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# Report

## Alternative fuels for offshore vessels

**Analysis of alternative fuels based on environmental performance, technical maturity of machinery and systems, operational requirements, economics and fuel availability in the near term future (2025-2035).**


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### Report No:

[OC2024 F-005] - Internal


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**KEYWORDS**
Alternative fuels
Energy transition
Offshore vessels
Shipping

**VERSION**
R5

**DATE**
2024-04-25

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**CLIENT(S)**
Norwegian Shipowners' Association

**CLIENT'S REFERENCE**
Elisabeth Lokshall

**PROJECT NO.**
302004710

**NO. OF PAGES**
102

**SUMMARY**
Offshore vessels stand out from cargo ships and passenger ships by their operating profile and machinery configuration. This study examines the fuel options based on potential to reduce GHG emissions, technical maturity of machinery, tanks and systems as well as fuel availability and economics.
The change in life cycle costs and abatement cost are calculated for LNG, biomethane, liquid biofuels, methanol, hydrogen and ammonia for three offshore ship cases: PSV, AHTS and CSV.
We find that biomethane is the least costly option, followed by liquid biofuels and biomethanol with 3% to 10-15% higher life cycle costs. Ammonia and hydrogen are not only more costly but also more complex technically. Supply of all alternative fuels are near non-existent and must be developed on demand or in tandem with demand.
Total GHG (TTW) from offshore vessels can be reduced from 3.5-4.5 to 0.7-1.1 Mt/y.

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| REPORT NO. | ISBN | CLASSIFICATION | CLASSIFICATION THIS PAGE |
|---|---|---|---|
| [OC2024 F-005] | N/A | Internal | Internal |

# Document history

| VERSION | DATE | VERSION DESCRIPTION |
|---|---|---|
| 0 | 2023-11-12 | First draft for review by client. |
| R1 | 2023-12-06 | Final draft for review by client.<br>Updated based on comments given 22 November (e-mail) and 27 November (meeting). |
| R2 | 2023-12-18 | Second draft for review by client.<br>Updated based on comments 11 December (e-mail and meeting).<br>Executive summary completely revised.<br>Comments on retrofitting included for each fuel in chapter 8.<br>Reference list added at the end of the report. |
| R2.1 | 2023-12-21 | Minor update with spelling and minor corrections. |
| R3 | 2024-01-23 | Updates and corrections |
| R3.1 | 2024-01-30 | Updates and corrections |
| R3.2 | 2024-02-02 | Minor updates and corrections. |
| R4 | 2024-02-23 | Chapter 12.7 on total GHG from offshore vessels revised with more details on the estimation method and alternative estimates.<br><br>Minor corrections and improvements. |
| R4.1 | 2024-02-26 | Comparison tables added as chapter 13.<br>Comment on retrofit options added in executive summary. |
| R5 | 2024-04-25 | Final version. |

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**APPENDICES**

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# 1. Summary and recommendations

## 1.1. Executive summary

The Intergovernmental Panel on Climate Change (IPCC) calls for a 45% reduction in greenhouse gas (GHG) emissions by 2030, compared to 2019. The International Maritime Organization (IMO) has agreed to reduce GHG emissions by 20-30% within 2030 and 70-80% within 2040 and reach net zero emissions around 2050, using 2008 as the baseline. The Norwegian Shipowners' Association's GHG strategy adopted a goal to only build vessels with zero emission technology from 2030.

Achieving these goals require smarter operations, better logistics, energy efficiency measures as well as alternative fuels. This report analyses alternative fuels for offshore vessels. The main findings and conclusions can be summarized as follows. In general, the conclusions and recommendations are similar for the three subtypes investigated (PSV, AHTS and CSV).

Note that there are considerable challenges with all alternative fuels. The recommendation thus points towards the least complicated alternative(s).

| | |
|---|---|
| *Greenhouse gas emissions* | Alternative fuels should be evaluated by all relevant greenhouse gas emissions ($CO_2$, methane and $N_2O$) over the life cycle, i.e. from well to wake.<br><br>Hydrogen, ammonia, methanol and synthetic fuels can give higher emissions than diesel and give near zero emissions depending on the production pathway. Around 99% of the *current* production of hydrogen, ammonia and methanol is based on fossil primary energy.<br><br>Biofuels (liquid biodiesel, biomethane and biomethanol) can give low emissions, zero emissions or be climate negative in a life cycle perspective depending on the raw material, production process and supply chain. In addition to low greenhouse gas emissions, biofuels must meet a range of sustainability criteria.<br><br>Onboard carbon capture (OCCS) may enable continued use of fossil fuels onboard but will likely not reduce emissions to zero or near zero.<br><br>The study finds that the GHG emissions can be reduced by 70-80% with alternative fuels. The total emissions from Norwegian offshore vessels can thus be reduced from abt. 3.5-4.5 Mt/y to 0.7-1.1 Mt/y. |
| *Fuel supply* | In 2021, 99.9% of the energy consumed by ships was fossil based. As alternative fuel for maritime use, only LNG may be considered widely available today. Methanol, ammonia and hydrogen are produced today but primarily for other uses and sectors, e.g. petrochemicals, fertilizer and petroleum refining. Small volumes of biofuels are piloted. Methanol is used as fuel by vessels transporting methanol.<br><br>Blue hydrogen and ammonia (produced from natural gas) depend on carbon capture and storage (CCS). Green hydrogen and ammonia (produced with electrolysis) depend on renewable electricity, which is a scarce resource. The renewable share is 14% worldwide and approximately 50% in Norway. We must therefore expect significant competition for climate neutral energy which may affect cost and availability especially of energy intense alternative fuels such as hydrogen and synthetic fuels.<br><br>The political will to produce hydrogen and ammonia is high, but there are few committed plans.<br><br>Synthetic fuels depend on both renewable electricity and CCS or direct air capture (DAC). There are virtually no plans for production of synthetic fuels for shipping.<br><br>Biofuels can be produced from several different raw materials, including waste streams, in many locations worldwide. Production volume potential is hard to map because of the fragmented sourcing and value chain. |

*Machinery*

Production, supply and fuel availability for all alternatives, with the possible exception of LNG will be limited, and we therefore see a need for multifuel capability in energy systems onboard. Multi fuel machinery are important for flexibility, reliability, redundancy and allows vessels to operate worldwide.

Dual fuel internal combustion engines (ICE) are a proven technology platform for alternative fuels. Variants of four stroke medium speed engines are available for methanol and hydrogen while engines for ammonia are under development.

Fuel cells for hydrogen are currently introduced in ships as pilot projects and under development for ammonia. Fuel cells are expected to remain expensive, have higher thermal efficiency, high reliability but shorter lifetime than combustion engines. The performance of maritime fuel cells systems has yet to be proven onboard.

Offshore vessels have very high engine power installed (MCR) compared to the average load. To cover 90% of the operating time, only 50% of the installed engine power of a PSV must be arranged for alternative fuels. For an anchor handler and CSV, 25% and 40% respectively of the engine power must be arranged for alternative fuels.

Batteries will play an important role to enhance the energy efficiency of combustion engines, provide spare power and redundancy and handle power fluctuations, especially for vessels powered by fuel cells.

*Tanks*

Alternative fuels contain less energy per volume.  Most alternative fuels require cylindrical pressure tanks for storage, affecting either the size of the vessel or the operating range. Liquid biofuels as well synthetic diesel may be used in existing tanks and bunkering infrastructure.

Hydrogen has very low energy density per volume. Safety is a major issue. Ammonia has a bit better energy density but has significant safety hazards related to toxicity and corrosivity for living organisms. Novel concepts for storage of hydrogen (e.g. LOHC) and ammonia are under development to mitigate the low energy density and safety concerns.

Methanol and biofuels can be carried in hull tanks with minor upgrade of the specification (larger volume, bigger piping and tank coating) at modest cost. Stainless steel is an even better option for methanol.

*Economics*

The economics of alternative fuels is determined mainly by the fuel price and carbon price. The equipment cost can be reduced significantly by accepting that the alternative fuel machinery will only cover 90% of the operating time.

Fuel cells are currently much more expensive than internal combustion engines. Fuel cell costs are expected to decline but remain 4-5 times more expensive per kW compared to combustion engines. Four stroke dual fuel engines for alternative fuels cost 25-130% more than conventional engines. It is expected that this cost difference will be reduced with learning and scaling.

Storage and systems are expensive, especially for hydrogen, but also for ammonia and LNG/biomethane. Novel concepts for storage of ammonia and hydrogen are under development.

Methanol is the least costly fuel in terms of engine and system cost.

Costs for design, classification, construction, maintenance, repair etc are difficult to estimate at this point in time due to the very limited experience with new energy systems and carriers.

The economic analysis gives the same recommendations for PSV, AHTS and CSV. Biomethane is the least costly option with only 3% higher life cycle costs, followed by biofuels and biomethanol (10-15% higher life cycle costs) and ammonia (15-20%) and hydrogen (20-30%).

*Retrofit*

Hydrogen and ammonia are not only the most expensive solution; they are also the most complex fuels for retrofitting. Containerized solutions to cover a portion of the energy demand is possible.

Liquid and gaseous biofuels and synthetic MGO and LNG can replace diesel and LNG respectively and thus the easiest option for retrofitting. Unfortunately, synthetic fuels are almost prohibitively expensive.

Low emissions methanol is also feasible for existing ships.

## 1.2. Summary

*Background and motivation*

IMO has agreed to reduce GHG by 20-30% by 2030 and 70-80% by 2040, compared to 2008, and reach zero emissions around 2050. In the Norwegian Shipowners' Association's GHG strategy from 2020, the ship owners adopted a goal to only build vessels with zero emission technology from 2030. Any vessel ordered today with a life expectancy of 20-30 years must therefore have 80-100% lower emissions than today. For all practical purposes, this means zero or near zero emission.

This requires smarter operation, better logistics and significant efforts to reduce energy demand through operational and technical measures, as well as a transition to alternative fuels. This reports analyses the fuel options for offshore vessels.

Although the specific and detailed requirements applicable to offshore vessels is still pending, we must assume that the overall goals set by the IMO as well as EU and individual states such as Norway, also apply to offshore vessels.

*Status*

Worldwide, offshore vessels emitted ca 21 Mt in 2018 corresponding to around 2% of total global shipping emissions. The importance of offshore vessels is much larger in Norway where it is responsible for 13% of all shipping emissions in Norwegian waters and 25% of domestic shipping $CO_2$.

The transition to alternative fuels in shipping started with LNG in 2000. Offshore vessels were early movers; the second and third vessel built for LNG was offshore vessels; Viking Energy and Stril Pioneer in 2003. LNG can reduce GHG emissions by up to 30% if the gas is produced with low emissions and combusted with very, very low methane slip and is alone a good contribution to decarbonization.

But the urgent need to curb global warming motivates us to move ahead to more advantageous fuels. There are at least five types of alternative fuels for shipping:

| | *Type* | *Fossil variant* | *Low emission variants* |
|---|---|---|---|
| | Liquid fuel oils | MGO, MDO, LSFO | Liquid biofuel and synthetic diesel (E-MGO) |
| | Gases | LNG | Biomethane and synthetic LNG (E-LNG) |
| | Methanol | Fossil methanol | Biomethanol and synthetic methanol (E-methanol) |
| | Hydrogen | Grey hydrogen | Blue and green (and pink and turquoise) hydrogen |
| | Ammonia | Grey ammonia | Blue and green (and pink and turquoise) ammonia |

In 2021, 99.89% of the energy used in shipping was still fossil. The transition to alternative fuels is just in its infancy and is not moving ahead at the required pace.

*Offshore vessels*

The segment consists of many specialized vessels supporting production of energy on the continental shelf, primarily oil and gas in the various phases from exploration, installation, production, and decommissioning. The Norwegian offshore fleet consist of around 175 platform supply vessels (PSV), 60 anchor handling, tug and supply vessels (AHTS) and 140 construction vessels (CSV) and 55 seismic research vessels. This study focuses on PSV, AHTS and CSV. Supporting production of renewable energy offshore and possibly also seabed mining are examples of future work for offshore vessels.

Worldwide, the segment consists of around 5,000 vessels, of which around 450 are owned, operated, or controlled by around 60 Norwegian shipping companies. The average age is approximately 14 years, and the typical life expectancy is 20-25 or even 30 years in a rare, few cases. This study therefore also discusses the potential for converting existing ships to run on alternative fuels.

Most offshore vessels are powered by 4-6 generator sets with electric power transmission. Batteries are retrofitted to many vessels to reduce the specific fuel oil consumption, avoid low load running and ensure redundancy. Batteries will likely play an important role in the future as well, especially in combination with fuel cells.

*Climate effect of alternative fuels*

The climate advantage of alternative fuels should be evaluated based on the life cycle emission factors, so called well to wake which is the sum of well to tank (WTT) (emissions during production and supply of the fuels) and tank to wake (TTW) (emissions from the use of fuels onboard). The emission factors should reflect all relevant greenhouse gases. In addition to $CO_2$, methane ($CH_4$) is important for natural gas, biomethane and synthetic LNG and $N_2O$ is important for ammonia.

No new fuels give zero emissions in a life cycle perspective, but many can give significant reductions. The climate effect of possible combinations of fuels and machinery is presented in the diagram below, based on their life cycle emissions (WTW = WTT + TTW).

Many of the alternative fuels discussed today are available in grey and green versions: 99% of the hydrogen, ammonia and methanol produced today is based on fossil energy sources and have higher emissions well to wake than diesel. But the most climate friendly versions of these fuels can also emit 65-99% lower GHG compared to diesel.

Note also that there is a range in the emission factor for biomethanol and LNG depending on the production and combustion. LNG available in Norway today can cut GHG by up to 30% if the engine's methane slip is minimized (say, to 1 g/kWh).

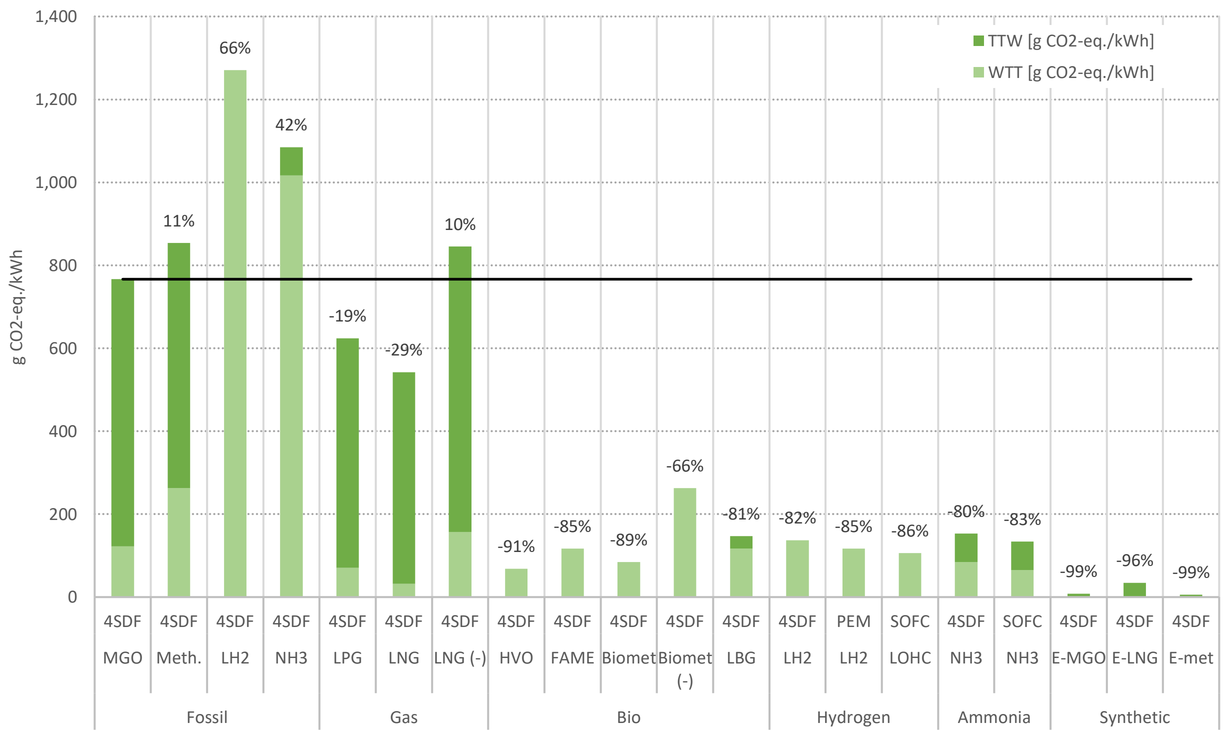



*Figure 12: emission factors for alternative fuels well to tank (WTT) and tank to wake (TTW).*

Production of alternative fuels with low emissions depend on abundance of renewable electricity, carbon capture and storage (CCS) and sustainable biomass. The supply of alternative fuels further depends on the competition between sectors. Finally, the supply will likely need strong signals from the market either through regulations or economic incentives.

While electricity produced in Norway has very low GHG emissions, this is not the case worldwide. Electric power used in port and to charge batteries is generally *not* climate neutral.

With limited renewable energy worldwide including in Norway, the energy required to produce alternative fuels is also a concern.

*Machinery, tanks and systems*

Most alternative fuels have less energy per volume and thus require larger fuel tanks and bigger piping. Based on the required endurance, we estimate the fuel consumption and necessary tank capacity and tank compartment volume. This ultimately requires a somewhat larger vessel and we estimate the change in enclosed volume, gross tonnage and ship length. For some fuels, the necessary lengthening is reasonable and possible while for other fuels it seems to be unreasonable and too large to realize. Novel tank concepts can alleviate this.

Four stroke medium speed internal combustion engines for all alternative fuels are either available or under development for commercial launch within 1-3 years. High speed engines are suitable for all fuel except ammonia. *Current* gas engines can take blends of hydrogen and LNG up to 25/75 or even 40/60.

Fuel cells of PEM (proton exchange membrane) type are available in sizes up to 4 MW today, while solid oxide fuel cells (SOFC) are still under research and development. The efficiency, maintenance need and operating reliability of fuel cells are expected to be good, but not fully documented. Neither is the lifetime of fuel cells fully documented, which is expected to be shorter than the vessel's lifetime.

The systems and tanks for the new fuels are perhaps more complex and less developed than the engines. Storage and systems for methanol are quite straightforward and experience from various methanol tankers and from carriage of methanol as a cargo on offshore vessels help. The tanks are hull tanks, coated or stainless steel. Ammonia will likely be cooled (-33°C) and carried in cylindrical tanks, despite the low volumetric efficiency. Novel concepts with box-shape are under development for ammonia. Hydrogen can be carried in cryogenic tanks (-253°C), under high pressure or in an organic liquid (LOHC) Cryogenic storage is complex and expensive and is under piloting on the first LH2-carrier Frontier Susio. Pressurized storage takes up too much space to be efficient for vessels with large energy needs. LOHC is a clever concept that, once proven successful and ready, can address many of the arguments against hydrogen, both safety and space requirements. LOHC is still a few years away from realization. Novel concepts with nearly box-shaped tanks are under development for hydrogen too.

All in all, we expect that engines, fuel cells, tank concepts and systems will be developed and become commercially available for offshore vessels around 2030, provided that there is both sufficient R&D and commercial interest. Demand signals in the form of adopted regulations or economic incentives will also help.

Offshore vessels experience significant variation in their work and the required engine power varies. On average, only 10-30% of the installed power is needed. From the operation profile, we find that if only a part of the machinery (50% for PSV, 25% for AHTS, 40% for CSV) is configured to run on alternative fuels, the vessel can still run on alternative fuels 90% of the operating time. This minor compromise is particularly important until machinery for alternative fuels become affordable.

*Energy transition based on multi-fuel capability*

Alternative fuels will be sparsely available only in select ports and in low quantities in the beginning. The high cost of alternative fuels may prohibit full and continuous use and new machinery and systems will likely be less reliable than today's fine-tuned technology. These factors speak in favour of building vessels with capability to run on multiple fuels.

Based on the review of machinery, tanks and systems, the report finds that some fuels are compatible with others. Three combinations seem feasible and practical:

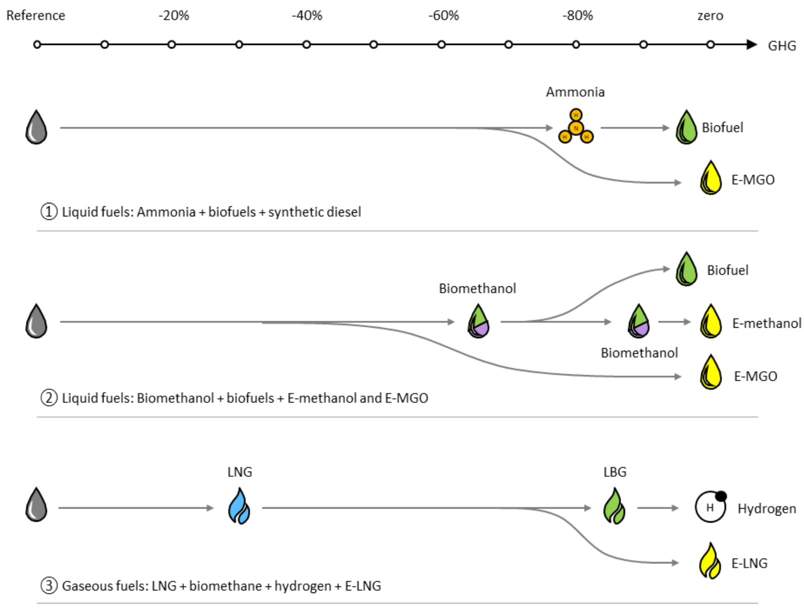



*Figure 17: Fuel transition pathways based on multi-fuel technology.*

*Fuel production and supply*

Access to alternative fuels in large quantities and in the right locations worldwide is critical for their uptake. In 2023, fossil fuels covered 99.89% of shipping's energy demand. Therefore, unfortunately, we cannot evaluate the supply side based on current production and it is hard to evaluate it based on planned production either, because there are very few realistic and committed plans. Rather, we must evaluate the fuels based on their production potential and or political goals. The potential is determined by some key factors:

1. For biofuels, liquid and gaseous, the critical factor is access to sustainable biomass. The potential production volume also increases with technology that can squeeze the most out of the raw materials, at a reasonable cost. Biofuels can be produced from a number of different raw materials, including waste streams. The potential for liquid biofuels for transport is estimated to 210 Mt/y in 2027 worldwide. The potential for biomethane is estimated to 620 Mt/y by 2030, 25 Mt of this in Europe.

2. Green hydrogen, green ammonia and synthetic fuels depend on abundant and cheap electricity. These fuels require a lot of electricity, which is a scarce resource. Only 11-14% of the primary energy we have today is renewable. Increasing the renewable electricity production takes time and has negative environmental implications. Pockets of stranded renewable electricity, i.e. renewable electricity produced in regions that cannot (economically) be connected to a grid can also be used to produce green fuels.

3. Blue hydrogen and ammonia hinges on carbon capture and storage or utilization (CCS/U) becoming established at large scale. Although the technology is mature, few plants are in operation. The Norwegian Northern Lights project is moving ahead, and this opens up possibilities for blue fuels. We note with concern, though, that so far, Equinor and Vår Energi have pulled out of blue hydrogen.

Production plans for ammonia suggest a production of 15-130 Mt/y by 2030 while plans for hydrogen end up at around 40 Mt by 2030. For methanol, the list of projects planned give a total of around 10 Mt/y by 2030. These estimates are uncertain and pending on a lot of factors; mainly political and commercial but also technical.

At this very early stage of the energy transition, it seems that ship owners and operators must not only develop and order a multi fuel vessel but also develop the fuel supply chain as part of the newbuilding process. In practice, this means tying links with both the charterer and the energy suppliers and set up agreements for fuel supply for the foreseeable future. This requires long contracts, 10-15 years minimum both ways; with the charterer and with the energy supplier.

Luckily, offshore shipping has an advantage over other shipping sectors; the charterer and energy supplier *can* be the very same company. The oil and gas companies would like to expand their portfolio away from fossil energy products. They can leverage their role as charterer of offshore vessels to create a market for alternative fuels for ships that eventually other shipping sectors can tap into.

*Costs*

The capital cost of offshore vessels built for alternative fuels will be higher. We estimate that cost for machinery, tanks and systems based on dialogue with suppliers. Engines for alternative fuels will be up to 130% more expensive. Fuel cells will cost 5-15 times more than conventional diesel engines.

Operating costs increase mainly because alternative fuels are more expensive; the price factor is 2-3 for biodiesel and biomethane, 2.5-4.4 for ammonia, 3.3-4.5 for hydrogen and 6-9 for synthetic fuels. We assume a carbon price of 1500 NOK growing at 3% Y/Y.

*Case study: PSV, AHTS and CSV*

Building on the operation profile, the review of machinery, tanks and systems and the emission factors well to wake, we analyse 18 combinations of fuel and machinery. We look into the specifics of platform supply vessels (PSV), anchor handlers (AHTS) and construction vessels (CSV). For each case, we estimate the present value (PV) of the life cycle costs.

Offshore vessels are sophisticated and quite expensive both to build and operated. A high fuel cost is only a relatively small share of the total life cycle costs and will be diluted to a larger degree for offshore vessels than for, say, bulk carriers. We find that the present value of all costs occurring throughout the life cycle costs increases by less than 5% for biomethane, around 10-15% for biofuels and biomethanol, around 20-30% for hydrogen and around 15-25% for ammonia. The cost increase is very high for synthetic fuels; around 30-70%. This is summarized in the diagram below for all three vessel types. In general, the three curves follow each other, which means that the conclusion of the economic evaluation is fairly consistent across the three case vessels.

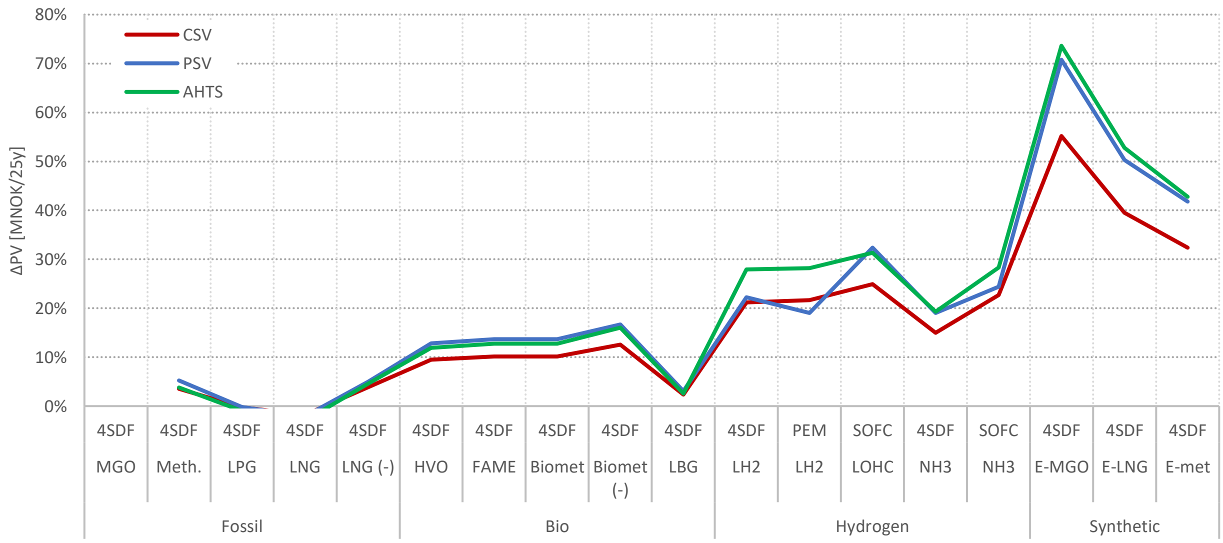



*Figure 40, 46, 52 combined: Change in total life cycle costs for offshore vessels with alternative fuels (relative to MGO). (Note that the values for LPG, LNG and E-fuels lie outside the chart)*

**For all three cases (PSV, AHTS and CSV), biomethane comes out with the lowest life cycle costs, followed by biodiesel and biomethanol and ammonia in combination with 4SDF engines.** Ammonia combined with 4SDF-engines outperforms hydrogen. These fuel options should be investigated further by the shipowners in collaboration with charterers and energy suppliers.

Please observe that the conclusions depend on a number of uncertain factors which must be monitored in the years to come.

# 2. About the project and this report

The objective of this report is to review and analyse possible alternative fuels for the offshore fleet and conclude with clear recommendations for platform supply vessels (PSV), anchor handling, tug and supply vessels (AHTS) and construction vessels (CSV).

The main objective of alternative fuels is to reduce greenhouse gas (GHG) emissions. The other environmental effects of a transition to alternative fuels are not included in the study scope. Our review focuses on the emission reduction and technical, economic, and practical factors as well as fuel availability in the near-term future, i.e. the next decade.

The study considers the differences and commonalities between platform supply vessels (PSV), anchor handling, tug and supply vessels (AHTS) and offshore construction vessels (CSV). The different needs and opportunities for the three vessel types are addressed and individual recommendations given for each type, as applicable.

This report is written on request from the offshore group of the Norwegian Shipowners' Association and in close dialogue with representatives from DOF, Eidesvik and Solstad. The report is written to contribute to an informed discussion among the members and, ultimately, help shipowners decarbonize their fleet quickly and in an economic and practical way.

The methodology and key assumptions, both technical and commercial factors, has been chosen by SINTEF Ocean and have been discussed with the association and the abovementioned three shipowners.

The energy landscape is changing rapidly, and the conclusions and recommendations reached in this report – at this very early stage in the energy transition – is likely to change in the next few years or decade.

## 2.1. Report structure

Chapter 4 reviews the various climate goals relevant for offshore vessels. GHG emissions from offshore vessels in Norway are put in context by comparing them to the total GHG emissions from Norwegian O&G-related GHG emissions.

Chapter 5 describes the offshore flee, including number of vessels, total GHG-emissions, and key technical features of offshore vessels. We then look at the three subtypes; PSV, AHTS and CSV and their operating profile which forms an important basis for our analysis. Finally, we discuss the commercial realities for offshore vessels.

Chapter 6 presents key evaluation criteria for alternative fuels while the actual evaluation comes in chapter 7-9.

Chapter 7 examines the GHG emission factors for alternative fuels together with the energy losses and energy efficiency well to wake, i.e. how well the primary energy available is utilized throughout the value chain from well to wake.

Chapter 8 discusses the types of machinery (engines and fuel cells), fuel storage tanks and systems required for alternative fuels. We discuss the maturity and availability of such technology as well as complexity and cost.

Chapter 9 explains how alternative fuels impact the ship design, e.g. how the ship size and main dimensions must be increased because most alternative fuel require more space and how the machinery room arrangement and machinery weight is increased when having dual fuel machinery onboard. We also explain the feasibility for retrofit.

Chapter 10 examines the availability of alternative fuels today and in the near-term future (2025-2030) based on current, planned and possible production capacities. At this very early stage of the energy transition, we also look to political goals as an indication of future fuel availability. The critical factors that can help or hinder the development of each fuel is discussed first, in chapter 10.1.

Chapter 11 discusses the economic implications of alternative fuels. We discuss how we model the capital cost and operating cost based on the type of fuel and type of machinery and fuel storage. The fuel cost is estimated based on fuel consumption and forecasted fuel prices. The final cost element is the price of carbon. We calculate the present value of all major cost elements over 25 years of operation.

In chapter 12, we build on the emission factors, review of technology, economic cost factors and fuel availability explained in chapter 7-11 to analyse the case for platform supply vessels (PSV), anchor handlers (AHTS) and construction vessels (CSV). For each of these three cases, we estimate the tank space, the machinery power and fuel consumption so that we can calculate the additional cost for 18 fuel and machinery combinations. We estimate the abatement cost for each combination. We also look at the fleet level and estimate the GHG emission reduction for the entire Norwegian controlled offshore fleet and the fuel demand as well.

In chapter 13, we present a side-by-side comparison on storage, machinery and fuel availability.

Finally, in chapter 14, we comment on next steps to realize the energy transition for offshore vessels.

## 2.2. Scope of alternative fuels

The fuels can be categorized according to their origin (fossil, bio, synthetic) and end product (oils, gas, methanol, hydrogen and ammonia) as indicated by table 1 below. Ethanol and LPG are not included in the study scope. Black/grey/brown hydrogen or ammonia are also excluded.

| | Origin | Fossil | | Sustainable biomass | Synthetic |
|---|---|---|---|---|---|
| | Prerequisite | without CCS | with CCS | Multiple sustainability criteria | Renewable electricity |
| End product | Oil | MGO | | FAME, HVO, ~~ethanol~~ | E-diesel |
| | Gas | LNG, ~~LPG~~ | | Biomethane (LBG) | E-LNG, ~~E-LPG~~ |
| | Methanol | Methanol | | Biomethanol | E-methanol |
| | Hydrogen | - | Blue hydrogen | | Green hydrogen |
| | Ammonia | - | Blue ammonia | | Green ammonia |

*Table 1: Categorization of alternative fuels acc. to origin and end-product.*

Note that while biogas and biomethane are commonly used interchangeably, these are two distinct gases and only the latter is relevant as fuel for marine combustion engines. Biomethane is upgraded biogas (see chapter 7.5 and 10.5).

# 3. Notes, definitions and key assumptions

### 3.1.1. Note on geographical scoping of emissions; international vs national/domestic

Shipping emissions are split into national and international emissions. In the 3 IMO GHG study (up to 2012), the split was based on vessel type and size. In the 4 IMO GHG study (from 2012), the split is made based on the departure and arrival port. Note the following definitions:

*International shipping*: Vessels sailing between ports or offshore installations in *two different* countries. International shipping is a separate account in global emission inventories and IMO is the key regulating organ.

*National/domestic shipping*: Vessels sailing between ports or offshore installations in the *same* country. National shipping can to some extent be regulated by national governments, but in practice follows international IMO regulations. The IMO-reports calculate national emissions based on AIS-data, while the official national emission inventories are based on fuel sales; these two methods give quite different results and there is thus uncertainty or confusion about *national* shipping emissions.

This discrepancy is especially noticeable in Norway, where a tax on fuel incentivises many operators to bunker abroad even for mainly domestic operation. The discrepancy is illustrated by the below emission figures based on two official sources: Regjeringens handlingsplan for grønn skipsfart, 2019 and SSB (table 13931).

| | | |
|---|---|---|
| *Norwegian national shipping emissions (2019)* | $CO_2$ based on AIS:<br>4.8 Mt (2019)<br>9% of Norway's GHG | GHG [$CO_2$-eq.] based on fuel sales:<br>2.8 Mt (2019)<br>5% of Norway's GHG |

To complicate things, emissions in a certain geographic area such as the Norwegian exclusive economic zone (EEZ) is also relevant and referred to in this report.

### 3.1.2. Definitions: Climate neutral and climate negative

Positive emissions: Emissions > 0.

Negative emissions: Emissions < 0, i.e. that more $CO_2$-equivalents are avoided or captured in one phase than those released in another phase. This is applicable to some biofuels where direct release of methane is avoided, and this effect dominates and more than cancels out the $CO_2$ and $CH_4$ emitted during combustion.

Climate neutral or net zero emissions: Positive emissions from one phase cancels out negative emissions in another phase. Emissions in one phase can be significant and climate neutral is not the same as zero emissions.

Zero emissions: No emissions.

### 3.1.3. Terminology: Climate vs carbon

While *low carbon* or *carbon neutral* strictly speaking refers to $CO_2$ only, the terms are often understood to encompass all greenhouse gases. The terms *low climate* and *climate neutral* are more precise.

### 3.1.4. Key assumptions

The environmental evaluation shall be limited to emission of greenhouse gases only. Air pollutants ($NO_X$, $SO_X$, PM including black carbon) are not included, as these emissions are governed by various MARPOL regulations.

Costs and economic calculations are in Norwegian kroner (NOK).

Emissions are to be considered in a lifecycle perspective, well to wake (WTW).

Focus on environmental performance and technical realities to ensure that the conclusions are practical and achievable.

The assumed lifetime of vessels is 25 years. Some charterers require tonnage < 20 years, but this practice should be and is challenged. Safety and environmental performance should be linked to other factors than age. This is particularly important in the context of alternative fuels because a long lifetime helps to justify higher capex.

# 4. Environmental status 2022 and goals

Offshore supply vessels contribute to the production of oil and gas and are therefore considered both part of the energy sector and the maritime sector. The environmental goals of both sectors are thus relevant and is reviewed as part of this report.

## 4.1. GHG status: Emissions from O&G production and offshore vessels in 2022

Emissions from production of oil and gas represented 25% of Norwegian emissions in 2022: 12.2 of 48.9 Mt $CO_2$-eq. in 2022 [SSB].

Around 20% of the emissions from Norwegian O&G production comes from maritime activities, that is offshore vessels, tankers and mobile offshore units or drilling and production rigs and vessels [VPS]. Half of this comes from offshore vessels. This breakdown is illustrated in the below figure:

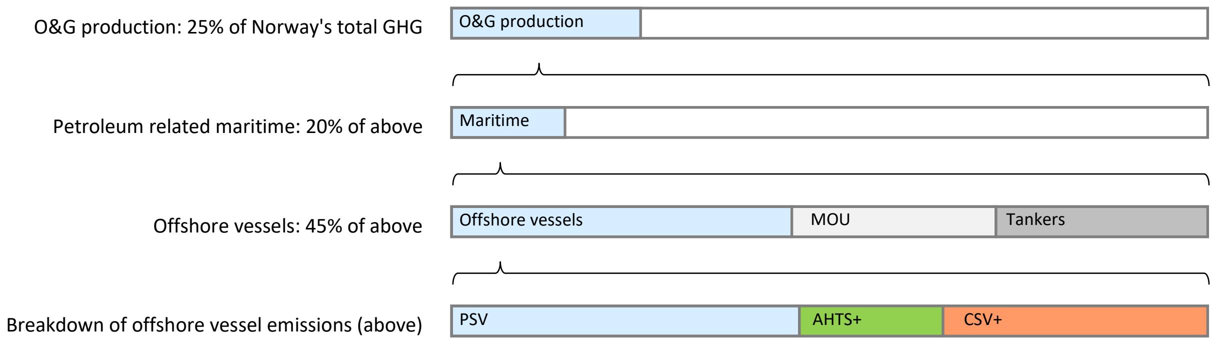



*Figure 1: Emissions from offshore vessels in Norwegian water (exclusive economic zone, EEZ) in context.*

## 4.2. Relevant climate policies and targets

The **Intergovernmental Panel on Climate Change**'s (IPCC) reports conclude that emissions must drop by 45% by 2030, relative to either 2010 or 2019, if the global temperature increase shall be limited to 1.5°C and by 84% by 2050 [The special report on global warming of 1.5°C, 2018, The 6th assessment report, 2023].

The **International Maritime Organization** sets environmental standards for international shipping that in practice applies to national shipping as well. IMO focuses on the main emitters; tankers for crude oil, chemicals and gas (30% of shipping's GHG emissions), container vessels (22%) and dry bulkers (18%). Creating regulations that fit both cargo vessels and offshore vessels alike is a challenge. The IMO GHG revised GHG strategy from July 2023 targets 40% lower carbon intensity by 2030 and 70% lower carbon intensity by 2050. On absolute emissions, IMO targets 50% lower emissions by 2050 and added intermediate *indicative* checkpoints; 20-30% lower GHG by 2030 and 70-80% lower by 2040. The reference year for all IMO legislation is 2008, when emissions peaked. IMO has also agreed to reach minimum 5% uptake of alternative fuels by 2030 and strive for 10%.

The **EU** has agreed to cut GHG emissions by 55% by 203, compared to 1990, and the union is in the process of adopting a string of measures; the so-called Fit for 55 package of environmental regulations. Relevant to offshore shipping are the EU MRV reporting scheme which lays the foundation for the EU emission trading scheme and FuelEU Maritime. The EU ETS is a cap-and-trade carbon pricing regime applicable to many industries since 2005 and to shipping from 2024 and to offshore vessels > 5,000 GT from 2027. Mindful of the general European sentiment on environment and climate and recalling the various EU proposals to IMO MEPC 80, we believe it is only a matter of time before the EU adopts even stricter GHG goals.

**Norway** has committed to reduce GHG by 55% from 1990 to 2030 and to achieve the majority by reducing national emissions. Significant cuts are expected in the transport sector, where offshore shipping belongs. A white paper from 2017 targeted 50% cut by 2030 for shipping [Regjeringens handlingsplan for grønn skipsfart, 2019]. In terms of economic incentives, Norway adds a tax on marine fuels, but the Norwegian carbon price does not apply to transport including shipping.

The oil and gas sector is under immense pressure to reduce or eliminate emissions from its production as well as from the subsequent use. The **Norwegian offshore oil and gas industry** agreed in 2020 to reduce GHG emissions from production by 50% by 2030, relative to 2005 [Konkraft, Feb 2020]. Emissions from offshore vessels are accounted for as the O&G companies' scope 1 or 3 emissions and thus not clearly included in the O&G sectors emissions and goals.

**Equinor**, a major charterer of offshore vessels targets 50% cut in maritime emissions in Norway from 2005 to 2030. The same reduction shall be achieved globally by 2050 [Equinor, Energy Transitions plan, 2020].

In the **Norwegian Shipowners' Association** climate strategy (2020), the members agreed to reduce the carbon intensity by 50% from 2008 to 2030 and to build nothing but vessels with zero emission technology from 2030. This entails vessels *capable* of conducting *the majority* of its operations without emissions. In practical terms, this means that some emissions can be accepted in a few operating modes or weather conditions or other rarely occurring situations. The Association's strategy also reflects the fact that zero emission shipping requires support from other actors, e.g. the energy sector, ports and charterers.

To conclude; all industries should reduce their absolute emissions measured in metric tonnes of $CO_2$-equivalents by 50% by 2030, by 80% by 2040 and to near zero by 2050. The risk of carbon leakage should be avoided by considering and including emissions along the entire life cycle from production (well to tank) to use (tank to wake).

## 4.3. Status for the energy transition in the shipping sector

The transition to alternative fuels started with LNG in 2000 and offshore vessels were early movers with the first LNG-fuelled supply vessel in 2003. 36 offshore vessels can operate on LNG [DNV AFI]. LNG can reduce GHG emissions, but the urgent need to curb global warming motivates us to move ahead to more advantageous fuels.

In 2021, 99.89% of the fuel used by ships was of fossil origin, i.e. either heavy fuel oil (HFO), light fuel oil (LSFO), diesel/gas oil (MDO/MGO) or natural gas (LNG). In 2019, the share of fossil energy was 99.95% and in 2020 99.91%. The uptake of other fuels are thus very slowly increasing, but is still at very low level [IMO DCS reports 2019, 2020, 2021]

Many cargo ships are now ordered for operation on methanol. Very few vessels including offshore vessels are ordered, built and equipped for operation on hydrogen and ammonia.

The energy transition has started, but is not moving ahead at the required pace.

## 4.4. Air pollutants

This report focuses on global warming and greenhouse gases. A transition to new fuels can have effects on air pollution, e.g. biomethane will give lower $NO_X$-emissions than liquid biofuels and ammonia have a risk of higher $NO_X$ than methanol. Hydrogen is the only fuel with zero GHG as well as near zero air pollutants in use (tank to wake).

Emission of NO, and $SO_X$, is regulated by MARPOL regulations. Soot-related particles are governed partly and indirectly while other particles and black carbon from shipping are not yet regulated.

Emission of air pollutants is not included in the scope of this study.

## 4.5. A note on energy efficiency

Worldwide, approximately 11-14% of the primary energy is renewable [BP, IEA], in EU 17% [Eurostat] and in Norway the share is around 50% [Klimastiftelsen and SSB]. Renewable energy is by no means an abundant resource. It takes time to build new production capacity and such new capacities very often has a negative impact on nature and biodiversity and a high cost. Therefore, the energy demand to produce alternative fuels is an important factor. We elaborate on this in chapter 7.3.

Because alternative fuels are more expensive (ref chapter 11.3), require more space onboard (ref chapter 8) and are sparsely available (ref chapter 10) there are economic and practical advantages of increasing energy efficiency before introducing alternative fuels.

Therefore, reducing energy consumption by smart operations, good ship design, energy efficient systems and outfitting, good maintenance including hull and propeller cleaning should be the first step in all decarbonization programmes. Energy harvesting such as utilizing wind-assisted propulsion, waste heat recovery and heat pumps may also be relevant solutions for some vessel types.

# 5. Offshore vessels

The preferred fuel for offshore vessels will vary and depend on many different factors such as the operation profile, requirements to machinery, safety and competence, operating region and need to redeploy vessels to other regions, need for flexibility to sell or acquire vessels, relationship with charterers and their preferences, inter alia.

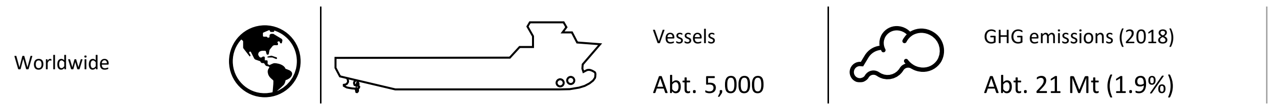
The report therefore starts by exploring the technical features of offshore vessels and their operation.

## 5.1. The offshore fleet

Offshore vessels support energy production on the continental shelf, primarily oil and gas, in the various phases from exploration, installation, production and decommissioning. Different types of offshore vessels contribute throughout the value chain. The advent of offshore wind farms requires specialized vessels for installation as well as service.

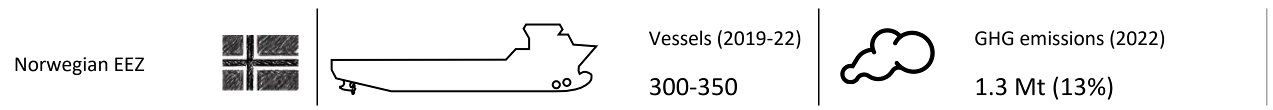
Future offshore vessel designs may evolve to support many disparate sectors such as offshore wind, space missions (launches and recoveries), carbon capture (transport) and subsea mining. Operational concepts involving a mothership and autonomous smaller vessels as well as offshore charging buoys are also on the horizon, says ABS [ABS: Future OSV designs and operations].

On a global scale, the offshore segment is quite small both in terms of fleet and emissions. Approximately 5,000 vessels operate globally [Maritime Insight, Clarksons]. The total GHG emissions from offshore vessels summed up to approximately 21 million tonnes $CO_2$-equivalents in 2018 [IMO 4th GHG-study]. This is less than 2% of the total GHG emissions from shipping.




Offshore vessels may be a small sector on the global scene, but they represent a much larger share of the maritime activity in Norway. In the period 2019-2022, a total of 300-350 vessels did work for Norwegian offshore petroleum production [VPS, May 2022].

The total $CO_2$ emissions from offshore vessels in the Norwegian exclusive economic zone reached 1.3 Mt $CO_2$ and the national share of this was about 90% [Kystverket, VPS]. Offshore vessels thus represent 13% of Norwegian shipping emissions, and 2-2.5% of the total national emissions.




There are approximately 60 Norwegian ship owners owning and or operating offshore vessels [Norwegian Shipowners' Association].

## 5.2. Age profile

The average age of the Norwegian Shipowners' Association members' offshore vessels is 14 years. Seismic and research vessels are generally older while the average age for PSV, AHTS and CSV is 13 years.

The below age distribution indicates that half of the vessels are built after 2010 and have around 10 years of service left. This suggests that finding solutions for existing vessels are quite important to avoid premature recycling of otherwise fully functional ships and the related environmental and economic burden. The possibility to convert and retrofit existing ships to new fuels are discussed in separate chapters for each fuel option in chapter 8.

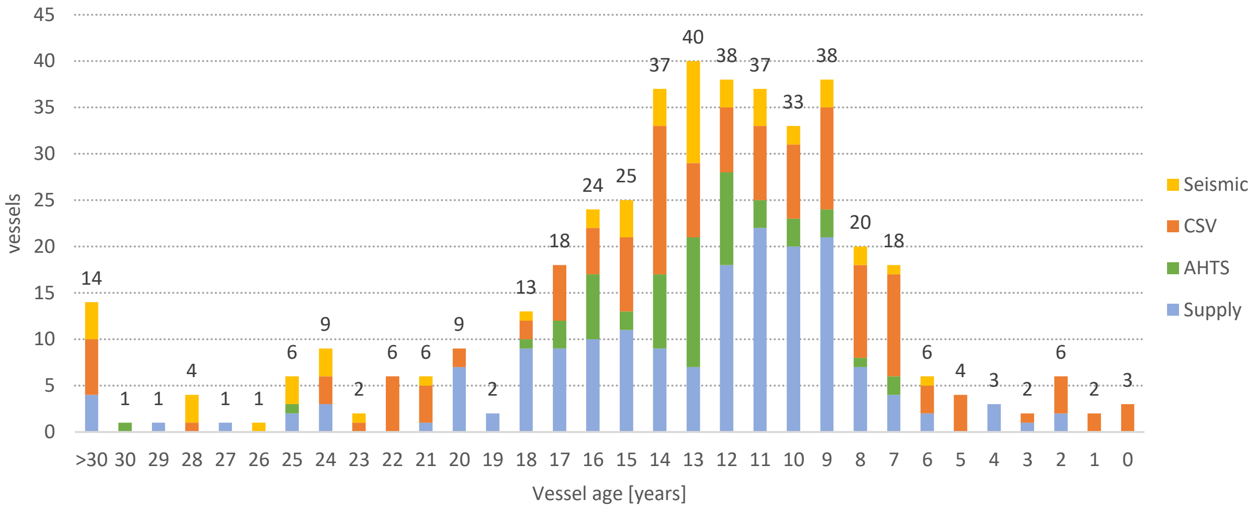



*Figure 2: Age profile offshore vessels controlled by Norwegian shipowners (source: Norwegian Shipowners' Association)*

Worldwide, 35% by number and 20% by deadweight is built before 2000 and the orderbook is only approximately 2% of the existing fleet [Maritime-Insight]. This indicates that at least 35% of the current fleet should be replaced in the next few years.

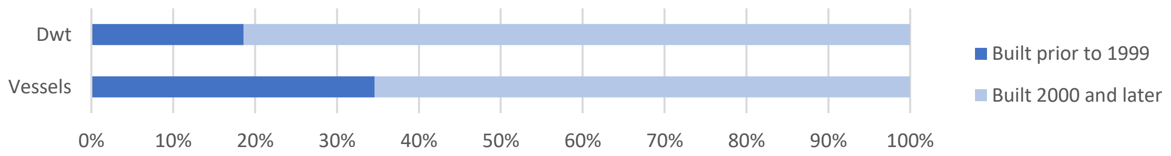



*Figure 3: Breakdown of global offshore fleet (source: Maritime-Insight)*

## 5.3. Types of offshore vessels

There are multiple subtypes tailormade for various services and duties. The fleet controlled i.e. owned or operated by Norwegian companies consists of about 175 (40%) platform supply vessels (PSV), 60 (10%) AHTS, 140 (35%) construction vessels (CSV) and 55 seismic research vessels. This report focuses on the first three subtypes, PSV, AHTS and CSV.

The fleet operates worldwide.

By dwt and gross tonnage, construction vessels make up a larger share due to their size.

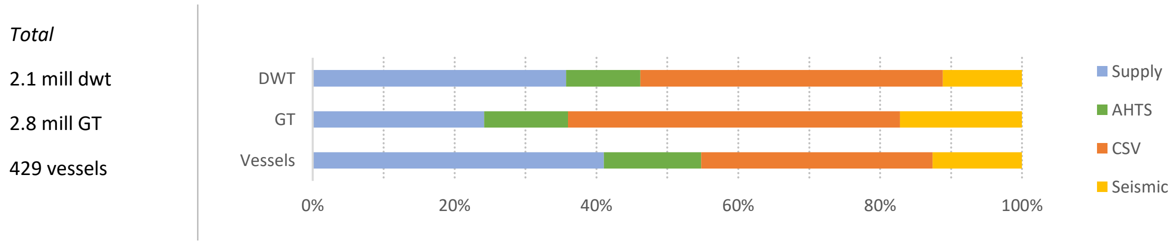



*Figure 4: Total (left) and breakdown (diagram) of the Norwegian offshore fleet (data from Norwegian Shipowners' Association).*

The total number of vessels is used to estimate the total greenhouse gas emissions from the fleet in chapter 12.7 and the fuel demand in chapter 12. 8.

The Norwegian fleet by flag, i.e. vessels registered in NOR or NIS, totalled 222 vessels and 1.1 mill GT in 2023 [SSB]. About half is registered in NOR and half in NIS. Most of the vessels (71%) in NOR and NIS are Norwegian-owned.

### 5.3.1. Platform supply vessels (PSV)

Supply vessels ferry supplies and consumables to and from drilling and production rigs offshore, both liquids in tanks and solids on deck. Their size is typically measured by the deck area and the tank capacities. Many are equipped for firefighting. Supply vessels make up approximately 40% by number and 25% by tonnage of the Norwegian offshore fleet.

During DP operation within the 500 m zone from offshore installations there are redundancy requirements that dictate that the vessel can utilize max 50% of the total power capacity. Some clients require an even higher power margin, through activity specific operating guidelines (ASOG). This leads to running of more engines on part load or very low engine loads for prolonged periods of time.

### 5.3.2. Anchor handling, tug and supply vessels (AHTS)

These vessels tow large offshore modules including fixed, floating, and modular platforms, lay out anchors and chains and hook up floating production platforms and vessels. Anchor handlers also move fixed and floating wind turbines, and this is expected to become a more important source of work in the future. Tensioning of anchors for mooring both oil & gas structures as well as floating wind turbines by require high bollard pull capacity and this is the defining criteria for installed power, which dictate the large engine installations for these vessels.

Therefore, AHTS vessels have high machinery power and special propellers for high bollard pull, which is often an indication of their capacity. AHTS vessels make up approximately 15% by number of vessels and 10% by tonnage.

### 5.3.3. Construction vessels (CSV)

Construction vessels undertake various construction, installation or inspection work at sea while using dynamic positioning for stationkeeping. We include pipe and cable laying vessels, and diving support vessels in this category.

Work is carried out through a moonpool or over the side or stern. Cranes handle subsea processing equipment to the seabed, remotely operated vehicles (ROV) for well intervention and inspection or repair work on pipelines or cables. They also assist with laying cables and pipes including trenching. Erection, assembly and mooring of large offshore wind turbines also require assistance from construction vessels. Construction vessels also assist with decommissioning and transport of end-of-life structures to shore for final dismantling and recycling. Construction vessels must also accommodate large numbers of crew and industrial personnel.

During DP operation within the 500 m zone from offshore installations there are redundancy requirements which dictate that the vessel can utilize max 50% of the total power capacity. Some clients require an even higher power margin, through activity specific operating guidelines (ASOG). This leads to running of more engines on part load or very low engine loads for prolonged periods of time. Construction vessels make up approximately 30% by number of vessels and 50% by tonnage.

### 5.3.4. Seismic research vessels

In addition to the above three major subtypes, seismic research vessels make up a sizable group; about 55 seismic research vessels corresponding to 13% by number and 17% by tonnage of the Norwegian controlled offshore vessels. These vessels map the seabed using sound emitting devices and seismic reflection. This vessel type is not included in our study.

A rough analysis of seismic vessel operations indicate that these have a high fuel consumption when streaming and that his operating mode makes up a large share of the total operating time [PGS], [Shearwater].

### 5.3.5. Wind installation (CSOV) and wind service operation vessels (SOV)

The expected growth in offshore wind turbines will require a large number of offshore vessels both for installation and for periodic service. Installations will likely be carried out by offshore construction vessels (CSV) with operations similar to those performed for oil and gas installations. Service will be carried out by purpose-built vessels or modified platform supply vessels (PSV). Towing back to shore for maintenance will also be needed [Europower, 15 Jan 2024].

In addition to the above, vessels built for diving support and research are quite similar in operation and outfitting. The conclusions of this report may be relevant to these as well.

## 5.4. Technical key features

The key features of the three most important offshore vessel subtypes are summarized as follows. Note that all figures and facts in table 2 are approximate but representative for the respective vessel categories.

| | **PSV**<br>**Platform supply vessel** | **AHTS**<br>**Anchor handling, tug and supply** | **CSV**<br>**Construction vessel** |
|---|---|---|---|
| LOA | 82-95 m | LOA 92-95 m | 92-160 m |
| Breadth | 18-22 m | 22-24 m | 21-33 m |
| Deadweight | 4-5,000 t | 3-5,000 t | 3-13,000 t |
| Gross tonnage | 3-5,000 | 3-8,000 | 5-23,000 |
| Fuel(s) | MGO mainly, | MGO | MGO |

| | | | | |
|---|---|---|---|---|
| | | LNG: around 40 vessels (dual fuel).<br><br>Biodiesel or biogas in limited volumes/cases. | | |
| DP class | | DP II | DP II | DP II or DP III |
| Engine configuration | | Diesel electric | Direct drive,<br>diesel electric,<br>combined (hybrid) | Diesel electric |
| Engine power | | 8-10 MW | 16-28 MW | 10-30 MW |
| No. of engines/generators | | 3-4 | 4-6 | 4-6 |
| Engine type | | Primarily medium-speed engines (750-900 rpm) and some high-speed engines (1,200-1,800 rpm).<br><br>1,500-4,500 kW/engine or genset.<br><br>Typically, 6-9 cylinders, but also up to 16.<br><br>Main makers: Bergen Engines (prev. Rolls-Royce), Cat, MAN, Wärtsilä.<br>Also: Cummings, Mitsubishi, MTU, Scania. | | |
| Battery | Norway | Most vessels 500-800 kWh | Some vessels 1-2 MWh | Some vessels 1-2 MWh |
| | Worldwide | | No | |
| Shore power | Norway | Most vessels | Some vessels | Some vessels |
| | Worldwide | Generally, shore power is not (yet) available in offshore ports/hubs worldwide. | | |
| Fuel cons. | At 10 kn | 10-15 t/d | 15-20 t/d | 20-40 t/d |
| | DP-mode | 6-8 t/d | 10-12 t/d | 6-16 t/d |
| | In port | 1.5-3 t/d | 2-3 t/d | 2-5 t/d |
| | Average | 8 t/d | 15 t/d | 15 t/d |
| Endurance | Alt. fuel | 1 week | 4 weeks | 4 weeks |
| | Backup fuel | 1 week | 1 week | 1 week |
| | Basis | Tank capacity to be calculated based on average energy demand, not MCR. | | |
| Multi fuel possibility | | Single fuel possible on long term contracts / MGO backup preferable (Norway) | Required; MGO backup | Required; MGO backup |
| Reference vessels | | Normand Falcon<br><br>Normand Sygna<br><br>NS Frayja<br><br>Skandi Kvitsøy | Normand Drott<br><br>Skandi Vega<br><br>Skandi Iceman | Normand Vision<br><br>Skandi Acergy |

*Table 2: Key characteristics of offshore vessel subsegments*

## 5.5. Machinery configuration

Most offshore vessels are powered by four (or up to six) generator sets to handle different operating modes and ensure high reliability and redundancy. Batteries may be added to avoid uneconomical low load running while maintaining redundancy.

The onboard power system is mainly electric, with electric thrusters and/or main propulsors. Power distribution onboard is either AC or DC (alternating current or direct current). Due to class requirements for DP operations the machinery systems configuration requires redundancy, including separate machinery spaces.

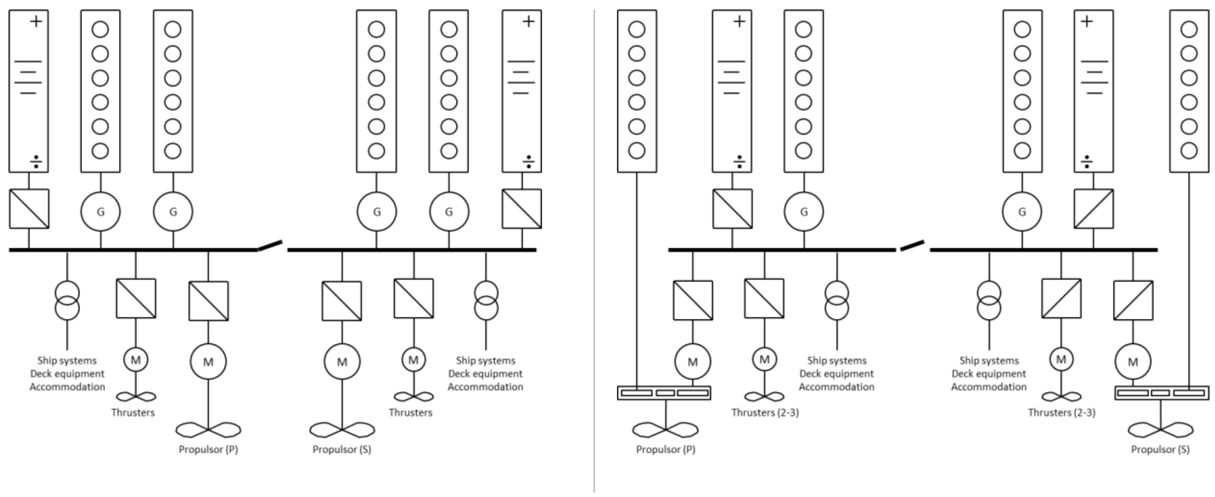



*Figure 5: Typical machinery configuration (one line diagram) for offshore vessels (left) and AHTS (right). Variations occur.*

## 5.6. Operating profile

Understanding the operations of a vessel is essential to find an alternative fuel and machinery that is practical and environmentally favourable while meeting all requirements to safe and reliable service.

Based on operations data for 9 offshore vessels, we find the breakdown of fuel consumption (energy demand) per operating mode. This helps to identify the most important operating mode for each of the vessel types.

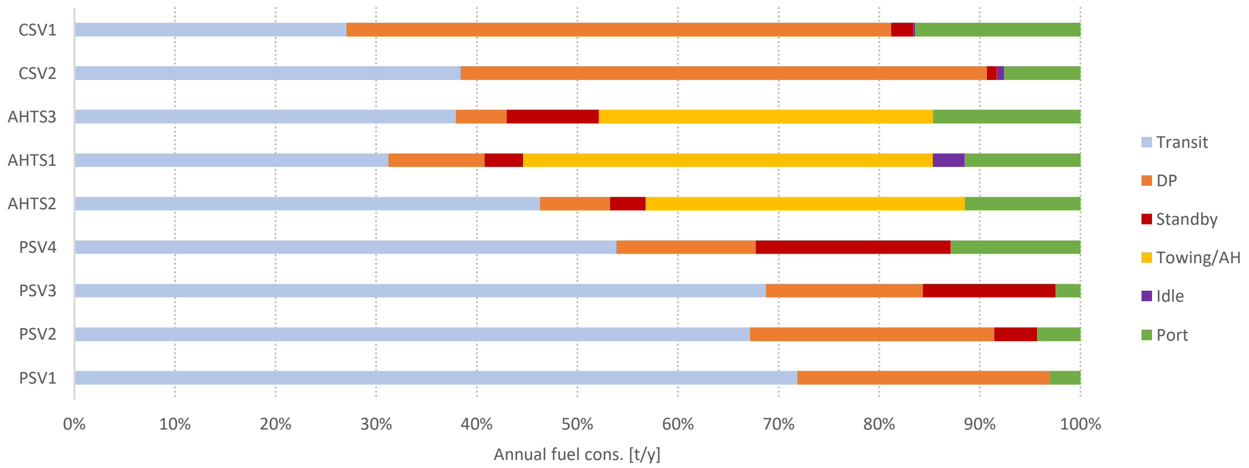



*Figure 6: Breakdown of total energy demand for nine representative offshore vessels.*

A report on emissions from offshore vessels operating in Norway found that, on average, approximately 6-7% of the vessels' total GHG emissions are emitted in port [VPS, 2021].

### 5.6.1. Platform Supply vessels

Transit is important for supply vessels; around 40% of their operating time is spent in transit, while the energy consumption in transit is 50-70% of the total. Transit is characterized by continuous running at relative constant load of the machinery over some time. Need for redundancy and reserve power is low compared to the other operating modes occurring close to fixed/floating installations, where the possible consequence of black out is very high. 15-25% of the energy consumption is in DP and 5-20% in standby.

Supply vessels spend 5-10% of energy in port.

### 5.6.2. AHTS

Anchor handlers see more variety in their operations. Only 30-45% of the energy is spent in transit.

In addition to transit, most energy is spent when towing and anchor handling; combined 30-40%. These operating modes are characterized by slow speed and high bollard pull with periods of intense running of winches and other critical equipment. Losing power is not an option in these modes; generating sets are running at part load to have spare power immediately available; alternatively, batteries are standby if they have sufficient power/energy.

Transit is also important (30-45%). Half the time is spent in port and consumption here is thus high; 10-15% of the total.

### 5.6.3. CSV

Construction vessels spend 40-60% of their time in DP and consume more than 50% of their energy in this mode. DP mode means construction work is undertaken, whether this means lowering or hoisting heavy processing equipment to the seabed or inspection or repair work on pipelines. Such work is characterized by highly fluctuating power demand and high requirements to reliability, redundancy, immediately available spare power.

Construction vessels can spend much time in port (40%) to prepare (mobilize/demobilize) for projects. Due to the size and accommodation capacity, energy demand in port is higher than for supply vessels; as much as 15% of the total.

### 5.6.4. Wind service vessels

Vessels helping to install or service offshore wind farms generally have the same operation as a CSV when installing and as a PSV when servicing.

## 5.7. Commercial aspects; opportunities and restrictions

Environmental, technical and practical considerations are important, but by the end of the day a possible transition to low or zero carbon fuels must be economically and commercially feasible for the ship owner, charterer and other stakeholders. It is therefore interesting to map the commercial realities for the offshore fleet.

Offshore vessels are contracted by the energy majors on time charter and spot contracts. Approximately 60% of the vessels in the North Sea are on time charters, which can last from a few months up to ten years. Contracts for five years with options for extension 1-5 years are common.

Generally, longer time charter contracts are more common for supply vessels while anchor handlers and construction vessels are contracted based on job duration. Short contracts put the economic risk of technical upgrades on the ship owner, especially if the payback time is much shorter than the contract period.

Traditionally, charterers of offshore vessels as well as cargo vessels have been responsible for covering the fuel cost. This split does not necessarily incentivize ship owners to invest in fuel efficient machinery and energy saving devices and new contract arrangements to align the interests of ship owners and charterers are needed, including longer contract periods and or sharing of costs, savings and risks. Some oil and gas companies take responsibility for emissions from maritime activities by including them as scope 1 emissions, while others report this as scope 3.

| | PSV | AHTS | CSV |
|---|---|---|---|
| Contract type | Time charter | Project-/job-based contracts | ← |
| Contract duration | 5 + 1-3 years | | Short: 1-6 months |
| Fuel cost responsibility | Charterer | Primarily charterer, but some projects are undertaken based on a fixed total costs where the owner is responsible for the fuel cost. | |
| Mobility | Low; vessels operate primarily within a fixed geographic area | Medium | High; vessels shift between regions depending on activity levels |
| Asset play | Vessels are sometimes sold | Long term ownership | Long term ownership |

*Table 3: Commercial realities for the OSV subsegments*

The introduction of alternative fuels must be coordinated and agreed with the oil and gas companies chartering the vessels. Some charterers have indicated preference for or scepticism to some of the alternative fuels based on the safety risks.

An oil major on the Norwegian continental shelf has appeared sceptical to see hydrogen close to their production facilities offshore due to the risk of explosions. Considering the strong position of this oil major, this scepticism must be considered a major obstacle for hydrogen. On the other hand, the same oil major seems to be more positive to ammonia by e.g. supporting R&D projects.

Until the oil & gas companies' preferences are specifically confirmed, we keep all options open and include all fuels listed in chapter 2.2 in scope.

Offshore vessels work for the oil & gas companies. Many of the energy majors have ambitions to not only reduce GHG from their operations but also to produce climate neutral energy and fuels. Equinor, for example, wants to produce hydrogen from natural gas, but have so far withdrawn from two concrete initiatives; the Aurora project [NTB, 3 March 2022] and the Barents Blue project [Equinor, 1 Feb 2023]. Equinor has also entered into a contract with Mærsk to supply biomethanol (see chapter 10.6 for details).

The relationship between operators of offshore vessels and the energy majors should be leveraged to find solutions that will eventually benefit both the shipowner/operator and the energy majors. Equinor's biomethanol contract with Mærsk suggest that the company should be in a position to supply the same to ships they have on contract.

# 6. Evaluation criteria for evaluation of alternative fuels

A successful fuel transition strategy must consider many different aspects and meet many requirements. Before we go into the analysis in chapter 7-11, we list a number of aspects to consider in figure 7 below. In this feasibility study, we focus on the criteria in bold text.

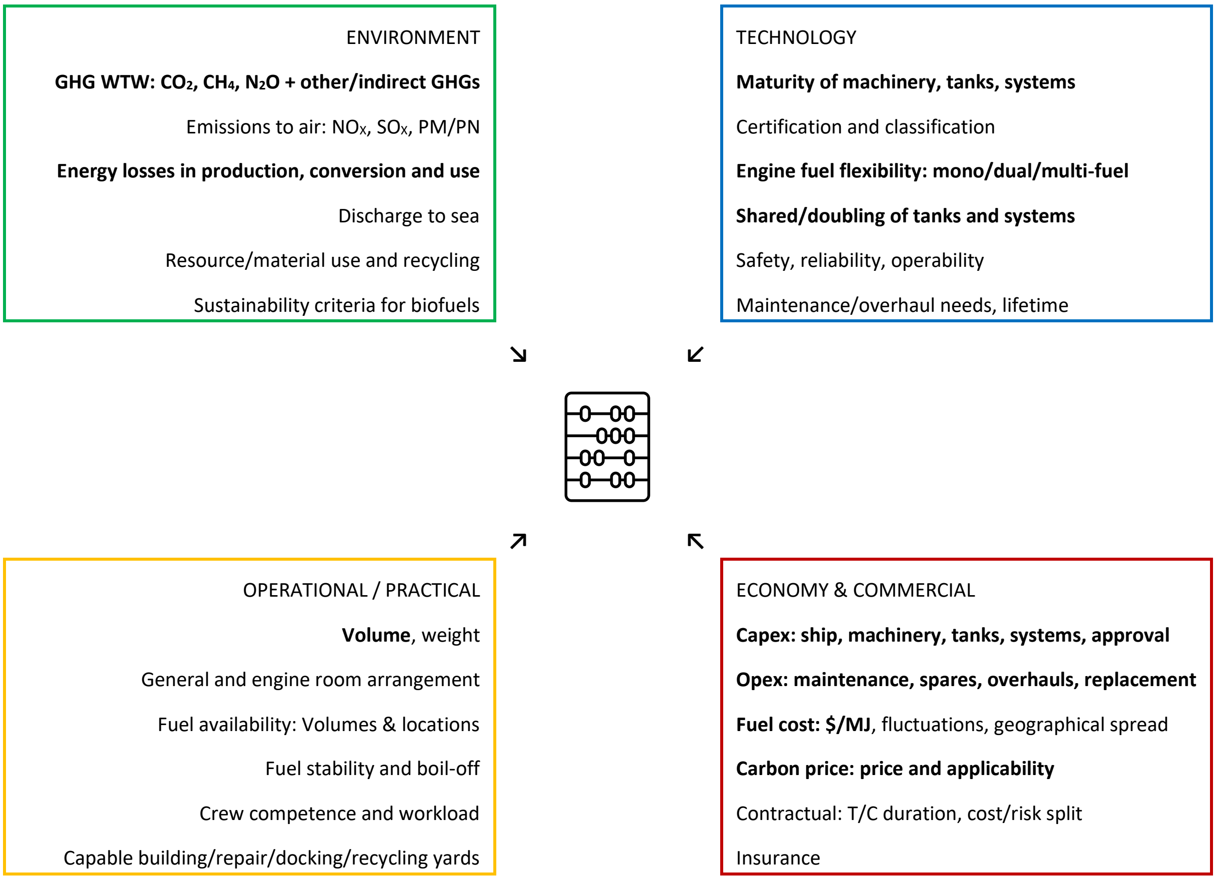



*Figure 7: Evaluation criteria for alternative fuels [Gamlem, Smart Maritime Sea map to green shipping, 2023].*

We evaluate the climate effect of alternative fuels in chapter 7.

We evaluate technology (machinery, tank, and systems) for alternative fuels in chapter 8.

We discuss the various alternative fuels impact on the ship design, main dimensions, and general arrangement in chapter 9.

We evaluate the supply of alternative fuels in chapter 10.

We discuss the framework for the economic evaluation in chapter 11.

The agreed scope for this report does not include the plain text items, and we suggest that these may be addressed in later work.

# 7. GHG emissions and energy use for alternative fuels

The below illustration indicates the GHG emissions of the various alternative maritime fuels relative to MGO. The footprint of some fuels depends on the production pathway. For biomethane, biodiesel, biomethanol and LNG we indicate an emission range, depending on the raw material, the production process, and the logistics.

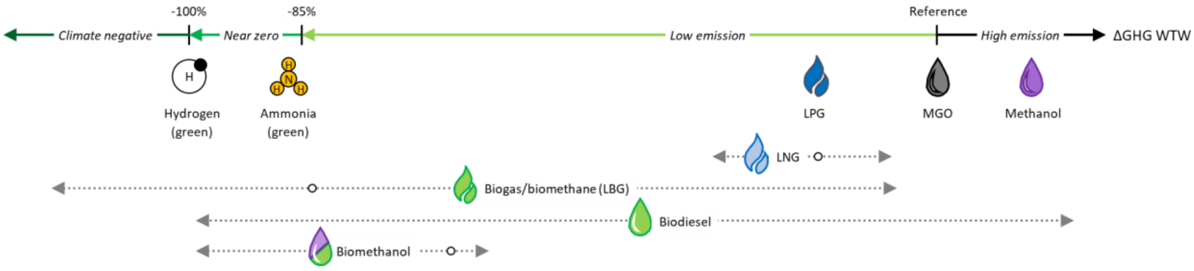



*Figure 8: Overview and classification of alternative fuels based on their GHG footprint well to wake from low (left) to high (right).*

This chapter describes the different alternative fuels suggested or available today. In many cases there are several different variants of the same fuel due to the production process. It is thus difficult to give general statements on the environmental effect of fuels.

In addition, there are many different views on the terms low and zero emissions and no universally accepted definitions. No existing fuels have zero emissions, and there is relevance to the question of what "zero emission" actually means – i.e. how low is "zero". We suggest, as shown in figure 8 above that the threshold for near zero is set at 85% and below with MGO emissions as baseline. Climate negative fuels can cut emissions more than 100% (ref chapter 3.1.2).

## 7.1. Life cycle perspective on greenhouse gases for fuels

Reducing greenhouse gas emissions is the main objective of the forthcoming energy transition. The key criterion is therefore the emission factors well to wake for the various alternative fuels.

With today's fuel oils, direct emissions (TTW, scope 1) are the largest source of GHG from ships with nearly 90% of fuel related life cycle emissions [Kramel et al, 2021, Winebrake et al, 2007]. This is due to change with the advent of new fuels. Some new fuels will have zero emissions in use but significant emissions in production. We must therefore take a holistic well to wake (WTW) perspective on emissions – and energy conversion losses.

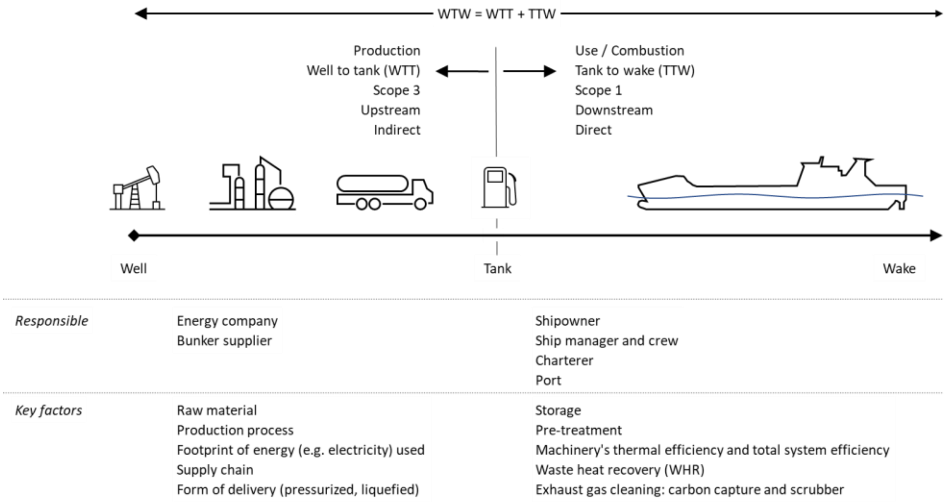



*Figure 9: Emissions scope*

This shift of focus from tank to wake-emissions to well to wake-perspective is finally also increasingly reflected in EU and IMO regulations and policies.

Note that taking a holistic view and including all GHGs from well to wake in the decision making does not necessarily mean taking economic responsibility for the same emissions scope when any carbon price is added to emissions. We expect that any carbon price will be paid for production emissions (WTT) by the energy supplier and for combustion emissions (TTW) by the ship owner.

Emission factors are generally presented per MJ or kWh. Well to tank emissions are generally given in g $CO_2$-eq./MJ i.e. based on the energy content of the fuel while tank to wake factors are given in g $CO_2$-eq./kWh. The latter takes the thermal efficiency of the engine or fuel cell into account and is thus case-specific and pertains to a certain machinery and system.

We convert from g $CO_2$-eq./MJ to g $CO_2$-eq./kWh using the thermal efficiency ($\eta$) of the machinery:

$$\frac{g\ CO_2\text{-}eq.}{kWh} = \frac{g\ CO_2\text{-}eq.}{MJ} \cdot \frac{1}{\eta} \cdot \frac{3600}{1000}$$

For example, a fuel with 5 G/MJ in a machinery configuration with efficiency 0.425 results in an emission factor of 42.35 g/kWh.

## 7.2. Life cycle perspective for the vessel

Ideally, we should take a life cycle perspective on the vessel as well, including hull fabrication, outfitting, machinery and systems. Premature retirement and scrapping and recycling of vessels also bring environmental burdens. While many of these can be eased by safe and environmentally friendly recycling, demolition and new construction will always increase use of energy and resources.

This falls outside the scope of this study but should be included as part of a total life cycle assessment for a new vessel.

## 7.3. Energy use; conversion losses, thermal efficiency

In addition to the GHG emission factors well to wake, the energy losses and thus energy efficiency ($\eta$) in production, conversion and combustion is critical in a world where renewable and climate neutral primary energy are scarce resources.

Over the last five decades, primary energy supply has grown by approximately 2% pa, from 230 EJ in 1971 to 606 EJ in 2019. While total energy demand has tripled, the renewable share has remained the same for the last 50 years, 13-14% [IEA, 2021]!

Looking ahead, two scenarios by IEA and Shell suggests a renewable share of 42% [IEA] and 67% [Shell sky] in 2050. Note that scenarios are explorations of what is required to reach certain goals, in this case global warming well below 2°C, not a forecast of the most likely future.

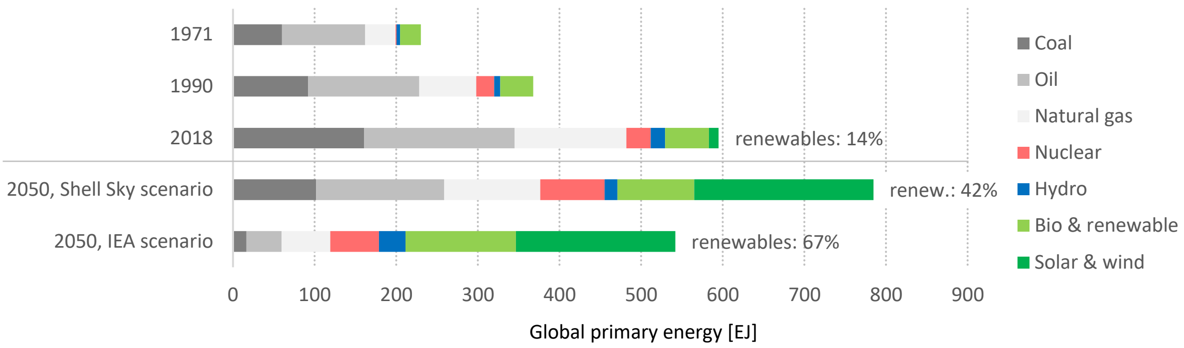



*Figure 10:: Primary energy sources in 1971, 1990 and 2018 [IEA, 2021| ↗] and according to two scenarios for realizing net zero emissions by 2050 (IEA) and 2070 (Shell Sky).*

The share of renewables is higher if we focus on electricity production only; 29% globally [IEA] , 39% in the EU [Eurostat], 20% in the US [EIA] and 97% in Norway [NVE]. Norway has approximately 50% of the hydropower capacity in Europe [Statkraft]. But even with this unique access to renewable power, renewables cover only approximately half when all energy consumption is accounted for [Klimastiftelsen].

The conclusion must be that renewable energy is and will likely remain scarce for the next few decades. This explains the importance of reducing energy demand across all sectors and also to carefully consider the energy demand in production of alternative fuels.

This concern applies to hydrogen, ammonia and synthetic fuels in particular, because of the very high energy demand to produce these fuels.

## 7.4. Liquid fuel oils

MGO is the standard fuel for offshore vessels while low sulphur blends of residual and distilled oil are the norm in deep sea shipping still. MGO will therefore be the benchmark in our analysis. Diesel is also the so called "fuel comparator" in the EU's review of sustainable biofuels.

MGO covered 32% of the energy demand of ships globally in 2018, while 64% came from residual fuels including blends. The share of MGO is growing due to the 2020 sulphur cap. Statistics for European shipping suggest that LSFO has replaced HFO while the share of MGO/MDO has increased only slightly [EU MRV data for 2018, 2019, 2020].

The footprint of MGO varies with the composition of the crude oil and the need for refining and also the transport distance and transportation mode, but the variation is less than for other fuels. While a standard value for MGO is 14.5 g $CO_e$-eq./MJ, Equinor produces MGO at only 7.6 g $CO_2$-eq./MJ at Mongstad [Tomas Ryberg].

The emission factor for MGO can be reduced with onboard CCS. This technology is at the pilot stage today, with small scale demonstrators running under ideal conditions. The first large scale pilot will be tested under realistic conditions by Wärtsilä Moss, Solvang and SINTEF Ocean from 2024-2026. Based on indications, we foresee approximately 60% reduction of the well to wake emission factor.

There are multiple liquid biofuels: Biodiesel or FAME (fatty acid methyl esters), HVO (hydrotreated vegetable oils) and alcohols such as methanol ($CH_3OH$) and ethanol ($C_2H_5OH$). Biofuels can be produced from a number of raw materials; rape seed, palm oil, sunflower oil, soy beans, sugar beet and sugar cane, corn/maize, wood and black liquor. The raw materials can be virgin or waste or byproducts from other industrial processes. The emission factor varies significantly depending on the raw material. In the lack of case specific emission factors, we can rely on standard values compiled from numerous sources in e.g. the EU Renewable Energy Directive. In general, liquid biofuels can reduce GHG by 40% to around 100%. Some biofuels will give much higher emission than diesel if the climate effect of indirect land use change is negative (e.g. deforestation for palm oil production). A set of broad sustainability criteria shall prevent this.

Synthetic liquid fuel oil is constructed from hydrogen and carbon from a point source (biproduct of another industrial process) or by direct air capture (DAC). The process must be set up so that the GHG emitted is offset by the $CO_2$ captured, taking energy and emissions in the production into account. The synthetic fuel thus becomes climate neutral.

The following emission factors are based on Lindstad et al assuming η = 0.425 for the engine:

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Emission factor [g $CO_2$-eq./kWh] | Fossil | 122 | 644 | 766 |
| | Bio | | | Net zero |
| | Synthetic | | | Net zero |

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Energy eff. [-] | Fossil | 0.83 | 0.425 | 0.35 |
| | Bio | 0.40 | 0.425 | 0.17 |
| | Synthetic | 0.28 | 0.425 | 0.12 |

To conclude: liquid biofuels can reduce GHG considerably with no or minimal changes to tanks, systems or machinery. There are some complicating factors discussed in chapter 8.2. Synthetic diesel is tempting from a climate perspective, but questionable due to the high energy losses in production. Synthetic diesel is worse than synthetic methanol and synthetic methane, but technically more convenient.

## 7.5. Gas (LNG, biomethane and E-LNG)

Natural gas comes in the form of LNG and LPG. LNG has been a maritime cargo since the inception of LNG-carriers and was initially introduced as fuel for such vessels based on gas boil-off from cargo tanks. It was introduced as a fuel to other vessels in 2000.

LPG is today only used as fuel by LPG-carriers; there is currently little interest in using LPG as fuel on other vessels.

There is significant variation in the footprint of LNG depending on the natural gas resource, the extraction method, flaring, leakages from production and transport, the ambient temperature at the liquefaction stage, distance to market and other factors. A review of emission factors from researchers and gas producers finds that the emission factor WTT varies from 5 to 30 g $CO_2$-eq./MJ = 42-254 g/kWh.

LNG from Snøhvit/Melkøya in Hammerfest, Norway, has a footprint of 3.8 g $CO_2$-eq./MJ *cradle to gate* and this will drop to 0.8 g/MJ when the plant is powered by renewable electricity, planned from 2030 [Equinor]. Small scale LNG suppliers in Norway produce LNG with less than 5 g $CO_2$-eq./MJ [Gasnor, Gasum].

Biogas is a mix of methane ($CH_4$) and primarily $CO_2$, with small traces of other compounds (nitrogen, hydrogen, sulphur). Biomethane is a purified variant of biogas intended for combustion machinery used by ships, trucks and rail. The advantageous climate effect of biomethane comes from avoiding the release of methane that would otherwise be released if the raw material was left to decompose naturally. Depending on the raw material used and the production and logistics, the greenhouse gas emissions all included (well to wake) can be reduced by 35% and up to 206% [EU RED II, Annex Vi, part B, page 113]. A conservative estimate can be 65% reduction; this is the threshold EU requires for sustainable biofuels for the transport sector [EU RED II, article 29.10].

Synthetic LNG is carbon neutral, but the methane slip makes the net GHG emissions positive (> 0). With 1 or 7 g $CH_4$/kWh, the total GHG becomes 34-213 g $CO_2$-eq./kWh.

The emissions from combustion of methane (LNG, biomethane and synthetic LNG) depends on the combustion process i.e. the engine type that is used:

Pure gas engines employ the Otto principle, using a pre-mixing of gas and air before the cylinder. Ignition is by spark plug, and a very high air-to-fuel ratio give lower combustion temperatures and thus low $NO_x$ formation while retaining high thermal efficiency. This concept is known as lean burn spark ignited (LBSI).

Some DF engines also use a pre-mix of gas and air, while ignition is achieved by use of diesel fuel injection into a pre-chamber providing flame ignition to the compressed gas-air mix in the cylinder. These engines also achieve very low $NO_x$ emissions and high thermal efficiency when running on high gas fractions. Such engines can also run on 100% liquid fuel (e.g. MGO or biofuel) using a Diesel combustion process (compression ignition). When running on 100% liquid fuel the engine has lower thermal efficiency than a comparable diesel engine. This concept is known as low pressure dual fuel (LPDF) and the most common combustion principle for dual fuel diesel/gas medium speed engines.

All engines using pre-mixing of gas and air will have methane slip from the cylinder to the exhaust gas channel. This methane slip stems from unburnt methane in the cylinder during the combustion process. Small volumes of the compressed air/gas mix will be in areas where conditions are not favourable for combustion. This is a direct consequence of the combustion process for pre-mixed fuel engines. The methane slip has been reduced since the first pure gas and dual fuel engines were introduced, but the high GWP-factor for methane ($GWP_{100}$ 29.8, ref IPCC AR6WG1, Chapter 7, page 1017) means that only a few grams of methane slip is detrimental, and that methane slip must be reduced as much as possible.

Otto cycle medium speed dual fuel engines have a methane slip of 4-7 g/kWh [Ushakov, Stenersen & Einang, 2019]. The newest engine technology can beat this and bring the methane slip down to 1-2 g/kWh [Wärtsilä Sep 2023, MAN Oct 2023] though such advancements should be verified by long term independent testing, both at design load and low and transient loads. To conclude, we can use 1 g/kWh as best case and 7 g/kWh as worst case.

Some DF engines employ the Diesel combustion principle also for gas where all fuel is injected directly into the cylinder at the end of the compression stroke. The fuel self-ignites due to the temperature and pressure inside the cylinder. Since the fuel ignites on injection all fuel is combusted and thus there is a potential for zero methane slip. Some engines in this category still have methane slip, due to the design of the injection nozzle where a small volume of gas remains and can expand unburnt with the exhaust. Engines using the diesel cycle have high $NO_x$ formation due to combustion temperature and pressure. This concept, known as high pressure dual fuel (HPDF), is so far only applied to two-stroke engines and thus currently not available for offshore vessels.

Blends of methane and hydrogen can be one way to reduce methane slip to a minimum. Thus, blending in hydrogen not only reduces the share of LNG but also improves the combustion.

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Emission factor [g $CO_2$-eq./kWh] | Fossil | 42-254 | 510-688 | 542-845 |
| | Bio | Near zero or net negative WTW | | |
| | Synthetic | | | 34-213 |

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Energy eff. [-] | Fossil | 0.83 | 0.425 | 0.35 |
| | Bio | 0.83 | 0.425 | 0.35 |
| | Synthetic | 0.33 | 0.425 | 0.14 |

The climate effect of LNG can be significant (up to 30% below MGO) or indeed negative. Biomethane and synthetic gas can give near zero emissions. Although there are high energy losses associated with synthetic gas, synthetic gas is slightly better than synthetic diesel and synthetic methanol in terms of energy losses.

## 7.6. Methanol

Methanol is the simplest liquid hydrocarbon ($CH_3OH$), with the highest ratio of hydrogen to carbon. Taking the heating value into account, the emissions from combustion are reduced by 8% compared to MGO.

With today's production, the lower combustion emissions are cancelled out by higher emissions in production. More than 99% of the methanol produced today is from fossil sources; 65% is produced from natural gas reformation and 35% based on coal gasification while only 0.2% is biomethanol [IRENA, 2021]. Methanol from natural gas emits 15% more well to tank, so a transition from MGO to the methanol we have today does not make sense as the well to wake emission factor is 11% above MGO.

There is variation between the suppliers; Equinor produces methanol at Tjeldbergodden with 20.9 g $CO_2$-eq/MJ [Tomas Ryberg], while a standard value for fossil methanol is 31 $CO_2$-eq/MJ. This difference explains why case-specific emission factors should be used and that the arguments for or against methanol (and all alternative fuels) varies.

Biomethanol can be produced from sustainable biomass such as forestry and agricultural waste and byproducts, sewage, solid municipal waste and black liquor from the pulp and paper industry. The climate effect thus varies considerably and varies between sources: reduce GHG well to wake by 60-95% on well to wake basis [IRENA, Innovation outlook renewable methanol, 2021].

Synthetic methanol is climate neutral in a life cycle perspective, but this entails that climate neutral electricity is used in the production. With Norwegian electricity the footprint becomes close to 10 g $CO_2$-eq./MJ. As for all synthetic fuels, the energy losses in conversion are terribly high.

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Emission factor [g $CO_2$-eq./kWh] | Fossil | 263 | 591 | 854 |
| | Bio | | | 20-260 |
| | Synthetic | | | Net zero |

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Energy eff. [-] | Fossil | 0.63 | 0.425 | 0.27 |
| | Bio | 0.63 | 0.425 | 0.27 |
| | Synthetic | 0.31 | 0.425 | 0.13 |

From a climate point of view, only biomethanol and synthetic methanol makes sense. The very high energy losses for synthetic methanol makes this option viable only in a world with abundant clean energy or in regions with stranded renewable energy which cannot be connected to the grid.

## 7.7. Hydrogen

There are multiple variants of hydrogen (and ammonia) based on the primary energy and process used. These are distinguished by colour coding.

More than 99% of the hydrogen produced today is grey hydrogen [IEA, 2022] which means it is made using fossil fuel as its primary energy resource. The majority comes from natural gas (48%), oil (30%) and coal (18%) and is produced without carbon capture and storage (CCS) [IRENA, 2018]. The production emissions are therefore high and cancel out the advantage in use. Even with zero emissions in use, the well-to-wake emissions are 67% above MGO in a life cycle perspective.

The global hydrogen production of 95 Mt/y emits almost as much as shipping; 900 vs 1,056 Mt $CO_2$ [IEA]. It makes sense to decarbonize the existing production volumes first. Plans for low carbon hydrogen production total around 24 Mt by 2030, i.e. approximately ¼ of the current production [IEA, 2022]. There are multiple pathways to low carbon hydrogen.

Blue hydrogen is produced from natural gas with CCS. The technology is quite close to commercialization, but there is no scale yet; only four production sites apply CCS today [Bloomberg NEF 2020]. The capture rate at scale is uncertain, but can be 60-90% [Li et al, 2022, Gardarsdottir, 2021]. This means that blue hydrogen will give low but not zero GHG; in fact life cycle analysis for blue hydrogen conclude with 10-16 g $CO_2$-eq/MJ [LR/UMAS 2020, Pettersen, 2022] and up to 40 g $CO_2$-eq/MJ even with CCS [DNV ETO Hydrogen forecast to 2050, 2022]. Equinor assumes 96% $CO_2$ capture rate and says blue $H_2$ can be produced with only 5-12 g $CO_2$-eq./MJ in Norway and Germany [Equinor, 2023].

Hydrogen from coal with CCS is also labelled blue. This route is particularly interesting for lignite (brown coal) which cannot be transported and must be combusted or converted in situ. Coal-based hydrogen is developed by Australia and Japan, inter alia.

Green hydrogen is made by electrolysis of water using zero emission primary energy. This covers less than 0.1% of the current global $H_2$-production [IEA, 2019]. Electrolysis was used in the Norwegian fertilizer industry from 1927 to 1993 but was discontinued and replaced by grey hydrogen from natural gas due to the lower production cost.

With around 90% hydropower and a footprint of 10-20 g $CO_2$-eq./kWh [NVE, 2019-22], electrolysis makes more sense in Norway than in Europe and worldwide where the footprint is approximately 260 and 440 g $CO_2$-eq./kWh, respectively [Ember climate, 2022].

Pink hydrogen is a variant produced by electrolysis using electricity from nuclear power. This is climate neutral, but the environmental and societal concerns and controversy around nuclear power apply to pink hydrogen as well. If the hydrogen will be green or pink depends on how the energy sector develops and whether nuclear power regains political support in countries such as Germany and Japan. Nuclear power cover 5% of primary energy today and 10% in the future 2050 scenarios from IEA and Shell alike (ref chapter 7.3)

Other less mature and discussed options include hydrogen produced by pyrolysis of natural gas with pure carbon as a byproduct (turquoise hydrogen) and hydrogen produced by gasification of biomass (light green).

The energy efficiency TTW is determined by the type of engine or fuel cell used. Both internal combustion engines and fuel cells of various types are suitable for hydrogen. Both types are commercially available in smaller sizes. The thermal efficiency of fuel cells is thought to be quite high, but this is not confirmed in full scale and long-term use. Neither are hydrogen engines tested over long periods in realistic conditions.

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Emission factor [g $CO_2$-eq./kWh] | Black | 1,279 | 0 | 1,279 |
| | Blue | 137 | 0 | 137 |
| | Green | | | Near zero |

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Energy eff. [-] | Black | 0.44 | 0.425-0.55 | 0.19-0.24 |
| | Blue | 0.40 | 0.425-0.55 | 0.17-0.22 |
| | Green | 0.40 | 0.425-0.55 | 0.17-0.22 |

To sum up, the hydrogen available today increases GHG by 66% but green and blue hydrogen can reduce GHG by 80-100% depending on the specifics of the production. The $CO_2$ capture rate is critical for blue hydrogen and the electricity footprint is critical for green hydrogen.

The high energy loss in the production of hydrogen is a major concern in a world with scarce access to renewable electricity. On the positive side, the losses to produce hydrogen are lower than the losses to produce synthetic fuels.

## 7.8. Ammonia

Ammonia is primarily produced for use as synthetic nitrogen fertilizer, but with no carbon and three hydrogen atoms it is also an interesting hydrogen carrier and thus a potential fuel. Ammonia will likely produce $N_2O$ and $NO_X$ when combusted. The volumes of these exhaust gases are not yet known as ammonia as a fuel is still under research and development. Suitable countermeasures must be employed to reduce or remove such emissions.

Ammonia is produced by the Haber-Bosch process, which converts atmospheric nitrogen by a reaction with hydrogen gas using an iron catalyst under high temperature and pressure. Ammonia may be colour coded similar to hydrogen. Ammonia is produced primarily from natural gas without CCS (72%) and coal (22%), naphtha and fuel oil. As little as 0.02 Mt of 185 Mt (0.011%!) was produced using renewable primary energy in 2021 [IRENA, 2022].

Grey ammonia emits as much as 120-130 g $CO_2$-eq./MJ in production [Lindstad, IEA] Based on uncertain and preliminary estimates for $N_2O$-emissions in use, the total well to wake emissions end up at 1,085-1,169 g $CO_2$-eq./kWh, around 40-50% above MGO.

Blue ammonia with $CO_2$ removed by CCS may have significantly lower footprint. With 60% capture rate, the footprint becomes 45 g $CO_2$-eq./MJ and with 90% capture the footprint drops to 16 g/MJ. The climate advantage well to wake is then 40% and 73% respectively (based on data from Equinor/Ryberg). We must conclude that blue ammonia can *reduce* but not *eliminate* GHG.

Green ammonia, using hydrogen produced by electrolysis with climate neutral electricity, has near zero emission in production and the total WTW emissions are determined by the formation of $N_2O$. With Norwegian electricity, the footprint WTT becomes around 10 g $CO_2$-eq./MJ [Tomas Ryberg]

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Ammonia can be combusted in an engine or fed to a fuel cell. Both options are under development. The path to a commercially available engine seems shorter; several major engine makers intend to have ammonia engines on the market in 2025-26. A critical factor for ammonia engines is the formation of $N_2O$. With a global warming potential ($GWP_{100}$) of 273 [IPCC AR6WG1, Chapter 7, page 1017] every gram of $N_2O$ is a devastating blow and more damaging for ammonia than methane is for LNG. With only 2 g $N_2O$/kWh, blue ammonia loses its advantage over MGO. It takes 2.4 g $N_2O$/kWh for green to lose its advantage over MGO. The below emission factors TTW are based on 0.25 g $N_2O$/kWh.

Ammonia does not burn easily and requires more pilot fuel than the other fuels. As the engines are under development, the exact ratio of pilot fuel remains to be seen. Emissions from combustion of pilot fuel must be factored in unless sustainable biofuel or synthetic diesel is used.

For a vessel burning ammonia in a combustion engine with η = 0.425:

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Emission factor [g $CO_2$-eq./kWh] | Black | 1,016 | 68 | 1,085 |
| | Blue | 136 | 68 | 204 |
| | Green | 85 | 68 | 153 |

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Energy eff. [-] | Black | 0.48 | 0.425 | 0.20 |
| | Blue | | 0.425 | |
| | Green | 0.53 | 0.425 | 0.23 |

For a vessel using ammonia in a fuel cell with η= 0.55, the emission factors for WTT become slightly lower.:

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Emission factor [g $CO_2$-eq./kWh] | Black | 820 | 68 | 942 |
| | Blue | 105 | 68 | 173 |
| | Green | 65 | 68 | 134 |

| | | *WTT* | *TTW* | *WTW* |
|---|---|---|---|---|
| Energy eff. [-] | Black | 0.48 | 0.55 | 0.26 |
| | Blue | | 0.55 | |
| | Green | 0.53 | 0.55 | 0.29 |

To conclude; ammonia must be produced with CCS or by electrolysis and the formation of $N_2O$ must be minimized to nearly negligible levels if ammonia shall be a meaningful step forward. Emissions from pilot fuel can also reduce the climate effect of ammonia.

The high energy losses in the production of ammonia is a major concern in a world with scarce access to renewable electricity. On the positive side, the losses to produce ammonia are lower than the losses to produce hydrogen and synthetic fuels.

## 7.9. Electricity: By cable in port or from batteries at sea

Electricity by cable can power ships in port while batteries can supply electricity also at sea. Batteries can also function as an energy saving device by facilitating optimal running of generator sets. Although this is very valuable and highly relevant for offshore vessels, this report concentrates on alternative fuels.

Batteries as an energy carrier has two key advantages: Once the electricity is produced, the efficiency of a battery, an electric motor and power electronics is much higher than that of rotating machinery; η = 0.8-0.9 vs. 0.4-0.5. Second, electricity has a very low footprint in Norway and quite low footprint also in most of Europe. The below map indicates where and just how advantageous it is to use grid electricity. Note the significant variation and Norway's remarkable and enviable position.

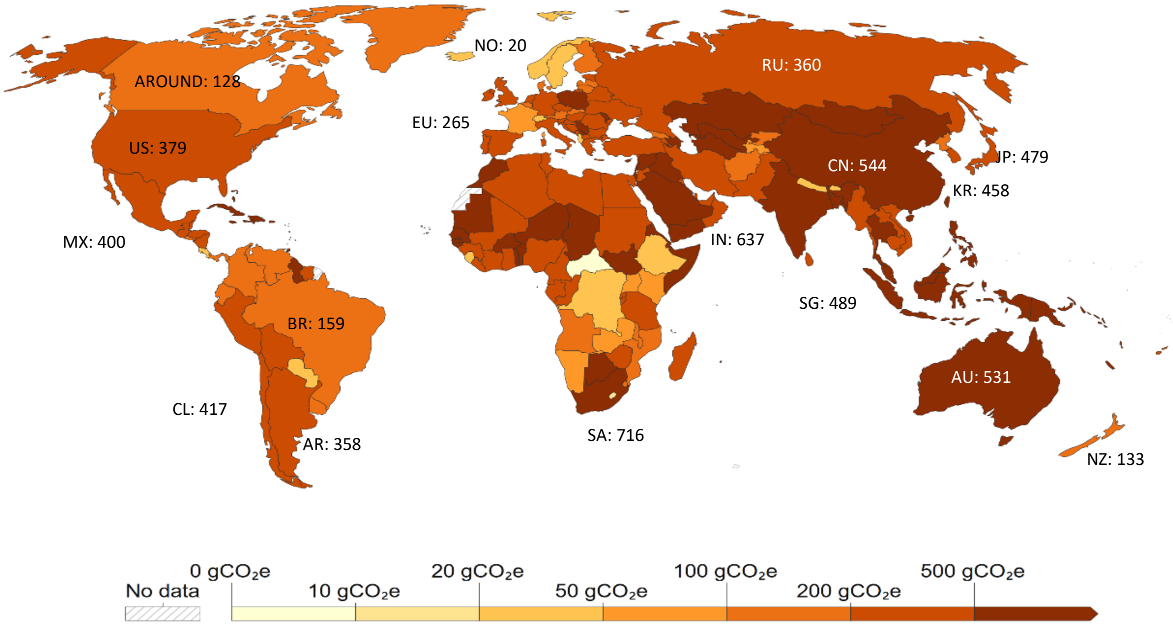


*Figure 11: GHG- intensity map for global electricity production from Our world in data, 2022 [↗] based on Ember Climate (from various sources including the European Environment Agency and EIA) .*

Because the footprint is lower than that of a diesel generator and noting the high transmission efficiency compared to the onboard generators, a vessel should connect to shore power when in port. In addition to GHG, this avoids local pollution of NOX, SOX, PM and unburned hydrocarbons.

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## 7.10. Summary and overview

The emission factors well to tank (WTT) and tank to (TTW) wake can be summed up in the following diagram. The percentage printed on top of each bar indicate the change in well to wake (WTW) emissions relative to MGO (e.g. HVO reduces life cycle GHG emissions by 91% compared to MGO).

In the below diagram, note that the fossil variants of methanol, hydrogen and methanol gives higher emissions well to wake than MGO.

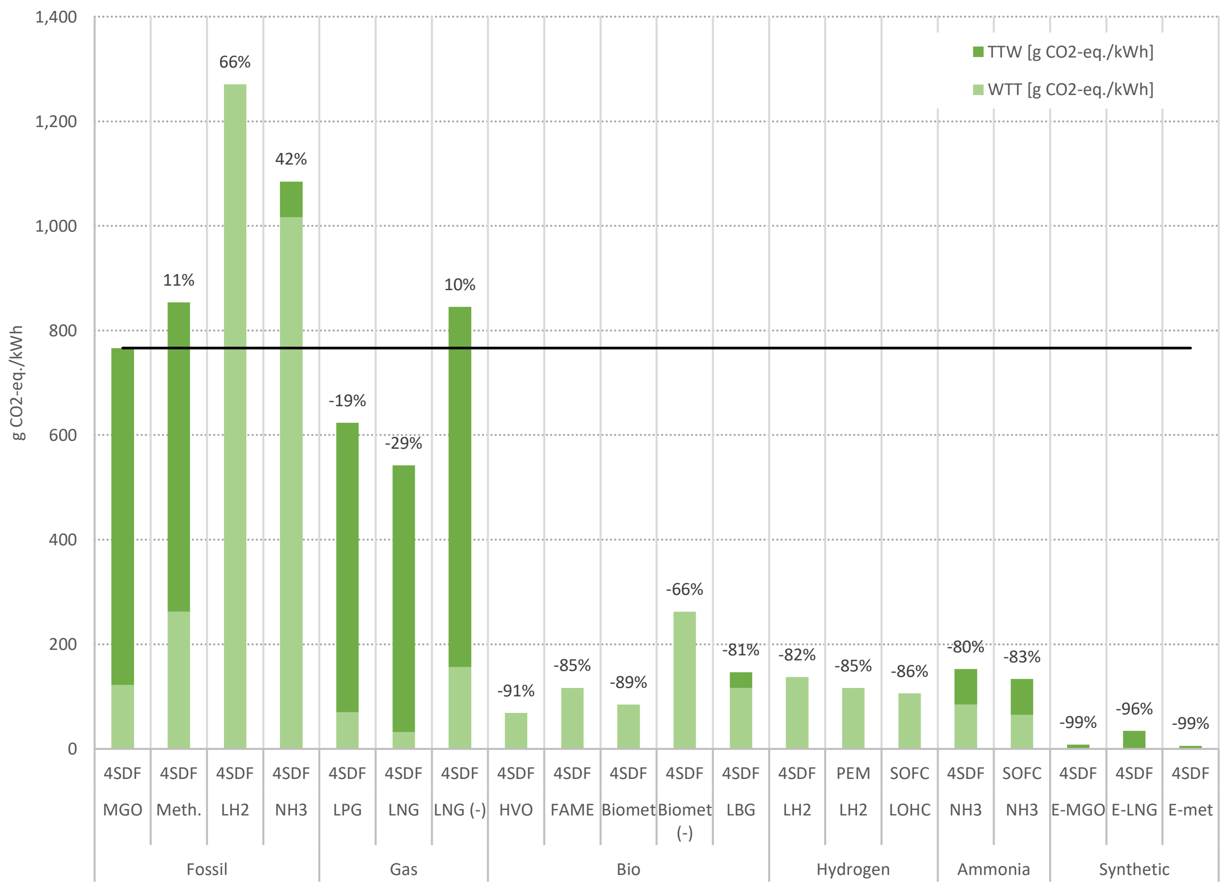


*Figure 12: emission factors for alternative fuels well to tank (WTT) and tank to wake (TTW).*

Some or most alternative fuels are not really produced in any meaningful quantities today and some also rely on relatively novel technology, supporting systems or raw materials. For example, synthetic fuels rely on direct air capture, a relatively novel technology, blue hydrogen and ammonia rely on CCS being scaled up and biofuels rely on access to sustainable biomass. Noting this, we find it reasonable to assume that new fuels will be phased in gradually as the supply side needs time to develop and scale up.

Also, because new fuels will be sparsely available at least in the initial period, a vessel wanting to use alternative fuels may not get access to it everywhere.

## 8. Machinery, systems, tanks, competence and other practical aspects

In this chapter, we will review the technical aspects of the fuel transition. Many pieces in the puzzle will be developed as part of the first pilot projects and we must therefore wait a few years until the equipment and systems reach the same level of maturity as LNG. This means more cumbersome design work and approval process according to the alternative design principle.

In this study, we focus on the key components; engine or fuel cell, tanks and systems.

The lower heating value (LHV) and density together with the thermal efficiency of the machinery determine the specific fuel oil consumption and the flow rate. Below, the left diagram indicates the specific fuel consumption [g/kWh] for various alternative fuels. The right diagram indicates the daily fuel oil consumption for various alternative fuels relative to MGO; e.g. if a vessel consumes 1 t/d MGO, the same vessel will need just above 2 t/d of ammonia or methanol. Both diagrams are based on the same engine thermal efficiency (η = 0.425).

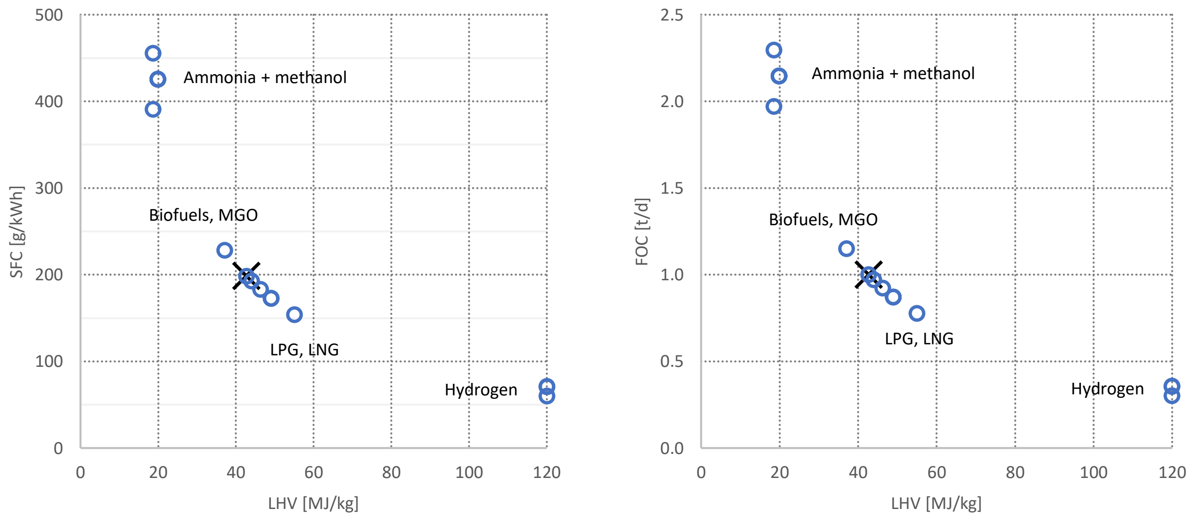


*Figure 13: Specific fuel consumption (left) and flow rate (right) as function of fuel's lower heating value (LHV). Note the signifiant increase for ammonia and methanol due to lower heating value.*

## 8.1. Liquid fuel oils

New liquid fuel oils such as biodiesel and other liquid biofuels generally pose no or few new requirements to the machinery and systems. Many engines can use biofuels without modifications. Biofuels can be labelled B100 as pure biofuel or blends as e.g. B20 where the number indicates the share of biofuel (NB: by volume, not energy).

### 8.1.1. Machinery

Generator sets based on four stroke engines (4S) are the de facto standard for offshore vessels. Some have dual fuel engines (abbreviated 4SDF). Medium speed (750-900 rpm) variants power PSV, AHTS and CSV while high speed (1,200-1,800 rpm) engines are also common for platform supply vessels.

Diesel fuel has very beneficial properties in terms of energy density, stability and safety. The diesel engine has also been developed and optimized over more than a hundred years and has a proven track record on thermal efficiency and reliability.

| | | | |
|---|---|---|---|
| Flash point<br>> 60°C | Flammable range<br>0.5-7% | LHV<br>42.7 MJ/kg | Storage<br>Hull tanks, ambient cond. |

Most modern machinery is approved for some biofuels, though certain adjustments must be made or precautions taken after consultation with the engine maker considering the specifics of the particular engine.

FAME (Fatty Acid Methyl Ester) has physical properties similar to those of conventional diesel. It is non-toxic and biodegradable. Because FAME contains more oxygen, $NO_X$ emissions can increase (typically by 10-20% [Wärtsilä]), and a new EIAPP-certificate is likely necessary. FAME has a lower heating value than MGO, around 37 MJ/kg.

HVO (Hydrotreated Vegetable Oils) can be made fully compliant with distillate marine fuels (ref ISO8217) [Goodfuels] and thus easy to use in a diesel engine. HVO has higher heating value than MGO due to its higher fraction of hydrogen; around 44 MJ/kg.

In terms of cost, generator sets for offshore vessels based on medium or high speed four stroke engines costs in the region of 400 USD = 4,000 NOK/kW. We do not see any reason for a cost penalty if the engine specification shall include biofuels, except perhaps due to additional shop test and emission measurements and certificates.

The thermal efficiency will vary between the engine types. High speed engines have lower thermal efficiency, e.g. around 0.40 [Cat 3516C] than medium speed engines, e.g. 0.43-0.47 [Wärtsilä W31, W26, W25, W32]. To reflect the lower efficiency at part loads, energy consumption is calculated based on η 0.425, corresponding to 198 g/kWh with MGO and 173 g/kWh with LNG.

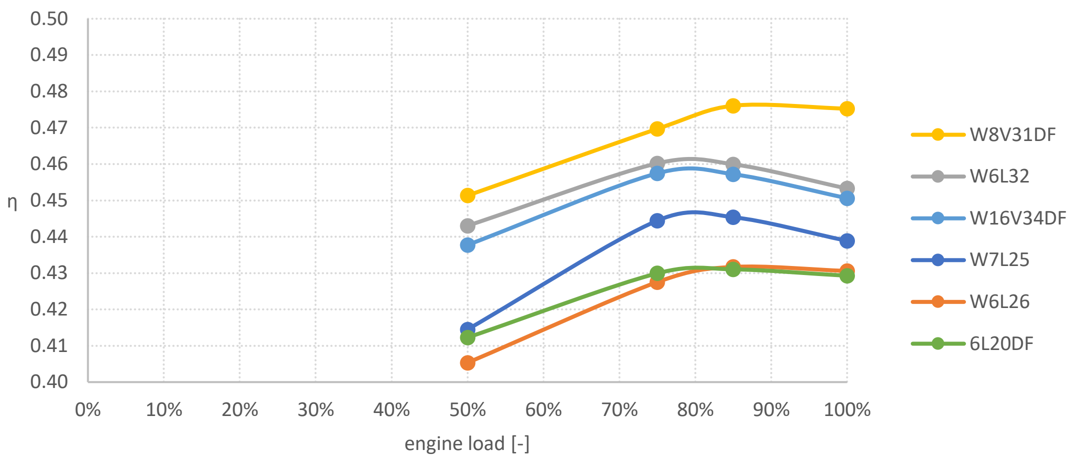


*Figure 14: Thermal efficiency of various Wärtsilä engine options.*

### 8.1.2. Storage and fuel supply and treatment systems

Liquid fuels including biofuels and synthetic diesel is stored in hull tanks and transferred by standard fuel piping. The major cost element is tank instrumentation: tank level gauges, thermometers, and piping connections with flow meters as necessary. Storage tanks must be arranged at safe distance to the outer hull, as per MARPOL Annex I, Reg. 12A. Fuel oil storage tanks can generally be arranged to utilize the space onboard very efficiently.

Some biofuels will cause microbial activity, typically when water is present in the fuel tank [Wärtsilä].

Biofuels are more susceptible to oxidation and therefore less stable when stored for long periods of time. When oxidized, some derivatives are formed due to degradation and these compounds may contaminate the oil fuel [Komariah et al, 2023]. This must be considered for vessels with quite long port stays and mobilisation before projects.

Some biofuels are also more corrosive than fossil diesel. Tank coating should be considered depending on the biofuel type; generally, this requires epoxy-based coatings while tanks for alcohols can be coated with zinc-silicate [Jotun].

Using biofuels and MGO may require more tanks to keep each batch separate, and also separate service tanks. This has impact on general arrangement and costs.

The tank required for hull tanks is quite simply a function of the specific gravity of the fuel (kg/m$^3$) and the maximum allowed filling level. At 95% filling level and 850 kg/m$^3$, 10 t MGO requires 12.4 m$^3$ tank space.

The cost for hull tanks for MGO and biofuels is a fixed cost per tank rather than a function of the tank size, because the major cost components are the outfitting; tank level gauges, thermometer, piping connections, flow meters. Tank heating, if necessary, is still a function of the volume.

#### 8.1.3. Retrofit

Liquid fuel oils including biofuels and synthetic diesel can be easily introduced on existing vessels. There are no major modifications required, but tank coating can be required for some biofuels. Depending on the number of fuel tanks and the functionality of the current piping system (e.g. segregations, transfer and return lines), additional lines for filling, transfer and supply may be required.

## 8.2. Gas (LNG, biomethane and E-LNG)

Liquid natural gas (LNG) has been used as a marine fuel on LNG carriers since the inception of this vessel type. LNG carriers were powered by steam turbines before four stroke and two stroke diesel engines took over. LNG is also combusted in gas turbines on offshore oil and gas platforms. In 2000, the first LNG-powered ferry, Glutra, was put in service in Norway, in 2003 two offshore vessels (Viking Energy, Stril Pioneer), in 2011 a product tanker, in 2013 two ropax ferries, in 2015 a container vessel and in 2018 a cruise ship.

Today, nearly 40 offshore vessels can run on LNG [DNV AFI], and the fuel is thus well known to yards, designers, shipowners and crew. More than 800 ships with machinery and tanks for LNG are on order, around 40% of the orderbook [DNV ETO 2023].

The fleet of LNG carriers is set to expand as there are 312 vessels on order and 688 active vessels [IGU].

Natural gas is a blend of several hydrocarbon gases; the main fraction is methane ($CH_4$), but also propane, butane and other heavier gases are present. The composition of natural gas varies depending on the reservoir, and the gas is characterized by its methane number. The methane number is an expression of the knock resistance of the gas mix, calculated partly as the fraction of hydrogen to carbon but also including the knock resistance values of each gas constituent. Most fossil natural gas have methane number less than 100 due to the presence of other heavier gases.

#### 8.2.1. Machinery

Natural gas, biomethane and synthetic methane can be combusted in two and four stroke engines. Both pure gas and dual fuel variants exist, with various ignition systems. The basic division is between engines employing the Otto combustion principle where fuel is pre-mixed with air before the cylinder, and engines employing the Diesel principle where fuel is injected directly into the cylinder.

Pure gas engines use spark ignition and the properties of natural gas lends itself towards high air/fuel ratios – so called lean burn. This leads to high efficiency and very low emissions of $NO_x$.

In dual fuel (DF) engines, the gas is premixed with air and compressed in the cylinder while the liquid fuel is directly injected either into a pre-chamber or the cylinder itself. DF engines can normally run on 100% liquid fuel. Approximately 80% of the gas engines installed have dual fuel capabilities [DNV AFI], which increases the operational flexibility and geographical operating area of the vessel.

Biomethane can be blended with fossil LNG; this has been demonstrated on e.g. large container ships or CMA CGM (IGU].

| Flash point | Flammable range | LHV | Storage |
|---|---|---|---|
| -188°C | 4-14% | 49 MJ/kg | Cryogenic and around 4-9 bar |

Only four stroke engines are relevant for offshore vessels. Many are available in dual fuel versions for methane, and many have a long track record. There is still research and development work going, especially to improve the thermal efficiency and reduce the methane slip.

DF gas engines still cost around 25-50% more than their diesel counterparts according to our consultation with makers and 50-100% more according to the literature [e.g. Baldi et al, 2019, Korberg et al, 2021]. We set the cost to 500-600 USD = 5,000-6,000 NOK/kW in our economic analysis.

### 8.2.2. Storage and fuel supply and treatment systems

Methane is carried in liquid form to maximize the energy density. While several different containment systems exist for LNG as a *cargo*, pressure vessels dominate for LNG as a *fuel*. The major advantage is the handling of pressure build up due to boil off from temperature increase and thus longer holding time. This is indeed important for offshore vessels which spend much time in port and operate at low intensity in standby.

LNG is cryogenic at -163 °C and requires special materials for tanks and piping. Due to fire and explosion risk intrinsically safe electrical equipment (EX) and double walled piping with purging and ventilation arrangements are also required.

Consultation with makers and review of other sources and case studies suggest a cost of 5 NOK/kWh equivalent to 30,000 NOK/$m^3$ LNG. The variation is significant, with higher costs for smaller tank sizes because of the fixed cost for the tank space / cold box, interface, bunkering station, venting etc.

Novel concepts based on box-shaped tanks are developed by Norwegian companies such as LNT (Drammen, Singapore) and Lattice Technology (Oslo, Korea) as well as GTT (Paris). The key advantage offered is better volumetric efficiency: these concepts typically utilize approximately 0.80 of the tank compartment compared to 0.30-0.50 for cylindrical pressure vessels.

### 8.2.3. Retrofit

A conversion from MGO to methane (LNG, biomethane and synthetic LNG) is possible but expensive. Modern engines can be converted, or new engines can be fitted. The need for double walled piping may make pulling of piping in the engine room complicated.

An LNG-tank requires much more space than conventional MGO-tanks and thus the endurance will be reduced unless tanks can be arranged under or on deck without competing with cargo for space.

## 8.3. Methanol

In 2016, the Norwegian tanker Lindanger was the first ocean going vessel to use methanol as a fuel and methanol did not receive much attention as a possible fuel until very recently. Now, however, approximately 150 ships with machinery and tanks for methanol are on order, around 8% of the orderbook, compared to just nearly 30 vessels in operation [DNV ETO 2023].

Methanol has, together with LNG, an advantage over the other fuels in that they are included in the IGF code while ammonia and hydrogen require case-by-case approval according to the alternative design principle.

### 8.3.1. Machinery

Methanol is already carried by platform supply vessels as a cargo and the handling of methanol is thus known to the crew onboard. It is also carried as a cargo by large methanol tankers, so there is operational experience amongst officers, class surveyors, maritime authorities and construction and dry-docking yards.

Methanol can be combusted by both four stroke, medium and high speed, as well as two stroke engines. Engines for methanol are already on the market and being installed in new vessels, from multiple makers (Wärtsilä, ABC, MAN) and under development by others (Cat and others). Engine makers will generally start with one engine model and extend the range on demand.

| Flash point | Flammable range | LHV | Storage |
|---|---|---|---|
| 11-12°C | 6-36% | 19.9 MJ/kg | Hull tanks, stainless steel |

The diesel process with direct, high pressure fuel injection lends itself to combustion of methanol. Ignition requires a pilot fuel, MGO or biodiesel biofuel, around 5-10% of the energy depending on engine load for four stroke and less for two stroke engines. R&D is ongoing to reduce the amount of pilot fuel as much as possible. Some engines have common rail fuel injection. With high pressure direct injection, the thermal efficiency is on level with a diesel engine. With port injection, the share of methanol will be smaller.

Existing engines can be converted, as demonstrated by the Sten Germanica retrofit project in 2015. The lower heating value of the fuel means a larger volume must be injected for the same engine power, thus requiring different injectors. Methanol four stroke engines are available today and more engine models, including high speed variants, will become available in the few years ahead.

Methanol engines need more instrumentation and have more complicated fuel injection thus leading to 50-75% higher engine costs; i.e. around 600-700 USD = **6,000-7,000 NOK/kW**. Some sources put the cost to just 10% above MGO. We will likely see significant cost reduction with scale, especially on the operation and maintenance side, where scale is perhaps even more important. In the long term, engines for methanol can be priced similar as engines for LNG.

### 8.3.2. Storage and fuel supply and treatment systems

Methanol has low heating value relative to its volume, but similar density to MGO. Methanol requires larger storage volume and piping cross section to supply the same energy as MGO; approximately 2.5 times more. This makes retrofitting challenging as there is often little available space in most engine rooms and pipe ducts.

Methanol is a liquid under ambient conditions and can be stored at ambient temperature and pressure. Methanol can be stored in hull tanks. Cofferdams between the methanol tank and neighbouring compartments are not required but may be considered necessary for safety reasons.

Methanol is corrosive and tanks must therefore be constructed from stainless steel or protected by corrosion inhibitors and special coatings if built from carbon steel. Experience from methanol carriers and from carriage of methanol in bulk on offshore vessels provide guidance on materials and maintenance standards.

Methanol is toxic and can be absorbed in the body by skin or eye contact, inhalation or ingestion. Methanol vapour is heavier than air and thus accumulates at deck level and remains in poorly ventilated areas such as corners of the engine room. It must therefore be transferred in double wall piping with leak detection and systems for ventilation and purging.

It dissolves rapidly if spilled to sea water and is biodegradable [LR]. The lethal concentration is much lower for methanol than fossil fuels [Methanol Institute]. Its low flashpoint contributes to increased fire and explosion hazards [LR].

Methanol burns in concentrations from 6-36%. The flame is blue, smokeless and difficult to see in daylight. The liquid and any vapours must be kept away from ignition sources. The fuel tanks should be inerted to reduce explosion risks [LR].

Corrosion protection, double walled piping with suitable valves, instrumentation and monitoring contributes to 50% higher storage costs for methanol, compared to MGO [e.g. Kanchiralla, 2022].

### 8.3.3. Bunkering and handling

Bunkering equipment and practices are much closer to that for conventional liquid fuels as both are liquids at ambient conditions.

Also, the general experience from handling of methanol both on methanol tankers and offshore vessels provide a good basis for handling methanol as a fuel. Offshore vessels are thus better positioned to use methanol than for example container vessels and dry cargo vessels.

### 8.3.4. Retrofit

A ropax was converted from MGO to methanol in 2015. The low energy density means that much larger fuel tanks will be needed if the endurance shall be maintained. Storage tanks for methanol should ideally be stainless steel, but coated tanks are possible.

As indicated by diagram 15, due to the low energy density of methanol, the fuel flowrate must be doubled if methanol shall supply the same power to the engine. This means that fuel pipes between tank and engine must be replaced by much larger piping. This may be difficult, but not impossible, in a small engine room.

## 8.4. Hydrogen

Hydrogen is typically associated with fuel cells but can also be used with internal combustion engines. Land-based storage systems for hydrogen have been around for decades, but not onboard vessels until the launch of the Japanese Susio Frontier in late 2021.

Hydrogen has the highest LHV of applicable fuels for shipping at 120 MJ/kg. It is also the lightest substance we know. This combined means that for practical purposes its volumetric energy density is the lowest of all applicable fuels. Hydrogen is also characterised by a very wide flammability and explosive range (similar to ethylene), while having an extremely low ignition energy at 0.02 mJ. This is 40 times lower than e.g gasoline, and three orders of magnitude lower than diesel.

| Flash point | Flammable range | LHV | Storage |
|---|---|---|---|
| 12°C | 4-74% | 120 MJ/kg | Cryogenic / pressurized / LOHC |

### 8.4.1. Fuel cells

Fuel cells are far from new technology. The principle was first described in 1839, but the first practical application was in NASA's space programmes. Fuel cells have been used in cars since 2015 and also to power rail locomotives. We now see 3 and 4 MW systems being installed in single vessels such as container (e.g. Samskip's newbuild from Cochin shipyard) and cruise vessels (e.g. Nova Silver from Meyer Werft). Global production for all industries was around 2.3 GW in 2021 [E4, Fuel cell industry review 2021].

There are many different types of fuel cells, with different pros and cons. Proton exchange membrane (PEM) is the most mature and common type. It handles load variations better than solid oxide fuel cells (SOFC) but does not achieve the same thermal efficiency. Approximately 64% by number and 86% by power were PEM cells [E4, Fuel cell industry review 2021]. PEM cells require very pure hydrogen (>99.999%), while other types are more robust with regards to impurities.

The advent of fuel cells (PEM) in cars, buses, trucks and forklifts can be important for the possible mass production of fuel cells and subsequent scale effects on production costs. In 2021, only approximately 16,000 cars with fuel cells were built globally; almost doubling from 2020 [E4, Fuel cell industry review 2021]. Corvus is working with Toyota, and this can bring economies of scale to marine applications.

Fuel cells offer a number of advantages over combustion engines: High fuel efficiency, silent operation, and good performance at low loads.

Thanks to no moving parts, fuel cells achieve high reliability and operability and low operating and maintenance costs compared to rotating machinery [Shakeri et al, 2020]. The need for multiple stacks, the balance of plant (auxiliary systems necessary for the operation of the fuel cell) and advanced power electronics means that fuel cell systems are complex. This may affect the need for maintenance.

Fuel cells offer high energy efficiency; 0.35-0.60 [Shakeri et al, 2020] though the exact thermal efficiency in marine applications have not been demonstrated over time. A 6 KW solid oxide fuel cell achieved 0.61-0.67 efficiency in tests in 2023 [Alma, 3 July 2023]. A fuel cell performs better at lower loads, e.g. at 50-70% of max load. Utilization of waste heat from high-temperature cells is likely factored in when efficiencies above 0.60 are proposed. All taken into account, after consulting literature and makers, we believe η 0.45-0.50 is realistic.

On the negative side, fuel cells and SOFC in particular, do not handle rapid load variations well and should be used in tandem with batteries or other energy carriers to meet offshore vessel's requirement for instantly available power reserve when on DP and handle power fluctuations when working. While many/most offshore vessels have batteries already, a move to fuel cells will likely require larger battery packs.

Although we see shipboard installations, fuel cells are still immature and under development. To quote *The fuel cell industry in review, 2021*: "How much does a fuel cell cost is still a tricky question to answer though… prices vary dramatically by fuel cell type and system need". It is perhaps misleading to make an economic evaluation based on today's prices; yet it is risky to base it on future price indications as well.

Hydrogen Europe has set the following target prices for fuel cells: 1,500 EUR/kW in 2024 and 1,000 EUR/kW in 2030 [Hydrogen Europe, SRIA]. We believe these goals are not yet reached.

While the literature often says 1,000-2,000 USD or EUR/kW, indications from makers today suggest approximately 2,000 USD or EUR/kW. Thus, we assume around 2,000 = 20,000 NOK/kW for the first commercial installations for PEM.

There is also uncertainty regarding the lifetime of fuel cells; if they do not last the full lifetime of the vessel, the investment must be taken more than once.

### 8.4.2. Internal combustion engines

Hydrogen has very high energy content per mass and a high flame speed. Hydrogen can be fed to diesel engines, in fact there are medium speed four stroke engines commercially available today. The major engine makers are all developing their four stroke engines to run on $H_2$. There are certainly challenges, such as the fine tuning of the combustion to balance efficiency with maximum combustion pressure levels and $NO_X$ formation.

Interestingly, some existing LNG DF engines can blend in up to 25% hydrogen [Wartsila], and H2 ratios up to 40 and 60% have been tested [Bergen Engines, 2021]. This opens up the door for an early transition. Not only will the hydrogen cut the $CO_2$-emissions pro rata, it will also have an advantageous effect on the methane slip.

Gas turbines can burn 75% hydrogen today [GE], though the thermal efficiency of these ($\eta \approx 0.38$) make them less attractive for most ships except special applications where light weight is essential.

Hydrogen was thought to be applicable for four strokes only, but just this year, J-Eng announced efforts to develop a two stroke engine for hydrogen based on a gas engine [J-Eng]. While this may seem irrelevant for the offshore sector, it can help to advance the hydrogen case overall.

Hydrogen four strokes are thought to be twice the price of conventional diesel engines; 700-900 EUR/kW = 7-9,000 NOK/kW.

### 8.4.3. Storage: Pressurized, cryogenic/liquid and LOHC

The energy content is high per mass, but very low per volume. Hydrogen thus requires a lot of space for storing. The density increases from 0.090 kg/m3 at ambient temperature and pressure to 23 kg/$m^3$ (250 x) at 350 bar to 70.8 kg/$m^3$ (approximately 800 times) as a liquid at -253°C. This explains the need for high pressure or cryogenic storage.

Hydrogen can be stored in at least three different ways, and we see research and development in even more ways to store hydrogen, e.g. on the surface (adsorption) or within (absorption) of metals and chemical compounds. Combinations of pressure and temperature can also be used, so called cryo-compressed tanks with temperatures from -120 to -196°C.

Some ship designs have reached the stage of approval in principle, primarily based on pressurized containment systems. Only two vessels have been built with $LH_2$-storage: the Norwegian ferry Hydra and the Japanese $LH_2$-carrier Susio Frontier.

LNG-tanks provide a good basis for design and sizing and cost factors for liquid $H_2$-storage, though the insulation must be substantially improved to cater for the extremely low storage temperature.

The most mature tank concept is pressure vessels, from 250 to 500 bar. Land-based vehicles use tanks for 700 bar, but this is not feasible for large volume tanks. Containerized solutions are developed with long cylindrical tanks stacked to maximise the capacity within the container frame. This allows quick recharge of a vessel by lifting drained $H_2$-containers off and charged $H_2$-containers onto the vessel. The capacity depends on the pressure: from 7 to 14 kg $H_2$/$m^3$ at 250 and 500 bar respectively [Umoe composites, Xperion, Hexagon]. A 20 ft container can take 350-500 kg hydrogen. The same or a bit better energy density can be expected if the pipes are fitted inside the hull. This is just 1/5 of the energy that the same container can take if built for compressed natural gas (CNG).

While the tank concept is mature, the number of tanks and not least the number of valves and connections and instrumentation can pose a challenge if the required total tank volume is high. Pressurized hydrogen will naturally leak through tank walls due to the small size of the hydrogen gas molecule. This limits tank holding times to less than three weeks.

The highest energy density is achieved with liquefied hydrogen stored at -253°C. Liquefied hydrogen has been used as rocket fuel and stored on shore and transported by barge, typically in spherical or cylindrical tanks with vacuum and panel insulation [Kawasaki]. Though the technology is mature, only a fraction (500 t / 94 Mt = 0.0005%!) of the global $H_2$-production is liquefied [IEA, Global hydrogen review 2022, p. 132]. The majority of the liquefaction capacity built was intended for NASA.

Capital cost for liquefaction plants is high and so is the energy demand and thus operating cost. Around 12-15 kWh/kg $H_2$ is needed to liquefy hydrogen, equal to 37-45% of the LHV. R&D indicates that a better process can halve the required energy for liquefaction, but this has yet to be shown at scale [Van Hoecke et al, 2021].

The first shipment of liquefied hydrogen took place in February 2022, from Australia to Japan. The ferry Hydra is also in operation. This demonstrates that concepts for cryogenic storage are working, but not yet shelf ware. The very low temperature is an obvious challenge. Cooling down the tank before first loading takes time and this procedure must be repeated after docking and repairs requiring gas free vessel. To maintain the low temperature, around 20% of the tank volume must be filled at all times, thus the useful capacity is only 80% of the tank volume.

At these temperatures, some hydrogen will boil off and increase the tank pressure. Tank holding times beyond two weeks require re-liquefaction onboard, which normally is cost-prohibitive.

Cryogenic tanks for LNG and $LH_2$ as fuel generally comes as pressure vessels, though novel concepts with box shape to improve the volumetric efficiency are under development.

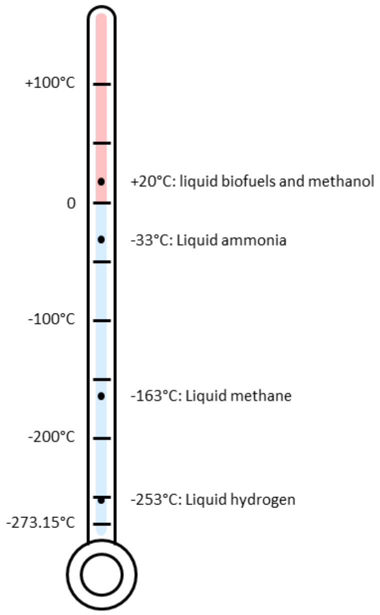


*Figure 15: Storage temperature for hydrogen vs. the other alternative fuels.*
*(Note that these fuels can be stored under pressure as well).*

The third option for storing $H_2$ is absorbing it in an organic liquid (e.g. dibenzyltoluene) known as LOHC. The liquid can be stored in conventional tanks and has handling characteristics similar to heating oils. This makes handling easier and safer and reduces the required storage volume, although another storage tank for dehydrogenated liquid is required.

The hydrogen is extracted from the liquid before it is fed to a fuel cell or engine. This minimizes the volumes of pure $H_2$ onboard and thus the risks associated with $H_2$. Dehydrogenation; the extraction of hydrogen from the organic liquid is an endothermic process requiring approximately 10 kWh/kg [Hydrogenious, Van Hoecke et al 2021]. This is both for heat (250-300 °C) and pressure (30-50 bar). Some of the required heat may be taken from waste heat flows to alleviate the high energy requirement for dehydrogenation. Because of the need for heat, LOHC is best combined with SOFC which operates at 600-900°C [Hydrogenious]. Nonetheless, the use of LOHC incurs an additional energy loss to the overall energy system onboard.

The liquid can be stored in ordinary hull tanks at ambient temperature and pressure. In addition to tanks for hydrogen-charged liquid, an additional tank for drained liquid is required. With e.g. four storage tanks, the tank space requirement thus increases by 25%. The organic liquid weighs around 900-1,000 kg/m$^3$ and stores around 54 kg $H_2$/m$^3$ [Hydrogenious].

The extracted hydrogen must meet the purity required by the fuel cell; the need for very pure $H_2$ for PEM fuel cells is another argument or combining LOHC and SFOC.

LOHC is selected for a wind service vessel, yet the makers say the technology is at TRL 5.

As the smallest atom, hydrogen escapes easily and even permeates through material. Double walled piping is necessary with adequate systems for gas detection, shut off and purging. Sparks, high temperature surfaces and ignition sources must be avoided. Leakage from compressed storage will normally disperse quickly, but there are cases (e.g. the explosion in Sandvika, Norway, June 2019) where hydrogen leaking from a 900 bar reservoir accumulated in open air with subsequent ignition and explosion. Cryogenic hydrogen will accumulate in a pool before eventually boiling off and dispersing. The extremely low temperature of liquid hydrogen means that the air molecules become solids and thus no buoyancy is available to disperse the cold hydrogen gas initially.

When it comes to volume, weight and cost, we use LNG-tanks as basis and add a cost factor for the novelty and uncertainties pertaining to $LH_2$. The first projects will be very expensive, and this is reflected in the factor of 100; it is difficult to find or assume a cost that is representative for future projects at the moment. Indications from makers and literature suggest 20-100 NOK/kWh equivalent to 50,000-200,000 NOK/m$^3$ $H_2$. This is approximately 50-100 times the price of LNG tanks and systems.

Pressurized tanks are cheaper: around 100 NOK/kWh = 75,000 MNOK/m$^3$ $H_2$ [Zenith]. Pressurized tubes are not a solution for large volumes of hydrogen.

### 8.4.4. Retrofit

Hydrogen cannot easily be introduced to an existing vessel.

If the vessel is fitted with gas engines, hydrogen can be used in a moderate ratio (e.g. up to 25-40%) provided that the engine can be fitted with a fuel supply system. New nozzles are required for higher ratios of hydrogen.

A fuel cell covering a part of the total installed power is another option. Such systems can be arranged in a containerized solution but will likely not cover a large portion of the energy demand.

Double walled piping requires more space. A hydrogen tank requires much space onboard and careful positioning. Voids/cofferdams are required and proper venting and purging systems. The safety challenges with hydrogen will likely require the use of deck space for tanks and the use of compressed hydrogen.

The most realistic option for retrofit use of hydrogen is through LNG/hydrogen-blending or fuel cells for part loads.

## 8.5. Ammonia

Ammonia is a colourless gas with a characteristic smell that makes it possible to smell even a very small leak, even at concentrations that do not constitute a health risk [ABS]. It is highly toxic in concentrated form; In low concentrations, ammonia can be irritating to the eyes, lungs, and skin and be immediately life threatening at high concentrations or through direct skin contact.

Ammonia has narrow flammability range (15-27%) and high ignition energy (8 mJ; milli joule). It also has high heat of vaporization and a high auto-ignition temperature. All this combined leads to low combustibility as a fuel.

Ammonia will corrode nickel and copper found in seals, gaskets, valves and electrical components; this puts special requirements to the materials used in engines, storage tanks and piping.

Among ships on order, there are nearly 60 vessels being *prepared* for a later possible conversion to ammonia, so called ready-notation [DNV ETO 2023].

### 8.5.1. Engines for ammonia

In terms of combustibility, ammonia is quite the opposite of hydrogen. Kaj Portin, Wärtsilä, explains: "Whereas with hydrogen you have high combustibility, and fast flame speeds at stoichiometric ratios, ammonia does not burn very well and slows down the combustion process at higher concentrations" [Motorship, May 2020].

Ammonia has poor combustion characteristics and relies on larger volumes of pilot fuels than other alternative fuels. When used in Otto cycle engines there is the same issue with slippage of unburned fuel as for LNG/methane. High pressure injection, Diesel cycle, helps to minimize or eliminate ammonia slip and thus the health and safety risk for people onboard and near the vessel. Ammonia has also low viscosity, with subsequent requirements to lubrication oils.

The slow combustion of ammonia will emit much $NO_X$ from the nitrogen in the fuel ($NH_3$) and likely require SCR to meet Tier II emission limits, and certainly to meet Tier III.

The long quenching distance also leads to incomplete combustion and the formation of unburnt ammonia in combustion chamber crevices [Motorship, May 2020]. The level of $N_2O$ in the exhaust is not yet known and much research and development must go into this as only 1 g/kWh will destroy the climate effect of ammonia. At 2-3 g $NO_2$/kWh, the entire climate advantage over diesel is cancelled.

| Flash point | Flammable range | LHV | Storage |
|---|---|---|---|
| -33°C | 15-27% | 18.6 MJ/kg | Refrigerated / pressurized |

Considering the poor combustibility of ammonia, slow speed, two stroke engines with high pressure direct injection will likely be a good concept to achieve high efficiency, complete combustion and low ammonia slip. But also four stroke engines are developed for ammonia by several makers; Wärtsilä, Bergen Engines, MAN and Japan Engine Corp. Slow combustion rate means that ammonia will likely be difficult for high speed engines [Cat].

Test engines are running in various laboratories today and will be commercially available within a year: Many medium speed four stroke engines are planned from several engine makers over the next few years. Engine makers will generally start with one engine model and extend the range on demand.

For safety reasons, there is a safety zone 500 m around offshore installations and above critical bottom equipment. Vessels operating within this zone need to keep 50% available power in reserve to fulfil the requirements for DP-operations within this safety zone. Typically, this means that each generator set must run at low loads below 50% and at these low engine loads, current test results show there will be a need for a significant amount of MGO as pilot fuel. This may mean that ammonia cannot be used when in DP. This possible incompatibility must be clarified by the makers once the engine development has progressed. Using hybrid systems including batteries that may function as spinning reserve may alleviate this, as may future technology innovation.

Although it may seem too much of an uphill battle to amend the safety and redundancy requirements, we would like to comment that a major overhaul in one area (i.e. fuels) will likely require adjustments in other areas such as shore side infrastructure, operations, contracts and also rules and regulations including redundancy requirements. The required redundancy can perhaps be provided by large batteries.

### 8.5.2. Ammonia and fuel cells

High temperature fuel cells are more robust with better tolerance for impurities in the fuel supply. Solid oxide fuel cells (SOFC) can take ammonia directly while PEM-cells require a cracker to convert ammonia to $H_2$ before the cell in addition to a purifier or filter

SOFC generally achieves higher efficiency but has poor transient performance and rely, even more than PEM cells, on batteries to handle load variations. A 6 KW solid oxide fuel cell achieved 0.61-0.67 efficiency in tests in 2023 [Alma, 3 July2023]. The high operating temperature means that high quality waste heat will be available and high temperature fuel cells are thus a good match with LOHC.

SOFC are still a few years away from a commercial product and the equipment cost is thus not clear. The below capex roadmap by one maker (Almas) illustrates this well. Today, we put the price at 6,000 EUR/kW = 60,000 NOK/kW for SOFC.

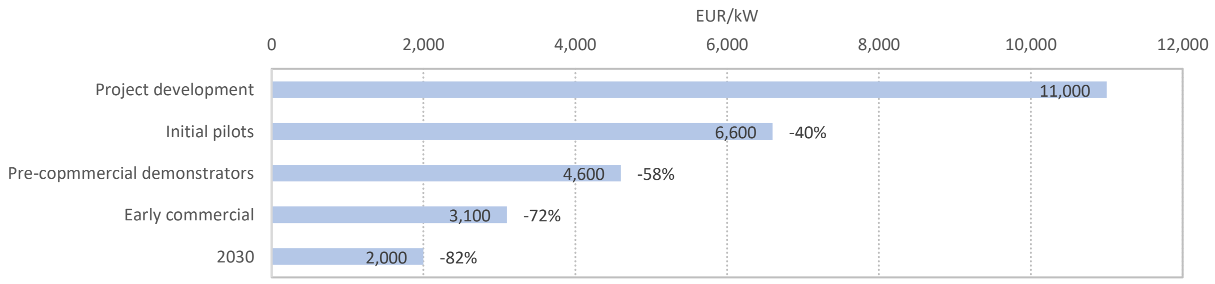


*Figure 16: Capex roadmap i.e. expected development in capex with R&D, learning and scale [Alma clean power]*

A high temperature cell responds even slower than a PEM and we assume that a larger battery pack is required to handle the need for immediate ramp-up that is so important for offshore vessels.

### 8.5.3. Storage

Ammonia can be stored in liquid form at 8.6 bar and at ambient temperature (20°C) or cooled down to -33°C. Liquefaction by cooling is considered safer [Wärtsilä], yet pressure vessels are needed also for cooled tanks.

Both cylindrical pressure vessels (Type C) and prismatic tanks can be used. Pressure vessels for liquid ammonia reduces the boil off rate and need for reliquefication but have a higher capex. The LNG tanks that can be used for ammonia are limited to those that are constructed from stainless rather than the more commonly used nickel alloys, based on the risk of corrosion.

Since ammonia is corrosive to copper, copper alloys, alloys with a nickel concentration larger than 6% and plastic, these materials must be avoided in the fuel system. Special materials must be used in pipe gaskets as well as engine sealing rings [MAN, 2019].

We consider Type C tanks to be the most mature tank type for ammonia, although new tanks concepts based on box construction are thought to be cheaper, and utilize the underdeck space better, but more relevant for larger tank volumes [LNT]. The space requirement also speaks in favour of box shaped tanks.

Compared to LNG tanks, the material specification for ammonia will be higher while the insulation requirements will be relaxed. We assume the same cost per volume as for LNG; 30,000 NOK/m$^3$; equal to 7.5 NOK/kWh.

### 8.5.4. Retrofit

As indicated by diagram 13 and 19, due to the low energy density of ammonia, the fuel flow rate must be doubled in order to supply the same power to the engine. This means that fuel pipes between tank and engine must be replaced by much larger piping. This may be difficult, but not impossible, in a small engine room.

Due to its toxicity, additional barriers to avoid leaks that spread and contaminate engine rooms, control rooms and other nearby compartments must be introduced, and this complicates a change from MGO to ammonia on existing vessels. Current class requirements to emissions of ammonia to ambient air may also prohibit retrofit.

## 8.6. Batteries

Batteries cannot power the entire vessel based on current battery chemistries. Batteries can however play a valuable role to improve the specific fuel consumption of combustion engines by using batteries for peak power and also to recover kinetic energy from winches and cranes. We can therefore discuss batteries as energy carriers and energy saving technology.

### 8.6.1. Batteries as energy carrier

If powered only by electricity from batteries, a PSV with approximately 1,500 kW shaft power and 7 days endurance will require a 250 MWh battery ($1.5 \cdot 24 \cdot 7$ MWh). This will cost around 1,500 MNOK and the battery will occupy approximately 6,000 m$^3$ which requires the vessel to be lengthened by around 60 m. With today's battery technology, batteries as the only energy carrier onboard is unrealistic.

Batteries can still be used as energy reserve onboard to enable low load operations for extended periods of time, for providing high power spinning reserve for shorter periods and for other tasks covering part of the energy and/or power requirements onboard.

It is important to distinguish between batteries for power and batteries for energy, as they need different chemistries and have different operating characteristics. These different types of batteries are not interchangeable. Using a power battery for energy through deep discharge will permanently damage the capacity and reduce lifetime. See key figures for power batteries vs. energy batteries in table 4 below.

### 8.6.2. Batteries for energy saving

But batteries and electricity can contribute to reduced energy consumption and emissions in offshore vessels in many ways.

First, shore power can take the energy demand in port. The operation profile suggests that this can cover 2-12% for PSV, 11-15% for AHTS and 8-16% for CSV (ref figure 6 in chapter 5.6).

Second, batteries can contribute to peak shaving and provide power margin so to allow the gensets to run at a better engine load factor. Both of these effects apply to vessels with gensets regardless of fuel.

Third, larger batteries are needed for vessels powered by fuel cells to avoid large transient loads that will affect fuel cell capacity and longevity. This is especially the case for SOFC, but batteries are also necessary for PEM. Therefore, we assume that the battery installation must be doubled for PEM and tripled for SFOC compared to the battery size installed in a vessel with combustion engines. A detailed study of this seems prudent and we expect that AHTS and CSV will need larger battery packs than PSV considering the intense work they undertake.

This adds to the cost of the vessel and require a larger battery room. The necessary volume is estimated based on 88 kWh/m3 battery [Corvus] and a battery room twice the size of the battery pack [TBC]. E.g. a 1,000 kWh battery measures 11.4 $m^3$ and requires a room with 22.7 $m^3$.

| | *High power* ← | | → | *High energy* | |
|---|---|---|---|---|---|
| *Battery type* | *Orca Energy* | *Dolphin Power* | *Dolphin Energy* | *Blue Whale* | *Range* |
| kg/kWh | 13 | 8 | 5.6 | 9.1 | 5.5-13 |
| Relative to MGO | 77 | 47 | 34 | 54 | 35-75 |
| $m^3$/kWh | 0.011 | 0.013 | 0.010 | 0.008 | 0.008-0.013 |
| Relative to MGO | 60 | 70 | 53 | 41 | 40-70 |

*Table 4: Specific weight and volume for maritime batteries [Corvus].*

The battery cost is approximated to 600 EUR = 6,000 NOK/kWh, after consultation with makers.

### 8.6.3. Retrofit

Batteries and shore power can easily be retrofitted to existing ships, though the cost is much higher than for newbuilds. Batteries will likely play a central role to improve energy efficiency and to support fuel cells and to provide redundancy.

## 8.7. Robust fuel transition strategies

Alternative fuels will be sparsely available only in select ports and in low quantities in the beginning. The high cost of alternative fuels may prohibit full and continuous use and new machinery and systems will likely be less reliable than today's fine-tuned technology. These factors speak in favour of building vessels with capability to run on multiple fuels.

Based on the review of machinery and systems in chapter 8.1-8.5, we see three practical multi-fuel combinations:

1. A vessel built for ammonia can also combust biofuel and synthetic diesel. This combination requires dual-fuel ammonia/diesel engines and double tank systems for ammonia (cooled/pressurized) and conventional hull tanks for MGO, biodiesel or synthetic diesel.

2. The second option is centred around methanol. The vessel can change between biomethanol and synthetic methanol as available and preferred, but also use biodiesel and E-MGO. Methanol requires dedicated tanks. Note that the pathway indicates that there are different types of biomethanol with different climate effect (see figure 12 in chapter 7.10).

3. The third combinations focused on gas. The vessel can start using fossil LNG today and reduce GHG immediately, then use biomethane as much as possible or available. Many gas engines can take blends of hydrogen today and future engines will be able to combine large shares of hydrogen (60-85 -100%). This gives the vessel one low-carbon fuel (LNG) and two climate neutral fuels (biomethane and hydrogen) to play with. Synthetic LNG is also compatible.

Finally, all vessels will likely have capacity for MGO. This guarantees continuous operation worldwide.

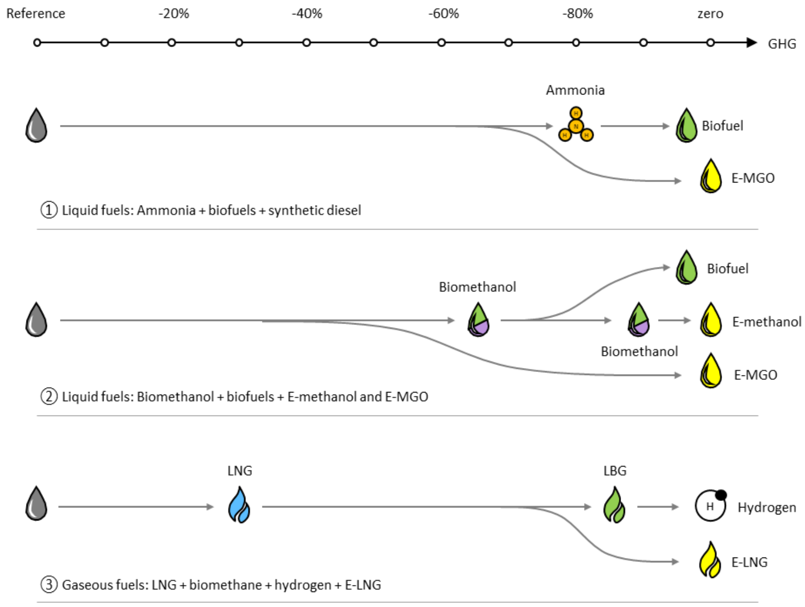


*Figure 17: Fuel transition pathways based on multi-fuel technology.*

We sum up the technology readiness level (TRL) for machinery options and fuel storage solutions for alternative fuels. Note that the below classification is the authors' subjective opinion at the time of writing.

| | |
|---|---|
| Invention | Basic principles observed |
| | Technology concept formulated |
| Concept validation | First assessment feasibility concept and technologies |
| | Validation integrated prototype in lab environment |
| Prototyping and incubation | Testing prototype in user environment |
| Pilot production and demo | Pre-production product |
| | Low scale pilot production demonstrated |
| Initial market introduction | Manufacturing fully tested, validated and qualified |
| Market expansion | Production and product fully operational |

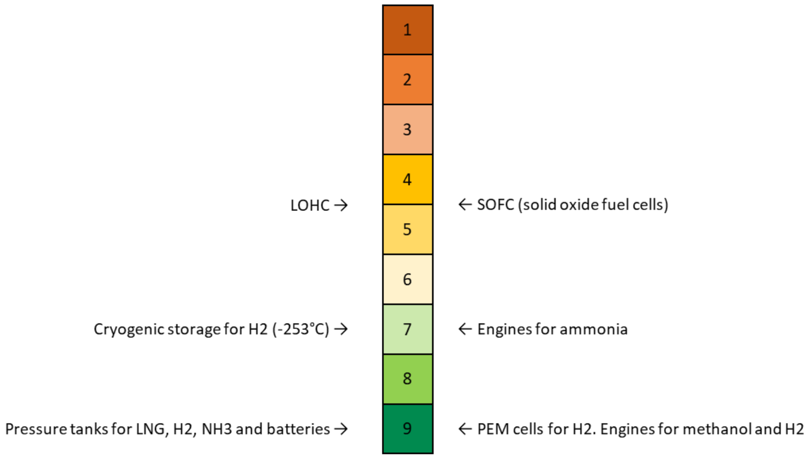


*Figure 18: approximate Technology Readiness Level (TRL) or various technologies for alternative fuels (authors' opinion).*

# 9. Impact on the ship design, main dimensions and general arrangement

Ships are designed primarily around the main function of the vessel, e.g. transportation of cargo or passengers or the service or work to be performed. The design is generally optimized with regards to total cost of ownership (capital cost, operating cost including maintenance, spares, service and manning, fuel cost etc) while meeting requirements to reliability, operability, redundancy, safety and environmental performance.

The machinery configuration is set up to support this and should ideally take as little space and cause as little work as possible. The introduction of new fuels will – unfortunately – change this in many ways as will be detailed in the sections of this chapter.

## 9.1. Endurance and tank compartment size

The biggest impact on the general arrangement is expected to come from the need for larger fuel tank compartments. The tank compartment is determined by two factors; the energy content per volume and the type of fuel storage tank.

Most alternative fuels contain less energy per volume and thus the net tank volume must be bigger. The below diagram indicates the energy content per mass (x-axis) and per volume (y-axis) for the fuel only. Observe that MGO is the most energy dense fuel per volume.

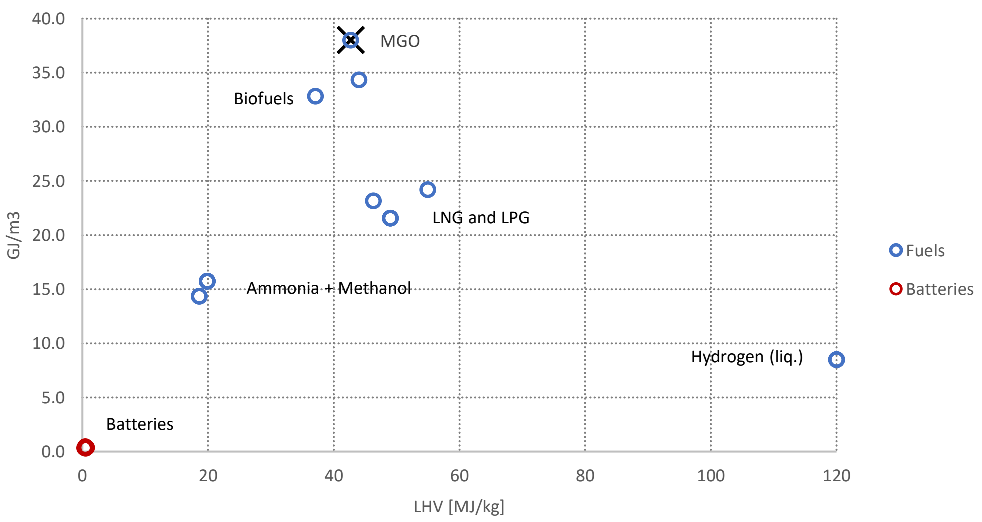


*Figure 19: Energy density per mass [MJ/kg] and volume (GJ/m³].*

In addition to the energy density of the fuel itself, many alternative fuels require cylindrical tanks, some with thick insulation, and cofferdams/voids that adds to the tank compartment space.

LNG, LPG, biomethane, hydrogen and ammonia require pressure vessels that utilize less internal space; only approximately 30%-50% of the tank compartment required (illustrated by figure 20 below). A large tank diameter contributes to improve the volumetric utilization ratio.

Novel concepts based on box-shaped tanks are developed for LNG, $LH_2$ and ammonia by Norwegian companies such as LNT (Drammen, Singapore) and Lattice Technology (Oslo, Korea) as well as in France by GTT (Paris). The key advantage offered is better volumetric efficiency: these concepts typically utilize approximately 80% of the tank compartment [Lattice Technology].

To sum up, most alternative fuels require more space onboard for two reasons: the energy density and specific gravity of the fuel alone (the black line in diagram 20) and also the need for pressure vessels to store them (the red line in diagram 20). Cylindrical tanks have inherently low volumetric efficiency. This is summed up in figure 20 below: The gap between the black and red lines are due to the tank concept.

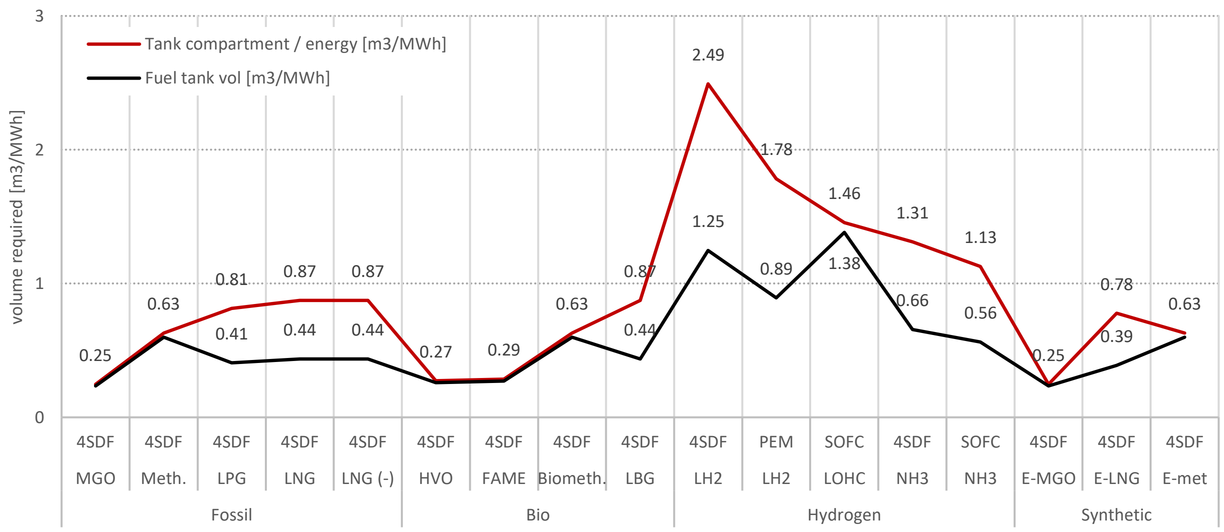


*Figure 20: Space requirement for alt. fuels: without (black) and with (red) effect of tank type. Note that MWh refers to the energy delivered by the engine i.e. taking the thermal efficiency of the engine or fuel cell into account.*

In the figure, the following assumptions are made. Endurance is set to one (1) week for PSVs and four (4) weeks for AHTS and CSVs respectively. The required fuel tank volume (black line) is calculated based on the average power demand and required endurance operating on the alternative fuel plus a margin of seven days on a basic fuel (either MGO or LNG). We calculate the necessary increase in hull length to accommodate the necessary fuel tanks under the cargo deck.

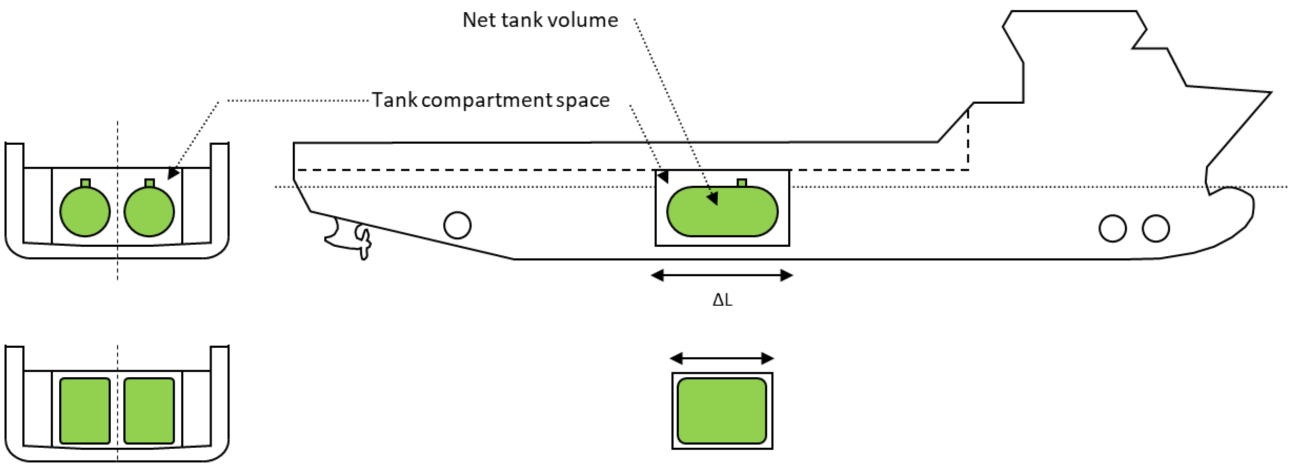


*Figure 21: Increase in hull length to accommodate fuel tanks under the cargo deck, effect of cylindrical vs box-shaped tanks.*

## 9.2. Machinery room arrangement

The transition to new fuels will likely be gradual and require dual fuel or multifuel machinery and systems. This means tanks for (at least) two different fuels. With this comes two bunkering stations, two transfer lines, double set of service tanks and systems for fuel treatment. This means larger engine rooms, fuel compartments and a bit bigger pipe duct.

## 9.3. Machinery and equipment weight and effect on displacement

Doubling of systems and some machinery will add to the weight and displacement of the vessel. This effect is considered to be marginal and of secondary importance and shall be revisited at a stage where the projects have matured.

*Double systems for machinery and fuel→ weight → displacement → T, $C_B$ or reduced dwt. → $C_R$ → power → fuel consumption.*

# 10. Fuel production and supply

Access to alternative fuels is perhaps the most critical factor for their uptake. In 2023, alternative fuels supplied only a negligible share of the energy consumed by ships both globally and regionally. The only fuel with a meaningful share is LNG. There are also some very small volumes of LPG and methanol consumed by LPG carriers and methanol tankers. We note a number of trials with biofuels and orders for new vessels *equipped* or *prepared* for alternative fuels.

Infrastructure is critical to ensure supply of alternative fuels to ports where offshore vessels dock. A study by UCL found that 85% of the costs to decarbonize shipping will likely go into fuel production and infrastructure [UMAS, Carlo et al, 2020].

In this chapter, we will review current, planned and potential production capacity in the near-term future.

Fuel availability can be reviewed at a macro and micro level; it can be available in a region but not in a specific port. For example, LNG is available today in multiple ports around the North Sea but not in Aberdeen which is a particularly important UK offshore base. We will consider a fuel to be *available* even if the last leg in the distribution chain required to make it available in a specific port is not (yet) established.

Offshore vessels operate worldwide and especially construction vessels and anchor handlers are moved depending on demand. Contracts longer than five years are rare. This requires fuel flexible solutions initially, while building sufficient capacities for new fuels in key offshore hubs worldwide.

The North Sea has the highest number of offshore rigs (stationary and mobile) with 14% of the global total followed by the Gulf of Mexico (13%), Persian Gulf (12%), Far East Asia (12%), Southeast Asia (11%) and Mexico (7%) [Rystad Energy, 2018].

Therefore, our mapping of fuel availability looks at the potential or planned capacity worldwide and in Europe and we take a particular look at Norway. While ammonia, methanol and liquid as well as gaseous biofuels are relatively easy to transport as cargo, hydrogen needs to be produced at or close to the bunkering facility.

This study is written to guide first movers in the near future. We therefore focus on the current and planned production capacity for alternative fuels in the near term i.e. the next 5-10 years.

## 10.1. Drivers and barriers for alternative fuels

Unfortunately, the analysis of future availability of alternative fuels is full of reservations. There are no or few reliable and accurate forecasts. Rather, we must rely on the production potential and or political goals or preconditions for production of each of the fuels.

The potential production volumes and availability for shipping are determined by multiple factors:

**Renewable electricity:** Fuels based on hydrogen require significant electricity. Renewable or climate neutral electricity is a scarce resource both worldwide and even in Norway. Building more production capacity takes time and has potential negative implications on nature; possible loss of biodiversity, indirect land use change, massive need for resources (i.e. materials such as steel, cement, copper), carbon release from deforestation and marshland etc. Access to renewable electricity is a very basic precondition and unfortunately, some projects fail to materialize for this reason [e.g NRK ,4 Dec 2023]

**CCS**: Blue fuels can be produced from fossil sources with capture and subsequent utilization or storage of $CO_2$. While this technology is technically quite mature, it is not commercially mature and scaled up. New processes for pre-combustion carbon capture, e.g. methane pyrolysis, are still at the R&D level.

**Sustainable biomass**: Biofuels require access to sustainable biomass and the potential for this is not very well mapped. Many argue that there is not and will not be sufficient volumes of sustainable biomass for biofuels, although some studies conclude that there is potential for much larger production than today and, more importantly, that the raw material basis is very wide and thus complicated to map completely. The potential for using marine biomass for producing biofuels has not been thoroughly mapped.

**Price signals**: The potential for producing new fuels is also, as most things today, a matter of pricing. If prices are high enough and the political will strong enough, new production technologies will typically surface. And conversely; when the price disadvantage of alternative fuels seems too high to overcome by carbon prices etc., prospective fuel producers or their investors may pull the plug and postpone or cancel their plans. We have seen this lately for ammonia production in Sauda and Hammerfest [Ryfylke, 31 Oct 2023, TU, 1 Feb 2023].

**Demand side competition**: We must also expect fierce competition for limited volumes of alternative fuels. This competition will be between sectors and between individual operators. Mærsk's interest in methanol can be a blessing and a curse; with a demand of 6 Mt/y the Danish giant will both drive up production of methanol but also take a large share of the total green methanol produced.

## 10.2. Fuel demand from offshore vessels

Having a clear understanding of the fuel volumes needed for offshore vessels can be useful to see the supply side figures in context. Demand per vessels and for the Norwegian (controlled) fleet (see figure 4 in chapter 5.3) is summarized in the below table. The demand for the offshore fleet reflects the total demand for a fleet of 375 vessels. Fuel demand for seismic vessels is excluded.

This fleet will operate in many geographical regions.

The figures are calculated based on the energy demand indicated in the operation profile of the reference vessels for this study. Efforts to reduce energy consumption is thus not factored in and the below is therefore a conservative estimate.

| | | *(annual fuel consumption per vessel)* | | | | |
|---|---|---|---|---|---|---|
| | | *PSV* | *AHTS* | *CSV* | *Seismic* | *Fleet total* |
| Number of vessels | | 175 | 60 | 140 | | 375 |
| MGO | [t/y] | 2,750 | 5,320 | 5,300 | | 1,540,000 |
| Liquid biofuel | [t/y] | 2,670 | 5,150 | 5,120 | | 1,500,000 |
| Methane (LNG/biomethane/E-LNG) | [t/y] | 2,400 | 5,630 | 4,600 | | 1,340,000 |
| Methanol (fossil/bio/synthetic) | [t/y] | 5,900 | 11,400 | 11,330 | | 3,300,000 |
| Hydrogen | [t/y] | 980 | 1,900 | 1,880 | | 500,000 |
| Ammonia | [t/y] | 6,320 | 12,200 | 12,120 | | 3,000,000 |

*Table 5: Demand for alt. fuels from the Norwegian offshore fleet (metric tons per year).*

## 10.3. Overview: Current global production

Before looking at each alternative fuel, both current production and outlooks, we simply sum up the current production of all fuels and energy carriers irrespective of end user. Note that hydrogen, ammonia and methanol are currently used as industry feedstock and not energy so their use as energy will come in addition to whatever is needed by the current consumers.

The renewable share is indicated where applicable and we note that this is – so far – very small on the border to negligible for biomethane, methanol, hydrogen, ammonia.

| | | *Mt* | *EJ* | *TWh* | *Renewable* | *Source* |
|---|---|---|---|---|---|---|
| Fuel oils | Residuals | 390 | 16 | 4,450 | N/A | BP, 2021 |
| | Distillates | 1,320 | 57 | 15,900 | N/A | BP, 2021 |
| | Liquid biofuel | | | | | |
| Gas | LNG | 410 | 21 | 5,750 | N/A | BP, 2021 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Biogas | 29 | 1.4 | 400 | | Int. Gas Union |
| | Biomethane | 2 | 0.09 | 24 | | Int. Gas Union |
| | LPG | 330 | 15 | 4,200 | N/A | WLPGA, 2021 |
| Methanol | Methanol (fossil/bio/synthetic) | 98 | 2 | 540 | <0.2% | IRENA, 2021 |
| Hydrogen | | 94 | 11 | 3,100 | <1% | IEA, 2022 |
| Ammonia | | 185 | 3.5 | 950 | <0.1% | IFA, IEA 2021 |

*Table 6: Current global production of oils, gases, methanol, hydrogen and ammonia.*

## 10.4. Liquid biofuels

Liquid biofuels include ethanol, biodiesel (FAME) and HVO. Bioethanol is produced primarily in the US and Brazil from glucose-based feedstocks (sugar) while production of other biofuels is spread between countries and regions because they can be produced from a number of raw materials: rape seed, palm oil, sunflower oil, soybeans, sugar beet and sugar cane, corn/maize, wood and black liquor as well as waste products from fishing and farms.

In 2022, a total of around 0.3 Mt biofuels was bunkered in Singapore and Rotterdam, equal to around 0.1% of total maritime fuels that year [DNV, 22 June 2023].

The estimates for future production potential differ between the sources. Some of the discrepancy between sources can be explained by the type of raw materials included and the type of technology assumed available. The scope of raw materials is limited by technical, practical and sustainability factors. From the below diagram, we can conclude that there will be 150-370 Mt biofuel in the EU in a decade or two and that the potential worldwide is quite significant. The question is perhaps not whether there is potential for producing biofuels but just how sustainable and economical they are and also how competition for them will be. E.g. a common concern is that aviation will take whatever is produced and that biodiesel will be popular as drop-in fuel.

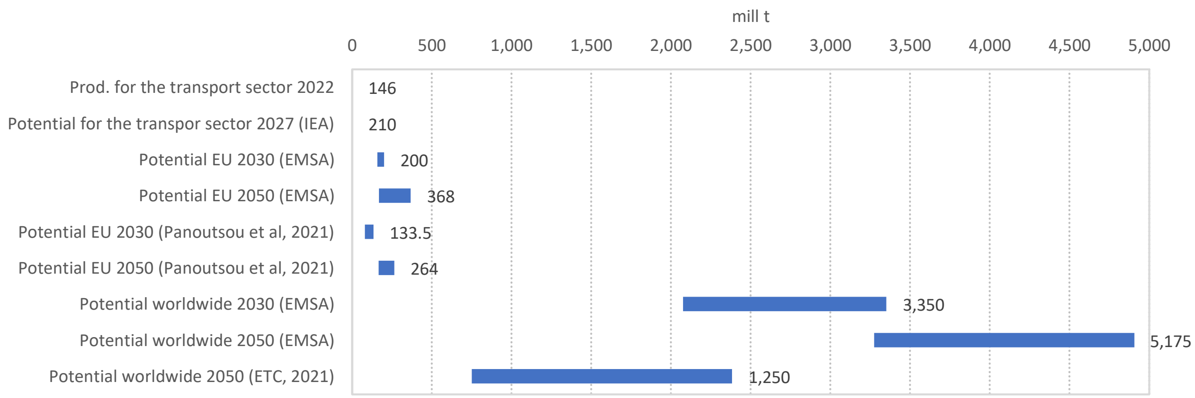


*Figure 22: Production and forecasted production of biofuels worldwide [IEA, EMSA, Panoutsou and Kyriakos Maniatis, 2021].*

On a global scale, IEA estimates the production of biofuels *for transport* in 2022 and 2027 to be around 150 and 210 Mt/y [IEA, Renewables 2022]. Around 15% of this is in Europe. The majority, around 2/3, is ethanol. IEA forecasts a growth rate of around 7.5% Y/Y.

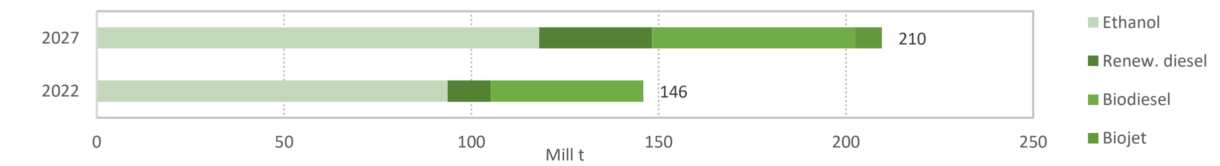


*Figure 23: Production and forecasted production of biofuels* for transport *worldwide [IEA].*

To sum up, the potential for biofuels for transport is high, but the competition for these biofuels will also be strong as decarbonizing mobility is a major undertaking in most societies worldwide.

| Worldwide | Europe | Norway |
|---|---|---|
| 210 Mt/y by 2027 | 200/368 Mt by 2030/2050 | |

## 10.5. Gas (methane): LNG, biomethane and E-LNG

Natural gas covers around 25% of global primary energy [BP] and is an important energy source worldwide. In Norway, less than half the reserves are exploited [Norsk petroleum]. LNG is produced primarily to send natural gas to markets far away; only 12% of the gas is liquefied for this purpose. A small share of this LNG is also used as a marine fuel; around 3% of the LNG produced globally covers 4% of shipping's energy need.

The liquefaction capacity can triple; from 478 Mt/y to 1475 Mt/y. Also, there are around 312 LNG carriers under construction and 668 active vessels [IGU, World LNG report 2023]. Together, this can indicate that LNG can be expected to grow and that there are good opportunities for sending a small share of this LNG to ships for fuel.

LNG is now available as a marine fuel primarily in Europe, but also in the Middle East, Singapore, Far East and US East Coast and Caribbean [DNV AFI]. Other locations can be served with bunker barges, of which there are approximately 35 of worldwide and 14 more on order with capacity from 187 to 30,000 $m^3$ and 8,000 $m^3$ on average [IGU, 2023]. The majority operates in Europe (21) but there are also 3 in Japan and Korea, 3 in Singapore and 3 along the US East Coast. Small volumes can also be supplied by truck.

However, the prospect of LNG is less interesting than the prospects of biomethane and synthetic LNG which are climate neutral or even climate negative. Still, we believe that the good outlook for LNG is important because vessels transitioning to new fuels will find it risky to rely on a single fuel, especially one that is sparsely available.

### 10.5.1. Biogas and biomethane

Biomethane is produced either by upgrading biogas, which typically contains 45-75% methane; the rest is $CO_2$ and some other impurities. Biomethane can also be produced via gasification of biomass followed by methanation. This is less common and only contributes with 10% of the biomethane produced [IEA].

Current biomethane production is very limited; only around 30 Mt/y (1.5 EJ) or 15 of the total natural gas production [IEA, IGU, 2021]. But the potential is significant and IGU estimates that biomethane can increase twentyfold; to 620 Mt/y (31 EJ) or equivalent to 20% of current natural gas production [IGU, global renewable and low-carbon gas report, 2021]. Another study, from CE Delft in 2020, found the potential for biomethane to be 40-120 EJ in 2030 and 40-180 EJ in 2050 [Nelissen et al, 2020].

For comparison, the total energy demand from shipping is around 14 EJ. We must expect strong competition for biomethane as this can replace gas for power generation and any other applications. E.g. natural gas covers around 20% of Europe's electricity production [EU].

In Denmark, the gas grid is filled with 80/20 natural gas and upgraded biogas (biomethane) and this ratio will turn upside down to 20/80 by 2030. In real numbers, this means around 0.82 Mt (0.04 EJ) [Danish ministry of climate, energy and utilities, Green gas strategy, 2021].

In Norway, 56 facilities produced 740 GWh = 55,000 t/y in 2022 of which only 14,000 t were liquefied. Plans for 26 new production facilities will double this within the next few years [Biogass Oslofjord]. The potential in Norway was estimated by Norwegian Institute for Sustainability Research [Lyng and Berntsen, 2023] to 0.4-1.6 Mt/y for current and future raw material base and current and future technology.

| Worldwide | Europe | Norway |
|---|---|---|
| 620 Mt/y by 2030 (pot.) | 25 Mt/y by 2030 (pot.) | 0.4-1.6 Mt (pot.) |

While liquefied hydrogen will likely benefit from scale and be large plants (Equinor foresees 3-5 hydrogen hubs in Europe), biomethane is a 1000-piece jigsaw puzzle where a range of different raw materials are collected from a number of sources and geographical locations. Thus, mapping he potential of biomethane accurately is harder and we can expect revised figures once new sources appear to be worthwhile investigating pending prices and new technology.

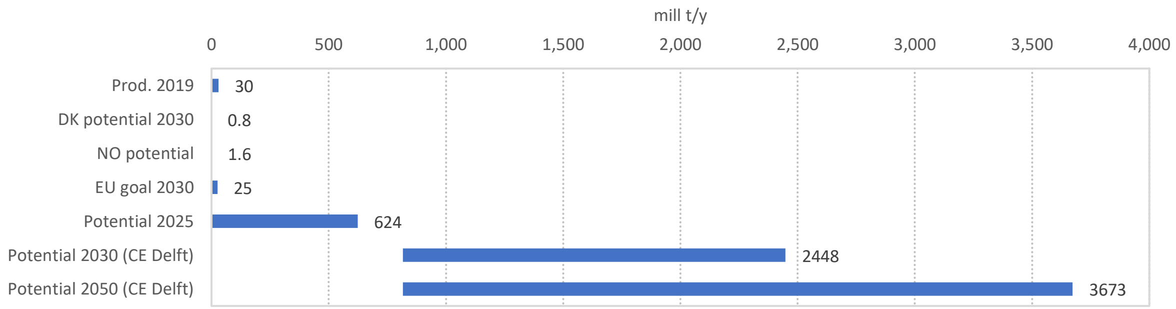


*Figure 24: Biogas/biomethane production; current, goals and potential.*

The Nordic countries all have the resources to make biomethane; fish, farm and organic waste in Norway, forestry waste in Sweden and Finland and biproducts from farms in Denmark. All countries have municipal waste and sewage and the production benefits from a mix of raw materials. Biomethane currently flies below the radar and receives little political attention in Norway. The situation is better in Sweden and Denmark.

A map of Norwegian biogas production facilities is compiled by biogassbransjen.no.

## 10.6. Methanol: fossil, biomethanol and E-methanol

Methanol is a petrochemical feedstock used to produce plastics, paints, carpets, textiles, medicines, and other everyday products. It can be used as a fuel directly or in various forms e.g. dimethyl-ether (DME). Around 1/3 of the methanol is used as a fuel today.

Global production was around 98 mill. t in 2019. Worldwide, the entire current methanol production is fossil: 65% is based on natural gas reformation while 35% is based on coal gasification. Only 0.2% of the methanol produced today is renewable, mostly biomethanol [IRENA, 2021].

Equinor produces around 900,000 t methanol in Norway, at Tjeldbergodden, with natural gas from Haltenbanken. This is about ¼ of the European methanol production [Equinor]. While the methanol produced at Tjeldbergodden is fossil, Equinor can offer biomethanol for Mærsk using certified biomethane on the so-called mass-balance basis [Mærsk, 8 Sep 2023].

Mærsk needs 6 Mt/y and is signing contracts for 2 Mt/y so the volumes are quite massive compared to current production [Hydrogeninsight, 4 Nov 2022]. This can both stimulate production of methanol but the very high volumes needed by Mærsk can also be a threat to other current and future methanol consumers.

Biomethanol can be produced from sustainable biomass such as forestry and agricultural waste and byproducts, sewage, solid municipal waste and black liquor from the pulp and paper industry. The production potential of biomethanol depends both on sustainable raw materials and production technology.

Synthetic or green methanol is produced using green hydrogen and $CO_2$ from bioenergy (BECCS) or directly from the air (DAC).

Worldwide, there are plans for almost 100 production facilities for renewable methanol with a total planned annual capacity of approximately 10 Mt/y; split 40/60 between bio and synthetic methanol [Methanol Institute]. USA and China hold ¼ each. For offshore vessels, the capacity planned in Denmark, Sweden and the Netherlands is of interest. The estimate is quite uncertain; Bloomberg New Energy put the estimate at just 5.5 Mt/y [Bloomberg, Aug 2023]

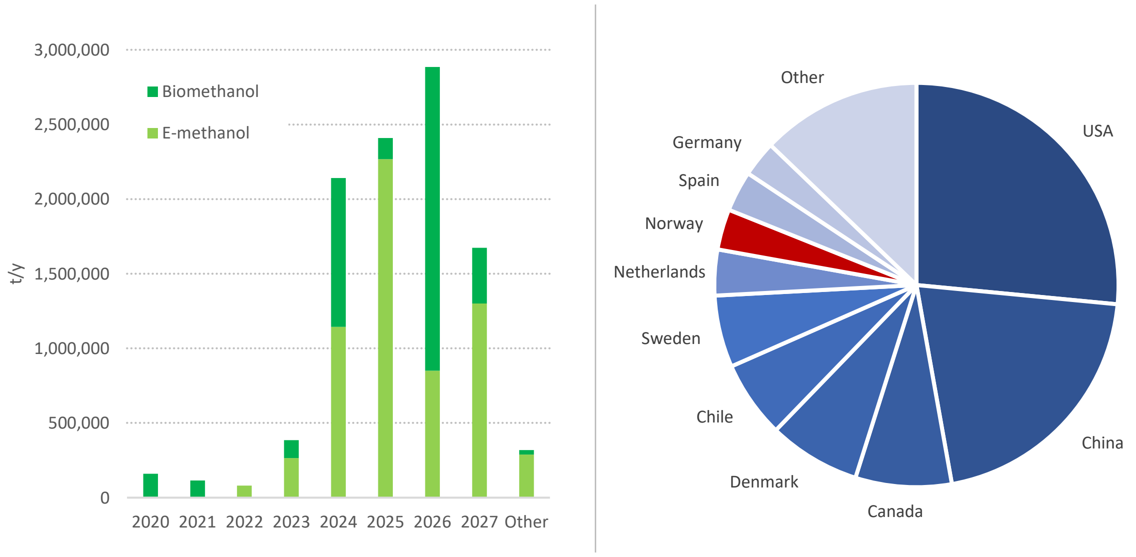


*Figure 25: Planned production capacity for renewable methanol.*

There are four projects listed in Norway with a total of 330,000 t/y planned.

Worldwide

10 Mt by 2030 (planned)

Europe

3-4 Mt (planned)

Norway

0.33 Mt (planned)

### 10.6.1. Infrastructure

Methanol is available in more than 100 ports worldwide including the main bunkering hubs [Methanol Institute]. Despite this global availability, only vessels carrying methanol and therefore having commercial links to the methanol industry have used methanol as fuel.

The first bunkering from a bunker barge were reported in May 2021 [Motorship, 14 May 2021].

## 10.7. Hydrogen

The global hydrogen production was approximately 94 Mt in 2021 [IEA]. The majority is produced from natural gas and some from coal, and nearly nothing is produced with low emission [IEA]. Only four production sites use carbon capture and storage today [Bloomberg NEF, 2020]. Scaling up production to replace the current production of fossil-based hydrogen and also producing surplus volumes for the steel industry and transport sector is clearly a massive undertaking.

If announced plans for production of low emission hydrogen are realized, the global annual production can reach around 38 Mt by 2030, i.e. around 40% of the current production [IEA, 2023].

In last year's report the estimated future capacity was 24 Mt, so many projects have been announced in the last year. Note also that some projects fail to materialize or are postponed, e.g. Equinor's Aurora project. Some projects are stopped because the fuel price will be uncompetitive, while others fail to secure renewable electricity. In that respect the estimates must be considered quite uncertain.

EU plans to produce 10 Mt renewable hydrogen and import the same by 2030 [EU, 20 June 2023].

The US intends to produce 3 Mt/y in the short term, while the long-term demand is estimated to 10 MT by 2030, 20 Mt by 2040 and 50 Mt by 2050. In this estimate, demand for hydrogen for ammonia, biofuels and power to liquid fuels are included together with industrial applications e.g. steel [WRI, 25 July 2023]

Equinor intends to produce $H_2$ from 2 GW in 2030 and increase the production by 2 GW every two years to 10 GW in 2040, first blue hydrogen and then green hydrogen [Equinor]. Statkraft targets 2 GW by 2030. The sum of all Norwegian projects is 0.8 GW in 2025 and 11.5 GW in 2030 [Norsk Hydrogenforum at Gasskonferansen, 8 Nov 2023]

Worldwide

38 Mt/y by 2030 (pot.)

Europe

10+10 Mt/y (goal) by 2030

Norway

11.5 GW (<2000 t) by 2030

To sum up, the potential both in EU and worldwide is high, but the road to realize these potentials will be complicated. Electrolysis is well proven, but the access to renewable energy is the big question mark. Also, high energy losses in production of hydrogen coupled with high energy prices is a challenge. The alternative use of renewable electricity is a second challenge, noting that fossil fuels and coal in particular still cover 16% of the Union's electricity [EU]

### 10.7.1. Blue hydrogen

When or if natural gas and coal becomes unacceptable as energy products, they can be converted into low carbon hydrogen with the help of CCS. While the GHG emissions are reduced, but not entirely eliminated depending on the capture rate, there are significant energy losses in the conversion process. As much as two thirds of Norway's natural gas reserves are not yet produced. These reserves can be the basis for Norwegian production of blue hydrogen.

Even if only a very small share of the current natural gas stream is converted to blue hydrogen, it would give $CO_2$ volumes exceeding the storage capacity of the Norwegian Longship project (1.5 Mt $CO_2$/y [Regjeringen, 27 Sep 2023]. This confirms that a serious production of blue hydrogen will require substantially larger infrastructure for not only capturing but also storage of $CO_2$.

Australia and Japan are advancing similar plans with Australia's large reserves of lignite (brown coal).

### 10.7.2. Green hydrogen

Green hydrogen is produced by splitting water with electrolysis. The technology is well known, electrolysers are produced today and were in commercial operation in Norway until 1993 when 65 t/d was produced in Glomfjord before that production was outcompeted by natural gas. Interestingly, Glomfjord is one of several locations where climate neutral production by electrolysis can return.

Norway plans to establish five hydrogen hubs: Glomfjord, Rørvik, Hitra, Florø and Kristiansand all target around 8 t/d = 2,920 t/y by 2024-25. In addition, we see plans in Mo, Narvik, Hellesylt, Ørskog, Hardanger and other places. The majority of these are based on electrolysis. A 2.5 MW (1 t/d) plant has operated in Berlevåg since 2020 [Varanger kraft]

To produce 10 mt hydrogen, EU requires 500 TWh. This is around 1/5 of the current European electricity production (2641 TWh in 2022 [EU]). This confirms that serious production of green hydrogen cannot be planned in a vacuum but relies on access to renewable (hydro power, wind, tidal, geothermal) or climate neutral (nuclear energy). Expanding Europe's renewable production by 1/5 is not done overnight. And because unstable energy sources such as wind and sun require balanced power to ensure reliable supply, a secondary energy source must be established alongside, especially when the share of sun or wind becomes high.

We must also expect strong competition for climate neutral hydrogen, which is needed as a building block in many industrial processes and as an energy carrier in many different applications.

### 10.7.3. Infrastructure

Small volumes of hydrogen can be compressed and trucked over shorter distances. Larger volumes will likely be carried as liquefied hydrogen at sea or in pipes. The first $LH_2$-tanker (Susio Frontier) has been in operation since December 2021.

A grid network for hydrogen exists already with around 4,300 km of piping mainly in Europe and North America. Nearly 100 projects adding 30,000 km are planned, more than 80% of this in Europe [Rystad, 2023]. Existing gas pipes for natural gas can be used and the first conversion is under way so that hydrogen can be transported from 2025 [Hydrogen Europe].

## 10.8. Ammonia

The global production of ammonia was 185 Mt/y in 2020, nearly all from fossil sources, primarily natural gas (72%) and coal (22%). 70-85% goes to fertilizers [IEA, IRENA]. Ammonia takes around 45% of the current hydrogen production [IRENA , 2022].

1/10 of all ammonia is traded internationally and ammonia is therefore a known maritime cargo and chemical compound and available in many corners of the world.

Various overviews of planned ammonia production projects give quite different impressions: IEA sums up the planned capacity to 8 Mt, while IRENA finds a total of 15 Mt. A more recent study for EMSA finds project with a total of 133 Mt planned and announced [IEA, IRENA, EMSA].

If climate neutral ammonia shall become a meaningful maritime fuel while simultaneously replacing the fossil-based ammonia produced today, a massive scale up is required. Yara explained that their plans for producing green ammonia would take 5-7 years to realize [Yara, 16 Aug 2021].

Yara plans to produce 800,000 t ammonia with electrolysis at Herøya. This requires around 450-500 MW, while the total electrolysis capacity worldwide was 100 MW in 2019 [DN, 8 Dec 2020]. This factor illustrates the massive undertaking. So far, Yara has decided on a pilot plant producing 20,500 t/y [Yara, 17 Dec 2021]. Yara is also pursuing blue ammonia production at Sluiskil, the Netherlands [Yara, 20 Nov 2023]. Yara intends to make a side stream of these volumes available as marine fuel.

Beyond Yara, there are other prospective projects under way: In Skipavika (0.1 Mt), Korgen (0.2 Mt), Narvik (0.45 Mt), Glomfjord (0.03 Mt), SAUDA (0.2 Mt) and Hammerfest (1-3 Mt). The majority are based on electrolysis, while Hammerfest is based on natural gas and CCS. The total planned capacity from these is 2-4 Mt/y.

| Worldwide | Europe | Norway |
| --- | --- | --- |
| 15-133 Mt/y by 2030 | | 3-5 Mt/y (planned) |

While there has been many good news about ammonia and its possible use as a marine fuel, we also observe that many struggle to move forward in time and at scale. E.g. Yara is moving forward with a small pilot while the 800,000 t plant is still pending final investment decision. Equinor and Vår Energi pulled out the blue ammonia production facility planned in Hammerfest – but in came Fertiberia, a Spanish producer of fertilizers [TU, 1 Feb 2023].

Despite these news, however, ammonia seems to be a fuel that is still making progress in large part due to Yara's commitment. And it does make sense that an established major player that needs green or blue ammonia in its own value chain shall take responsibility for developing climate neutral production for internal demand and sell whatever it can to external takers.

## 10.9. Fuel map for Norway

Based on the above review, we present the following map of planned production facilities.

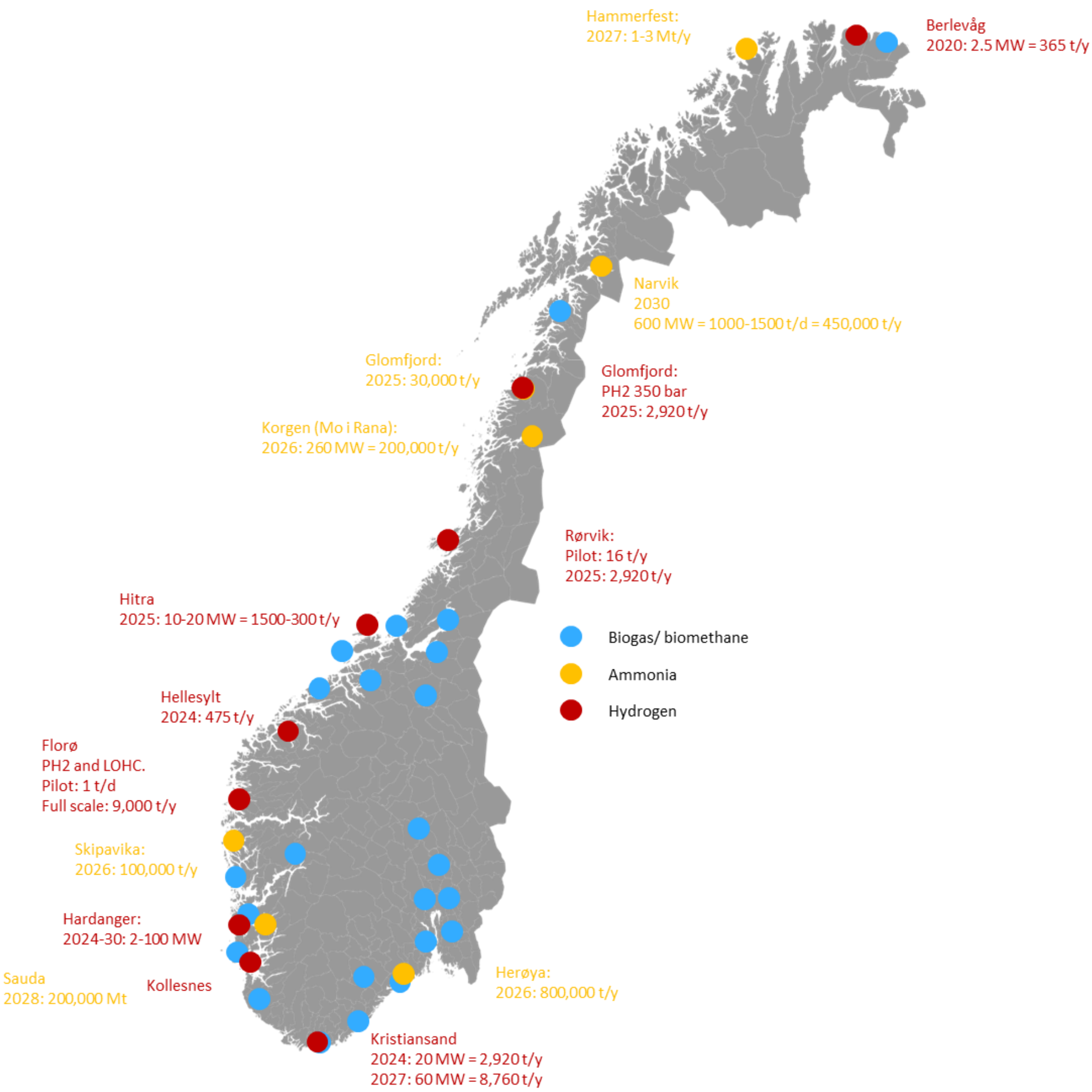


*Figure 26: Map of planned/announce/possible production facilities for biogas/biomethane, ammonia and hydrogen.*

## 10.10. Chapter summary

The good news is that many alternative fuels can be produced from different raw materials and with different technology. This means that the production can utilize the raw materials and resources available in different regions. All the fuels, biofuels and blue and green hydrogen-based fuels can be produced in many corners of the world.

The not so good news is that there is currently very little commitment to producing alternative fuels despite a lot of interest from governments and industrial players. There are high ambitions and many plans, but most seem to hinge on something being realized or someone else moving first. We even see many plans being postponed or cancelled.

**Biofuels: Liquid (FAME/HVO) and gaseous (LBG)**: There are clearly limited sustainable biomass resources available today, but we believe that the resource base has not been mapped as well as it deserves. Biomass is everywhere. It has been too troublesome to establish value chains for biomass for bioenergy because fossil energy has been so cheap and efficiently organized. Various studies indicate a significant potential for both liquid and gaseous biofuel. The competition for it will likely be strong.

**Biomethanol and synthetic methanol**: There are plans for almost 100 production facilities worldwide including many in Europe and some in Norway. Methanol is perhaps the most sought after and talked about fuel at the moment and in a game where everyone is waiting for a strong first mover to move, this can be a significant advantage that helps to realize methanol.

**Blue hydrogen and ammonia**: The key factor to realize blue fuels is carbon capture and storage. While everyone agrees that CCS is necessary to reach the climate goals, the progress in terms of project realization is slow. CCS is still at the development stage and not really close to the stage where it is all about scaling up.

**Green hydrogen and ammonia**: The key factor to realize green fuels is renewable energy, or climate neutral energy. In chapter 7.3 we learned that the share of renewables is still low which means that it will take many years and likely decades before we have surplus of renewable electricity. Until then, there will be fight for the available renewable energy. Stranded energy, i.e. renewable electricity that cannot be fed into a grid can be earmarked for production of alternative fuels for the transport sector. Solar power in Morocco is one example of such stranded energy assets that can be turned into ammonia [EDF, Sailing on solar, 2019].

To conclude, there is no single alternative fuel that seems to be very easy to produce at large scale with low costs in multiple locations.

All in all, the above means that the offshore sector must likely take an active part in developing the fuel supply they need. The energy sector will likely not move on its own, at least not in scale. And the energy sector will likely appreciate firm contracts to ensure that investments in new production capacity and infrastructure for alternative fuels for ships are not waste.

# 11. Economic evaluation

The overall economic effect of alternative fuels depends not only on the fuel price but also on other cost elements. Fuel costs are more important for low value vessel (such as dry bulkers and tankers) than for sophisticated high-specification vessels (such as cruise and offshore vessels) because the other cost elements are quite high for the latter group of ships.

The economic analysis of alternative fuels rests on the following assumptions:

There are four major cost elements:

*Total life cycle costs = capital cost + operating costs + fuel cost + carbon/greenhouse gas tax*

The useful lifetime of the vessel is set to 25 years, starting in 2025 and ending in 2049. The total cost is evaluated by the present value (PV) today of all expenditures, using an interest rate (IRR) of 6.5%, which we consider to be representative today.

The residual value is set to zero. The rationale behind zero residual value is that the scrap value equals and pays for the demolition and recycling work. This assumption is perhaps conservative, but not unrealistic for ships with low steelweight and labour-intensive demolition.

The economic analysis is undertaken using Norwegian kroners (NOK). Shipbuilding and marine equipment are generally priced in USD or EUR. The average currency exchange rate the last decade was 9.7 NOK/EUR and 8.3 NOK/USD while the average for the last 12 months was 11.2 and 10.4 respectively. The economic analysis is done in Norwegian Kroner (NOK) using exchange rates of 10 NOK/USD and 10 NOK/EUR.

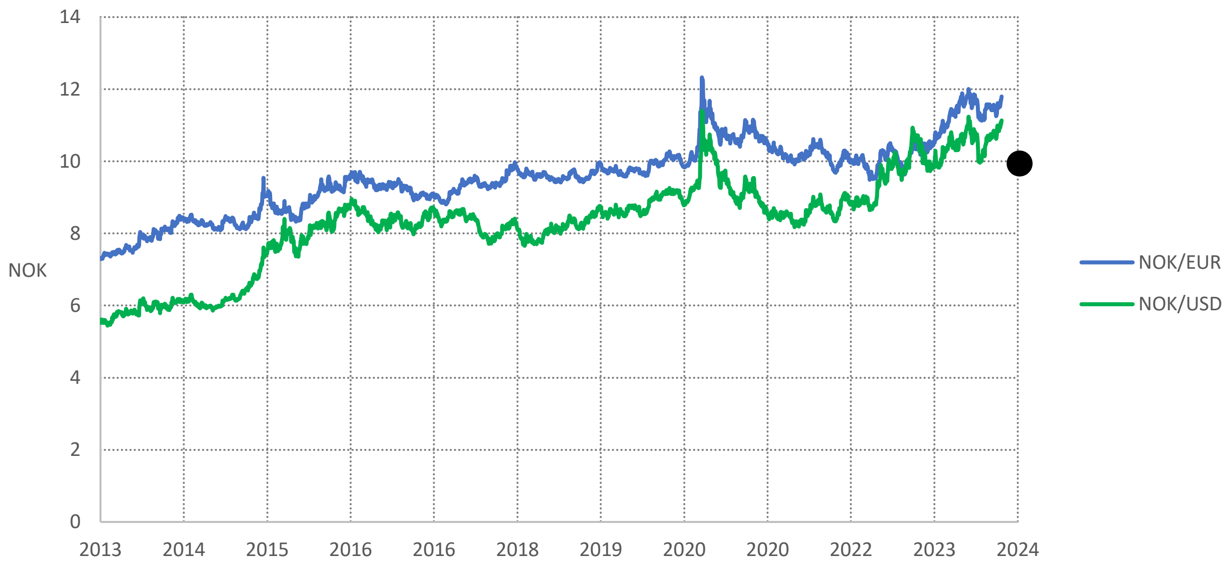


*Figure 27: Currency exchange rates [Norges Bank]*

## 11.1. Capital cost (capex)

The capital cost is the acquisition cost of a new vessel. The capital cost depends on the size and technical specification i.e. the outfitting, machinery and systems installed onboard.

The total capex for the reference vessel (running on MGO) is indicated in figure 28 below. We use this capex as the starting point in our economic analysis and vary the cost of machinery, tanks and systems while we keep the other cost elements fixed.

| | |
|---|---|
| PSV | 700 MNOK |
| AHTS | 1.5 BNOK |
| CSV | 2.5 BNOK |

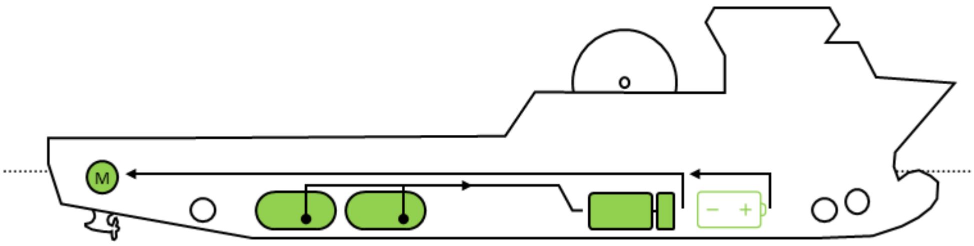


*Figure 28: Overall capex for offshore vessels and marking of key components affected by the fuel choice.*

To model the impact of the fuel choice, we need specific cost factors of the type EUR/kW or EUR/kWh or EUR/m$^3$ etc. This useful but crude approach has its pros and cons: Not all costs scale linearly with the size of the engine, genset or tank volume, but are fixed. E.g. for engines, the capex is cheaper per kW for an engine with many cylinders. Also, the type has impact, e.g. fuel injection by common rail or not. There can be a difference of 10-20% depending on the cylinder number [MAN]. The model does incur some inaccuracies, but we believe the magnitude will be more or less correct and thus the model will give valid conclusions.

The total cost is much more than the equipment cost; installation, interfacing, commissioning, classification etc all adds to the total. As an example the battery cost can be 10 times per installed kWh for retrofit [Larsen]. In this study, we assume that much of the installation work will be the same for a hydrogen engine and a diesel engine. This assumption does not apply well to the case of fuel cells, which require more detailed investigation.

Prices for engines and generator sets are summarized below:

| | *NOK/kW* | *Δ* | *Notes* |
|---|---|---|---|
| MGO | 4,000 | Base case | Many engine makers. Variation between high and medium speed engines. |
| LNG DF | 5-6,000 | +25-50% | Depends on engine type, e.g. common rail for liquid fuel injection or not, high/low pressure fuel injection. |
| Methanol DF | 6-7,000 | +50-75% | Will drop to the level of LNG with scale and time. |
| $H_2$ DF engine | 7-9,000 | +80-130% | |
| $H_2$ PEM fuel cell | 20,000 | 5x | |
| Ammonia DF engine | 6-7,000 | +50-75% | |
| Ammonia SOFC | 50-60,000 | 12-15x | |

*Table 7: Cost factors for engines (approximate).*

Pricing of fuel storage and systems for bunkering, transfer and fuel treatment is more complex because this is generally a mix of separate components delivered to the yard for installation but also yard scope of supply.

E.g. hull tanks for liquid oil fuels and methanol are entirely yard supply because these tanks are an integrated part of the hull and only requires coating (depending on the fuel type) and outfitting: sensors (such as level gauges, temperature etc), pumps, pipe connections for transfer, overflow etc etc. Methane, hydrogen and ammonia require special tanks, typically pressure vessels.

The additional cost of having many rather than only 1 or 2 tank is much higher for pressure vessels than it is for hull tanks.

| | NOK/kWh | k | NOK/m³ | Notes |
|---|---|---|---|---|
| MGO | 0.2 | | 2,000 | Hull tanks. Cost reflects outfitting and instrumentation. |
| LNG DF | 5 | | 9-18,000 | Pressure vessels Type C + low pres. fuel gas supply system. |
| Methanol DF | 0.5-1 | 5x MGO | 2-4,000 | Hull tanks, stainless steel or coated. |
| H2 liquid | 20-100 | 4-20x LNG | 50,000-200,000 | Vacuum tank. Very size dependant. |
| H2 pressurized | 100 | 20x LNG | 75,000 | Depending on pressure and configuration. |
| H2 LOHC | ? | | | |
| Ammonia | 2.3-4.5 | 1.5x LNG | 9-18,000 | Assumed same as tanks and systems for LNG. |
| Ammonia SOFC | ↑ | | | Cost of cracker to be added |
| Batteries | 5-10,000 | | | Depending on battery type. |

*Table 8: Cost factors for tank and systems (approximate).*

## 11.2. Operating costs (Opex)

The principal components of daily operating costs are manning, stores, spares and consumables, routine repair and maintenance, insurance and administration [Martin Stopford, Maritime Economics 1997].

OPEX
- Manning
- Insurance
- Stores, spares and consumables
- Routine repair and maintenance
- Administration

Each element is to some extent affected by the fuel choice:

Novel or complex machinery will require training of engineers to acquire the necessary certificates. The crew pool will in the early days of the energy transition be smaller and this can have an upwards impact on cost. Crewing cost is the most important cost element for offshore vessels.

Insurance cost can increase because the risks associated with having hydrogen or ammonia onboard are not equally well known and mapped – although it remains to be seen if the risks associated with these fuels are much higher. In the case of damages or malfunction, there will be fewer yards to call for repair and thus the repair cost can be higher and result in longer offhire. Some teething troubles must be expected with new technology. This can partly be mitigated by having multi-fuel machinery.

New engines will require other spare parts and consumables produced, at least in the first few years, by the original engine makers. There will be a cost disadvantage for spares until the number of engines become high and spare parts are produced in large numbers. Fuel cells, on the other hand, do not have the same wear and tear, but the gradual or continuous replacement of cells will be costly. The lifetime of fuel cells in a marine environment are not known. The need for routine repair and maintenance remains to be seen for both fuel gas supply systems to engines. Novel systems will require run-in and experience building until they reach the same level of reliability as today's systems.

Administration costs can be higher for ships with new fuels because these fuels will be less available. Vessel related costs accounts for around 90% of total operating costs [Solstad, Q4-report, 2022].

In our model, we have together with operators analysed the daily opex. We assume that machinery related operating costs will be doubled for alternative fuels; a quite conservative assumption. Further, we assume that opex will grow 3% pa Y/Y.

## 11.3. Fuel cost

Naturally, the two most important drivers for fuel cost are fuel consumption and the fuel price. The first can be estimated with reasonable accuracy, while the latter is a bit of guesswork. One of the most complex things to forecast is energy prices. We have analysed the forecasts from four sources: DNV Energy Transition Outlook 2022, LR/UMAS Techno-economic assessment of zero-carbon fuels (March 2020), Mærsk McKinney Møller centre for zero emission shipping (MMKMC) and IRENA's series of Innovation outlooks for inter alia renewable methanol (2021) and renewable ammonia (2022).

The energy prices are compared based on energy content [USD/GJ] in diagram 31 and then indexed against MGO/VLSFO om diagram 32 because it is the relative magnitude and variation between the alternative fuels we are after.

We use the midpoint energy prices in our analysis, indicated by the dots in the diagrams. Note the significant variation/uncertainty for synthetic LNG and synthetic methanol and green hydrogen and green ammonia.

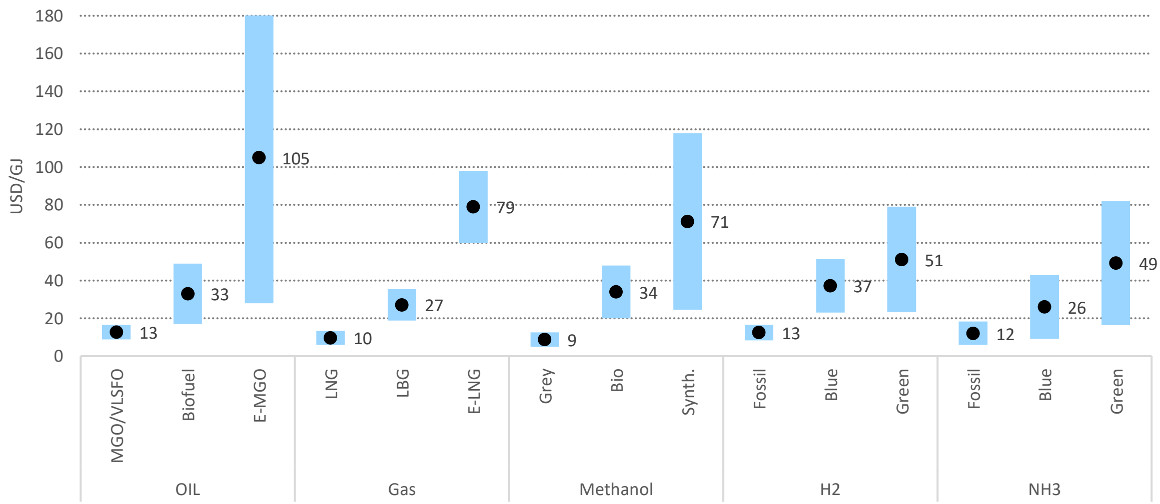


*Figure 29: Price forecast alternative fuels, indexed against MGO/VLSFO.*

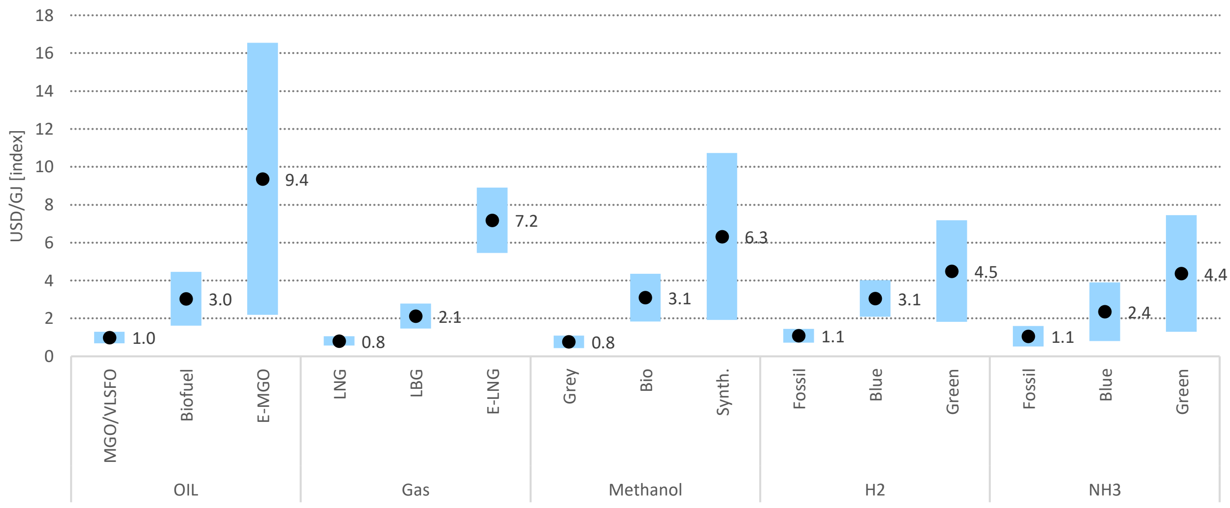


*Figure 30: Price forecast alternative fuels (indexed against MGO).*

From figures 29-30, we note significant spread in the forecasted prices for synthetic fuels, and also for green hydrogen and ammonia. All of these fuels require large quantities of emission free electricity in their production and the price of emission free electricity not only varies between countries but is also hard to forecast one or two decades ahead. We note less variation for the biofuels of all types; liquid, gaseous and biomethanol.

We apply the following energy prices in our economic mode and assume an annual growth rate of 3% pa for all energy prices.

| | *NOK/GJ* | | | | | *Indexed* | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | *Fossil* | *Bio* | *Synthetic* | *Blue* | *Green* | *Fossil* | *Bio* | *Synth* | *Blue* | *Green* |
| MGO | 130 | 350 | 1000 | | | 1 | 3 | 9 | | |
| Methane | 100 | 270 | 790 | | | 0.8 | 2 | 7 | | |
| Methanol | 90 | 340 | 710 | | | 0.8 | | 6 | | |
| H2 | 130 | | | 370 | 510 | 1.1 | | | 3.3 | 4.5 |
| Ammonia | 120 | | | 260 | 490 | 1.1 | | | 2.5 | 4.4 |

*Table 9: Cost factors for fuel.*

## 11.4. Carbon price / emission allowance cost

A price on carbon is considered instrumental to achieve the Paris climate goals. It is a natural consequence of the polluter pays principle, a key principle in environmental law and also enshrined in Norwegian environmental policy.

The rationale behind a carbon price is to put a price on GHG emissions that will motivate reduction in emissions. A high price on emissions can justify investments and costly operating practices that would otherwise be uneconomical. In a cap-and-trade system, the price shall be set so that emissions do not exceed the desired emission levels or emission cap.

Today, around 70 carbon pricing schemes cover 23% of global GHG [World Bank]. The rate varies from near zero to 150 USD/t $CO_2$. The Norwegian tariff is somewhere in the middle with 90 USD/t [World Bank].

Offshore vessels currently pay for $CO_2$-emissions when bunkering in Norway (mineraloljeavgift). The tariff is applied to the fuel and is 2.53 NOK/l MGO equivalent to around 890 NOK/t $CO_2$ (assuming ρ 890 kg/m³ and 3.206 g $CO_2$/g fuel).

**The EU** is extending its emission trading scheme (ETS) to shipping from 2024 and to offshore vessels above 5,000 GT from 2027 and possibly also to offshore vessels below 5,000 GT. Around 60-70% of the AHTS and construction vessels but only 15% of the PSV are above 5,000 GT, in total around half the fleet. No vessels fall below the 400 GT threshold.

**The IMO** has discussed carbon pricing before; around 2011 and again in the most recent Marine Environmental Protection Committee meetings but without success. While there is substantial support for some kind of economic incentive, the matter seems to be too delicate for all sides to agree.

Regardless of the above, we assume that the EU ETS or another carbon pricing scheme will apply to all offshore vessels, above and below 5,000 GT, in the entire period 2025-2049. The price level is not set and is hard to predict. Refinitiv predicts a price hike from 90 to 150 EUR/t in 2030 while today's futures prices suggest an increase from 90 to around 120 EUR/t in 2030 [Grønn bok, 2023]. The Norwegian ministry of Finance has laid down standard values for socioeconomic analysis [Regjeringen, 22 Dec 2022]. These run from 800 in 2023 to approximately 2,000 NOK/t $CO_2$-eq. in 2049.


*Figure 31: EU ETS carbon price (historic) [Klimastiftelsen]*

A 90% reduction target, currently under debate in the EU, will warrant higher carbon prices. Researchers at London Stock Exchange Group believe a carbon price of 400 EUR/t is necessary to support the 90% target [Euractiv, 5 Oct 2023].

We can also turn the equation around and ask what carbon price is necessary to make a certain technology competitive. The carbon price shall be at least as high as the cheapest solution that can be applied at scale.

We apply a carbon price of 1,500 NOK/t $CO_2$-eq. with annual growth 3% Y/Y.

While the EU ETS will be phased in 2024-2026 and not applicable to offshore vessels from the beginning, we assume in this study that all annual emissions will be taxed. Further, we calculate the carbon price based on well to wake emissions, though we appreciate that the taxation of production emissions will be addressed to the energy producers and not the vessel. Yet, this assumption rests on the assumption that the taxation of carbon must apply throughout the fuel's value chain.

## 11.5. A comment on accuracy and uncertainties

We must underline that the economic analysis builds on some key factors with significant impact on the conclusions that are quite uncertain – and cannot be estimated with certainty at the moment. These include:

The **equipment cost for tanks and systems** reflects the immature stage of development, especially for hydrogen and ammonia, and the complete lack of scale for these systems. Indications suggest that prices for LNG tanks and systems have halved in a decade.

The **fuel prices depend on a range of input factors**. Blue hydrogen and ammonia depend on the natural gas prices, which we have seen fluctuate dramatically in the last two years. The blue fuels also depend on CCS, which is still at an early stage with many plans but few projects under realization. Synthetic fuels also depend on $CO_2$ capture, either from point sources or direct air capture, which are also immature technology without scale. Finally, green fuels and synthetic fuels depend on the electricity prices.

Biofuels, on the other hand, are less energy demanding in production and rely on more proven technology but the access to sustainable raw materials and the true cost of these remains to be seen. Today, a majority of the biofuels produced are conventional/1st generation (i.e. not sustainable).

The **carbon price** can play a significant role in incentivizing a shift away from fossil fuels. The rate and indeed the applicability of EU ETS and possibly other similar schemes are unknown today, but considering the appreciation of market based measures, among industry and government alike, we expect this to be a central tool going forward.

The **lifetime** or mean time between overhaul of novel equipment or components is not yet proven and thus the maintenance and replacement intervals remain to be seen. This concern applies especially to batteries and fuel cells where cell replacement must be expected in the course of 25 years of active service.

# 12. Case studies

We have so far explained the effect on greenhouse gas emissions of the various fuel options (chapter 7), reviewed the technology with focus on machinery and fuel storage options (chapter 8) and explained how the transition to alternative fuels leads to larger tank compartment space onboard (chapter 9). We continued by discussing the prospects for their availability (chapter 10) and key economic factors (chapter 11).

Now, we combine alle these factors in an integrated model to analyse the economics of alternative fuels. We examine 18 combinations of fuels and machinery for three vessels cases: PSV, AHTS and CSV.

Each case is analysed in separate chapters (12.2 - 12.4). It turns out that the economic analysis gives fairly consistent results for the three ship cases, and we therefore sum up the economics in chapter 12.5 for all three. In chapter 12.6, we look at the abatement cost for all three cases before we evaluate the total climate effect (12.6) and fuel demand (12.7) for the offshore fleet as a whole.

The supply side does not vary between the three ship cases. In chapter 10.10, we concluded that there is really no meaningful supply of any of the fuels and that plans for future production are not committed. Therefore, the supply side must likely be developed on demand. The consumer must take part in this, either directly or through long partnerships or contracts. We do not consider that any of the fuels has a clear advantage or shortcoming when it comes to supply, simply because the supply side and infrastructure is in its infancy, for all fuels.

## 12.1. Methodology of the integrated techno-economic model

First, we analyse the principal particulars, and the intended service offshore vessels perform. We analyse the operating profile including the energy accounts and use this for calculating fuel consumption, emissions, tank capacities, engine power and ultimately both capex (capital cost) and opex (operating costs).

The methodology and modelling can be summarized by the below two flow charts. The first chart explains how we model fuel consumption and fuel cost, GHG emissions and carbon tax and use the fuel consumption to calculate required tank space and thus tank cost and effect on the vessel's main dimensions.

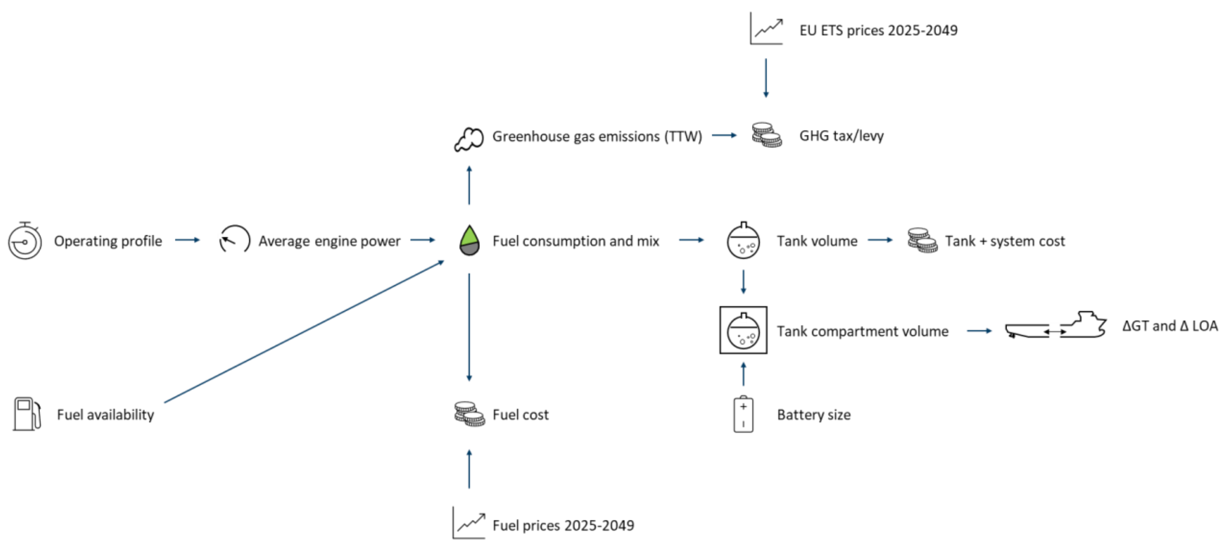


*Figure 32: Model for estimating key factors (1/2)*

Considering the fact that most alternative fuels are not available today and that it will take time to begin and scale up the production capacity of green/sustainable alternative fuels, we believe that the transition to alternative fuels will be gradual and start in the earnest and then scale up.

Based on the current availability and complexity of scaling up fuel production and technology maturity, we could argue that some fuels will become feasible sooner than other fuels, i.e. liquid and gaseous biofuels can be used in small quantities today while there is virtually no green ammonia, hydrogen or methanol available. However, because the landscape if evolving quickly both in terms of technology and fuel production and infrastructure, and because some fuels can become sufficiently available in some regions to justify a transition, we assume a gradual phasing in schedule as follows:

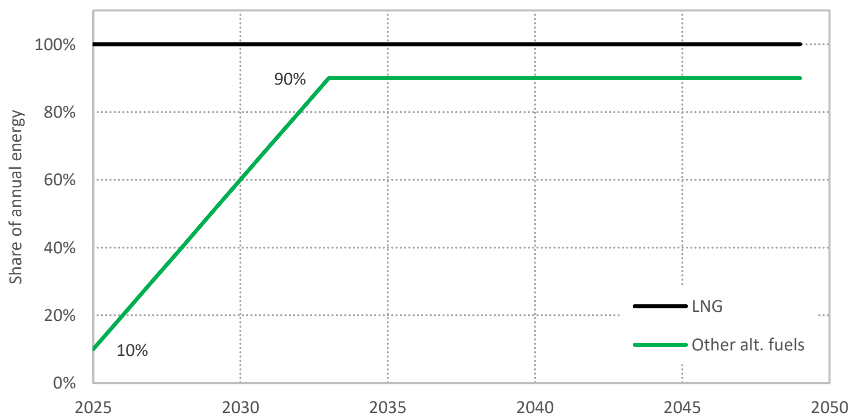


*Figure 33: Phasing in schedule for alternative fuels.*

The second flow chart explains how we use the operating profile to determine the capacity (kW) of the machinery so that the vessel can run 90% of its operations on alternative fuels, in order to minimize the machinery cost.

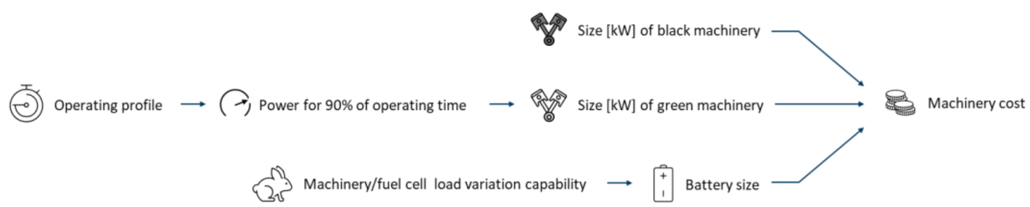


*Figure 34: Model for estimating key factors (2/2)*

The conclusions clearly depend on many of the assumptions we make on engine efficiency, fuel prices, carbon prices and the cost for machinery and equipment. In this project, we have developed a framework that allows us to investigate sensitivities i.e. analyse how the conclusions will be based on a different set of assumptions or technical parameters.

## 12.2. Platform supply vessels (PSV)

Platform supply vessels are less costly, operate on fairly fixed and predictable schedules and require only seven (7) days endurance on the alternative fuel. They typically have 8-10 MW engine power installed, divided by 4 generator sets.

*Operation*

The operating profile suggests that a PSV spends 40% of the time in DP, 44% in standby and 17% in port. Most of the energy is spent in transit. Clearly, reliability is important in transit too, but the need for instantly available power reserve and requirements to reliability and redundancy is a bit lower than in DP. This means that the slow response of fuel cells is ok in transit. There is less strict requirements to power margin in transit than in DP.

*Green machinery*

They typically have 8 MW installed but on average use only 1-2 MW (10-30% of MCR). Based on the operating profile, we find that if 4 MW out of 8 MW are capable of burning alternative fuels, this will cover 90% of the operating time for a PSV. In diagram 35 below, the vertical line indicates this 90% threshold, and the horizontal line indicates the 4 MW required.

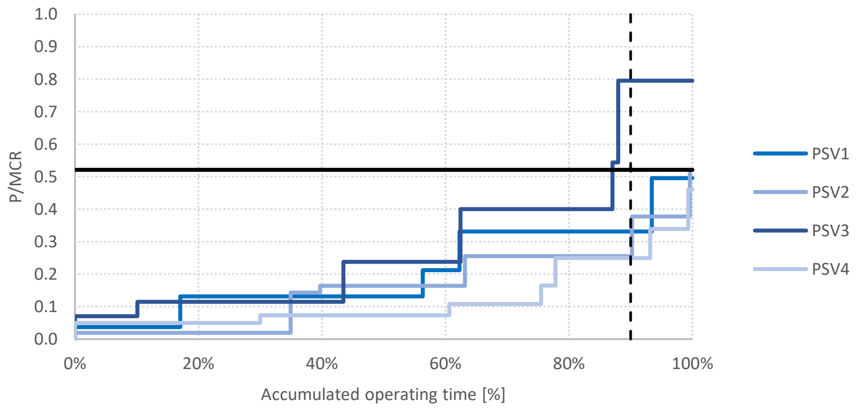


*Figure 35: engine load vs operating time for PSV.*

*Tank compartment*

To cover 7 days of operation, and having 7 days margin on the basis fuel, we calculate the required tank volume and tank compartment for the various fuel options. The diagram shows that the tank compartment space increases by nearly 100% for LNG and as much as 300-400% with hydrogen and 160-190% with ammonia.

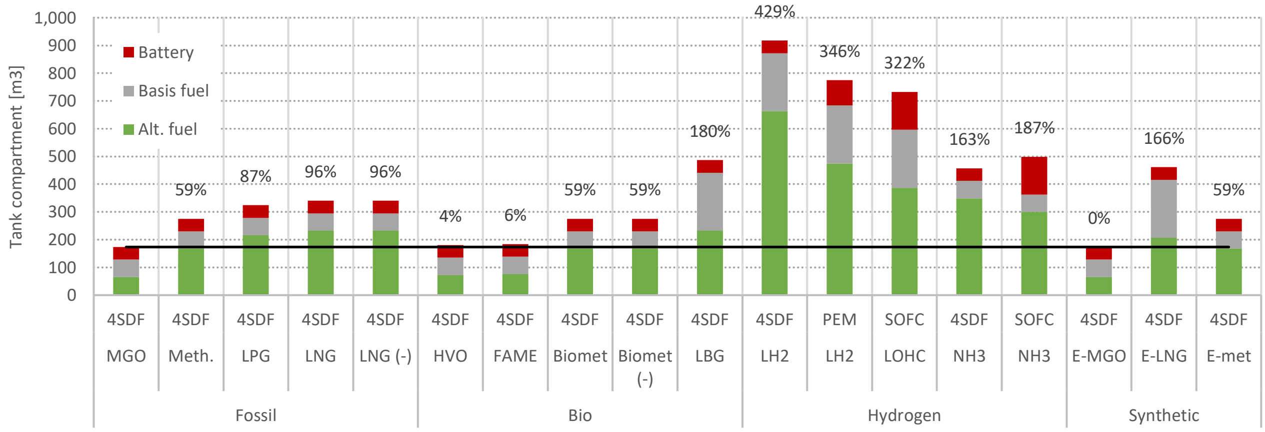


*Figure 36: Tank compartment volume (PSV).*

*Ship size: Gross tonnage and length*

To accommodate these tanks, the vessel tonnage must be increased; by up to 4% and LOA extended by up to 8 m (for $LH_2$), assuming that the entire tank compartment is arranged under the cargo deck. We consider this size increase to be practical.

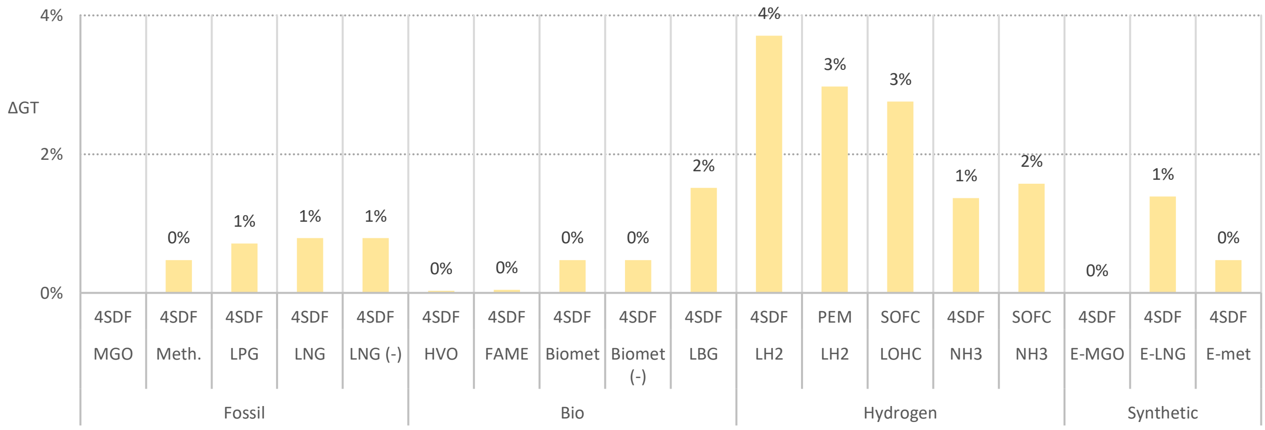


*Figure 37: Change in GT to accommodate alternative fuels (PSV)*

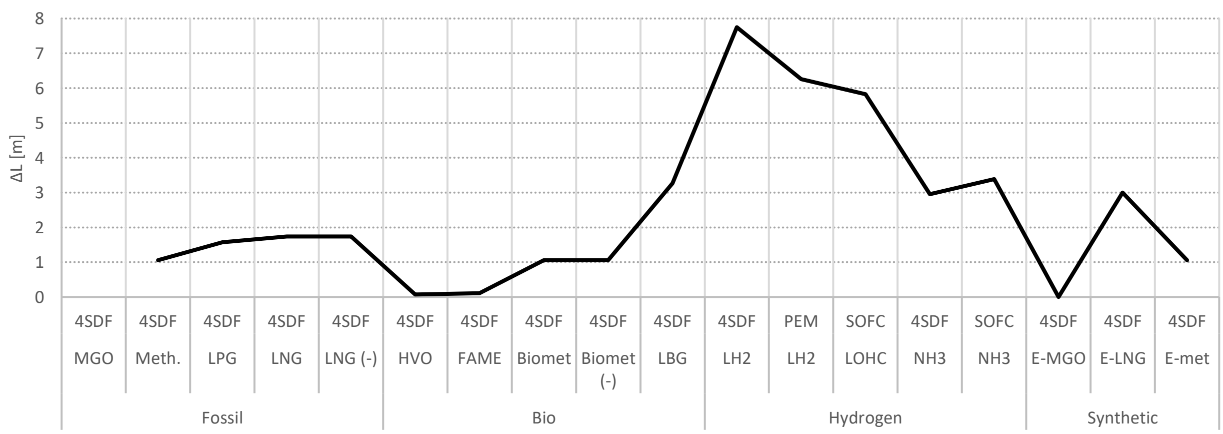


*Figure 38: Change in LOA to accommodate alternative fuels (PSV)*

*Economics*

When fuel consumption, machinery size and tank size has been estimated, we find the present value (PV) of the total life cycle costs, including capital and operating costs as detailed in chapter 11.

The total life cycle costs for the 18 combinations of fuels and machinery span from around 1900 to 3,250 MNOK (ref diagram 39 and 40 below). The highest costs come with synthetic fuels, not surprising given the high fuel cost multiple identified in chapter 11.3. Biomethane comes out best, with only 3% higher costs all in all, followed by biodiesel and biomethanol.

Among the hydrogen alternatives, hydrogen with fuel cells and ammonia combined with 4SDF comes out with 19% higher life cycle costs. Hydrogen combined with fuel cell outperforms hydrogen with 4SDF because of the slightly higher efficiency. The hydrogen alternative using SOFC, on the other hand, becomes much more expensive and here the high efficiency cannot compensate.

The two below diagrams suggest that biomethane is the least costly alternative, followed by HVO and biomethanol, hydrogen with PEM and ammonia with 4SDF.

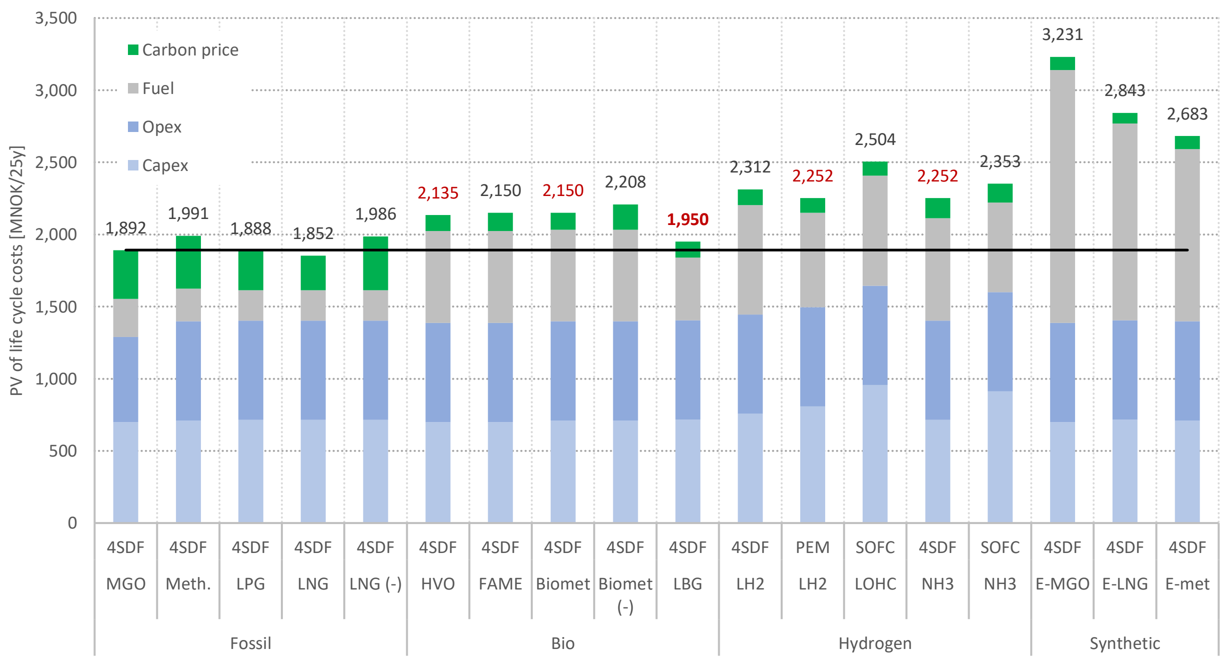


*Figure 39: PV of total lifecycle costs for PSV with alternative fuels.*

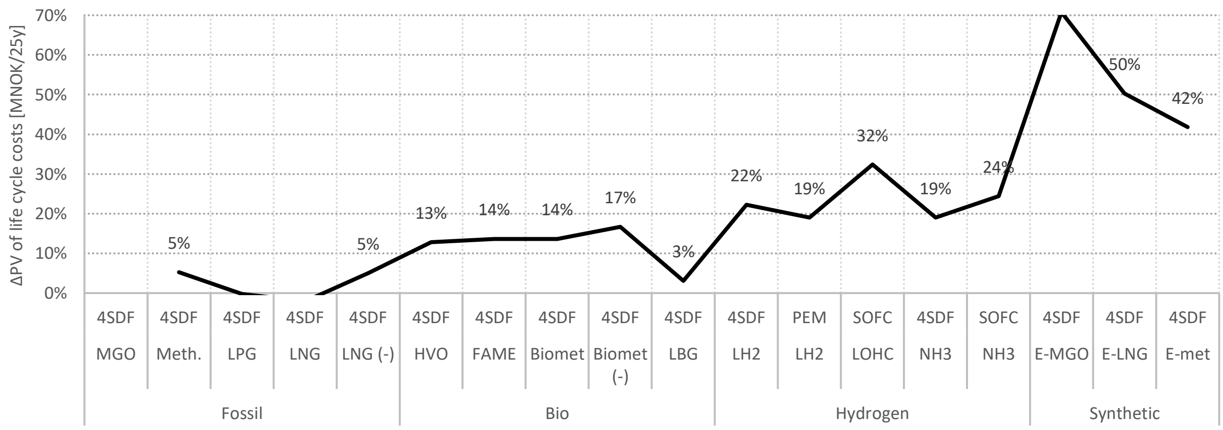


*Figure 40: Change in PV of total lifecycle costs for PSV with alternative fuels.*

*Conclusion and recommendation*

Biomethane is the least costly alternative (+3% only), followed by biofuels and biomethanol (+13-14%). Hydrogen combined with a PEM fuel cell and ammonia combined with a 4SDF comes out slightly more expensive (+19%).

Biomethane can be combined with and build on LNG as a basic fuel. LNG is commonly available and thus a good backup fuel that on its own cuts GHG by 5% to 30%, the higher number depending on the natural gas being produced with low emissions and combusted with no or very low methane slip. An offshore vessel built for gas operation gives near zero local pollution which is appreciated in port and when sailing near the coast, which is very much the case for platform supply vessels. Dual fuel gas engines are available and well known and this makes biomethane a safe choice without too many risks. On the supply side, however, serious work must be done to secure access to biomethane. Production is low, but existing, in many countries around the North Sea and elsewhere and the potential for more is there, considering the many raw materials that can be sourced.

Biomethanol is the second cheapest option. Methanol is technically more straightforward than hydrogen and ammonia with less complexity in both engine and fuel tanks. Biomethanol can be supported by synthetic methanol, but this option is among the costliest options in today's environment.

Hydrogen combined with PEM fuel cells and ammonia combined with 4SDF engines are the most attractive hydrogen-based fuel options. Both are more complicated and require a rethink of the general arrangement and a larger vessel. With the short endurance requirement of only seven days, the necessary upsizing seems possible though.

## 12.3. Anchor handling tug supply (AHTS)

*Operation*

Anchor handlers spend only 10-15% of their time towing with high power, yet this mode represents 30-40% of the energy demand. 20-30% of time is spent in transit and 40-50% of the time is spent in port with very low consumption.

*Green machinery*

AHTS typically have 20-26 MW installed but on average use only around 3 MW (10-15% of MCR). Based on the operating profile, we find that if 7 MW out of those 20-26 MW are capable of burning alternative fuels, this will cover 90% of the operating time for an AHTS. In diagram 41 below, the vertical line indicates this 90% threshold, and the horizontal line indicates the 7 MW required.

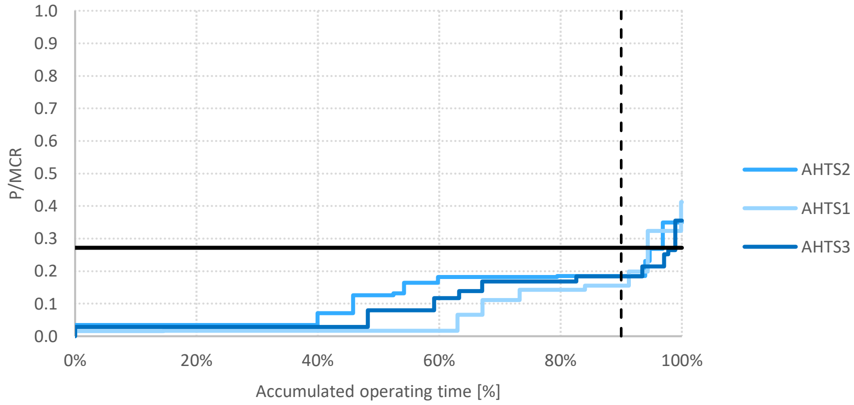


*Figure 41: engine load vs operating time for AHTS.*

*Tank compartment*

Anchor handlers need four weeks endurance, and the fuel tank capacity must thus be much larger than for PSVs. While the tank compartment for PSVs sailing one week was just 200-900 m³, we see 700-5,500 m³ being necessary for an anchor handler. This clearly has implications for the main dimensions of future AHTS. The increase in tank compartment size is very high for an AHTS; 200% up for LNG and around 300% up for ammonia.

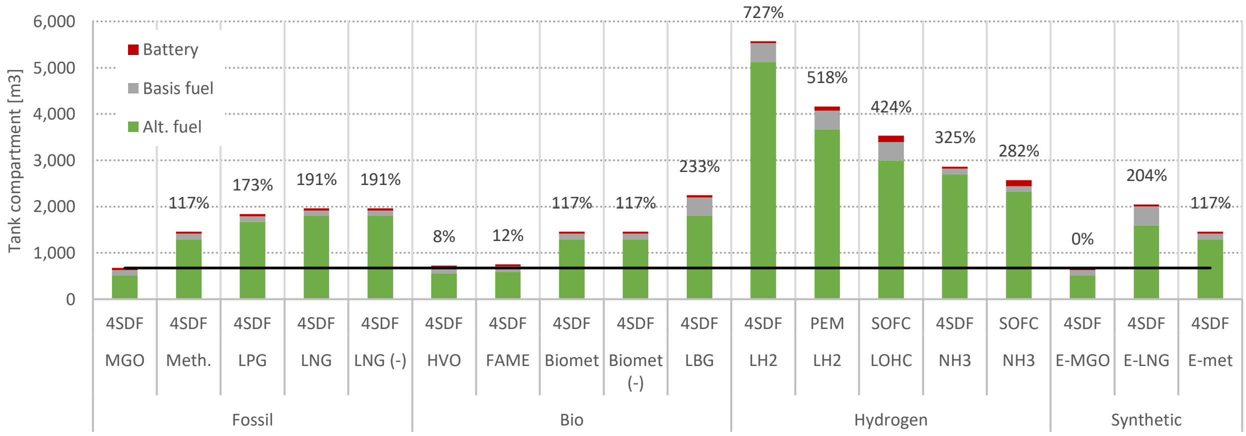


*Figure 42: Tank compartment volume (AHTS).*

*Ship size: Gross tonnage and length*

As a result, an AHTS must be significantly larger (see diagram 43-44 below). We estimate GT to increase up to 16%. The hydrogen alternative with PEM cell or LOHC will be 30-35 m longer while an AHTS with ammonia must be 20-25 m longer. Extending a PSV 8 m is more realistic than building an AHTS that is up to 50 m longer (ref diagram 44 below). This means that the most space demanding fuels (hydrogen) are off the chart unless box-shaped tanks can be developed. There are R&D efforts on this around the world.

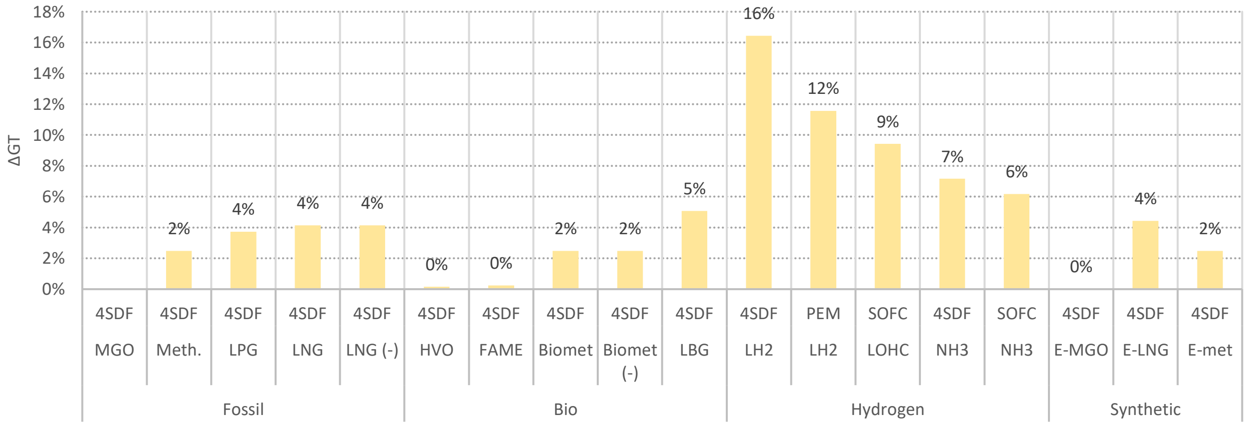


*Figure 43: Change in GT to accommodate alternative fuels (AHTS)*

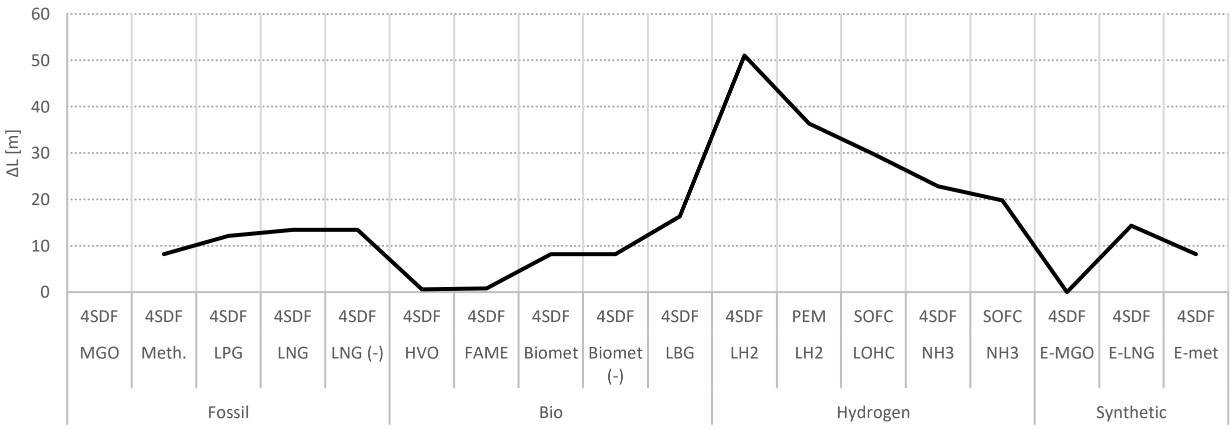


*Figure 44: Change in LOA to accommodate alternative fuels (AHTS)*

*Economics*

Looking at costs, we see (from diagram 45 below) that the biomethane case is again good, so are biofuels (HVO, FAME) and also biomethanol; just 12-16 % more expensive in a life cycle perspective. For anchor handlers, where the green machinery and tank capacity are a few sizes up from a PSV, the capex for machinery and tanks make the hydrogen options less interesting economically. The ammonia case based on a 4SDF engine looks better.

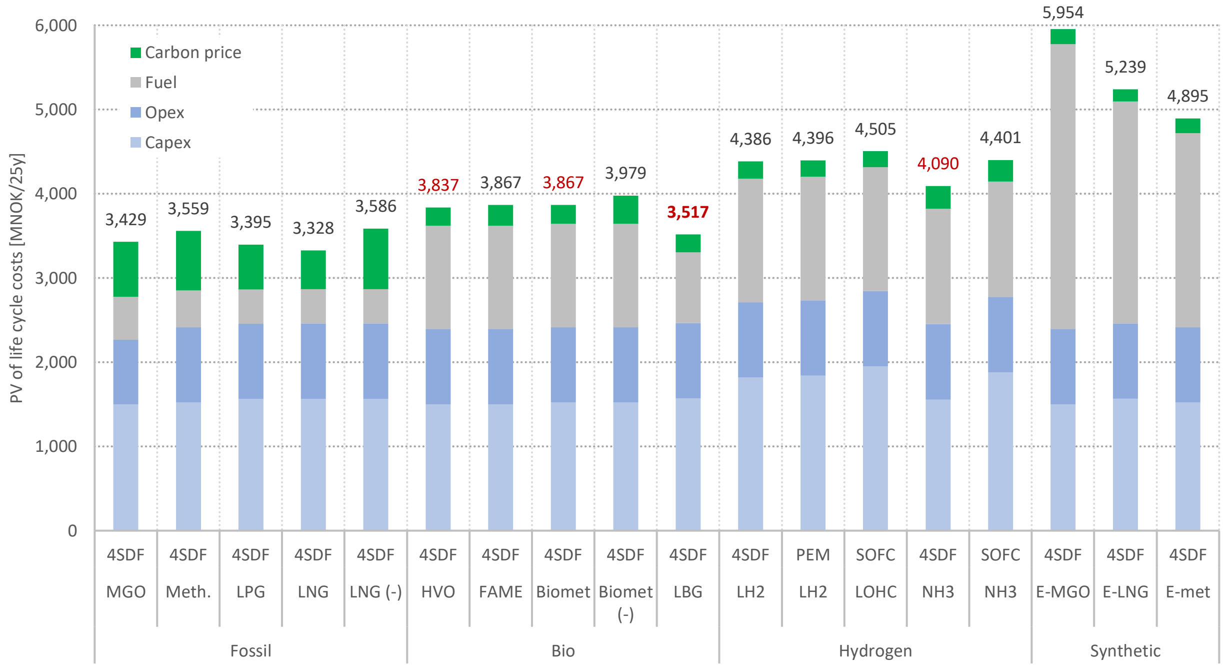


*Figure 45: PV of total lifecycle costs for AHTS with alternative fuels.*

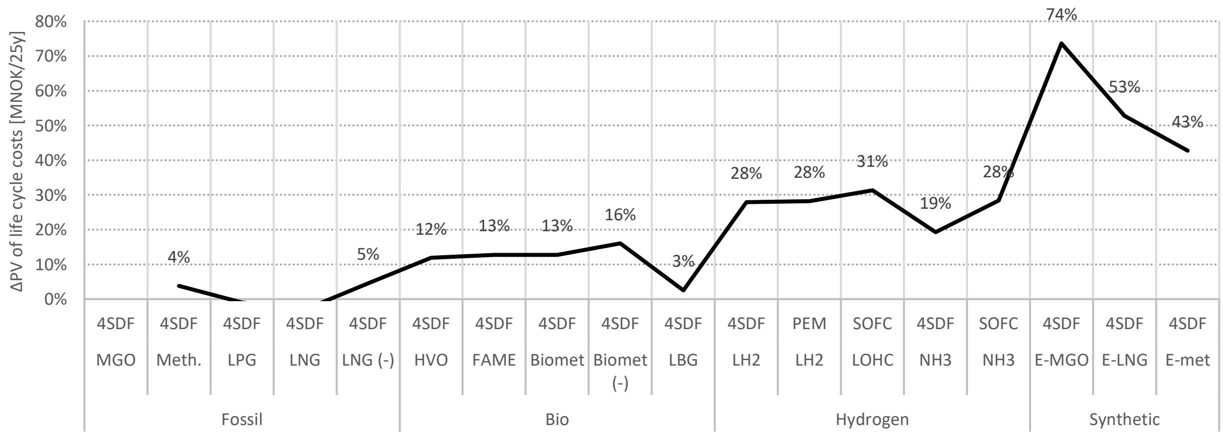


*Figure 46: Change in PV of total lifecycle costs for AHTS with alternative fuels.*

*Conclusion*

The conclusions are quite similar to those for a PSV, with a few exceptions.

Biomethane is the least costly alternative (+3% only), followed by biofuels including biomethanol (+13%).

Ammonia combined with a 4SDF gives lower cost than ammonia combined with a solid oxide fuel cell, given today's prices. Cylindrical tanks for ammonia for four weeks of service requires a ship 6-7% larger and 20-25 m longer than today. A different general arrangement or tank type (box-shaped) can alleviate this.

Hydrogen can be combined with either 4SDF or a PEM fuel cell; these two machinery options give the same cost increase (+28%). The long endurance required by an AHTS (four weeks of continuous operation) results in very large tank capacities and tank compartment, and this is especially noteworthy for hydrogen which requires a 35-50 meter longer vessel to accommodate the tanks. A different general arrangement or tank type (box-shaped or LOHC) can alleviate this somewhat.

## 12.4. Offshore construction vessel (CSV)

Construction vessels are the largest breed of offshore vessels with the largest variation in service. They are more expensive than the other two types. Also, construction vessels are perhaps even more mobile and require reliable access to fuel supply worldwide.

*Operation*

The operating profile will thus vary significantly from vessel to vessel and year to year depending on the work they have been put to. 40-60% of the operating time is spent in DP. 10-20% of the time is spent in transit but the energy demand in this mode is still 25-40% of the total. Time in port varies.

*Green machinery*

Construction vessels have 10-30 MW installed, on average approximately 20-25 MW. Analysing the figures, we see that the average power demand is very modest in relation to the power installed; around 3 MW (15% of MCR). Based on the operating profile, we find that if 7 MW out of those 20-25 MW are capable of burning alternative fuels, this will cover 90% of the operating time for a CSV. In diagram 47 below, the vertical line indicates this 90% threshold, and the horizontal line indicates the 7 MW required.

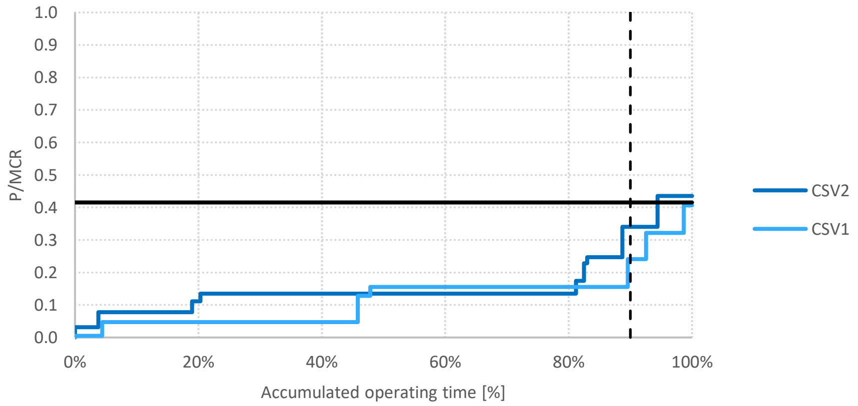


*Figure 47: engine load vs operating time for CSV.*

*Tank compartment*

Construction vessels spend time in port for mobilizing but should be able to spend four weeks working at sea. The average power demand is very similar to AHTS and the tank space required is also very high. Unlike AHTS, there is more space in a construction vessels and the increase in tonnage and ship length is thus relatively smaller and perhaps more acceptable for a CSV.

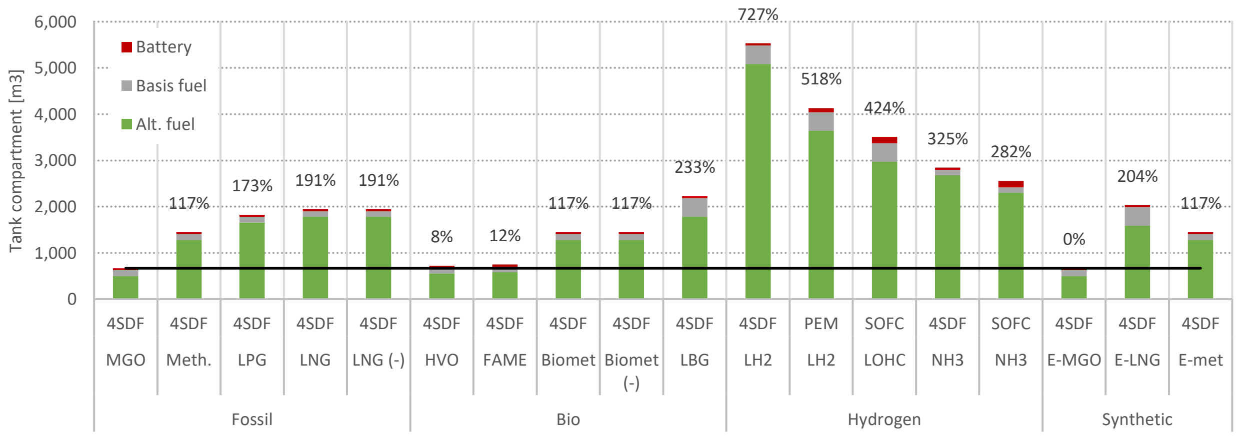


*Figure 48: Tank compartment volume (CSV).*

*Ship size: Gross tonnage and length*

To accommodate the fuel volumes required, a construction vessel must be built with up to 8% more enclosed space. This can be achieved by extending the section under the deck by 25 m. Note that the relative increase is much smaller for a CSV because these vessels are quite large already.

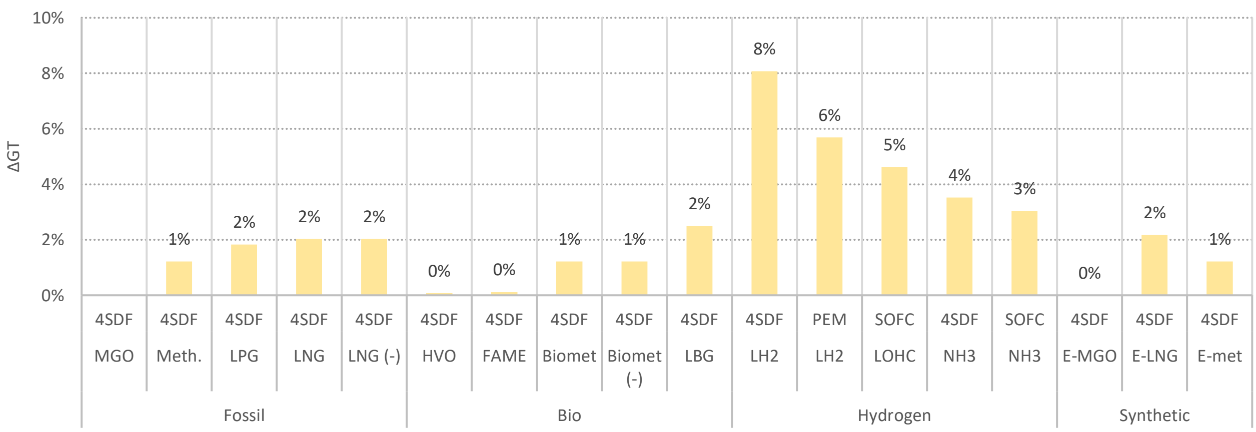


*Figure 49: Change in GT to accommodate alternative fuels (CSV)*

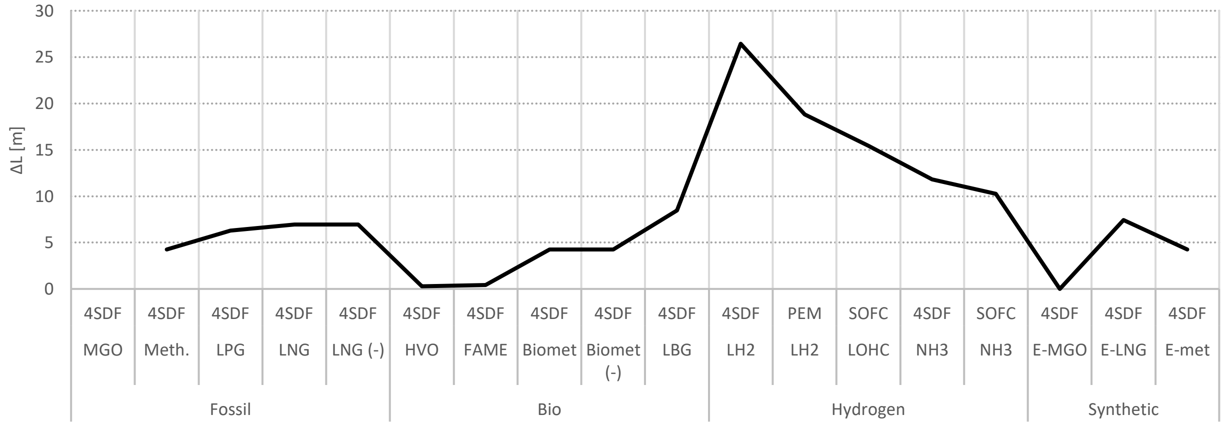


*Figure 50: Change in LOA to accommodate alternative fuels (CSV)*

*Economics*

We then turn to costs: Again, biomethane and biofuels including biomethanol are favourable, followed by ammonia with 4SDF ahead of hydrogen.

Construction vessels are very costly due to their outfitting and high DP-class requirements and highest requirements to safety, redundancy, reliability etc. This makes the additional cost for running on alternative fuels, both capex and fuel cost less important. This explains that the cost increase was 12-13% for biofuels on an AHTS but is only 9-10% on a CSV. And while the three hydrogen alternatives added 28-31% to the life cycle costs of an AHTS, they add just 21-25% for a CSV.

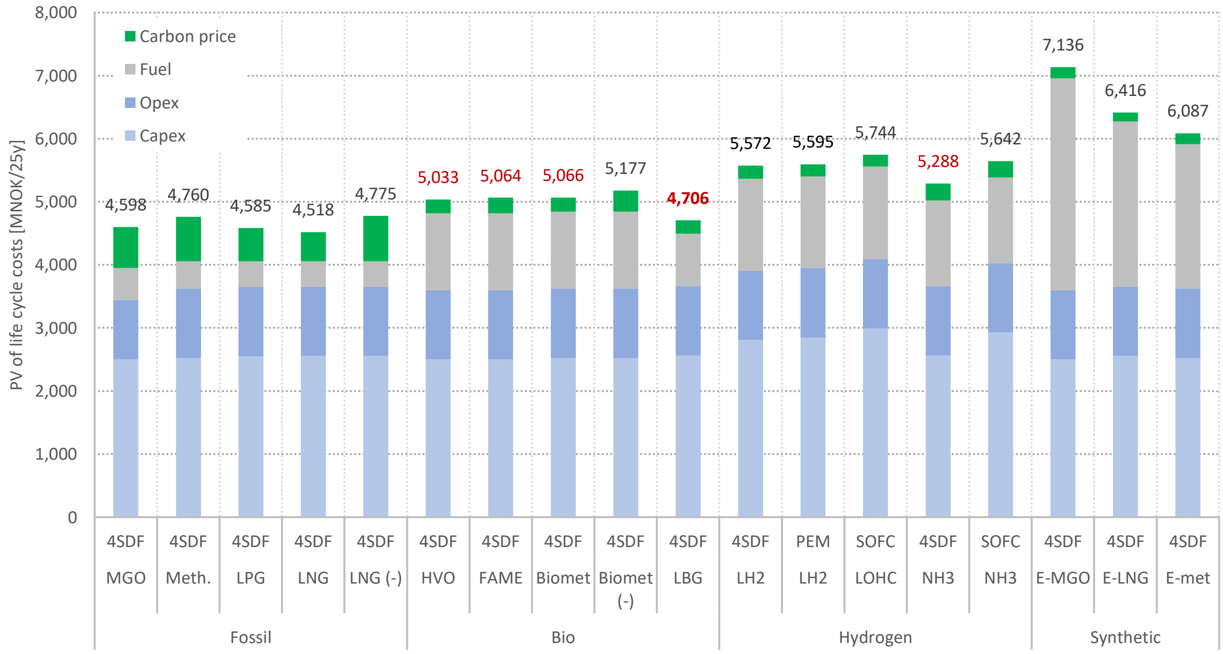


*Figure 51: PV of total lifecycle costs for CSV with alternative fuels.*

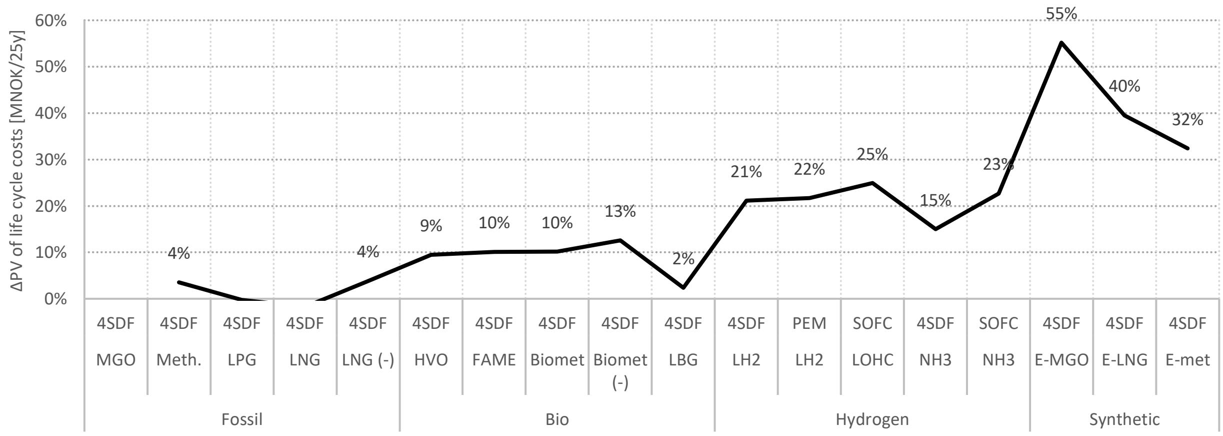


*Figure 52: Change in PV of total lifecycle costs for construction vessels with alternative fuels.*

*Conclusion*

The conclusion for a CSV is quite similar to those for a PSV and an AHTS, with some exceptions.

Again, biomethane (+2% only) and biofuels including biomethanol (+9-10%) are the least costly alternatives also for construction vessels.

Ammonia is best combined with a 4SDF (+15%), because of the so far very high price for SOFC type fuel cells. The enclosed volume of the vessel must only be increased around 3-4% (compared to 6-7% for an AHTS) to hold ammonia tanks for four weeks service.

Hydrogen increases the life cycle costs by around 21-22%, and for a CSV, hydrogen with PEM or 4SDF comes out equal. LOHC combined with solid oxide fuel cells are a bit more costly, but saves space onboard; with this option the construction vessel must be stretched only 15 m compared to 20-25 m with $LH_2$.

## 12.5. Conclusions & recommendations for all three vessel types

*Green machinery*

To cover 90% of the operating time with alternative fuels, approximately 50% of the installed power should be green (i.e. prepared for running on alternative fuels). For AHTS and CSV, the share must be approximately 25% and 40% respectively.

*Economics*

For all three vessel cases (PSV, AHTS and CSV), the *economic evaluation* is fairly consistent: The fuel option with lowest impact on life cycle costs is biomethane, followed by biodiesel and biomethanol with 9-14% higher life cycle costs.

Ammonia combined with a combustion engine is the least costly hydrogen-based option. Ammonia combined with a fuel cell gives much higher life cycle costs due to the very high cost of solid oxide fuel cells. When or if this technology develops successfully and reaches a scale where the cost drops, the picture can change.

Hydrogen combined with a fuel cell is a less costly option for platform supply vessels with small engine installations than for AHTS and CSV where the high cost of PEM cells cancels out the thermal efficiency advantage.

| | | PSV | AHTS | CSV |
|---|---|---|---|---|
| | LBG | +3% | +3% | +2% |
| | HVO | +13% | +12% | +9% |
| | Biomethanol | +14% | +13% | +10% |
| | NH3 4SDF | +19% | +19% | +15% |
| | LH2 PEM | +19% | +28% | +22% |
| | LH2 4SDF | +22% | +28% | +21% |
| | NH3 SOFC | +24% | +28% | +23% |

*Table 10: Change in PV of life cycle costs for the top 7 fuel and machinery options.*

## 12.6. Abatement cost for the three ship cases (PSV, AHTS, CSV)

The abatement cost is what we have to pay for each t of GHG avoided and is calculated to compare emission reduction measures across projects or industries so that we can allocate the resources where they are most effective.

$$\text{Abatement cost} = \frac{\Delta COST}{\Delta GHG} \quad \frac{NOK}{t\ CO_2\text{-eq.}}$$

The abatement cost for the three vessel types and all fuels varies: around 250-350 NOK/t $CO_2$-eq. for biomethane, around 1300-1500 NOK/t for the biofuels and 1300-1900 NOK/t for biomethanol, 2000-3400 NOK/t for hydrogen and 2300-3600 NOK/t for ammonia. The abatement cost for the synthetic fuels is much higher; 4000-5500 NOK/t and the abatement cost for LNG and LPG is negative.

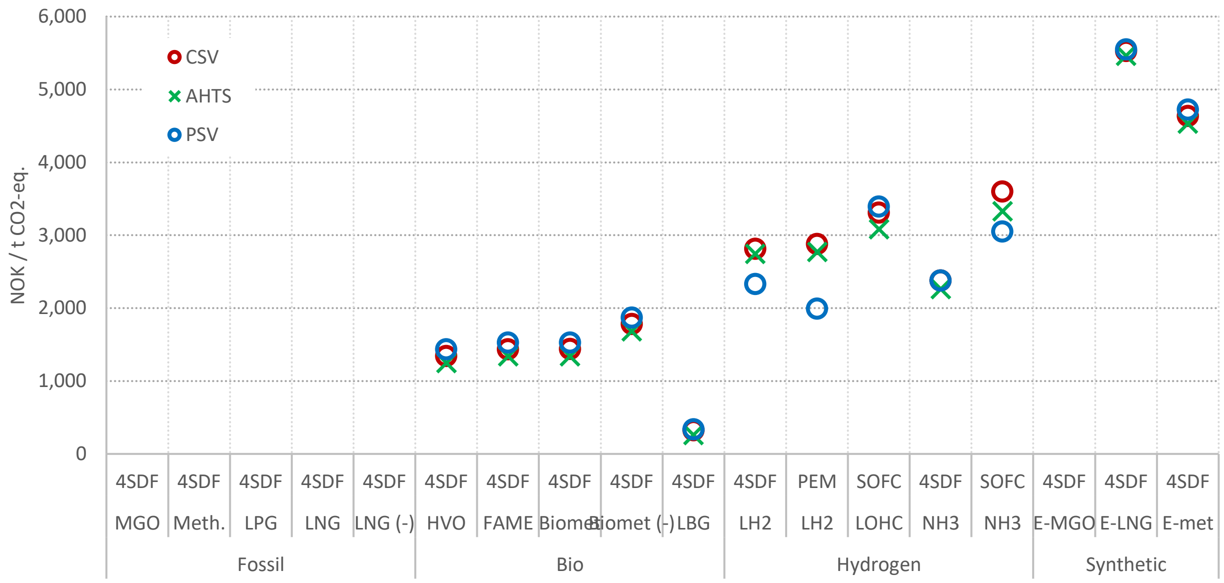


*Figure 53: Abatement cost for alternative fuels for offshore vessels.*

## 12.7. Reduction in GHG on fleet basis

We will now estimate the total emissions reduction potential for the offshore fleet. First, we look at the relative change in GHG emissions, both tank to wake (fig. 54) and well to wake (fig. 55). We then estimate the absolute change in GHG emissions.

This total effect is determined by the emission factor for each fuel (ref. fig. 12 in chapter 7.10), the phasing in schedule for each fuel (ref. fig 33 in chapter 12.1) and the total number of vessels.

In this study, we have focused on three vessel types, and we will estimate the effect for this fleet based on a total number of 175 supply vessels, 60 anchor handlers and 140 construction vessels, in total 375 vessels. In addition to these vessels, there are about 55 seismic research vessels in the Norwegian offshore fleet (ref. diagram 4 in chapter 5.3).

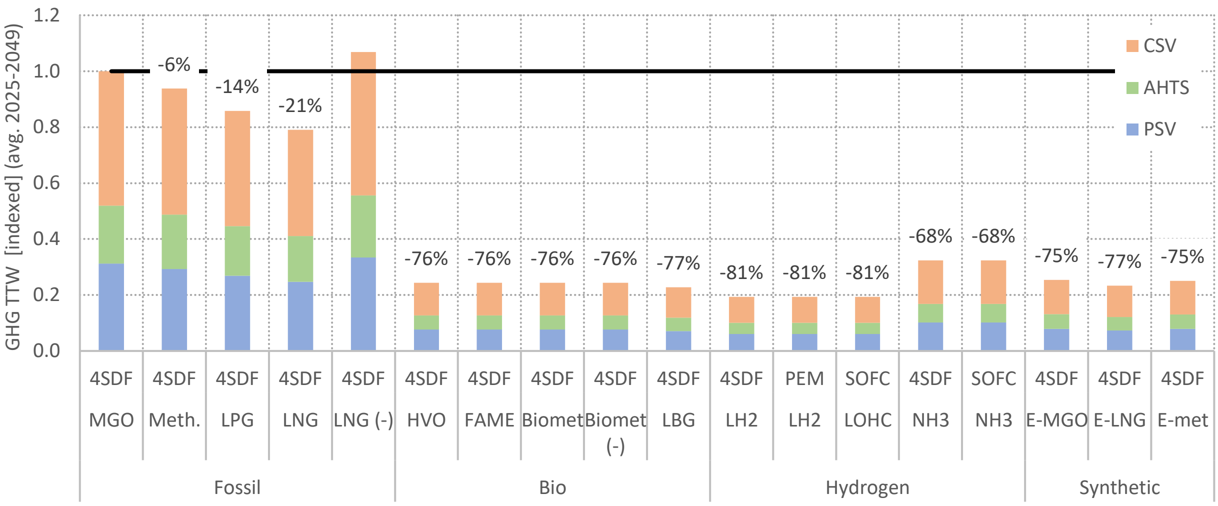


*Figure 54: Annual GHG emissions <u>tank to wake</u> from the Norwegian offshore fleet (PSV, AHTS and CSV; seismic vessels excluded) with alt. fuels in an average year in the period.*

With alternative fuels, GHG emissions tank to wake can be reduced by 70-80% (ref. figure 54 above). On a well to wake basis, GHG emissions can be reduced by 50-70% and up to 80% with synthetic fuels (ref. figure 55 below).

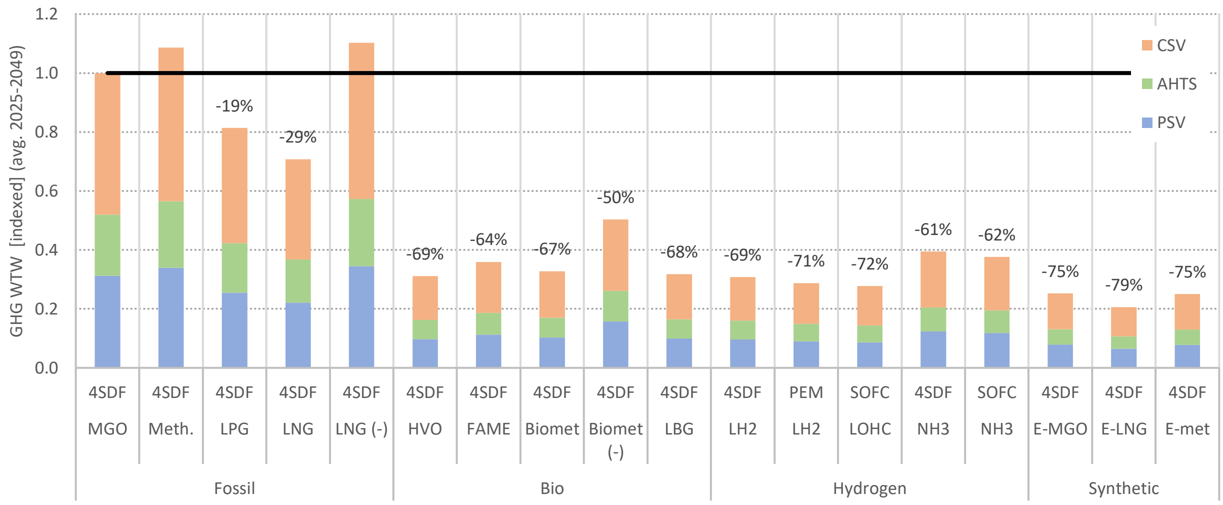


*Figure 55: Annual GHG emissions <u>well to wake</u> from the Norwegian offshore fleet (PSV, AHTS and CSV; seismic vessels excluded) with alt. fuels in an average year in the period.*

To get from *relative* to *absolute* emissions reduction, we estimate the total GHG emissions <u>tank to wake</u> for the fleet with MGO. There is no consensus on the total emissions for the offshore fleet and the emissions can be estimated in several different ways:

1. In this report, SINTEF Ocean estimates the total GHG emissions <u>tank to wake (TTW)</u> from 375 PSV, AHTS and CSV to approximately 4.8 Mt/y. This estimate is based on the operation profile of four PSV, three AHTS and two CSV (see fig. 35, 41 and 47). While we believe that the fuel consumption of these reference vessels is more or less representative for the entire offshore sector, we also know that the energy demand for offshore vessels, especially construction vessels, vary significantly from year to year based on the activity level and projects undertaken.

2. To check our own estimate, we have therefore analysed the sustainability reports of 13 Norwegian owners of offshore vessels. These reports suggest that the total $CO_2$ or GHG emissions was ca 3.6 Mt for a total of 326 vessels. If we assume that the emissions per vessel is the same for the vessels not included in any sustainability reports, we reach a total of abt. 4.1 Mt for a fleet of 375 vessels and abt. 4.7 Mt/y for a fleet of 430 offshore vessels.

The sustainability reports analysed include reports from DOF, Edda Wind, Eidesvik, Havila and Voldstad Maritime, Island Offshore Østensjø Rederi, PGS, Shearwater Geoservices, Siem Offshore, Simon Møkster Shipping, Solstad, Subsea7 and Tidewater.

We consider this estimate to be the most robust because it builds on actual emission reporting by companies operating around 70% of the Norwegian offshore fleet.

3. Some shipowners (Solstad, Havila, Island Offshore) inform the carbon intensity (e.g. CO2 emissions per day) of their fleet and distinguish between PSV, AHTS and CVS. Based on these daily $CO_2$ emissions, we calculate the total $CO_2$ to 2.7-3.5 Mt/y for a fleet of 375 offshore vessels and 3.6-4.2 for 430 vessels.

4. Worldwide, IMO found the total GHG emissions from 4,322 offshore vessels to be 20.9 Mt in 2018 IMO 4th GHG-study]. This suggests around 1.8 Mt for a fleet of 375 vessels and 2.1 Mt for a fleet of 430 vessel (seismic vessels included). We have reasons to believe that the Norwegian offshore fleet has a higher carbon intensity than the average because of the fleet composition. While Tidewater has abt. 75% platform supply vessels [Tidewater], the share is ca 45% for the Norwegian fleet (by number of vessels) [NR]. Also, we believe weather conditions are harsher and thus energy for e.g. stationkeeping is higher on the Norwegian continental shelf.

5. Throughout this report, we have omitted seismic research vessels. A rough estimate for the total GHG from this subtype can be obtained by taking the daily $CO_2$ emissions informed by GPS [PGS] and Shearwater Geoservices [Shearwater] and multiply with the total number of Norwegian seismic vessels (55 vessels). This suggests ca 0.8-1.4 Mt/y. We have not studied the data for seismic vessels carefully but believe the data from PGS are not representative.

The above can be summed up in table 11:

| | *Method/basis* | *Source* | *Fleet* | *Vessel types* | *GHG TTW [Mt]* | *Accuracy* |
|---|---|---|---|---|---|---|
| 1 | Based on operation profile for 9 reference vessels (ref. table 2) | SINTEF Ocean based on data from 3 offshore operators | 375 | PSV+AHTS+CSV | 4.8 | Medium high |
| 2 | Sustainability reports with emissions for abt. 300 vessels | SINTEF Ocean analysis based on data from 13 Norwegian owners | 375 | All offshore | 4.1 | Robust |
| | | | 430 | ↑ | 4.7 | ↑ |
| 3 | Carbon intensity for PSV, AHTS and CSV | SINTEF Ocean analysis based on data from 3 Norwegian owners | 375 | PSV+AHTS+CSV | 2.7-3.5 | Medium low |
| | | | 430 | All offshore | 3.6-4.2 | ↑ |
| 4 | Average carbon intensity of the global offshore fleet | SINTEF Ocean estimate based on data from IMO 4th GHG-study | 375 | Not specified | 1.8 | Uncertain |
| | | | 430 | ↑ | 2.1 | ↑ |
| 5 | Carbon intensity for seismic research vessels | SINTEF Ocean analysis based on data from 2 Norwegian owners | 55 | Seismic | 0.8-1.4 | Uncertain |

*Table 11: Estimates for total annual GHG or $CO_2$ emissions tank to wake from the Norwegian offshore fleet.*

To conclude, the total GHG emissions from the fleet of 375 PSV, AHTS and CSV analysed in this report is likely ca 3.5-4.5 Mt/y.

A reduction of 70-80% means that the total GHG can be reduced from 3.5-4.5 Mt to 0.7-1.1 Mt/y.

## 12.8. Fuel demand for the Norwegian offshore fleet

Based on the fleet composition and a total fleet of 375 vessels, the aggregated fuel demand can be estimated for each fuel based on the phasing in schedule assumed. The estimate is based on the total fuel consumption estimated by SINTEF Ocean as per method 1 explained in chapter 12.7 and likely a bit on the high side.

The diagram shows the average annual demand for the period 2025-49; note that demand will be lower in the first few years and higher in the late part of the period as alternative fuels replace the basis fuel.

Demand for MGO and LNG as basis fuel is not included.

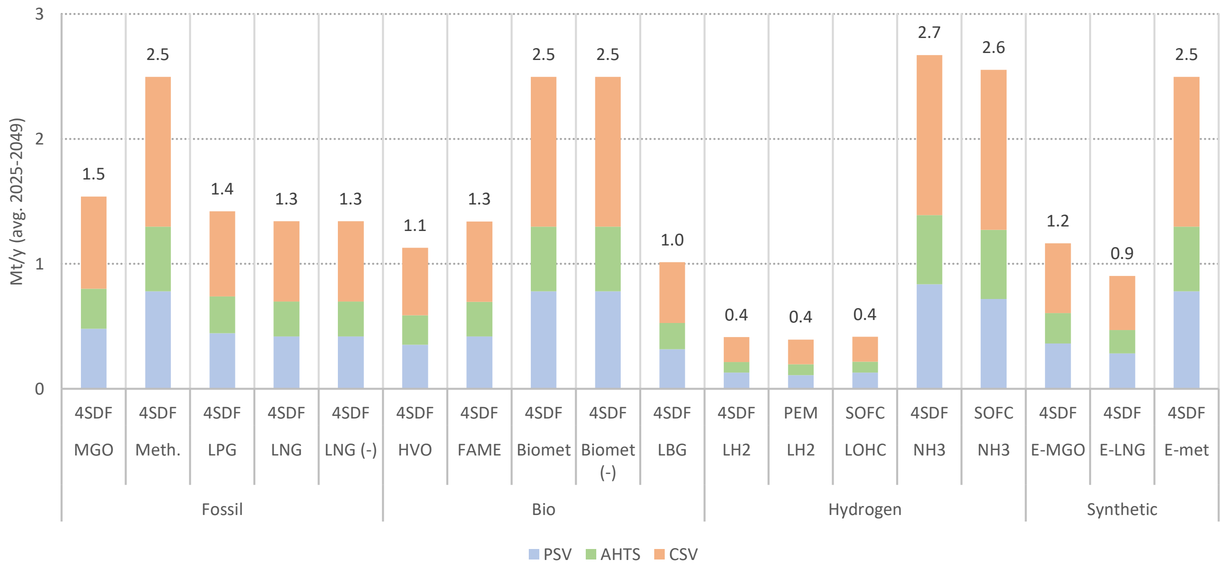


*Figure 56: Annual fuel demand for the average year in the period 2025-49, i.e. around 2031.*

# 13. Comparison tables

The first table lists some physical properties with impact on storage together with tank technology options.

| | | | *LHV* | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | *ρ [kg/m³]* | *[MJ/kg]* | *[GJ/m³]* | *Tank type* | *Storage temp. [°C]* | *Tank net volume* | *Tank room volume* | *TRL* |
| Liq. | MGO | 890 | 42.7 | ⭐ 38 | ⭐ Hull tank | Ambient | ⭐ 1 (ref) | ⭐ 1 (ref) | 9 |
| | E-MGO | ↑ | | | ↑ | | | | |
| | FAME | 885 | 37.1 | 10.3 | Hull tank, coated | Ambient | 1.16 | 1.16 | 9 |
| | HVO | 780 | 44.1 | 12.3 | ↑ | Ambient | 1.11 | 1.11 | 9 |
| Gas | LNG | 440 | 48-50 | 21-22 | Pressure vessel | -163°C | 1.8 | 3.5 | 9 |
| | E-LNG | ↑ | | | ↑ | | | | |
| | Biomethane | ↑ | | | ↑ | | | | |
| Methanol | Biomethanol | 791 | 19.9 | 7.4 | Hull tank, stainless steel or coated | Ambient | 2.4 | 2.4 | 9 |
| | E-Methanol | ↑ | | | ↑ | | | | |
| $H_2$ | Hydrogen | 70.8 | ⭐ 120 | 8.5 | Cryo. (-253°C) | Up to -253°C | 4.5 | 8-10 | 7-8 |
| | | | | | LOHC | Ambient | 6 | 6 | 5 |
| | Ammonia | 771 | 18.6 | 14.3 | Pressure vessel | -33°C | 2.7 | 4.5-5.5 | 7-9 |

*Table 12: Comparison of storage options (the best option is indicated by ⭐)*

The next comparison table sums up machinery options. The flexibility to run on multiple fuels is best explained by figure 17 in chapter 8.7

| | | *ICE DF* | | | *Fuel cell* | | |
|---|---|---|---|---|---|---|---|
| | | *2S* | *4S MS* | *4S HS* | *PEM* | *SOFC* | *Regulations* |
| Liq. | MGO | X | X | X | | | *Prescriptive* |
| | E-MGO | ↑ | | | | | |
| | FAME | ↑ | | | | | |
| | HVO | ↑ | | | | | |
| Gas | LNG | X | X | X | | | |
| | E-LNG | ↑ | | | | | |
| | Biomethane | ↑ | | | | | |
| Methanol | Biomethanol | X | X | Under dev. | | | |
| | E-Methanol | | | | | | |
| $H_2$ | Hydrogen | Under dev. | X | | X | Under dev. | Alternative design |
| | Ammonia | Under dev. | Under dev. | N/A | Under dev. | Under dev. | |

*Table 13: Comparison of machinery options.*

The next comparison table sums up the availability of alternative fuels.

| | | *Availability* | | | | |
|---|---|---|---|---|---|---|
| | | *Fossil variant* | *Green Variant* | *Blue variant* | *Bio variant* | *Key enabler* |
| Diesel | MGO | High | | | | |
| | E-MGO | | Very low | | | Abundant or stranded renewable electricity |
| | FAME | | | | Low | Sustainable biomass |
| | HVO | | | | Low | Sustainable biomass |
| Gas | LNG | High | | | | |
| | E-LNG | | Very low | | | Abundant or stranded renewable electricity |
| | Biomethane | | | | Low | Sustainable biomass |
| Methanol | Fossil meth | >99% | | | | |
| | Biomethanol | | | | Low | Sustainable biomass |
| | E-Methanol | | Very low | | | Abundant or stranded renewable electricity |
| $H_2$ | Hydrogen | >99% | <1% | <1% | | Abundant or stranded renewable electricity or carbon capture and storage (CCS) |
| | Ammonia | >99% | <1¤ | <1% | | |

*Table 14: overview of fuel availability.*

# 14. Next steps

Once the study has been digested by the shipowners operating offshore vessels, we suggest moving forward by summing up the intentions of the shipowners' and discuss how the three sides; owners/operators, charterers and the energy sector supplying the future fuels can coordinate their activities in order to realize the emissions reductions identified in this study.

To leverage scale and to speed up construction of shoreside supply and infrastructure and minimize the cost of this, the shipping sector should as far as possible agree to use a single alternative fuel.

The cost of fuel is normally covered by the charterer directly. This practice applies to most offshore vessels as well as other cargo ships sailing on time charters. While there are good reasons for this practice, it is also acknowledged as a major obstacle for technical upgrades resulting in lower fuel consumption because the economic burden (investment) falls on the shipowner and the economic advantage (lower fuel cost) falls on the charterer.

The same alignment of interests applies to the choice of alternative fuels: Owner and charterer should align early and enter long term contracts to split costs and risks for both capital, operating and fuel costs and ensure the total is minimized to the advantage of both parties.

# 15. Abbreviations and terminology

| | |
|---|---|
| abatement cost | Cost per emission reduction [e.g. NOK/t $CO_2$]. (Norwegian: tiltakskostnad) |
| AC | Alternating current |
| AER | Annual Efficiency Ratio. |
| AIS | Automatic Identification System, information system to identify and track vessels including their identity, type, position, course, speed, navigational status and other safety-related information. Also used as basis for stating emissions e.g. in the IMO GHG-studies. |
| ASOG | Activity Specific Operating Guidelines |
| BECCS | bioenergy with carbon capture and storage |
| BC | Black carbon, an indirect greenhouse gas. |
| CAMO | Critical Activity Mode of Operation |
| capex | Capital expenditure (investment) |
| carbon intensity | Carbon or greenhouse gas emissions per activity, e.g. $CO_2$ per transport work or value created. |
| carbon leakage | Shifting of emissions from onboard use to the production phase |
| CCUS | Carbon capture, utilization, and storage |
| CCS | Carbon capture and storage |
| $CH_4$ | Methane, a potent greenhouse gas ($GWP_{100}$ 29.8±11, $GWP_{20}$ 82.5±25.8) |
| CII | Carbon Intensity Indicators, ratio of greenhouse gas emissions by transport work (IMO MEPC resolutions 335-339(76) |
| climate negative | Emissions reduction above 100% |
| CNG | Compressed natural gas |
| Cradle to gate | Scope for emissions (and other factors, e.g. cost or energy use) from fuel production, where the emissions from transportation from factory to consumer and bunkering is excluded. Thus, emissions cradle to gate $<$ emissions well to tank. |
| DAC | Direct air capture, extract $CO_2$ directly from the atmosphere (IEA) |
| DC | Direct current |
| DE | Diesel electric, power generation by engine (commonly, but not necessarily, a diesel engine) and electric power transmission |
| DCS | Data collection system, an IMO instrument for reporting of fuel, emissions and proxy for transport work (IMO) |
| DF | Dual fuel, engines capable of burning two fuels. See also multi fuel. |
| DP | Dynamic positioning |
| E | Exa, SI-prefix, $10^{18}$ |
| ECA | Emission control area |
| EEDI | Energy Efficiency Design Index (IMO) |
| EEXI | Energy efficiency existing ships index, an equivalent to EEDI for existing ships |
| energy density | Energy per volume [e.g. $J/m^3$] |
| EEOI | Energy efficiency operational indicator (IMO) (IMO MEPC.1/Circ. 684, 17 August 2009) |
| FAME | Fatty acid methyl esters |

| | |
|---|---|
| G | Giga, SI-prefix, $10^9$ (one billion) |
| GHG | Greenhouse gas [$CO_2$-equivalents], see Kyoto gases |
| GT | Gross tonnage, a function of the moulded volume of all enclosed spaces of the ship (IMO) |
| GWP | Global warming potential, a factor to convert and compare the GHG-effect of other greenhouse gases to $CO_2$. Unless otherwise specified, the timescale used is 100 years ($GWP_{100}$) and factors taken from IPCC, WG1AR6, chapter 7, table 7.15 (page 1017). |
| $GWP_{100}$ | GWP for a timescale of 100 years, the most commonly used horizon |
| $GWP_{20}$ | GWP for a timescale of 20 years i.e. focusing on the near term effects |
| HFO | Heavy fuel oil, e.g. RME, RMG, RMK. (ref ISO 8217), also known as residual fuels |
| HVO | Hydrotreated vegetable oils |
| $H_2$ | Hydrogen |
| IGC-code | The International Code of the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk |
| IGF-code | International Code of Safety for Ships Using Gases or Other Low-flashpoint Fuels; an international standard for ships, other than vessels covered by the IGC Code, operating with gas or low-flashpoint liquids as fuel. |
| ILUC | Indirect land use change |
| IMO | International Maritime Organization, the UN body for shipping (London/International) |
| IPCC | Intergovernmental Panel on Climate Change (Genève/International) |
| IRENA | The International Renewable Energy Agency, established 2011. |
| Kyoto gases | The main six greenhouse gases: carbon dioxide ($CO_2$), methane ($CH_4$), nitrious oxide ($N_2O$), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexachloride (SF6) |
| LCA | Life cycle assessment |
| LBG | Liquefied biogas or biomethane, methane produced from biological raw materials, wastes or byproducts |
| LHV | Lower heating value, the energy content of fuels [kJ/kg, MJ/kg] |
| LNG | Liquefied natural gas, primarily methane |
| LPG | Liquefied petroleum gases, mixes of propane, butane and other hydrocarbons |
| $LH_2$ | Liquefied hydrogen |
| M | Mega, SI-prefix, $10^6$, (one million) |
| MARPOL | IMO's International Convention for the Prevention of Pollution from Ships |
| MEPC | Marine Environment Protection Committee, one of IMO's five main committees (IMO) |
| MCR | Maximum continuous rating, the maximum power [kW] an engine can deliver continuously |
| MDO | Marine diesel oil, DMB (ref ISO 8217) |
| MGO | Marine gas oil, e.g. DMA, DMZ (ref ISO 8217) |
| MSC | Maritime Safety Committee, one of IMO's five main committees (IMO) |
| Multi fuel | An engine capable of burning several (more than two) different fuels. See also dual fuel. |
| MRV | An EU instrument for reporting of energy, fuel, emissions and transport work (EU DG CLIMA) |
| $N_2O$ | Nitrous oxide, a potent greenhouse gas $GWP_{100}$ 273±130, $GWP_{20}$ 273±118) |
| NCR | Nominal continuous rating |
| $NH_3$ | Ammonia |

| | |
|---|---|
| $NO_X$ | Nitrogen oxides; NO, $NO_2$, $N_2O_3$, but mainly $NO_2$ |
| OC | Organic carbon |
| OCCS | Onboard carbon capture and storage: Systems for capturing $CO_2$ from ship's funnel for onboard storage and delivery to shore for permanent storage. |
| opex | Operating expenditure |
| PEM | Proton exchange membrane, a type of fuel cell considered most suitable for mobile applications. |
| $PH_2$ | Pressurized hydrogen |
| $PM_{10}$ | Particulate matter with diameter < 2.5 µm (µm = 1/1000 mm, 1/1,000,000 m) |
| $PM_{2.5}$ | Particulate matter with diameter < 2.5 µm (µm = 1/1000 mm, 1/1,000,000 m) |
| ppm | Parts per million |
| PV | Present value, depreciated value of future income or costs. |
| Scenario | A coherent, internally consistent, and plausible description of a possible future state of the world. |
| Specific energy | Energy per weight [J/kg] |
| SFC | specific fuel consumption [g/kWh] |
| SMR | Steam methane reforming, process for producing hydrogen from natural gas. |
| SOFC | Solid oxide fuel cell, high temperature fuel cell with high efficiency but limitations in operations. |
| $SO_X$ | Sulphur oxides; primarily $SO_2$ and $SO_3$ |
| SRL | System readiness level, an index of the maturity and availability of complete systems rather than individual components. |
| T | Terra, SI-prefix, $10^{12}$, (one trillion) |
| TTW | Tank to wake: Emissions, other environmental effect or energy use arising onboard the use from use. |
| tier I, II or III | Emission limit standard for $NO_X$ for marine machinery (IMO) |
| TRL | Technology Readiness Level, an index of the maturity and availability of technology under research and development (NASA or EARTO) |
| WTT | Well to tank: Emissions, other environmental effect or energy use from production, refining, conversion, transport, bunkering etc before the fuel is onboard the vessel. WTT emissions fall within scope 3. Electricity provided is scope 2. |
| WTW | Well to wake: Emissions, other environmental effect or energy use during the whole life cycle taking all effects into account. Broadly equivalent to scope 1-emissions.<br>WTW = WTT + TTW = well to tank + tank to wake |

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