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Low-carbon maritime fuelling

A technoeconomic analysis of different low-carbon maritime fuelling options

Imperial College London Consultants

IChemE

UCL

Sargent Centre for Process Systems Engineering

Contents

This is the second edition of the Low-carbon maritime fuelling report, which was first published on April 2025. Changes have been made in February 2026 on the following pages:

- Page 9: Clarification added on the limitations of the study, regarding a lack of comparative analyses of the energy design of fuels in ship engines.
- Page 59: Clarification added on the assumptions behind the load factor assumed within the analysis.
- Page 80: Added Table 49 on DAC assumptions and heat prices.

List of abbreviations

Abbreviation	**Definition**
AEGLs	Acute exposure guidelines levels
Alk	Alkaline electrolyser
ASU	Air separation unit
CAPEX	Capital expenditure
CCU	Carbon capture and utilisation
DAC	Direct air capture
EC	European Commission
GHG	Greenhouse gas
H	High scenario (global parameters)
HB	Haber-Bosch process
HFO	Heavy fuel oil
IBC	International building code
IMO	International Maritime Organization KPI Key performance indicator
L	Low scenario (global parameters) LCOA Levelised cost of ammonia
LCOF	Levelised cost of fuels
LCOH	Levelised cost of hydrogen
LCOM	Levelised cost of methanol
LH_2	Liquefied hydrogen
LHV	Lower heating value
LNG	Liquefied natural gas
M	Medium scenario (global parameters) MGO Marine gas oil
NPFA	National Fire Protection Association O&M Operation and maintenance
OPEX	Operating expenditure
PEM	Polymer electrolyte membrane
rWGS	Reverse water gas shift
SCR	Selective catalytic reduction
STP	Standard Temperature and Pressure SW Seawater
UK	United Kingdom

List of notations

Notation	**Definition**
°C	Temperature unit (degrees Celsius)
£	British pound sterling
Bar	Pressure unit equal to 100,000 Pascal
C1	Cost of facility 1
C2	Cost of facility 2
CO	Carbon monoxide
CO_2	Carbon dioxide
EJ	Exajoule (1018 Joules)
GJ	Gigajoules (109 Joules)
GW	Gigawatt (109 Watts)
H	Hour/hours
H_2	Hydrogen
H_2O	Water
kg	Kilogram
knots	Speed unit (1 nautical mile per hour; 1 nautical mile is 1.852 km)
kWh	Kilowatt-hour (equivalent to 3.6 megajoules)
L	Volume unit (litre; equivalent to 10-3 m3)
m/s	Speed unit (meters per second)
Mt	Mass unit (106 tons or 109 kg)
MW_{el}	Megawatt of electricity
N	Year in project's lifespan
N	Project's lifespan
N_2O	Nitrous oxide
NO_x	Nitrogen oxides
OH-	Hydroxide ion
R	Discount rate
R	Scaling factor
RV_N	Residual values of all technologies by end of project lifespan
S_1	Size/capacity of facility 1
S_2	Size/capacity of facility 2
t	Mass unit (1000 kg)
Ton	Mass unit (1000 kg)

1. Introduction from the National Engineering Policy Centre

Taking a systems approach to policy

The policy landscape is complex in nature. Policymakers face the challenge of designing and implementing policies that have the potential to impact multiple interconnected government departments, economic sectors, stakeholders, and the environment within which they all exist. At the National Engineering Policy Centre, we advocate for the application of systems approaches in decision making to tackle this complexity, allowing policymakers to:

- Identify points of greatest leverage, where interventions will make most difference.
- Identify incentives in the system that are working against the overall goal.
- Reduce the risk of unintended consequences.
- Reveal important synergies, interdependencies, and trade-offs in a system.

The National Engineering Policy Centre is a partnership of 42 engineering organisations led by the Royal Academy of Engineering. It has a successful track record of applying systems approaches to policy challenges, including taking a systems approach to achieving net zero, providing access to engineering expertise in our fellowship to support the application of systems thinking in policy and developing our own frameworks for applying the tools of systems approaches in policy.

Genesis of the report and its commission

In November 2022, the Department for Transport approached the National Engineering Policy Centre to support them in understanding the systemic implications of choices around future low-carbon maritime fuels and characterise the implications of such choices on the wider energy and chemical process systems.

The National Engineering Policy Centre and the Institution of Chemical Engineers scoped the challenge with the Department for Transport, and with support of Imperial Consultants, the National Engineering Policy Centre commissioned the Sargent Centre for Process Systems Engineering, a Multi-Institutional Research Centre of departments at the Imperial College London and University College London, to carry out a socio-technical analysis of the value chains associated with the production, storage and transportations of different low-carbon fuels, and the implications for the hinterland.

Although the Department for Transport helped scope this research, the findings and recommendations are those of the authors and do not necessarily represent the views or opinions of the Department for Transport. The information or guidance in this document (including third party information, products and services) is provided by Department for Transport on an 'as is' basis, without any representation or endorsement made and without warranty of any kind whether express or implied. Any errors are the fault of the authors. To the fullest extent permitted by law, Department for Transport shall not be liable or responsible for any error or omission in this document.

The work was overseen by the National Engineering Policy Centre's Climate and Sustainability Working Group, which comprises a diverse range of engineering expertise from various sectors which require urgent transformation if the UK is to meet its net zero target including experts from the energy, infrastructure and transport sectors. The report was peer-reviewed in accordance with the National Engineering Policy Centre's processes by reviewers with expertise in process engineering from industry and a range of academic institutions, including members of the Institution of Chemical Engineers' Learned Society Committee.

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2. Executive summary

A technoeconomic analysis has been undertaken with a view to understanding the implications of producing all of the UK's maritime fuel demands from renewable electricity sources.

To ensure scalability and to avoid contention with other fuel pathways (e.g. aviation fuels) as well as to avoid large-scale land-use considerations, the scope was set such that the review considers fuels that are produced only from these sources and not waste or bio-derived fuels. Given the likely dependence of the bulk of the fleet on chemical fuels, electric drive alternatives (battery or nuclear) were not considered in the scope provided by DfT but we note that they will find some application. Similarly, for carbon containing fuels, the carbon dioxide should be entirely renewable; as the re-use of fossil carbon (e.g. from power plant emissions) will only reduce the overall footprint but not generate a zero-carbon fuel chain. Here we follow one of the main conventions of the "Renewable Fuels of Non-Biological Origin" and define renewable carbon dioxide as that captured from the atmosphere.

The interest from DfT in this study is a "well-to-tank" analysis because of their interest in the overall implications of the upstream implications of decarbonising fuel chains and hence the focus is primarily on the production element, with some consideration of transport and storage of the fuels. The implications for marine propulsion system modifications depending on the fuel used is out of scope, hence alternative fuels are compared on an energy content basis. Other decarbonisation strategies such as use of blue hydrogen or onboard carbon capture are also out of scope.

This report therefore examines the production of four different types of renewable, low-carbon maritime fuels: hydrogen, ammonia, methanol and synthetic hydrocarbons, which are the four options most commonly considered in the industry as being the most likely and practical decarbonisation options. The fuels were to be based on renewable electricity, water and nitrogen and carbon dioxide from the atmosphere, without any dependence on other materials e.g. waste or biomass.

The analyses focus primarily on quantitative measures to compare the alternative fuel pathways, with a particular focus on levelised cost (£/GJ) and chain efficiency (energy in/energy out, %), which are typical metrics used in this sector. These figures were evaluated through the establishment of standard production processes for all four fuels based on a plant size of 300MWe input (for the hydrogen electrolysis which drives all the processes), and calculation of material and energy balances together with estimates of capital expenditure for each. Figures for 2020 and 2050 were generated for different sets of assumptions around global parameters such as costs of electricity and discount rates, leading to a range of KPI values. We note that due to the inherent uncertainty in some of the parameters associated with the assumptions, the estimates arrived at are in a broad range.

Cost estimates for 2050 for the four fuels were found to be as follows:

- **Compressed hydrogen: 16–32 £/GJ**
- **Ammonia: 22–43 £/GJ**
- **Methanol: 21–45 £/GJ**
- **Synthetic hydrocarbons: 36–88 £/GJ**

The corresponding chain efficiencies were found to be:

- Compressed hydrogen: 48–69%
- Ammonia: 40–57%
- Methanol: 39–64%
- Synthetic hydrocarbons: 31–50%

These figures give an indication of the amount of upstream electricity generation which would be required to produce a unit quantity of fuel.

In comparison with the costs above, a typical recent wholesale price for diesel fuel would be of the order of £20-25/GJ; there has been considerable recent price volatility. This cost differential equates to an implied cost of carbon dioxide of about £100/t. A cargo ship can consume between 900 and 18,000 GJ/day of fuel, depending on the size and speed.

These results generally indicate that the more convenient the fuel for downstream handling (e.g. logistics, storage and end use) the more expensive it is. This means that there is a trade-off between production cost of fuel and retrofit/conversion of all the downstream elements of the value chain. Methanol and ammonia, which are being considered by several major shipping companies, may be a promising compromise between these competing considerations but more analysis is required.

Hence, the next steps of the analysis should include an estimation of these downstream costs, noting that no interventions are needed for synthetic hydrocarbons.

The study also included the implications for electricity supply, both in aggregate and regionally. The latter is likely to be more important for fuels where the supply chain may be shorter (e.g. hydrogen and possibly ammonia). It was found that demands of between 7 and 11 GW will need to be met by 2050 for complete de-fossilisation of this sector (i.e. fuels taken on board in the UK). An additional area that should be considered is the implications for deployment of direct air capture of carbon dioxide, given the relative immaturity of this technology. It should be noted that the other technologies considered in this report are all already available.

A limitation of this work is that it does not consider in detail the implications for post-production infrastructure, e.g. transport and storage of the fuels, modification to ports and modification to vessel fuel storage and propulsion systems (noting that synthetic hydrocarbons will not require material modifications). Furthermore, the fuels are compared on an energy content basis while the fuel efficiency of different fuels (knots/GJ) may differ; this may form part of a future study. As part of this, a limitation is that this study does not perform comparative analyses of the energy density of fuels in ship engines as this was beyond the scope of the commissioned analysis. Future research can address these important but remaining areas of consideration.

In summary, there are technically feasible pathways to produce chemical fuels for maritime transport and the electricity requirements associated with producing the quantities estimated to meet UK originating demands are compatible with renewable or nuclear energy ambitions. The costs of the different fuels are higher than those derived from fossil fuel today, but the implied carbon price is also within expected ranges.

There are important choices to be made by a range of stakeholders including engine and ship OEMs and operators, international associations, governments etc. At this stage, there are research and development activities exploring all the fuel chains considered here, and further integrated analysis of the fuel chain, port infrastructure and ship systems will be required.

The remainder of this report includes more detail on the scope, four sections covering the analysis of each fuel chain (providing detailed workings on cost / efficiency and other risks / benefits to consider for each fuel), a section providing a comparison of all four fuels with a view to highlighting the important considerations and difference between them, a section on regional analysis (which considers the spatial nature of the demands and likely electricity supply locations and hence implications for regional supply chains), and conclusions.

3. Scope of the study

Background

This report aims to understand the implications of choices around future maritime fuels and characterise the implications of such choices on the wider energy and chemical process system. This analysis will include the value chains associated with the production, storage and transportation of different fuels, and the implications for the hinterland. Economic, thermodynamic, environmental and safety implications of each fuel type (when produced at scale) should also be analysed.

Scope and methodology

The fuels of interest include hydrogen, methanol, ammonia and synthetic hydrocarbons. Biofuels are not to be considered. Carbon sources for the carbon-containing fuels should be renewable and hence we focussed on direct air capture.

The methodology starts by developing an understanding of the demand side which includes a spatial analysis of major UK ports and expected future demands for maritime fuels at these ports. Future analyses may include mode splits and implications for port infrastructure and vessel propulsion systems.

We then develop scenarios for the upstream value chains for each fuel type, understanding the implications for wider resources (e.g. electricity and water) for fuel production, transportation and storage. The implications for system economics, infrastructure implications and additional power generation that would be required for each different fuel option under these scenarios are analysed and quantified. This includes the environmental and safety requirements as well as considerations for production, storage and distribution of each different fuel.

The project does not involve making a choice between fuel types, but rather developing quantitative and qualitative performance measures and analyses of the fuel value chains and documenting these clearly, together with underlying data and assumptions. Furthermore, the implications of different fuels for the actual propulsion systems were not considered here and our analysis is based on the energy content of the different fuels.

The project is not meant to involve original research to derive underlying data, but rather a synthesis of existing academic and grey literature together with calculations of the performance measures and production of an integrated report. While our observations are not based on a formal and rigorous techno-economic analysis, we have identified general trends that provide a useful understanding of the cost-effectiveness of the pathways we have considered.

Deliverable

The outcome of the project is a relatively short report that presents an initial analysis of the key findings for each fuel pathway under these different demand scenarios against important metrics. This initial report will feed into a planned Maritime Technology Roadmap.

4. Methodology

The study involves analysing the supply chains for four future alternative maritime fuels: hydrogen, ammonia, methanol and synthetic hydrocarbons. Hydrogen is assumed to be produced via water electrolysis powered by electricity generated by renewable sources, specifically wind and solar as per the scope of this study, and the other three fuels are assumed to use this hydrogen as an input. The supply chains of each fuels is described in their respective sections (Sections 4 to 7).

For each of the analysed fuels, we describe the supply chains involved and their main components, calculate the main KPIs defined in this report, and include a section on safety and environmental considerations. The main KPIs calculated for each fuel are the levelised cost on a mass and energy basis, the total chain efficiency, and the per unit water use across the supply chains. The boundaries of the supply chains are Well-to-tank, i.e., from solar or wind electricity generation to fuel storage (tanks), and do not include fuel end use. We assume the water is saline and requires desalination upstream of electrolysis and other water uses. Desalination is hence included in the supply chains.

To calculate the levelised cost, we assumed a common plant size driven by an electrolyser system of 300 MW_{el} of input electricity. The chosen plant size is based on existing or planned projects. However, it is likely that a case-to-case optimised approach could achieve lower levelised costs, which is a limitation of this study. Using data from the literature, we present the mass and energy balances for all components involved in each supply chain, scaled to the common electrolyser size, for three global scenarios. Table 1 shows the assumptions regarding electricity prices, plant lifetime, discount rate, annual utilisation factor, and electrolyser capacity, for the three global scenarios – low (L), medium (M), and high (H). Only the annual utilisation impacts the mass and energy balances, affecting annual production, and electricity and water consumption. For synthetic hydrocarbons and methanol, CO_2 is assumed to be obtained from direct air capture (DAC). For further information, see table 49 in the Appendices.

Table 1: Global scenarios assumptions.

	Low	Medium	High
Electricity price (£/MWh)	30	50.7	0
Plant lifetime (years)	20	25	30
Discount rate	0.04	0.07	0.1
Annual utilisation	0.6	0.75	0.9
Electrolyser capacity (MW_{el})	300	300	300

Using the mass and energy balances of each scenario and supply chain, we calculated the required installed capacity of each supply chain's components. The equipment capacity is scaled by the electrolysers' capacities and are not affected by the utilisation rate.

To calculate the levelised cost for each scenario and supply chain, we used data from academic literature and public reports for capital expenditure (CAPEX), operating expenditure (OPEX), and efficiency parameters, together with the global scenario parameters in Table 1.

Data sources and specific fuel assumptions are presented in each section. All equipment is sized for a 300 MW_{el} electrolyser.

The annual utilisation rates from the global parameters are considered to calculate annual production and electricity demands for the different technologies and supply chains. CAPEX, OPEX, and annual production rates are used to calculate the levelised cost of fuels for the different supply chains (LCOF) using Equation 1, considering the three scenarios from the global parameters. Specific data and methods can be found in Sections 4–6.

Equation 1.

$$LCOF = \frac{\sum_{n=0}^{N} \frac{CAPEX_n + OPEX_n}{(1+r)^n} - \frac{RV_N}{(1+r)^N}}{\sum_{n}^{N} \frac{Fuel\ produced_n}{(1+r)^n}}$$

Where:

r is the discount rate (from global parameters)

n is the year in the project's lifespan

N is the project's lifespan from the global parameters

RV_N is the residual values of all technologies by the end of the project's lifespan

When the lifetime of a given technology is lower than the project's lifespan, a reinvestment is considered (e.g., stack replacements for electrolysers). When the lifetime is given in hours, reinvestment years are calculated based on annual utilisation rates from the global parameters. Residual values for all technologies are calculated assuming linear depreciation, with a zero value at the end of a technology's lifetime.

The chain efficiency is then calculated by dividing the total annual fuel produced (on an energy, i.e. lower heating value basis) by the total electricity consumed, for each scenario and supply chain. The water consumption is calculated by dividing the total water consumption for each scenario and supply chain, by the total fuel production (on an energy basis).

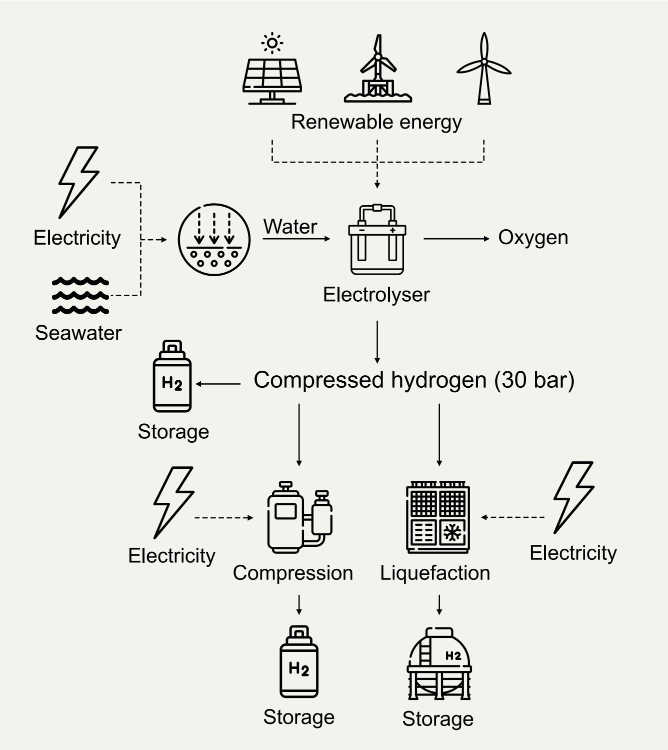
Finally, Section 9 presents a regional analysis of potential maritime fuel demands for the four studied fuels, and the required renewable generation capacity to supply these demands. The specific methodology and assumptions are presented in Section 9.

5. Analysis – Hydrogen

5.1 Process description

Figure 1 shows the three hydrogen supply chains analysed in this study. Hydrogen is produced via water electrolysis powered by renewable electricity (wind/solar generation). Water used in the electrolyser is produced by desalinating seawater through reverse osmosis. The electrolyser separates the water molecules into oxygen and hydrogen using renewable electricity and the gaseous hydrogen leaves the electrolysers at 30 bar.

Figure 1: Hydrogen supply chains studied.



The three supply chains involve either producing hydrogen for direct use at 30 bar, further compression to 350 bar and storing it (considering a storage capacity of 1 day), or liquifying hydrogen and storing it in a liquid hydrogen terminal. Electricity is the only energy input for reverse osmosis, electrolysis, compression, and liquefaction, and we assume it is produced from renewable sources.

To determine the energy and mass balances, we assume a 300 MW_{el} electrolyser, and scale all the other processes to match the electrolysers' electric input. Two types of electrolysers are considered: alkaline and polymer electrolyte membrane (PEM).

Alkaline electrolysers consist of two electrodes operating in a liquid alkaline electrolyte solution of either potassium hydroxide or sodium hydroxide. Hydroxide ions (OH-) are transported from the cathode to the anode, generating hydrogen in the cathode side. In PEM electrolysers the electrolyte is a solid polymeric material. Water reacts in the anode forming oxygen and positively charged hydrogen ions (protons). Hydrogen ions move across the membrane to the cathode side, combining at the cathode with the electrons from the external circuit to form gaseous hydrogen. Additionally, given electrolysers' future cost and efficiency uncertainties, we analyse the three supply chains for 2020 and 2050 values for both electrolysers (PEM and alkaline).

Table 2 shows the mass balances for the different technologies and supply chains, and Table 3 shows the energy balances, considering a 75% utilisation as per the M scenario from the global parameters. Specific data used for the mass and energy balances is shown in Table 4. Note that the common base for the different scenarios is a 300 MW_{el} electrolyser (electricity input). This means that all electrolysers use the same amount of electricity, but their difference in efficiencies translate into different hydrogen yields and water consumptions. It should also be noted that boil-off rates for liquefaction and regasification were not accounted for in this work, because no assumption was made for the storage times of liquid hydrogen, and because the analysis for liquid hydrogen did not include regasification.

Table 2: Mass balances for hydrogen supply chains, different electrolyser assumptions. 75% utilisation. Calculations with data presented in Table 4.

Mass balance

	Electrolyser year assumption	RO desalination	Tonne/year	Alkaline electrolyser	Tonne/year	PEM electrolyser	Tonne/year
Intput	2020	Seawater	Alk: 769,922 PEM: 740,977	Water	323,367	Water	311,211
	2050	Seawater	1,095,000	Water	459,900	Water	459,900
Output	2020	Water	Alk: 323,367 PEM: 311,211	Hydrogen	30,797	Hydrogen	29,639
		Brine	Alk: 446,555 PEM: 429,767				
	2050	Water	459,900	Hydrogen	43,800	Hydrogen	43,800
		Brine	635,100				

Table 3: Energy balances for hydrogen supply chains, different electrolyser assumptions. Only energy input for all processes is electricity. 75% utilisation. Calculations with data presented in Table 4.

Energy balance

	Electrolyser year assumption	RO desalination MWh/year	Alkaline electrolyser MWh/year	PEM electrolyser MWh/year	Compression (to 350 bar) MWh/year	Liquefaction MWh/year
Intput (electricity)	2020	Alk: 1,374 PEM: 1,323	1,971,000	1,971,000	Alk: 92,391 PEM: 88,917	Alk: 425,921 PEM: 409,909
	2050	1,955 MWh/year	1,971,000	1,971,000	131,400	605,754

To calculate the cost KPIs, literature data on the capital expenditure (CAPEX) and operating expenditure (OPEX) were used, for a 300 MW_{el} electrolyser. Annual utilisation rates from the global parameters are considered to calculate annual production and electricity demands for the different technologies and supply chains. CAPEX, OPEX, and annual production rates are used to calculate the levelised cost of hydrogen (LCOH) for the different supply chains using Equation 1, for the three scenarios from the global parameters and the described electrolyser values. Table 4 shows the input data for costs, electricity consumption, and lifetimes for all hydrogen supply chains' technologies used in this study.

Table 4: CAPEX, OPEX, lifetime, and electricity consumption of technologies

Technology	Reference year	Unitary CAPEX	OPEX	Electricity consumption	Efficiency (LHV base)	Lifetime	Source
Alkaline electrolyser system	2020	600 £/kW$_{el}$	1.5% CAPEX annually	64 kWh/ kgH_2	52%	From global parameters	(1)
	2050	455 £/kW$_{el}$	1.5% CAPEX annually	45 kWh/ kgH_2	74%		
Alkaline stack only	2020	197 £/kW$_{el}$				60,000 hours	(1)
	2050	73 £/kW$_{el}$				100,000 hours	(1)
PEM electrolyser	2020	750 £/kW$_{el}$	1.5% CAPEX annually	66.5 kWh/ kgH_2	50%	From global parameters	(1)
	2050	340 £/kW$_{el}$	1.5% CAPEX annually	45 kWh/ kgH_2	74%		
PEM stack only	2020	290 £/kW$_{el}$				65,000 hours	(1)
	2050	73 £/ kWel				110,000 hours	(1)
RO desalination (recovery ratio 0.42 from seawater)		1,065 £/m^3/day	2.25% CAPEX annually	4.25 kWh/m^3 desalinated water		30 years	(2, 3, 4)
Liquefaction day annually and liquefied hydrogen terminal		4,402 £/kg/ day	2% CAPEX annually	13.83 kWh/ kg LH_2		40 years	(5, 6)
Compressor (30-350 bar)		1,320 £/kg/hr	2% CAPEX annually	3 kWh/kg H_2		20 years	(7, 8)
Compressed storage (350 bar)		440 £/kgH_2	2% CAPEX annually			20 years	(Internal communication)

5.2 Results and KPIs

Levelised cost of hydrogen (LCOH)

Table 5 summarises the LCOH and KPIs for the three hydrogen supply chains and three global scenarios (L, M, H), considering PEM and alkaline electrolyser values for the years 2020 and 2050. The LCOH at 30 bar was found to range between 2.67 and 5.63 £/kg – depending on the global scenarios – for 2020 alkaline and PEM electrolyser values, while this range shifts to 1.61 and 3.49 £/kg for 2050 electrolyser values. Liquid hydrogen's levelised cost ranges were calculated as 4.63-8.27 £/kg and 3.57-6.13 £/kg for 2020 and 2050 electrolyser values, respectively. Compressed hydrogen at 350 bar was found to range between 2.90 and 6.01 £/kg for 2020 electrolyser values, and between 1.84 and 3.89 £/kg for 2050 values.

Table 5: Annual H_2 production, water requirement, LCOH, and chain efficiency for different scenarios and supply chains.

	L	M	H	Unit
Electricity price	30	50	70	£/MWh
Plant lifetime	20	25	30	years
Discount rate	4%	7%	10%	
Utilisation	60%	75%	90%	
Capacity	300	300	300	MW_{el}
Alkaline electrolyser, 2020 values				
Annual H_2 production	24,638	30,797	36,956	ton H_2/year
Annual H_2 production (LHV)	2,955,515	3,694,393	4,433,272	GJ H_2/year
Water requirements		0.09		ton H_2O/GJ H_2
LCOH 30 bar	2.67	3.93	5.23	£/kgH_2
LCOH 30 bar (LHV)	22.3	32.7	43.6	£/GJ
Chain efficiency		52%		
LCOH Liq H_2	4.63	6.22	7.86	£/kg LH_2
LCOH Liq H_2 (LHV)	38.6	51.9	65.5	£/GJ
Chain efficiency		43%		
LCOH 350 bar	2.90	4.24	5.63	£/kgH_2
LCOH 350 bar (LHV)	24.17	35.35	46.90	£/GJ
Chain efficiency		50%		

Alkaline electrolyser, 2050 values

Annual H_2 production	35,040	43,800	52,560	ton H_2/year
Annual H_2 production (LHV)	4,203,398	5,254,248	6,305,098	GJ H_2/year
Water requirements		0.09		ton H_2O/GJ H_2
LCOH 30 bar	1.70	2.58	3.49	£/kgH_2
LCOH 30 bar (LHV)	14.2	21.5	29.1	£/GJ
Chain efficiency		74%		
LCOH Liq H_2	3.61	4.88	6.13	£/kg LH_2
LCOH Liq H_2 (LHV)	30.1	40.7	51.1	£/GJ
Chain efficiency		57%		
LCOH 350 bar	1.93	2.90	3.89	£/kgH_2
LCOH 350 bar (LHV)	16.08	24.15	32.41	£/GJ
Chain efficiency		69%		

PEM electrolyser, 2020 values

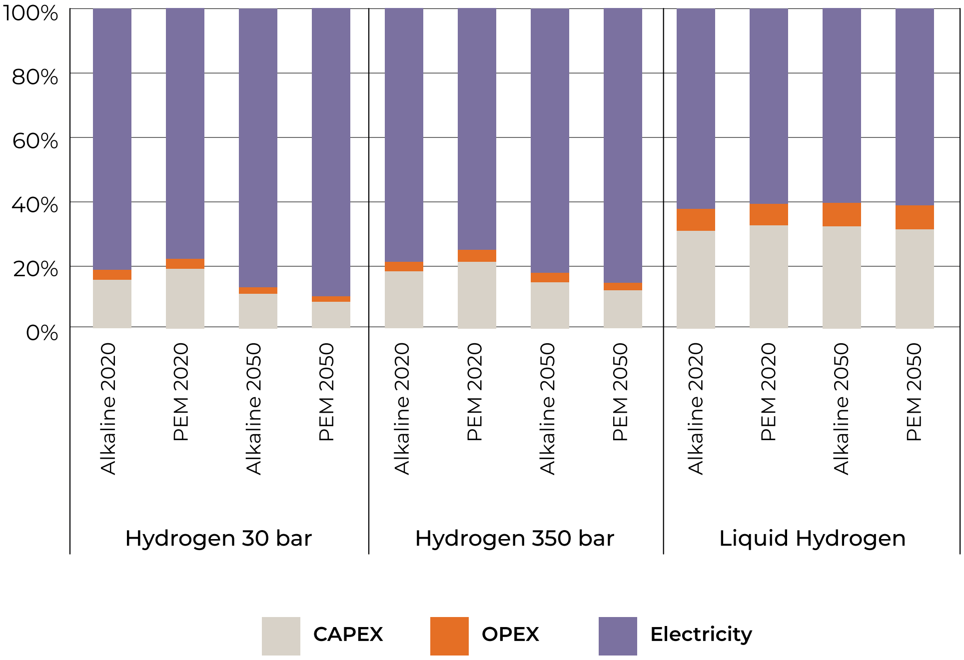
Annual H_2 production	23,711	29,639	35,567	ton H_2/year
Annual H_2 production (LHV)	2,844,405	3,555,506	4,266,607	GJ H_2/year
Water requirements		0.09		ton H_2O/GJ H_2
LCOH 30 bar	2.97	4.29	5.63	£/kgH_2
LCOH 30 bar (LHV)	24.7	35.8	46.9	£/GJ
Chain efficiency		50%		
LCOH Liq H_2	4.73	6.59	8.27	£/kg LH_2
LCOH Liq H_2 (LHV)	39.44	54.94	68.91	£/GJ
Chain efficiency		41%		
LCOH 350 bar	3.19	4.61	6.01	£/kgH_2
LCOH 350 bar (LHV)	26.60	38.40	50.08	£/GJ
Chain efficiency		48%		

PEM electrolyser, 2050 values

Annual H_2 production	35,040	43,800	52,560	ton H_2/year
Annual H_2 production (LHV)	4,203,398	5,254,248	6,305,098	GJ H_2/year
Water requirements		0.09		ton H_2O/GJ H_2
LCOH 30 bar	1.61	2.50	3.41	£/kgH_2
LCOH 30 bar (LHV)	13.5	20.9	28.4	£/GJ
Chain efficiency		74%		
LCOH Liq H_2	3.57	4.80	6.04	£/kg LH_2
LCOH Liq H_2 (LHV)	29.8	40.0	50.4	£/GJ
Chain efficiency		57%		
LCOH 350 bar	1.84	2.81	3.81	£/kgH_2
LCOH 350 bar (LHV)	15.34	23.47	31.74	£/GJ
Chain efficiency		69%		

Figure 2 shows the cost split into CAPEX, OPEX, and electricity for all of the supply chains, for 2020 and 2050 alkaline and PEM electrolyser values, and for the M global scenario. Electricity costs are the main cost component for all supply chains, of which the main consumer is the electrolysers.

Figure 2: Cost disaggregation for hydrogen supply chains, M global scenario.



Chain efficiency

The chain efficiency is the ratio of electricity input (electrolysis, liquefaction, compression) to the energy content (LHV basis) in the produced hydrogen. The chain efficiency for hydrogen at 30 bar was estimated to be between 50% and 52% for 2020 electrolysers, and 74% for 2050 electrolysers, as shown in Table 5. Liquefied hydrogen's chain efficiency was estimated as 41%-43% for 2020 electrolysers, and as 57% for 2050 electrolysers. Chain efficiencies for compressed hydrogen at 350 bar are estimated to be 48-50% for 2020 electrolysers, and 69% for 2050 electrolysers. The highest impact on chain efficiency was the electrolyser, which is why improvements in electrolyser efficiency in 2050 leads to such improvements in chain efficiencies.

Water consumption

Given that compression and liquefaction do not require considerable volumes of water, all hydrogen supply chains require 0.09 tonnes of water per GJ of hydrogen, as shown in Table 5.

Safety and environmental issues

Hydrogen's main safety concern relates to its high flammability, low activation and ignition energy, high flame speed (3.15 m/s), and high flammability range, which increases in a mixture with pure hydrogen. It dissipates quickly in open areas but leaks in contained spaces can lead to the quick formation of flammable gas mixtures. Given its low boiling point, liquid hydrogen must be stored below -253°C. Contact with skin can cause cold burns and skin damage. Whilst hydrogen is not toxic, high concentrations can displace oxygen and act as an asphyxiant.[9]

The risk of hydrogen explosions can be minimised with proper protocols. Hydrogen flow or agitation can cause electrostatic charges resulting in sparks and ignition. To avoid hydrogen ignition, handling equipment must be protected from charge build up and sparks. Flames are invisible and odourless, which when added to their high speed means that they can be difficult to detect. Gaseous hydrogen systems should account for deflagration propagation protections (pressure relief systems, rupture disks or relief panels), and pipe purging and ventilation practices to avoid deflagration and detonation. Contained areas should include hydrogen gas detection and proper ventilation to avoid gas build up. Low pressure liquefied hydrogen tanks can be at risk of pressure build-up, so protections such as pressure relief and valves must be in place.[9]

Odorous sulphur-based compounds that are typically added to natural gas cannot be used for hydrogen, as it may react and degrade. Hence dedicated hydrogen sensors and leak detection strategies must be implemented in contained spaces. Dry chemical or carbon dioxide extinguishers can be used to extinguish a hydrogen fire.[9]

Due to hydrogen's small molecular size, it is capable of dispersing though materials and permeating into certain fluids or solids. Certain metallic materials and surfaces can suffer from hydrogen embrittlement, as the molecule can be absorbed and collected at grain boundaries in metals. This can lead to brittle failures, cracks, and fractures. Low-alloy steels can also degrade from hydrogen. Table 6 shows the acceptability of different metal and non-metal materials for hydrogen use applications.

Table 6: Materials compatible with hydrogen service.[9]

Material	Hydrogen phase		Notes
	Gas	Liquid	
Aluminium and aluminium alloys	Acceptable	Acceptable	N/A
Austenitic stainless steels with >7% nickel (e.g., 304, 304L, 308, 316, 321, 347)	Acceptable	Acceptable	Beware of martensitic conversion at low temperature if stressed above yield point
Carbon steels	Acceptable[1]	Not acceptable	Too brittle for cryogenic service
Copper and copper alloys (e.g., brass, bronze, and copper-nickel)	Acceptable	Acceptable	N/A
Gray, ductile or cast iron	Not acceptable	Not acceptable	Not for hydrogen service
Low-alloy steels	Acceptable[1]	Not acceptable	Too brittle for cryogenic service
Nickel and nickel alloys (e.g., Inconel and Monel)	Acceptable[1]	Not acceptable	Susceptible to hydrogen embrittlement[2]
Nickel steels (e.g., 2.25%, 3.5%, 5%, and 9% Ni)	Not acceptable	Not acceptable	Beware of ductility loss
Titanium and titanium alloys	Not acceptable	Acceptable	Beware of susceptibility to hydrogen embrittlement
Chloroprene rubber (neoprene)	Acceptable	Not acceptable	Too brittle for cryogenic service
Dacron™ (or equivalent)	Acceptable	Not acceptable	Too brittle for cryogenic service
Fluorocarbon rubber (Viton™ or equivalent)	Acceptable	Not acceptable	Too brittle for cryogenic service
Mylar (or equivalent)	Acceptable	Not acceptable	Too brittle for cryogenic service
Nitrile (buna-n)	Acceptable	Not acceptable	Too brittle for cryogenic service
Polyamides (nylon)	Acceptable	Not acceptable	Too brittle for cryogenic service
Polychlorotrifluorethylene (PCTFE)	Acceptable	Acceptable	N/A
Polytetrafluorethylene (Teflon™ or equivalent)	Acceptable	Acceptable	N/A

1 Procedures specified by ASTM B849 and SAE USCAR-5 would reduce risks of hydrogen embrittlement

2 Hydrogen embrittlement is not an issue at cryogenic temperatures

When used as a replacement for fossil fuels, hydrogen would prevent carbon dioxide emissions into the atmosphere. However, recent evidence suggests that hydrogen leakage would have an indirect global warming potential, as it would decrease the tropospheric concentration of hydroxyl radicals, leading to an increased atmospheric lifetime of methane and its climate impacts.[10] Hydrogen's global warming potential (GWP) has been estimated as 11 in a 100 year base, and as 33 in a 20 year base.[10] Hydrogen supply chain routes have a significant impact on fugitive emissions, with green hydrogen emissions (as those described in this report) ranging from 0.1% to 6.9% (average 2.6%).[11, 12]

6. Analysis – Ammonia

6.1 Process description

Large-scale ammonia production was established at the beginning of the 20th century with the introduction of the Haber-Bosch process, where ammonia is produced using hydrogen, nitrogen and electricity as inputs. As ammonia is important for modern societies through its use in fertilisers and in agriculture in general, the Haber-Bosch process has been optimised over many decades. However, it is a highly carbon intensive process as the hydrogen feedstock mostly comes from fossil fuels (e.g., steam methane reformation of natural gas or coal gasification). Also, the electricity needed is considerable and comes from grid electricity, which can also be fossil fuel intensive. Thus, green ammonia production can play a large role in the reduction of the greenhouse gas emissions[13]

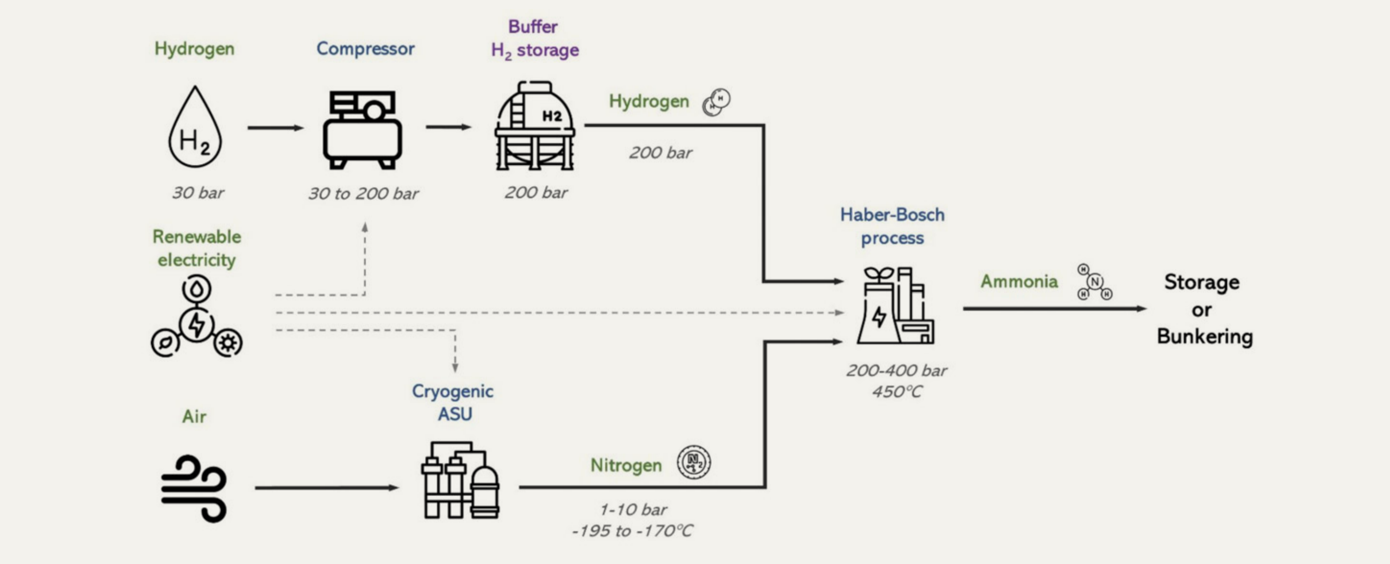
Typically, green ammonia production requires only green hydrogen and nitrogen as raw materials, using electricity from renewable sources. Ultimately, assuming that all integrated processes consume renewable energy, green ammonia can be considered a low-carbon fuel, depending on the accounting conventions for embodied energy.

Focusing on green ammonia production, the Haber-Bosch process can be used to synthetise ammonia using green hydrogen and nitrogen.[2]

Regarding the system design, green hydrogen is produced in a water electrolysis plants using exclusively renewable electricity. In parallel, the energy requirements for the desalination of water can be provided from renewable sources. Detailed descriptions on the production of green hydrogen can be found in the Section 3. The green hydrogen is supplied directly as a feedstock, with buffer storage to secure flexible operation of the Haber-Bosch process. Another assumption concerns the compression of the hydrogen pumped into the gas storage tank. In parallel, nitrogen is separated from air in air separation units (ASU) which are powered by renewable electricity.[2, 14]

Techno-economic analysis of green ammonia production is conducted based on a 300 MW_{el} electrolyser. A detailed flowsheet of the green ammonia production is shown in Figure 3.

Figure 3: Flowsheet of green ammonia production.



Ammonia synthesis – Haber-Bosch process:

In a Haber-Bosch reactor hydrogen and nitrogen are converted to ammonia under high temperature (400°C) and high pressure (between 200 to 400 bar). The reaction is exothermic releasing 0.72 MWh/tNH3 of heat. Hydrogen and nitrogen are fed into the reactor at a 3:1 stoichiometric ratio (hydrogen: 17.65 % w/w, nitrogen: 82.35 % w/w).[14] As the reaction does not lead to complete conversion at industrial conditions, a recycle loop is required to optimise the conversion rates. A conversion factor equal to 99% is assumed (15).

The Haber-Bosch process is optimised for continuous operation at high loads and consequently a high availability factor of 95% (8,322 hours of operation per year) is adapted for this analysis. This availability factor differs from the various scenarios of electrolyser utilisation. Thus, the design of the production system is affected, and buffer storage of compressed hydrogen is used to ensure the constant production of ammonia.[14]

For a mid-scale plant, the energy demand is assumed to be 0.64 MWh/tNH_3.[16] This is for the feed compression of hydrogen from STP and nitrogen at 8 bar. In this analysis hydrogen is fed at 30 bar instead of STP and consequently a specific consumption of 0.53 MWh/tNH3 is used. This assumption is selected to coincide with the assumption of 0.64 MWh/tNH3 for both the Haber-Bosch and ASU energy requirements on several technoeconomic analyses.[14, 17]

Finally, regarding the capital cost of the process, this is estimated on the hourly hydrogen consumption, equal to 452 £/kW (LHV H_2 in) and the O&M costs are evaluated as 2% of the total CAPEX per year.[14]

Buffer Hydrogen Storage:

Hydrogen is supplied at 30 bar from the electrolysers which are assumed to operate in variable utilisation levels according to the scenarios investigated. Thus, intermediate hydrogen storage is necessary to allow the pumping to the Haber-Bosch process at constant flows. The Haber-Bosch process operates optimally at high loads and continuous mode. Hence, the intermediate hydrogen storage is an imperative assumption in order to ensure flexible operation.[14]

Hydrogen is stored at 200 bar pressure in compressed gas tanks. Storage duration equal to 1 day of hydrogen production at maximum power rating is assumed while the maximum storage level must not exceed 90% of tank's capacity. Furthermore, hydrogen boil-off during operation and storage can lead to significant losses of up to 1% per day (18). These losses are assumed to be included in the raw material conversion factor of Haber-Bosch process which is set equal to 99%. Regarding capital expenditure (CAPEX) for large-scale hydrogen storage in compressed tanks (4,500 to 50,000 tonnes), several values are mentioned in the literature ranging from 400 to 1,200 £/kgH_2. Especially for a compressed storage tank at 200 bars 546 £/kgH_2 is used, Moreover, the fixed annual operating costs are set to 1% of the total CAPEX. Variable operational cost, such as electricity, do not occur for pressurised storage as addition reliquification or refrigeration requirement do not apply.[19]

Hydrogen Compressor:

A compressor is necessary to compress the hydrogen from 30 bar pressure to 200 bar. The operation of the compressor is assumed to follow the pattern of hydrogen production. Regarding its cost evaluation, literature data on compressor capital costs are scarce. Wang, Kowal[8] mentions a CAPEX of 5.28 million £ per reciprocating compression system with final pressure 50-300 bars and flow rate of 4 tonne/h, which is quite close to the flow rates of green hydrogen for the investigated scenarios. Thus, the CAPEX is estimated as a linear approximation of the latter value. Furthermore, an annual operation and maintenance (O&M) cost equal to 1% is considered. The variable operational requirements of the compressor are assumed to be an electrical supply of 3 kWh/kgH_2 and is assumed to be supplied by renewable sources. In the literature, a wide range of values can be found, depending on the output pressure and the underlying compressor efficiency. The assumed value is set based on a range of 2 to 7 kWh/kgH_2 electrical consumption and assuming a high efficiency of the compression system.[19]

Nitrogen production:

A cryogenic air separation unit (ASU) is used for nitrogen production due to its maturity and scalability. A cryogenic ASU compresses the air feed and separates the compounds of the air (75.51% w/w nitrogen) in order to provide nitrogen of high purity (99.99%) in cryogenic conditions (1-10 bars, -195 to -170°C).[20] In parallel, an oxygen product can be separated but this is not considered in this study. For this study, the slow dynamic response is neglected, and no nitrogen storage is necessary as it is assumed the cryogenic ASU operates in parallel to the Haber-Bosch process in continuous mode and with an availability factor of 95%. Regarding its technical considerations, the ASU has a require electrical demand of 0.11 MWh/tN2 (at 8 bars).[16] A CAPEX of 1.28 M£/(tN2/h) is assumed and annual O&M cost equal to 2% of the CAPEX.[20]

Based on the description of the processes and the literature sources, techno-economic parameters are summarised in Table 7.

Table 7: Techno-economic parameters on ammonia production system.

	Haber-Bosch	Buffer H_2 Storage	H_2 Compressor	Cryogenic ASU
Availability factor	95%	100%	60-90%	95%
Electricity Consumption	0.53 MWh/t_{NH3}	-	3 MWh/t_{H2}	0.11 MWh/t_{N2}
CAPEX	452 £/kW (LHV H_2 in)	546 £/kg_{H2}	1.32 M£/(tH_2/h)	1.28 M£/(t_{N2}/h)
O&M (% CAPEX/y)	2.0	1.0	1.0	2.0

Mass and energy balance

The mass and energy balances for the process were determined for 12 scenarios which considered the 2 different electrolyser types (Alkaline and PEM), the time frames considered (2020 and 2050) and the global assumptions parameters (L, M, H). The balances are presented for the base scenario- Alkaline electrolyser and 2050 techno-economic parameters for the “M” scenario in the global assumptions. The mass and energy balances, on an hourly basis are reported in Table 8.

Table 8: Mass and energy balances of ammonia subsystem.

	Compounds	Haber-Bosch	H_2 Compressor	Cryogenic ASU
Input	Air (t/h)	-	- 3	2.53
	H_2 (t/h)	5.26	6.67 (30 bar)	-
	N_2 (t/h)	24.56	-	-
	Electricity (MWe)	18.90	20.00	2.70
Output	H_2 (t/h)	- 6.67	(200 bar)	-
	N_2 (t/h)	-	-	24.56
	NH_3 (t/h)	29.53	-	-

6.2 Results and KPIs

Based on the techno-economic assumption and the mass and energy balances (Table 8) the cost and other KPIs can be estimated. Detailed results are presented for the base scenario (i.e., Alkaline electrolyser in 2050, M global assumptions). Firstly, the infrastructure costs and the fixed costs for the O&M costs for the base case are summarised in Table 9 and Table 10.

Table 9: Infrastructure cost for the ammonia system.

	Haber-Bosch	Buffer H_2 Storage	H_2 Compressor	Cryogenic ASU
CAPEX (M£)	79.36	97.07	8.80	31.34
O&M (M£)	1.59	0.97	0.01	0.63

Moreover, variable operating expenditure (OPEX) also constitute a significant component of the total cost. This includes the costs of electricity and hydrogen and are reported in Table 10.

Table 10: Operational costs due to resources consumption.

	Electricity	Hydrogen
Consumption	284.11 TWh/year	43,800 t_{H2}/year
Unit value	50 £/MWh	2.58 £/kg_{H2}
Total cost (M£/year)	14.21	113.16

From these cost components and the ammonia production rate, the levelised cost of ammonia (LCOA) was calculated using Equation 1. The chain efficiency is estimated as a percentage of the total energy content in the upstream to the total energy content of the input. Results for the base case scenario are summarised in Table 11.

Table 11: Levelised cost of ammonia (LCOA) for the base scenario.

Category	
Total annual cost (M£/year)	149.22
Ammonia annual production (t_{NH3}/year)	245,718.00
LCOA (£/t_{NH3})	607.27
LCOA (£/GJ_{NH3} (LHV NH_3))	32.30
Chain efficiency (%)	56.87

of the cost in shown in Figure 4 and shows hydrogen constitutes 76% of the LCOA, while electricity is 10%. Moreover, the electricity price plays a significant role on the cost of hydrogen. Hence, the LCOA is strongly dependent on the assumed electricity price.

The results in the previous section are for the base case. The results for all scenarios are given in subsections below.

Levelised cost of ammonia (LCOA) and breakdown

LCOA results for all scenarios are presented in Table 12.

Figure 4: Ammonia's production cost breakdown for the base scenario.

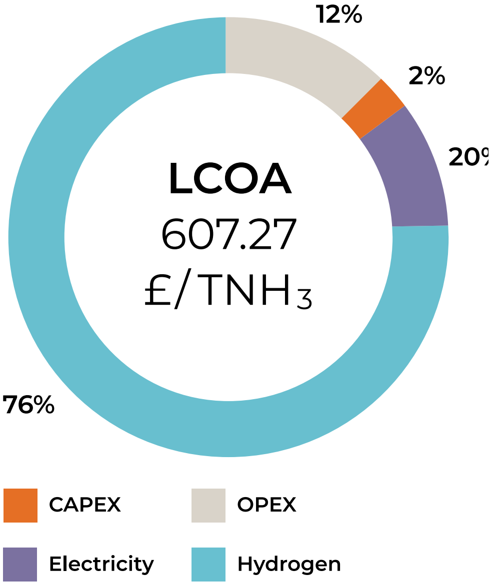


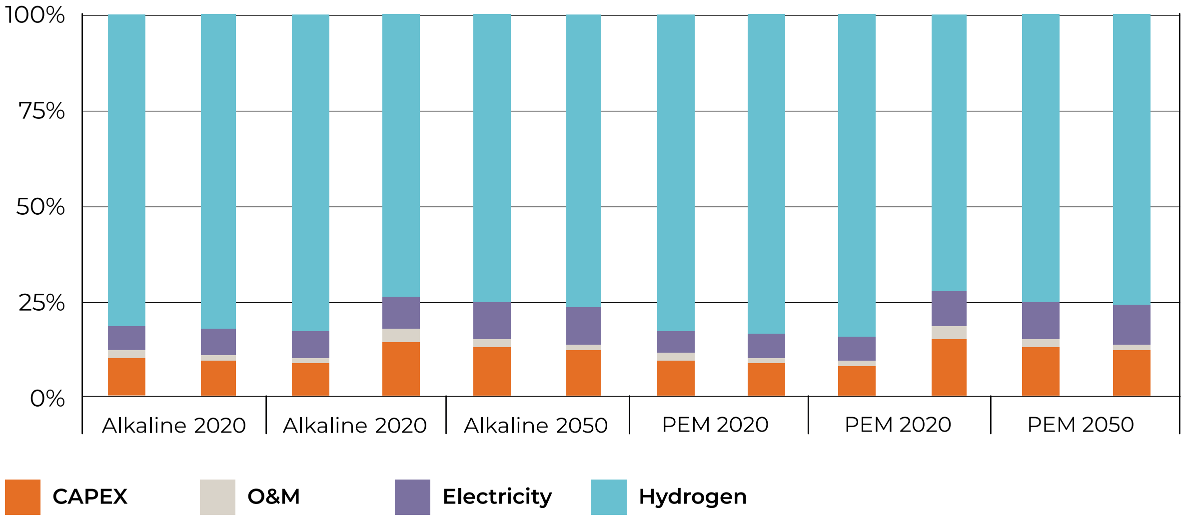
Table 12: Scenario analysis of LCOA.

			Scenarios		
KPI	**Electrolyser**	**Year**	**L**	**M**	**H**
LCOA (£/t_{NH3})	Alkaline	2020 2050	582.7 409.8	846.8 607.3	1120.1 810.5
	PEM	2020 2050	635.5 393.9	912.0 592.7	1191.9 795.8
LCOA (£/GJ_{NH3}) (based on LHV NH_3)	Alkaline	2020 2050	31.0 21.8	45.0 32.3	59.6 43.1
	PEM	2020 2050	33.8 21.0	48.5 31.5	63.4 42.3

The results of the scenario analysis demonstrated a reduction in the LCOA of around 30% is expected in 2050 compared to the estimated values of 2020. Moreover, the large ranges in the LCOA are estimated for the different assumptions and global parameters, as prices in the "H" scenarios are almost double those in the "L" scenarios.

However, the levelised costs of green ammonia estimated here are significantly higher than what has been reported in other technical reports or scientific literature. Some indicative summaries of LCOA comparisons are provided in IRENA and AEA (2022)[2]cand Valera-Medina and Bãnares-Alcántara.[13] In particular, works by Nayak-Luke and Bañares-Alcántara[21] and Salmon and Bañares-Alcántara[22] estimated the LCOA to be as low as 10-14 £/GJ in the best locations in the world for 2030. Towards an investigation of this work's higher LCOA to the literature, the cost breakdown is reported to indicate the most important cost components. Cost breakdown for all scenarios are presented in Figure 5.

Figure 5: Ammonia's production cost breakdown for all scenarios.



The breakdown of the cost displays the same pattern in all of the scenarios. Hydrogen is the most important cost component for ranging from 73% to 84% of the total cost. This is why the reduction in the cost of hydrogen in 2050, due to the predicted enhancements in hydrogen production efficiency, lead to a notable reduction of its impact on the cost of ammonia. However, as has been indicated in the previous section, hydrogen costs depend heavily on electricity prices. Consequently, electricity is the major determinant on the levelised cost of both hydrogen and ammonia. Overall, the variable electricity costs amongst the scenarios are reflected in the corresponding ranges of the LCOA.

Thus, the levelised cost of electricity may implicitly be the main reason our estimated LCOA is higher than what has been reported in the literature. As demonstrated by Nayak-Luke and Bañares-Alcántara[21] hydrogen production costs are the most significant component. In this study, the percentage of hydrogen towards the total cost is even higher. This mainly comes from the global assumptions- prices of zero-carbon renewable electricity. In particular, the assumed electricity prices represent scenarios for the UK, that may be higher than the price in other countries. For example, Armijo and Philibert[14] estimate the LCOA to be as low as £19/GJ while consistently estimating the LCOE to be 20-40 £/MWh for locations such as Argentine and Chile. Therefore, the higher assumed prices for electricity in the UK lead to higher LCOA in this study.

Chain efficiency

The results on chain efficiency are given in Table 13.

Table 13: Energy efficiency of the ammonia supply chain.

Electrolyser	Year	Efficiency (%)
Alkaline	2020	40.63
	2050	56.87
PEM	2020	40.11
	2050	56.87

These results show an increase in the chain efficiency, which comes as a consequence of the expected increase in the efficiency of hydrogen electrolysis technologies. The Haber-Bosch process is considered as a well-established and optimised process and thus increases to the efficiency are not expected. This is the reason why the related techno-economic parameters are considered constant for 2020 and 2050. So, the increase in chain efficiency depends solely on the developments in hydrogen production technologies.

Water consumption

Moreover, the specific requirements of water can be estimated. Ammonia's production subsystem does not require any water apart from the water which is used in the electrolyser. The specific water consumption for ammonia is estimated to be 99.5 $kgH_2O/GJNH3$. This is for purified water, while the corresponding value for seawater (SW) is 237 kgSW/GJNH3.

6.3 Safety and environmental issues

In this section the risks concerning ammonia are summarised and safety guidelines for its use as a marine fuel are proposed.

Flammability

Ammonia has lower flammability and a narrower flammable range than other fuels. The spontaneous ignition temperature is relatively high (651°C) and so is the minimum ignition energy (680 MJ). In any case ammonia is flammable and the ignition sources must be isolated. However, the fire risks either onboard or during its handling are lower.[23] Established regulations (e.g., EC or NPFA) do not consider ammonia as extremely flammable (see Table 13). Hence, ammonia does not require a hazard pictogram, opposed to conventional shipping fuels as HFO, MGO or LNG.[24]

Corrosion on materials

Moreover, low risks exist regarding the compatibility of ammonia with common equipment materials. Ammonia can be used in standard carbon and stainless-steel pipes and fittings. Ammonia only corrodes specific materials such as copper, brass, zinc, natural rubber and some plastics which must be avoided (24).

Ammonia as pollutant

From an environmental perspective, risks regarding air pollution have to be investigated. Carbon emissions from green ammonia production are considered zero, as total energy requirements come from renewable sources. However, combustion of ammonia may lead to nitrogen oxides (NO_x). Established limits on NO_x emissions (e.g., by IMO Tier III) enforce the installation of Selective Catalytic Reduction (SCR) systems in ships. This uses a catalyst in order to reduce the NO_x emissions in the exhaust. N_2O emissions may be generated and so the calibration of the system is necessary to avoid emissions and penalties. Finally, as ammonia does not contain any sulphur, it would inherently comply with the sulphur emissions standards.[24, 25.]

Toxicity

The most important risk of ammonia pertains to its toxicity, which can impose many hazards both to humans and the environment (plants, animals, aquatic life). Ammonia is toxic via inhalation for humans and depending on the concentration and exposure time it can lead to various symptoms from headaches, eye damage and skin burns to difficulties in breathing and fatal damage. Established acute exposure guidelines levels (AEGLs) exist for ammonia as it is classified as a hazardous substance. In the same context, ammonia's danger to the environment depends on the concentrations and its dispersion due to wind conditions. Ammonia spills could be toxic at ground levels and lead to mortality of aquatic life in marine environments. In particular, ammonia dissolves in water and is a serious threat to aquatic organisms as it limits the availability of oxygen and has long-lasting effects on the local environment. Any remaining ammonia evaporates and is converted in to a threat to other organisms that may meet lethal concentrations.

Thus, many safety guidelines must be adapted for the handling of ammonia both inland and onboard. Such measures include:

- Gas detection systems to identify leakages,
- Gas absorbing water tanks,
- Ventilation systems,
- Water curtain systems to knock down ammonia vapour,
- Eye cleaning stations,
- Safety showers,
- Personal protective equipment like clothing, gloves, glasses, boots etc.

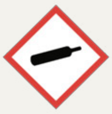
Furthermore, personnel who works close to ammonia may require gas-tight suits, breathing apparatus and thermal protection (in case of refrigerated ammonia).[23, 24]

Safety regulations for use in ships

A positive asset for ammonia is its inclusion in existing safety regulations. For instance, the IBC Code (International Code for the Construction and Equipment of Ships Carrying Dangerous Chemicals in Bulk, Amended by Resolution MEPC.225[64]) provides the international standards for the safe carriage of aqueous ammonia on ships. Moreover, the IGC Code (International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk) extends the international standards for equipment in ships and the safety of ships, crews, and the environment. Besides, attempts have also been directed towards the establishment of regulations for shipping using alternative fuels. In particular, the IGF Code (International Code of Safety for Ships Using Gases or Other Low-Flashpoint Fuels) provides the international standards for ships using low-flashpoints fuels (such LNG) as fuel. Overall, both regulations for shipping ammonia as a commodity are established and safety codes have been recently published for the use of alternative shipping fuels. Thus, ammonia use as shipping fuel could be feasible, if the IGF Code would extend the regulations for its use as fuel in ships. The latter entails more risks than ammonia's carriage as commodity.[25]

Overall, ammonia displays risks which are manageable. Moreover, the existence of regulations on its carriage in ships offers an advantage to its use as a marine fuel. In Table 14, the hazardous characterisations of ammonia are summarised.

Table 14: Safety characterisation of ammonia.

Symbol	Characteristic	Ranking	Notes
	Flammability	Cat. 2	–
	Gas under pressure	–	Gas under pressure may explode if heated
	Toxicity	Cat. 3	Toxic if inhaled
	Skin erosion	Cat. 1/1B	Severe skin burns and eye damage
	Hazards to aquatic environment	Cat. 1	Very toxic to aquatic life
	Summary (US NPFA704)	Health Hazard: 3 Fire Hazard: 1 Instability: 0	Extreme danger for health, low flammability (Anhydrous NH_3)

7. Analysis – Methanol

Methanol is one of the most commonly produced and used chemicals in the world. Currently methanol is widely used in the synthesis of other chemicals, such as acetic acid, olefins and formaldehydes, but it can also be used as a fuel. In the maritime sector, methanol was first used as a fuel in 2015 when a passenger ferry was converted to run on methanol and in 2016 with the world's first methanol (dual fuel) tanker.[26, 27] As it is an alcohol it is a good replacement to conventional marine fuels in terms of its combustion properties, which is why there is increasing interest in using it as a fuel.[28]

Currently, methanol is produced from syngas with natural gas and coal accounting for the vast majority of the feedstocks used. Due to the heavy dependence on fossil fuels, traditional methanol has little climate change benefits over traditional marine fuels. Therefore, alternative synthesis pathways for methanol should be considered if it to widely used in the maritime sector for decarbonisation purposes. This includes green methanol, which is methanol produced from sustainable and renewable hydrogen and carbon dioxide sources. As the carbon dioxide comes from a renewable source (such as direct air capture) the carbon emitted from the combustion of methanol can be considered zero or neutral as the carbon is being/will be recycled i.e., the carbon released from combustion can be captured again and used to produce fuel, thus no additional carbon is being released into the atmosphere.

7.1 Process description

To produce methanol, the green methanol or eMethanol route is considered. eMethanol is methanol produced from carbon dioxide (CO_2) and hydrogen (Figure 6). The hydrogen is produced from electrolysis (alkaline and PEM) and details of this can be found in Section 4. The CO_2 is produced from a direct air capture (DAC) unit and solid sorbent DAC is considered. Renewable energy (wind and solar) is used to meet the energy demands of both the electrolyser and DAC unit. Only CO_2 from DAC is considered due to the DfT's strict definition of renewable fuels (see Sections 2 and 3).

The hydrogen and CO_2 are fed into the reactor where a mixture of water and methanol is produced (along with unreacted gas which is fed back into the reactor). The reactor is an adiabatic fixed-bed catalytic reactor which uses copper and zinc-based catalysts.[29] To separate out the water and methanol, the liquid stream is fed through a series of heaters and a distillation column to separate out the water and methanol. The amount of hydrogen and CO_2 needed to produce methanol is 0.19 kg hydrogen and 1.37 kg CO_2 per kg methanol (Table 15).[30] The reaction between the hydrogen and CO_2 to produce methanol is exothermic and it is assumed the heat produced is sufficient to produce the steam used in the process.[30] Thus, the only energy input is electricity (compression of gas into the reactor).

The mass and energy requirements of the electrolyser can be found in Section 4. For the DAC unit, the global parameters for energy demand (heat and electricity) were used (Section 3). The energy demand is based on the amount of CO_2 required by the methanol synthesis process, which is determined by the output of the electrolyser. The hydrogen output of the 300 MW_{el} electrolyser was used to determine the methanol output, and thus the mass and energy balance will vary depending on the hydrogen input (Table 19).

Figure 6: Diagram of eMethanol production stages. The electrolysis process described in Section 4 is considered for hydrogen.

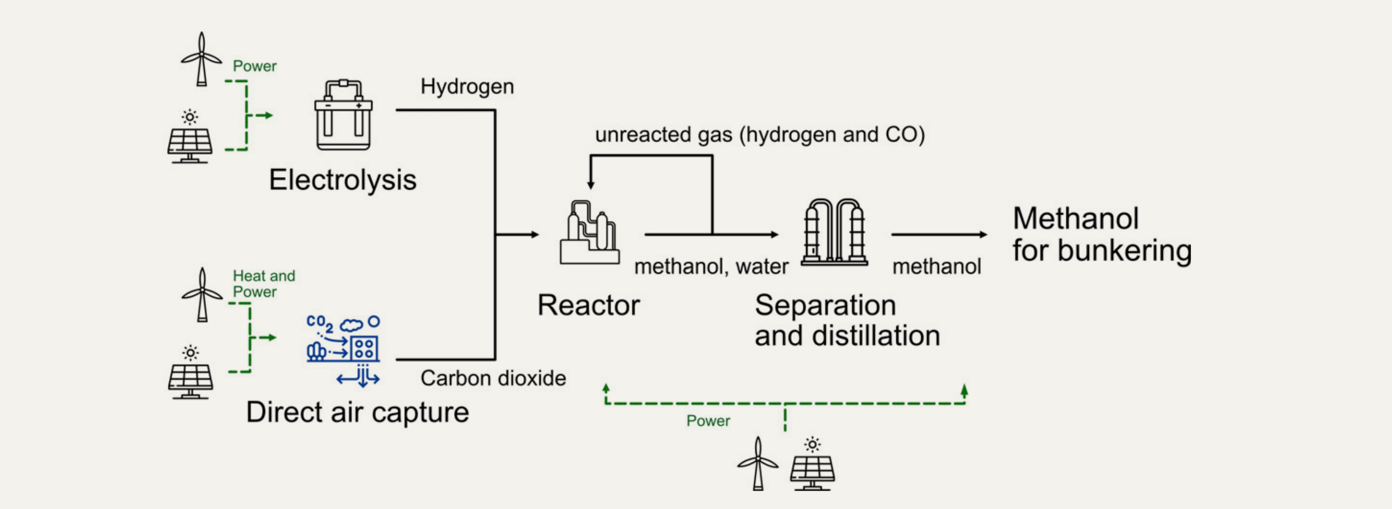


Table 15: Mass and energy balance data for eMethanol process (30).

	Mass balance							
	Electrolysis	**kg/h**	**Direct air capture**	**kg/h**	**Reactor**	**kg/h**	**Separation and distillation**	**kg/h**
Intput	Water	See section 4	Air	3,077	Hydrogen	0.19	Methanol and water	1.56
Output	Hydrogen	See section 4	Carbon dioxide	1.37	Methanol and water mixture	1.56	Methanol	1
	Oxygen	See section 4					Water	0.56
	Energy balance							
	Electrolysis	**kWh/h**	**Direct air capture**	**kWh/h**	**Reactor**	**kWh/h**	**Separation and distillation**	**kWh/h**
Intput	Electricity	See section 4	Electricity	0.44	Electricity	0.15	Heat (medium pressure steam)	-0.46
			Heat	0.002			Heat (low pressure steam)	-0.03

To calculate the cost KPIs, literature data on the capital expenditure (CAPEX) and operating expenditure (OPEX) were used (Table 16 and Table 17, respectively). The CAPEX data for the methanol synthesis process was taken from literature and scaled by applying scale of economies:[31]

Equation 2.

$$\frac{C_2}{C_1} = \left(\frac{S_2}{S_1}\right)^R$$

Where:

C_1 is the cost of facility 1

C_2 is the cost of facility 2

S_1 is the size/capacity of facility 1

S_2 is the size/capacity of facility 2

R is the scaling factor for technologies in facilities 1 and 2

It was necessary to scale the costs as the literature costs are for a 500 kg methanol per hour plant (4,000 t methanol per year) Sollai, Porcu (29), while the methanol production rate based on a 300 MW_{el} electrolyser is 25,000 to 53,000 t methanol per year. This approach was used as detailed cost data was available in the paper by Sollai, Porcu (29). Other cost data was available but were less detailed (aggregated costs which did not specify what was considered in CAPEX or OPEX), were missing cost categories (e.g., hydrogen storage) or were specific to another country i.e., China. Scaling factors (Table 18) were determined for the CAPEX and relevant OPEX categories (labour, general and admissions, taxes and insurance and maintenance) and a CAPEX and OPEX calculated for each methanol production capacity (Table 19). The CAPEX and OPEX were used to calculate the levelised cost of methanol using Equation 1. 3The CAPEX was also used to calculate the CAPEX per EJ methanol produced.

Table 16: Capital expenditure (CAPEX) of the methanol production process. These values are the literature values and were scaled to estimate the CAPEX for the different H_2 inputs Sollai, Porcu (29).

CAPEX	Million £
Gas compression	1.95
Gas storage	0.31
Methanol synthesis	1.09
Engineering, procurement and construction	0.76
Project and process contingencies	1.42
Site preparation	0.19
Permit fees	1.42

Table 17: Operating expenditure (OPEX) values used to estimate levelised cost of producing eMethanol.[29]

OPEX category	Value	Units
Electricity	30 to 70	£ per MWh
Catalyst	95.24	euros per kg
Labour	211	1000s euros per year
General and admissions	42	1000s euros per year
Property taxes and insurance	297	1000s euros per year
Maintenance	53	1000s euros per year
Maintenance (compressors)	88	1000s euros per year

Table 18: Scaled CAPEX for the different hydrogen inputs / scenarios.

	CAPEX category						
Category	Gas compression	Gas storage	Methanol synthesis	Engineering, procurement and construction	Project and proces contingencies	Site preparation	Permit fees
Literature data (Million £)	1.95	0.31	1.09	0.76	1.42	0.19	1.42
Scaling factor, R[31]	0.60	0.65	0.66	0.65	0.65	0.65	0.65
2020 Alkaline electrolyser							
(Low)	15.91	3.01	11.12	7.34	13.77	1.83	13.77
(Medium)	18.19	3.48	12.89	8.49	15.92	2.12	15.92
(High)	20.29	3.92	14.54	9.56	17.92	2.39	17.92
2050 Alkaline electrolyser							
(Low)	19.65	3.78	14.04	9.23	17.31	2.31	17.31
(Medium)	22.47	4.38	16.27	10.67	20.02	2.67	20.02
(High)	25.07	4.93	18.36	12.02	22.53	3.00	22.53
2020 PEM electrolyser							
(Low)	15.55	2.94	10.84	7.16	13.43	1.79	13.43
(Medium)	17.78	3.39	12.56	8.28	15.53	2.07	15.53
(High)	19.83	3.82	14.18	9.32	17.48	2.33	17.48
2050 PEM electrolyser							
(Low)	19.65	3.78	14.04	9.23	17.31	2.31	17.31
(Medium)	22.47	4.38	16.27	10.67	20.02	2.67	20.02
(High)	25.07	4.93	18.36	12.02	22.53	3.00	22.53

Table 19: Methanol production and catalyst requirements for each hydrogen scenario.

Hydrogen scenario	LCOH	£ of H_2 per year	t methanol per year based on this H_2 quantity	MJ methanol per year	kg catalyst
2020 Alkaline electrolyser					
(Low)	2.67	6.58 x10^7	1.30 x10^5	2.59 x10^9	2,414
(Medium)	3.93	1.21 x10^8	1.63 x10^5	3.24 x10^9	3,018
(High)	5.23	1.93 x10^8	1.96 x10^5	3.89 x10^9	3,621
2050 Alkaline electrolyser					
(Low)	1.70	5.96 x10^7	1.85 x10^5	3.69 x10^9	3,433
(Medium)	2.58	1.13 x10^8	2.32 x10^5	4.61 x10^9	4,292
(High)	3.49	1.83 x10^8	2.78 x10^5	5.53 x10^9	5,150
2020 PEM electrolyser					
(Low)	2.97	7.04 x10^7	1.25 x10^5	2.50 x10^9	2,323
(Medium)	4.29	1.27 x10^8	1.57 x10^5	3.12 x10^9	2,904
(High)	5.63	2.00 x10^8	1.88 x10^5	3.74 x10^9	3,485
2050 PEM electrolyser					
(Low)	1.61	5.64 x10^7	1.85 x10^5	3.69 x10^9	3,433
(Medium)	2.50	1.10 x10^8	2.32 x10^5	4.61 x10^9	4,292
(High)	3.41	1.79 x10^8	2.78 x10^5	5.53 x10^9	5,150

In addition to the costs listed in Table 16 to Table 18, the cost of hydrogen fed into the process, as well as the DAC is also factored in the cost KPI calculations. The LCOH is used as the cost of hydrogen and is considered as a OPEX cost. For DAC, the global parameters were used to calculate to the CAPEX, as well as the cost of electricity and heat (OPEX). See the Appendix for all CAPEX and OPEX data used to calculate the economic KPIs of eMethanol.

The levelized cost of methanol (LCOM) is calculated per GJ methanol produced and the LHV of methanol is assumed to be 19.9 MJ/kg.[32] Other KPIs considered as chain efficiency and water consumption. The chain efficiency is the ratio of electricity input to MJ methanol produced while the water consumption is the ratio of the water consumed (from the electrolyser) per GJ methanol produced.

7.7 Results and KPIs

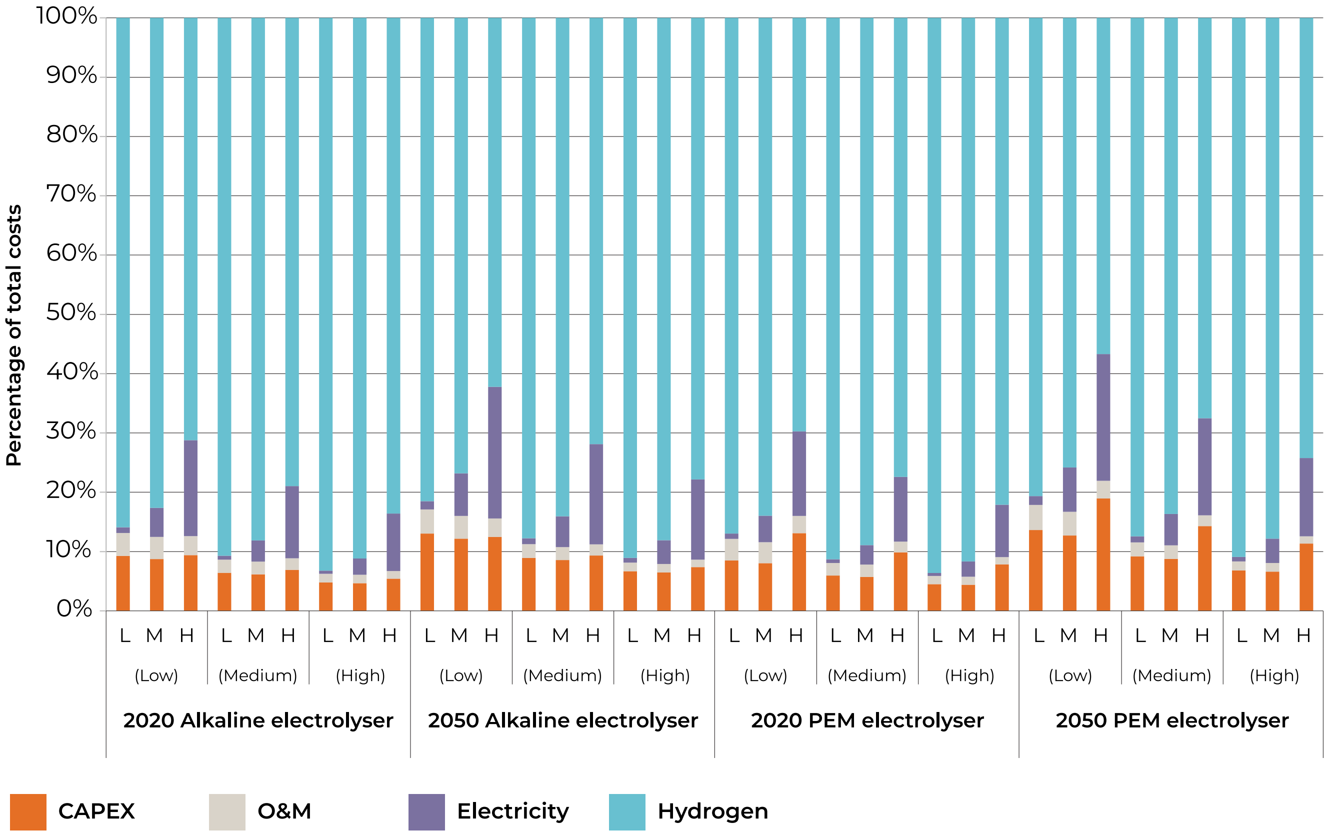
Levelised cost of methanol (LCOM)

The levelised cost of methanol was estimated to range from 20 £/GJ to 62 £/GJ (average of 38 £/GJ) as indicated in Table 20. The OPEX is the main cost factor, account for 81 to 95% of the total cost (Figure 7), of which the hydrogen is the most important cost, account for 70 to 98% of the OPEX. The cost of hydrogen is driven by electricity. Therefore, the cost of hydrogen and the cost of renewable electricity are the most important factors in the cost of eMethanol.

Table 20: Levelised cost of methanol (MeOH) for each H_2 scenario and low (L), medium (M) and high (H) global parameters.

Hydrogen scenario	Global parameters (for DAC, electricity cost, lifespan and discount rate)	£/GJ MeOH (LHV)	£ per t MeOH
2020 Alkaline electrolyser (low)	L	30.81	613.04
	M	32.30	642.86
	H	38.06	757.39
2020 Alkaline electrolyser (medium)	L	42.40	843.73
	M	43.92	873.92
	H	49.68	988.70
2020 Alkaline electrolyser (high)	L	54.48	1084.19
	M	56.01	1114.67
	H	61.79	1229.63
2050 Alkaline electrolyser (low)	L	21.03	418.48
	M	22.56	448.87
	H	28.33	563.78
2050 Alkaline electrolyser (medium)	L	29.10	579.04
	M	30.64	609.77
	H	36.43	724.89
2050 Alkaline electrolyser (high)	L	37.54	746.95
	M	29.09	777.93
	H	44.89	893.22
2020 PEM electrolyser (low)	L	33.73	671.16
	M	35.22	700.90
	H	32.52	647.15
2020 PEM electrolyser (medium)	L	45.88	912.96
	M	47.39	943.09
	H	41.75	830.73
2020 PEM electrolyser (high)	L	58.33	1160.83
	M	59.86	1191.25
	H	51.20	1018.93
2050 PEM electrolyser (low)	L	20.17	401.47
	M	21.70	431.86
	H	22.22	442.17
2050 PEM electrolyser (medium)	L	28.34	563.92
	M	29.88	594.65
	H	28.42	565.49
2050 PEM electrolyser (high)	L	36.78	731.83
	M	38.33	762.81
	H	38.42	692.98

Figure 7: Breakdown of CAPEX versus OPEX for eMethanol for each scenario considered.



CAPEX per EJ

The CAPEX per EJ of methanol was found to range from 257 to 532 billion £/EJ methanol (average 375) as shown in Table 21. The DAC unit is the most important CAPEX category, accounting for over half the CAPEX in all of the scenarios.

The cost of DAC is uncertain as the technology has a technology readiness level of 6 (large-scale and prototype level of use). Advances in DAC could result in the cost dropping, which would reduce the impact of DAC on the CAPEX.

However, any reductions in the cost of DAC would have limited impacts on the LCOM as this is largely driven by hydrogen (and electricity). Outside of DAC, gas compression, contingencies and permit fees are important, but are five to 18 times smaller.

Table 21: CAPEX per EJ methanol, chain efficiency and water consumption for each H_2 scenario.

Hydrogen scenario	CAPEX per EJ per year	Chain efficiency	Water consumptin (t water/GJ)
2020 Alkaline electrolyser (low)	2.89x10^{11}	45%	0.10
	3.55 x10^{11}	44%	0.10
	5.30 x10^{11}	40%	0.10
2020 Alkaline electrolyser (medium)	2.79 x10^{11}	45%	0.10
	3.45 x10^{11}	44%	0.10
	5.20 x10^{11}	40%	0.10
2020 Alkaline electrolyser (high)	2.71 x10^{11}	45%	0.10
	3.37 x10^{11}	44%	0.10
	5.12 x10^{11}	40%	0.10
2050 Alkaline electrolyser (low)	2.73 x10^{11}	64%	0.10
	3.39 x10^{11}	61%	0.10
	5.14 x10^{11}	54%	0.10
2050 Alkaline electrolyser (medium)	2.64 x10^{11}	64%	0.10
	3.30 x10^{11}	61%	0.10
	5.05 x10^{11}	54%	0.10
2050 Alkaline electrolyser (high)	2.57 x10^{11}	64%	0.10
	3.23 x10^{11}	61%	0.10
	4.98 x10^{11}	54%	0.10
2020 PEM electrolyser (low)	2.91 x10^{11}	43%	0.10
	3.57 x10^{11}	42%	0.10
	5.32 x10^{11}	39%	0.10
2020 PEM electrolyser (medium)	2.81 x10^{11}	43%	0.10
	3.46 x10^{11}	42%	0.10
	5.21 x10^{11}	39%	0.10
2020 PEM electrolyser (high)	2.73 x10^{11}	43%	0.10
	3.38 x10^{11}	42%	0.10
	5.13 x10^{11}	39%	0.10
2050 PEM electrolyser (low)	2.73 x10^{11}	64%	0.10
	3.39 x10^{11}	61%	0.10
	5.14 x10^{11}	54%	0.10
2050 PEM electrolyser (medium)	2.64 x10^{11}	64%	0.10
	3.30 x10^{11}	61%	0.10
	5.05 x10^{11}	54%	0.10
2050 PEM electrolyser (high)	2.57 x10^{11}	64%	0.10
	3.23 x10^{11}	61%	0.10
	4.98 x10^{11}	54%	0.10

Chain efficiency

The chain efficiency is the ratio of electricity input (electrolysis, DAC and methanol synthesis) to the energy content of the methanol produced. It was estimated to range from 39 to 64% with an average of 51% (Table 21). The factor which impacts the chain efficiency the most if the electricity demand of the electrolyser (84 to 99% of total electricity demand), although the DAC also has an impact (up to 15% of total electricity demand).

Water consumption

The water consumption was found to be the same for all of the scenarios (0.1 t water/GJ methanol, Table 21). Only water consumption in the electrolyser was considered, which is the same for all of the scenarios. Water is produced in the methanol synthesis stage. If this is taken into account as a credit, then the water consumption would decrease.

Safety and environmental issues

In comparison to traditional marine fuels, methanol has some additional safety and environmental issues.[28, 33, 34] Methanol is a hazardous liquid which poses fire and human health risks. The fire risks are due to methanol being highly flammable with a flashpoint much lower than traditional marine fuels (flashpoint of 11°C and boiling point of 65°C).[28] Due to the low flash point, methanol vaporises/evaporates when exposed to air, which can occur from leaks in containers or from discharge when disconnecting fuelling pipes, so there is the risk of fire.

From a human health perspective, methanol is poisonous as humans have limited capability to convert methanol into carbon dioxide. If consumed, methanol would result in a build-up of formic acid in the liver, causing intoxication. However, as methanol is a polar liquid it is completely miscible in water. Also, there are many microorganisms which can metabolise methanol and convert it into carbon dioxide.[28] Therefore, if methanol is released into any water bodies, it will rapidly biodegrade. Thus health/environmental issues are strictly related to humans.

Despite these issues, when these are translated into additional measures and infrastructure adjustments, additional measures are minimal.[34] The main additions relate to minimising the risks of fire and direct contact to humans. For fire risks, segregating containers, double barrier protection, and additional leak detection would be needed. For human health risks, any methanol handling systems in the supply chain need to be fully closed off, making direct contact as minimal as possible. For both fire and human health risks, increasing ventilation can also be applied as this would decrease the risk of fire and impact from inhalation.

8. Analysis – Synthetic hydrocarbons

The shipping industry is a major contributor towards global greenhouse gas (GHG) emissions, and there is an increasing need to find sustainable alternatives to conventional fossil fuels.[35] Synthetic hydrocarbons, also known as e-fuels or electrofuels, have emerged as a potential solution to decrease the environmental footprint of the shipping sector.[36, 37]

Synthetic hydrocarbons can be produced from renewable feedstocks and can be used as direct substitutes for traditional fossil fuels such as gasoline, diesel, or kerosene. Synthetic hydrocarbons can be liquid or gaseous fuels and are tailored to have similar properties as traditional fossil fuels, depending on the production process and the desired end-use, and they are compatible with existing combustion engines and fuelling infrastructure.[38, 39, 40] Examples of synthetic hydrocarbons include synthetic diesel, synthetic gasoline, and synthetic aviation fuel. These alternative fuels are often used as a means to decrease greenhouse gas emissions, increase energy security, and broaden fuel sources.[37] Synthetic hydrocarbons in this study are produced using green hydrogen (H_2) from renewable energy sources, such as wind, solar, or hydropower, and carbon dioxide (CO_2) from direct air capture (DAC).[36, 41] In this report, we explore the feasibility of using synthetic hydrocarbons as a shipping fuel and provide an overview of their value chain.

8.1 Process description

The production of synthetic fuels typically involves three main process steps: (a) syngas production, (b) synthetic hydrocarbon production through the Fischer Tropsch synthesis, and (c) product separation and upgrading.[42] A simplified process flow diagram is illustrated in Figure 8.

Feedstock acquisition

The H_2 feedstock is produced using alkaline or PEM water electrolysis, powered by renewables, based on current (2020) and future (2050) scenarios and it is provided at 30 bar (43) (see Section 4). In this study, we consider 300 MW_{el} of green H2 as input for the Fischer-Tropsch plant. The CO_2 feedstock is obtained via carbon capture and utilization (CCU), where CO_2 is captured from the atmosphere through direct air capture (DAC). The CO_2 is provided at 20°C and 1 bar and it is compressed at 30 bar with a multi-stage compressor to reach the target process pressure.[43, 44]

Feedstock conversion to syngas

The syngas, which is the main feedstock of the Fischer-Tropsch process, is produced through the reverse water gas shift (rWGS) reaction of the H_2 and CO_2 feedstocks using a nickel-based catalyst.[45] Syngas is a gaseous mixture that mainly consists of hydrogen (H_2) and carbon monoxide (CO), and it is used as an intermediate in the production of a wide range of chemicals.[46]
The two reactants are mixed and preheated at 900°C, as the rWGS reaction takes place at high temperatures to ensure a high CO yield. Then the mixture enters the high-temperature rWGS reactor.[41, 42, 43, 47]

Fischer-Tropsch synthesis

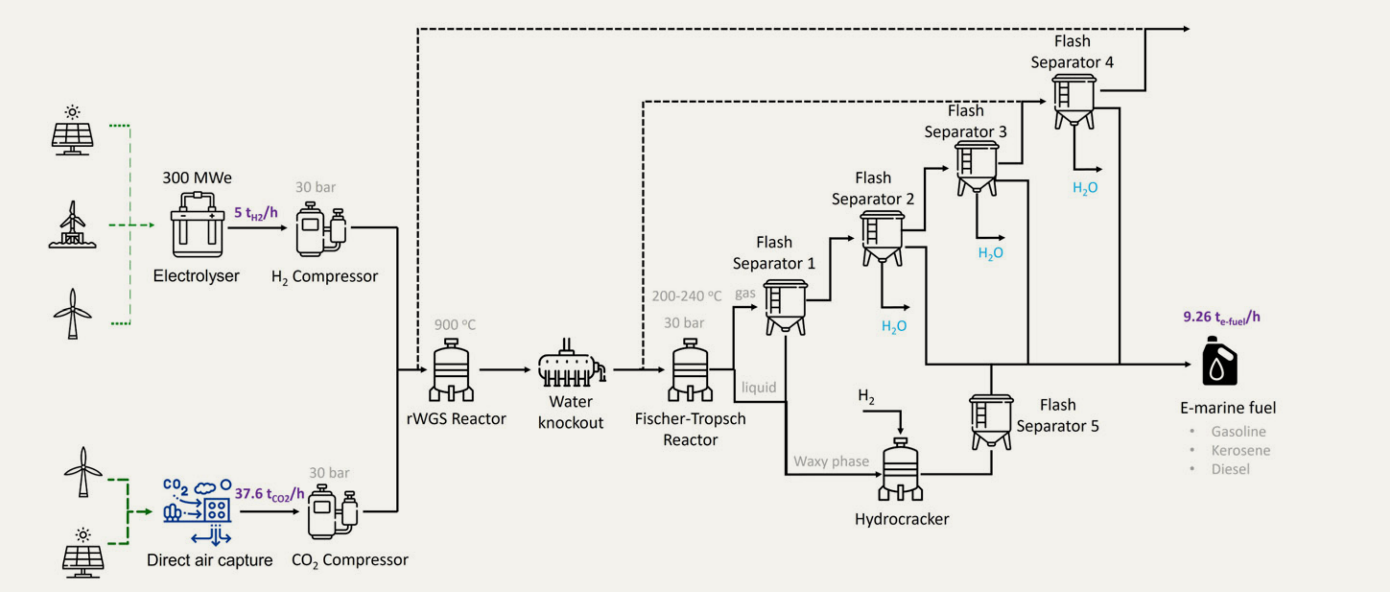
The Fischer-Tropsch synthesis stage converts the syngas into liquid hydrocarbons and other organic products by a series of exothermic polymerisation reactions.[41, 46] Fischer-Tropsch synthesis is a well-established and fully commercialised process technology for the production of a variety of hydrocarbon products.[48, 49] In terms of catalysts, iron and cobalt are usually used for industrial applications.[44, 45, 46] In this study, the low-temperature Fischer-Tropsch process (200–240°C) is considered using a cobalt catalyst at 30 bar,[43, 45] since the main products of the low-temperature Fischer-Tropsch represent a mix of diesel and kerosene.[43, 47] In the high-temperature Fischer-Tropsch (300–350°C), iron catalysts are usually used to produce gas, olefins, and gasoline.[47] The Fischer-Tropsch product, also known as syncrude, is separated into a liquid and a gaseous stream.[42]

Product separation and upgrading

The liquid syncrude then goes to the hydrocracker. The gaseous stream is flashed and the liquid product of the first flash vessel is split into a liquid phase and a waxy phase.[42, 44] The light waxes are combined with the liquid syncrude and supplied to the hydrocracker. Hydrocracking is a catalytic cracking process that is able to transform longer hydrocarbon chains into desired fuel fractions by adding H_2 to aromatics and olefins to produce alkanes and naphthenes.[44, 45, 46] All the resulting Fischer-Tropsch gas streams, as well as the hydrocracking product, go through a series of distillation/flash separations, whose operating conditions are adjusted, to obtain synthetic fuels with similar properties to commercial marine fuels.[45, 46] Gaseous streams that leave the flash vessels contain unreacted valuable reactants (CO and H_2) and are recycled back into the process. All liquid products from each flash vessel are collected, mixed and brought to ambient conditions to form the final e-marine fuel.

Water that is produced in the rWGS reactor and the Fischer-Tropsch reactor is removed with a knockout drum and the flash vessels, respectively, and is treated by a wastewater treatment process.[44] This water can then in principle be recycled and used to reduce the overall water consumption of the synthetic fuel production process. Additionally, the heating demands of the synthetic fuel synthesis process such as heat for upgrading, distillation, or the rWGS reaction, can be met internally through the surplus heat generated by the Fischer-Tropsch synthesis process, or by utilising the remaining Fischer-Tropsch by-products in a burner to provide heat.[42, 47, 50] As a result, no external thermal energy is needed to cover the total synthetic marine fuel production heat demand.[42, 43, 50]

Figure 8: Simplified process flow diagram for the production of synthetic hydrocarbons. Mass flows for the feedstocks and final e-marine fuel are illustrated for the alkaline electrolysis 2050 'M' scenario.

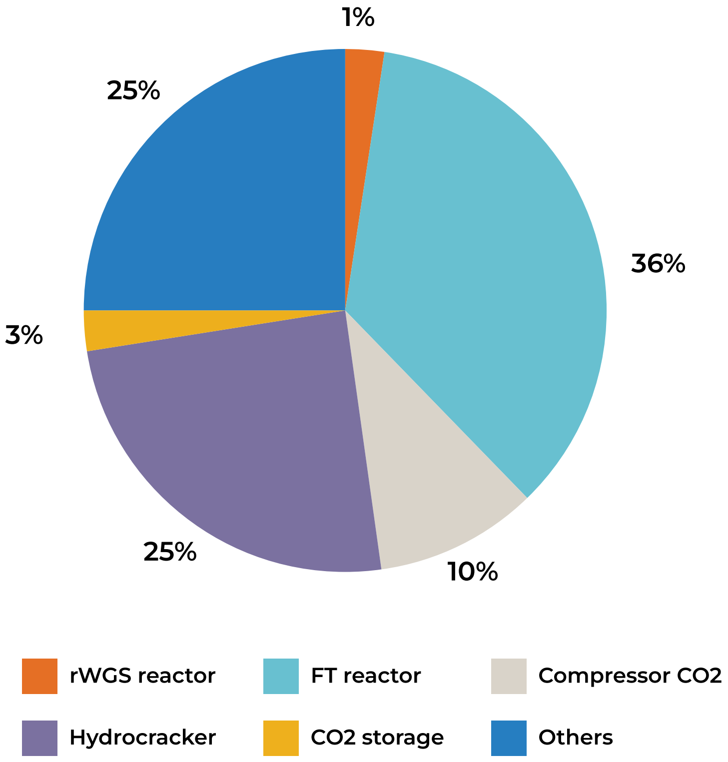


8.2 Results and KPIs

The Fischer-Tropsch process is evaluated through a techno-economic analysis for the base year 2022. The production of e-marine fuel is based on green hydrogen from renewable sources and carbon dioxide from direct air capture (DAC). The analysis considers a fixed input flow rate of 300 MW_{el} of hydrogen and explores the Fischer-Tropsch plant's performance under different scenarios. The scenarios and results for current (2020) and future (2050) values of alkaline and PEM electrolysers as presented in Section 4 are used as input in this section. Additionally, the low (L), medium (M), and high (H) scenarios outlined in the global parameters for plant lifetime, discount rate, electricity price, heat price, and values for DAC are used. Hence, three scenarios for each electrolyser technology (i.e. L, M, H) for current and future values are explored. The total of 16 scenarios for the evaluation of the Fischer-Tropsch process, the key inputs, and the results are presented in Table 22 and Table 23 for each electrolyser technology, respectively.

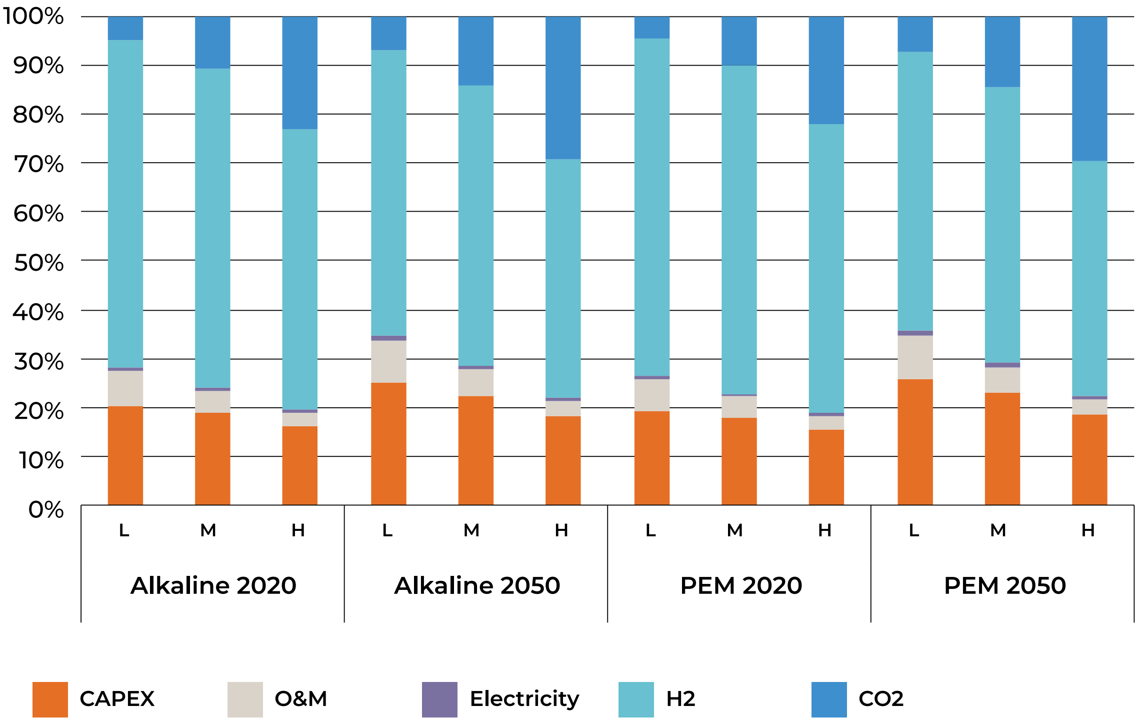
The following general assumptions are made. The feed stream contains only H_2 and CO_2. The hourly H_2 input for each of the 16 scenarios is determined by dividing the total annual H_2 production of Section 4 by the number of the Fischer-Tropsch plant full-load hours (8,260 h/y).[47] The main material and energy streams are displayed in Section 12.2 of the Appendix for each scenario. Since most marine engines are compatible with diesel, we assume that the e-marine fuel possesses similar properties to diesel in our analysis.[43] The average chemical composition of the e-marine fuel corresponds to the chemical formula C16H34. The e-marine fuel has a density of 0.84 kg/L and a lower heating value (LHV) of 44 MJ/kg (30.8 MJ/L). The electricity cost of the Fischer-Tropsch process is mainly attributed to the CO_2 compressor. The levelised cost of e-marine fuel (LCOF) is considered constant over the years and it is calculated based on the LHV.

Figure 9: Capital cost breakdown of the Fischer-Tropsch process for the main equipment for the alkaline electrolysis 2050 'M' scenario.



The capital expenditure (CAPEX) for the Fischer-Tropsch process is calculated as shown in Section 12.2 and it varies between 347.6–586 million £. It should be noted that the CAPEX is increased in the 2050 scenarios as the improvement in the electrolyser efficiency leads to higher H_2 production rates and thus the Fischer-Tropsch equipment is scaled up to accommodate the higher H_2 flowrates. As shown in Figure 9, the major contributor to the Fischer-Tropsch capital expenditures is the Fischer-Tropsch reactor followed by the hydrocracker and the CO_2 compressor. The breakdown of CAPEX in Figure 9 corresponds to the alkaline electrolysis 2050 'M' scenario, but similar trends are expected for all scenarios. Other costs include the product separation and upgrading equipment, as well as other related costs, such as piping, civil works, steel, instrumentation, electricals, insulation, paint, general and administrative overheads, contract fees, design, engineering and procurement, and contingencies.[46] The operation and maintenance cost (O&M) is calculated as 2% of the CAPEX.

Figure 10: Levelised cost of synthetic hydrocarbons breakdown for all scenarios.



The CO_2 cost based on DAC-CCU has a significant impact on the levelised cost of the e-marine fuel (LCOF) and its contribution to the LCOF varies between 2.4–25.6 £/GJefuel. However, as the DAC technologies continue to mature and future cost reductions are taken into account, the impact of CO_2 on the final e-fuel cost will decline (see L, M, and H scenarios in Figure 10). The H_2 cost as shown in Figure 10 is the most sensitive in the Fischer-Tropsch fuel cost and it varies between 32.8–64.1 £/GJefuel and 36.4–69.0 £/GJefuel for alkaline (Table 22) and PEM (Table 23) electrolysers, respectively. As the price of renewable electricity reduces and the electrolysers become more efficient, a big decrease in the e-marine fuel will be observed, especially in the long-term, when the H_2 contribution to the final e-marine fuel cost can go down to 19.8-42.8 £/GJefuel (see 2050 scenarios in Figure 10). The Fischer-Tropsch fuels have a big cost variability as shown in Figure 10, which is mainly attributed to their relatively new technological status.[40] Specifically, the total e-marine fuel levelised cost varies between 49.0–116.5 £/GJefuel and 34.5–87.8 £/GJefuel for the 2020 and the 2050 values of the electrolyser, respectively. Overall, based on our results it is expected that the LCOF will be decreased approximately by 25–30% in 2050 compared to the estimated values of 2020. Our analysis showed that the LCOF highly depends on the end price of the critical feedstocks (H_2 and CO_2). Moreover, Tables 22 and 23 suggests a noticeable increase in LCOF as we progress from the 'L' to 'H' scenarios. These scenarios are based on different assumptions about the global parameters and significantly affect the final e-marine fuel cost.

The specific water requirements of the Fischer-Tropsch process are presented in Table 22 and Table 23. Specifically, the requirement of desalinated purified water is 128.8 kg/GJ e-fuel for all scenarios. However, the Fischer-Tropsch process produces a lot of water in the reverse water gas shift and Fischer-Tropsch reactions. The amount of water produced from the Fischer-Tropsch process is presented in the mass balances of Appendix 12.2. Therefore, with the assumption of a 70% water recycling in the process, the total water consumption of the value chain can be reduced to 83.2 kg/GJ for all scenarios considered.

Finally, to evaluate the Fischer-Tropsch process performance we assess three chain efficiencies, namely power-to-marine fuel efficiency, chemical conversion efficiency, and the chemical conversion of the carbon atom of CO_2 to synthetic hydrocarbons efficiency (or carbon conversion efficiency), as shown in Table 22 and Table 23 (42). The formula for each chain efficiency can be found in Appendix 12.2. The power-to-marine fuel efficiency relates the electricity input to the energy content of the e-marine fuel, and it is directly linked to the electrolyser efficiency. The power-to-marine fuel efficiency ranges between 31.1–34.9% for 2020 values, and it is expected to significantly increase to approximately 44.2–49.3% in 2050. The chemical conversion efficiency, which describes the chemical conversion of CO_2 and H_2 to e-marine fuel, remains constant for all scenarios at 67.9%. Finally, a carbon conversion efficiency of 76.8% is calculated for all scenarios.

Table 22: Summary of key inputs and results of the techno-economic assessment for synthetic hydrocarbon production with alkaline water electrolysis for the 2020 and 2050 scenarios.

		2020			2050		
		L	M	H	L	M	H
Inputs							
CO_2	[t/h]	22.4	28.0	33.6	31.9	39.8	47.8
H_2	[t/h]	3.0	3.7	4.5	4.2	5.3	6.4
Outputs							
Fuel output	[t/h]	5.5	6.9	8.3	7.9	9.8	11.8
	[kt/y]	45.6	57.0	68.5	64.9	81.1	97.4
	[MW_{LHV}]	67.5	84.4	101.3	96.0	120.1	144.1
Consumption							
Electricity	[MW]	193.7	248.8	314.1	194.9	253.1	325.8
Water w/o recycle	[kt/y]	258.7	323.4	388.0	367.9	459.9	551.9
	[kg/GJ_{efuel}]			128.8			128.8
Water w/ recycle	[kt/y]	167.1	208.8	250.6	237.6	297.0	356.5
	[kg/GJ_{efuel}]			83.2			83.2
Chain efficiencies							
Power to e-fuel	[%]	34.9	33.9	32.2	49.3	47.4	44.2
Chemical conversion	[%]			67.9			67.9
Carbon conversion	[%]			76.8			76.8
Specific costs							
CAPEX	[M£]	347.6	406.8	460.4	441.7	517.1	586.0
OPEX	[M£ y^{-1}]	6.9	8.1	9.2	8.8	10.3	1.7
Levelised cost of CO_2	[£/t_{efuel}]	107.2	342.6	1125.4	107.2	342.6	1,125.4
	[£/GJ_{efuel}]	2.4	7.8	25.6	2.4	7.8	25.6
Levelised cost of H_2	[£/t_{efuel}]	1442.7	2120.1	2821.0	919.2	1394.6	1883.1
	[£/GJ_{efuel}]	32.8	48.2	64.1	20.9	31.7	42.8
Levelised cost of e-fuel	[£/t_{efuel}]	2154.8	3236.8	4898.5	1567.9	2431.3	3863.5
	[£/GJ_{efuel}]	49.0	73.6	111.3	35.6	55.3	87.8

Table 23: Summary of key inputs and results of the techno-economic assessment for synthetic hydrocarbon production with PEM water electrolysis for the 2020 and 2050 scenarios.

		2020			2050		
		L	M	H	L	M	H
Inputs							
CO_2	[t/h]	21.6	26.9	32.3	31.9	39.8	47.8
H_2	[t/h]	2.9	3.6	4.3	4.2	5.3	6.4
Outputs							
Fuel output	[t/h]	5.3	6.6	8.0	7.8	9.8	11.8
	[kt/y]	43.9	54.9	65.9	64.9	81.1	97.4
	[MW_{LHV}]	65.0	81.2	97.5	96.0	120.1	144.1
Consumption							
Electricity	[MW]	193.6	248.4	313.1	194.9	253.1	325.8
Water w/o recycle	[kt/y]	248.9	311.2	373.4	367.9	459.9	551.9
	[kg/GJ_{efuel}]			128.8			128.8
Water w/ recycle	[kt/y]	160.8	201.0	241.2	237.6	297.0	356.5
	[kg/GJ_{efuel}]			83.2			83.2
Chain efficiencies							
Power to e-fuel	[%]	33.6	32.7	31.1	49.3	47.4	44.2
Chemical conversion	[%]			67.9			67.9
Carbon conversion	[%]			76.8			76.8
Specific costs							
CAPEX	[M£]	338.7	396.3	448.6	441.7	517.1	586.0
OPEX	[M£ y^{-1}]	6.8	7.9	9.0	8.8	10.3	11.7
Levelised cost of CO_2	[£/t_{efuel}]	107.2	342.6	1125.4	107.2	342.6	1,125.4
	[£/GJ_{efuel}]	2.4	7.8	25.6	2.4	7.8	25.6
Levelised cost of H_2	[£/t_{efuel}]	1602.6	2317.5	3038.4	871.0	1350.5	1838.9
	[£/GJ_{efuel}]	36.4	52.7	69.0	19.8	30.7	41.8
Levelised cost of e-fuel	[£/t_{efuel}]	2321.9	3443.6	5127.3	1519.8	2387.2	3819.3
	[£/GJ_{efuel}]	52.8	78.3	116.5	34.5	54.3	86.8

Safety and environmental considerations

Synthetic hydrocarbons produced via the Fischer-Tropsch route, coupled with Direct Air Capture (DAC) and renewable electricity, have the potential to produce synthetic hydrocarbons with minimal environmental impact. However, like any industrial process, the production of synthetic hydrocarbons using the Fischer-Tropsch process has associated safety and environmental issues that should be addressed to ensure the safe and sustainable operation of the process.

One potential issue is the flammability of hydrocarbons.[51] Hydrocarbons can ignite when exposed to high temperatures, thus proper handling and storage procedures must be followed to reduce the risk of fire or explosion. However, marine diesel has the advantage of being less flammable compared to gasoline.[52] Furthermore, the production process for these fuels involves the use of CO and H_2 gases, which must be stored at high pressures. This presents a risk of gas leaks or explosions if proper storage protocols are not followed. Carbon monoxide (CO) is a toxic gas that can also pose health hazards if not handled with care.[53]

To ensure the safe production and use of Fischer-Tropsch-based marine fuels, it is essential to implement strict safety protocols and procedures throughout the entire supply chain, from production to storage and transportation. This involves regular equipment inspections, training of personnel on safety procedures, and monitoring of areas where these fuels are being produced or used.

Synthetic hydrocarbons have the potential to be a viable option as a shipping fuel, offering carbon neutrality, drop-in replacement capability, and high energy density. However, challenges related to cost, scalability, and sustainability of feedstocks need to be addressed for widespread adoption. Continued research, development, and investment in synthetic fuel production technologies, renewable energy sources, and infrastructure are needed to unlock the full potential of synthetic fuels as sustainable shipping fuels.

9. Comparative analysis

Below we summarise the most important performance measures and other features associated with each fuel chain in Table 24 and Table 25. A pattern emerges which essentially indicates that the more convenient the fuel for downstream handling (e.g. logistics, storage and end use) the more expensive it is. This means that there is a trade-off between the production cost of fuel and retrofitting / converting all downstream elements of the value chain. Hence, the next steps of the analysis should include an estimation of these downstream costs, noting that no interventions are needed for synthetic hydrocarbons.

Table 24: Overview of the comparison of the four alternative e-marine fuels.

		Hydrogen			Ammonia	Methanol	Synthetic fuels
		30 bar	Liq	350 bar			
Levelised cost (£ per GJ)							
Technology	**Year**						
Alkaline	2020	22.3–43.6	38.6–65.5	24.17–46.9	31.0–59.6	30.81–61.79	49.0–111.3
	2050	14.2–29.1	30.1–51.1	16.08–32.41	21.8–43.1	21.03–44.59	35.6–87.8
PEM	2020	24.7–46.9	39.44–68.91	26.6–50.08	33.8–63.4	32.52–59.86	52.8–116.5
	2050	13.5–28.4	29.8–50.4	15.34–31.74	21.0–42.3	20.17–38.33	34.5–86.8
Levelised cost (£ per t)							
Technology	**Year**						
Alkaline	2020	2,673–5,226	4,631– 7,863	2,899– 5,626	582.7–1,120.1	613.14–1,229.63	2154.8–4,898.5
	2050	1,703–3,488	3,612–6,126	1,929–3,888	409.8–810.5	418.48–893.22	1,567.9–3,863.5
PEM	2020	2,969– 5,629	4,731–8,266	3,191–6,008	635.5–1,191.9	647.15–1,191.25	2,321.9–5,127.3
	2050	1,614–3,407	3,572–6,044	1,840–3,807	393.9–795.8	401.47–762.81	1,519.8–3,819.3
Chain efficiency (%)		50–74	41–57	48–69	40.1–56.9	39–64	31.1–49.3
Water consumption (kg water/GJ)			87.5		99.5	99.7	83.2–128.8
Energy density (LHV)[a]			120 MJ/kg		18.8 MJ/kg	19.9 MJ/kg	44 MJ/kg

Table 25: Overview of the advantages and disadvantages of the four alternative e-marine fuels.

Hydrogen	Ammonia	Methanol	Synthetic fuels
Advantages	**Advantages**	**Advantages**	**Advantages**
· Produces no CO_2 upon combustion · Cheapest to produce · Hydrogen leaks could be a precursor global warming · Hydrogen can be stored in numerous forms (compressed, liquefied, as liquid organic hydrogen carries, in metal hydrides) which will also impact fuel storage	· Green ammonia production, using solely renewable energy, leads to zero carbon emissions. Furthermore, nitrogen oxides' emissions during ammonia's combustion can be eliminated by selective catalytic reduction (SCR) systems[24] · Maturity on ammonia synthesis process (Haber-Bosch) · No requirement for cryogenic storage · Existing global supply chain infrastructure · Ammonia is already carried in vessels · No carbon or sulphur emissions upon combustion (in ICEs or ECs) · Combustion characteristics of ammonia, such as flame velocity and heat release, do not prohibit its use as a fuel[54] · Studies from several consortiums have demonstrated the similarity of ammonia engines to current internal combustion engines (ICE).[55] Higher efficiencies can be achieved in the future exploiting fuel cell systems in ships which directly use ammonia[56]	· Similar properties to conventional marine fuels · Limited infrastructure adjustments · Low cost · Not geographically restricted but would be advantageous to locate close to source of hydrogen and carbon dioxide · Easy to transport	· Same chemical properties as conventional petrol and diesel · Cleaner-burning compared to the fossil fuel alternative · High energy density · Drop-in replacement · Not geographically restricted · Storage and transportation using existing infrastructure · Water consumption decreases significantly if water produced in the Fischer Tropsch and reverse water gas shift reactions is utilised
Disadvantages	**Disadvantages**	**Disadvantages**	**Disadvantages**
· Would require new ships and ports infrastructure · Expensive to store and transport · More convenient to co-locate production with demand · Highly flammable · Small molecule which can cause embriklement of transport and containing materials	· Environmental and human health risks as ammonia is toxic · Nitrogen oxides emissions; SCR systems are required · Required changes in ships combus-on systems · Storage investments is ships and ports; Lower energy density than marine fuels · Ammonia's on-board storage may require 2.75 times more space than HFO	· Produces CO_2 upon combustion, but this CO_2 can be considered as recycled as it is derived from DAC · Lower energy density than traditional marine fuels · Additional fire risks in comparison to traditional marine fuels · Additional human health risks in comparison to traditional marine fuels · Cost would be incurred to convert fuel infrastructure and ships to methanol	· High cost · Requires significant amounts of renewable electricity · Produces CO_2 upon combustion · Sustainability of feedstocks

Key considerations for e-marine fuels

1. Carbon neutrality:
Hydrogen, specifically green hydrogen, is a zero-emission fuel. Green ammonia production, using solely renewable energy, leads to zero carbon emissions. Furthermore, nitrogen oxides' emissions during ammonia's combustion can be eliminated by selective catalytic reduction (SCR) systems.[23] Methanol and synthetic hydrocarbons produced using H_2 from carbon-free electricity (e.g., derived from solar or wind) and CO_2 from direct air capture, can result in net-zero CO_2 emissions when used as a shipping fuel.[38, 39] This means that the entire lifecycle of e-marine fuels, from production to consumption, can have a significantly lower carbon footprint compared to traditional fossil fuels and thus significantly reduce the shipping industry's contribution to climate change. It should be noted that producing methanol and synthetic hydrocarbons with currently available grid electricity would result in positive carbon emissions.[38]

2. Energy density:
The long distances and heavy loads associated with maritime transport require fuels with high energy density to enable efficient transportation.[35, 40] The main limitation to methanol being used as a marine fuel is that it has a lower energy density than conventional marine fuels. Therefore, more fuel and thus larger fuels tanks and storage tanks are needed. Synthetic hydrocarbons offer a promising solution for reducing the shipping industry's carbon footprint, especially for long-haul transportation where high energy content is critical for efficient shipping practices.[39] Synthetic hydrocarbons have a high energy density, providing similar or even higher energy content compared to traditional fossil fuels, making them suitable for long-haul shipping.[36, 57] High energy density is an important consideration for future alternative fuels, ensuring that sufficient energy can be stored onboard without requiring additional space for fuel storage, which might limit the space available for carrying cargo.[35, 36, 40]

3. Infrastructure:
Hydrogen, specifically green hydrogen, is a zero emission fuel, but using it as a marine fuel would require significant overhauls to existing fuel (transport, bunker and other storage needs) infrastructure, as well as to the engine systems of ships. Hydrogen can be stored in numerous forms (compressed, liquefied, as liquid organic hydrogen carrier, in metal hydrides) which will also impact fuel storage. Ammonia, methanol, and synthetic hydrocarbons are made using hydrogen, so they can be also considered hydrogen carriers. The benefits of ammonia in comparison with hydrogen pertain to its practicality in large scale storage (no cryogenic storage) and ease in transportation.[10] There exists a global supply chain infrastructure (along with safety regulations) for ammonia transportation both inland and by ships. As vessels already carry ammonia for long transoceanic voyages, its use as fuel depends only on combustion technologies' readiness and the extension of existing regulations. In this context ammonia has an additional advantage in comparison to hydrogen.[23] Similar is the case for methanol. Studies from several consortiums have demonstrated the similarity of ammonia engines to current internal combustion engines (ICE).[55] Higher efficiencies can be achieved in the future exploiting fuel cell systems in ships which use ammonia.[56] The conversion of the fleet to operate on ammonia instead of the conventional fuels may constitute a significant cost. Moreover, additional costs on auxiliary equipment, port and onboard storage technologies may be imperative. (Compact data on the latter and for different sizes of vessels are reported in Hansson, Brynolf[57]). Converting fleets to methanol would also incur additional costs but to a lesser degree. Ammonia's on-board storage may require 2.75 times more space than HFO but is significantly smaller than other low-carbon options such hydrogen or batteries. Methanol may require even smaller space (2.33 times more than HFO) than ammonia for on-board storage.[55] Synthetic hydrocarbons offer a

promising solution for achieving a net-zero future, as they can seamlessly replace traditional fossil fuels by leveraging existing infrastructure, vessels, and engines.[38, 39, 40] Additionally, their easy handling, transportation, and storage with the current systems make them a potentially feasible and practical solution for decarbonizing the shipping sector in the short- to medium-term future.[38, 58] This is important given the long lifetime of ships.[35, 39] A ship's lifetime typically ranges from 25 to 30 years. Understanding the average age of the fleet is crucial to deciding the type of alternative fuel to manufacture.[40] Through the Fischer-Tropsch process, a variety of fuels can be produced, ranging from conventional fuels that can be used in existing engines, such as diesel, gasoline, and kerosene, to fuels specifically designed for pollution reduction. Specifically, it is expected that in the medium-term (5-10 years) synthetic hydrocarbons will be used as a drop-in replacement for fossil fuels, and in the long-term (10-30 years) there is a possibility that the emergence of newer and more advanced fuels will occur.

4. Energy input and cost:
The production of e-marine fuels is generally more energy-intensive and costly than the production of traditional fossil fuels.[50] The production of e-marine fuels requires a significant amount of renewable energy for processes like electrolysis, which can pose challenges in terms of the availability and scalability of renewable energy sources.[38, 46, 49] In addition, the cost of producing e-marine fuels is currently higher than the cost of fossil based marine fuel, which are typically leftover products from oil refining, which can impact their availability, affordability, and accessibility as a shipping fuel.[29, 45, 46, 47] However, advances in renewable energy technologies and improvements in the e-marine fuel production processes may help to decrease costs and increase efficiency over time. One viable alternative for fuel production is the establishment of multi-fuel production facilities that allow for the sharing of costs and resources. These facilities are designed to produce different types of fuels with varying energy densities, enabling the production of multiple fuels in a single location. For example, a synthetic hydrocarbon aviation fuel facility could produce marine fuel as a by-product, thereby optimizing resource utilisation and cost efficiency. It should be noted that the cost of fossil fuels does not reflect the environmental and health costs associated with their use. As regulations and policies increasingly reflect the true cost of carbon emissions, the cost competitiveness of e-marine fuels may improve.

5. Sustainability of feedstocks:
The sustainability of ammonia, methanol and synthetic hydrocarbons rely heavily on the availability of renewable feedstocks, such as hydrogen and carbon dioxide, which are derived from renewable energy sources and direct air capture. Green hydrogen can be geographically restricted as it can only be effectively produced in areas with high renewable electricity potential. Commercial hydrogen, ammonia, and synthetic hydrocarbons plants are typically designed for large-scale production.[36] However, to leverage isolated renewable electricity, smaller-scale production plants may be required.[36] This could enable a more localised (or decentralised) production of e-marine fuels, utilising renewable energy sources and captured carbon in a more targeted and sustainable manner. On the other hand, the supply of CO_2 from direct air capture is less constrained geographically[59] as it can be installed anywhere, but it is currently costly and not available at scale.[60, 61] Ensuring that the feedstocks used in e-marine fuel production are sourced sustainably and do not pose risks regarding land use, water consumption, food production and other environmental considerations, presents a challenge in balancing the fuel demand to the supply of feedstocks.[37, 38, 49, 62]

10. Regional analysis

10.1 Regional analysis assumptions

The next step of this report is to develop an understanding of the demand side which includes a spatial analysis of major UK ports and expected future demands for each e-marine fuel at these ports, based on the chain efficiencies identified in the previous sections. Understanding the fuel demands at each port can help in evaluating the infrastructure requirements, such as production facilities, storage, refuelling stations, and transportation networks. It enables stakeholders to plan and allocate resources effectively to meet the anticipated fuel demands.

It is essential to pinpoint the geographical locations that could fast-forward the energy transition in the UK's maritime sector.[40] To do that, the current (2021) and future (2050) fuel demands of 53 major UK ports are estimated, to identify potential locations for e-marine fuel production and bunkering. The 53 major ports, as identified by the DfT, accounted for 98% (435.35 million tonnes) of port freight traffic in 2021 as shown in Table 26. Including data from these major ports provides a representative picture of the overall trade activity of the UK.

The current fuel demand in each UK port is estimated based on the port freight traffic in each port (Table 26*), and the total fuel consumption in shipping (Table 27**), for the year 2021.

We then use a DfT forecast for UK port freight traffic in 2050 (Table 28***) to project the future fuel demand for each UK port. The amount of freight traffic passing through ports is closely tied to energy consumption. Analysing port freight traffic allows for the identification of specific areas with higher concentrations of industrial and commercial activities, highlighting the regions where fuel demands are likely to be the greatest.

In this report, the methodology assumes a linear relationship between fuel consumption and port freight traffic, thereby neglecting the potential impact of vessel types and sizes on fuel consumption. It is acknowledged that different types and sizes of vessels can influence the amount of fuel consumed during maritime operations. Considering these factors would provide a more accurate estimation of fuel demands. Furthermore, the analysis assumes that the bunkering patterns of e-marine fuels, remain consistent with those of fossil marine fuels. However, it is important to recognize that the introduction of alternative fuels may lead to changes in bunkering practices and infrastructure requirements.

Based on the above, the total and regional expected fuel demand for UK shipping in 2050 is determined (Table 28 and Table 29).

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* Source for blue values: DfT Port level statistics, PORT0302 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1094572/port0302.ods

** Source: DfT Energy and environment statistics, ENV0101 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1123217/env0101.ods

*** Source: DfT Port level statistics, port-freight-forecasts-2019-data, medium scenario https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1123217/env0101.ods

Table 26: UK major port freight traffic by port and route for inwards and outwards travel for all cargo types in tonnage for 2021. The port freight traffic is split to domestic and international travel.

ENGLAND							
Region / Port	**Domestic**	**International**	**Unspecified**	**Grand total**	**Domestic**	**International**	**Grand total**
North West							
Fleetwood	0.0	0.0	0.0	0.0	0.00%	0.00%	0.00%
Heysham	4281.0	628.1	0.0	4909.1	0.98%	0.14%	1.13%
Liverpool	5623.8	28827.1	3.4	34454.3	1.29%	6.62%	7.91%
Manchester	949.4	6404.6	0.0	7354.1	0.22%	1.47%	1.69%
North West Total	**10854.3**	**35859.8**	**3.4**	**46717.5**	**2.49%**	**8.24%**	**10.73%**
North East							
Sunderland	8.0	945.5	0.0	953.5	0.00%	0.22%	0.22%
Tees and Hartlepool	6920.2	19909.9	1.1	26831.1	1.59%	4.57%	6.16%
Tyne	485.3	3487.0	0.0	3972.3	0.11%	0.80%	0.91%
North East Total	**7413.5**	**24342.4**	**1.1**	**31756.9**	**1.70%**	**5.59%**	**7.29%**
Yorkshire							
Goole	25.5	1202.5	0.0	1227.9	0.01%	0.28%	0.28%
Grimsby and Immingham	4658.4	45368.6	0.2	50027.2	1.07%	10.42%	11.49%
Hull	439.4	8922.4	33.8	9395.6	0.10%	2.05%	2.16%
Rivers Hull and Humber	2741.7	6820.1	0.0	9561.8	0.63%	1.57%	2.20%
Yorkshire Total	**7864.9**	**62313.5**	**34.1**	**70212.5**	**1.81%**	**14.31%**	**16.13%**
East Midlands							
Boston	6.2	835.4	0.0	841.6	0.00%	0.19%	0.19%
River Trent	73.0	794.2	0.0	867.2	0.02%	0.18%	0.20%
East Midlands Total	**79.2**	**1629.6**	**0.0**	**1708.8**	**0.02%**	**0.37%**	**0.39%**
East of England							
Felixstowe	199.6	21265.6	4.2	21469.4	0.05%	4.88%	4.93%
Great Yarmouth	418.5	924.1	102.7	1445.3	0.10%	0.21%	0.33%
Harwich	68.0	4504.0	0.0	4572.0	0.02%	1.03%	1.05%
Ipswich	576.7	1735.6	0.0	2312.4	0.13%	0.40%	0.53%
East of England Total	**1262.9**	**28429.3**	**106.8**	**29799.0**	**0.29%**	**6.53%**	**6.84%**

Region / Port	Domestic	International	Unspecified	Grand total	Domestic	International	Grand total
London							
London	10997.0	40774.1	1.7	51772.8	2.53%	9.37%	11.89%
London Total	**10997.0**	**40774.1**	**1.7**	**51772.8**	**2.53%**	**9.37%**	**11.89%**
South East							
Dover	77.3	19796.6	0.0	19873.8	0.02%	4.55%	4.56%
Medway	2301.9	7577.4	0.0	9879.3	0.53%	1.74%	2.27%
East Newhaven	511.7	474.5	0.0	986.2	0.12%	0.11%	0.23%
Portsmouth	1102.5	1879.0	0.0	2981.5	0.25%	0.43%	0.68%
Ramsgate	39.2	2.3	0.0	41.5	0.01%	0.00%	0.01%
Shoreham	1268.1	548.4	0.0	1816.5	0.29%	0.13%	0.42%
Southampton	2567.4	25030.5	0.0	27597.9	0.59%	5.75%	6.34%
South East Total	**7868.1**	**55308.7**	**0.0**	**63176.8**	**1.81%**	**12.70%**	**14.51%**
South West							
Bristol	2518.4	4512.3	0.0	7030.7	0.58%	1.04%	1.61%
Fowey	143.7	244.4	0.0	388.1	0.03%	0.06%	0.09%
Plymouth	890.3	1426.8	0.0	2317.1	0.20%	0.33%	0.53%
Poole	211.6	320.0	0.0	531.5	0.05%	0.07%	0.12%
South West Total	**3764.0**	**6503.5**	**0.0**	**10267.5**	**0.86%**	**1.49%**	**2.36%**
England Total	**50103.9**	**255160.8**	**147. 2**	**305411. 8**	**11.51%**	**58.61%**	**70.15%**

NORTHERN IRELAND

Region / Port	Domestic	International	Unspecified	Grand total	Domestic	International	Grand total
Belfast	13084.8	6781.8	0.0	19866.5	3.01%	1.56%	4.56%
Kilroot Power Station Jetty	440.9	53.5	0.0	494.4	0.10%	0.01%	0.11%
Larne	3164.8	27.3	0.0	3192.1	0.73%	0.01%	0.73%
Londonderry	232.4	1598.4	0.0	1830.8	0.05%	0.37%	0.42%
Warrenpoint	2903.9	709.0	0.0	3612.9	0.67%	0.16%	0.83%
NI Total	**19826.7**	**917**	**0.0**	**28996.7**	**4.55%**	**2.11%**	**6.66%**

SCOTLAND

Region / Port	Domestic	International	Unspecified	Grand total	Domestic	International	Grand total
Aberdeen	2605.7	957.4	0.0	3563.1	0.60%	0.22%	0.82%
Cairnryan	3129.0	0.0	0.0	3129.0	0.72%	0.00%	0.72%
Clyde	2100.3	6301.6	7.6	8409.5	0.48%	1.45%	1.93%
Cromarty Firth	169.3	254.6	0.0	423.9	0.04%	0.06%	0.10%
Dundee	112.2	331.5	7.9	451.5	0.03%	0.08%	0.10%
Forth	1433.5	18335.6	8.3	19777.4	0.33%	4.21%	4.54%
Glensanda	2833.6	3289.1	0.0	6122.7	0.65%	0.76%	1.41%
Loch Ryan	2728.5	0.0	0.0	2728.5	0.63%	0.00%	0.63%
Orkney	433.1	2345.0	0.0	2778.1	0.10%	0.54%	0.64%
Peterhead	922.7	43.3	0.0	966.0	0.21%	0.01%	0.22%
Stranraer	0.0	0.0	0.0	0.0	0.00%	0.00%	0.00%
Sullom Voe	1256.5	4937.8	0.1	6194.4	0.29%	1.13%	1.42%
Scotland Total	**17724.5**	**36795.8**	**23.9**	**54544.2**	**4.07%**	**8.45%**	**12.53%**

WALES

Region / Port	Domestic	International	Unspecified	Grand total	Domestic	International	Grand total
Cardiff	1032.1	540.5	0.0	1572.6	0.24%	0.12%	0.36%
Fishguard	6.4	200.7	0.0	207.1	0.00%	0.05%	0.05%
Holyhead	0.5	3756.9	0.0	3757.4	0.00%	0.86%	0.86%
Milford Haven	4257.4	26064.4	0.0	30321.9	0.98%	5.99%	6.96%
Newport	283.9	2485.0	0.0	2768.9	0.07%	0.57%	0.64%
Port Talbot	339.4	7066.3	0.0	7405.7	0.08%	1.62%	1.70%
Swansea	44.1	355.2	0.0	399.2	0.01%	0.08%	0.09%
Wales Total	**5963.9**	**40469.1**	**0.0**	**46432.9**	**1.37%**	**9.29%**	**10.66%**

All UK major ports	**93619.0**	**341595.7**	**171.1**	**435385.7**	**21.50%**	**78.46%**	**100.00%**

Table 27: Petroleum consumption in shipping by fuel type in 2021.

Fuel type	Petroleum consumption in shipping (2021) (Mt/y)
Gas oil	1.9
Fuel oils	0.6
Total	2.5

Table 28: Forecasted scenario for UK port freight traffic in 2050.

2050	
All cargo (tonnage)	48,409

Table 29: Estimated total fuel consumption and electricity demand for the three forecasted UK port freight traffic scenarios (2050).

2050	
Fuel consumption (Mt/y)	3.7
Fuel consumption (GJ/y)	164,668,816
Fuel consumption (GW)	5.2

10.2 Regional electricity demand

Meeting the increasing demand for alternative fuels in the coming decades is a significant challenge due to the projected insufficiency in fuel production capacity.[63] To ensure that supply meets demand, identifying potential production locations for these fuels is crucial. Therefore, the average regional electricity demand for each fuel chain in 2050 was estimated using the chain efficiencies from the previous sections, assuming 100% demand coverage for each fuel and no fuel splits. The 'M' scenario for 2050 electrolyser values was used for the demand analysis. Table 31 presents the potential average total electricity demand for each fuel chain in 2050. It was found that demands of between 7 and 11 GW will need to be met by 2050 for complete de-fossilisation of the maritime sector. To compare the power usage of the electrical grid in the UK for the year 2022 was 32 GW. The regional demand for each fuel chain was determined by using the regional splits in Table 30, as illustrated in Figure 11 for hydrogen and ammonia and Figure 12 for methanol and synthetic hydrocarbons.

Table 30: Estimated regional electricity demand for the major UK ports in 2050.

UK Region	Port	Domestic (GW)	International (GW)	Grand Total (GW)
North West	Fleetwood	0.000	0.000	0.000
	Heysham	0.051	0.008	0.059
	Liverpool	0.067	0.346	0.413
	Manchester	0.011	0.077	0.088
North West total		**0.130**	**0.430**	**0.560**
North East	Sunderland	0.000	0.011	0.011
	Tees and Hartlepool	0.083	0.239	0.322
	Tyne	0.006	0.042	0.048
North East total		**0.089**	**0.292**	**0.381**
Yorkshire	Goole	0.000	0.014	0.015
	Grimsby and Immingham	0.056	0.544	0.600
	Hull	0.005	0.107	0.113
	Rivers Hull and Humber	0.033	0.082	0.115
Yorkshire total		**0.094**	**0.747**	**0.842**
East Midlands	Boston	0.000	0.010	0.010
	River Trent	0.001	0.010	0.010
East Midlands total		**0.001**	**0.020**	**0.020**
East of England	Felixstowe	0.002	0.255	0.257
	Great Yarmouth	0.005	0.011	0.017
	Harwich	0.001	0.054	0.055
	Ipswich	0.007	0.021	0.028
East of England total		**0.015**	**0.341**	**0.357**

UK Region	Port	Domestic (GW)	International (GW)	Grand Total (GW)
London	London	0.132	0.489	0.621
London total		**0.132**	**0.489**	**0.621**
South East	Dover	0.001	0.237	0.238
	Medway	0.028	0.091	0.118
	Newhaven	0.006	0.006	0.012
	Portsmouth	0.013	0.023	0.036
	Ramsgate	0.000	0.000	0.000
	Shoreham	0.015	0.007	0.022
	Southampton	0.031	0.300	0.331
South East total		**0.094**	**0.663**	**0.758**
South West	Bristol	0.030	0.054	0.084
	Fowey	0.002	0.003	0.005
	Plymouth	0.011	0.017	0.028
	Poole	0.003	0.004	0.006
South West total		**0.045**	**0.078**	**0.123**
England total		**0.601**	**3.060**	**3.663**
Northern Ireland	Belfast	0.157	0.081	0.238
	Kilroot Power Station Jetty	0.005	0.001	0.006
	Larne	0.038	0.000	0.038
	Londonderry	0.003	0.019	0.022
	Warrenpoint	0.035	0.009	0.043
Northern Ireland total		**0.238**	**0.110**	**0.348**

UK Region	Port	Domestic (GW)	International (GW)	Grand Total (GW)
Scotland	Aberdeen	0.031	0.011	0.043
	Cairnryan	0.038	0.000	0.038
	Clyde	0.025	0.076	0.101
	Cromarty Firth	0.002	0.003	0.005
	Dundee	0.001	0.004	0.005
	Forth	0.017	0.220	0.237
	Glensanda	0.034	0.039	0.073
	Loch Ryan [Note 2]	0.033	0.000	0.033
	Orkney	0.005	0.028	0.033
	Peterhead	0.011	0.001	0.012
	Stranraer [Note 2]	0.000	0.000	0.000
	Sullom Voe	0.015	0.059	0.074
Scotland total		**0.213**	**0.441**	**0.654**
Wales	Cardiff	0.012	0.006	0.019
	Fishguard	0.000	0.002	0.002
	Holyhead	0.000	0.045	0.045
	Milford Haven	0.051	0.313	0.364
	Newport	0.003	0.030	0.033
	Port Talbot	0.004	0.085	0.089
	Swansea	0.001	0.004	0.005
Wales total		**0.072**	**0.485**	**0.557**
All UK major ports		**1.123**	**4.097**	**5.222**

The regions with the highest fuel demand are Yorkshire, South East, Scotland, London, North West, and Wales, as shown in Figure 11 and Figure 12. However, the infrastructure requirements for each fuel chain vary significantly. Hydrogen and ammonia require co-location of demand and supply as they need to be produced close to the point of consumption due to their high transportation costs. In contrast, methanol and synthetic hydrocarbons can be produced remotely and transported to the point of consumption, making them more flexible in terms of location.

Table 31: Estimated total average electricity demand for the maritime sector in 2050.

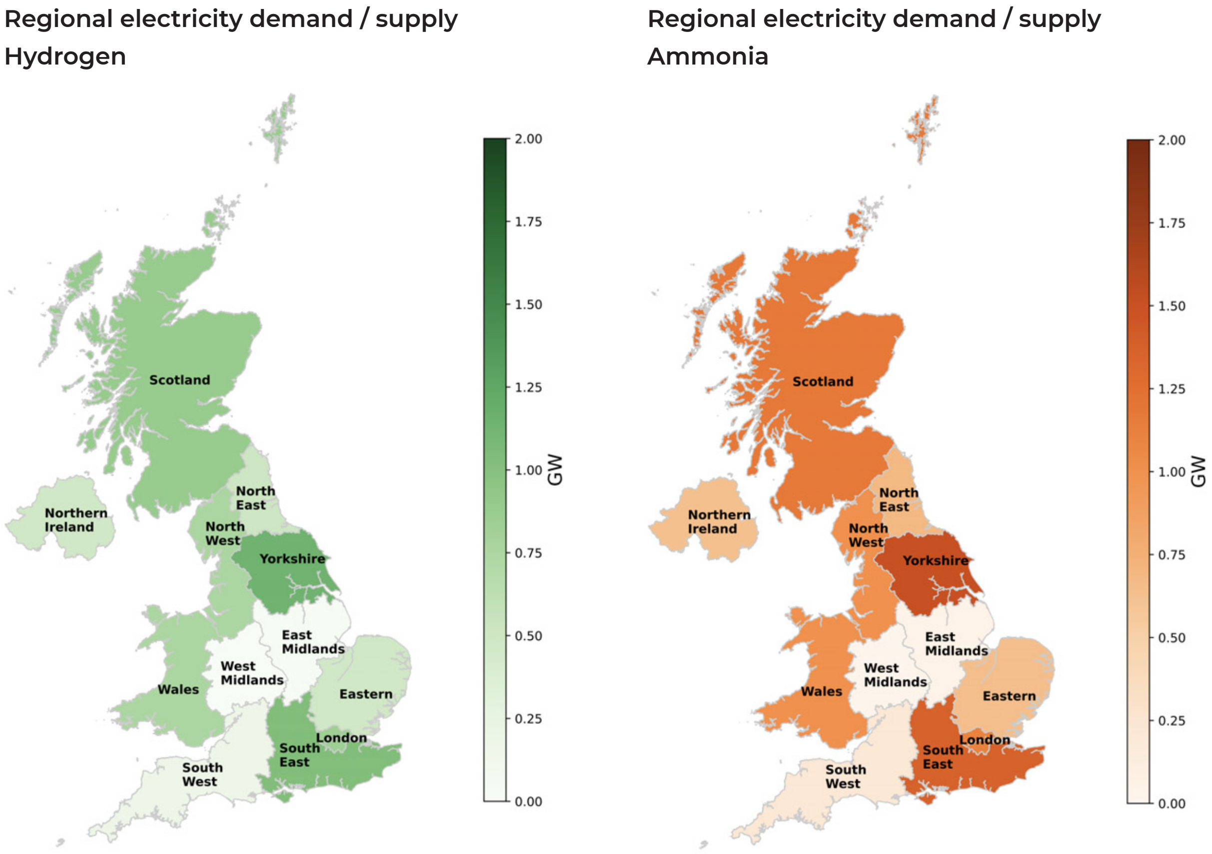
Fuel	Chain efficiency (%)	Electricity demand (GW)
Hydrogen	74.0	7.05
Ammonia	55.7	9.38
Methanol	61.0	9.59
Synthetic Hydrocarbons	47.4	11.0

10.2.1 Hydrogen and Ammonia

The infrastructure requirements for hydrogen and ammonia are significantly different from those of conventional fossil fuels. They also have higher safety risks/considerations methanol, synthetic hydrocarbons and traditional marine fuels due to their higher flammability and toxicity. The production, storage, and transportation of hydrogen and ammonia require high infrastructure changes, including new pipelines, storage tanks, and end-use technologies, which can be expensive and time-consuming to implement. Additionally, hydrogen and ammonia have low energy density and require large storage volumes or compression to be transported efficiently, making their transportation costs high. Therefore, to minimise costs, infrastructure retrofitting needs and safety concerns, locating facilities which produce hydrogen and ammonia closer to ports would be advantageous.

However, the storage and transport of ammonia are cheaper compared to hydrogen due to its higher energy density and lower reactivity. Hence, ammonia could be a more cost-effective alternative in regions where the demand is high.

Figure 11: Regional electricity demand for the hydrogen and ammonia fuel chains.



Regional electricity demand / supply
Hydrogen

Regional electricity demand / supply
Ammonia

10.2.2 Methanol and Synthetic Hydrocarbons

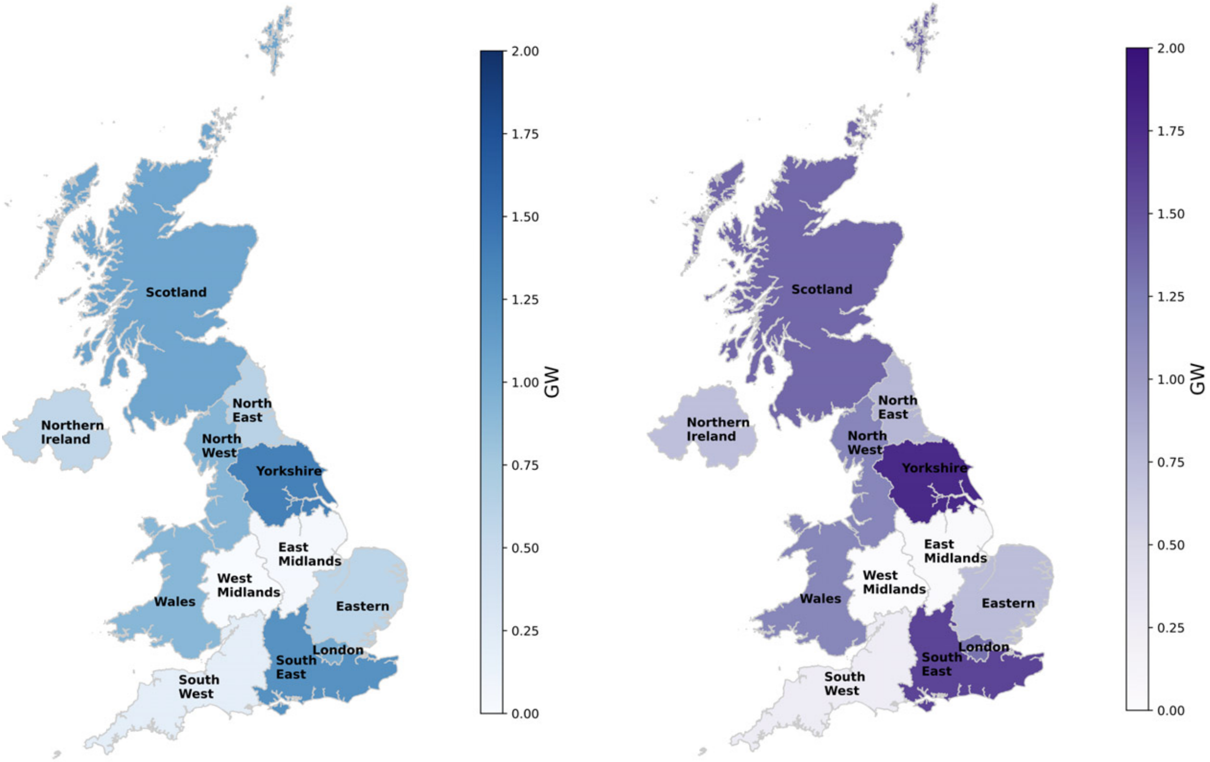
Methanol and synthetic hydrocarbons do not need to be produced near ports and can be transported via tanker trucks, making their infrastructure requirements less complex than those of hydrogen and ammonia. Methanol would require some modifications to the fuel storage and transportation infrastructure due to its higher volatility and potential for water absorption in comparison to traditional marine fuels.

On the other hand, synthetic hydrocarbons, as a drop in fuel, can use existing energy infrastructure and are compatible with existing internal combustion engines making them a more straightforward alternative fuel option. However, the production of synthetic hydrocarbons requires a significant amount of renewable electricity, rendering them highly dependent on the availability of renewable energy sources.

Despite the ease in transporting both methanol and synthetic hydrocarbons, both are still flammable liquids, which poses a safety risk in the transportation and distribution of these fuels. Therefore, to minimise safety concerns, locating facilities which produce methanol and synthetic hydrocarbons close to ports would be beneficial in minimising safety concerns.

Overall, the infrastructure requirements for the four candidate alternative fuels vary significantly, and careful consideration of the regional electricity demand and the associated infrastructure requirements is needed to ensure the successful implementation of alternative fuels for decarbonizing the UK maritime sector.

Figure 12: Regional electricity demand for the methanol and synthetic hydrocarbon fuel chains.



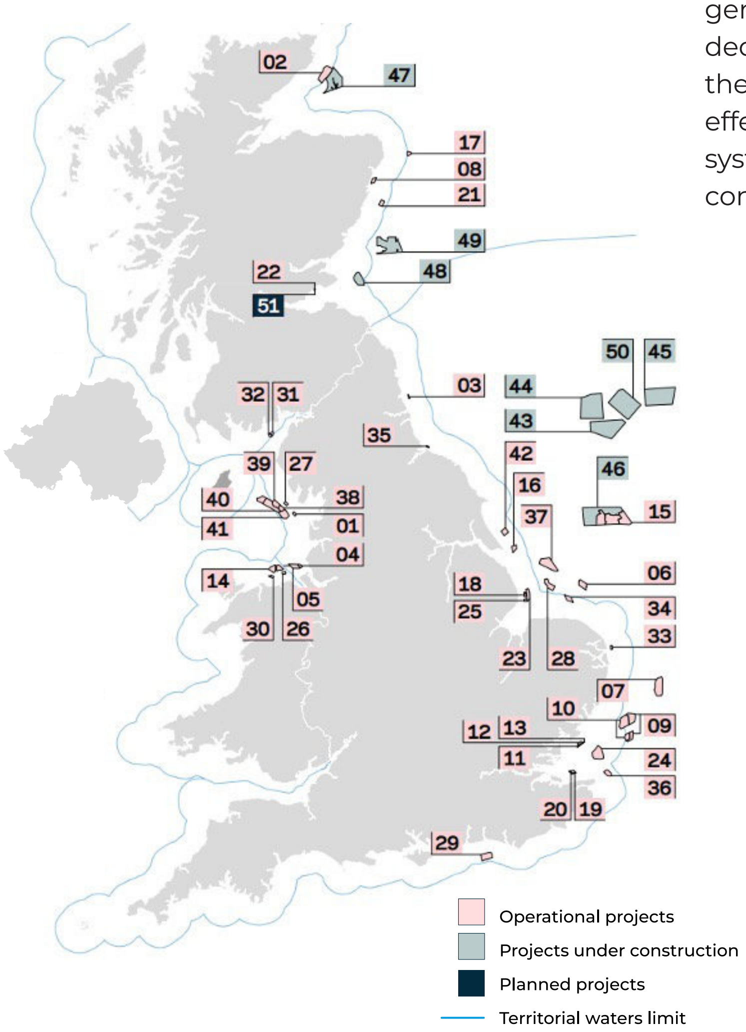
Regional electricity demand
Methanol

Regional electricity demand
Synthetic hydrocarbons

10.3 Regional supply implications

In order to meet the electricity demand for each fuel chain, it is necessary to identify the regions with high renewable electricity potential. To estimate the off-shore wind electricity potential, a similar analysis to section 9.1 was conducted. Specifically, data on the existing wind farm installations are investigated.[64] In this report, the focus is set on both the offshore wind farms' geographical positioning and their corresponding capacity for renewable electricity generation. Regarding the former, current capacity allocation in the UK is important to assess the renewable electricity capabilities across the geographical regions of the analysis. Then, total generation capacity data and future predictions are necessary to estimate the required proportional contribution for the fuel's production. Moreover, to perform the calculations, the installed capacities are converted to a net generation basis using a de-rating factor. In particular, renewable sources that cannot contribute at 100% of their capacity for the whole time horizon due to weather conditions are considered (National Grid ESO, 2022b). Hence, load factors or generally de-rating factors are used to estimate the net electricity generation of the installed capacity of offshore wind technologies and consequently to account for intermittency.

Figure 13: UK offshore wind farm projects allocation in 2021.[64]



For this analysis, the assumptions around the load factor were aligned towards the future system for 2050. With grid sleeving and a mix of renewable generation with built-in diversity rather than a dedicated power line from a renewable plant to the fuel synthesis, the assumption includes effective storage to be in place in the overall system. Hence a load factor of 75% may be a conservative estimate for this study.

Figure 13 presents a detailed map containing all operating and planned wind farms in Great Britain's territory in 2021.[64] Based on Figure 13, the wind farm projects are fitted into the 12 geographical regions of the selected UK's spatial resolution. The offshore wind capacity allocation to each region is estimated based on a total of 20.34 GW power rating of installed or planned projects in 2021.[64] Finally, by assuming the offshore wind capacity regional allocation constant, regional splits were determined based on the current capacity. These regional splits were then used to project the potential regional renewable electricity generation in 2050.

Regarding the total capacity and the net generation capabilities, historical data on installed capacities and generation can be found in the Digest of UK Energy Statistics by the Department of Business, Energy, and Industrial Strategy.[65] Furthermore, the latter source mentions the de-rating factor, which is used to convert the installed capacities to a net capability basis. For instance, in 2021 the installed offshore capacity is 11.26 GW while a load factor equal to 0.43 is proposed to convert the capacity to a net generation basis.

Future projections on the installed capacity of offshore wind are obtained from the Future Energy Scenarios (FES) of the National Grid ESO, which is the main electricity provider in the UK.[66] Following the "System Transformation" scenario an offshore wind capacity of 97.5 GW is forecasted and a corresponding load factor equal to 0.51 is estimated. This load factor is used as an assumption of the future de-rating factor to convert the installed capacity on a net generation basis.

In this level of analysis, some important issues regarding the considerations remain. The assumed capacity installations for the future have to obey in land availability constraints. Land availability data for preliminary estimations, which can be used towards data verification, are provided by Quarton & Samsatli.[67] Then, regarding electricity generation, additional considerations about electricity storage or further de-rating factors can be taken into consideration in order to more conservatively account for renewables intermittency. For instance, the contribution of offshore wind generation in the capacity market is proposed to have significantly lower de-rating factor equal to approximately 0.11.[68] However, focusing on the used load factors, an acceptable slight raise in their value for the future is observed, which is also predicted from special technical reports in the field.[69]

Table 32: Parameters on offshore wind capacities.

Year	2020	2050
Capacity (GW)	**20.34**	**97.5**
De-rating (load) factor	**0.43**	**0.51**

All data for the total estimated off-shore wind electricity potential in the UK in 2050 are summarised in Table 32. Table 33 presents the current off-shore wind capacity in the UK for 2021, including projects under construction and secured contracts, and the estimated potential regional renewable electricity generation in 2050. Figure 14 illustrates the potential regional electricity supply from offshore wind energy in 2050.

Table 33: Off-shore current and projected (including projects under construction and secured contracts) wind capacity in 2021, and potential off-shore wind electricity generation in 2050.

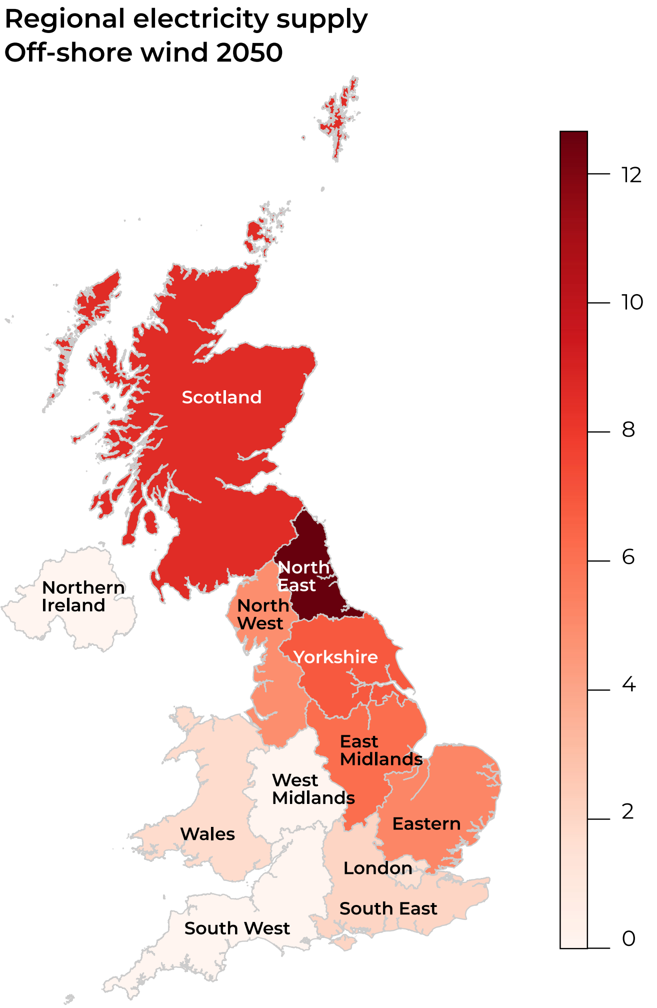
UK Region	Offshore wind project	Capacity (MW) (2021)	Capacity (%)	Total generation output (GW) (2050)
North West	Barrow	90	0.44%	0.22
	Burbo Bank	90	0.44%	0.22
	Burbo Bank Extension	259	1.27%	0.63
	Ormonde	150	0.74%	0.37
	Walney	1 184	0.90%	0.45
	Walney 2	184	0.90%	0.45
	Walney Extension	659	3.24%	1.61
	West of Duddon Sands	389	1.91%	0.95
North West total		**2005**	**9.86%**	**4.91**
North East	Blyth Demonstration	42	0.21%	0.10
	Teesside	62	0.30%	0.15
	Dogger Bank A	1235	6.07%	3.02
	Dogger Bank B	1235	6.07%	3.02
	Dogger Bank C	1200	5.90%	2.94
	Sofia Offshore Wind Farm	1400	6.88%	3.43
North East total		**5174**	**25.44%**	**12.66**
Yorkshire	Westermost Rough	210	1.03%	0.51
	Hornsea	1 1218	5.99%	2.98
	Hornsea 2	1386	6.82%	3.39
Yorkshire total		**2814**	**13.84%**	**6.89**
East Midlands	Humber Gateway	219	1.08%	0.54
	Triton Knoll	857	4.21%	2.10
	Inner Dowsing	97	0.48%	0.24
	Lynn	97	0.48%	0.24
	Lincs	270	1.33%	0.66
	Race Bank	573	2.82%	1.40
	Dudgeon	402	1.98%	0.98
East Midlands total		**2515**	**12.37%**	**6.16**
East of England	Sheringham Shoal	317	1.56%	0.78
	Scroby Sands	60	0.30%	0.15
	East Anglia ONE	714	3.51%	1.75
	Galloper	353	1.74%	0.86
	Greater Gabbard 5	04	2.48%	1.23
	Gunfleet Sands Demonstration	12	0.06%	0.03
	Gunfleet Sands I	108	0.53%	0.26
	Gunfleet Sands II	65	0.32%	0.16
East of England total		**2133**	**10.49%**	**5.22**

UK Region	Offshore wind project	Capacity (MW) (2021)	Capacity (%)	Total generation output (GW) (2050)
London	London Array	630	3.10%	1.54
London total		**630**	**3.10%**	**1.54**
South East	Thanet	300	1.48%	0.73
	Kentish Flats	90	0.44%	0.22
	Kentish Flats Extension	50	0.25%	0.12
	Rampion	400	1.97%	0.98
South East total		**840**	**4.13%**	**2.06**
South West		0	0.00%	0
South West total		**0**	**0.00%**	**0**
England total		**16111**	**79.22%**	**39.43**
Northern Ireland		0	0.00%	0
Northern Ireland total		**0**	**0.00%**	**0**
Scotland	Robin Rigg East	84	0.41%	0.21
	Robin Rigg West	90	0.44%	0.22
	Levenmouth Demonstration	7	0.03%	0.02
	Forthwind	12	0.06%	0.03
	Beatrice	588	2.89%	1.44
	Moray East	953	4.69%	2.33
	Hywind Scotland	30	0.15%	0.07
	European Offshore Wind Deployment Centre	97	0.48%	0.24
	Kincardine	50	0.25%	0.12
	Neart na Gaoithe	448	2.20%	1.10
	Seagreen (Phase I)	1140	5.61%	2.79
Scotland total		**3499**	**17.21%**	**8.56**
Wales	Gwynt y Mor	576	2.83%	1.41
	North Hoyle	60	0.30%	0.15
	Rhyl Flats	90	0.44%	0.22
Wales total		**726**	**3.57%**	**1.78**
All UK offshore wind		**20336**	**100.00%**	**49.77**

Source (blue values): The Crown Estate https://www.thecrownestate.co.uk/media/4095/2021-offshore-wind-report.pdf

The regions with high off-shore wind renewable electricity potential in the UK, including North East, Scotland, Yorkshire, and East Midlands, have the potential to supply the renewable electricity required for alternative maritime fuel production (Figure 14). While hydrogen and ammonia require co-location of supply and demand, methanol and synthetic hydrocarbons can be transported via tanker truck to regions that may not have high renewable electricity potential. Utilising the existing energy infrastructure for storage and transportation of these fuels allows for flexibility in supplying them to high-demand regions, even if their production facilities are not located near ports or areas with high renewable electricity potential.

Figure 14: Potential regional off-shore wind electricity generation in 2050.



It is important to consider the proximity of the renewable electricity potential regions to the high-demand regions. For instance, the North East can supply renewable electricity to Yorkshire, which has a high demand for alternative maritime fuels. Similarly, Scotland can potentially supply renewable electricity to the North West and Wales. However, the South East has a significant demand for alternative maritime fuels but a low renewable energy potential and a lack of nearby high-renewable energy regions, which poses a challenge for meeting this demand. In this case, utilizing alternative fuels like methanol or synthetic hydrocarbons may be more feasible, as they can be transported from high-renewable potential regions located farther away.

In conclusion, identifying potential locations for alternative fuel production in the UK requires careful consideration of the renewable electricity potential regions and their proximity to the high-demand regions. It is important to note that hydrogen plays a crucial role as a feedstock for the production of ammonia, methanol, and synthetic hydrocarbons. This means that the production of these fuels is interdependent, and the availability and proximity of hydrogen production facilities need to be considered as well in the cases where hydrogen is not produced in-house.

11. Conclusions

This project has developed a high level technical and economic analysis of four different renewable, low-carbon fuel chains for marine transport: hydrogen, ammonia, methanol and synthetic hydrocarbons. They are compared on the basis of levelised cost and chain efficiency. Considering a typical cost of renewable fuel being £30/GJ and assuming a cost of £23/GJ for fossil diesel, the implied mitigation cost is approximately £100/tCO_2.

There is a clear trade-off between the convenience of the fuel in terms of the interventions required downstream of fuel production and the cost of the fuel, with for example hydrogen in compressed form being the lowest cost fuel but requiring the most interventions and synthetic hydrocarbons being the most expensive but requiring no substantial interventions.

A regional analysis of demand was also undertaken to understand the implications for power generation. Between 7 and 11 GW of dedicated demand for these production processes would be required by 2050, assuming complete substitution of fossil-based marine fuels. Depending on the ease of transport of the fuels, there are regional implications. For example, there are significant demands for maritime fuel in the south and south-east of England but wind resources are further north, meaning that there may need to be significant investments in transport or electricity transmission infrastructure if hydrogen is to be used in these regions.

For methanol and synthetic fuels production, there is also the need to invest in large-scale direct air capture of carbon dioxide; this industry is in its infancy. The other processes studied here are generally at a high level of maturity.

Future work should consider in detail the implications for post-production infrastructure, e.g. transport and storage of the fuels, modification to ports and modification to vessel fuel storage and propulsion systems. Also, in this analysis the fuels are compared on an energy content basis while the fuel efficiency of different fuels (knots/GJ) may differ.

Although this analysis focuses primarily on the assessment of individual fuel types, it is recommended that future work includes a consideration of fuel splits in the regional analysis. By exploring various combinations of fuels, it may be possible to fulfil the total demand more effectively, rather than relying solely on one type of fuel. This approach could help optimise the overall energy mix while considering factors such as availability, infrastructure requirements, and technological advancements for each fuel type.

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13. Appendices

13.1 Methanol CAPEX

Table 34: CAPEX for all eMethanol scenarios considered.

Global parameters	Gas compression	Gas storage	Methanol synthesis	Engineering, procurement and construction	Project and process contingencies	Site preparation	Permit fees	DAC CAPEX
2020 Alkaline electrolyser (Low)								
L	15.91	3.01	11.12	7.34	13.77	1.83	13.77	75.12
M	15.91	3.01	11.12	7.34	13.77	1.83	13.77	107.31
H	15.91	3.01	11.12	7.34	13.77	1.83	13.77	193.17
2020 Alkaline electrolyser (Medium)								
L	18.19	3.48	12.89	8.49	15.92	2.12	15.92	93.90
M	18.19	3.48	12.89	8.49	15.92	2.12	15.92	134.14
H	18.19	3.48	12.89	8.49	15.92	2.12	15.92	241.46
2020 Alkaline electrolyser (High)								
L	20.29	3.92	14.54	9.56	17.92	2.39	17.92	112.68
M	20.29	3.92	14.54	9.56	17.92	2.39	17.92	160.97
H	20.29	3.92	14.54	9.56	17.92	2.39	17.92	289.75
2050 Alkaline electrolyser (Low)								
L	19.65	3.78	14.04	9.23	17.31	2.31	17.31	106.84
M	19.65	3.78	14.04	9.23	17.31	2.31	17.31	152.63
H	19.65	3.78	14.04	9.23	17.31	2.31	17.31	274.73
2050 Alkaline electrolyser (Medium)								
L	22.47	4.38	16.27	10.67	20.02	2.67	20.02	133.55
M	22.47	4.38	16.27	10.67	20.02	2.67	20.02	190.78
H	22.47	4.38	16.27	10.67	20.02	2.67	20.02	343.41
2050 Alkaline electrolyser (High)								
L	25.07	4.93	18.36	12.02	22.53	3.00	22.53	160.26
M	25.07	4.93	18.36	12.02	22.53	3.00	22.53	228.94
H	25.07	4.93	18.36	12.02	22.53	3.00	22.53	412.09

Global parameters	Gas compression	Gas storage	Methanol synthesis	Engineering, procurement and construction	Project and process contingencies	Site preparation	Permit fees	DAC CAPEX
2020 PEM electrolyser (Low)								
L	15.55	2.94	10.84	7.16	13.43	1.79	13.43	72.30
M	15.55	2.94	10.84	7.16	13.43	1.79	13.43	103.28
H	15.55	2.94	10.84	7.16	13.43	1.79	13.43	185.90
2020 PEM electrolyser (Medium)								
L	17.78	3.39	12.56	8.28	15.53	2.07	15.53	90.37
M	17.78	3.39	12.56	8.28	15.53	2.07	15.53	129.10
H	17.78	3.39	12.56	8.28	15.53	2.07	15.53	232.38
2020 PEM electrolyser (High)								
L	19.83	3.82	14.18	9.32	17.48	2.33	17.48	108.44
M	19.83	3.82	14.18	9.32	17.48	2.33	17.48	154.92
H	19.83	3.82	14.18	9.32	17.48	2.33	17.48	278.86
2050 PEM electrolyser (Low)								
L	19.65	3.78	14.04	9.23	17.31	2.31	17.31	106.84
M	19.65	3.78	14.04	9.23	17.31	2.31	17.31	152.63
H	19.65	3.78	14.04	9.23	17.31	2.31	17.31	274.73
2050 PEM electrolyser (Medium)								
L	22.47	4.38	16.27	10.67	20.02	2.67	20.02	133.55
M	22.47	4.38	16.27	10.67	20.02	2.67	20.02	190.78
H	22.47	4.38	16.27	10.67	20.02	2.67	20.02	343.41
2050 PEM electrolyser (High)								
L	25.07	4.93	18.36	12.02	22.53	3.00	22.53	160.26
M	25.07	4.93	18.36	12.02	22.53	3.00	22.53	228.94
H	25.07	4.93	18.36	12.02	22.53	3.00	22.53	412.09

Table 35: OPEX for all eMethanol scenarios considered.

Global parameters	Labour	General and admissions	Property taxes and insurance	Maintenance	Maintenance (compressors)	Catalyst	Electricity (methanol)	Electricity (DAC)	Heat (DAC)	Hydrogen
2020 Alkaline electrolyser (Low)										
L	0.48	0.15	1.09	0.93	0.32	0.00	0.60	0.12	0.00	65.78
M	0.48	0.15	1.09	0.93	0.32	0.00	1.01	2.90	0.01	65.78
H	0.48	0.15	1.09	0.93	0.32	0.00	1.41	13.51	0.03	65.78
2020 Alkaline electrolyser (Medium)										
L	0.48	0.15	1.09	0.93	0.32	0.00	0.75	0.15	0.00	121.03
M	0.48	0.15	1.09	0.93	0.32	0.00	1.26	3.62	0.01	121.03
H	0.48	0.15	1.09	0.93	0.32	0.00	1.76	16.88	0.04	121.03
2020 Alkaline electrolyser (High)										
L	0.48	0.15	1.09	0.93	0.32	0.00	0.91	0.18	0.00	193.28
M	0.48	0.15	1.09	0.93	0.32	0.00	1.51	4.34	0.01	193.28
H	0.48	0.15	1.09	0.93	0.32	0.00	2.11	20.26	0.05	193.28
2050 Alkaline electrolyser (Low)										
L	0.48	0.15	1.09	0.93	0.32	0.00	0.86	0.17	0.00	59.57
M	0.48	0.15	1.09	0.93	0.32	0.00	1.43	4.12	0.01	59.57
H	0.48	0.15	1.09	0.93	0.32	0.00	2.00	19.21	0.05	59.57
2050 Alkaline electrolyser (Medium)										
L	0.48	0.15	1.09	0.93	0.32	0.00	1.07	0.21	0.00	113.00
M	0.48	0.15	1.09	0.93	0.32	0.00	1.79	5.15	0.01	113.00
H	0.48	0.15	1.09	0.93	0.32	0.00	2.51	24.01	0.06	113.00
2050 Alkaline electrolyser (High)										
L	0.48	0.15	1.09	0.93	0.32	0.01	1.29	0.25	0.00	183.43
M	0.48	0.15	1.09	0.93	0.32	0.01	2.15	6.18	0.01	183.43
H	0.48	0.15	1.09	0.93	0.32	0.01	3.01	28.81	0.07	183.43

Global parameters	Labour	General and admissions	Property taxes and insurance	Maintenance	Maintenance (compressors)	Catalyst	Electricity (methanol)	Electricity (DAC)	Heat (DAC)	Hydrogen
2020 PEM electrolyser (Low)										
L	0.48	0.15	1.09	0.93	0.32	0.00	0.58	0.11	0.00	70.42
M	0.48	0.15	1.09	0.93	0.32	0.00	0.97	2.79	0.01	70.42
H	0.48	0.15	1.09	0.93	0.32	0.00	1.36	13.00	0.03	70.42
2020 PEM electrolyser (Medium)										
L	0.48	0.15	1.09	0.93	0.32	0.00	0.73	0.14	0.00	127.15
M	0.48	0.15	1.09	0.93	0.32	0.00	1.21	3.48	0.01	127.15
H	0.48	0.15	1.09	0.93	0.32	0.00	1.70	16.25	0.04	127.15
2020 PEM electrolyser (High)										
L	0.48	0.15	1.09	0.93	0.32	0.00	0.87	0.17	0.00	200.24
M	0.48	0.15	1.09	0.93	0.32	0.00	1.45	4.18	0.01	200.24
H	0.48	0.15	1.09	0.93	0.32	0.00	2.03	19.50	0.05	200.24
2050 PEM electrolyser (Low)										
L	0.48	0.15	1.09	0.93	0.32	0.00	0.86	0.17	0.00	56.41
M	0.48	0.15	1.09	0.93	0.32	0.00	1.43	4.12	0.01	56.41
H	0.48	0.15	1.09	0.93	0.32	0.00	2.00	19.21	0.05	56.41
2050 PEM electrolyser (Medium)										
L	0.48	0.15	1.09	0.93	0.32	0.00	1.07	0.21	0.00	109.50
M	0.48	0.15	1.09	0.93	0.32	0.00	1.79	5.15	0.01	109.50
H	0.48	0.15	1.09	0.93	0.32	0.00	2.51	24.01	0.06	109.50
2050 PEM electrolyser (High)										
L	0.48	0.15	1.09	0.93	0.32	0.01	1.29	0.25	0.00	179.23
M	0.48	0.15	1.09	0.93	0.32	0.01	2.15	6.18	0.01	179.23
H	0.48	0.15	1.09	0.93	0.32	0.01	3.01	28.81	0.07	179.23

13.2 Synthetic hydrocarbons

Mass balances

The mass balances were performed based on the following block flow diagram (Figure 15) according to the simplified chemical reactions for the reverse water gas shift reactor and the Fischer-Tropsch reactor. The overall conversion in the Fischer-Tropsch reactor is 80%,[42] and the hydrogen to carbon monoxide feed ratio is 2.05.[42, 45, 46, 47]

Reverse water gas shift: $CO_2 + H_2 \rightleftharpoons CO + H_2O$

Fischer Tropsch: $16CO + 34H_2 \rightarrow C_{16}H_{34} + 16H_2O$

Figure 15: Basic block flow diagram for the mass balance calculations of the Fischer-Tropsch process.

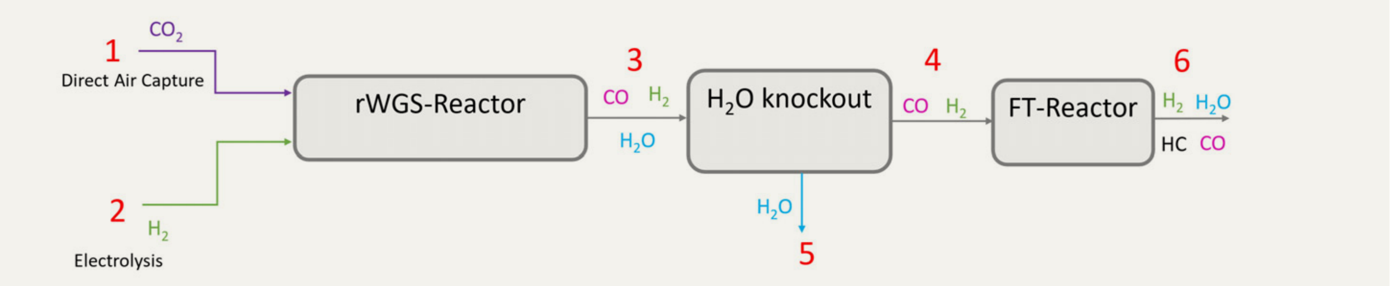

Table 36: Mass balances for the Fischer-Tropsch process based on 2020 values for alkaline water electrolysis (Low Scenario).

Alkaline 2020 - L												
	1		**2**		**3**		**4**		**5**		**6**	
Species	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**
CO_2	509.3	22411.4	0.0	0.0	20.4	896.5	20.4	896.5	0.0	0.0	20.4	896.5
H_2	0.0	0.0	1491.4	2982.7	1002.4	2004.8	1002.4	2004.8	0.0	0.0	220.0	440.1
H_2O	0.0	0.0	0.0	0.0	489.0	8801.6	0.0	0.0	489.0	8801.6	391.2	7041.2
CO	0.0	0.0	0.0	0.0	489.0	13691.3	489.0	13691.3	0.0	0.0	97.8	2738.3
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.4	5525.4

Table 37: Mass balances for the Fischer-Tropsch process based on 2020 values for alkaline water electrolysis (Medium Scenario).

Alkaline 2020 - M												
	1		**2**		**3**		**4**		**5**		**6**	
Species	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**
CO_2	636.7	28014.2	0.0	0.0	25.5	1120.6	25.5	1120.6	0.0	0.0	25.5	1120.6
H_2	0.0	0.0	1864.2	3728.4	1253.0	2506.0	1253.0	2506.0	0.0	0.0	275.0	550.0
H_2O	0.0	0.0	0.0	0.0	611.2	11001.9	0.0	0.0	611.2	11001.9	489.0	8801.6
CO	0.0	0.0	0.0	0.0	611.2	17114.1	611.2	17114.1	0.0	0.0	122.2	3422.8
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.6	6906.8

Table 38: Mass balances for the Fischer-Tropsch process based on 2020 values for alkaline water electrolysis (High Scenario).

Alkaline 2020 - H												
	1		**2**		**3**		**4**		**5**		**6**	
Species	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**
CO_2	720.4	31698.3	0.0	0.0	28.8	1267.9	28.8	1267.9	0.0	0.0	28.8	1267.9
H_2	0.0	0.0	2109.4	4218.8	1417.8	2835.6	1417.8	2835.6	0.0	0.0	311.2	622.4
H_2O	0.0	0.0	0.0	0.0	691.6	12448.8	0.0	0.0	691.6	12448.8	553.3	9959.0
CO	0.0	0.0	0.0	0.0	691.6	19364.8	691.6	19364.8	0.0	0.0	138.3	3873.0
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.60	7815.1

Table 39: Mass balances for the Fischer-Tropsch process based on 2050 values for alkaline water electrolysis (Low Scenario).

Alkaline 2050 - L

	1		2		3		4		5		6	
Species	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**
CO_2	724.4	31873.9	0.0	0.0	29.0	1275.0	29.0	1275.0	0.0	0.0	29.0	1275.0
H_2	0.0	0.0	2121.1	4242.1	1425.6	2851.3	1425.6	2851.3	0.0	0.0	312.9	625.9
H_2O	0.0	0.0	0.0	0.0	695.4	12517.8	0.0	0.0	695.4	12517.8	556.3	10014.2
CO	0.0	0.0	0.0	0.0	695.4	19472.1	695.4	19472.1	0.0	0.0	139.1	3894.4
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.8	7858.4

Table 40: Mass balances for the Fischer-Tropsch process based on 2050 values for alkaline water electrolysis (Medium Scenario).

Alkaline 2050 - M

	1		2		3		4		5		6	
Species	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**
CO_2	905.5	39842.4	0.0	0.0	36.2	1593.7	36.2	1593.7	0.0	0.0	36.2	1593.7
H_2	0.0	0.0	2651.3	5302.7	1782.0	3564.1	1782.0	3564.1	0.0	0.0	391.2	782.4
H_2O	0.0	0.0	0.0	0.0	869.3	15647.2	0.0	0.0	869.3	15647.2	695.4	12517.8
CO	0.0	0.0	0.0	0.0	869.3	24340.1	869.3	24340.1	0.0	0.0	173.9	4868.0
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.5	9823.0

Table 41: Mass balances for the Fischer-Tropsch process based on 2050 values for alkaline water electrolysis (High Scenario).

Alkaline 2050 - H

	1		2		3		4		5		6	
Species	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**	**kmol/h**	**kg/h**
CO_2	1086.6	47810.9	0.0	0.0	43.5	1912.4	43.5	1912.4	0.0	0.0	43.5	1912.4
H_2	0.0	0.0	3181.6	6363.2	2138.5	4276.9	2138.5	4276.9	0.0	0.0	469.4	938.8
H_2O	0.0	0.0	0.0	0.0	1043.1	18776.6	0.0	0.0	1043.1	18776.6	834.5	15021.3
CO	0.0	0.0	0.0	0.0	1043.1	29208.1	1043.1	29208.1	0.0	0.0	208.6	5841.6
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.2	11787.6

Table 42: Mass balances for the Fischer-Tropsch process based on 2020 values for PEM water electrolysis (Low Scenario).

PEM 2020 - L												
	1		2		3		4		5		6	
Species	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h
CO_2	490.2	21568.8	0.0	0.0	19.6	862.8	19.6	862.8	0.0	0.0	19.6	862.8
H_2	0.0	0.0	1435.3	2870.6	964.7	1929.4	964.7	1929.4	0.0	0.0	211.8	423.5
H_2O	0.0	0.0	0.0	0.0	470.6	8470.7	0.0	0.0	470.6	8470.7	376.5	6776.5
CO	0.0	0.0	0.0	0.0	470.6	13176.6	470.6	13176.6	0.0	0.0	94.1	2635.3
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.5	5317.7

Table 43: Mass balances for the Fischer-Tropsch process based on 2020 values for PEM water electrolysis (Medium Scenario).

PEM 2020 - M												
	1		2		3		4		5		6	
Species	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h
CO_2	612.8	26961.0	0.0	0.0	24.5	1078.4	24.5	1078.4	0.0	0.0	24.5	1078.4
H_2	0.0	0.0	1794.1	3588.3	1205.9	2411.8	1205.9	2411.8	0.0	0.0	264.7	529.4
H_2O	0.0	0.0	0.0	0.0	588.2	10588.3	0.0	0.0	588.2	10588.3	470.6	8470.7
CO	0.0	0.0	0.0	0.0	588.2	16470.7	588.2	16470.7	0.0	0.0	117.6	3294.1
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.4	6647.1

Table 44: Mass balances for the Fischer-Tropsch process based on 2020 values for PEM water electrolysis (High Scenario).

PEM 2020 - H												
	1		2		3		4		5		6	
Species	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h
CO_2	735.3	32353.2	0.0	0.0	29.4	1294.1	29.4	1294.1	0.0	0.0	29.4	1294.1
H_2	0.0	0.0	2153.0	4305.9	1447.1	2894.1	1447.1	2894.1	0.0	0.0	317.6	635.3
H_2O	0.0	0.0	0.0	0.0	705.9	12706.0	0.0	0.0	705.9	12706.0	564.7	10164.8
CO	0.0	0.0	0.0	0.0	705.9	19764.9	705.9	19764.9	0.0	0.0	141.2	3953.0
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.3	7976.5

Table 45: Mass balances for the Fischer-Tropsch process based on 2050 values for PEM water electrolysis (Low Scenario).

PEM 2050 - L

	1		2		3		4		5		6	
Species	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h
CO_2	724.4	31873.9	0.0	0.0	29.0	1275.0	29.0	1275.0	0.0	0.0	29.0	1275.0
H_2	0.0	0.0	2121.1	4242.1	1425.6	2851.3	1425.6	2851.3	0.0	0.0	312.9	625.9
H_2O	0.0	0.0	0.0	0.0	695.4	12517.8	0.0	0.0	695.4	12517.8	556.3	10014.2
CO	0.0	0.0	0.0	0.0	695.4	19472.1	695.4	19472.1	0.0	0.0	139.1	3894.4
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.8	7858.4

Table 46: Mass balances for the Fischer-Tropsch process based on 2050 values for PEM water electrolysis (Medium Scenario).

PEM 2050 - M

	1		2		3		4		5		6	
Species	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h
CO_2	905.5	39842.4	0.0	0.0	36.2	1593.7	36.2	1593.7	0.0	0.0	36.2	1593.7
H_2	0.0	0.0	2651.3	5302.7	1782.0	3564.1	1782.0	3564.1	0.0	0.0	391.2	782.4
H_2O	0.0	0.0	0.0	0.0	869.3	15647.2	0.0	0.0	869.3	15647.2	695.4	12517.8
CO	0.0	0.0	0.0	0.0	869.3	24340.1	869.3	24340.1	0.0	0.0	173.9	4868.0
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.5	9823.0

Table 47: Mass balances for the Fischer-Tropsch process based on 2050 values for PEM water electrolysis (High Scenario).

PEM 2050 - H

	1		2		3		4		5		6	
Species	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h	kmol/h	kg/h
CO_2	1086.6	47810.9	0.0	0.0	43.5	1912.4	43.5	1912.4	0.0	0.0	43.5	1912.4
H_2	0.0	0.0	3181.6	6363.2	2138.5	4276.9	2138.5	4276.9	0.0	0.0	469.4	938.8
H_2O	0.0	0.0	0.0	0.0	1043.1	18776.6	0.0	0.0	1043.1	18776.6	834.5	15021.3
CO	0.0	0.0	0.0	0.0	1043.1	29208.1	1043.1	29208.1	0.0	0.0	208.6	5841.6
HC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.2	11787.6

Lang factor method for CAPEX estimation

In the Fischer-Tropsch technoeconomic analysis, we utilized the Lang factor method to estimate the capital expenditures (CapEx) required for the e-marine fuel synthesis process. The Lang factor is a ratio that expresses the total cost of a process plant as a multiple of the cost of its major equipment items. It is calculated by multiplying the total cost of the process plant by the Lang factor, which is determined based on the process technology, location, and other factors. The Lang factor was assumed 3.63 for this process based on Turton et. al.[70] This method provided an approximate estimate of the CapEx required for the Fischer-Tropsch process, which we used in our economic analysis. However, it is important to note that the Lang factor method has limitations and may not accurately reflect the actual capital costs of the project.

The purchased cost of equipment was determined based on:[46]

$$PC = PC_{ref} \times \left(\frac{S}{S_{ref}}\right)^{D} \times \left(\frac{CEPCI_{2022}}{CEPCI_{ref}}\right)$$

Here PC is the purchased cost of equipment, PC_{ref} is the same purchased cost but in monetary units of the reference year, S represents the capacity scale in 2022, S_{ref} denotes the reference capacity scale, and D expresses the scaling factor. The chemical engineering plant cost index for 2022 ($CEPCI_{2022}$) is assumed to be 801.3.[71] The cost of purchased equipment is calculated as the cost of main equipment (reverse water gas shift reactor, Fischer-Tropsch reactor, carbon dioxide compressor, hydrogen compressor, hydrocracker, and carbon dioxide storage for 1 day) multiplied by 1.333 to account for the rest of the process equipment.

It is assumed that the OPEX is 2% of the CAPEX. The annualised CAPEX (ACC) is the CAPEX divided by the annualization factor of the global parameters for each scenario.

Indicative CAPEX calculations for the alkaline electrolysis 2050 'M' scenario

The CO_2 compressor cost is estimated based on the following equations.[72]

Theoretical power requirement for a compressor (isentropic):

$$Power = \left(\frac{3.03 \times 10^{-5}}{\gamma}\right) P_{in} Q_{in} \left[\left(\frac{P_{out}}{P_{in}}\right)^{\gamma} - 1\right]; \qquad \gamma = \frac{C_p / C_v - 1}{C_p / C_v};$$

Where *Power* in hp; Q_{in} in ft m^{-3}; P_{in}, P_{out} in lbf ft^{-2} and $\gamma = 0.23$

Installed cost:

bhp = Power / 0.9

$$IC = \frac{M\,\&\,S}{280}(517.5)(bhp)^{0.82}(2.11 + F_c)$$

Where bhp is the brake horsepower, M&S= 2895 (for 2022), *Fc = 1* is a cost factor for centrifugal motor design.

Table 48: CAPEX calculations for main equipment

Unit	Ref cost (M EURO)	Design variable	Unit	Ref size	Scaling factor	Reference year	Reference	Size	Cost (M£)
rWGS reactor	2.40	Flowrate	t/day	2556	0.65	2014	(46,47)	1543.96	2.02
FT reactor	10.50	Feed rate	MScf/h	2.52	0.72	2003	(45,46)	11.29	51.78
Compressor CO_2	-	Duty	MW	-	-	-	(72)	3.88	13.82
Compressor H_2	-	Duty	MW	-	-	-	(72)	0.00	0.00
Hydrocracker	28.96	Vol flow of products	bpd	2250	0.65	2005	(73)	1776.31	35.73
CO_2 storage (20 bar) (liquid)	-	-	-	-	-	2022	(29)	-	3.48
							Cp (total)		142.4
							CAPEX (M£) (@2022)		517.1
							O&M (M£/y)		10.3

Table 49: DAC assumptions and heat prices used to model the cost of procuring CO_2 in the production of synthetic methanol and synthetic hydrocarbons.

Global variables	Value		
Variable	**L**	**M**	**H**
Electricity price (£/MWh)	30	50	70
Plant lifetime (years)	20	25	30
Discount rate	0.04	0.07	0.1
Annualisation factor	17.2920333	11.65358318	8.51356372
Electrolyser utilisation (%)	60	75	90
DAC CAPEX (£M/tpd)	0.1533	0.219	0.3942
DAC electricity (MJ/t)	80.1	1165	3881
DAC heat (MJ/t)	1.85	4.5	19.3
Heat price (£/MWh)	15	25	35

Electricity and heat are operating costs for DAC while CAPEX covers equipment, infrastructure etc.

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