

# Techno-economic competitiveness of renewable fuel alternatives in the marine sector

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## ABSTRACT

The maritime sector accounts for almost 3% of global greenhouse gas emissions and is under increasing pressure to decarbonise rapidly. Renewable fuels represent a promising pathway for decarbonisation, but their high costs hinder adoption. Carbon Capture and Storage (CCS) can further augment marine fuel decarbonisation but adds to the cost. This work presents a harmonised cost comparison of four promising renewable carbon fuels (methanol, dimethyl ether (DME), liquefied natural gas (LNG) and bio-oil) produced either from routes utilising biomass (biofuels, including CCS) or CO<sub>2</sub> (e-fuels). The differing technology status of the fuel production routes has been accounted for using the RAND Corporation method to estimate the cost of pioneer plants. Additionally, the impact of different levels of carbon taxation (15 or 140 €/t CO<sub>2</sub>) on the economic viability of the alternative fuels has been examined. None of the renewable fuels were found to be close to the incumbent fuels without carbon taxation, which needs to be considerable to adequately bridge the cost gap. Methanol and DME produced using point CO<sub>2</sub> capture are the lowest cost choices if full scale sale of the oxygen by-product is considered. The biofuel routes remain at a premium to the existing fuels, while the direct air capture (DAC)-based fuels are the most expensive among the options studied, besides requiring completely renewable electricity for their carbon footprint to not exceed that of fossil fuels. Renewable LNG has a particularly high cost gap, bringing its status as a potential bridging fuel into doubt.

## 1. Introduction

International maritime transport accounts for 90% of global trade and almost 3% of global greenhouse gas (GHG) emissions [1,2], emphasising the economic importance and environmental impact of the sector. By 2050, the International Maritime Organization (IMO) targets reducing the carbon intensity and GHG emissions of shipping by 70% and 50%, respectively, compared to 2008 [3]. A range of measures have been considered to meet these goals, including mandatory speed restrictions, improving energy efficiency and zero emission fuels [4]. The use of renewable carbon fuels can potentially reduce shipping sector emissions by over 50% by itself, and hence deserves special consideration [5].

The two main options for large-scale use of sustainable hydrocarbon fuels are biofuels made from biomass and renewable energy and e-fuels made using carbon dioxide and electricity [6]. In a previous work [7], we concentrated on the first option and identified four promising biofuels for the shipping industry. The prospects of the four candidates —

bio-methanol (bio-MeOH), bio-dimethyl ether (bio-DME), bio-liquefied natural gas (bio-LNG) and pyrolysis/hydrothermal liquefaction bio-oil — were found to be very similar to each other when viewed in terms of a combination of their present technology status, potential availability, GHG mitigation potential, cost, marine vessel compatibility and carbon capture and storage (CCS) potential. Given the relatively limited availability of sustainable biomass [8,9] and the need to adapt shipping infrastructure to a new fuel, it would be desirable to determine among these the most promising fuel to prioritise its deployment.

During our consultations with shipping industry stakeholders, it has repeatedly been seen that they consider cost to be the most important of all the fuel desirability criteria put to them [7]. While this does not diminish the importance of the other criteria, it does imply that clarity on the economic competitiveness of the fuels is essential for building up stakeholder support for their deployment. This is corroborated by other studies which show that fuel cost and GHG emissions potential are likely to be the most important factors for successful deployment of alternative fuels [10,11]. Therefore, the four fuels mentioned above have been examined here in greater depth in terms of their techno-economic

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**Abbreviations:**

AD	Anaerobic Digestion
AEC	Alkaline Electrolysis Cell
BMC	Bare Module Cost
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CEPCI	Chemical Engineering Plant Cost Index
DAC	Direct Air Capture
D&E	Design and Engineering cost
DME	Dimethyl ether
DR	Debt ratio
EU-ETS	European Union Emissions Trading Scheme
FCI	Fixed Capital Investment
GHG	Greenhouse Gas
GoO	Guarantee of Origin
HTL:	Hydrothermal Liquefaction

IEA	International Energy Agency
IMO	International Maritime Organization
IRR	Internal Rate of Return
ISBL:	Inside Battery Limits
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
MEA	Monoethanolamine
MeOH	Methanol
MGO	Marine Gas Oil
MSP	Minimum Selling Price
NPV	Net Present Value
OSBL:	Outside Battery Limits
PEMEC	Polymer Exchange Membrane Electrolysis Cell
SOEC	Solid Oxide Electrolysis Cell
TCI	Total Capital Investment
TRL:	Technology Readiness Level
WACC	Weighted Average Cost of Capital

potential.

While biomass is likely to be the most viable method of producing these selected fuels in the short term, further down the road the route to the analogous e-fuels may become competitive with biofuels if adequate quantities of renewable electricity become available at sufficiently low prices. Since the fuels are similar or identical in composition regardless of their origin, biofuels and e-fuels can be mixed and used without the need for additional infrastructure or affecting engine operation, meaning that they can be complementary rather than conflicting options. This is especially important since neither biofuels nor e-fuels are likely to by themselves completely meet the global requirement for liquid fuels. In addition, their production may also be synergistic when any CO<sub>2</sub> released during the biofuels production process is used as feedstock for e-fuels production. We therefore also evaluated the costs of producing methanol, DME and LNG via the electrosynthesis route, and the combination of both routes. Since bio-oil does not have an appropriate e-fuel analogue, its production has only been considered from biomass feedstock. Additionally, since meeting GHG reduction targets will almost certainly require carbon capture and storage (CCS) to accompany bio-fuels use [12,13], we have also evaluated the impact of adding CCS to the price of the biofuels.

Several articles and reports have been published in recent years looking at the suitability of various low carbon fuels for the shipping sector. Some of these studies do not look at shipping alone – instead they look at the broader transport sector, including road and air transport as well [14,15], and thus do not focus on the issues distinctive to the maritime sector. The studies that do confine themselves to the shipping sector mostly do not focus exclusively on techno-economics, but look at a range of factors such as potential fuel availability by 2030, stakeholder interest, compatibility with shipping infrastructure, environmental impacts, etc. [16–19]. Among the most relevant literature, one recent article examined marine fuel techno-economics of a range of propulsion options, including battery-electric propulsion, liquid hydrogen and ammonia in addition to bio- and e-fuels, to conclude that the ideal propulsion system depends on factors such as the type of ship, utilisation rate and fuel cost [20]. A similar study carried out for inland shipping in Croatia also concluded that the most cost-effective option varies based on ship type [21].

In addition to examining the cost impact of CCS, this study also differs from these prior works in that it provides a harmonised comparison of the production pathways using previously reported process modelling data. Different biofuel routes are at different levels of technological readiness, and this harmonised comparison enables a more equitable evaluation of their cost effectiveness over the near and

medium terms. Two scopes have therefore been considered for each pathway – a pioneer plant and an nth plant – with the RAND Corporation method cost growth factor [22] used to estimate the increased risk associated with building the pioneer plant.

Renewable carbon fuels account for around 0.1% of the energy consumption of the marine sector today, and if the ‘15% in 2030 and 83% in 2050’ low-carbon fuels penetration recommended in the IEA Net Zero Scenario [23] is to be achieved then the present trajectory of the development and deployment of these fuels is inadequate. This has led to calls for market-based measures being introduced for these fuels to become more viable economically [24]. These include the Marshall Islands and Solomon Islands proposing a levy of 100 US\$/tCO<sub>2</sub>-eq emitted by vessels by 2025, with this increasing either annually or every five years by 30% or 100% [25]. The commodity trading firm Trafigura has likewise proposed a levy of 250–300 US\$/tCO<sub>2</sub>-eq, stating that only the introduction of a significant levy on carbon-intensive fuels will enable progress towards decarbonising the global shipping industry [26]. This emphasis on carbon levies makes studying the effect of different levels of taxation on the economic viability of alternative fuels worthwhile, and so this has been examined in this work as well.

## 2. Methods and data collection

### 2.1. Conversion pathway selection

There are multiple routes for producing the selected fuels, depending on the feedstock selected and the conversion technology employed. The feedstock and conversion process combinations considered here are shown in Fig. 1.

The technology readiness levels (TRLs) of the fuels given in Fig. 1 may be subject to debate, especially for the less-established technologies. Indeed, it is often hard to find a consensus value in literature, which is why a range, e.g. 6–8, has been provided for most of the routes, rather than a single number. This range represents the values derived from multiple reference sources [27–34], and should simply be considered indicative of the maturity of the technology. The one exception is LNG production by anaerobic digestion (AD), which has been assigned a TRL of 9 since biomethane production via AD and methane purification and liquefaction are commercial technologies [35,36].

In general, the biofuel routes are relatively better developed, and can therefore be considered to be available at scale in near-term (till 2030) and medium-term (till 2050) scenarios. While the e-fuels routes are less developed, they can potentially provide a far larger source of liquid fuels. The only constraints are land, the equipment, and most

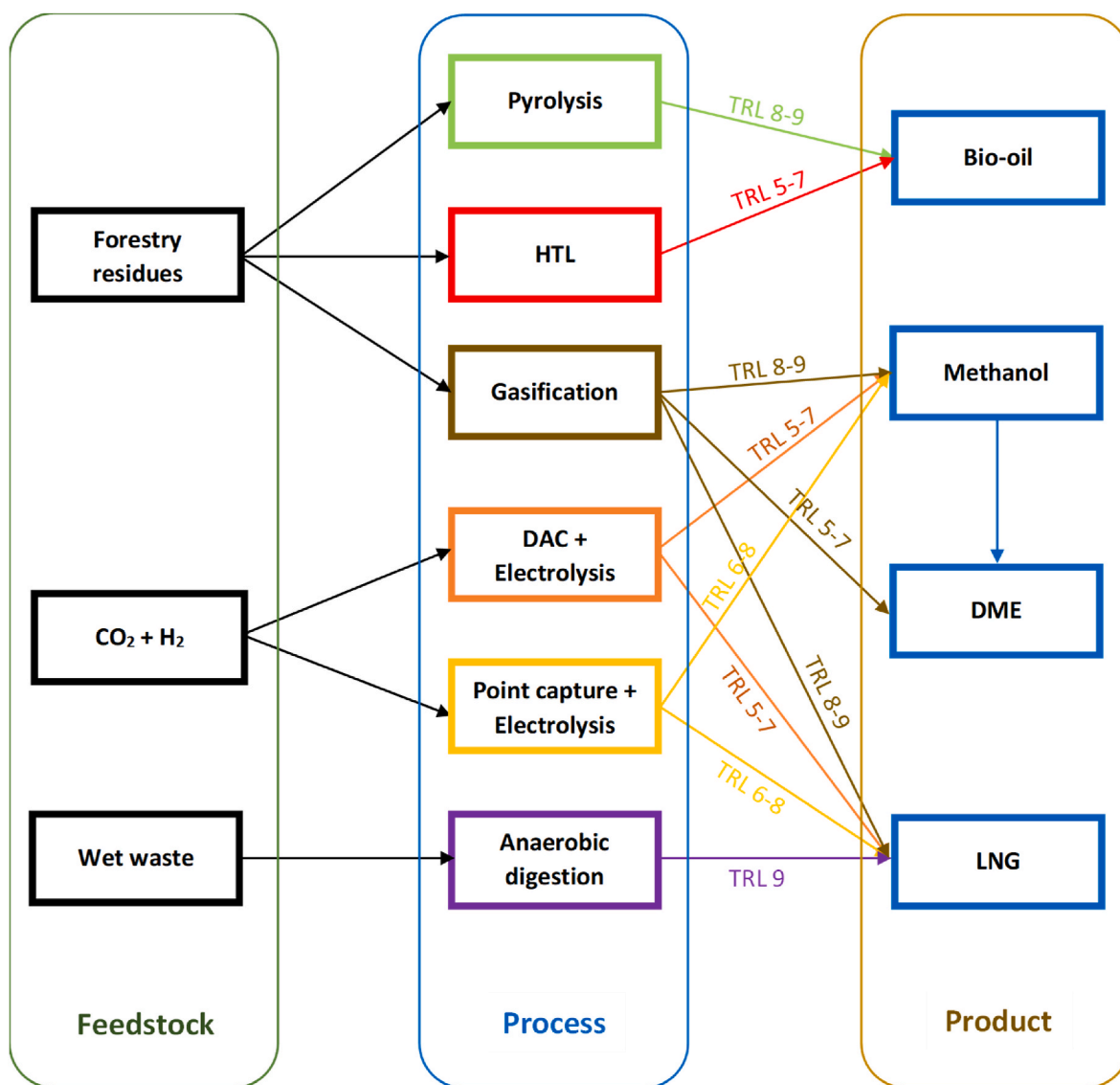


Fig. 1. Feedstock, conversion processes and products examined. 'Wet waste' here refers to manure, food wastes, sewage sludge, fermentation residue, etc.

importantly, the large quantity of renewable energy required to capture CO<sub>2</sub> — either directly from air or from a point source — and electrolyse water to generate hydrogen. To put the renewable energy requirement into context, the global shipping energy demand in 2018 was around 11 EJ, a figure expected to increase moderately but steadily till the middle of this century [37]. Meeting this entire energy demand with direct air capture e-MeOH using present technology (10–11 MWh electricity required per ton of methanol [38]) would require over 6000 TWh of electricity, an amount that would require most of today's renewable electricity production (8300 TWh in 2021 [39]) to be diverted to the shipping industry only. At the same time, the total energy supply from biomass in 2019 was 56.9 EJ, with biofuels use in transport 4 EJ [40]. This makes meeting a substantial portion of the shipping sector energy requirements using biofuels alone difficult as well, unless a large amount of biomass is redirected from other use cases. A more realistic scenario in the near-to medium-term, therefore, is for the shipping sector to mitigate supply issues by using a mixture of bio- and e-fuels, depending on their cost and availability. In the long-term, if e-fuels do become widely available at low prices, then their exclusive use could be adopted without any change in infrastructure.

As mentioned above, for e-fuels, DAC and point source capture are two possible routes. While DAC can potentially lead to larger-scale,

location-independent CO<sub>2</sub> capture, it is also a lesser developed and potentially less effective technology, with greater energy requirement due to the much lower CO<sub>2</sub> concentration in air as compared to flue gases. Post-combustion capture of CO<sub>2</sub> from large point sources, such as power plants or industrial process plants, is a much more developed technology [41], and may therefore be more relevant, albeit not more sustainable, in the short-to-medium term. Indeed, unlike biofuels and DAC-fuels, fuels made using carbon captured from point sources of fossil CO<sub>2</sub> emissions are not carbon neutral, and instead need to be considered as delayed CO<sub>2</sub> emission. As both the routes have potential, they have both been considered here. The selected DAC process [42] uses an aqueous KOH sorbent coupled with a calcium caustic recovery loop. The point capture technology uses standard monoethanolamine (MEA)-based absorption. Since the e-fuels routes will only be interesting from economic and environmental standpoints when large-scale availability of low-cost renewable electricity is ensured, the combined natural gas-electricity configuration in Ref. [42] has been considered for the DAC route in place of the all-natural gas configuration. The hydrogen for this process is generated via water electrolysis using a Polymer Exchange Membrane Electrolysis Cell (PEMEC), as this technology is more mature than Solid Oxide Electrolysis Cell (SOEC) and better suited for large-scale hydrogen production than Alkaline Electrolysis Cells (AEC)

[43].

The four fuels evaluated in this work are described briefly below. A more detailed description of the production routes and their present status as marine fuels can be found in our earlier work [7].

### 2.1.1. Methanol

Methanol is one of the most widely produced organic chemicals, but is presently produced almost entirely from fossil fuel (natural gas and coal). There are several possible routes for producing methanol renewably, with the woody biomass gasification-to-methanol and e-MeOH pathways being the most promising [44].

The e-MeOH pathway has been modelled as per the generic e-fuels pathway given in Section 2.1. For bio-MeOH synthesis, indirect gasification has been assumed, as this has been reported as being more cost-efficient than direct gasification [45]. Additionally, a train of distillation columns has been included in the calculations so that the methanol produced is of US Federal Grade AA specifications [45]. This grade requires >99.85 wt% methanol and is the standard for methanol purity in the industry. While fuel grade (M100) methanol, having slightly lower purity than Grade AA methanol, can also plausibly be the final product, prior work has shown that it only affects the selling price by about 3% [45], and so for simplicity only Grade AA methanol has been considered here.

### 2.1.2. DME

DME is a methanol derivative that has several advantages over methanol, such as being less toxic and having a higher cetane number [46]. It can be made from biomass either directly or via methanol as an intermediate [47]. Although the direct route is held to be better from a techno-economic standpoint, it is still under development, while the indirect route is commercially available [48,49]. Here, we have considered both direct and indirect DME synthesis for biomass gasification, while for e-DME, only the indirect route has been included due to a lack of adequate techno-economic literature covering the direct power-to-DME route. Like bio-MeOH, both direct and indirect bio-DME production would allow for CCS, and hence this aspect has also been assessed.

### 2.1.3. LNG

LNG is increasingly being used as a shipping fuel, but fossil LNG is still a major GHG emitter and hence renewable LNG is required to curb emissions from the shipping sector. Bio-LNG could utilise the existing LNG infrastructure while also reducing the carbon footprint of the marine sector. It can either be produced thermochemically via gasification or biochemically using anaerobic digestion [50,51]. While the two processes are somewhat complementary in terms of feedstock, it is nevertheless necessary to evaluate the techno-economics of both these processes to see if either can be competitive enough to contribute substantially to the shipping fuel mix. Here, LNG produced by the gasification of biomass route is referred to as bio-LNG, while LNG produced by anaerobic digestion is denoted AD-LNG, unless otherwise specified.

Biogas, depending on the source, contains 45–70% methane, with CO<sub>2</sub> accounting for most of the remaining fraction [52,53]. As LNG contains 85–95+% methane [54,55], separating CO<sub>2</sub> from biogas is an essential part of upgrading it to bio-LNG. Therefore, bio-LNG production is naturally suited to CCS, and this has accordingly been considered. Additionally, the e-LNG route has also been looked at, for the reasons outlined in Section 2.1.

### 2.1.4. Bio-oil

Biomass can be thermochemically converted to a liquid fuel called 'bio-oil'. Biomass pyrolysis and hydrothermal liquefaction (HTL) are two of the most prominent processes for bio-oil production, with the former being more developed technologically but the latter producing a higher quality bio-oil [56]. To be used as a marine fuel, pyrolysis bio-oil would need upgrading, particularly with hydrogenation and distillation

required to reduce the oxygen and water contents to acceptable levels. HTL bio-oil has been suggested as a drop-in marine fuel, but is likely to require some upgrading as well, though to a lesser extent than for pyrolysis bio-oil, due to the lower moisture and oxygen content and higher calorific value of the raw HTL bio-oil [56–58]. In this work, therefore, the two routes have been evaluated to see which is more feasible from the standpoint of cost.

## 2.2. Techno-economic model

All the hypothetical alternate fuel plants are located in Rotterdam, the largest European sea port and a harbour location deemed representative here for the North-western European region. Around 9 million m<sup>3</sup> of bunker fuel is sold annually in Rotterdam Port [59]. Considering a volumetric energy density of 37 MJ/l [60,61], the annual bunker fuel energy supply at this port is 333 PJ. For a woody biorefinery, in most cases, a fuel production output capacity of 9–18 PJ/y would be technically feasible [62], and hence a plant producing 15 PJ/y of fuel, meeting around 5% of the Rotterdam port bunker fuel consumption, has been considered as the basis here. Point-capture e-fuel plants are likewise limited by the flue gas availability on location. DAC e-fuel plants are not subject to the same constraints, but may face other challenges such as ensuring an adequate supply of renewable electricity for hydrogen production and process energy, water, land, etc. To facilitate a uniform comparison, the same size (15 PJ/y fuel output) has been considered for the e-fuel plants.

The only process route for which a different plant size has been used is anaerobic digestion for biomethane production. The size of these plants is limited by the availability of wet biomass waste, which is difficult to transport, and this explains why the average European biomethane plant size is only around 1000 m<sup>3</sup>/h [63]. The requirement of 15 PJ/y has therefore been met in this study by 86 plants each producing 1000 m<sup>3</sup>/h of biomethane. Since obtaining adequate quantities of a particular homogeneous feedstock may not be possible, especially across all the plants, a 80:20 (wt%) mixture of manure and clover grass was taken as feed [64]. While the (bio)methane produced via the gasification and e-fuel routes is assumed to be liquefied on-site to LNG, that produced via anaerobic digestion is assumed to be injected into the natural gas grid before potential liquefaction at a central location. This is because installing a liquefaction plant at the small scale of anaerobic digestion plants is impractically expensive. As the distance between the digestion plant and the point of grid injection is highly variable, the cost of transporting the biogas through this distance has been excluded. A liquefaction cost of 3 €/GJ has been assumed for all the LNG routes [65, 66].

A Guarantee of Origin (GoO) or similar certification of renewable origin may be required by the producer to affirm that the fuel produced is indeed renewable – indicative costs for these have been included for all fuels, based on a value of 0.028 €/MWh produced for biofuels and 0.004 €/MWh produced for e-fuels [67]. For e-fuels, a future all-renewable grid electricity supply may remove this requirement, but this has not been considered.

### 2.2.1. nth plant analysis

The techno-economic model for a nth plant, i.e., a plant based on mature technology, was constructed as per Towler and Sinnott [68]. First, the bare module cost (BMC) from reference studies was used to calculate the fixed capital investment (FCI). Given that there are generally multiple studies available for each process route, the reference study was chosen based on three factors: a) the proximity of the size of the reference plant to the plant size used here; b) the feedstock, process and product being similar to those in Fig. 1; c) the completeness of information on the BMC, mass balance and utility requirements.

The BMC of each equipment from the reference study was scaled up to the size of the present study by either using the scaling factor for the equipment as specified in the original work, or in its absence, with a

default value of 0.6, as per the well-known six-tenths rule [69–72]. The installed cost of this equipment was then calculated either by using the installation factor given in the reference or a default factor of 2.47 [45, 73]. The costs were updated to 2021 values by using the Chemical Engineering Plant Cost Index (CEPCI). To ensure an equitable treatment, the capital cost of the utility and auxiliaries (such as storage tanks, instrument air dryers, pumps, etc.) was maintained at 2.5% of the installed cost of the rest of the plant equipment, as this value is broadly consistent with that given in multiple literature sources [45,73–76]. Finally, if the reference values are in a different currency, then the average currency rate for 2021 was used to convert the costs to Euros. The complete equation for calculating the total Inside Battery Limits (ISBL) installed cost is

$$ISBL (\text{€}) = (\text{Base currency/Euro})_{2021} * 1.025 * \sum \left[ \text{Reference BMC} * \frac{CEPCI_{2021}}{CEPCI_{\text{Base year}}} * \text{Installation factor} * \left( \frac{\text{Required size}}{\text{Reference size}} \right)^{\text{Scaling factor}} \right] \quad (1)$$

The Outside Battery Limits (OSBL) cost was calculated by adding 40% to the ISBL cost [68]. The design and engineering (D&E) cost and the contingency (X) cost were respectively 25% and 10% of the combined ISBL and OSBL costs [68]. The fixed capital investment (FCI) was thereafter calculated as

$$FCI (\text{€}) = ISBL + OSBL + D\&E + X \quad (2)$$

The key design assumptions and ISBL costs for each route are summarised in Table 1, with more detailed cost and other modelling

**Table 1**  
Design assumptions and ISBL costs used in this study.

Product	Process	Feedstock	Key design assumptions	ISBL cost (M€ <sub>2021</sub> ) @ 15 PJ/y output	Reference
Methanol	Gasification	Sawdust/shaving pellets	<ul style="list-style-type: none"> <li>Grade AA methanol</li> <li>Indirectly heated gasifier</li> <li>Thermal efficiency 48% LHV</li> </ul>	294	[45]
	Electrosynthesis – DAC	Carbon dioxide and water	<ul style="list-style-type: none"> <li>Grade AA methanol</li> <li>Direct Air Capture of CO<sub>2</sub> using alkaline sorbent and caustic regeneration loop</li> <li>Natural gas provides portion of energy requirements and CO<sub>2</sub> captured</li> <li>Hydrogen generation using Polymer Exchange Membrane Electrolysis Cell (PEMEC) water electrolysis (66% LHV H<sub>2</sub> efficiency)</li> <li>Oxygen by-product sold at 100 €/t</li> </ul>	800	[42,74,77, 78]
	Electrosynthesis – Point capture	Carbon dioxide and water	<ul style="list-style-type: none"> <li>Grade AA methanol</li> <li>MEA-based CO<sub>2</sub> absorption process</li> <li>Hydrogen generation using Polymer Exchange Membrane Electrolysis Cell (PEMEC) water electrolysis (66% LHV H<sub>2</sub> efficiency)</li> <li>Oxygen by-product sold at 100 €/t</li> </ul>	250	[74,77–79]
DME	Gasification - 1 step	Sawdust/shaving pellets	<ul style="list-style-type: none"> <li>99.9% purity DME</li> <li>VTT's Ultra-Clean Gas process</li> <li>Thermal efficiency 60% LHV</li> </ul>	704	[80,81]
	Gasification - 2 step	Sawdust/shaving pellets	<ul style="list-style-type: none"> <li>99.85% purity DME</li> <li>Indirectly heated gasifier</li> <li>Thermal efficiency 51% LHV</li> </ul>	277	[45]
	Electrosynthesis – DAC	Carbon dioxide and water	<ul style="list-style-type: none"> <li>Direct Air Capture of CO<sub>2</sub> using alkaline sorbent and caustic regeneration loop</li> <li>Natural gas provides portion of energy requirements and CO<sub>2</sub> captured</li> <li>Hydrogen generation using Polymer Exchange Membrane Electrolysis Cell (PEMEC) water electrolysis (66% LHV H<sub>2</sub> efficiency)</li> <li>Oxygen by-product sold at 100 €/t</li> </ul>	796	[42,45,74, 78]
	Electrosynthesis – Point capture	Carbon dioxide and water	<ul style="list-style-type: none"> <li>MEA-based CO<sub>2</sub> absorption process</li> <li>Hydrogen generation using Polymer Exchange Membrane Electrolysis Cell (PEMEC) water electrolysis (66% LHV H<sub>2</sub> efficiency)</li> <li>Oxygen by-product sold at 100 €/t</li> </ul>	256	[45,74, 77–79]
LNG	Anaerobic digestion	Manure (80 wt%) + clover grass (20 wt%)	<ul style="list-style-type: none"> <li>1000 m<sup>3</sup>/h biomethane output per plant</li> <li>Membrane separation of CO<sub>2</sub></li> <li>Product contains 97% methane</li> <li>Thermal efficiency 50% LHV</li> </ul>	1290 <sup>a</sup>	[64,82,83]
	Gasification	Sawdust/shaving pellets	<ul style="list-style-type: none"> <li>Indirectly heated gasifier (MILENA)</li> <li>Thermal efficiency 48% LHV</li> <li>Wobbe Index of product 44 MJ/m<sup>3</sup></li> </ul>	669	[84,85]
	Electrosynthesis - DAC	Carbon dioxide and water	<ul style="list-style-type: none"> <li>Direct Air Capture of CO<sub>2</sub> using alkaline sorbent and caustic regeneration loop</li> <li>Hydrogen generation using Polymer Exchange Membrane Electrolysis Cell (PEMEC) water electrolysis (66% LHV H<sub>2</sub> efficiency)</li> <li>Oxygen by-product sold at 100 €/t</li> </ul>	1046	[42,77,78]
	Electrosynthesis – Point capture	Carbon dioxide and water	<ul style="list-style-type: none"> <li>MEA-based CO<sub>2</sub> absorption process</li> <li>Hydrogen generation using Polymer Exchange Membrane Electrolysis Cell (PEMEC) water electrolysis (66% LHV H<sub>2</sub> efficiency)</li> <li>Oxygen by-product sold at 100 €/t</li> </ul>	375	[45,74, 77–79]
Bio-oil	Pyrolysis	Sawdust/shaving pellets	<ul style="list-style-type: none"> <li>Circulating fluidised bed pyrolyser</li> <li>Bio-oil upgraded to 0.5 wt% oxygen content, Total Acid Number of 2, water content &lt;1 wt%, LHV 36 MJ/kg</li> </ul>	462	[86]
	HTL	Sawdust/shaving pellets	<ul style="list-style-type: none"> <li>Bio-oil upgraded to below 2 wt% oxygen, LHV 39 MJ/kg</li> </ul>	442	[45]

<sup>a</sup> 86 plants each with ISBL 15 M€.



assumptions given in Section S2 of the ESI.

For the operating cost calculations, the quantities in the reference were scaled up based on the reported mass and energy balances. The prices of the feedstock and utilities used are given in Table 2. The woody biomass feedstock was assumed to be pellets made from sawdust or shavings, with 10% moisture content. As for HTL, wet feedstock is not only admissible but preferable, the feed moisture content has been assumed to be raised to 50 wt% prior to insertion into the reactor to bring it in line with the original study [45]. The natural gas price used is the average price in the EU for medium size non-household consumers in 2020, while the electricity price is the benchmark baseload electricity price for 2021. Straight line depreciation is used for the depreciation calculations, with a depreciation period of 10 years, a plant life of 25 years from the start of operation, and zero salvage value assumed. A working capital requirement of 5% of the total fixed capital investment has been used, in line with de Jong [87].

The required amounts of catalysts, solvents and other chemicals were extrapolated from the original reference and the costs updated to 2021 values using the Producer Price Index by Commodity for Chemicals and Allied Products: Basic Inorganic Chemicals [94]. The operating labour costs were calculated using Cevdalli and Zaidman's modification of Wessel's formula for plants with a normal level of automation [70]. The operating supervision and quality control costs were both taken to be 20% of the operating labour cost [70], to which they were added to obtain the total labour cost. The other operating costs such as maintenance and insurance were calculated as per [68,70], and are given in ESI Table S1.

The start-up schedule for the nth plants was as per [22,68], and is given in Table 3. As can be seen, in years 3 and 4, the plant operates at 30% and 90% capacity respectively. The cost of consumables and utilities are scaled down proportionately, while other costs, such as labour, rent and insurance are kept at the full value. An exception to this start-up schedule was for the anaerobic digestion units, which, because they are small scale and commercially mature, are considered to start full operation in year 2, a conservative assumption.

The minimum selling price (MSP) of the fuel has been calculated via a cash flow analysis. The MSP is the price at which the net present value (NPV) of the plant becomes zero, with a minimum acceptable internal rate of return (IRR) set at 10%. The Weighted Average Cost of Capital (WACC) is calculated as per [68].

$$WACC = DR * i_d + (1 - DR) * i_e \quad (3)$$

where DR = debt ratio.

$i_d$  = interest rate due on debt

$i_e$  = cost of equity.

The cost of equity is equal to IRR when NPV is 0, and hence is 10% in our study. In the base case, a debt interest rate of 1.5% has been assumed, in line with the European corporation cost-of-borrowing in

**Table 2**  
Base case financial and production assumptions.

Item	Value	Unit	Reference
Wood pellets price	105	€/dry t	[88]
Woody biomass LHV	17.5	MJ/kg	[88]
Natural gas price	6.9	€/GJ	[89]
Electricity price	36	€/MWh	[90]
Water price	0.02	€/m <sup>3</sup>	[79]
European labour cost in 2021	29.1	€/h	[91]
Target Internal Rate of Return	10	%	[87]
Interest rate for debt financing	1.5	%	[92]
Plant financing debt percentage	80	%	[87]
Plant life	25	y	
Depreciation period	10	y	
Corporate tax rate	21.7	%	[93]
Plant salvage value	0	€	
Capacity factor	90	%	

**Table 3**

Plant start-up schedule.

Year	FCI schedule	Plant availability
1	30% of fixed capital	0
2	50% of fixed capital	0
3	20% of fixed capital + working capital	30%
4		90%
5		100%

March 2022 [92]. Along with a 80 : 20 debt-equity ratio, this gives a WACC of 3.2%.

### 2.2.2. Pioneer plant analysis

The reference studies assume that the plants for which the cost analyses have been reported are 'nth' plants, for which the necessary equipment is fully developed and readily available. The nth plant assumptions do not account for additional costs associated with 'first of a kind' plants, such as special financing, equipment redundancies, large contingencies and longer start-up times [86]. Therefore, the costs of the nth plant designs are assumed to reflect the costs at a point in the future when the technology is mature, with several plants operational. However, heuristics and biases associated with nth plant estimates mean that they are very often too optimistic with respect to cost and performance expectations [22,95]. As the alternative fuels discussed here are still in varying stages of development, a pioneer plant analysis may be more suitable to assess their potential in a near-term scenario. The method developed by the RAND corporation is widely used in techno-economic assessments of novel biofuel technologies [96–99], and is therefore used here to estimate the increase in fuel MSP for pioneer plants. The exception again is biomethane production via anaerobic digestion, which, being a commercial technology, is not analysed in this way.

The RAND method uses two equations (Eqns. (3) and (4) below), one for estimating the plant cost and the other for the plant performance [22, 87].

$$\begin{aligned} \text{Cost growth} = & 1.12196 - 0.00297 * \text{PCTNEW} - 0.02125 \\ & * \text{IMPURITIES} - 0.01137 * \text{COMPLEXITY} + 0.00111 \\ & * \text{INCLUSIVENESS} + C * \text{PROJECT DEFINITION} \end{aligned} \quad (3a)$$

$$\begin{aligned} \text{Plant performance} = & 85.77 - 9.69 * \text{NEWSTEPS} + 0.33 \\ & * \text{BALEQS} - 4.12 * \text{WASTE} - 17.91 * \text{SOLIDS} \end{aligned} \quad (4)$$

The definitions and range of values of the parameters in Eqns. (3) and (4) are given in Table 4, with the actual values of the parameters used for every fuel route are given in Section S3 of the ESI.

The cost growth factor is used to calculate the Total Capital Investment (TCI) of the pioneer plant as:

$$TCI_{\text{Pioneer}} = \frac{TCI_{\text{Nth}}}{\text{Cost growth factor}} \quad (5)$$

The plant capacity in the first year is calculated as per:

$$\text{Plant performance (Year 1)} = \text{Nameplate capacity} \times \text{Plant performance factor} \quad (6)$$

It is assumed that the plant availability then ramps up 20% every year till the capacity factor of 90% is reached.

### 2.2.3. CCS analysis

The applicability of carbon capture technology to the production of alternate fuels depends both on the fuel itself and the production route. For electrosynthesis routes, CO<sub>2</sub> is captured either from the air or from a flue gas stream and used as a reactant, and therefore its capture from the fuel production process itself is ruled out. Pre-combustion capture is possible during bio-MeOH and bio-DME synthesis and necessary for bio-LNG production. In all the process routes considered for these biofuels,

**Table 4**  
Variables in RAND model.

Variable name	Definition	Permissible range of values
PCTNEW	Percentage of commercially unproven technologies in plant capital cost	0–100
IMPURITIES	Expected difficulties with process impurities	0–5
COMPLEXITY	Number of process blocks in plant	1+
INCLUSIVENESS	Percentage of three items included in scope of estimate: - Land purchase/leases/ property rentals - Initial plant inventory/ warehouse parts/catalysts - Pre-operating personnel costs	0–100
C	Commercialisation status of technology	–0.04011 for commercial or pre-commercial processes; –0.06361 for processes with a substantial R&D component
PROJECT DEFINITION	Levels of site-specific information and engineering included in estimate	2 (maximum definition) – 8 (minimum definition)
NEWSTEPS	Number of process steps unproven at commercial scale	0+
BALEQS	Percentage of mass and heat balance equations based on actual plant data	0–100
WASTE	Expected difficulties with waste handling	0 (none) – 5 (severe)
SOLIDS	Whether the plant processes primarily solid feedstocks or products	1 if yes, 0 if no

CO<sub>2</sub> separation is included in the referenced process design. Therefore, only the capital and operation costs for drying the CO<sub>2</sub>, compressing it to 35 bar and transporting it 200 km via pipeline have been included [100, 101]. The distance of 200 km is based on estimated average distances for CO<sub>2</sub> transport from a CCS cluster in Rotterdam to a storage reservoir under the North Sea [102].

In case of bio-oil, post-combustion capture is most suitable for both the pyrolysis and HTL routes, but this would mean capturing the CO<sub>2</sub> on-board ships, a possibility deemed impractical and not considered here. Lozano et al. studied pre-combustion CO<sub>2</sub> capture from the gas phase of HTL (containing 61–90 vol% CO<sub>2</sub>) [103,104], and found the process to be techno-economically feasible, and hence pre-combustion capture has been considered for HTL. For pyrolysis systems, the CO<sub>2</sub> content in the gas-phase is generally much lower, and varies widely (1–58 vol%) based on the process parameters [105,106]. This makes arriving at a broadly-applicable estimate of pre-combustion CCS costs for pyrolysis difficult, but we have nevertheless carried out the exercise for the system studied. Unlike for the bio-MeOH, bio-DME and bio-LNG systems, the cost of the carbon capture equipment has been added for the HTL and pyrolysis systems, due to these not being included in the original plant cost.

For every route, the labour costs have been recalculated for the entire plant considering the CO<sub>2</sub> drying and compression as an additional process unit, and the benefits, insurance and miscellaneous costs have been updated based on the capex for the plant inclusive of the CCS equipment. The parameters used for the CCS cost calculations are given in Table 5. The cost terms in the table mentioned are the base values, which have been updated in the calculations using cost indices as described in Section 2.2.1.

#### 2.2.4. Combining biofuels and e-fuels plant

We mentioned above that CO<sub>2</sub> is a by-product of methanol and DME production, and CCS is one way of handling the generated CO<sub>2</sub>. An alternative to sequestration would be to use the CO<sub>2</sub> as a fuel feedstock.

**Table 5**  
Parameters for CCS plant economic analysis.

Parameter	Unit	Value	Reference
CO <sub>2</sub> captured	t/y	516,800	[45]
Bio-MeOH		1,309,000	[107]
Bio-DME-direct		359,100	[45]
Bio-DME-indirect		11,000	[108]
Anaerobic digestion			
LNG			
Gasification LNG		680,000	[102]
HTL bio-oil		233,500	[45]
Pyrolysis bio-oil		45,400	[86]
CO <sub>2</sub> capture rate	%	95	[100]
CAPEX for CO <sub>2</sub> drying and compression	€/tCO <sub>2</sub> /y	24	[100]
Maintenance	% of CAPEX	3	[68]
Electricity for CO <sub>2</sub> treatment and compression	GJ <sub>e</sub> /tCO <sub>2</sub>	0.3	[100]
Pipeline connection cost	€/tCO <sub>2</sub> /y	4.3	[101]
Unit CO <sub>2</sub> transport cost	€/tCO <sub>2</sub> /km	0.05	[102]
CO <sub>2</sub> transport distance	km	200	[102]
CO <sub>2</sub> storage cost	€/tCO <sub>2</sub>	13	[102]

Indeed, provided the ample availability of low-cost renewable electricity, a combined biofuels-e-fuels plant could be considered, where the biogenic CO<sub>2</sub> from the biofuels section would be used to produce more of the same fuel via an electrosynthesis route [44]. This possibility has been briefly examined here for methanol as an example, but the outcomes can be applied to other biofuels-e-fuels combinations as well.

To ensure that the comparison with the standalone plants is congruous, the size of the combined plant has been kept at 15 PJ/y. The respective size of the biofuel and e-fuel plant will naturally depend on factors like the amount of CO<sub>2</sub> produced and captured in the process, the efficiency of the e-fuels plant, etc. Under the parameters studied here, the size of the bio-MeOH plant has been reduced to 68% that of the standalone plant, with the CO<sub>2</sub> output from this plant adequate for a point CO<sub>2</sub> capture e-MeOH plant that is big enough for the combined methanol output to be 15 PJ/y.

### 3. Results

The costs of the different fuel options in the base case are shown in Fig. 2. The 2021 price ranges (minimum and maximum prices) of marine gas oil (MGO) in Rotterdam [109], fossil LNG [110] and European fossil methanol [111] are also given as benchmarks, showing the price reductions necessary for the alternative fuels to be economically competitive. A sensitivity analysis is presented in Section 4 and an assessment of the costs with different carbon pricing in Section 5.

A first inspection of Fig. 2 shows that, on the whole, the alternative fuels are more expensive than the conventional fuels on an energy basis, with methanol and DME produced by point capture in an nth plant being the cheapest, and cost-competitive with fossil methanol. It is worth mentioning here that the costs of e-fuels are greatly lowered due to revenue from the sale of oxygen as a by-product (see Section 4 for a sensitivity analysis). Another interesting point is that bio-DME by the indirect route is slightly less expensive than bio-MeOH, with the cost of the additional DME synthesis unit cancelled out by the lower cost of methanol purification and the higher integrated process energy efficiency [45].

The combined bio-MeOH – e-MeOH plant is found to be slightly more expensive than the stand-alone bio-MeOH and e-MeOH plants in case of the pioneer plants, with the cost difference with the bio-MeOH plant negligible for the nth plants. The higher cost is not very surprising, since the component plants in the combined plant are smaller than their stand-alone counterparts, and hence have a higher unit capital cost due to a relative lack of the economies of scale. In real life, the capital cost of the combined plant will likely be lower than that estimated here due to savings occurring from reducing equipment duplication (such as by combining the methanol synthesis reactors) and eliminating certain

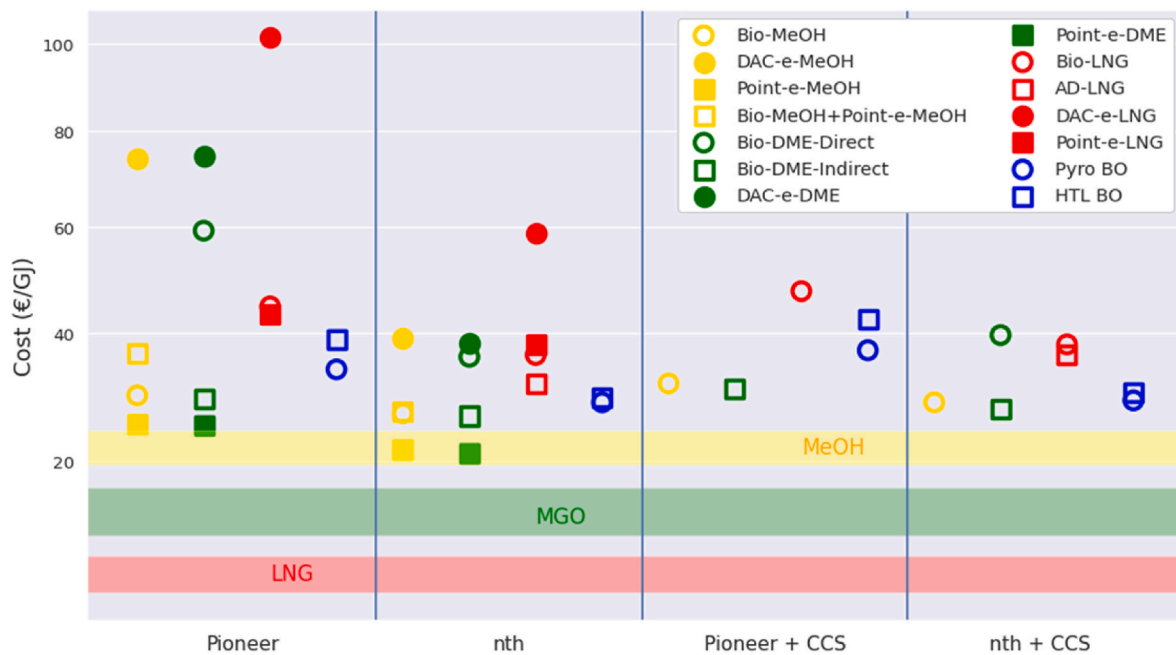


Fig. 2. Overview of cost of alternative fuels compared with existing marine fuels. The coloured bands in the graph represent the cost ranges of fossil methanol, MGO and LNG. For the CCS columns, only routes which where CCS would be applicable are displayed.

parts of the equipment train (like the water gas shift reactor) [44], and hence the combined plant should be more cost-competitive.

Other trends emerge from Fig. 2 on closer inspection. One, not surprisingly, is that DAC-based e-fuels are considerably more expensive than ones based on point CO<sub>2</sub> capture, which is due to the higher capital costs of direct carbon capture. Methanol and DME prices are largely similar for a particular route (e.g., if DAC methanol and DME are compared), while for LNG, anaerobic digestion is the cheapest route, followed by biomass gasification, point CO<sub>2</sub> capture and DAC. The direct route for bio-DME is considerably more expensive than the indirect route, with the difference even more significant for the pioneer plants. It should be mentioned that the direct DME configuration selected from the literature [107] is one that is better suited for CCS, providing it with an advantage when carbon credits are applied (Section 5), but penalising it in the cost comparison here. For bio-oil, the pyrolysis route is marginally cheaper than HTL in case of nth plants, with the difference being larger for pioneer plants. It is important to mention here that in case of pyrolysis, monetisation of the pyrolysis aqueous fraction, which contains C6 anhydro-sugars and other polar components [112], may enhance its competitiveness. However, while there are several possibilities for utilising this fraction, such as fermentation, hydrogenation, steam reforming, etc. [112,113], an integrated deployment of any of these routes with pyrolysis bio-oil synthesis at a commercial scale is not really well-developed, and hence has not been considered here. Biochar is another by-product which can be utilised in multiple ways, and whose sale has also been neglected here.

Finally, Fig. 2 shows that the addition of CCS to the biofuels route only increases costs marginally, indicating the viability of using CCS as a short-term strategy for achieving negative emissions. Longer term, the capture technology installed can be used for carbon capture and utilisation (CCU) to increase the carbon efficiencies of the biofuels processes.

#### 4. Sensitivity analysis

The values displayed in Fig. 2 were obtained using base case numbers for all the parameters. This section discusses the results of a sensitivity analysis conducted to assess the effect of changing the most important

parameters on the fuel production cost.

##### 4.1. Parameters varied

For all the fuels, both the fixed and working capital are dependent on the ISBL costs, which therefore has a major impact on the fuel production cost. The ISBL costs may vary due to factors such as the specificity of the process considered, plant size, materials of construction, location, etc. The sensitivity of the different fuel costs to this parameter was examined by considering ISBL costs that were 50% lower and higher than the base values. This has been represented as Total Capital Investment (TCI) in the figures below.

The biomass cost is a large part of the fuel production cost in any biofuel plant. In literature, a wide range of costs have been assumed, depending on the biomass type, location, sustainability, etc. At the lower end, costs of woody biomass may be as low as 20 €/t [114], but 40 €/t is considered a more realistic lower limit for large biofuel plants [80]. On the other hand, pellet prices can go up to 175 €/t or even higher [88], and hence this has been used as a reasonable upper price limit here. For anaerobic digestion, wet feedstock prices may easily vary from 0 to 40 €/t [64,115], and this is the range considered here.

Like biomass, the electricity prices used in cost estimates in literature also show a wide variation. Prior studies have shown that prices below 10 €/MWh may be required for e-fuel plants to be economically viable, and some cost estimates have relied on optimistic assumptions about surplus electricity being available at low costs to arrive at low e-fuel prices [116]. Certain forecasts of baseload electricity prices, on the other hand, predict prices of around 85 €/MWh towards the middle of the century [117]. We have therefore examined the effect of electricity being available at 10 €/MWh versus 85 €/MWh on the fuel costs. As preliminary results showed that this parameter made a negligible contribution to biofuel prices, only its effect on e-fuel prices was studied.

The cost of capital is a very important factor in the profitability of large process plants. The low interest rates in recent years have led to enterprises taking on large debt loads at reduced interest costs, and this has been beneficial for the adoption of new technologies. Renewable energy technologies, in particular, have high upfront costs, and the positive effect that low capital costs have had on reducing their levelized



costs has largely been underestimated due to overstating of technology learning effects [118,119]. A return to the pre-financial crisis 10-years average interest rate of 4.3% is expected to significantly impair renewable energy investments [120,121]. This threat has recently become more likely, with rising inflation leading to an increase in interest rates worldwide [122]. The added interest expense is likely to lead to more conservative debt-equity ratios, and hence we have considered

the effect of interest rates increasing to 4.3% and the debt-equity ratio falling to 0.5 (WACC = 7.15%). Alongside, the effect of WACC dropping to a hypothetical value of 1% has also been examined.

Finally, some of the processes have by-products whose sale may potentially reduce the breakeven price of the fuel. The most significant among these is the oxygen produced in electrolysis in the e-fuel processes, and its sale considered here subsidises the e-fuel prices

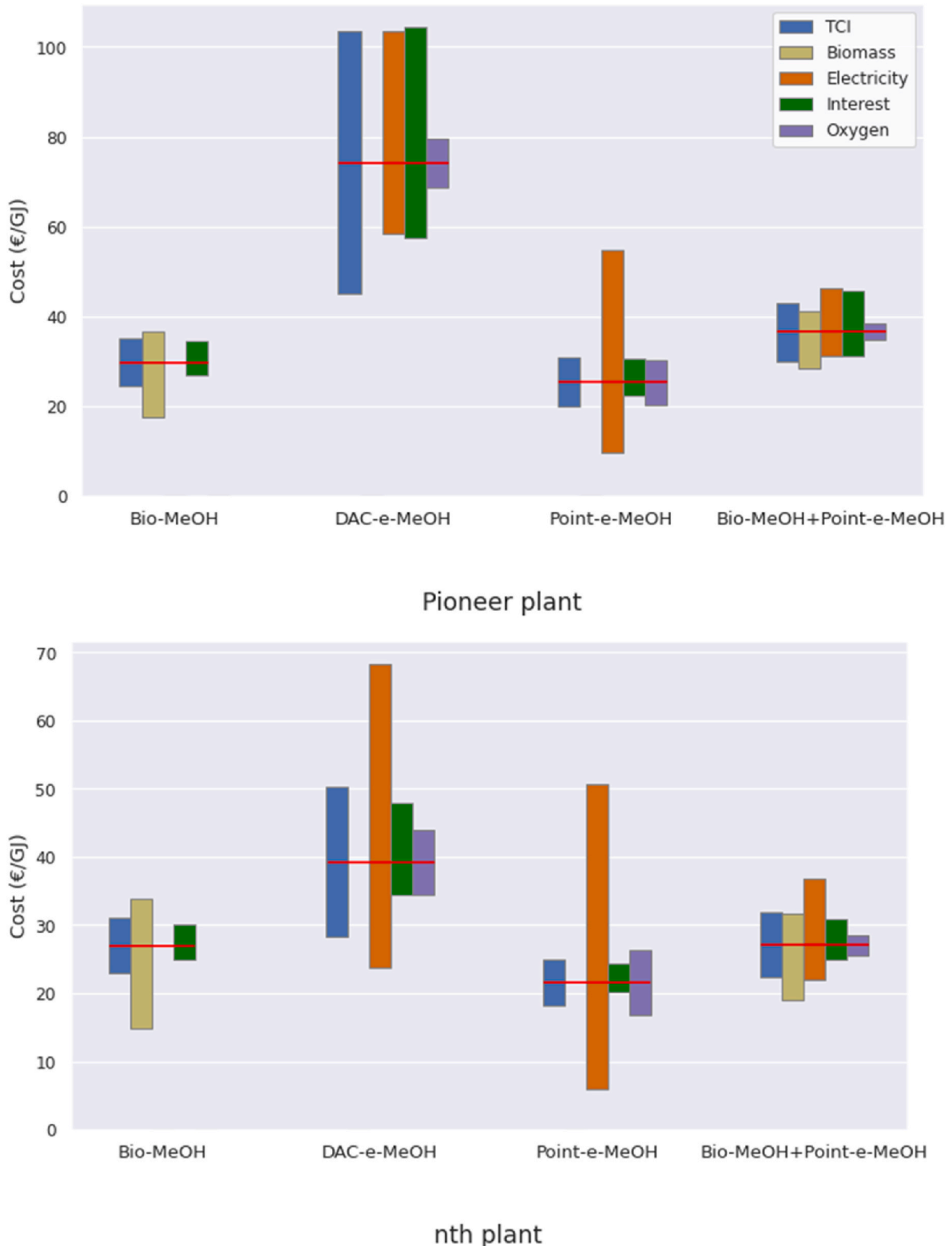


Fig. 3. Sensitivity analysis of renewable methanol for top: pioneer plants, bottom: nth plants. The base value for the particular route is shown by a red line.

substantially. It should be noted that should e-fuels production be scaled up considerably, then the amount of oxygen produced will likely exceed the amount that can be absorbed by the industrial sectors – extending the ‘e-MeOH meeting the entire shipping sector energy demand’ example given in Section 2.1, the 870 million tons of oxygen produced in that scenario will dwarf the <400 million tons global industrial oxygen market size [123]. Should oxygen prices drop, due to this or any other reason, then the e-fuel prices are likely to be affected markedly as well. Conversely, an uptick in oxygen demand, perhaps due to increasing requirements in the healthcare, steel, chemical, construction and aerospace sectors [124], or simply due to new use cases becoming practical due to increased availability, would have a positive e-fuel price impact. Therefore, the effect of a 50% rise or fall in oxygen prices has been appraised.

#### 4.2. Methanol

From Fig. 3, it is clear that bio-MeOH and point-e-MeOH prices are the least affected by fluctuations in the capital costs and interest rates. This is attributable to the relatively low proportion of these costs in the overall fuel costs, which is in turn due to the relative maturity of these options. The DAC plants have a much larger cost range, with their low technology readiness level (TRL) especially amplifying the range in the pioneer plant costs. The combined bio- and e-MeOH option is also rather susceptible to this, although to a lesser extent than the DAC plants.

On the feedstock front, low biomass feedstock prices can make bio-MeOH competitive with conventional methanol, while low electricity prices could make point-e-MeOH competitive with all but the cheapest fuels. The impact of electricity prices on the competitiveness of e-fuels is especially stark, though DAC-e-MeOH prices remain high even under optimistic conditions. As the electrolyser accounts for the vast majority (>90%) of the plant electricity consumption, any improvements in its efficiency will have a pronounced effect on lowering the product costs. Oxygen prices have a moderately strong impact on both the e-fuel routes. The higher maturity of the point capture route means that the oxygen price fluctuations play a bigger role than TCI or interest rate variations, while for DAC its influence is more limited in relative terms. The combined bio- and e-MeOH plant shines in this area, with the influence of both biomass and electricity price fluctuations mitigated due to it not being solely dependent on either as feedstock, while oxygen prices also do not cause significant changes in the fuel price due to the relatively small amount of oxygen produced.

#### 4.3. DME

The results for DME (see Fig. 4) are in line with those obtained for methanol, which is unsurprising considering the commonality in their production routes. It is interesting to see that changes in capital costs affect bio-DME produced by the direct route more significantly than the indirect route, which is more affected by the biomass price. Also, because of its lower technological maturity, TCI variation is much more important in pioneer DME-direct plants than nth plants.

#### 4.4. LNG

For LNG, the effect of the different parameters on the prices (see Fig. 5) follows a similar pattern to that seen for methanol and DME, but the impact of the electricity and oxygen prices on the e-fuels here is even larger than that observed in the previous cases. This is because LNG production requires more CO<sub>2</sub> capture and hydrogen and oxygen generation per GJ of fuel than methanol and DME, and therefore, electricity consumption and selling price of oxygen play more significant roles.

It is also seen that anaerobic digestion is very stable in price across the different parameters. Indeed, it could be argued that studying the effect of different capital costs is superfluous in this case, as the well-developed nature of the digestors makes large ISBL cost variations less

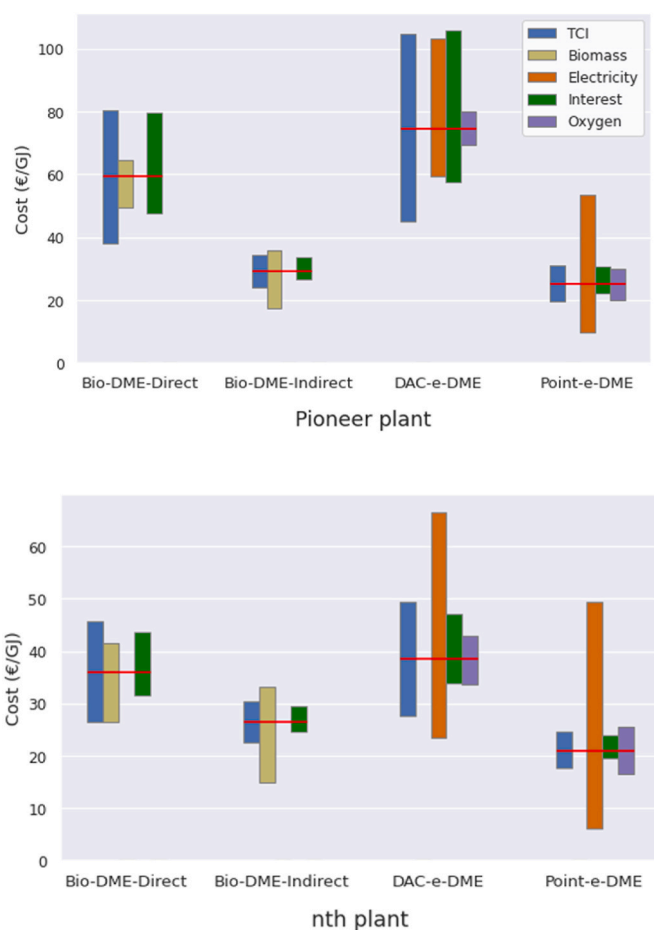


Fig. 4. Sensitivity analysis of renewable DME for top: pioneer plants, bottom: nth plants. The base value for the particular route is shown by a red line.

likely than for the other processes.

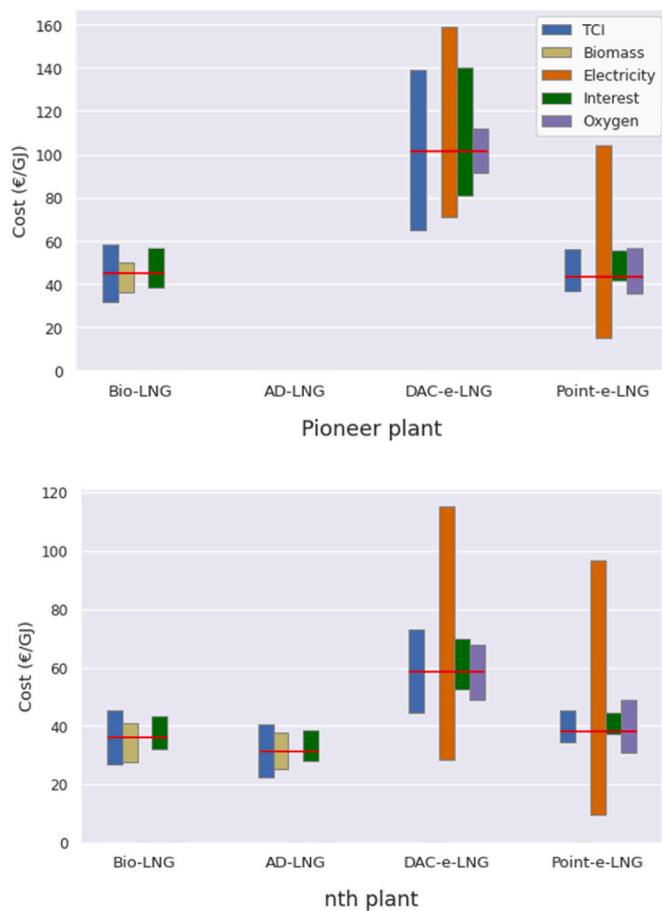
#### 4.5. Bio-oil

Pyrolysis and HTL are evenly matched across the different parameters (see Fig. 6), with pyrolysis faring slightly better in terms of insensitivity to biomass prices. Overall, at least for nth plants, the capital investment and biomass cost have roughly equivalent impacts on the price stability of the bio-oils.

#### 4.6. Capping oxygen

As mentioned earlier, the widespread deployment of e-fuel plants may make it difficult for all the generated oxygen to find a market. Seeing the heavy influence of the income from oxygen sales on the e-fuel prices, it would also be interesting to see what capping the oxygen sales to 25% of the generated oxygen does to the e-fuel prices (Fig. 7). We see that the oxygen cap raises the prices across the board significantly, and the point e-fuels become more expensive than their biofuel counterparts if the cap is implemented. The combined bio-MeOH-e-MeOH plant again fares the best due to the comparatively limited influence of oxygen sales on the output fuel price. These plants are also less likely to run into the problem of not being able to sell all of the oxygen simply because the generated quantity is itself considerably lower.

For completeness, the effects of varying the TCI, biomass costs and interest rates on the CCS processes is presented in Fig. S1 in the ESI. As expected, the results are similar to those seen earlier for the fuels without considering CCS, with biomass feedstock price being the biggest factor for methanol and DME-indirect and TCI the largest for bio-LNG.



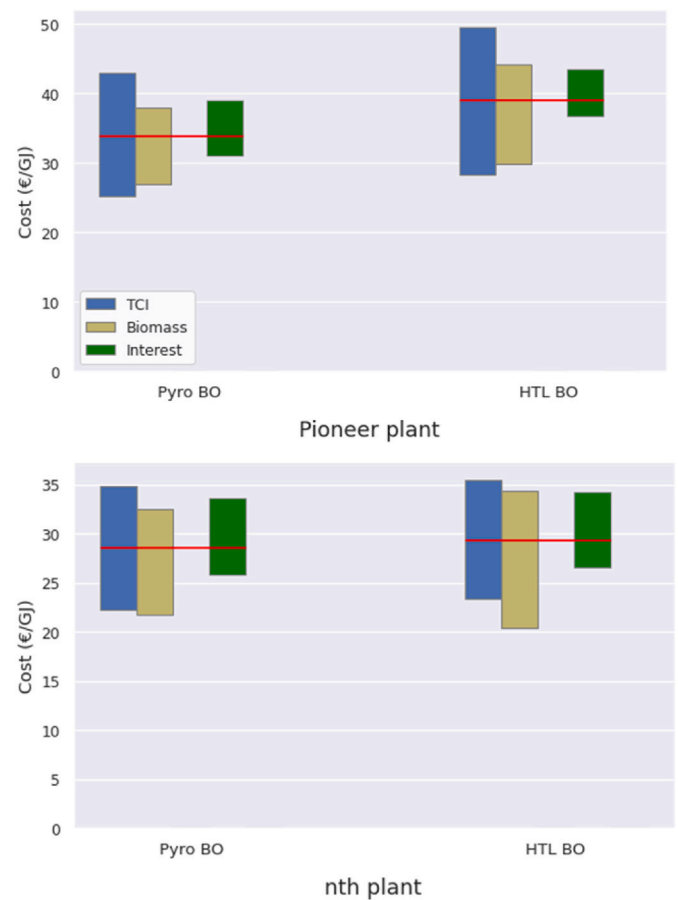
**Fig. 5.** Sensitivity analysis of renewable LNG for top: pioneer plants, bottom: nth plants. The base value for the particular route is shown by a red line. AD-LNG is not present in the top figure as only an nth plant analysis was conducted for this route.

Also, as seen earlier, processes at lower TRL levels are disproportionately affected by variations in TCI in case of pioneer plants.

## 5. Impact of carbon markets

Fig. 2 showed that all the alternative fuels are more expensive than their fossil counterparts. While the sensitivity analyses in Section 4 showed that positive developments in capital and operating cost terms will make alternative fuels more cost-competitive, it is unclear to what extent such improvements can be achieved, and under what timeline. As the entire reason for market uptake of alternative fuels would be their low-carbon nature, it is worth examining what carbon levies or credits would be needed to bridge the cost gap with conventional fuels.

A noteworthy recent development in this regard is the EU initiating the process of bringing shipping under the EU Emissions Trading Scheme (EU-ETS) [125]. Under the proposal approved by the European Parliament in May 2022, from 2024, 100% of emissions from ocean transport within the EU and 50% of that from non-EU to EU ports will be covered under the scheme, with the latter category being expanded to include to 100% of emissions from 2027 [125]. During the initial period, the scheme will act as a carbon tax – ship owners will be required to pay an amount equal to carbon allowances calculated based on their emissions – with a trading scheme expected to kick in after three years [126]. This scheme should incentivise ship owners to replace high-carbon fuels, that will be subject to higher carbon levies, with lower carbon alternatives. While evasion by ship owners is a concern [127], a more basic question is how far the levies will decrease the cost gap between the



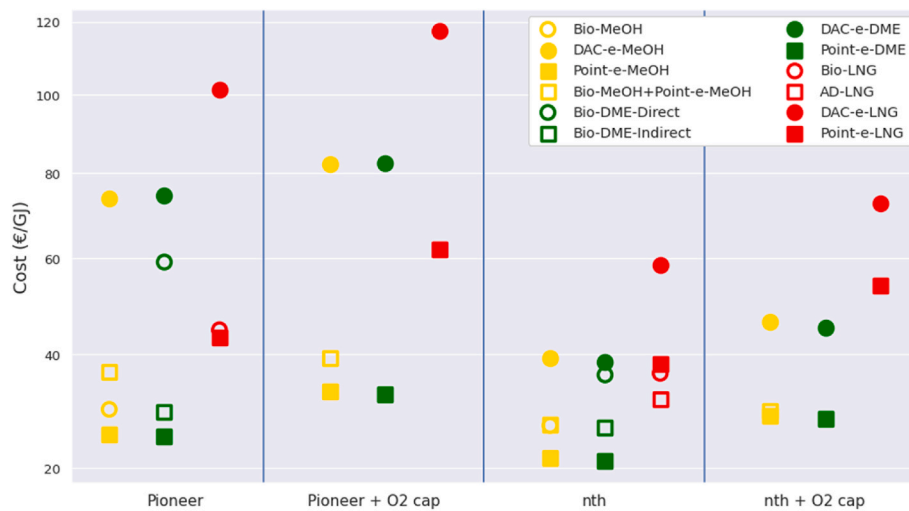
**Fig. 6.** Sensitivity analysis of bio-oil for top: pioneer plants, bottom: nth plants. The base value for the particular route is shown by a red line.

existing and the alternative fuels, since the amount to be paid by the shipowners will depend not only on their emissions but also on the carbon price. This section will look at the price required to properly bridge the cost gap. The emissions factors used for calculating the carbon footprints of the different routes are given in Table 6.

The first thing is to examine if alternative fuels are indeed lower-carbon than conventional fuels. While many factors go into deciding the carbon footprint of fuels, it is clear that, at least for the e-fuels, the emissions factor of the electricity used will have a massive impact on the footprint of the product. This is due to both the large quantity of electricity used in these processes and the fact that the emissions factor of electricity varies widely depending on the source. If the current European grid electricity factor is used, the values shown in Fig. 8 are obtained. To ensure an equitable comparison between the different fuels, CCS has not been considered here. We can see that all the e-fuels are much more carbon intensive than conventional fuels, while the biofuels are less. This reinforces the notion that large-scale deployment of e-fuels is only sensible in the presence of abundant, inexpensive and most importantly renewable electricity.

If we consider a scenario where only (near-)zero emission renewable electricity is used for producing the fuels, then the picture (Fig. 9) improves considerably, and we see that all the alternative fuels are now less carbon-intensive than their conventional counterparts. The notion of carbon prices enabling ship owners to take advantage of the lower carbon footprint of these fuels now becomes worthy of consideration. Therefore, an exercise to see the effect of carbon prices on the fuel prices has been carried out below.

To determine the impact of carbon credits on the fuel costs, in addition to determining the carbon savings, it is also necessary to decide on the carbon price to be used. As seen in Fig. S2, the recent past has seen



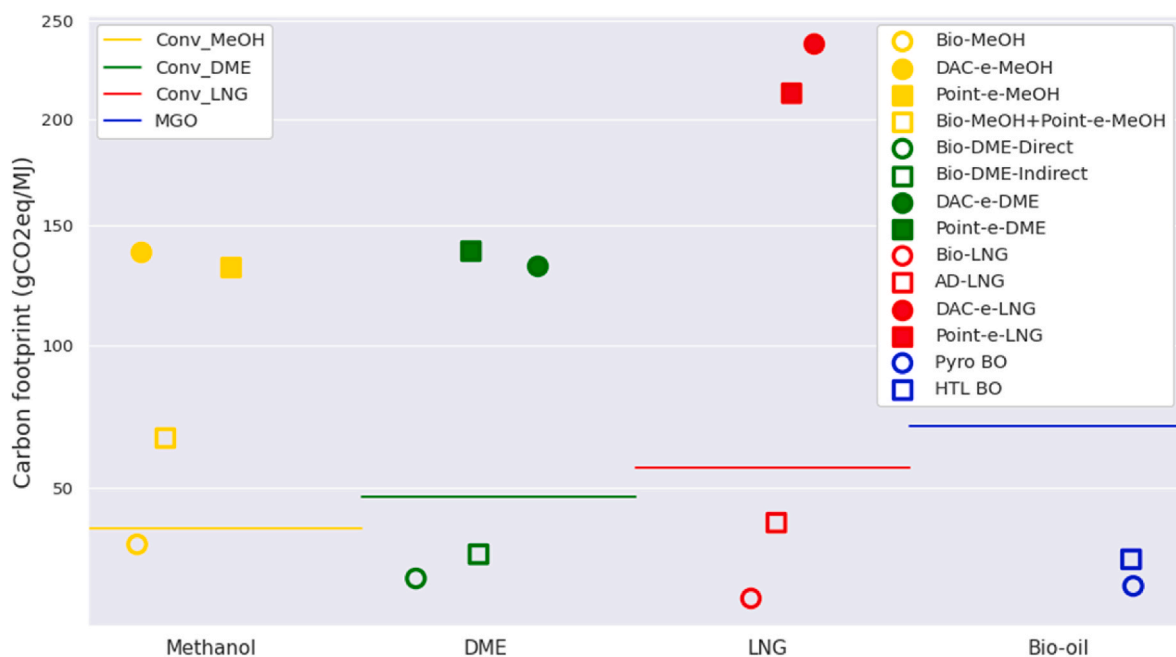
**Fig. 7.** Effect of capping oxygen sales at 25% of production of e-fuel prices. Biofuels are only shown in the ‘Pioneer’ and ‘nth’ columns, and AD-LNG only in the nth column. Bio-oils not shown due to absence of e-fuel routes.

**Table 6**

Emissions factors used for carbon footprint calculations.

Item	Value (kg CO <sub>2</sub> /GJ)	Reference
Conventional methanol	38.2	[74]
Conventional methanol using renewable electricity	34.6	[74]
Conventional DME	47.2	[128]
Conventional DME using renewable electricity	45.6	[128]
Conventional LNG	56.4	[129]
MGO/diesel	70.4	[130]
Anaerobic digestion biomethane	28.3	[64]
Pellets	15	[131]
Natural gas	56.4	[129]
EU electricity GHG intensity (2020)	64.2	[132]

EU carbon prices rising sharply from 23 €/t CO<sub>2</sub> in October 2020 to 90 €/t CO<sub>2</sub> in January 2022 [133]. This has led to projections of prices reaching 140 €/t CO<sub>2</sub> in 2030 [134], a price that has also been calculated as being essential for meeting EU 2030 emission targets [135]. However, it should be noted that the recent price history has been heavily influenced by developments like high natural gas prices leading to an increase in coal use for electricity production [136]. Such high carbon prices may therefore prove transient, given that prices were as low as 5 €/t CO<sub>2</sub> as recently as 2017 [133]. The influence of carbon pricing on the economic viability of alternative fuels has been examined by looking at two carbon prices: 15 €/t CO<sub>2</sub>, which is the lowest price over the past three years, and 140 €/t CO<sub>2</sub>, due to the reasons mentioned above. For simplicity, it has been assumed that ship owners are required to pay the entire carbon levy on the fuels, regardless of the type of ship, ports served, and other details. It is also assumed that negative emissions trade in the same manner and at the same price as capture and storage of fossil carbon.



**Fig. 8.** Carbon footprint of alternative fuels using present-day grid EU electricity and without carbon capture.



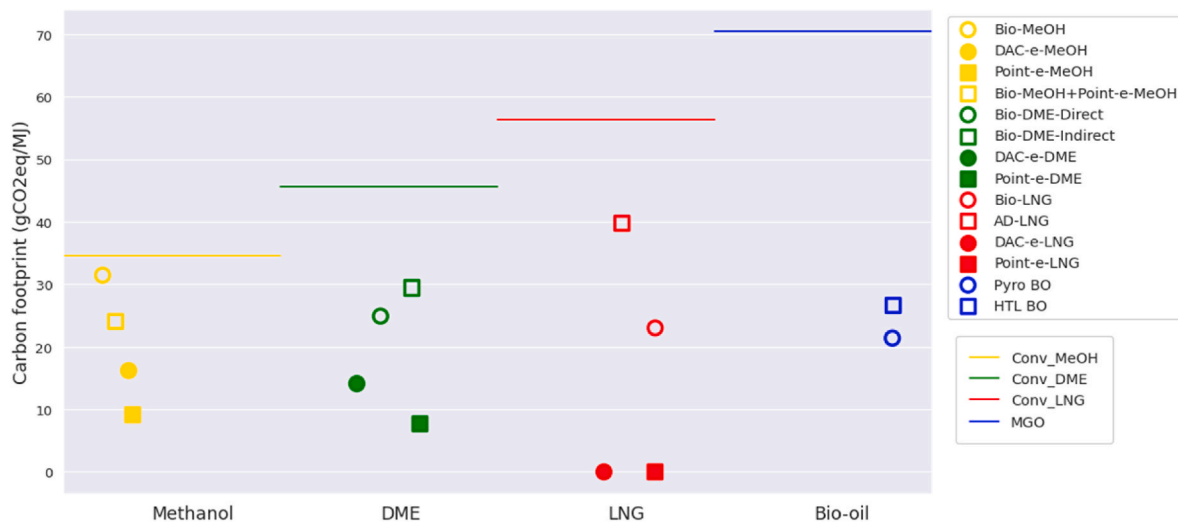


Fig. 9. Carbon footprint of alternative fuels using fully renewable electricity and without carbon capture.

It is clear from Fig. 10 that a carbon price of 15 €/t CO<sub>2</sub> is too little to make any real difference to the competitiveness of alternative fuels. A price of 140 €/t CO<sub>2</sub> is more significant, with point e-MeOH and point e-DME becoming competitive even with MGO in the nth plant scenario. Overall, however, the majority of the alternative fuel routes remain disagreeably expensive even when carbon pricing is considered, not just in the pioneer plant but also the nth plant scenarios. This is in line with recent work by other authors. One study, for instance, found that the abatement cost of carbon substituting MGO with alternative fuels will be 300–550 €/t CO<sub>2</sub> [137], while another stated that a CO<sub>2</sub> tax as high as 661 \$/t CO<sub>2</sub> may be required for decarbonising the maritime sector using hydrogen-based synfuels [138].

Comparing how the fuels would perform in the presence of a substantial carbon credit, DME appears to be the best option economically, achieving among the lowest costs across the four scenarios when a credit of 140 €/t CO<sub>2</sub> is applied. It is, however, also the most niche of the fuels examined, and shipping sector stakeholders would presumably need to be convinced of its widespread availability prior to adopting it. Methanol remains expensive even after applying the credit, although point capture-based e-MeOH is potentially competitive at least with fossil methanol even for pioneer plants. Its greater availability compared to DME may therefore lead to it being preferred as a fuel, despite the slightly higher costs. The bio-oils remain more expensive than the fossil fuels in every case, although for pyrolysis bio-oil, the sale of biochar or valorisation of the pyrolytic aqueous fraction could potentially reduce prices further. For HTL, marginally the best result is obtained when CCS is applied and high carbon prices are available. Even though this is an intriguing prospect, it needs to be implemented at least at demonstration scale before meriting more serious consideration. For pyrolysis, on the other hand, CCS application makes little difference, with the amount of CO<sub>2</sub> captured too little to make a serious difference either way.

The results obtained for LNG are worthy of special introspection. It can be seen that even with a high carbon levy, fossil LNG remains by far the lowest cost fuel, meaning that it will remain attractive to ship owners even under the EU-ETS regime. Green LNG, on the other hand, has the highest cost figures among all the alternative fuels on average, remaining more than twice as expensive as fossil LNG even under the most optimistic conditions. The cost gap makes the utility of fossil LNG as a ‘bridging fuel’ that will be replaced by green LNG in the future suspect. This corroborates previous work showing that LNG should only play a limited role in shipping, with either a ‘temporary’ or ‘transitional’ role unlikely to be in the best interests of shipping industry decarbonisation [139].

While the pioneer plant values cannot be easily compared, the results

obtained for the nth plants here are more or less in line with those that have been reported by previous authors. For methanol, one study found that present bio-MeOH prices could range between 20 and 25 €/GJ [140], while another reported a range of 15 and 46 €/GJ depending on feedstock costs, with that of DAC methanol between 51 and 108 €/GJ [44]. An older study had estimated a CO<sub>2</sub>-to-methanol production cost of 36 €/GJ in 2014, but this was assuming that CO<sub>2</sub> would be able for use at no cost, and hence adding CO<sub>2</sub> capture costs will increase the realisable methanol price [74]. Another study obtained slightly lower e-methanol costs (21–33 €/GJ), partly because it considered lower cost point CO<sub>2</sub> capture and favourable electrolyser capex [141].

Reported DME costs largely tend to be similar, with bio-DME costs in the 20–25 €/GJ range [140] and e-DME around 50–80 €/GJ [142,143]. For bio-LNG, some of the reported numbers are lower (15–30 €/GJ [84, 144,145]), which may be due to more optimistic assumptions, but a comprehensive recent study estimated a range of 20–50 €/GJ for anaerobic digestion and 25–65 €/GJ for gasification, and the numbers reported here fall well within this bracket. For e-LNG, on the other hand, both point capture and DAC-based processes are reported to have costs in the 20–35 €/GJ range [146,147], which is a fair amount cheaper than the costs calculated here, although even those numbers are much higher than fossil LNG prices. Pyrolysis bio-oils likewise have reported costs in the 19–23 €/GJ range [148,149], lower than the numbers calculated here, while for HTL, conflicting figures are available, with one study citing a cost of 24 €/GJ [148] and another around 50 €/GJ [150]. Part of the reason for the discrepancy between the numbers is simply due to differing assumptions, especially regarding feedstock prices. For instance, assuming a tipping fee for the feedstock reduces the HTL bio-oil price in the study cited above from around 50 to around 14 €/GJ [150]. Likewise, the updated capital costs used in this work tend to be considerably higher than those used in studies carried out years ago, which also explains the relatively higher cost figures obtained here.

## 6. Conclusion

This work has examined the production of four alternative fuels by different routes for both nth and pioneer plant settings and optionally including CCS. It was found that, at present, none of the fuels is cost-competitive with existing marine fuels. The pioneer plants in particular produce prohibitively expensive fuel, while the nth plants, at least for the bio-MeOH, bio-DME, point e-MeOH and point e-DME routes, are more reasonable. Furthermore, production of the fuels via electrosynthesis routes using European grid electricity was found to be more carbon intensive than fossil fuels, highlighting the need for renewable



**Fig. 10.** Cost of alternative fuels compared with existing marine fuels, considering fully renewable electricity, CCS, and top: carbon price of 15 €/t CO<sub>2</sub>; bottom: carbon price of 140 €/t CO<sub>2</sub>.

electricity usage as a precondition for their manufacture.

A combination of bio- and e-fuels appears to be a reasonably cost-effective option while also being more carbon efficient and resilient to feedstock price fluctuations. Given the difficulty of meeting shipping sector decarbonisation targets using either bio- or e-fuels by themselves, this synergistic route is worth further research. Given the large fuel requirement and the short timespans, however, even this combination of fuels may be insufficient for meeting the decarbonisation requirements of shipping, and CCS may therefore need to be involved to make up the shortfall. If this scenario does come to pass, then CCS-friendly fuels like methanol, DME or LNG will have an advantage over bio-oils.

The most optimistic scenario for alternative fuels is if a high carbon price becomes applicable to shipping fuels, levelling the playing field between alternative and fossil fuels to an extent. DME produced via

point CO<sub>2</sub> capture was found to be the most cost-competitive fuel in this scenario, while LNG remained too expensive even in the best case across all routes.

#### Credit author statement

Agneev Mukherjee: Investigation, Writing – original draft, Visualization; Pieter Bruijninx: Supervision, Writing – review & editing; Martin Junginger: Conceptualisation, Methodology, Supervision, Writing – review & editing

#### Declaration of competing interest

The authors declare that they have no known competing financial

interests or personal relationships that could have appeared to influence the work reported in this paper.

## Data availability

Data will be made available on request.

## Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.rser.2022.113127>.

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