regulations on the other hand are clear to be followed carefully. Part C-1 specifies requirements for drills and emergency exercises and operations, while part D elaborates on training that has to be done by the crew. Although these aspects are important once vessels are operational these aspects can mostly be left out during the design phase.

PART A sets out important definitions in a glossary and determines which alternative designs are contained within the IGF code and opens up for use of other gases or low-flashpoint fuels though an ''Alternative Design''. With functional requirements and regulations, Chapter 3 aims to provide a safe and environmentally-friendly design, construction and operation of ships with regard to their installations of systems for propulsion machinery, auxiliary power generation machinery and other machinery requiring gas or low-flashpoint fuels.

The general requirements set out in chapter 4 aim to ensure that necessary risk assessments are made in order to eliminate adverse effects or mitigate these once they do occur. It aims to limit the consequences of an explosion so that these don't disrupt the functioning of equipment/systems in any other place than that of which the event occurs, does not cause flooding or cause harm to persons operating under normal conditions, and does not interrupt with any incident response actions, such as the use of firefighting equipment or the access to life-saving appliances or escape routes.

PART A-1 focusses on specific requirements for ships using natural gas as fuel, either in its liquefied or gaseous state.

2.3.1.1 Ship design and arrangements

In chapter 5 functional requirements and regulations for safe location, space arrangement and mechanical protection of power generation equipment, fuel storage systems, fuel supply equipment and refuelling systems are covered. An important functional requirement is that the fuel tank is placed in a position where the probability of it being damaged during a collision or grounding is reduced to a minimum (minimum distance of B/5). Furthermore, fuel containment systems, piping and other sources of release are to be located and arranged in such ways that released gas can be safely discharged into open air. Fuel storage hold spaces should also be separated from the sea by a secondary barrier. Also, spaces containing fuel sources of release should be arranged in a manner that flammable, asphyxiating or toxic gas cannot propagate to space not designed for such gases. Fuel piping should also be shielded from any possible mechanical damage and the propulsion and fuel supply system must be designed such that safety action after any leakage does not go at the cost of power. Lastly, the probability of an explosion caused by gas or low-flashpoint fuels should be kept at a minimum.

2.2.1.2 Fuel containment

Chapter 6 aims to provide that gas storage is adequate so as to minimize the risk. Important functional requirements to consider are that the fuel tank is designed so that a leak from the tank or its connections does not cause any form of risk. Important to note is that the fuel tank should be designed with a life span of 20 or more years consisting of a primary and secondary liquid-tight fuel tank barriers, with the exception of tanks where the probability of a structural failure is neglectable. In this design accidental conditions such as collision, fire and floods are accounted for. Furthermore, when dealing with cryogen liquids exposure of ship materials other than the tank must be avoided, and leaks should be concealed once they occur. Also, storage tanks should be able to empty, purge and vent fuel containment spaces through the fuel piping systems.

2.2.1.3 Material and general pipe design

Chapter 7 discusses functional requirements and regulations regarding material and the general pipe design. The goal is to safeguard handling of fuel under all operating conditions. It highlights the importance of the capacity of fuel piping to absorb thermal expansion or contraction caused by extreme temperatures of the fuel without developing substantial wear and tear. Also, low temperature piping should be thermally isolated in order to prevent the temperature of the hull from falling below the design temperatures. Wall thickness requirements and (thermal) design conditions are set out.

2.2.1.4 Bunkering

In chapter 8 functional requirements and regulations regarding onboard bunkering are discussed in order to provide suitable onboard systems to ensure that bunkering can be done with minimized risks. Important general regulations require bunkering stations to be located on an open deck, providing for abundant natural ventilation. Bunkering stations located within closed or semi-enclosed spaces will be subject to special consideration during risk assessments. Furthermore, connections and piping are to be positioned such that any damage to the piping does not cause damage to the ships fuel tanks system, thereby preventing an uncontrolled gas discharge. If a leakage does occur during bunkering the surrounding hull and deck structure should not be exposed to unacceptable cooling.

2.2.1.5 Distribution of fuel to consumers

Chapter 9 focusses on ensuring safe and reliable distribution of fuel to consumers. The following functional requirements are highlighted. First, the fuel supply system should be arranged in a manner that minimizes the consequences of any fuel release. Also, the piping system for fuel transfer should be designed so that a failure of one barrier does not lead to a leak from the piping system into the surrounding area. Lastly, the risk associated with fuel lines outside the machinery spaces in case of leakage should be minimized in order to prevent injury to the crew or damage to the ship. Important to note is that fuel supply systems are to be redundant meaning that in single fuel installations supply to the consumer is arranged in segregation from the fuel tank to the consumer, thereby preventing an unacceptable loss of power. Single fuel installations therefore require two or more storage tanks, located within separate compartments. In case of dual fuel installations this is separation of gas tanks is not needed as redundancy is already achieved through the two fuel systems.

2.2.1.6 Power generation

In chapter 10 functional requirements and regulations in relation to power generation including propulsion and other gas consumers are discussed. The goal here is to provide safe and reliable delivery of mechanical, electrical or thermal energy. Accumulation of unburnt gaseous fuel is to be prevented and exhaust systems should be configured to prevent this from occurring. If the worst case of over pressure caused by ignited gas leaks is not accounted for in the design, pressure relief systems are needed. Furthermore, venting should be led away from the crew. Regulations vary per engine type and are grouped in four categories: 1) internal combustion engines of piston type, 2) duel fuel engines, 3) gas-only engines and 4) multi-fuel engines.

Important to note is that dual fuel engines should be able to continuously operate on only fuel oil once the gas fuel supply is cut off. Besides an automatic system must be fitted to change needlessly between gas fuel operation and fuel oil operation and vice versa with minimum fluctuations in engine power. For multi-fuel engines similar regulations apply as to that of dual-fuel engines, requiring smooth switching between fuels in case of a shutdown.

Table 4: Engine types and ignition sources

	Gas Only		**Dual Fuel**	**Multi Fuel**
Ignition Medium	Spark	Pilot fuel	Pilot fuel	N/A
Main fuel	Gas	Gas	Gas and/ or Oil fuel	Gas and/ or Liquid

Gas turbines should be designed with pressure relief systems and fitted to the exhaust system, taking into account explosions caused by gas leaks. Here as well, pressure relief systems within the exhaust uptake is to be led away from the crew to a safe location. Furthermore, exhaust monitoring systems will detect poorly combusted gaseous fuels during operation, shutting down the gas supply when such an event occurs.

2.2.1.7 Fire protection

Chapter 11 intends to provide for fire protection, detection and fighting for all system components of the vessel. Chapter 12 aims to provide prevention of explosions and to limit its effects once it does occur. Here reducing the probability of explosions, by reducing the number of sources of ignition and the probability of explosive gas mixtures is the most important functional requirement. Also hazardous zones hare determined for which different regulations and requirements are set out.

2.2.1.8 Ventilation

Ventilation within gas fuelled ships is essential and therefore deserves elaboration as to what the functional requirements and regulations are. The aim of chapter 13 is to deliver ventilation requirements for safe operation of gas-fuelled machinery and equipment. Important to note is that ventilation of hazardous spaces should be separated from those used for normal ventilation (non-hazardous spaces) and must be operational under all circumstances. Ventilation fans in spaces containing gas sources should also not produce a source of vapour ignition and should consist of non-sparking construction. It is made sure that hazardous and non-hazardous in and outlets do not have interacting air flows. Furthermore, in case hazardous and non-hazardous areas are located next to one another these should be arranged with an airlock of which the non-hazardous space is regulated at an overpressure to the hazardous space. This overpressure of the non-hazardous spaces and the under pressure of hazardous spaces is regulated by overpressure ventilation and extraction ventilation, and in case of disruption should be detected by audible and visual alarms. Also, the ventilation of machinery spaces that contain gas-fuelled consumers should be independent of all other ventilation systems.

2.2.1.9 Electric installations

Chapter 14 aims to ensure safe electrical installations that minimize the risk of ignition in the presence of an explosive atmosphere. Therefore, electrical generation, distribution, and associated control systems, should all be designed such that a single fault will not disrupt the ability of the fuel system to maintain fuel tank pressures and hull structure temperatures within regular operating limits. Electrical installations should not be present in hazardous areas unless essential for operational/safety purposes. Equipment that is installed within hazardous areas is evaluated and certified by an accredited testing authority or notified body recognized by the IMO.

2.2.1.10 Control monitoring and safety systems

Chapter 15 goes on to discuss control, monitoring and safety systems. The goal hereof is to provide the safe and efficient arrangement of control, monitoring and safety systems. In the functional requirements the importance of continuation of the gas fuelled installation during a single failure event is highlighted again. Also in case of two or more gas supply systems, these are required to meet the regulations and should be fitted with its own set of independent gas control and gas safety systems. Furthermore, gas detection applications should be placed near the gas engines.

2.2.1.11 Annex: Standard for the use of limit state methodologies in the design of fuel containment systems of novel configuration

The annex provides adequate procedures and relevant design parameters for limit state design of fuel containment systems of a novel configuration, such as methanol and hydrogen. In such limit state design a systemic approach is applied in which each structural element is evaluated with respect to possible failures outlined by IMO regulations.

The fuel containment design must take into account the possible consequences of a potential failure and classify these in accordance with their severity ranging from low, medium to high. Furthermore, the novel fuel configuration shall be subject to a three-dimensional finite element analysis, bucking strength analysis, and fatigue and crack propagation analysis. The fuel containment system will be subject to testing for structural resistance upon which safety margins for ultimate strength are introduced taking into account the nature of the load type (dynamic loads, pressure loads or gravity loads).

2.2.2 Requirements for ships using biodiesel as a fuel

Regulations for biofuel installations are not separately regulated like LFF and natural gas, but in order to ensure safe and environmentally responsible carriage, are subject to Annex I and Annex II of MARPOL. Depending on the volumetric mixture of the biodiesel blend ships fall under different regulations.

Biofuels containing more than 75% or more of petroleum oil are subject to ANNEX I of MARPOL. In case of carriage of such bio-fuel blends, Oil Discharge Monitoring Equipment (ODME) should comply with regulation 31 of ANNEX I of MARPOL and approved for the mixture transported. In order to get this approval it is important that the ship meets the following specific requirements. The system must be installed with a recording system that is able to continuously monitor the oil discharge. Failure to comply with ODME will automatically stop the discharge. Furthermore, when considering the deck fire-fighting requirements of SOLAS Chapter II-2, regulation 1.6.1 and 1.6.2 apply when carrying bio-fuel blends containing more than 5% ethyl alcohol and alcohol resistant foams should be used. Biofuel blends containing more than 1% but less than 75% of petroleum oil are subject to Annex II and should be carried under the conditions as described in MEPC.1 /Circ. 761 Guidelines for the carriage of blends of petroleum oil and bio-fuels chapter 4.2.1. Biofuels containing 1% or less of petroleum are subject to Annex II of MARPOL.

2.2.2.1 Special considerations

The biggest issue related to biofuel FAME cargo's is that of water contamination. FAME is hydroscopic and therefore highly sensitive to moisture contact either liquid or vapour. Once exposed to small amounts of moisture at any point in the supply system of FAME cargo exceeding the 300mg per kg will deem the fuel not fit for use causing microbiological growth, formation of fatty acids and resulting corrosive processes, and reduced stability of the fuel. For these reasons contact with water is to be avoided and can be complicated when considering tank cleaning procedures. Consideration also needs to be paid to the tendency of FAME to stick to the surfaces in the tanks which then re-emerges later on contaminating subsequent FAME loads. The ''water-allergy'' of FAME biofuels requires a lot of attention to detail when cleaning the tank, similarly the design must ensure the preventing of water contamination. Furthermore, biodiesel is subject to degradation when exposed to certain atmospheric conditions, light or high temperatures. Therefore, special consideration should be given to the location of the fuel tank assuring this is not exposed to these conditions. During voyages from a warm to cold region particular attention should be paid to prevent issues with the biofuel caused by a built up of waxy-like precipitates. In order to prevent solidification of the biofuel, proper heating installation are to be installed, accounting for additional installation costs. The Federation of Oils, Seeds and Fats Associations (FOFSA) has set out guidelines for temperature consideration for cargo temperature of FAME and may be applicable to fuel storage as well. In comparison to conventional fuels, biofuels are more sensitive fuels (IEA Bioenergy, 2017; Kallingeros, Dodos, Zannikos, & Tyrovola, 2017).

2.2.3 Requirements for ships using methanol as a fuel

The IGF code states that the overall safety requirement to novel fuel technologies is as follows: the safety, reliability and dependability of the systems shall be equivalent to that achieved with new and comparable conventional oil-fuelled main and auxiliary machinery. This level of safety is determined through conducting a risk assessment (Chapter 4.2 IGF Code) such as a hazard identification (HAZID) or failure mode, effect and critically analysis (FMECA) of the methanol fuel system. Obviously, the risk assessment is carried out during the design phase. Parallel to the system breakdown done by the IMO in the IGF Code, e.g. DNV GL has done the same for methanol fuelled ships, although slightly more concise. This system breakdown is used as guideline for the following paragraphs. It must also be noted that regulations for methyl-/ethyl alcohols in fuel cells is still under consideration by the IMO.

Nevertheless, the IMO Sub-Committee on Carriage of Cargoes and Containers in the 6th session (CCC 6) did finalize draft interim guidelines for the safety of ships using methyl/ethyl alcohol as a fuel that currently awaits for approval from the Maritime Safety Committee. Even though the amendments are still a draft, they have been included in the requirements for methanol here.

2.2.3.1 Ships design and arrangement

Chapter 5 of the CCC 6 amendments aims for a safe ship design and arrangement which provides mechanical protection of power generation equipment, fuel supply equipment and refuelling systems. Fuel tanks should be located such that the probability of a tank being damaged during a collision is reduced to a minimum. Fuel release sources should be located and arranged such that released fuel is led to safe locations. Access spaces containing potential fuel release sources should be arranged such that flammable, asphyxiating or toxic fuel does not escape to spaces not designed for its presence. Fuel piping must be protected against mechanical damage and the propulsion and fuel supply system should be designed as such that safety actions after leakage don’t lead to loss of power. Also the design of the machinery space should minimize the probability of fire or an explosion, paying close attention to leakage from pumps, valves and connections. Furthermore, the fuel containment system is to be located abaft the collision bulkhead and forward of the aft peak bulkhead. Independent fuel tanks may be situated above or below deck in fuel storage space and should be secured to the ship’s structure.

2.2.3.2 Fuel containment system

The storage system of LFF fuels includes a fuel cargo tank connected to the fuel service tank with standard piping. According to the DNV GL rules for classification of ships (Part 6, Chapter 2, section 6) requirements concerning storage of methanol rules can be divided into 1.) location of the fuel tanks, 2.) protection of the fuel tanks, 3.) Gas freeing, inerting and venting of fuel tanks, and 4.) special requirements for fuel tanks on weather decks.

Location of the fuel tanks

Fuel should be stored in safe locations, away from machinery and accommodation spaces and the horizontal distance between the fuel tank and the ship’s hull should be 800mm at minimum. Also the for and after peak of the ship should not be used to locate fuel tanks. Furthermore, each fuel type shall be arranged with two fuel service tanks in order to ensure propulsion and vital systems don’t shutdown during a single failure. Lastly each fuel tank should be able to run the operation (propulsion system and generator plant) for a period of no less than 8 hours with a normal operating load at sea.

Protection of the fuel tanks

If the fuel tanks are not bounded by bottom shell plating or a fuel pump room, they should be surrounded by protective cofferdams. These cofferdams are arranged with vapour and liquid leakage detection systems and the possibility to fill with water upon detection. This water filling is done through a system that does not consist of permanent connection to water systems in non-hazardous spaces. Emptying is done through a separate system. The fuel tanks should also be designed such that a leakage won’t endanger the ship, the people on board or the environment. This includes preventing the fuels from spreading to locations with ignition sources, reducing toxicity potentials and risk of oxygen deficiency or other negative impacts on crew health due to fuels and inert gases.

Gas freeing, inerting and venting of fuel tanks

Fuel tanks should be able to safely inert, purge, and free gas. Tanks without direct access to natural ventilation flows from the open deck should be provided with no less than two ventilation inlets and outlets to ensure complete gas-freeing is possible. Similar to LNG tanks methanol fuel tanks should be provided with pressure/vacuum relief systems that can be used during all operations. The tanks should also be provided with pressure vacuum relief valves to limit pressure in the tank, and a venting system cable of venting through over- and under pressure should be fitted. The venting system, of which the intake openings are at least 1.5 m above deck, should be connected to the highest point of every fuel tank and should be able to self-drain under all normal conditions. The fuel tank vent outlets normally should not be situated less than 3m above the deck or 4m away from a gangway. These outlets should be at least 10m away from the nearest air intake or opening to accommodation and service spaces and ignition sources. Furthermore, inert gas should be available permanently onboard, this may be portably stored or produced onboard using a production plant. The inert gas system needs to fitted with oxygen readers, pressure controls and monitoring arrangements appropriate to the fuel containment system.

Special requirements for fuel tanks on deck

If situated on a deck these fuel tanks must be protected against mechanical damage and surrounded by coamings. Special consideration must be taken to minimize fire hazards and ignition sources are to be kept to a minimum on the weather deck. Fuel tanks on the weather deck may be subject to a fire safety assessment.

Storage of methanol fuel is more complex when compared to conventional fuel oil due to physical and chemical properties of the fuel as outlined in chapter 1.4. Methanol is a low-flashpoint fuel, with relatively large explosive limits and is also toxic. Therefore, like natural gas fuel systems additional monitoring and control systems are needed to minimize risks associated with fuel leaks. Equipment such as overfill alarms, detection, monitoring and ventilation systems are required. In particular infrared fire detection system are important, considering that methanol-based fires are invisible. The above stated requirements clearly imply that additional space is needed to safely store methanol onboard of vessels. Requirements related to gas freeing, inerting and venting of tanks and the involved equipment are well-known systems also applied on LNG operating vessels. In comparison to MGO these components require additional installation costs.

Bunkering

The rules for bunkering of methanol according the DNV GL rules can be divided into 1.) the bunkering station and 2.) the fuel bunkering system individually.

Bunkering station

The bunkering station must be provided with sufficient natural ventilation and is to be separated from other non-hazardous areas of the ship through a gas tight bulkhead. Bunkering stations that don’t have this provision will be individually assessed to determine whether requirements for mechanical ventilation are met. The bunkering connections should installed with coamings and the control of the bunkering shall be done remotely so that the bunkering operations don’t cause any safety hazard. Besides, showers and eye wash stations for emergency usage are to be located in close proximity to areas where the possibility of accidental contact with fuels exists.

Fuel bunkering system

Every bunkering line should be fitted with a manually operated stop valve and a remotely operated shutdown valve and should be able to inert and free gas. Also, the bunkering line should be self-draining and the connecting coupling for transfer should be self-sealing if disconnected. All these aspects are known technologies and not very complex as these are already used in LNG shipping and relatively mature technologically.

Distribution of fuel to consumers

The fuel supply system and the fuel valve train running to the main engine are considered to be part of the distribution of fuel to consumers. Requirements regarding the safe distribution of methanol are divided into five groups according to the DNV GL rules for classification of ships (Part 6, Chapter 2, Section 6, 1.) general issues, 2.) protection of fuel transfer system, 3.) valves, 4.) fuel pumps and 5.) temperature control.

General issues

First of all the fuel distribution system should be entirely separated from all other piping systems on board the ship and should not be located at a distance less than 800 mm to its hull. Single fuel vessels should be arranged with redundancy and segregation from the fuel tank to the consumer, in order to prevent that a leakage in the fuel system does not lead to loss of propulsion, power generation and other main functions. Piping is to be arranged to account for gas-freeing and inerting and drip trays are to be provided below areas where leakages are likely to occur.

Protection of fuel transfer system

The fuel piping system must be protected against mechanical damage, and all piping containing methanol that pass through enclosed spaces in the ship should be enclosed in a pipe that is tight towards the surround areas (double piping). The fuel piping should not lead through non-hazardous spaces and in case where it does, the double walled fuel piping will be led through a dedicated duct which is also gas and water tight. The space between the inner and outer pipe is ventilated to open air and equipped with vapour and liquid leakage detection systems. Inerting of this annular space may be allowed as an alternative in low pressure fuel systems.

Valves

Storage tanks of LFF should have remotely operated and automated shut-off valves for inlets and outlets which should be located as close as possible to the tank. Other valves which are not easily accessible should be operated remotely as well as the main supply lines for fuel to the main consumers. Besides, there shall be one manual shutdown valve in the supply line to the engine assuring safe isolation during maintenance operations.

Fuel pumps

Pump rooms are located outside the engine room always and are gas/water tight to surrounding enclosed spaces and vented to open air. The pump rooms of LFF should be arranged for with detection and drainage of fuel leakages, and should have bilge systems, operable from outside the fuel pump rooms.

Temperature control

The temperature control system is to be installed as a secondary system that operates independently from other ship systems and should be provided with valves to isolate the system for each supply line or tank. Also when not in an empty condition, the pressure within the temperature control system should be greater than the maximum pressure head of the fuel tank. The control circuit is installed with a gas detection system with low level alarm and is also vented to open air.

Requirements regarding fuel distribution for methanol are more complex when compared to conventional fuels. Its flashpoint is very low (12°C), meaning that at room temperature the fuel will form flammable vapours. Therefore in addition to segregation by remotely operated valves, double walled piping and sufficient (natural) ventilation is needed. Gas detection systems must be located near the floor as methanol gas is heavier than air. The low viscosity of methanol means that leaks in the piping system can form easily, therefore these pipes must be sealed properly with appropriate materials. The added complexity of this fuel distribution system will lead to increased installation/maintenance costs.

Power generation

The power generation happens in the main engine which consists of additional methanol booster injectors and a liquid gas injection block fitted on the cylinder. According to the DNV GL rules for classification of ships (Part 6, Chapter 2, section 6) the requirements for methanol engines can be divided into three categories, 1.) general issues (applying to both dual fuel and LFF-only engines), 2.) functional requirements for dual fuel engines and 3.) functional requirements for LFF-only engines. These requirements are all in line with chapter 10 of the IGF code from the IMO.

General

Sealing of injection or admission equipment measures should be taken in order to prevent potential leakage of fuel into the engine room. The injection pumps and injection devices should be sufficiently lubricated. When starting the engine LFF should not be injected or administered to the cylinders until ignition is activated and the engine has reached a minimum rotational speed, requiring a pilot fuel. If the engine does not start (lack of ignition) within the expected time, the fuel supply is automatically to be shut down.

Functional requirements for dual fuel engines

In case of a shut-off of the LFF fuel supply, the engine should be able to continue its operation on oil fuel only and vice versa. Furthermore, switching between fuels should be possible without loosing engine function. Switching is done automatically making sure all preparations for switching are conducted.

Functional requirements of LFF-only engines

One single failure in the supply of fuel should not lead to the total loss of fuel supply and loss of engine function. LFF only engines are relatively new in development. Thus, so far only a handful of engine configurations with LFF have been ordered making this configuration relatively new/immature. Important to note is that methanol causes more engine wear in comparison to fuel oil, affecting the operation and durability of the engine.

Fuel processing and handling after the main engine

The fuel processing and handling after the main engine consists of a purge return system running throughout the entire fuel system. Especially the two following functional requirements apply according to the DNV GL rules for classification of ships (Part 6, Chapter 2, section 6).

1.) All piping containing LFF is arranged for gas-freeing and inerting
2.) There shall be one manual shutdown valve in the supply line to each engine to ensure safe isolation during maintenance operations.

The main solution to these two functional requirements is that the methanol fuel system is drained, purged and gas-freed throughout the entire system. It is then collected and transported back into the service tank or collected in a residue tank.

Nitrogen installation

Here a nitrogen installation is a large part of the total cycle to which the following requirements apply. Therefore, all the tanks containing LFF should be inerted and to prevent vapour running to any gas safe areas, two shut-off valves in series and a venting valve in between shall be installed. Additionally, a closable non-return valve shall be installed between the double block and bleed arrangement and the fuel tank, located away from non-hazardous areas and must be in operation under normal conditions.

The handling of methanol after the main engine is mainly related to dual fuel engines and in case of fuel switching. In an LFF engine designed by MAN Diesel purging is possible in the fuel piping allowing the fuel to return to the service tank. Purging and inerting is distributed for each sub-system by the nitrogen installation.

2.2.4 Requirements for ships using hydrogen as a fuel

Hydrogen specific requirements have not been set out within IGF code but will be also included in its revision in 2020 wherein fuels cells will be a new part E. This IMO development however will only cover the fuel cell installation and not the fuel storage and the fuel supply system meaning that the alternative design must comply with Part A regarding the code for fuel storage and fuel supply system until specific provision for these aspects are developed for alternative LFF. In order to apply hydrogen fuel successfully within maritime applications further regulatory and standardization work needs to be done by the IMO and classification authorities in order to close gaps within current regulations, requirements, codes and standards. One of the most promising hydrogen applications use a fuel cell technology Proton Exchange Membrane Fuel Cell (PEMFC) which uses hydrogen as primary fuel. Questions regarding onboard storage and use immediately arise and steps are being undertaken by DNV GL and the Norwegian government to regulate and allow this to happen properly.

Draft regulation for fuel cells are still immature in which relevant definitions, goals and functional requirements remain subject to discussion. Despite, the status of requirements as discussed during CCC3 in relation to hydrogen fuel cells will be outlined in the following paragraph to provide an initial insight into regulatory issues faced. It should be noted that this status is subject to alterations made by the IMO correspondence group and will likely be different during CCC4. Furthermore the IMDG code is also discussed as this covers hydrogen and other dangerous goods as packed cargo onboard.

Hydrogen fuel cell considerations during CCC3

Requirements relating to hydrogen fuel piping will be set out in an independent section PART E. In addition, ignition hazards created by static electricity generated by ventilation of the double walls should be considered within the technical provisions. Furthermore, drafted requirements point out that ventilation and exhaust systems cannot be united into a singular system. Figure 8 gives a schematic diagram of a generic fuel cell.

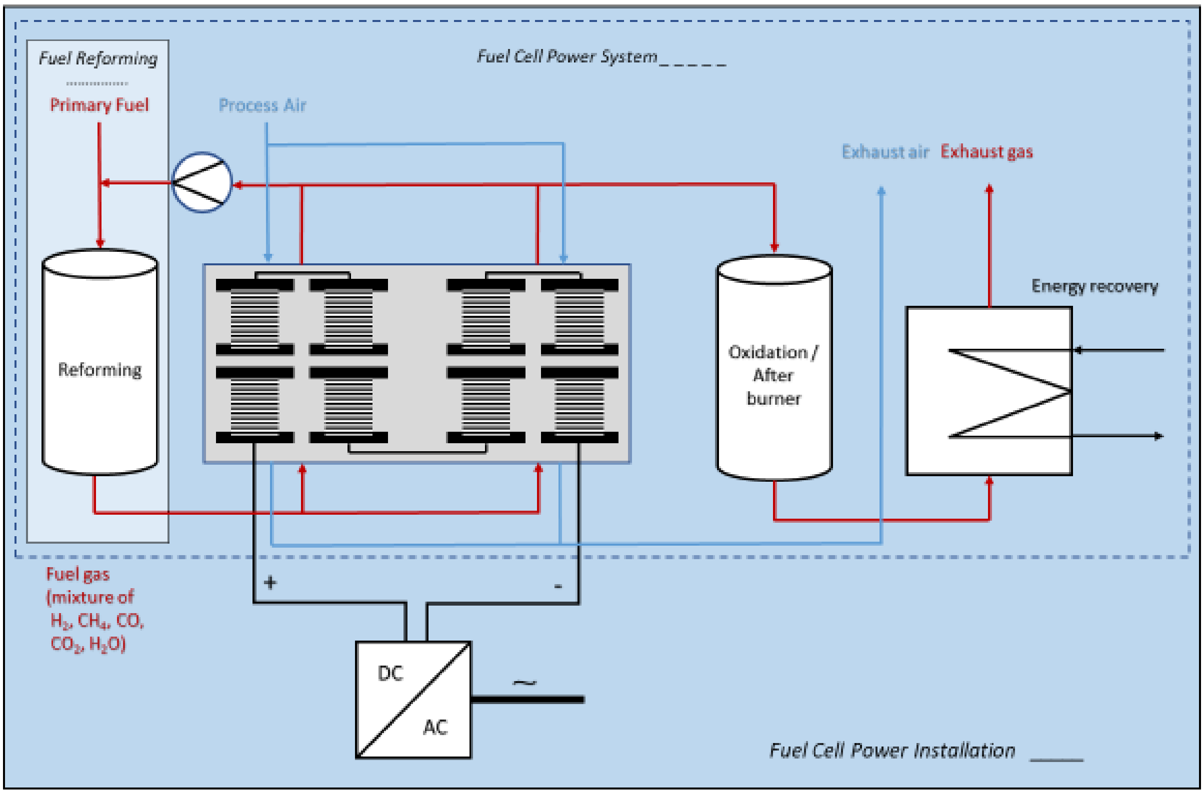


Figure 8: Generic Fuel cell Power Installation (DNV GL, 2017)

International Maritime Dangerous Goods Code (IMDG Code)

The IMDG sets out requirements for compressed and liquified hydrogen comparable to those for compressed natural gas (CNG) and LNG. In this IMDG code compressed and liquid hydrogen can be transported by cargo or passenger ships carrying more than 25 passengers, and should not be stowed under deck. CNG and LNG have exactly the same limitation within the IMDG code. The IGF code in contrast enables the storage of hydrogen and natural gas on-board passenger ships carrying more than 25 passenger. Hydrogen is similar to natural gas as they both should be stored under pressure or in liquefied form. It can be expected that storage quantities of hydrogen will be restricted and storage below deck prohibited (IMO, 2017).

2.2.5 Specific ship type considerations for ships using LFF

Specific requirements vary per ship type and according to the DNV GL rules for classification of ships (Part 6, Chapter 2, section 6) can be separated into three types; 1.) Working ships, 2.) Cargo ships and 3.) Passenger vessels.

2.2.5.1 Working ships

To working ships the following additional requirements regarding general aspects apply:

- LFF fuel tanks on deck are not permitted on offshore supply vessels
- The aft- and forepeak in offshore supply vessel cannot function as cofferdam space for a LFF fuel tank.

2.2.5.2 Cargo ships

With cargo ships additional requirements are set regarding the arrangement, fire safety and segregation of the cargo- and fuel system.

Arrangement

- A dedicated LFF fuel service tank must be provided. The piping system hereof is separated from cargo handling piping systems, except for the fuel transfer pipes from tanks intended for fuel storage.

Fire safety

- In order to reduce the consequences of fire and explosions in cargo tanks and in the cargo area measures are to implemented for the dedicated LFF fuel service tanks and LFF fuel supply systems.
- An acceptable measure to reduce the consequences of in-tank explosions, would be to inert the cargo tanks during cargo tank cleaning operations and inert gas purging prior to gas freeing. Inerting then should be performed for all cargo tanks regardless of the size of a vessel.
- LFF fuel tanks and tank connection spaces on the weather deck shall be protected by a water spray system for cooling and fire prevention and to cover exposed parts of the tank located on deck.
- Furthermore, a deck foam firefighting installation is required for chemical tankers.
- In order to manage and isolate damaged segments, a manual stop valve is to be fitted or the systems may be divided into two sections with control valves fitted in safe and accessible locations.
- The system is served by a water spray pump with sufficient capacity to deliver the required amount of water.
- A connection to the ships fire main is made through a stop valve.

Segregation of cargo- and fuel system

- Measures need to be provided in order to prevent inadvertent transfer of incompatible or contaminating cargo to the fuel system, after the fuel storage tanks have been loaded.
- When cargo tanks located within the cargo area are used as LFF fuel storage tanks, these cargo tanks should be dedicated as LFF fuel tanks when the ship is operational.
- Any cargo liquid pipe line for dedicated LFF fuel storage tanks is to be separated from liquid cargo piping serving other cargo tanks, including common liquid cargo piping.
- Cross-connection to cargo liquid piping serving common systems or other tanks may be accepted, if only the connections are arranged with spool pieces, typically swing bends. The arrangement of spool pieces must be so that if a spool piece is unintentionally left in place, inadvertent transfer of incompatible or contaminating cargo from or to the dedicated LFF fuel storage tank is not possible. Colour coding is used for the piping and manifold serving the dedicated LFF fuel storage tanks.
- The venting system of the cargo tank for dedicated LFF fuel tanks shall be separated from venting systems of other cargo tanks when operating on LFF.
- Other cargo handling systems serving other cargo tanks such as tanks washing, inert gas and vapour return shall be separated when used for LFF Fuel storage tanks. Inert gas systems may be accepted connected to a common system when used as LFF fuel storage tanks, provide the system is under continuous pressure.
- When locating the LFF fuel tanks special consideration should be payed to their compatibility with other cargoes. Thus, when carrying LFF fuel in the storage tanks, these

must not be located adjacent to cargo tanks intended for cargoes that are not compatible with the LFF.

2.2.5.3 Passenger vessels

To this groups the following additional requirements regarding general aspects apply.

- Areas classified as hazardous zones should be inaccessible for passenger at all times.
- The aft- and forepeak in passenger vessels must under no circumstances be used as a cofferdam space for a LFF storage tank.

2.3 Fuel prices

Determining whether the use of alternative fuels is viable can be done by looking at the price differential between an alternative fuel and MGO, as the additional capital investment involved in conversion or new build of vessels should be recovered through the price differential across time. The following paragraph will analyse the fuel prices of MGO and the alternative fuels examined in this study.

Figure 9 demonstrates fluctuations of MGO, LNG, biodiesel and methanol prices in €/MWh over the past decade. Grey hydrogen prices over the last decade have been left out due to a lack of consistent data. All fossil based fuels seem to follow the MGO prices fluctuations, although LNG has shown to maintain relatively stable prices per MWh. The normal distribution demonstrated in figure 9 shows how fuel prices over the past decade have been distributed. When looking at figure 9 and 10 it becomes evident that MGO prices have fluctuated most severely and that biodiesel and methanol are most correlated with MGO prices.

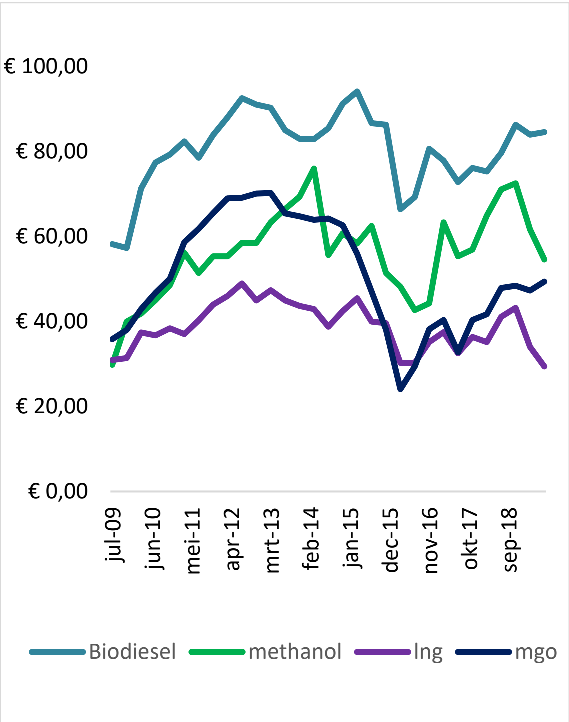


Figure 9: Price fluctuations in €/MWh.

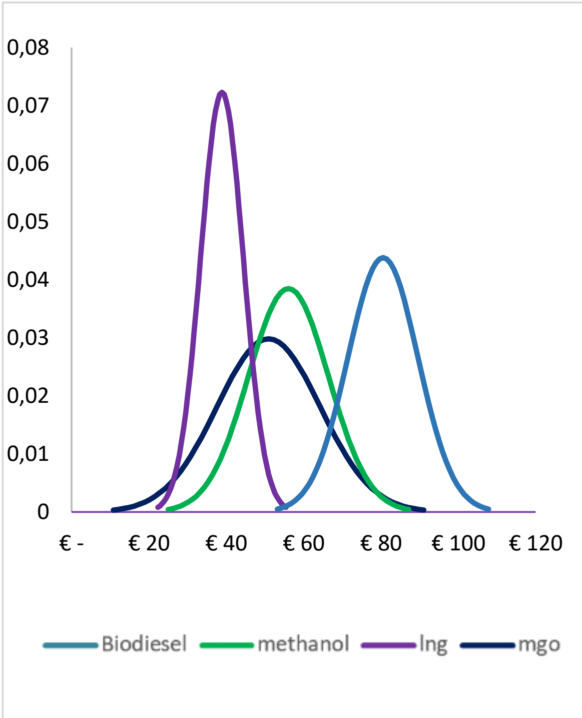


Figure 10: Normal distribution of fuel prices from 2009-2019

2.3.1 MGO

Historical data presented in Ellis and Tanneberger (2015), DNV GL (2019), and Bunker Index prices have been used to plot MGO prices. Historical prices between July 2009 and July 2015 where derived from Ellis and Tanneberger and prices onward from here were derived from DNV GL. Prices are presented in energy units, thereby providing a clear view on which alternative fuel is economically viable as specific weights vary greatly between the fuel types researched.

The price of MGO fuel is highly depended on the HFO price. The prices for MGO over the past decade have always fluctuated, sometimes quite severely. MGO prices between 2009 and 2019 have shifted anywhere between 35 €/MWh and 70 €/MWh as can be seen in figure 9. MGO fuel prices are expected to rise significantly after 2020 with the new sulphur cap entering into force limiting the use of the previously popular high sulphur fuel oil (HSFO). As a result, many ship owners will look for alternatives such as LNG, MGO, scrubbed HSFO and very low sulphur fuel oil (VLSFO). According to the International Energy Agency (IEA) and McKinsey it is expected that the share of MGO will increase significantly causing the price to rise swiftly reaching a new equilibrium in 2023, although a lot of uncertainty is pertained to exact numbers relating to the increase in prices of MGO.

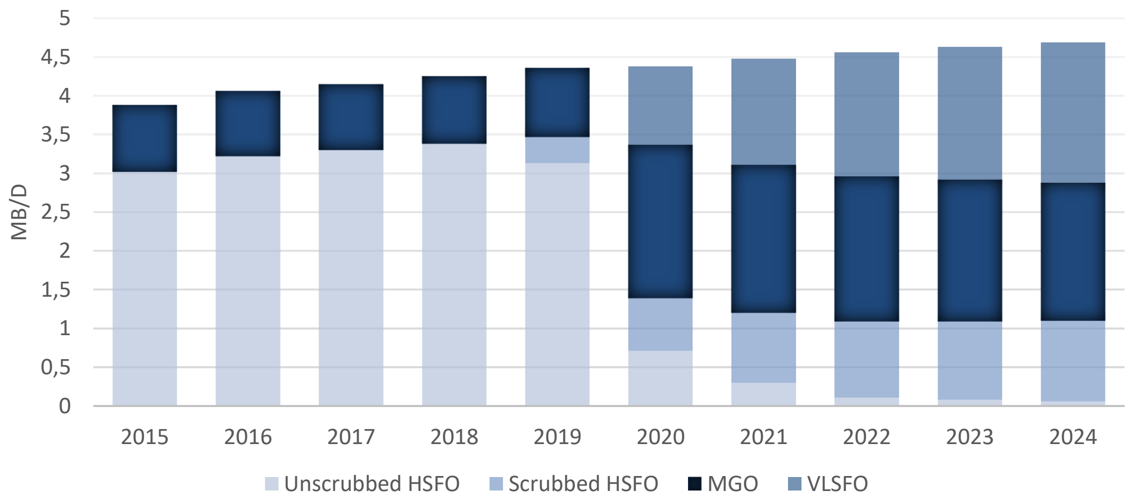


Figure 11: MGO Demand IEA outlook (IEA, 2017)

2.3.2 LNG

The fuel market for LNG is not yet as well-established as the conventional marine fuel market. Therefore, historical bunker prices for LNG dating back to 2009 could not be retrieved for the purpose of this research. As a substitute historical prices for natural gas in Europe have been used as the base for the estimate. Data on natural gas prices was derived from the ''Pink Sheet'' published by the World Bank on a monthly basis. To account for the costs associated with liquefaction, distribution, storage and bunkering an additional cost was added to obtain an accurate price estimate for LNG delivered to a ship, the additional costs account for 6 USD per metric ton (Ellis & Tanneberger, 2015). The resulting price estimations for LNG fuel for maritime use have been compared with other price references found in order to demonstrate the similarity with the LNG price estimate, which can be found in table 5. LNG prices per MWh are significantly lower than MGO prices with an average of 20% lower price per MWh. LNG prices also follow the prices of oil products as it is a fossil fuel (e.g. natural gas derived through the distillation process). International LNG contracts are often linked to crude oil prices, besides natural gas often times directly competes with oil products (E4tech , 2018).

Table 5: Price estimate compared to price reference

year	Price estimate (€/MWh)	Price reference
2015	€ 41.67	€ 44.04 (Lloyd's Register, 2015) € 43.31- € 51.71 (LNG24, 2015)
2012	€ 46.60	€ 41.43 (Bengtsson, et al., 2012)

2.3.3 Biodiesel

The fuel market for biodiesel is very diverse and prices differ quite significantly depending on the ratio of biodiesel in the blend. The higher the percentage of biofuel in the blend the higher the price. The US Department of Energy provides monthly fuel prices on a multitude of alternative fuels. Currently, there are different biodiesel fuels available of which the most popular blends are B5, B20 and B99-100, the number illustrating the percentage of biodiesel present in the mixture. For the price analysis B99/B100 was chosen, as it is the purest biodiesel available and can later be blended with regular MGO onboard ships. Biofuel is a lot more expensive (average 67%) in comparison to conventional MGO, but fluctuates along with MGO prices as can be seen in figure 9.

2.3.4 Methanol

Methanol as a marine fuel is still in its experimental stages, however its use is widely applied within the chemical industries. The world's largest producer and supplier of methanol, Methanex, updates regional contract prices for Europe, North America and Asia. In order to account for costs related to delivery to ships Bengtsson et al. (2012) added USD 37 to the stock price in order determine a reasonable price estimate for marine shipping. Over the last decade methanol was more expensive than MGO, although it is important to note that currently the prices are comparable with MGO. Furthermore, it is interesting to note that methanol prices fluctuate according to the natural gas prices as can also be seen in figure 9. The reason hereof being that the primary production feedstock for methanol is natural gas.

2.3.5 Hydrogen

Determining the cost price for hydrogen is quite difficult and subject to heavy fluctuations due to the immaturity of the fuel. Currently, the primary feedstock for hydrogen is natural gas and is mainly used for industrial purposes. Hydrogen prices differ greatly dependent on a wide variety of parameters such as, the feedstock, size of the production facility, the technology used (efficiency) and whether or not CO2 is sequestered and stored when produced from natural gas. Grey hydrogen is mainly dependent on the cost of natural gas, while green hydrogen is mainly dependent on the cost of renewable energy. Costs for grey hydrogen currently lie between €1.5/kg - €4/kg or €45/MWh - €120/MWh but is expected to decrease due to larger scale production and greater efficiency in the production process (World Energy Council , 2018; Glenk & Reichelstein, 2019).

Costs for green (liquified) hydrogen are mainly depended on the costs for renewable energy. The markets for renewable energy sources aren't as old as the fossil fuel energy markets, however have matured fairly rapidly over the past decade far exceeding previous predictions for price reductions (IRENA, 218). In order to determine the costs for green hydrogen, renewable energy prices must first be determined. For the analysis of renewable energy sources, two types of renewables were selected. The two types are wind energy (offshore) and solar power, as these are widely applied technologies that have extensive recorded price histories. Data on wind and solar energy prices presented by the International Renewable Energy Agency were used as a baseline for hydrogen cost price estimates. The data set is less elaborate when compared to the data set for other alternative fuels and only provides yearly averages from 2010 to 2018. Although this is made up for as the dataset provides a 95^{th} and 5^{th} percentile deviation from the mean, thereby clearly illustrating the spread in prices. From the mean averages of solar and wind energy an ''average price for renewable energy'' was determined as plotted in figure 12.

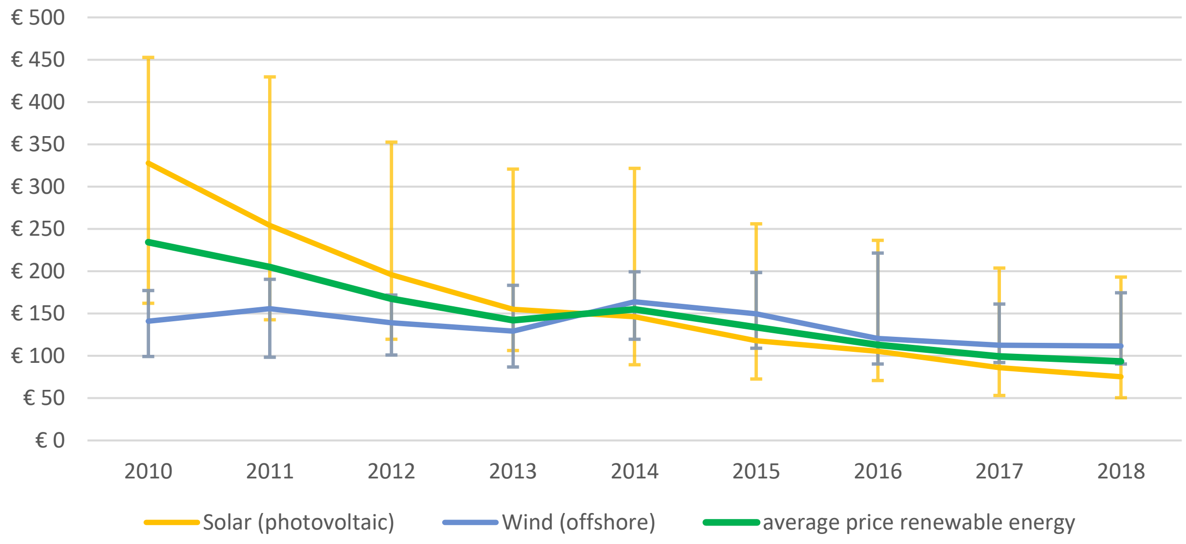


Figure 12: Solar and wind (offshore) prices per MWh

According to a recent report published by Lloyd's Register, 82% of all costs for hydrogen production from renewable energy are spend on primary energy for electrolysis, 6% would go to maintenance, 1% to the electrolysers and approximately 11% to the storage of the liquified hydrogen. Thus, to calculate the total costs, the average price for renewable energy must be multiple by 1.2195. From here the last step is to incorporate the energy efficiency of the electrolyser and fuel cell. Hydrogen Europe (2019) states that energy efficiency rates of electrolysers lie between 70-80%. According to DNV GL shipping fuel cell efficiencies range from approximately 40% (Phosphoric acid fuel cell) to 85% (Solid oxide fuel cell), with the most promising fuel cell having an efficiency of approximately 55% (Proton Exchange Membrane Fuel Cell). These different levels of efficiency have been plotted in figure 13 providing an estimate of green hydrogen prices over the past 8 years.

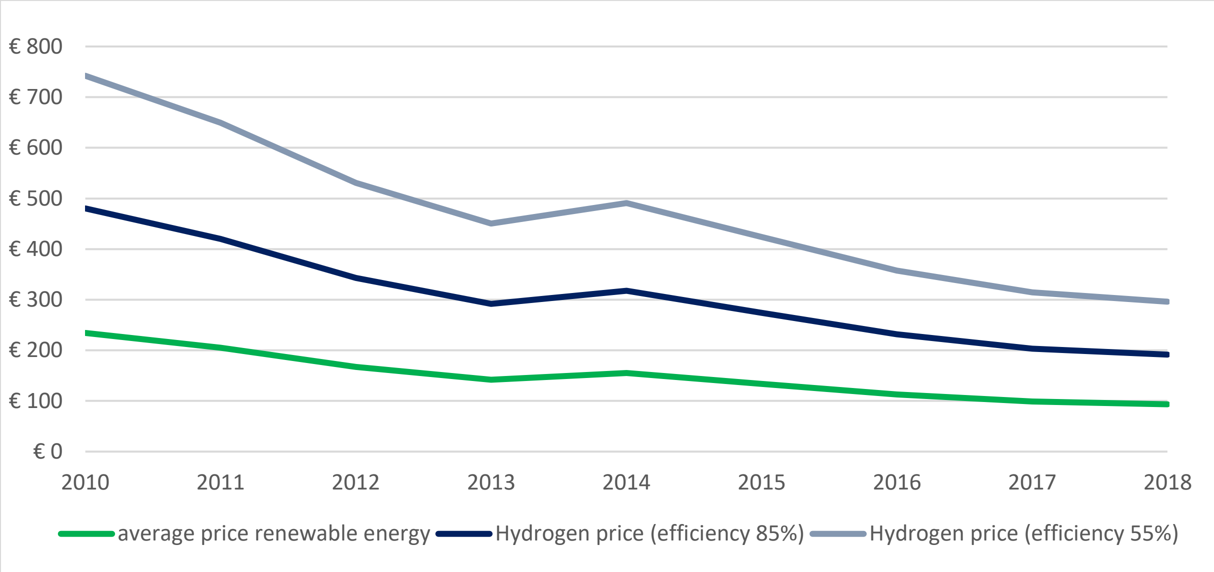


Figure 13: Hydrogen fuel prices

The estimated prices are similar to cost estimates found in relevant literature for green liquid hydrogen produced from electrolysis as reviewed by DNV GL, with price ranging anywhere between USD 3.5/kg and USD 8.3/kg (DNV GL , 2018).

Interesting to note is that independent of the efficiency levels of different hydrogen fuel cell technologies, prices have decreased significantly and already making its use in niche application cost competitive. Large scale production of green hydrogen has not yet occurred, however according to Glenk & Reichelstein (2019) it is likely that hydrogen production will also become cost competitive to match industrial-scale operations in approximately a decade. This is due to falling prices in renewable energy and the efficiency increase of electrolysers.

Large scale production of green hydrogen would be viable at a price of €3.23/kg or €96.9/MWh. Shell (2017) also determined hydrogen fuel costs at European fuel prices for passenger cars for 2020+ in which fuel prices were determined at €7/kg to €9.5/kg or €210/MWh- €285/MWh. It should be mentioned that the prices determined by Shell for 2020+ are very similar to the prices determined through the cost estimate for green liquid hydrogen production in this study for the year 2018, which are estimated to be anywhere between €191/MWh (€6.4/kg) and €296/MWh (€9.9/kg).

3. Constructing a business case for alternative fuels

3.1 Framework for business cases

This chapter will cover the primary costs associated with alternative fuel configurations for newly developed vessels in order to determine whether a business case can be constructed. In addition to the fuel price analysis outlined in chapter 2.5, an outlook based on historic price data using the normal distribution is given to determine five different price scenario's for each fuel, including MGO prices. Hence each fuel has five different fuel price scenarios very low(VL), low (L), average (A), high (H) and very high (VH) coinciding respectively with 2 standard deviations below the mean, 1 standard deviation below the mean, the mean, 1 standard deviation above the mean and two standard deviations above the mean. These five scenario's cover 95.4% of the fuel price data collected, although theoretically the upper price bound has no limit. These price assumption together with the amount of running hours and the capital expenditure costs form the basis for calculating the return on investment of costs associated with each particular alternative fuel.

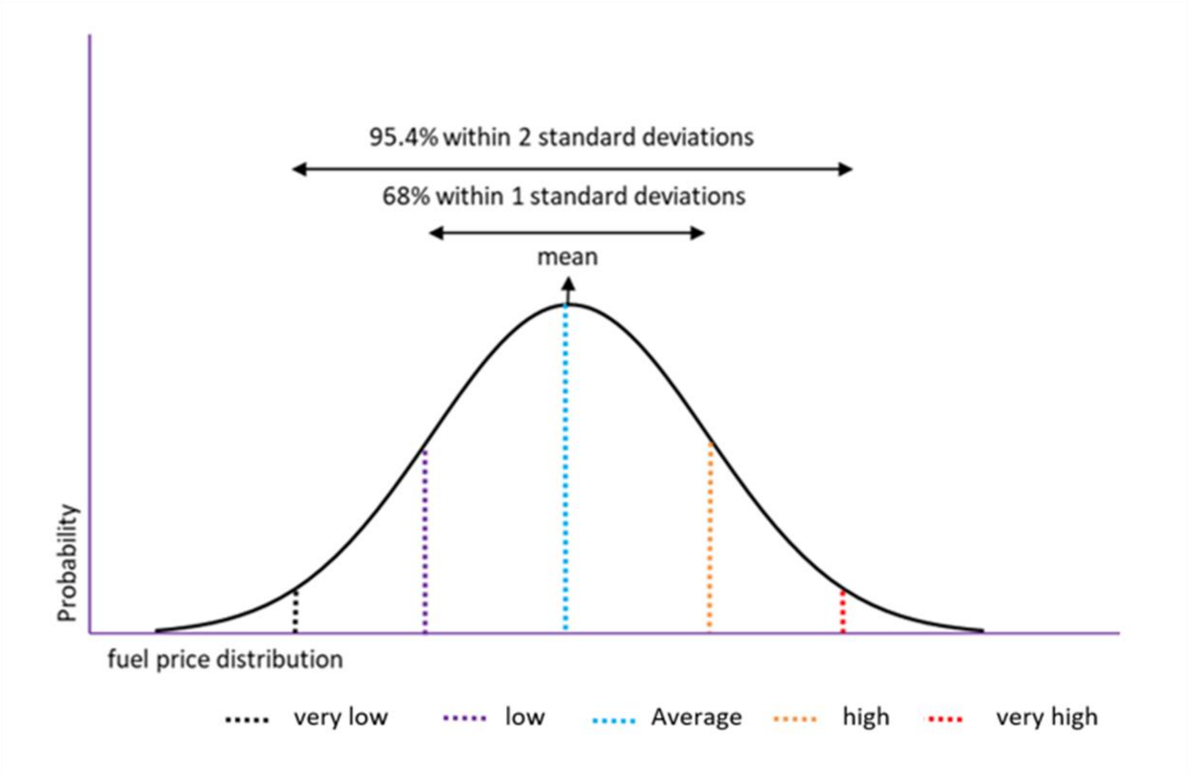


Figure 94: Fuel price scenarios based on normative distribution of fuel prices

This chapter will also cover the capital expenditure costs (CAPEX) needed for MGO and the alternative fuels in order to comply with emission regulations and design codes set out by the IMO. Operational costs will be calculated in €/MWh, similarly capital costs are determined by investment costs per kW installed. Fluctuations in ship types and different installed engine capacities are in this phase less influential for the evaluation of the business cases. Finally, issues pertaining to fuel availability and scalability will also be discussed.

3.1.1 Capex costs for alternative fuels

The upfront capital costs for the main machinery within vessels are assumed to consist of two components: the capital cost of the main propulsion system (main engines) and the capital costs associated with fuel storage and distribution systems. The system as a whole is described as the fuel system. Generally, the costs of the fuel system depend on the costs of the components and their size. However, capital costs of new technologies such as LNG, Methanol, and Hydrogen are also affected by parameters such as the predicted annual production volume, the learning curve ratio, and research and development activities (Raucci, 2017).

Due to lack of consistent literature, estimates of projected costs for marine hydrogen fuel systems were made. Furthermore, it must be noted that independent of the fuel choice, exhaust systems are equipped with selective catalytic reduction (SCR) in order to comply with NOx emission regulations set out in Tier III. The CAPEX costs for SCR installations are estimated at €100/kW (for vessels with an installed power larger than 1000kW), but are not included in the CAPEX as these would also apply to MGO fuelled engines.

3.1.1.1 LNG systems

Historically, the high capital investment costs for LNG installation and fuel system was and still forms a barrier for shipowners. LNG capital investment costs require long term, productive use of a vessel in order to ensure a return on investment. The largest share of the additional investment is related to the cryogenic LNG tank and cold box. The CAPEX costs also greatly vary dependent on were these tanks are located below or above deck. Furthermore, the expenditure also covers additional equipment on board ships such as fuelling equipment, the piping system as well as the LNG engine itself. However, SEA LNG (2018) and DNV GL (2018) in recent studies both demonstrated that LNG CAPEX have been decreasing in recent years caused by increasing competition between suppliers as the technology gains popularity. Investment costs related to LNG fuel engines, fuel tanks and piping are currently estimated at approximately €1000/kW (Stefenson, 2017).

3.1.1.2 Biodiesel systems

Capital investment costs for biodiesel fuel are mainly related to modifications made to the engines and the infrastructure for running on biodiesel (at present primarily HVO), although costs hereof depend on the mixture of the blend. Furthermore, additional costs are associated with ensuring air and water tight storage and transportation of fuel and heating. Engine manufactures estimate that these costs are less than 5% of the engine costs for FAME biodiesel. HVO is considered to have no additional costs. Due to the low CAPEX costs associated with biodiesel, these are not taken into account when calculating the return on investment.

3.1.1.3 Methanol systems

Additional costs related to the installation of methanol fuel systems (internal combustion engine, fuel tanks, piping etc) on board are estimated at approximately one third of the costs related to LNG fuel systems. In contrast to LNG fuel systems no special materials are needed to handle cryogenic temperatures or pressurized fuel thanks. In addition, less cargo space is lost when compared with LNG or hydrogen fuel options. Stena Germanica estimates the additional capital investment costs for methanol at approximately €400/kW. When conducting the return on investment calculations for this research a CAPEX of €350/kW, or 35% of the CAPEX of LNG will be assumed (DNV GL , 2018).

3.1.1.4 Hydrogen systems

Additional costs related to hydrogen fuel systems are similar to those of LNG fuel systems as both need to deal with pressurized and cryogenic liquids. Additional costs are related to modifications made to the vessel engines and infrastructure. However, storage tanks for hydrogen will be significantly more expensive as the fuel is stored at extremely low temperatures, adding costs for insulation quality. Furthermore, fewer maritime applications are currently available when compared with LNG making hydrogen fuel systems more expensive. Additionally, a fuel cell would be more costly than when hydrogen is used as a drop-in fuel for combustion engines. All remaining equipment and infrastructure needed, such as piping, ventilation, heat exchangers and pumps, will have comparable costs to LNG CAPEX. Currently, there is very limited data available on hydrogen piping and storage costs. Since it is not possible to find any consistent cost estimates within the current literature an estimate of the CAPEX for a drop-in hydrogen fuel system of €1400/kW is assumed (Raucci, 2017).

Regarding the costs associated with the main propulsion system, Taljegard et. Al. (2014) states that the costs for marine fuel cells range anywhere between 100 to 1500 USD/kW, excluding the costs associated with fuel storage and piping. While Ludvigsen and Ovrum (2012) refer to a target investment of 1500 USD/kW, Han et. Al. (2012) refers to an additional cost of 750 USD/kW for a fuel cell with a high production volume. Based upon these references a best estimate for the a fuel system including a fuel cell is assumed to range anywhere between €2000 and €3000/kW.

3.1.2 Fuel price future

Determining fuel prices is a rather complicated activity. Many variables such as evolution of trade, regulations, fuel prices and technology, only to name a few, all influence the development of fuel prices. However, it can provide a useful tool for testing out and discussing different scenario's if handled with care and transparently defined assumptions.

The global energy system is slowly transgressing into another stage as demand from Asia grows rapidly and renewable energy sources, mainly wind and solar, start to take up larger shares within the supply of energy. In particular the electricity sector is seeing its most staggering transformation since its genesis more than a century ago. Electricity is increasing its share in the global final consumption of energy, approaching 20% and set to rise even further. This shift is driven by technological advancements and supported by government policies. Growth of electricity demand is most modest within developed countries, but most developing countries could see demand double by 2040. In order to fill this cap in demand renewable energy policies will be at the centre of many strategies for economic development. This renewable energy will be cheaper in comparison to the renewable energy produced within developed countries. This is interesting when looking for affordable green fuel production, although costs for transportation and storage must also be accounted for. According to the IEA the overall demand for oil will increase rapidly within the next decades, coming almost entirely from developing economies. Oil use for cars is expected to peak within the mid-2020s, however ships are expected to keep overall oil demand on a rising trend up to 20% by 2030 in a business as usual scenario (IEA, 2017).

3.1.2.1 MGO, (bio-)LNG, Biodiesel and (bio-)Methanol prices

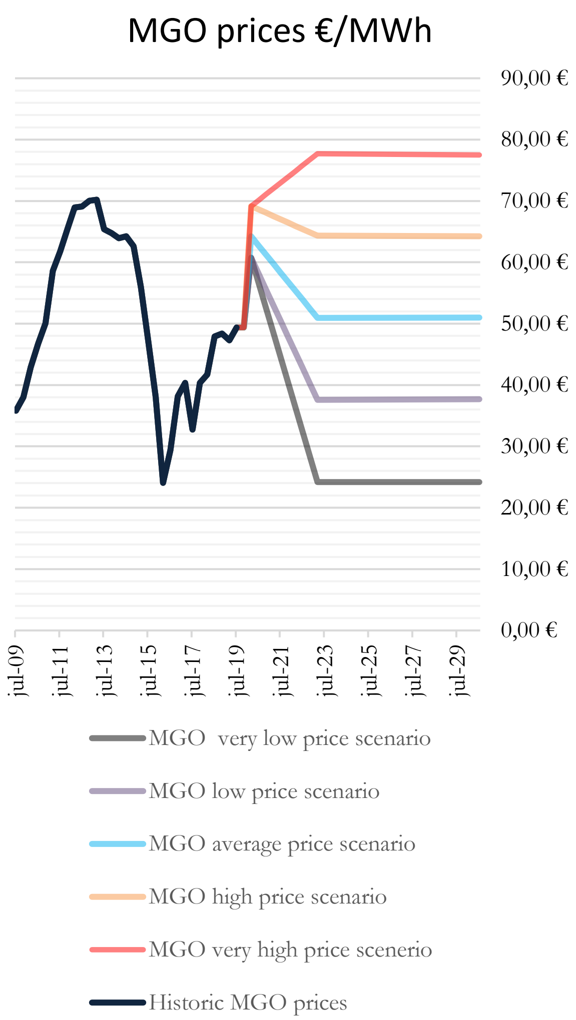
Oil and gas will continue to play a very important role in the outlook period of this research that lasts until 2030. In the long-term however, it is expected that the share of oil and gas within the mix will fall with approximately 9% by 2050 as of a 53% share in 2017. Furthermore, gas is expected to become the world's primary energy source. Contrary to other fossil fuels gas demand will peak towards 2035, while other oil products will peak before that time (DNV GL, 2017).

Within the maritime industry the 2020 Sulphur cap is expected to cause fuel prices to rise significantly caused by a peak in demand for low-sulphur fuels such as MGO, low-sulphur fuel oil and LNG. Robins

(2018) states that MGO prices are expected to jump from 650 USD/t to 800 USD/t, an increase of 23% after 2020. KPI Bridge Oil, an international bunker organisation, even anticipates an increase of 30-40%. According to Bunker Index the price of MGO at the moment is approximately 49,40 €/MWh. A 30-40% increase would drive up MGO price to approximately 64-69 €/MWh if the anticipated increase by KPI is realised. In order to calculate the ROI for alternative fuels five future MGO price scenario's where set out based upon historic prices. In every scenario there is a peak in prices occurring in 2020 after which prices reach a new equilibrium by 2023 as anticipated by McKinsey (2018). The low scenario assumes a 23% MGO price peak after 2020 as anticipated by Robins (2018), after which the MGO price drops to one standard deviation below the mean of the MGO prices (recorded between 2009 and 2019) to €37.58 /MWh in 2023. This scenario is more likely to occur if alternative fuels successfully penetrate the market quickly causing the demand for MGO to drop significantly. However, such a scenario is considered to be unlikely taking into account that average prices over the past decade have increased by only 1%.

The scenarios for MGO fuel prices have been based upon the normal distributions of fuel prices from the past decade (see figure 9). Constructing scenarios on historic prices is only useful when the fuel markets have matured extensively. Although, biodiesel, LNG and methanol are relatively new fuels within maritime applications, their use and production in other sectors has been around for an extended period of time. The moderate scenario assumes a peak increase in 2020 of 30% as of the current MGO price after which prices fall back to the average price recorded over the last decade. This scenario is considered to be the most likely based upon the historic analysis of MGO prices, although one could argue that prices will likely not fall back to ''normal'' due to the new regulations causing perpetual price increases of MGO. Furthermore, prices always tended to increase more than decrease over time. In fact, in a recent study where the investment opportunity of LNG as marine fuel was researched by SEA\LNG (2019) their 2020+ fuel price scenarios suggest that MGO prices are likely to increase and in none of the scenario's will decrease. For this reasons a high and extreme high scenario have been considered both assuming a peak increase of 40%. The high scenario reaches a new equilibrium at one standard deviation above the average. In the extreme high scenario the price continues to rise to two standard deviations above the mean average over the past decade. Although statistically unlikely this scenario could become a reality as oil markets are vulnerable to significant high price shifts resulting from radical changes to the markets, such as the IMO 2020 sulphur caps. Similar scenarios based on normal distributions of fuel prices from the past decade were created for LNG, biodiesel and methanol.

Determining prices for bio-LNG and bio-methanol on the basis of consistent historical price data was not possible as these alternative fuels are quiet novel. Nevertheless DNV GL provided information on the prices of bio-LNG and bio-methanol. Upon this data the two following assumption have been made with regards to bio-LNG and bio-methanol; 1.) bio-LNG is approximately 20% higher in price compared to fossil LNG, 2.) bio-methanol is assumed to be 50% higher in price compared to grey methanol. Hence when calculating return on investment periods for bio-LNG and bio-methanol, fossil LNG and methanol will be multiplied with a factor 1.2 and 1.5 respectively.



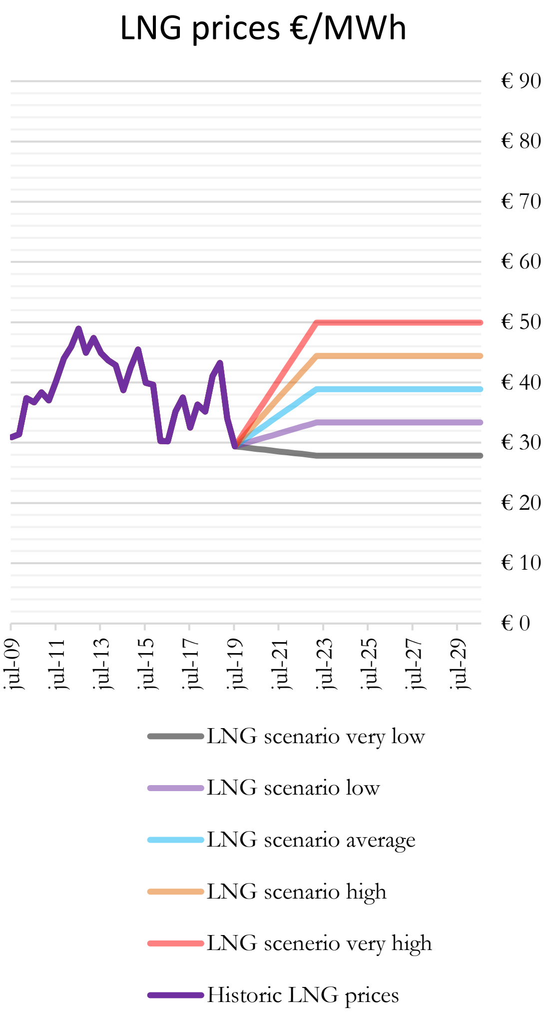


Figure 10: MGO and LNG historical prices and outlook

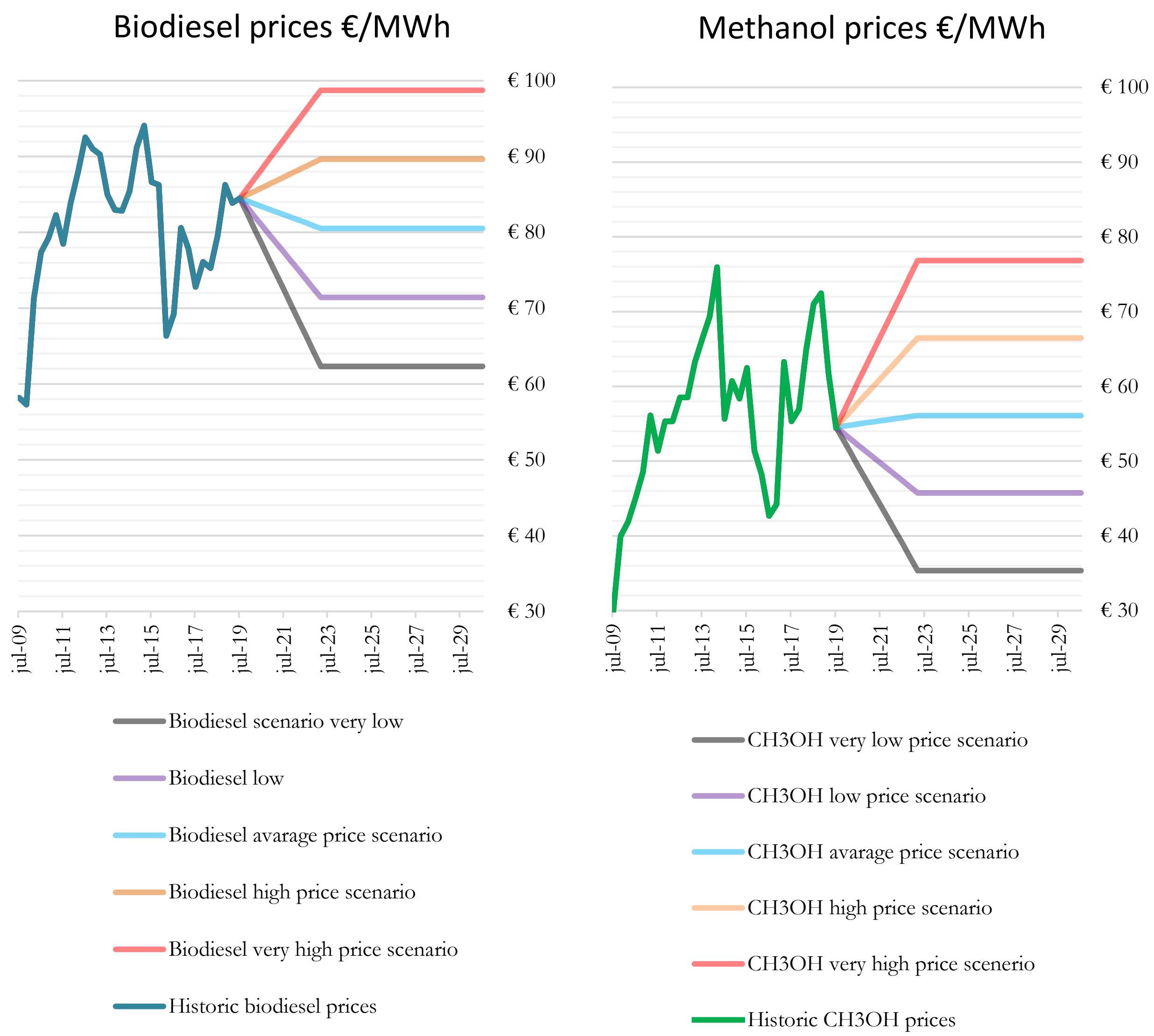


Figure 11: Biodiesel and Methanol historical prices and outlook

3.1.2.2 Renewable fuels prices

Renewable energy sources are expected to take an increasing share within the energy mix, driven mainly by a strong growth of solar and wind energy. The costs associated to using renewable energy for power generation therefore are expected to decrease rapidly. Power-to-gas and power-to-liquids have the potential to store large amounts of renewable energy making it one of the great unknown variables in many fuel price forecasts as it has the potential to become a major energy carrier having a major presence in the energy future. Glenk & Reichelstein (2019) suggest that hydrogen will become economically viable by 2030 for large scale industrial production. This however will likely not be enough to get a return on investment for maritime applications. In order for hydrogen to become economically viable it is expected that selling prices will need be at least half the price as described in their research or MGO prices need to be above €1/L at least (Glenk & Reichelstein, 2019).

In contrast to biodiesel, LNG, methanol and grey hydrogen, green hydrogen (produced from renewable energy) is still in its infancy and prices over de past decade have declined significantly. Therefore, constructing price scenarios from the normal distribution of green hydrogen prices (estimates) recorded over the past decade would not be a reliable method for constructing future price scenarios. Instead the exponential decline rate for renewable energy prices was determined using the formula illustrated in figure 12. Renewable energy prices for solar and wind have seen a constant decline in price since 2010 and according to IEA (2019) World Energy Outlook will continue to fall while oil prices will keep rising. Although the plotted graph below shows similarities with the Shell hydrogen study (2017) prices are still three times as high for green hydrogen, making a business case very unlikely. However, DNV GL provided data suggesting that green hydrogen prices are approximately twice as high compared to grey hydrogen. Therefore, grey hydrogen prices (€1.5/kg-€4/kg) will form the basis upon which future green hydrogen prices are calculated (grey hydrogen prices multiplied by a factor 2). Here as well the mean and standard deviation will be used to set out five different green hydrogen future scenarios.

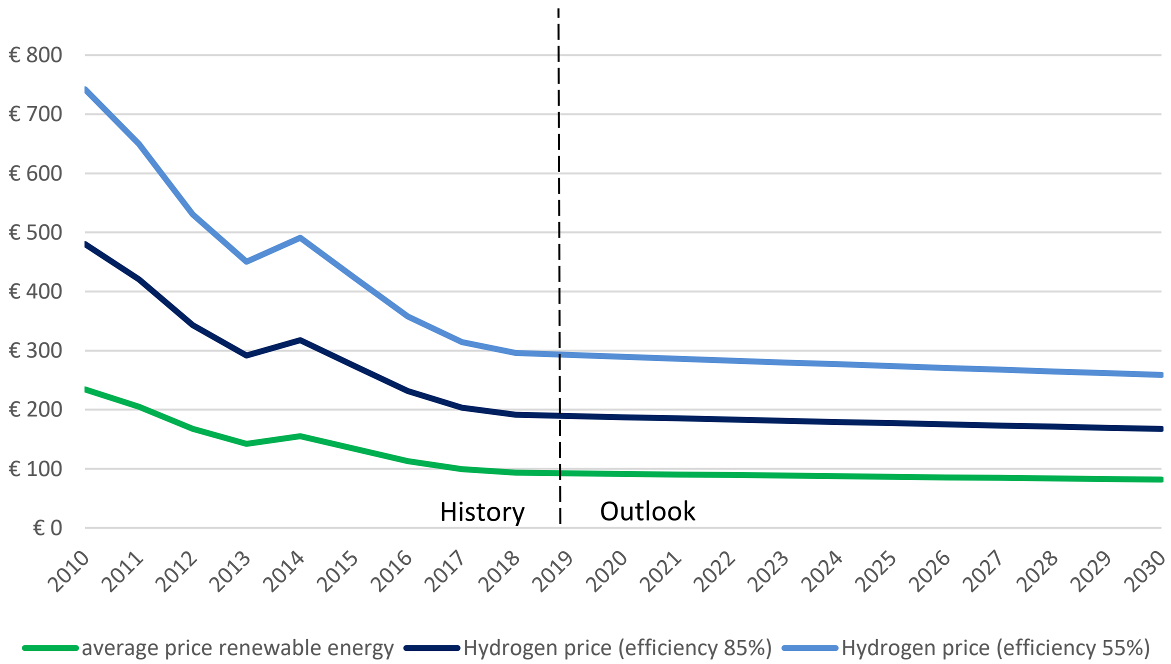


Figure 12: Renewable energy and hydrogen historical prices and outlook

3.1.3 Alternative fuels availability & scalability

Besides a viable business case, alternative fuels must be available across the world in sufficient quantities to meet the demand. When assuming minor growth in shipping applications for the studied alternative fuels, it is estimated that suppliers would be able to meet the demand of the shipping industry. However, uncertainty is still pertained as to what will happen if one alternative fuel is to become so attractive that a large number of shipowners would adopt its use within a short time frame. DNV GL (2018) states that LNG is the only fuel that can meet a rapid rise in demand, other alternative fuels including those studied within this research would require enormous investments in production capacity.

3.1.3.1 LNG

The demand for LNG as bunker fuel for maritime uses is growing and so is the availability of LNG as bunker fuel along major shipping routes. Existing LNG bunker infrastructure is located mainly within the Baltic and North Sea. However, all European regions have initiated a number of planned projects aimed at the expansion of LNG infrastructure and LNG availability. Likewise, in North America and in the Asia-Pacific a few ports have planned new LNG projects, thereby offering LNG bunkering. Furthermore, shale formations in North-America have increased the availability of natural gas in North America, followed by a decrease in natural gas prices (Henry Hub) making the fuel more attractive. There are no major limitations predicted to occur within the foreseeable future that would limit the availability of LNG as a shipping fuel. In fact, the production capacity for LNG is set to increase considerably. In fact, Rystad Energy (2019) states that the global LNG capacity is expected to increase from 396 Mt in 2018 to 434 Mt in 2019. The 10% increase comes mainly from the commissioning of US projects, doubling the US production capacity from 29 Mt to 61 Mt. Moreover, natural gas is expect to become more and more popular as it is the cleanest fossil fuel, with the number of liquefaction sites worldwide expected to double by 2040. In terms of fuel availability the IEA (2018) in their Outlook for Natural Gas, states that availability of natural gas until 2040 will be ample.

3.1.3.2 Biodiesel

Biodiesel availability is rather controversial as it often competes with food industry. Nevertheless, global production data shows that global biofuel production has expanded with 7% year-on-year in 2018 to 88 Mt produced. The IEA (2019) states that annual production growth will approach 3% over the coming 5 years. Geographical location greatly affects the availability of viable biomass offered for production of biofuels. There is limited experience with biodiesel fuelled vessels and related bunkering infrastructure. Besides, the shipping industry will be competing with the road and aviation transport sectors over available waste oils. Although HVO allows for significant GHG emissions reduction, its drawback lies with the limited availability of waste oils and fats and their usage is limited under EU policies as it raises sustainability concerns (IEA, 2019).

3.1.3.3 Methanol

The majority of methanol is currently produced from gas and coal, with steam reformation from natural gas being the lowest cost production method (grey methanol). Other feedstocks of methanol include biomass or any other carbon organic waste. In 2016 global methanol demand was approximately 80Mt, twice as high as in 2006. The total production capacity for methanol in 2018 was 137Mt. Annual demand for methanol is predicted to increase significantly, up to 146Mt by 2022. The largest consumer of methanol is Asia accounting for approximately 60% of the global demand, with the remaining share coming from North America, Western Europe and the Middle East. This distribution has been constant over the past decade. Unlike many other alternative fuels, the European Maritime Safety Agency argues that methanol is readily available worldwide through existing infrastructure. Indeed, it is used extensively throughout the chemical industry and large bulk storage terminals in Rotterdam and Antwerp are available comparable to LNG and other conventional fuels. In China methanol is increasingly used as blender or substitute for gasoline (Ellis & Tanneberger, 2015).

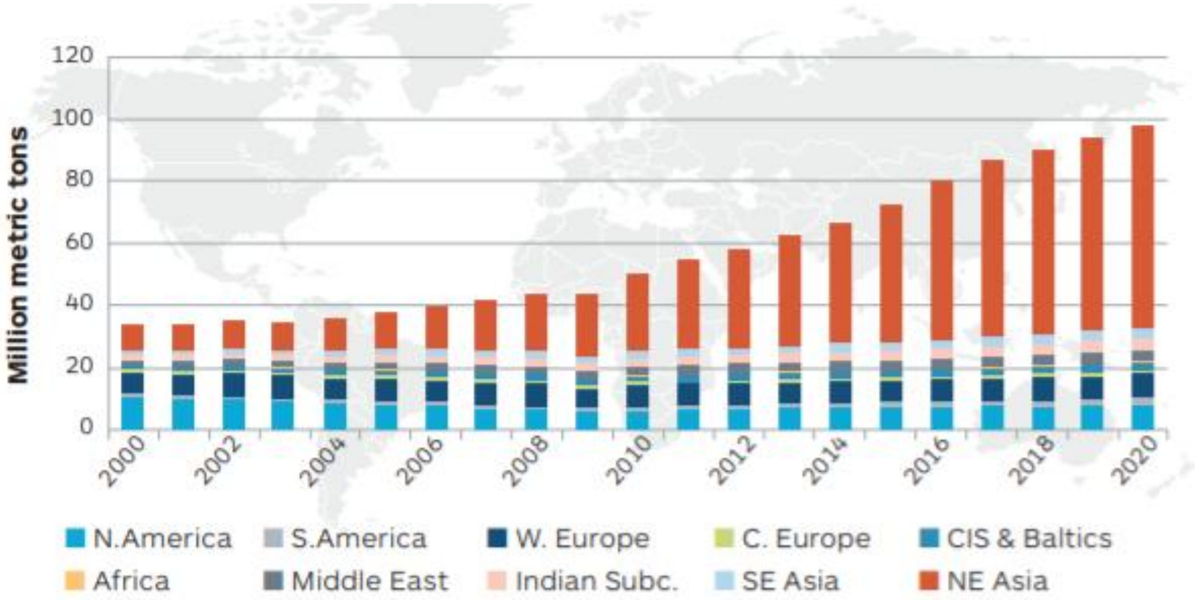


Figure 13: World methanol demand by region (IHS Chemical, 2016)

Green methanol produced from bio-mass faces similar challenges as other biofuels as it is often has limited availability or competes with food production landscapes. However, renewable methanol may be produced from a wide variety of renewable feedstocks, such a municipal solid waste, forestry residues, carbon dioxide and even from renewable hydrogen. Future availability of green methanol depends mainly on the availability of other low-costs electric power. Currently, green methanol is far from being widely available.

3.1.3.4 Hydrogen

Hydrogen, like methanol has a wide variety of feedstocks. At the moment most hydrogen is produced from natural gas accounting for more than 70 Mt produced annually on a global scale, only 4% is produced through electrolysis. Although hydrogen can be costly to produce, it is considered to be competitive when it can be produced from the surplus of energy from solar and wind energy which cannot be taken up by the grid. Unlike LNG and Methanol the hydrogen distribution network is rather limited, especially for the shipping industry. However, the hydrogen market is starting to develop as electrolyser installations over the last two years have increased the capacity for green hydrogen production significantly. However, this hydrogen infrastructure for the shipping industry would still require major investments and government incentives in order to catch air. Generally, there are no principal limitations to the production capacity of hydrogen as this can be produced also through electrolysis using water and renewable energy, meaning hydrogen is available around the world. As the capacity for renewable wind and solar energy grows increasingly so will the capacity for green hydrogen production. The major limitation for green hydrogen is to ensure that it is able to penetrate the market. Once this occurs there are very little limitations for the production of green hydrogen, as renewable energy (wind and solar) may be produced non-location specific.

3.2 Current business case for alternative fuels

Return on Investment (ROI) is a performance measure often used to determine the efficiency of an investment or to compare different investments with one another. To calculate a return on investment in this case, the price differential between MGO and the alternative fuel, is divided by the costs of the investment which are related to the capital expenditures. The ROI is calculated for new build vessels and are expected to be slightly higher for retrofits made to existing vessels.

The capital expenditures, as illustrated in chapter 3.1.1, have to be recaptured through the price differential between the alternative fuel and MGO. In order to calculate how long this would take the price scenarios highlighted in the previous chapter have been used as a guideline as to whether a ROI is possible. In total 12 combined scenarios have been assessed for the alternative fuels that currently have a business case or could in potential have one within the foreseeable future. All fuel prices have five price scenarios, Very Low (VL), Low (L), Average (A), High (H) and Very High (VH). In order to compare all possible outcomes of these different fuel prices scenario matrices have been set up. In these matrices fuel price scenarios of an alternative fuel are combined with an MGO price scenario from which a return on investment is then calculated. Furthermore, a likelihood is attached to each combined price scenario as to give an indication of uncertainty. Important to note is that in the combined scenario of e.g. VH.VL the first letter(s) apply to MGO (Very High) and the second letter(s) to the alternative fuel (Very Low).

Furthermore, a variation is made in operational hours, namely 4000, 6000 and 8000 operating hours. Logically, the more operational hours the engine has, the more benefit is made from the price differential, thus the shorter the ROI. The ROI's for 4000 and 8000 operating hours of each combined scenario are also indicated in the scenario matrix. Because fuel prices are given in price per energy unit and capital expenditures are also given in price per energy unit, making a distinction between different engine sizes is not required for this calculation.

In all cases a higher MGO price will lead to faster return on investment periods, just as lower alternative fuel prices reduce return on investment periods. However, not all alternative fuels have a business case at the moment. Hydrogen for instance will need to see significant production price reductions. However, these price reductions are not expected to occur within the coming decade unless significant CO2 taxes or hydrogen incentives are ratified.

Table 6: Fuel price scenarios (in Euro/Litre)

Euro/Litre	Very Low (VL)	Low (L)	Average (A)	High (H)	Very High (VH)
MGO	0.24	0.37	0.50	0.64	0.77
Bio Diesel	0.62	0.71	0.81	0.90	0.99
LNG	0.18	0.22	0.26	0.29	0.33
Bio LNG	0.22	0.26	0.31	0.35	0.39
MEOH	0.18	0.23	0.28	0.33	0.38
Bio MEOH	0.26	0.34	0.42	0.50	0.57
Grey LH2	0.11	0.16	0.21	0.26	0.32
Green LH2	0.21	0.32	0.42	0.53	0.63

3.2.1 Business case for LNG

In order for LNG to become a viable business case, MGO prices must be higher than the average price (> €0.50 EU/L) seen over the past decade. Obviously, a VH MGO price scenario (€0.77EU/L) and a VL LNG price scenario (€0.18EU/L) would result in the shortest ROI periods ranging between 1 and 3 years. While a VH LNG price scenario (€0.33EU/L) together with a VH MGO price scenario (€0.77EU/L) would still see reasonable ROI periods ranging from 3 to 5 years respectively to 8000 and 4000 operational hours. However, such high prices are not as likely to occur within the near future. Much more likely are the combined scenarios in which average to high MGO prices (€0.50-€0.64EU/L) coincide with average to high LNG prices (€0.26-€0.29EU/L). However, from these likely scenarios ROI periods are only sufficient if MGO prices tend towards the high scenario. Thus, under current conditions investing in a LNG installation for ships with more than 8000 working hours appears to have a favourable business case. Especially when considering that MGO prices are expected to rise towards this H price scenario (€0.64EU/L) with LNG prices likely moving towards the average LNG price scenario (€0.26EU/L).

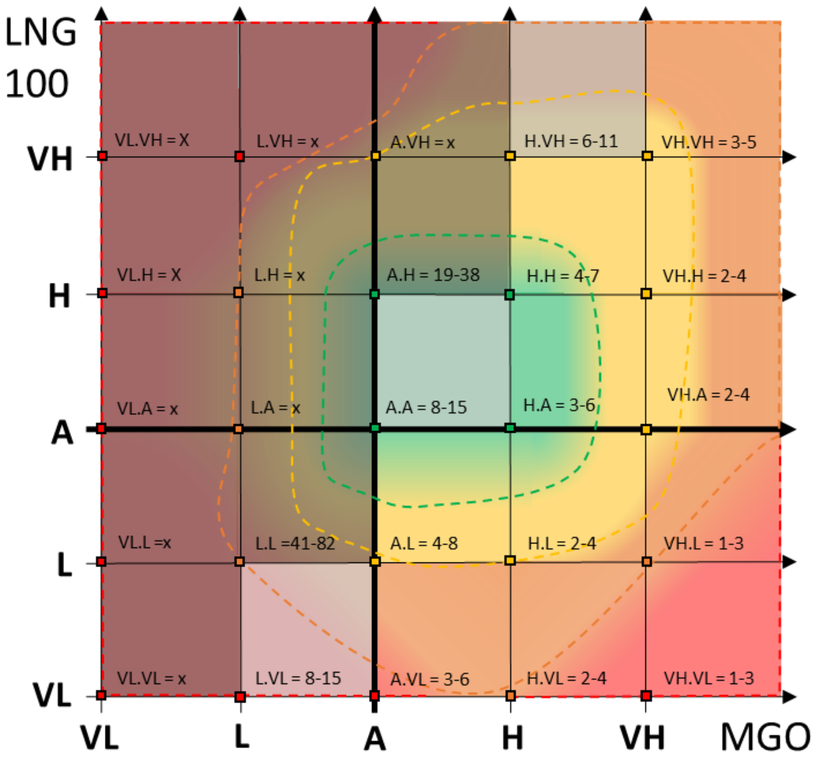
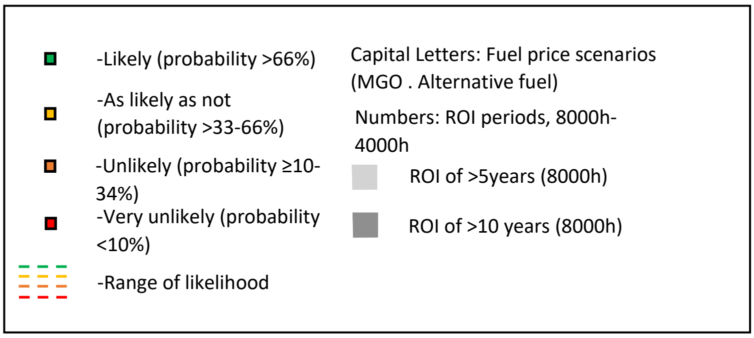


Figure 19: ROI periods for grey LNG



Reading guide

The X-axis represents the baseline MGO price scenario ranging from VL to VH (see table 5). While the Y-axis represents the alternative fuel price scenarios. The graph contains two main messages. First, it demonstrates under which scenario's a ROI can be made as illustrated by the number presented on the upper right of the scenario crossover. The lowest number constituting 8000 working hours, and the highest number representing 4000 working hours. If the lowest number falls within the range of 0-5 years the cell will be fully visible. However, if the lower value falls between 6-10 the cell will be covered with light grey shade, while cells with a lower value of >10 are covered by a darker shade of grey. Evidently one is able to see under what price conditions a ROI can be made and under which these chances are dim or impossible.

Additionally, the colourpoints (e.g., ▪) aim to visualize an indication of the likelihood of each combined scenario to occur, these points where then used to colour the entire cell, thereby showing the spread. It must be noted that these likelihoods have been determined on the basis of historical data and certain assumptions about future price evolutions as described in chapter 4.3 and therefore should only be used as an indication.

3.2.2 Business case for biodiesel

Since biodiesel has no or very little capital expenditures the business case for biodiesel depends merely on whether biodiesel fuel prices are cheaper when compared to fuel prices of MGO. This occurs only when biodiesel prices fall within the VL or L scenarios, and the MGO prices fall within the H or VH price scenario.

Table 7: Price scenarios biodiesel

EU/L	very low	Low	average	high	very high
MGO	€ 0.24	€ 0.37	€ 0.50	€ 0.64	€ 0.77
Biodiesel	€ 0.62	€ 0.71	€ 0.81	€ 0.90	€ 0.99

As can be seen in table 7, only a VH.VL, VH.L, and H. VL scenario would allow for ships to use a 100% biodiesel mixture onboard. However, as illustrated in figure 20 the likelihood of such price scenarios occurring is very low, especially when considering that in the past decade biodiesel prices have on average been 67% higher than MGO prices.

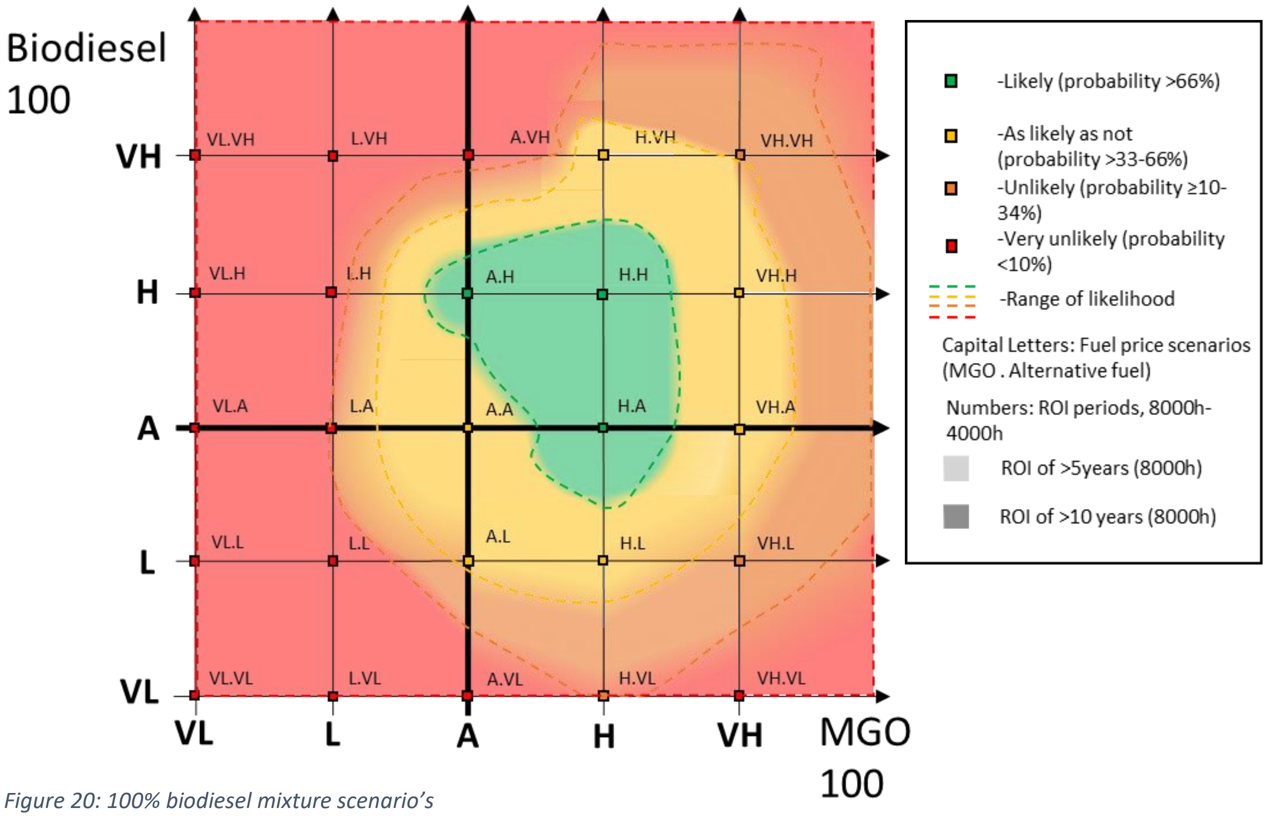


Figure 20: 100% biodiesel mixture scenario's

3.2.3 Business case for methanol

Currently the business case for grey methanol seems rather uncertain. Only under relatively high MGO prices (> €0.64/L) and average to low methanol prices (< €0.28/L) does the business case for methanol hold. Interesting to note is the stark transition coloured and dark grey shaded cells, indicating that small changes in fuel prices have a large impact on the ROI period of grey methanol. Although a business case is still possible with average MGO prices (€0.50/L) and very low (€0.18/L) to low (€0.23/L) MEOH prices these scenarios are deemed quite unlikely. Therefore, the present business case for green methanol, which is produced from CO2 and green hydrogen, appears to be rather dim as production costs are significantly higher.

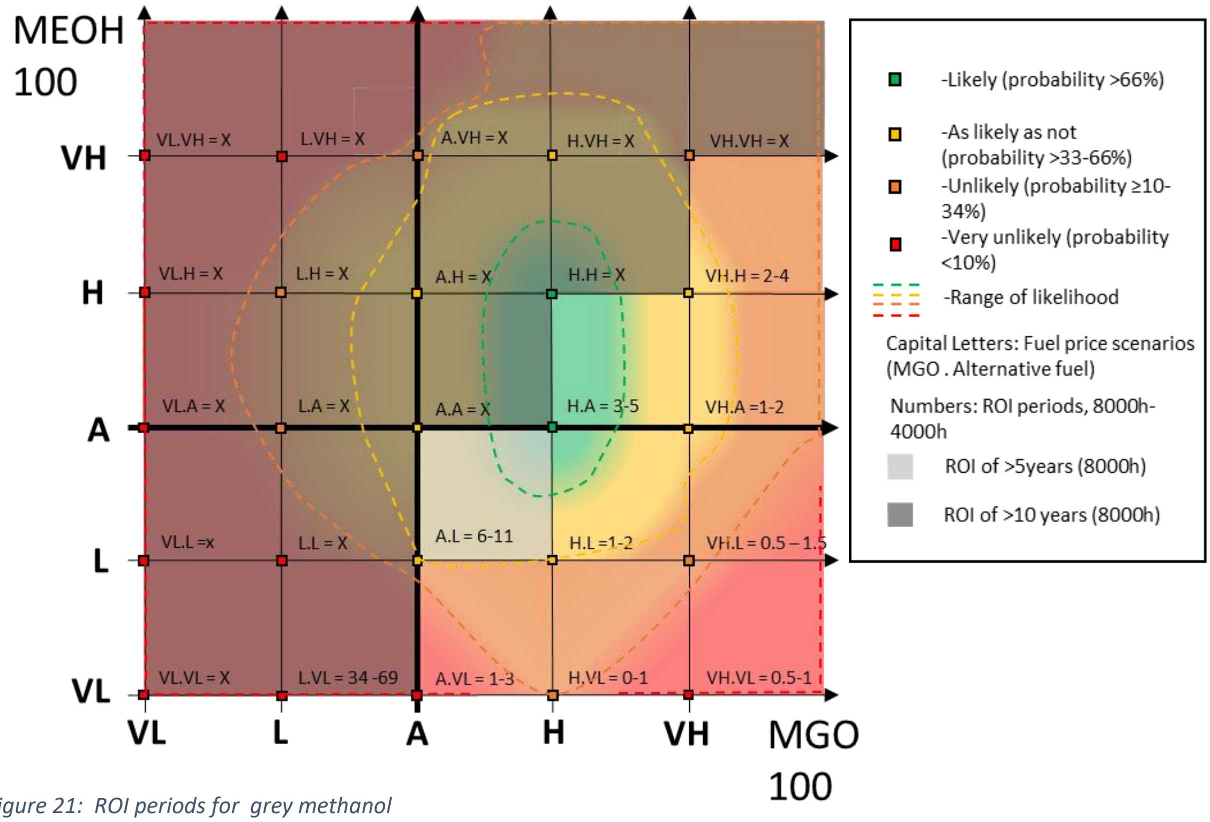


Figure 21: ROI periods for grey methanol

3.2.4 Business case for hydrogen

Currently prices for grey (and green) hydrogen are still too high to produce a feasible business case. There are only two combined scenarios for grey hydrogen that could lead to acceptable return on investment periods as demonstrated in figure 22. Although these scenarios are highly unlikely to occur they do demonstrate where prices ought to go if hydrogen (green and grey) are to become economically feasible for the maritime industry. At an average price of €0.5/L MGO, hydrogen prices would have to fall back to €0.08/L in order to get within a 5-10 years ROI range. To put this in perspective, the lowest green hydrogen price scenario for 2023 stands at 0.31/L meaning that green hydrogen prices would have to be at least 4 times lower. Thus, merely looking from an economic perspective hydrogen appears to still be far beyond the horizon. In order for hydrogen to become a viable and economically viable solution subsidies are needed that could either lower the production costs for hydrogen or reduce capital expenditures.

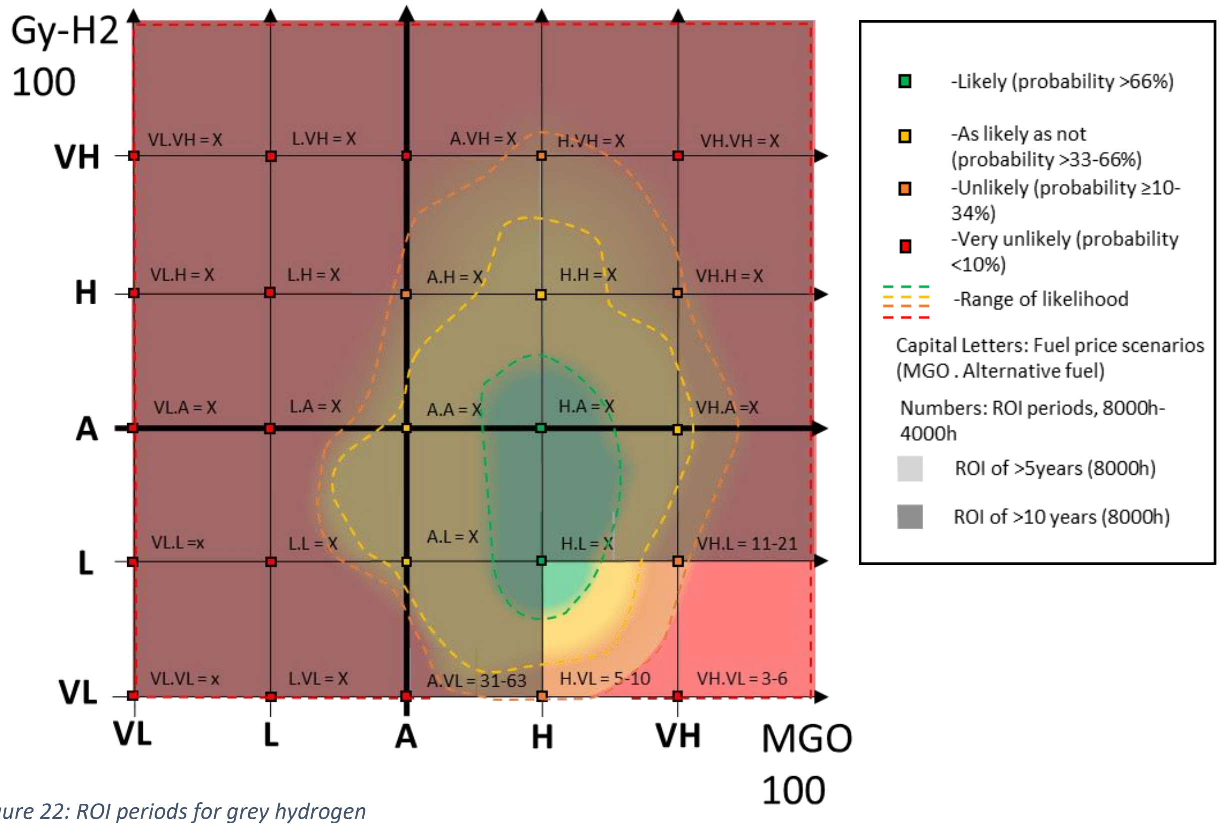


Figure 22: ROI periods for grey hydrogen

3.3 Business cases in CO2 reduction futures

In order to meet the CO2 reduction targets set by IMO alternative fuels must be incorporated into the fuel mix. This chapter will determine which fuel mixture would constitute the most suitable return on investment periods in the case of achieving a 20%, 50% or 100% CO2 emission reduction. The following paragraphs will seek to determine the ROI periods under these three CO2 emission reduction futures plotting these in 225 combined scenarios. Since biodiesel will be considered a carbon neutral fuel and does not require additional installation costs, a percentage of biodiesel is added to the MGO mixture in accordance with the CO2 emission reduction future. Initially one might deem a future as such to be highly unlikely, especially when merely looking at fuel price history of biodiesel as it is very expensive. However, when considering the targets set by the IMO regarding greenhouse gas emissions and local pollution, biodiesel is often seen as the most straightforward option providing shipowners with a fuel very much alike conventional diesel. In a recent interview van den Heuvel (2019) states that biodiesel is a good solution for the shipping industry for the short and medium term. In fact, some early adapters like Van Oord in cooperation with Shell recently started a large scale pilot project in which one of Van Oord's dredgers in Germany now uses a 50% biofuel and 50% MGO mixture. Biodiesel in these additional scenarios is viewed as a transition fuel that in theory could drive up the prices of the MGO/Biodiesel mixture upward, thereby opening up the business case for alternative fuels.

When assuming a future wherein CO2 emissions are reduced with 20%, an alternative blend of e.g. 20% bio-methanol is combined with a 80% grey methanol and compared to a MGO blend containing 20% biodiesel. Similarly, in a future with a 50% reduction in CO2 emissions an alternative blend, e.g. 50% green hydrogen combined with 50 grey hydrogen is compared to a MGO blend containing 50% biodiesel. These biodiesel blends (B20, B50 or B100) to which the alternative fuels are compared scenario's consist of variable MGO prices, ranging from VL to VH, and fixed Biodiesel prices are at VH price scenario (€0.99/L). The likelihood of a price scenarios occurring in CO2 reduction futures in the following figures is identical to those determined under the current circumstances as in these futures the assumption is simply made that these will occur. As a result different price scenarios have similar likelihoods.

3.3.1 20% CO2 reduction future: Increasingly imminent

In case of a future wherein CO2 emissions are reduced by 20% using biofuels a choice for 20% bio-LNG (BLNG) and 80% LNG as an alternative fuel would be most likely resulting in a sufficient return on investment. Interesting to note is that in such case all the likely scenarios constitute a ROI that is always 5 years or lower in case of 8000 working hours. The only as exception is the as likely as not scenario MGO prices fluctuate around the average(€0.50/L) and LNG prices are very high (€0.33/L). While LNG under current conditions often already provides sufficient ROI periods, a 20% reduction future would make LNG even more viable.

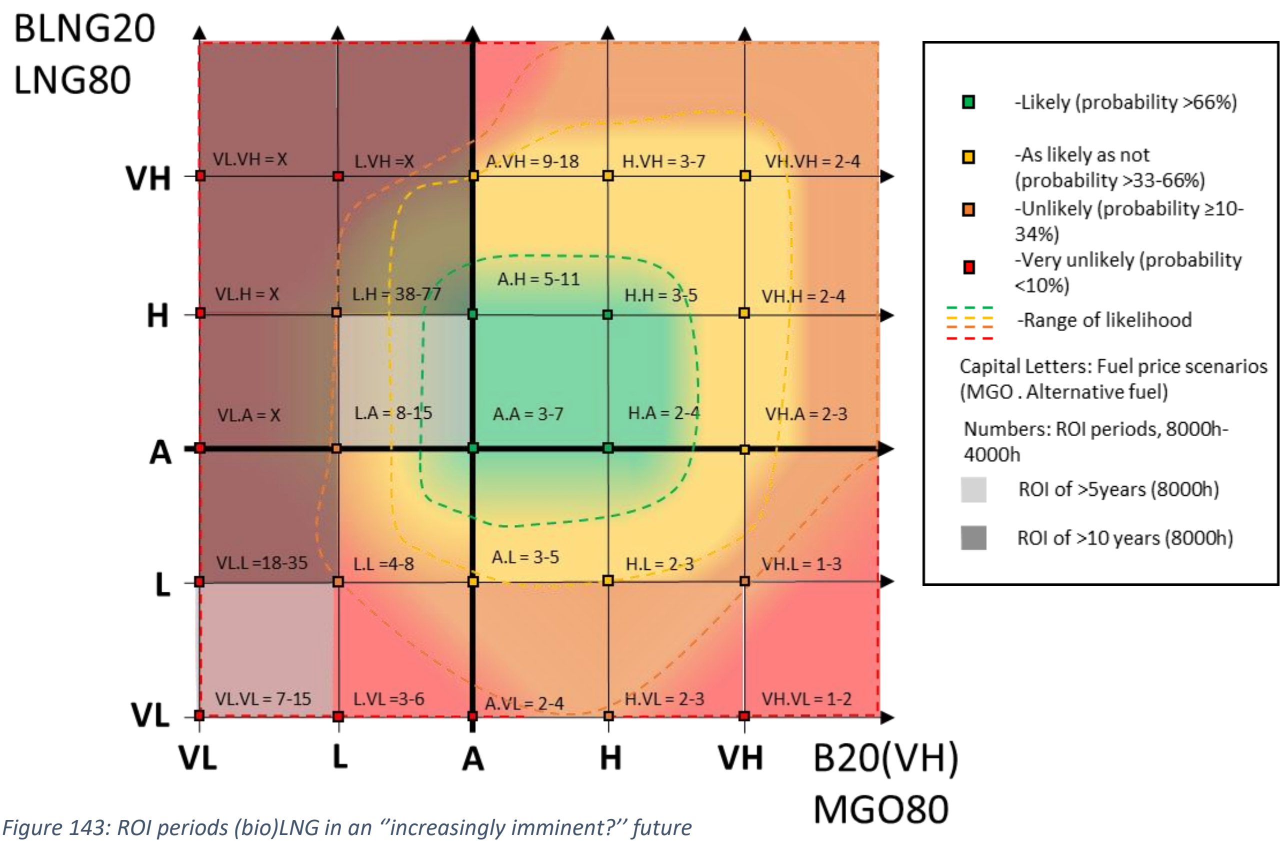


Figure 143: ROI periods (bio)LNG in an ''increasingly imminent?'' future

When comparing the 20% CO_2 reduction scenarios with the current cases for methanol a slight reduction in the ROI periods can be observed. Excellent ROI periods are achieved if MGO prices are high (€0.64/L) and bio-methanol and methanol prices remain around the average (BMEOH-0.28/L, MEOH-€0.42) prices recorded over the past decade. However, more than half of the scenarios does not provide a business case for methanol. Thus a lot of uncertainty is still pertained as to whether choosing methanol in a 20% CO_2 emissions future would be the preferred alternative fuel in terms of economic viability.

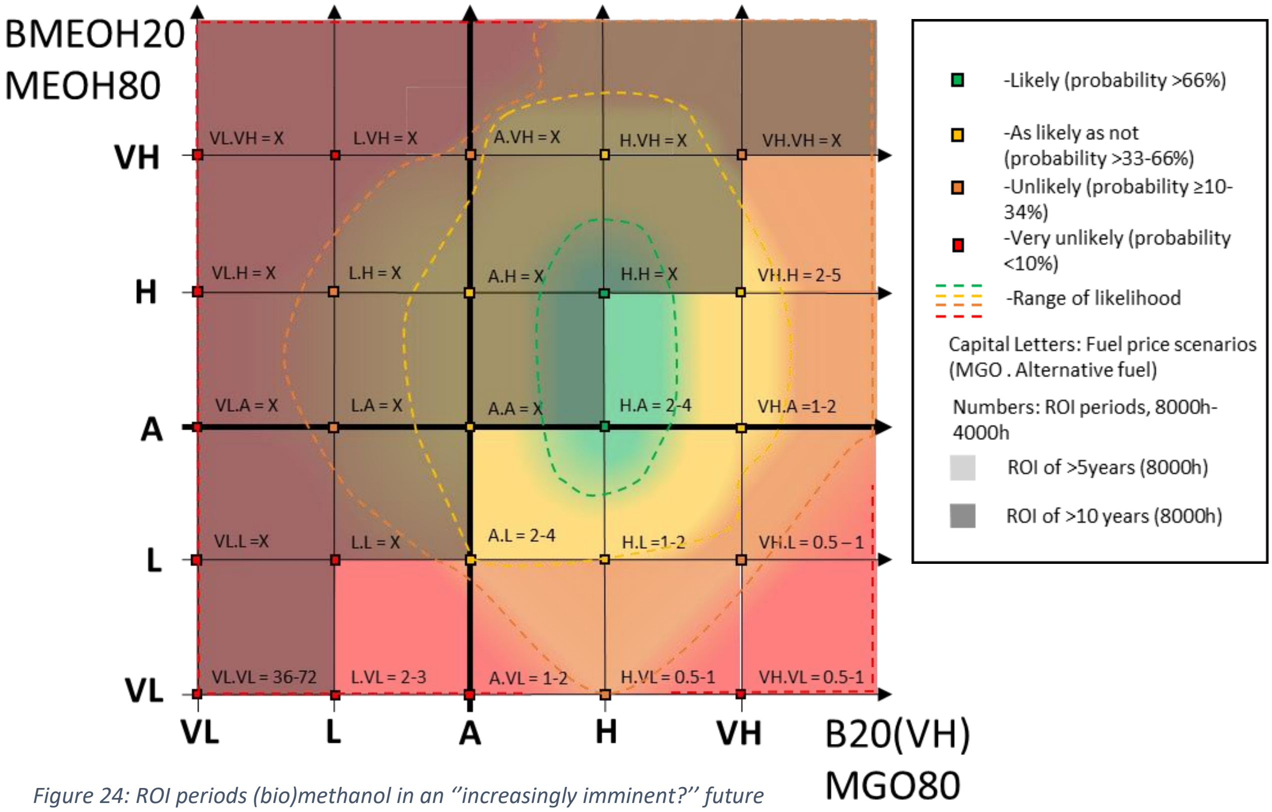


Figure 24: ROI periods (bio)methanol in an ''increasingly imminent?'' future

Nevertheless, feasible business cases for methanol are considerably higher than those for (green) hydrogen. In fact only a single very unlikely scenario containing a 20% green hydrogen fuel mixture put out a positive ROI. This is mainly due to the fact that green hydrogen is assumed to be twice as expensive as hydrogen produced from natural gas resulting in of the chart prices. Furthermore, it is important to note that this assumed green hydrogen price is relatively low. Especially when compared to the estimates outlined in chapter 4.3.2 in which the future price trajectory of green hydrogen is outlined.

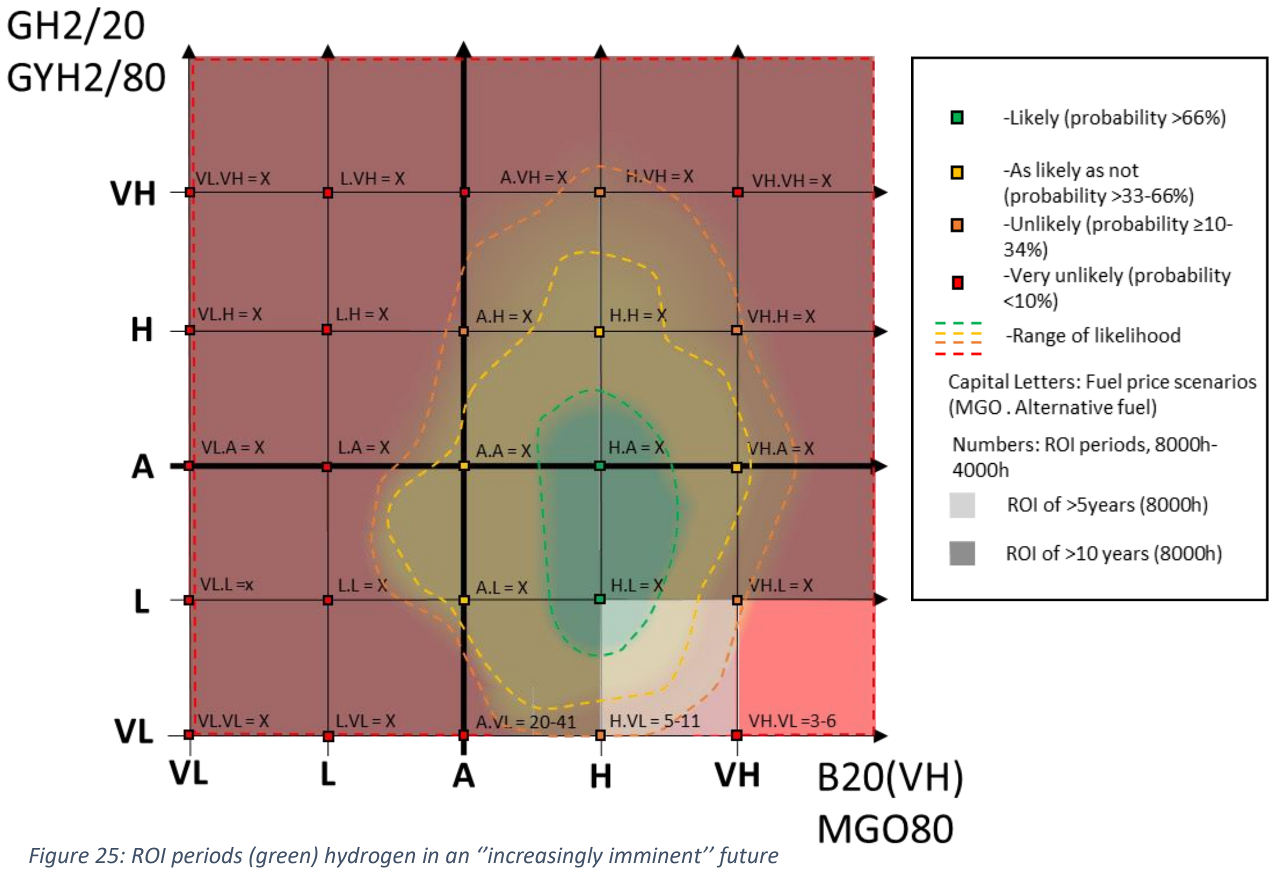


Figure 25: ROI periods (green) hydrogen in an ''increasingly imminent'' future

3.3.2 50% CO2 reduction future: 2050 Target

Not surprisingly the return on investment periods for all alternative (bio)fuels improve, with the one exception being hydrogen. Again (bio)LNG has the most favourable return on investment periods, followed by (bio)methanol and lastly by (green)hydrogen which under these conditions still is not feasible. (Bio)LNG on the other hand has just one dark grey cell which also is very unlikely to as price of all fuels tend to move in an upward direction across time. (see also figure 26)

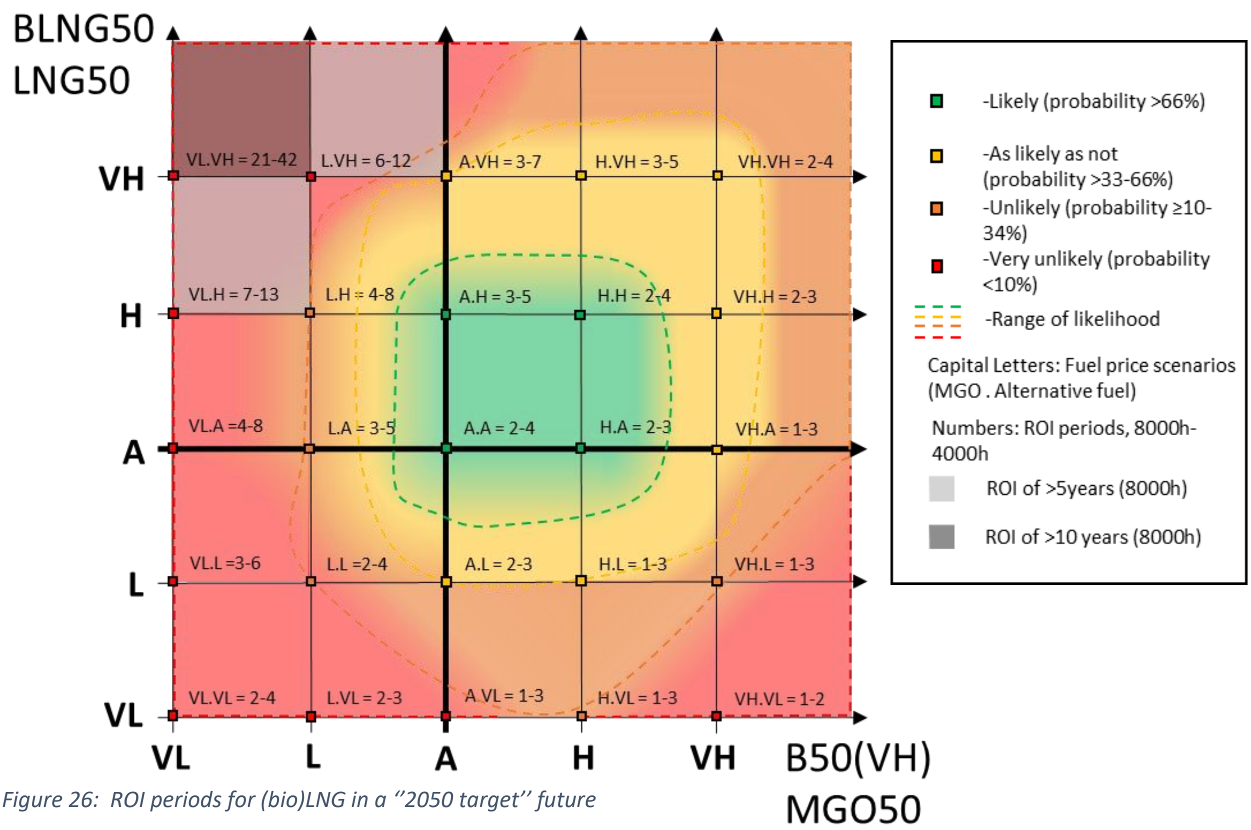


Figure 26: ROI periods for (bio)LNG in a ''2050 target'' future

When looking at the return on investment periods for (bio)methanol in a 50% CO2 reduction future even more cells appear to open up compared to a 20% CO2 reduction future. The fact that green methanol is approximately 1.5 times as expensive than grey methanol does not appear to have a lot of effect on the return on investment periods. Although more cells are now coloured it is still questionable if an investment in a methanol fuel system is justified. In fact one likely combined scenario in which (bio)MGO prices and (bio)MEOH prices are high (MGO=0.64, MEOH=0.33, and BMEOH=0.5) does not result in a return of investment. Thus, even in a future wherein CO2 reduction measures have received priority, making a solid business case for methanol remains difficult as chances are still relatively high that the investment won't be returned over time (see also figure 27)

Furthermore, using 50% grey and 50% green hydrogen in order to achieve CO2 reductions does not appear to be feasible in the 25 scenarios outlined in figure 28. In fact moving to a higher percentage of green hydrogen results in higher operational costs making it unappealing to shift from a B50(VH) and MGO50 blend to a G-H2/50 Gy-H2/50 blend.

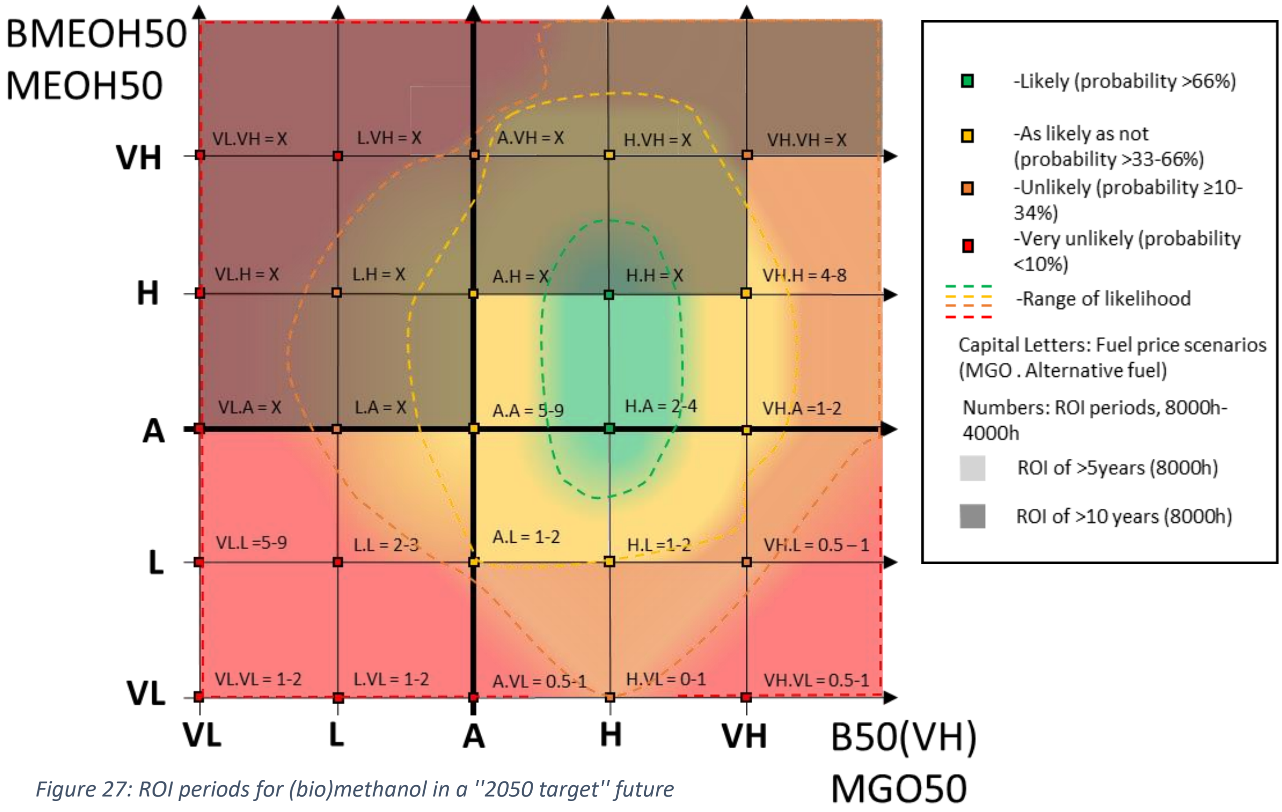


Figure 27: ROI periods for (bio)methanol in a ''2050 target'' future

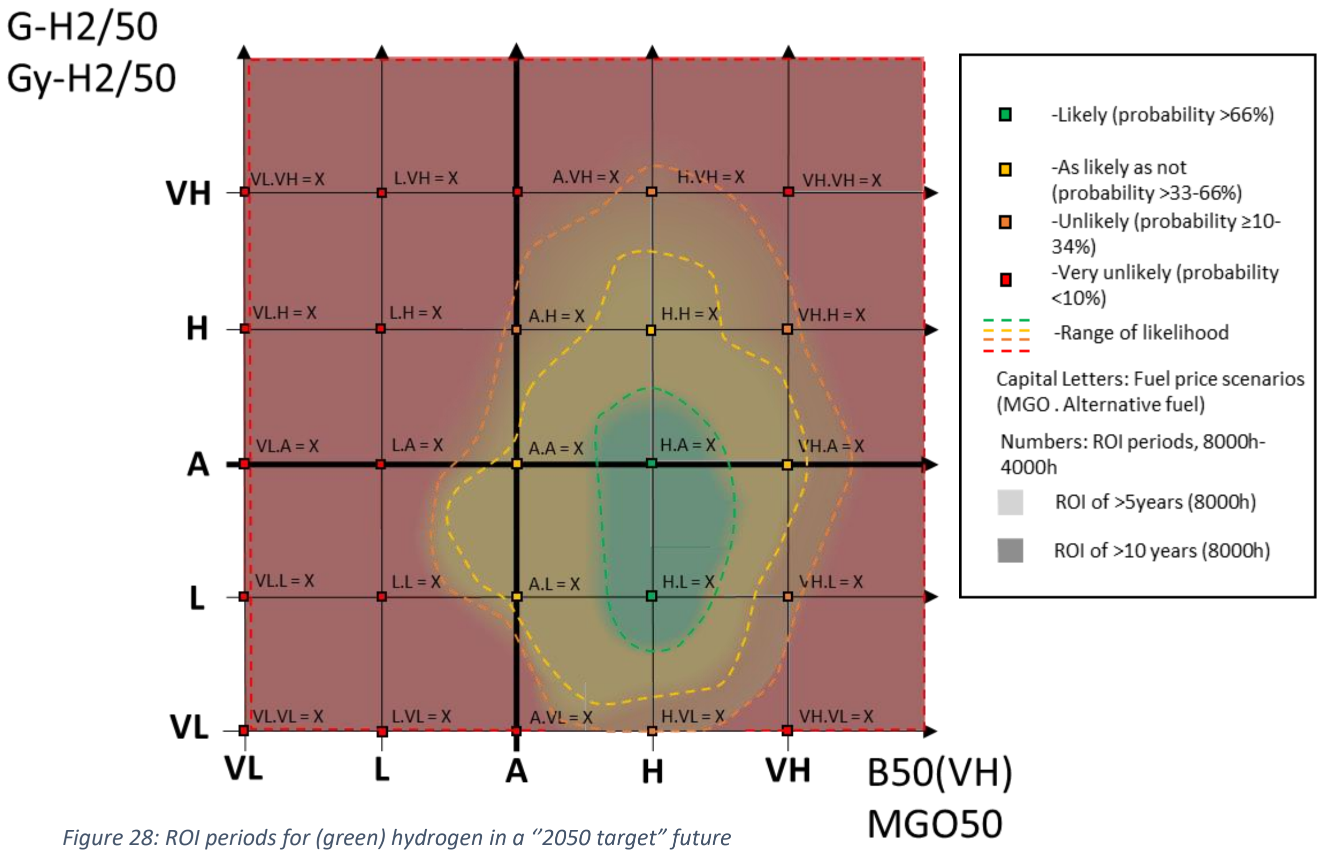


Figure 28: ROI periods for (green) hydrogen in a ''2050 target'' future

3.3.3 100% CO2 reduction future: Utopia

When analysing the combined scenarios for the alternative fuels in a utopia future it becomes evident that the return on investment periods don't improve in comparison to the ''2050 target'' future. In fact, return on investment periods become more extensive, although not as long as those outlined in the ''Increasingly imminent'' future. Nevertheless, the preferred alternative fuel in such a future would still be bio-LNG, followed by bio-methanol and lastly green hydrogen.

Looking at the return on investment periods for bio-LNG something interesting occurs. A 100% reduction future seems to reduce the return on investment periods slightly. Whereas the "2050 target" future only had one dark grey cell, the Utopia scenario has two, thereby illustrating a tipping point that occurs somewhere between the IMO target future and the Utopia future.

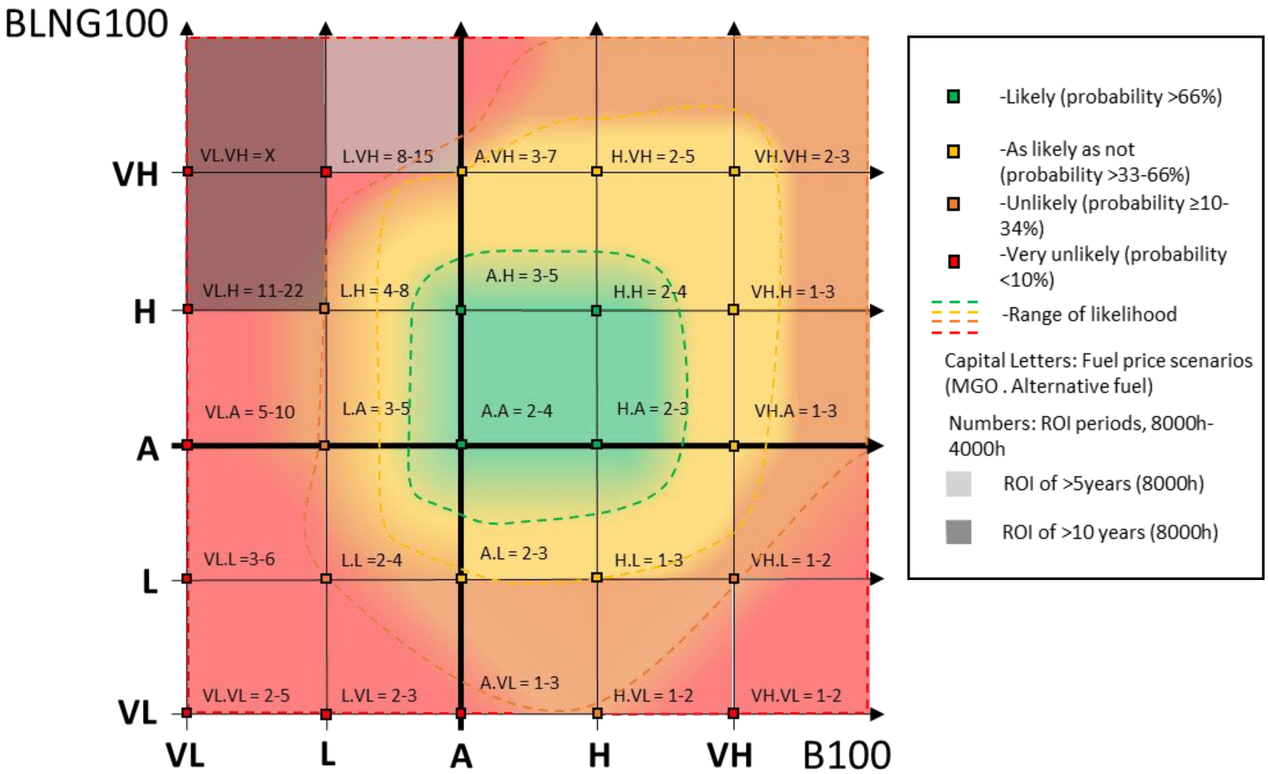


Figure 29: ROI periods for green LNG in a ''Utopia'' future

The same can be said for methanol return on investment periods which are slightly better off in the ''Utopia'' future when compared to the ''increasingly imminent'' future. Nine out of twenty five combined scenarios result in reasonable return on investment periods. The other fourteen scenarios prove that investing in methanol under these conditions can lead to positive results (see figure 30).

Similarly to the other scenarios green hydrogen appears to have no return on investment periods in the ''Utopia'' future. This again demonstrates that for green hydrogen to become feasible production costs must be reduced significantly in order to become economically viable for the shipping industry (see figure 31).

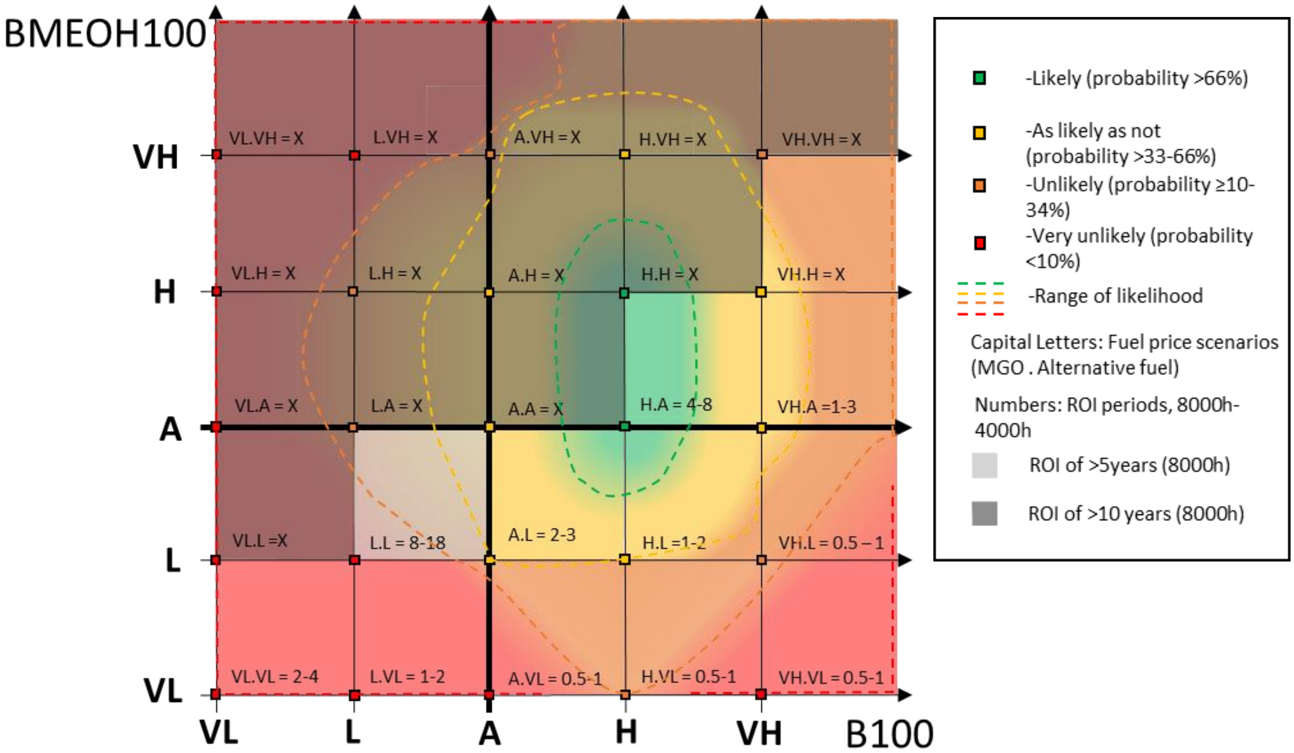


Figure 30: ROI periods for green methanol in a ''Utopia'' future

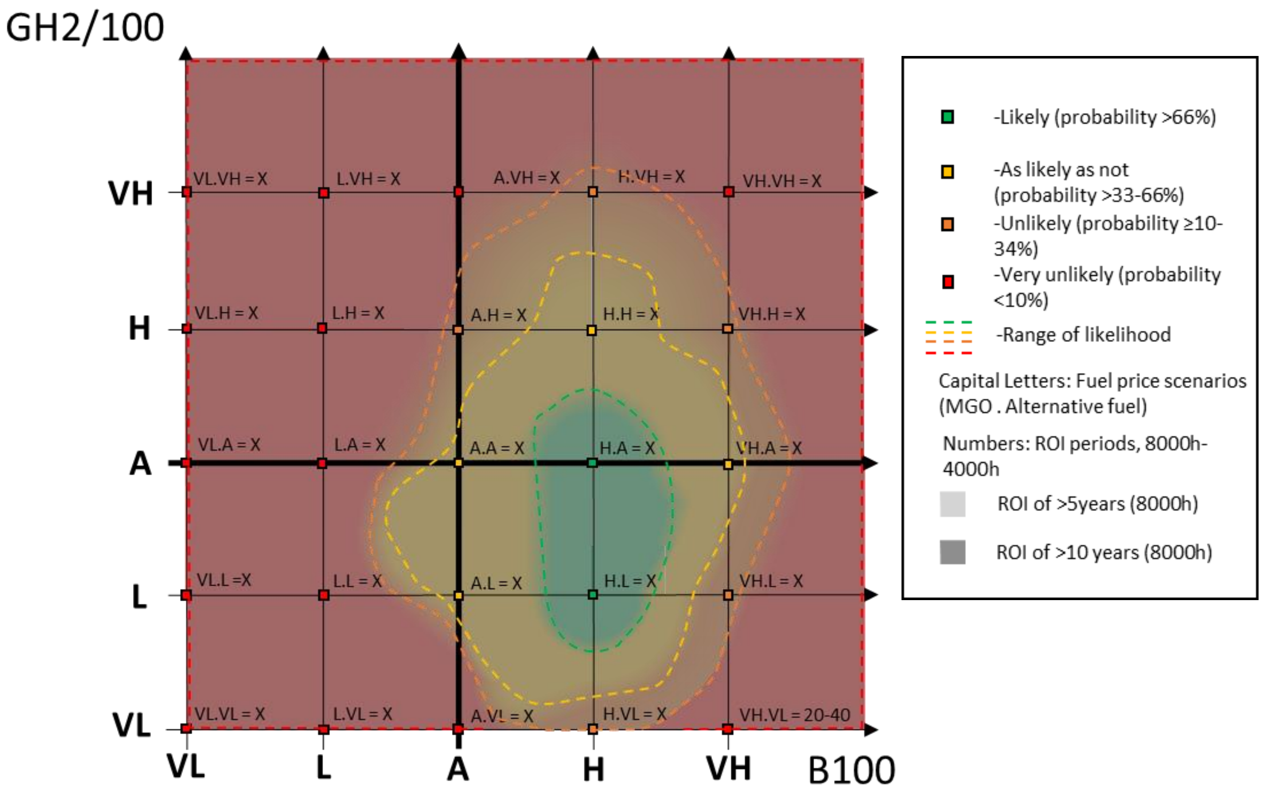


Figure 31: ROI periods for green hydrogen in a ''Utopia'' future

4. Conclusions

The results of this study provide a detailed insight into the technical and economic feasibility of four alternative fuel configurations, i.e. biodiesel, (bio)LNG, (bio)methanol and (renewable) hydrogen. Alternative fuel configurations were compared to Marine Gas Oil (MGO) from which prerequisites for further developments have been determined.

4.1 Technical configurations

The state of the art technology and regulations provided useful insight on the properties and how to handle and store low-flashpoint fuels. Both LNG and hydrogen are often stored at extremely low temperatures and under pressure. Therefore, LNG and hydrogen fuel systems will be distinctive from conventional fuel systems, e.g. fuel storage tanks should be insulated and a double walled fuel pipping network must be installed in order to prevent the cryogenic fluid from leaking causing safety and/or explosive hazards. The shipping industry already has experience with LNG, resulting in further developed technology and safety regulations. Important to note is that LNG requires approximately twice as much storage space as MGO. Furthermore, LNG has a gas-to-air flammability range of 4-15% making fires and similar incidents unlikely. Hydrogen is considered to be more hazardous when compared to LNG as it is stored at much lower temperatures (-254°C in comparison to -162°C for LNG). Besides, hydrogen ignites at relatively low temperatures and has a much larger flammability range (4-75%). Nevertheless, hydrogen is much lighter than air and will quickly dissipate into open air. In enclosed spaces however, sufficient ventilation is needed in case a leakage does occur. Although hydrogen has a very high energy density its liquid density is much lower than MGO resulting in a greater need for storage space of up to four times. Like LNG and hydrogen, methanol is a low-flashpoint fuel, yet its remaining chemical properties are very different as it is a toxic liquid under normal atmospheric conditions. The liquid density (weight) is similar to that of MGO. However, energy density is approximately twice as small. Methanol storage tanks therefore need to be twice as large in comparison to MGO. Its toxicity and relatively large explosive range require additional safety measures. These measure are associated with the fuel storage and supply system, monitoring and control systems and the ventilation system. Contrary to other novel fuel configurations, biodiesel (HVO) has very similar chemical and physical properties to those of MGO. Unlike FAME's it does not attract water and thus doesn't require additional adjustments otherwise needed to prevent water contamination of the fuel. Changing to HVO would require little adjustments in the fuel system and engine. Thus, changing to biodiesel (HVO) would cause the least amount of technical difficulties and associated capital expenditures.

4.2 Economic feasibility

Capital expenditures needed for alternative fuel configurations have to be recaptured through the price differential between the alternative fuel and MGO. The time it takes to recapture this value (ROI) was calculated using a wide variety of price scenarios that were based on historic price data. When looking at the historic price data it becomes evident that only LNG, and methanol have had lower prices (at times) per unit of energy than MGO. Hydrogen and biodiesel were often more expensive than MGO fuel prices. For hydrogen this situation might change as production costs are expected to decrease. Biodiesel prices however are expected to increase as demand for green fuel grows. MGO and LNG prices are also expected to increase as a consequences of the sulphur cap that will enter into force from 2020.

Looking at the price scenarios under business as usual circumstances it becomes evident that LNG forms the best alternative from an economic perspective. Nevertheless, half of the scenarios do not achieve a return on investment. Although these scenarios are not very likely to occur the investment is not without any financial risks. Shipowners who seek to minimize the financial risk of not recapturing an investment would be better of choosing biodiesel instead as it requires little CAPEX. This would enable them to change to a fuel that reduces emissions while not risking to lose a large amount of capital that was invested into a fuel configuration that won't paid itself back over time. Those who do choose to invest in an LNG application could start earning from their investment 5-10 years along the road. A (grey) methanol fuel configuration could also see excellent return on investment periods, although the risk of not making a ROI at all is equally high. Thus, (grey) methanol at the moment does not seem to be an economically viable and business sustaining investment. Hydrogen only appears to have a viable business case when MGO prices are extremely high (VH), while hydrogen prices are exceptionally low (VL). This scenario appears to be nearly impossible in the coming decade, deeming a hydrogen fuel configuration unfit from an economic perspective.

When looking at the three CO2 reduction futures a similar trend can be found where (green) LNG has very short ROI periods with little financial risks associated with the investment. In a 20% CO2 future some minor changes in the ROI periods for alternative fuels become visible. Most notably being that (green) LNG proves to be a relatively safe investment. While making a ROI (green) hydrogen in such a future becomes impossible.

In a future where the IMO target of 50% CO2 reduction is met the best overall ROI periods are for (green) LNG and (green) methanol fuels. In fact, only one very unlikely combined scenario, for (green) LNG does not make a ROI. Methanol in this CO2 reduction future also does well with more than half of the scenario's establishing a ROI. On the contrary hydrogen ROI periods seems to deteriorate in CO2 reduction futures, mainly because of the extreme high prices of green hydrogen. This clearly illustrates that, although hydrogen has great potential in terms of availability and greenhouse reductions, closing the business case on a hydrogen fuel system is very difficult. In order to significantly reduce WTT GHG emissions green hydrogen prices would have to drop below the very low price scenario of grey hydrogen which mostly likely won't occur anytime soon.

Thus, taking in consideration technical, regulatory and financial variables shifting towards biodiesel (HVO) appears to be the most acceptable alternative fuel configuration. However, in terms of availability clear obstacles exist as it competes with food security. The second best alternative appears to be (bio)LNG which generate good ROI periods in the most likely scenarios, regardless of which CO2 reduction future is followed. Methanol also appears to be a promising alternative fuel, however there are significant financial risks associated with the investment. Lastly, although hydrogen appears to have the greatest CO2 reduction potential and poses little threat to the environment, it isn't an economically viable alternative at the moment.

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