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MarE-Fuel: Sustainable Maritime Fuels - Executive Summary Report

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Publication date:
2021

Document Version
Publisher's PDF, also known as Version of record

Citation (APA):
Hendriksen, P. V., Sørensen, T. A., & Münster, M. (2021). *MarE-Fuel: Sustainable Maritime Fuels - Executive Summary Report*. Technical University of Denmark.

MarE-Fuel: Sustainable Maritime Fuels

- Executive Summary Report

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November 4th, 2021

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Contents

Introduction

This report presents the executive summary of the MarE-Fuel project financed by the Maritime Fund and the Lauritzen Fund. Partners of the project has been DTU, Anker Invest, Mærsk Line, Copenhagen Economics, OMT and DFDS.

In the MarE-fuel project the “total cost of ownership” for a fleet operator using several different green fuels in future has been estimated. The analysis considers the situation now (2020) and in 2030 and 2050. Furthermore, a roadmap illustrating possible transitions from the situation today to a zero emission maritime sector by 2050 has been constructed. This roadmap considers the emissions associated with use of various fuels, different scenarios for global emission caps for the sector and identifies the cheapest solutions over time. For both these analyses it is key to estimate the fuel costs for different fuels at various times in future. This is a non-trivial task involving projections to be made on both future costs of involved technologies and operating expenses related to use of electricity and purchase of resources like biomass.

The first chapter summarizes the work related to assessing future costs of green fuels. The second chapter presents the total cost of ownership (TCO) model taking both fuel costs and ship related costs as well as emissions into account. The third chapter summarizes roadmap scenarios for a transition towards different global GHG emission reduction targets for the shipping sector.

Chapter four contains some final remarks on limitations in the presented analysis, other barriers to reducing emissions from the sector and suggestions to further work.

Further information regarding models, assumptions and references can be found in the background reports:

- "MarE-Fuel: LCOE and optimal electricity supply strategies for P2X plants"
- "MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost"
- "MarE-Fuel: CO2-Taxes, Fuel Prices and Learning Rates"
- "MarE-Fuel: Total Cost of Ownership"
- "MarE-Fuel: Roadmaps for sustainable maritime fuels"

1 Future costs of green fuels

By Peter Vang Hendriksen

Background

Several different fuels have been addressed in the project. The level of detail in the analysis of the expected fuel costs varies among the fuels. Special emphasis has been placed on analyzing the expected costs of *methanol* and *ammonia* obtained via different synthesis routes. These are labelled “green”, “blue” or “grey” depending on the feedstocks. “Green” signifies only renewable resources as feedstocks. “Blue” refers to the case where some fossil feedstocks are applied (methane) and emission reduction is ensured by carbon capture and sequestration and “grey” refers to the case where the fuel is derived from natural gas. For the case of methanol the analysis has further considered three different green routes; 1) based on gasification of biomass and methanol synthesis after addition of hydrogen from electrolysis (“Bio-E-methanol”), 2) Via synthesis from CO2 and hydrogen from electrolysis, where the CO2 is obtained from capture from a point source of biogenic CO2 (BM-fired CHP plant or biogas plant), which is labelled “Green methanol CCU”, and finally 3) from CO2 captured from air combined with H2 from electrolysis; “Green methanol DAC”.

Methodology

The methodology adopted in assessing the expected future costs of green fuels is based on an assessment of the needed investments in all parts of the synthesis plant, the CAPEX, and an assessment on the operating expenses (OPEX). The method is further described in the report "MarE-Fuel: Energy efficiencies in synthesizing green fuels and their expected cost".

Plant OPEX

The operating expenses are dominated by expenses for purchase of feedstocks (natural gas and biomass) and expenses for acquiring electricity. Since the latter is very important for the overall result, quite some effort has been devoted in analysing what could be the future price of electricity. Expected future costs of biomass and natural gas were analysed in the project by Copenhagen Economics and are documented in Ref [1].

The expected future electricity costs that are applied in the model are documented in "MarE-Fuel: LCOE and optimal electricity supply strategies for P2X plants" Ref. [2]. Four different locations considered attractive for synthesis of green fuels were analysed due to their high potential for cheap electricity produced from either wind or sun. These were; Arica (Chile, very high sun potential, low wind), Ceduna (Australia, high wind, high sun), Dahkla (Morocco, very high wind and very high sun), and finally Esbjerg (Denmark, very high wind, low sun, and market for waste heat). Other interesting locations, such as Texas, can in the future be analysed with the developed framework. Different ways of obtaining the electrical energy were considered to find the economical optimum at the location. The local production from sun and wind at the location will vary over time (a certain capacity factor is associated with the wind turbines and solar cells) and so will the cost of grid electricity. The most favourable modes of operating at the specific locations, when considering both cost and emissions, were found to be either using own wind-turbines and solar cells only ("Behind the meter") or combining these with some purchased electricity from the local grid when the combination was more cost competitive ("BtM-Grid"). A local optimisation using the OptiPlant model, developed for this project, was employed at the selected sites. In this optimisation, besides finding the optimum between investing in PV/Wind turbines vs. grid purchase the model invests in local storage solutions like batteries and hydrogen tanks as long as the value of the extra fuel produced during the increased number of operation hours (enabled by the storage) pay back the extra investment. Assumptions regarding costs of the electricity generation technology as well as the cost of electricity purchased from the grid and how this is expected to develop from now "2020" to 2030 and 2050 can be found in the detailed report Ref. [2]. In assessing the future fuel costs, the most attractive among the four locations (the one giving the best compromise between low cost and low emission) was chosen. Further details on the plant OPEX can be found in Ref. [3].

Plant Capex

For the key fuels and synthesis routes the expected conversion efficiencies has been calculated from either detailed "Balance-of-plant-level modelling" (methanol and ammonia) conducted in the Mar-E-Fuel project or from analysing studies in literature (pyrolysis oil). Plant lay-outs were constructed and analysed (typically using Aspen) and conversion efficiencies and plant capex calculated. The approach is described in the report [3] and key assumptions are document in Ref. [4]. For all costs a learning curve is applied assuming that costs will decrease over time due to ramping up of production and due to economy of scale of bigger units. As cost reductions depend on the volume of plants implemented, the speed of learning - and thereby also the cost reductions – are somewhat uncertain.

It should be noted that with the assumed costs of storage technology, costs of grid electricity at the four analysed locations, the optimal mode of operation entails between 6500 and 7800 hours of operation at full load annually. The fuel production plant is subsequently "oversized" to deliver the targeted amount of annual fuel production given this limitation in equivalent annual full load hours. In this way the local capacity factor limitations of solar and wind factors in, not only on the cost of the electricity, but also on fuel synthesis plant Capex.

Results on expected future fuel costs

Calculated fuel costs now and in 2030 and 2050 are summarised in Tables 1 and 2 below

Table 1 Overview of projected future costs of selected green, blue, grey and black fuels (€2019/t)

Fuel	2020	2030	2050
	€/t	€/t	€/t
Green methanol "Bio-E-methanol"	725	570/**582**	453/**462**
Green methanol CCU	866	638	450
Green Methanol DAC	1053	811	558
Grey methanol	193	147	151
Green ammonia	716	536/**561**	355/**369**
Blue ammonia	558	447	392
Grey ammonia	199	152	155
Refined Pyrolysis oil	408	426	461
VLSFO	430	380	344
Liquified biogas	1015	1410	2328
LNG	215	155	159
LPG	381	336	304

Table 2 Predicted future costs of selected green, grey, black and blue fuels (€2019/GJ)

Fuel	2020	2030	2050
	€/GJ	€/GJ	€/GJ
Green methanol "Bio-E-methanol"	*36.4*	*28.6/**29.2***	22.8/**23.3**
Green methanol CCU	44.9	33.4	23.5
Green methanol DAC	53	41	28
Grey methanol	9.7	7.4	7.6
Green ammonia	38.5	28.8/**30.1**	19.1/**19,9**
Blue ammonia	30.0	24	21.1
Grey ammonia	10.7	8.2	8.3
Refined Pyrolysis oil	24.0	25.1	27.1
VLSFO	10.2	9.0	8.1
Liquified biogas LBG	20.3	28.2	46.6
LNG	4.3	3.1	3.2
LPG	8.0	7.1	6.4

Where two numbers are quoted the first one reflects the calculated cost on the cheapest of the four locations (Arica). The second number (in bold) refers to the situation in Dakhla, which cost-wise is very close to Arica but leads to significantly smaller emissions. Hence, with view to both emissions and cost, the latter case is considered the most relevant and serves as the base case for the further analyses.

The numbers in Table 1 and 2 refer to calculated production costs for the green fuels at one of the four specific locations and for the standard fuels the numbers are prices in Rotterdam. Before utilising the numbers in the roadmap model or in the TCO analyses, further a cost of transportation to Rotterdam is added as well a small profit. If for a specific fuel a pilot oil is needed for ensuring suitable engine operation this is further added (see details in chapter 2).

In the project we have also considered liquefied biogas, Liquified Natural gas and Liquified petroleum gas as possible fuels. The assumed costs/prices of these fuels are listed in the three last lines of the table. For the commercial products LPG and LNG the background for the assessment can be found in Ref. [1] and for the LBG-case in Ref [3]. The most thorough analysis has been conducted for methanol and ammonia, which is discussed in some detail here. For the other fuels the reader is referred to Ref. [1] and [3].

Key learnings on the cost of ***green methanol*** from the cost numbers summarized above are:

- The projected cost reduction over time from 2020 to 2050 is roughly a factor 2 for the CCU and around 1.5 for the bio-e methanol.
- Bio-e-methanol and green methanol-CCU end at very similar costs in 2050 (22.8-23.5 EUR/GJ)
- The Bio-E-methanol route provides a cheaper green fuel than when considering point source CO2, albeit the costs come close by 2050. Here, it should be noted that for *Green methanol CCU* a CO2 price of 0 is assumed and the point source plant economy is not taken into account, meaning that only the capture and synthesis expenses are included (an existing point source plant is considered).
- The cost of green methanol is 3-4 times the expected price of grey methanol

Key learning from the study of ammonia costs are:

- In the Mar-E-fuel reference case (see Table 1) the cost of green ammonia is ca. four times the cost of grey ammonia in 2020 and by 2050, green ammonia costs are about twice of those for grey ammonia.
- A cost reduction by a factor of 2 of the green ammonia is expected between now and 2050
- With the applied assumptions, Blue ammonia would be cost competitive versus green ammonia "now" whereas green ammonia is expected to become the cheaper option by 2050.
- Based on energy content the projected fuel costs for blue and green ammonia and green methanol (via the bio-E-methanol route) are fairly similar; being 21 €/GJ, 19 €/GJ and 23 €/GJ, respectively by 2050.

In general, there is a large gap between the fossil and the green fuels, while there is a smaller gap between the green fuels making it evident that policy measures are required to limit the consumption of fossil fuels and that it remains unclear which particular green fuels will be the most cost-efficient.

Above statements are based on a large number of assumptions documented in the reports [1,2,3,4]. In the following section the results are further discussed based on a sensitivity analysis

Discussion based on a sensitivity analysis

Blue ammonia

The cost of blue ammonia depends strongly on the natural gas price, carbon capture (CC) technology cost, and costs associated with CO_2 storage and liquefaction. Also there is an effect of electricity cost since both the HBL and the ASU consume electricity. However, electricity consumptions by these units are quite low compared with the energy content of the consumed natural gas. An assessment of expected CCS cost, now and in future, based on literature and interview with local experts has been conducted leading to estimates of 130, 107 and 87 €/tCO_2 by 2020, 2030 and 2050, respectively. CO_2 emission from ammonia synthesis is assumed to be 2.4 tCO_2/tNH_3 when the source of hydrogen is natural gas. Considering these assumptions, the cost of blue ammonia is estimated to be 558, 447 and 392 €/t NH_3 by 2020, 2030 and 2050, respectively. Further details can be found in Ref. [3]

Green ammonia

Both low- and high-temperature electrolyzers (AEC and SOEC) have been considered to produce the hydrogen required for the green ammonia production. Green hydrogen production is electricity-intensive and consequently, cost of electricity (COE) is a key parameter affecting the cost of green ammonia. Different plant locations giving different costs of electricity were analysed as outlined in the previous section. For the case of Esbjerg the possibility of utilizing onshore or off-shore wind power was examined. A full table of calculated fuel costs at the different locations considering the different ways of operating the plant by 2020, 2030 and 2050 are reproduced in Table 3 below. Details can be found in Ref. [2] and [3]

Table 3: Production costs for green ammonia €/t. The production costs were estimated for production units placed in different locations (Esbjerg, Arica, Ceduna, Dakhla), for different years (2020, 2030 and 2050), and for different scenarios (BTM, BTM-grid, Grid-Op and Unflexible), based on both SOEC and AEC technologies. The detailed meaning of the labels indicating how the electrical power is obtained ("BTM"="Behind the meter", BTM-Grid; "Behind the meter+grid supply", Grid.op; "Grid opportunist", Unflexible; "unflexible user" is explained in Ref, [2]. Numbers in bold face are considered base case values applied in the TCO and road-map analyses.

Locations	Scenarios	2020		2030		2050	
		AEC	SOEC	AEC	SOEC	AEC	SOEC
Arica	BTM	990	1397	768.4	720.2	503.1	419.7
	BTM-Grid	721	923.6	536.1	550.6	372.6	354.6
	Grid-OP	815.4	1001				
	Unflexible	871.9	1046				
Ceduna	BTM	998	1198	785.5	749.2	550.8	477.3
	BTM-Grid	795.8	994.5	598.3	608.1	400.4	380.7
	Grid-OP	910.1	1087				
	Unflexible	1088	1226				
Dakhla	BTM	794.5	968.1	635.1	624.5	495.1	446.3
	BTM-Grid	**716.3**	930.6	**561.3**	573.7	387.7	**369.3**
	Grid-OP	1027	1183				
	Unflexible	1091	1227				
Esbjerg_onshore and offshore	BTM	1125	1235	867.1	820.2	606.4	593.8
	BTM-Grid	773	964.6	682.2	682.4	439.8	410.6
	Grid-OP	773	964.6	686.6	911.6	439.8	410.6
	Unflexible	827.2	1009	802.7	757.9	631.6	571.5
Esbjerg Only offshore	BTM	1716	1382	965.5	907.5	753.2	668
	BTM-Grid	773	964.6	685.1	686.5	439.8	410.6

The above numbers are for the specific locations with the economical optimum of full load hours at these locations assuming also a certain operational range for the synthesis plant (40-100% max. by 2020, 10-100 % for 2030 and 2050). A sensitivity analysis has also been conducted. In this, a fully-flexible plant has been assumed, which is designed in such a way that no storage facility is required and the number of annual operation hours has been assumed to be 7884 hours. The variation in ammonia production cost from such a plant versus the cost of electricity is illustrated in Figure 1. In the figure, vertical lines show the electricity cost calculated for 2020, 2030 and 2050 at the cheapest among the four locations. The lowest COE is calculated to be 38 (Dakhla, BTM), 22.9 (Dakhla, BTM-grid) and 14.94 (Arica-BTM) €/MWh by 2020, 2030 and 2050, respectively.

The Figure illustrates the dominating effect the cost of electricity has for the fuel cost. As can be seen AEC-based plants results in cheaper ammonia by 2020, while by 2030 and 2050, SOEC results in lower ammonia costs.

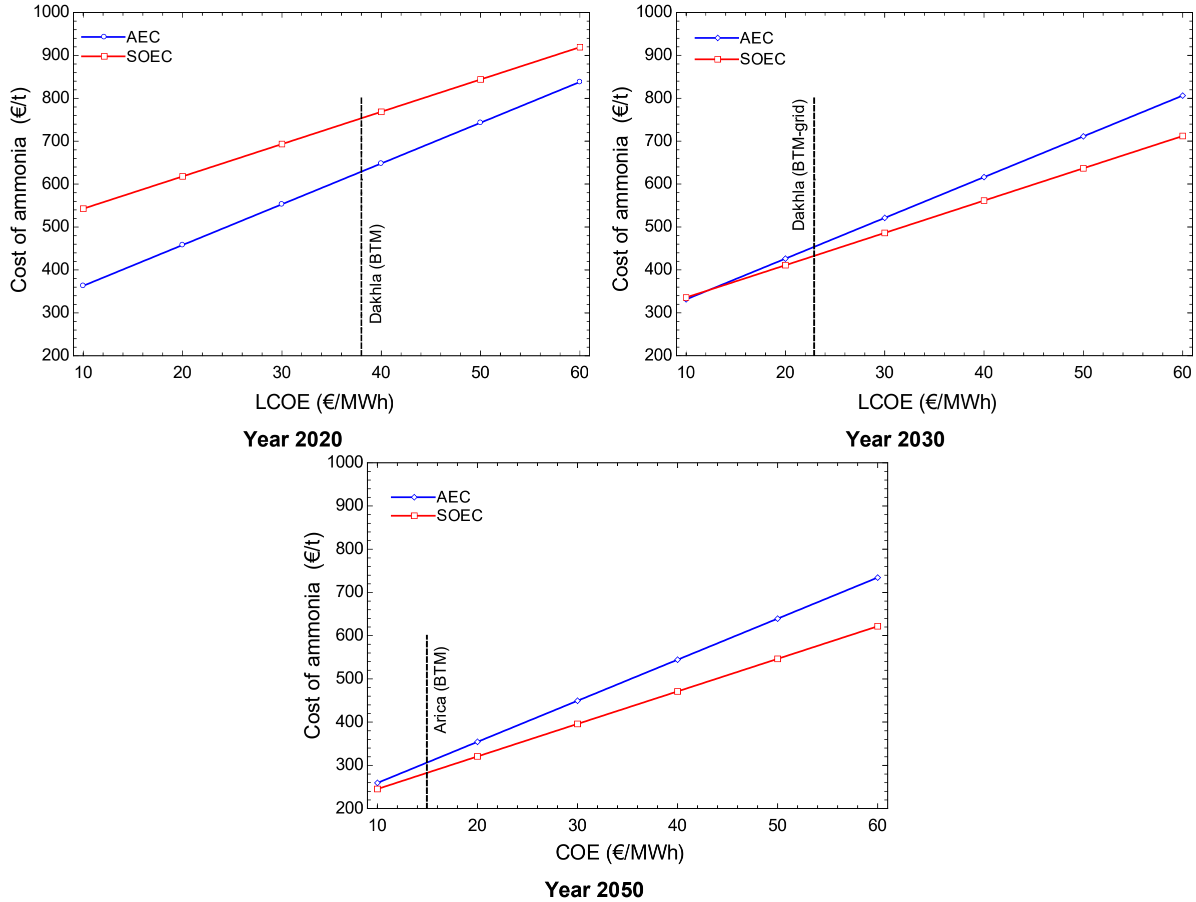


Figure 1: Estimated cost of green ammonia from a fully flexible plant operating 7884 hours a year as a function of the levelized cost of electricity.

Besides the LCOE, the electrolyzer CAPEX has a significant effect on the cost of green ammonia. The SOEC CAPEX is assumed to be 2770, 1140 and 400 €/kW, while AEC CAPEX is projected to be 840, 700 and 300 €/kW by 2020, 2030 and 2050, respectively. Since SOEC technology is only in the initial phase of commercialization, the projected future CAPEX is highly dependent on technological development. The electrolysis plant CAPEX is expected to decrease significantly due to mass manufacture effects and general technology improvements, but the numbers applied for both 2030 and 2050 are associated with significant uncertainty. The consequences of varying the Capex estimate by ±50% for the 2050 case are illustrated in Figure 2 for varying costs of electricity.

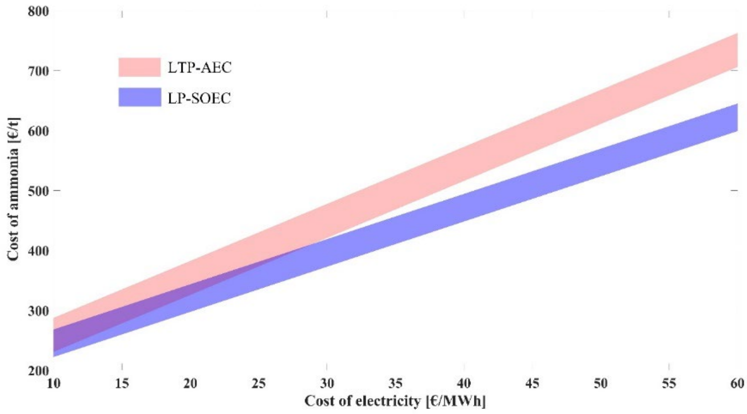


Figure 2: Effects of the CAPEX uncertainty on the estimated cost of ammonia by 2050

Evidently the relative importance of a variation in the electrolysis plant capex increases with decreasing cost of electricity;

- at 20 €/MWh the projected ammonia cost increases by 40 €/t (or by 30 %) if 50% is added to the electrolysis plant capex.
- Increasing the cost of electricity from 20 € /MWh to 26 €/MWH (a 30 % increase) results in an increase of the ammonia cost by 40 €/t.
- For the 2050 estimates, varying the electricity cost by ±25% around a base case value of 17 €/MWh results in a change in ammonia cost of ±30 €/t (±10%).
-

Comparing the projected costs of green and blue ammonia it is further noted that:

- For Blue ammonia to be cost competitive with green ammonia under the base case conditions in the sensitivity study (COE ~15 €/MWh) the CCS cost has to be less than 50 €/t.
- For green ammonia to be cheaper than Blue ammonia, with a CCS cost of 87 €/t, the cost of electricity has to be below 30 €/MWh.

Green Methanol (Bio-E-methanol)

The cheapest route to green methanol among the paths here analysed is via gasification of biomass to a synthesis gas, which after addition of H_2 from electrolysis is catalytically upgraded. Key to the cost of green methanol are biomass costs, plant- and electrolysis investments and electricity cost. With the assumed costs of storage technology and costs of grid electricity etc. at the selected locations, the optimal mode of operation entails between 6500 and 7800 hours of operation at full load annually (2020; 7900 hr, 2030; 7050 hr, 2050; 6500 hr). The fuel production plant is subsequently "oversized" to deliver the targeted amount of annual fuel production given this limitation. The same set of electricity costs and electrolysis capex values are used when assessing costs of green methanol and green ammonia. Results of these cost-assessments are presented in Table 4 below (all assumes a biomass cost of 6.8, 7.4 and 8.2 €/GJ in 2020, 2030 and 2050). The cheapest combinations in 2020, 2030 and 2050 are highlighted by bold face.

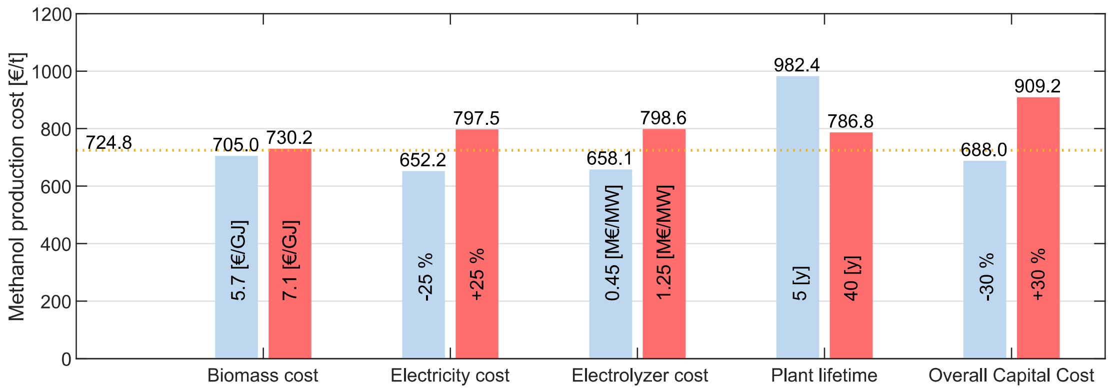
Table 4: Production costs for green methanol (€/t) via biomass gasification and electrolytic H2. The production costs was estimated for production units placed in different locations (Esbjerg, Arica, Ceduna, Dakhla), for different years (2020, 2030 and 2050), and for different scenarios (BTM, BTM-grid, Grid-Op and Unflexible), based on SOECs or AECs.

Location	Year	BTM	BTM-grid	Grid-Op	Unflexible	BTM	BTM-grid	Grid-Op	Unflexible
Electrolyzer		SOC	SOC	SOC	SOC	AEC	AEC	AEC	AEC
Esbjerg Onshore	2020	1034	843	843	869	971	765	765	802
Esbjerg Onshore	2030	737	645	651	684	825	705	709	787
Esbjerg Onshore	2050	609	495	495	573	699	546	546	677
Esbjerg Offshore	2020	1149	843	843	869	1087	765	765	802
Esbjerg Offshore	2030	795	649	651	684	894	706	709	787
Esbjerg Offshore	2050	649	495	495	573	759	546	546	677
Arica	2020	1527	819	864	890	868	729	794	833
Arica	2030	819	570	-	-	728	603	-	-
Arica	2050	527	453	-	-	572	497	-	-
Ceduna	2020	1040	874	926	994	779	778	857	981
Ceduna	2030	643	606	-	-	675	644	-	-
Ceduna	2050	532	470	-	-	598	517	-	-
Dakhla	2020	875	823	969	995	764	**725**	938	983
Dakhla	2030	613	**582**	-	-	670	620	-	-
Dakhla	2050	512	**462**	-	-	574	509	-	-
Esbjerg Offshore DH	2020	1145	840	840	865	1068	746	746	783
Esbjerg Offshore DH	2030	792	646	648	681	875	688	690	768
Esbjerg Offshore DH	2050	646	492	492	571	743	531	531	661

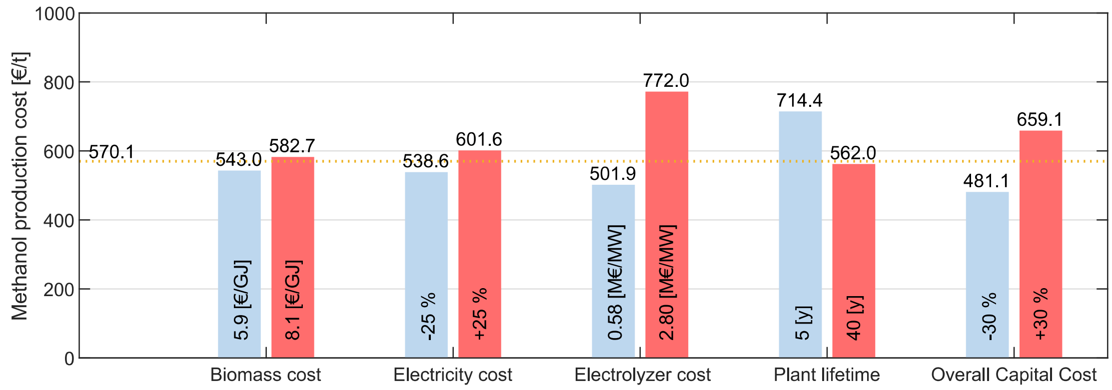
The numbers highlighted in bold face are the base case values applied in the TCO and roadmap analyses, as these locations and operation modes gives the best compromise considering both cost and emissions. Costs are similar, but emissions are lower for the chosen values.

The consequences of varying the parameters most import for the cost projections are illustrated in Figure 3, below. Here the dashed lines indicated the situation giving the lowest fuel cost in 2020, 2030 and 2050. For each of the main cost drivers a relevant variation considering uncertainty on the parameter was chosen.

(a)



(b)



(c)

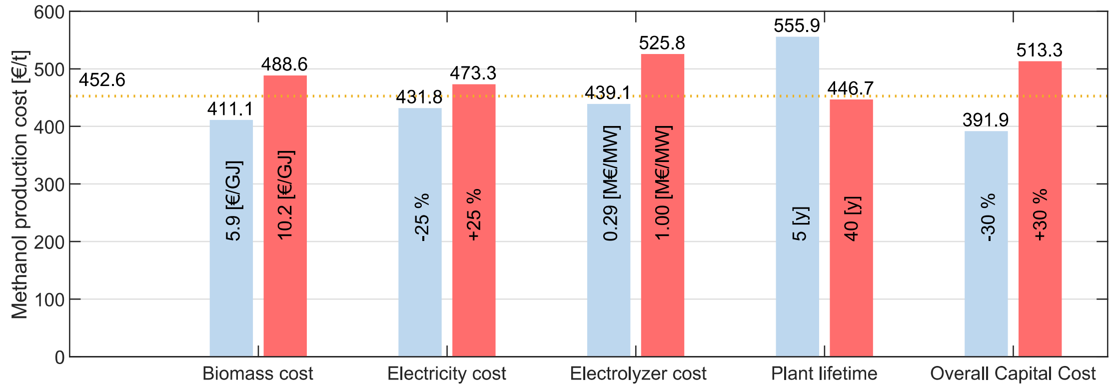


Figure 3: Illustration of the sensitivity of the methanol cost on various of the cost driving parameters under assumptions relevant for 2020 (a), 2030 (b) and 2050 (c). The base case is with the assumptions providing the cheapest fuel in 2020, 2030 and 2050 (725 €/t, 570 €/t and 453 €/t, respectively).

Key learnings from the site and sensitivity study are:

- The best locations among the considered ones for the production of green methanol are Arica and Dakhla – projected fuel costs in Esbjerg would be from 3 % (2020) to 10% higher (2050) assuming that surplus heat is sold and 6 % (2020) to 10% higher (2050) if the value of surplus heat was set to 0.
- Under the assumptions here applied (future electricity prices, grid tariffs, plant capex, , PV-wind turbine Capex) – the best economy is achieved when purchasing some electricity from the grid to maximize the number of operation hours. Under the applied assumptions *BtM-grid* fuel costs are typically 15-20 % lower than when operating completely behind the meter (island operation).
- The differences in projected fuel costs are in the range of 10 % depending on whether alkaline electrolysis or SOEC is applied.
- For the 2050 numbers varying the biomass cost by ±25% results in change in methanol cost of ±40 €/t (±10%)
- For the 2050 estimates, varying the electricity cost by ±25% around the base case value of 17 €/MWh results in a change in methanol cost of ±20 €/t (±5%).

2 TCO model

By Torben Anker Sørensen

The total cost of ownership (TCO) model is bottom-up estimation of costs and emissions from operating a containership in the sizes 1200 teu (6mW main engine), 2500 teu (14mW) and 15.000 teu (50mW). The model is striving to include all costs and emissions associated with operating a ship. Further information is available in the report "MarE-Fuel: Total Cost of Ownership" Ref [5].

Results from the TCO model using costs and emissions based on plants having their own behind the meter power production as well as buying power from the grid is shown below

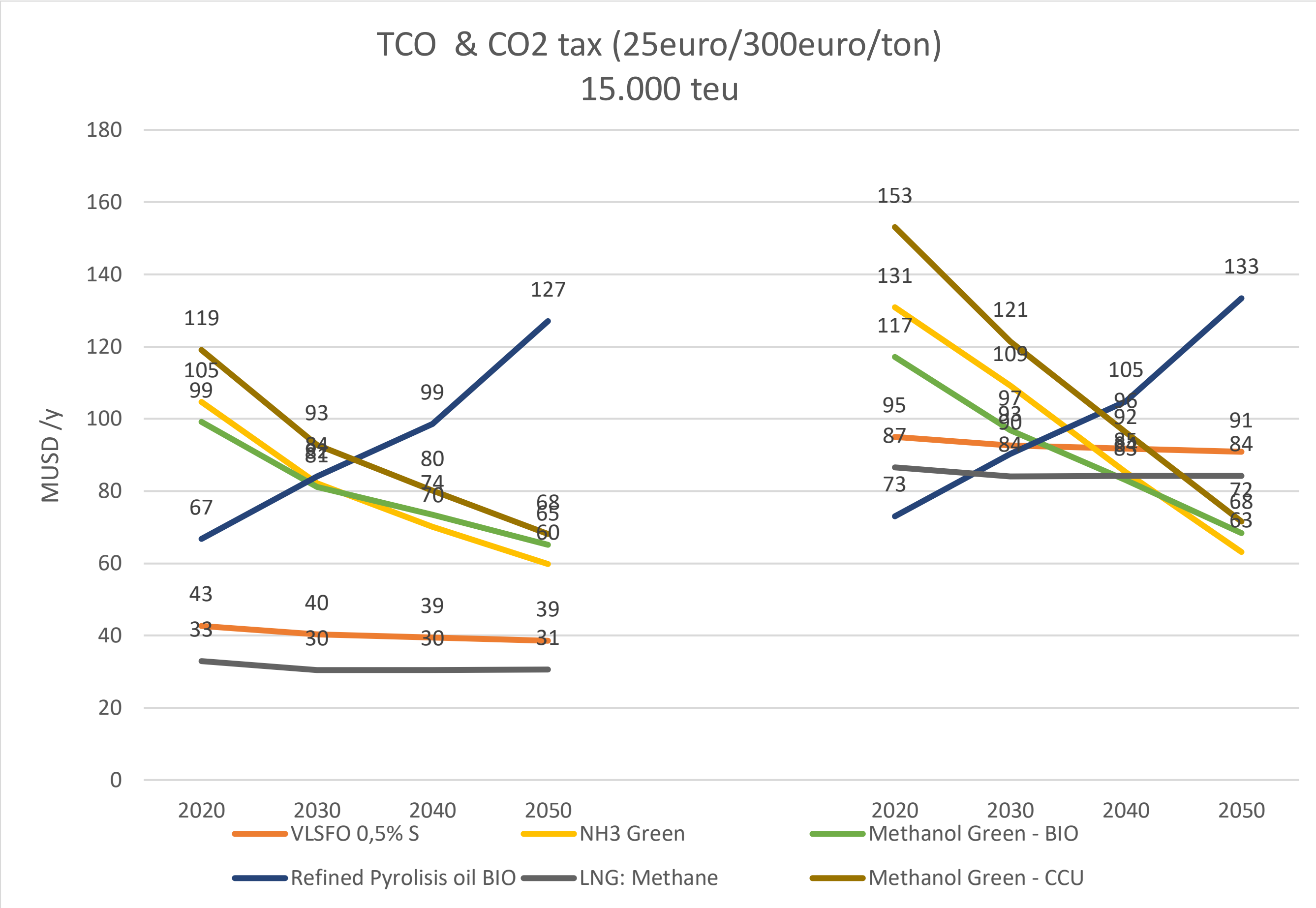


Figure 4: TCO of different fuels at different CO2 tax levels

The 2 clusters of data represent TCO in MUSD/y at LOW & HIGH CO2 tax, spanning a period from 2020-2050, for selected fuels:

- VLSFO, Ammonia Green, Methanol Green BIO, Refined Pyrolysis Oil-Bio, LNG Methane, Methanol Green CCU.

Low CO2 tax (25€/ton CO2):

Shipowners have no economic incentive to adopt green fuels, with a low CO2 tax. The green fuels remain 2-4 times more expensive than fossil fuels from 2020-2050. Unless higher income from operations compensates for extra OPEX and CAPEX, a voluntary shift into green fuels is highly unlikely.

Green NH3 and green Methanol are forecast to deliver similar cost levels over the period. Refined Pyrolysis oil is initially the cheapest green solution, at only +50% higher than fossil fuels, and can most likely be fitted to existing ships. The price for biomass based green fuels are likely to increase significantly after 2030, due to competing uses of biomass (Airplanes & industry).

HIGH CO2 tax (300€/ton CO2)

Shipowners are likely to have an economic incentive to shift to Refined Pyrolysis oil immediately after a high CO2 tax has been introduced. Refined Pyrolysis oil appear to be an attractive green option, enforced by the benefit of possibly be applied to existing ship, albeit with bigger tanks.

Green Methanol Bio appear to be competitive from 2030 onwards and NH3 from 2035, as well. From 2030-2035 the green solutions appear to be lower cost than fossil fuels.

A 300€/ton CO2 tax level is unlikely to be adopted by EU, US, or China. A gradual step up of tax level is more likely. In that event shipowners will have little incentive to shift into green fuels.

TCO shares

A comparison of cost shares depending on the CO2 tax, size of ship and fuel used is shown in the table below.

Table 5. TCO shares

TCO percentages					
2020	**25 euro/ton co2**				
1200 teu	FUEL	CO2 tax	Other	Capital	Total
VLSFO 0,5% S	29	6	40	25	100
NH3 Green	60	2	22	17	100
15000 teu	FUEL	CO2 tax	Other	Capital	Total
VLSFO 0,5% S	49	11	10	30	100
NH3 Green	80	2	5	13	100
2050	**300 euro/ton co2**				
1200 teu	FUEL	CO2 tax	Other	Capital	Total
VLSFO 0,5% S	14	46	24	15	100
NH3 Green	42	4	31	24	100
15000 teu	FUEL	CO2 tax	Other	Capital	Total
VLSFO 0,5% S	18	63	5	14	100
NH3 Green	64	6	8	22	100

Small ships spend less on fuel than large ships (29% vs 49%) based on fossil fuels and low CO2 tax. The small ship is much less sensitive to an increase in fuel costs, however small ships contribute only a fraction of global shipping CO2 emissions. It is assumed that 20% of ships deliver approx. 80% of emissions. Consequently, policymakers could initially introduce a technical regulation, forcing small ships, (likely to operate near shore) to adopt green solutions, without causing too much economic turmoil in the relevant value chains, ie a ban on CO2 emissions on ships operating between EU ports, as an example.

CO2 emissions: Well to Wake

Total emissions are calculated as Well to Wake emissions including production and combustion of fuels (primary and secondary), but excluding upstream emissions related to production of power plants and similar. Below, the emissions are shown for the different fuels in the Behind-the-meter with grid situation for a 15000 TEU size ship.

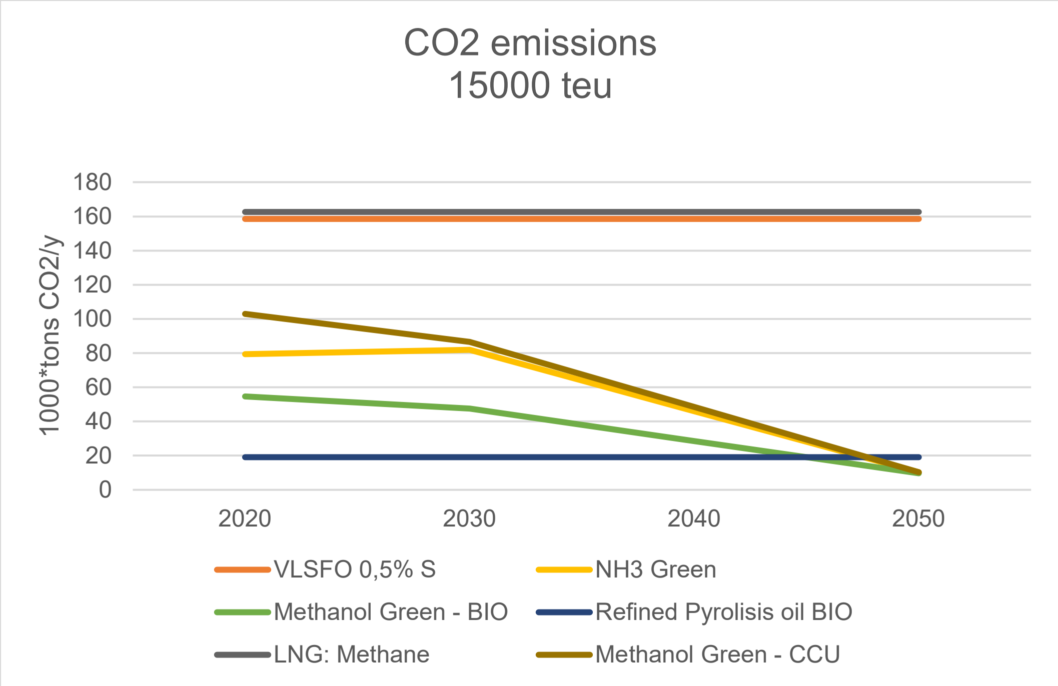


Figure 5: CO2e emissions for different fuels 2020-2050

The TCO model estimates total emissions of CO2 in *1000 tons/year. Green fuels have lower emissions than fossil fuels from 2020 onwards of a factor 8-16.

In 2020, fossil fuels emissions are at approx. 160.000 tons/year, and refined pyrolysis oil is at 20.000 tons/year, i.e., 8 times less than fossil fuels. Initially, electrical power from fossil sources is mixed into production, for cost reasons resulting in high emissions for e-fuels.

Eventually in 2050 other green fuels are at emissions of only 10.000 tons/year, i.e., a factor of 16 times less emissions than fossil fuels.

TCO Conclusions

Technical regulation is likely to be only option to deliver reduced emissions from shipping, and a gradual increase of CO2 tax will support the transition. Predicated on the fact that a high CO2 tax is unlikely for the 10-20 years, then shipowners do not have an economic incentive to reduce emissions.

However, the green fuels can deliver 8-16 times less CO2 emission, and consequently technical regulation is more likely to deliver a reduction in CO2 emissions, ie. a total ban on emissions on ships wishing to enter EU and/or US waters and harbours, or many other technical options.

The transition to green fuels will be gradual in the period 2020-2030. Existing ships are not relevant for green fuels except for perhaps refined pyrolysis oil, and therefore green capacity of ships will be predicated on how fast a next generation of ships can be built. In parallel the capacity to deliver electrical power and green fuel factories shall be built from zero, and such expansion is likely to take decades to materialize in practice.

Technical regulation of small ships, operating near shore, is possibly a first step. Small ship spending on fuel is relatively less, and a large increase in fuel costs may have relatively small impact on the relevant value chain total costs, because transportation is in turn a small fraction of total costs, of e.g. clothing. Examples of the expected impacts on consumer prices by Mærsk can be seen in Figure 6.

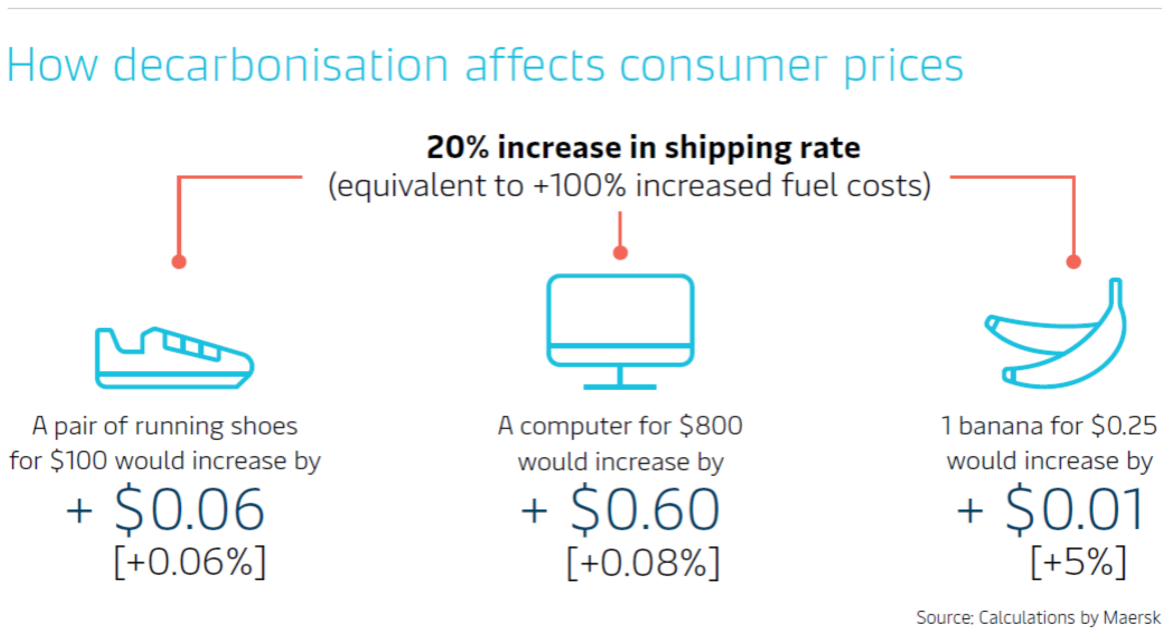


Figure 6: Impacts on consumer prices (MAERSK Sustainability Report 2020)

If fuel prices triple, the cost of a 100 USD running shoe is likely to go up by 0,12 USD.

3 Roadmap results

By Marie Münster

During the MarE-Fuel project, we developed plant models to assess the potential future costs of green methanol and green ammonia - and a TCO model focusing on ship costs. Based on these inputs, we developed a least-cost optimization model, which takes the ship stock and costs, engine types, fuel emissions and prices, biomass availability and CO2e emission caps into account as illustrated in Figure 7. The model and underlying assumptions are described in background report "MarE-Fuel: Roadmaps for sustainable maritime fuels" Ref [6]. The main results are summarised here.

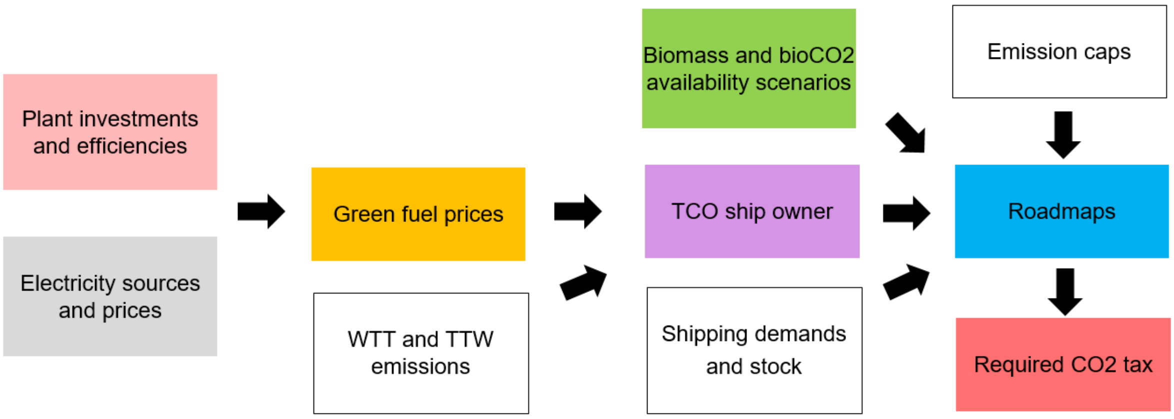


Figure 7 Roadmap model

The future fuel mix will largely depend on the prevailing framework conditions with regard to biomass availability and CO2 emissions reduction targets. With regard to biomass availability, only residual biomass potentials are taken into account. Most of these may be converted to pyrolysis oil or bio e-methanol. There is enough potential to cover all shipping demand in an optimistic scenario with high biomass potential and low competing demand (HBLD), if converted to bio e-methanol. In a scenario with medium biomass potential and medium competing demand (MBMD), there will be enough biomass to cover all shipping demand up to 2025 but none by 2035, if converting to the same fuel. With a low biomass potential there will be none. If converted to refined pyrolysis oil, substantially less shipping demand can be covered.

For the GHG emissions, the base case values entail operational emissions i.e. direct emissions from production and use of the fuels (WTW (op)). Emissions from electricity production has been normalized for the different fuels and are based on global average emissions from the IEA "Net-Zero by 2050" scenario. The emissions from use of power are reduced quickly and almost zero by 2050 (See Ref [6]).

In Figure 8, the emissions for 2020 are illustrated. The figure shows that the green fuels and blue ammonia (around 30-60 kg CO2e/GJ) have lower emissions than the fossil fuels (most around 90 kg CO2e/GJ) with grey ammonia having by far the highest emissions and LPG having the lowest emissions of the fossil fuels. It can furthermore be seen that emissions from use of average global electricity penalizes the e-fuels substantially by 2020, but when these emissions are substantially reduced, the e-fuels and pyrolysis oil have much lower emissions (below 10 kg CO2e/GJ) than blue ammonia and LBG (39 and 52 kg CO2e/GJ). To compare the fuels in a fair way, it could be argued that upstreams emissions associated with constructing e.g. wind turbines should be included. The green fuels would still come out with the lowest emissions, but with higher penalty to the e-fuels, depending on the emissions associated with electricity used for construction. For biomass, zero GHG emissions are assumed, as it is assumed that there will be no effects of utilizing waste biomass.

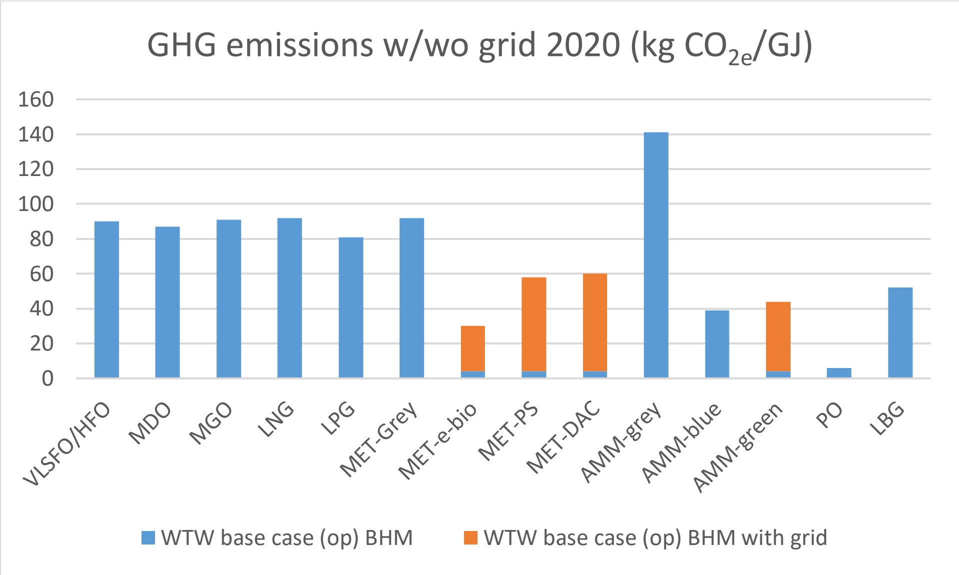


Figure 8: Average values of emissions by fuel (include pilot fuel) in kg CO2e/GJ in 2020 using GWP 100

The fuel mix will differ depending on which framework scenario occurs. In the different columns in Figure 9, the modeled GHG emissions caps can be seen from 50% to 99% reduction in 2050 compared to 2008.

Behind the Meter with Grid

In our baseline scenario, the electro-fuels are produced using grid electricity and local renewable production Behind-the-meter (Bhm-grid) (see the report " MarE-fuel: LCOE and optimal electricity supply strategies for P2X plants" Ref [2] for more details). The share of electricity used from the grid is presented in the report "MarE-Fuel: Roadmaps for sustainable maritime fuels" Ref [6]. The counted emissions are Well to Wake (WTW) including operational emissions, but omitting upstreams infrastructure emissions. In Figure 9 we show the baseline scenario. In this scenario, it can be seen that at high biomass availability (top row in the figure), refined pyrolysis oil, LNG, methanol produced from biomass and hydrogen (MeOH-ebio) and green ammonia are utilized as the main fuels. Based on the given assumptions, the pyrolysis oil is initially found to be cheaper than MeOH-ebio and it has the advantage that it can be used on existing ships.

In the case of medium biomass availability and low biomass availability (lowest rows in the figure), blue ammonia and green ammonia will play a significantly greater role in the long term. For the blue ammonia we have taken medium levels of methane WTW emissions from literature (see report "MarE-Fuel: Roadmaps for sustainable maritime fuels" Ref [6] for more info).

The red color in the figure indicates a gap. In these instances we cannot reduce the WTW emissions sufficiently with the given biomass availability and the assumed emissions from use of electricity from the grid. Due to lack of biomass and biogenic CO2, MeOH-DAC is found to be the available e-fuel with the lowest emissions, and it is used when there is a gap, although green ammonia is assumed to be slightly cheaper. If green CO2 is available, MeOH-PS is outcompeting MeOH-DAC, showing the sensitivity to assumptions. The early gaps which can be seen in the first years of the low biomass scenarios are linked to the assumed availability of new ships being built each year. It is assumed that all new ships are dual fuel and hence have the possibility to switch between fuels over time. Methanol ships are assumed to be available from 2020, ammonia ships from 2025 and multifuel ships from 2031 (See [Ref.6]).

The model does not have restrictions on ramping up of fuel production nor distribution and bunkering infrastructure, as this is difficult to assess at a global level within the timeframe of the project, and hence potentially unrealistic steep increases in the use of fuels can be seen over a few years. Such restrictions could however be implemented in future works.

The number (e.g. xxxx_WTW_50, xxxx_WTW_70, xxxx_WTW_99) represents the percentage of the reduction of GHG emissions from 2018 to 2050 going from left to right. The biomass availability is illustrated in the rows, going from high in the top, to low in the bottom. For example, in a "HBLD_WTW_99" scenario (top right) one recognizes the 99% reduction of all maritime GHG emissions by 2050 compared to 2008 levels measured in a well-to-wake (WTW) perspective with high biomass availability (HB) and a low demand from other sectors (LD).

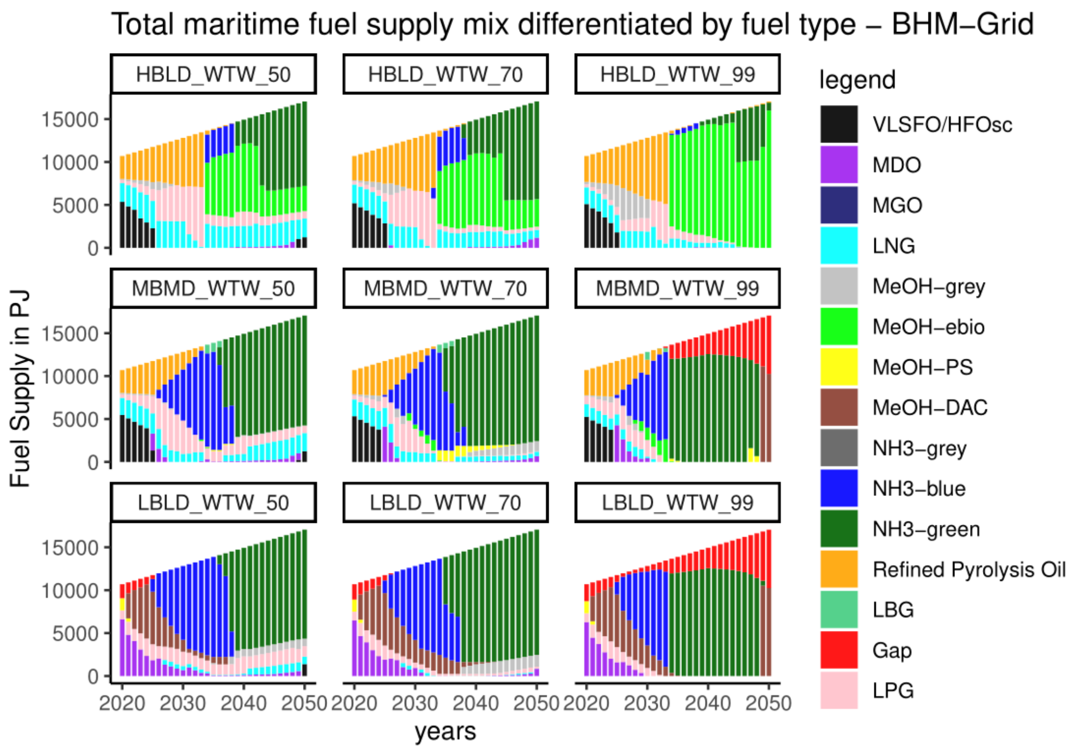


Figure 9: Future Fuel Mix for different biomass availability and GHG emission reductions scenarios in a BHM-grid world

These BHM-Grid results illustrate the dependence on available biomass and climate mitigation efforts in the maritime industry in the future very well. In considering these results, it is essential to emphasize that these results are subject to assumptions and uncertainties. The key use of this analysis is not to highlight a future fuel that will drive the decarbonization of the maritime sector, but rather to highlight possible pathways towards decarbonization. By identifying the marginal CO2 reduction costs a CO2-tax of up to 350 EUR/tCO2eq is found to be required already in 2030 to meet even a 50% reduction of GHG emissions, illustrating the combined challenge of applying this measure alone while using power with GHG emissions.

The results are highly sensitive to assumptions regarding emissions as illustrated in Figure 10.

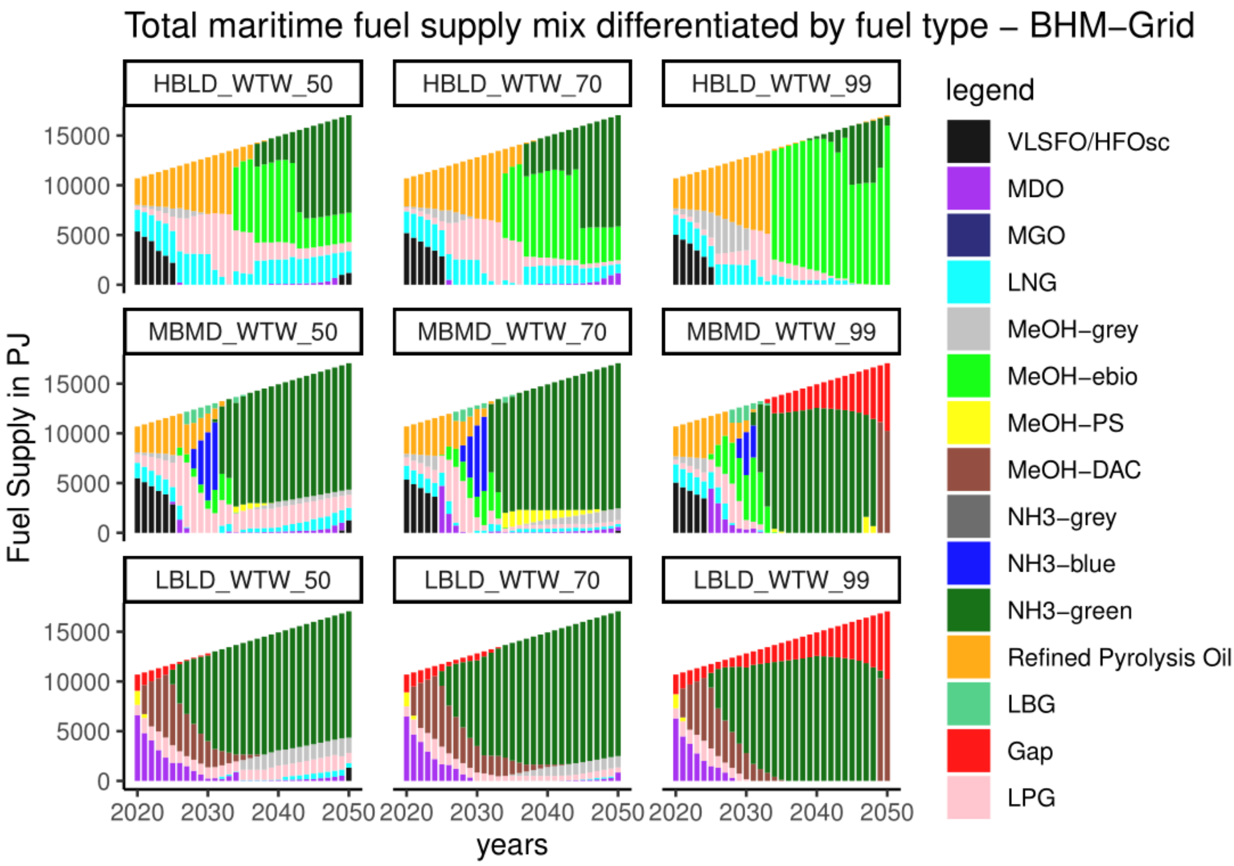


Figure 10: Baseline scenario upper bound (50[ktCO2eq/PJ] instead of 34 [ktCO2eq/PJ] in our baseline) blue-NH3 emission for different biomass availability and GHG emission reductions scenarios in our baseline scenario

As the WTW emissions associated with blue NH3 are highly uncertain, a sensitivity analysis was made with increased emissions for NH3 blue to the upper bound value found in literature. Here it can be seen that the use of blue ammonia decreases significantly, compared to the baseline scenario, if higher emissions are assumed. A similar response is seen when using a 20 year perspective on methane emissions for LNG. More sensitivity analyses can be found in the report "MarE-Fuel: Roadmaps for sustainable maritime fuels" Ref [6].

Behind the Meter

In addition to the baseline scenarios, other scenarios were examined. One of these is the behind the meter (BHM) scenario without connection to the electricity grid leading to more expensive power, but produced on renewable energy. This scenario with its sub-scenarios regarding biomass availability and GHG emission reduction targets can be seen in Figure 11.

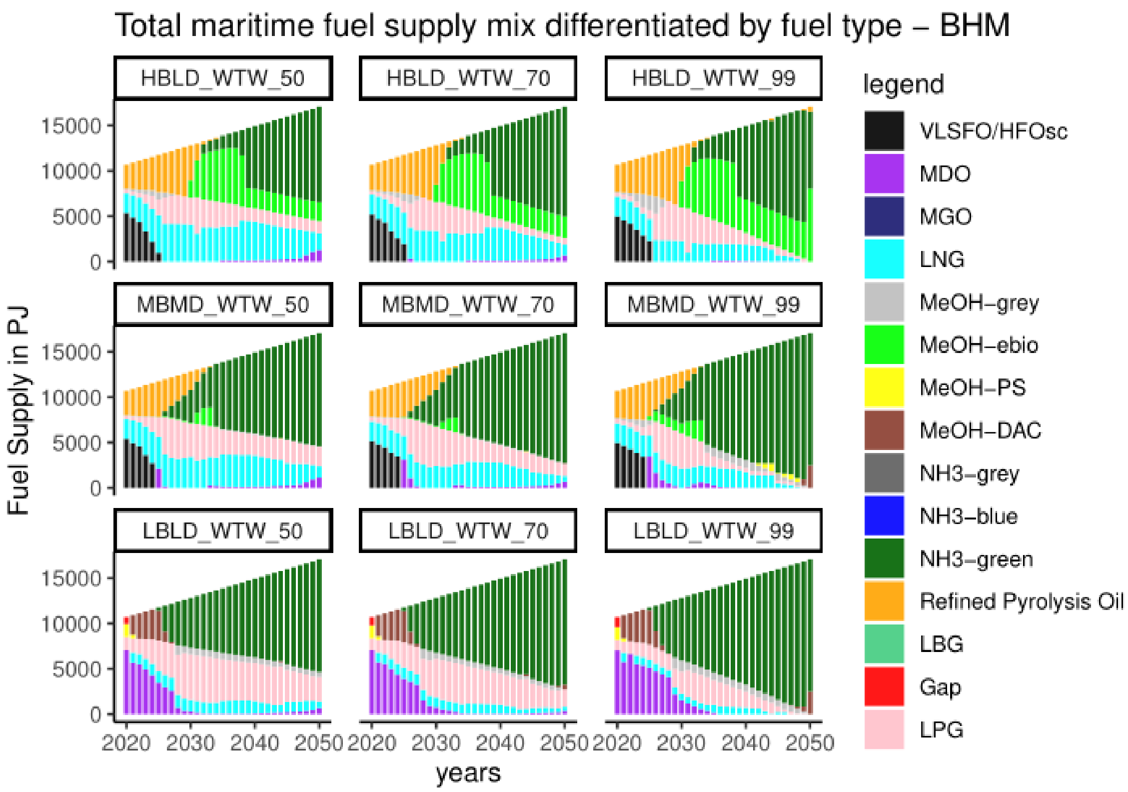


Figure 11: Future Fuel Mix for different biomass availability and GHG emission reductions scenarios where electricity is produced behind the meter (BHM)

In Figure 11, the different biomass availability scenarios as well as the different GHG emission scenarios can be recognized. In these scenarios, very few gaps are identified, namely a small gap in the first year of the low biomass scenarios, where there is a lack of new ships running on alternative fuels. In the case of high biomass availability (HBLD) again a lot of refined pyrolysis oil, then MeOH-ebio and last NH3 is used. In contrast, in scenarios with significantly less available biomass (MBMD and LBLD), NH3-green appears earlier and with higher shares. As NH3 is associated with less emissions from an early stage due to use of renewable electricity, there is more space under the global cap for fossil fuels such as LPG and LNG, while blue NH3 proves unfeasible. MDO plays a role in the short term, if biomass availability is low and no pyrolysis oil is available. MeOH-DAC on the other hand does not play a significant role in this scenario.

Applying a global cap allows a mixture of cheap fossil fuels and very low emission fuels to adhere to the restrictions. In reality, a mixture of policy measures may be implemented to achieve decarbonisation goals potentially leading to more use of medium emission fuels in a transition phase. The impact of different policy measures would be interesting to investigate further in future work. As electricity prices are determining for the cost of e-fuels, tariffs and traceable trading of green power as well as dynamic operation of plants are also important topics for future work as is subsidies e.g. for hydrogen and PtX projects, blending requirements and markets for certified green fuels.

Roadmap Conclusions

Based on the assumptions and the scenarios and sensitivity analysis outlined in the Roadmap background report, a number of conclusions can be drawn:

- On the *pathway* towards decarbonisation of the maritime sector a number of fuels will be required, i.e. there is not one overall winner.
- In the beginning of a transition period, low emission fossil fuels such as LPG, LNG and MDO may play an important part. The feasibility of LNG use is however highly sensitive to assumptions on emissions, and is not used if a 20 year GHG perspective is applied.
- The availability of biomass for the maritime sector is heavily determining for the choice of fuels. If plenty of biomass is available, refined pyrolysis oil may be feasible in the short term (subject to some uncertainty) and e-bio-methanol in the longer term, supplemented with green ammonia. In this case the cheapest pathway therefore appears to include use of fuels based on biomass, given the biomass costs applied - and that the biomass used can be considered CO2 neutral. Thus, biomass availability deserves even more attention in future works.
- Availability of green power is also determining for the ability to achieve 99% reduction of GHG. With medium or low availability of biomass, electro fuels are required to fulfil the demands, with the cheapest alternatives using some share of electricity from the grid. It does however not seem possible to achieve the 99% reductions if using some electricity from the grid, although a strong decrease in emissions from power production is assumed. Hence, due to the high consumption of electricity to produce electro fuels, the electricity has to be completely green in order to produce fuels, which can contribute to ambitious decarbonisation pathways. Thus behind-the-meter solutions - or traceable trading of green power - appears to be highly necessary for the feasibility of a high decarbonisation with electro fuels.
- In order to produce electro fuels with own supply of power from variable renewable sources such as wind and solar, flexible production and energy storages will be required to avoid over-sizing. It is not enough to have cheap green power, it has to be available most of the time in order to avoid high fuel production capacities.
- With limited biomass availability, green ammonia appears to be feasible after 2035 in many scenarios, but as the costs and emissions are similar to other electro-fuels, methanol based on CCU from biogenic point sources or direct air capture could also be competitive depending on local conditions.
- Marginal CO2 reduction costs of around 350 EUR/t CO2e were found already by 2030, indicating a need for a high CO2 tax or similar/ supplementary regulation to motivate a shift. As the green fuels will have higher fuel prices, than the fossil alternatives, robust certification schemes for the green fuels will be required to avoid fraud.
- Important cost drivers for green fuels are electricity prices, CAPEX of fuel plant and electrolyser and biomass prices

Our analysis reveals the different decarbonization fueling pathways for the maritime industry. It is clear that we cannot identify a single fuel that can achieve decarbonization of the maritime industry on its own. Instead, we see strong path dependencies with respect to future emission intensities, especially for the power grid, and also with respect to costs of the different technologies in general. However, it is clear that the maritime industry is at a crossroads. Immediate climate mitigation efforts towards net zero by 2050 are needed. In all of our findings, we find great transformation potentials that call for a sustainable transformation of the maritime industry.

4 Key learnings, challenges and future work

Conclusions on future costs of green fuels (Chapter 1) , the extra costs for the ship operator (Chapter 2) and possible transition paths (Chapter 3), that are consistent with emission reduction requirements have been outlined in the previous sections.

In addition to these, key leanings spanning across the tasks, noteworthy challenges in turning global shipping green and some shortcomings of the here presented analysis are outlined below

Key challenges

- The *scale of installing the full supply chain* for green fuels for the maritime sector is huge as illustrated by below two order of magnitude estimates.
    - *Capacities for 100% ammonia in 2050*. Assuming that 100 % of global shipping by 2050 is to be driven by ammonia would require an annual fuel production of 17500 PJ (or 925 mill t) a year, which would require on the order of 925 GW of electrolysis units and 1750 GW of wind turbines (or similar renewable power production capacity), corresponding to 29 years of build up at today's build-up rate of 60 GW/year. Today the global annual production of ammonia is ca. 180 mill t, so around 5 times the current production would be needed.

    - *Capacities for 100% e-bio methanol in 2050.* Less turbines and electrolysis capacity is required if the fuel is based on biomass, but this requires a significant infrastructure for handling waste biomass. By analogy to above example on ammonia, the required amount of biomass and wind power needed to fuel the 2050 global shipping fleet on e-bio methanol corresponds to around 630 GW wind and 11300 PJ biomass. This is less than half the wind power capacity needed if only ammonia was used. In terms of the biomass, it is around 50 times what can be extracted in Denmark annually considering only sustainable biomass (225 PJ/year), but then again the e-bio methanol production should also be globally distributed to make use of local waste biomass resources.

    - *Upscaling in production capacity*. Huge investments in additional wind turbine capacity, ammonia production and electrolysis units is required. It should be noted, that considering todays supply chains and annual global production capacities of wind turbines (or solar cells) such a build-up is in principle feasible; the requirement is 10 – 25 times current annual installation rate. For the chemical synthesis the required build up could also in principle be realized; the needed production rate corresponds to 1.5 to 4.5 times the 2020 production rate. However, the situation is different for electrolysis. Here, today only ~0,3 GW is currently in operation and the annual build up rate is ca. 0,2 GW/year. The scale up needed is thus by more than by a factor of 1000 (or in other words 4000 years at current build up rate). Hence, huge investments in production capacity build up for electrolysis is required to bring this sector to something that matches/resembles the global wind turbine industry.

- *Harbour infrastructure.* In the analysis we have not treated the required infrastructure changes in harbors. Whereas the investments here are smaller than what is required for the fuel and electricity production, a build-up has to take place in parallel to the shift in fuels and engine technology. Such infrastructure investments and build up could delay the shifts in fuels “predicted” in the roadmap discussion.

- *Required political/economic incentives to promote the transition are significant*
    - The required CO2 tax to make the cost of using grey methanol equal to green methanol (Bio-E-methanol) considering fuel costs and taxes only is ca. 200 €/t using 2020 estimates dropping to 30-60 €/t in 2050.
    - When benchmarking green and black fuels, also taking into account extra costs at the vessel level (TCO-level) a much higher CO2 tax is required for making equal the expenses with black and green fuels. By 2020 the CO2 tax needed to balance operation with green methanol to VLSFO exceeds 350 €/t. Using green fuel costs by 2050 the required tax is on the order of 175 €/t.
    - Above estimates show that very significant costs off-sets by CO2 taxing are required for making black and green alternatives equally expensive for the ship operator - in the range of 3 to 6 times the current ETS cost of ca. 60 €/t.
    - As it may be difficult to achieve global decisions on a very high carbon price, an alternative could be regulatory instruments such as blending requirements or bans - e.g. banning the bunkering of fossil maritime fuels in EU after 2030-5.

- *Extra cost for the ship operator translated to extra product costs*
    - The analysis carried out with the TCO model shows that when using a CO2 tax of 25 €/t the annual cost of running a 15000 teu ship would increase by a factor of 2.3 and 1.7 on shifting from VLSFO to Bio-E-methanol using 2020 and 2050 estimates, respectively. This would lead to significantly higher shipping rates (+70 - + 130 % assuming a one to one correlation between shipping rate and total cost of operation) and higher costs on imported products. However, costs related to transport of products are only a very small fraction of the cost to the consumer. This can be illustrated by below example;
        - A 100 % increase in fuel prices would, according to Mærsk, correspond to cost increases in the range of 0.06 % for running shoes, 0.08 % on computers and 5% on bananas. Hence, for valuable products even a 300 % increase in fuel costs would only have a marginal impact on product cost at the end consumer.

- *Further research*

In the MarEfuel project we have estimated expected future costs on a long list of candidate future fuels. On some fuels the analysis is quite detailed (ammonia and Bio-E-methanol) whereas on other fuels we have relied on literature estimates. The analysis relies on a series of assumptions and estimates where some are encompassed with a significant uncertainty. To reduce the uncertainty and improve credibility of the results it is recommended to look further into:

- Future assessment of biomass availability and the expected cost development when considering the competing demands from industry, aviation and the maritime sector
- More detailed models on CAPEX reductions of the electrolysis and fuel synthesis technologies considering; technology improvements, effects of mass manufacture and learning curves on manufacturing
- More realistic ramping up of global green fuel production capacities
- Differentiated local grid electricity supply (local prices, tariffs and emissions)

- Off-grid operation – including flexible operation and backup power supply (e.g. via H2 or NH3 engines)
- On-grid operation with trading on balancing markets
- Emission accounting – including upstreams emissions
- Certification schemes of green/ mixed fuels
- Regulation and market based measures to facilitate a green transition in line with the Paris agreement

References

[1] *MarE-Fuel: CO2-Taxes, Fuel Prices and Learning Rates, MarE-fuel project report 9/9 -2021, Copenhagen Economics.*

[2] *MarE-fuel: LCOE and optimal electricity supply strategies for P2X plants*, MarE-fuel project report 9/9-2021, DTU Management.

[3] *MarE-fuel: Energy efficiencies in synthesising green fuels and their expected cost,* MarE-fuel project report 9/9-2021, DTU Energy.

[4] *Appendix B, Key assumptions in predicting future costs of green fuels*, Appendix to MarE-fuel project report, 9/9-2020, DTU energy.

[5] *MarE-Fuel: Total Cost of Ownership*, MarE-fuel project report 29/9-2021, Anker Invest.

[6] *MarE-Fuel: Roadmaps for sustainable maritime fuels*, MarE-fuel project report 19/10-2021, DTU Management.