Review of electrofuel feasibility - Cost and environmental impact

Citation for the original published paper (version of record):
Grahn, M., Malmgren, E., Korberg, A. et al (2022). Review of electrofuel feasibility - Cost and environmental impact. Progress in Energy, 4(3). http://dx.doi.org/10.1088/2516-1083/ac7937

Progress in Energy

TOPICAL REVIEW • OPEN ACCESS

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To cite this article: Maria Grahn *et al* 2022 *Prog. Energy* **4** 032010

IOP Publishing Prog. Energy 4 (2022) 032010 https://doi.org/10.1088/2516-1083/ac7937

Progress in Energy

OPEN ACCESS

RECEIVED
28 October 2021

REVISED
1 June 2022

ACCEPTED FOR PUBLICATION
15 June 2022

PUBLISHED
29 June 2022

TOPICAL REVIEW

Review of electrofuel feasibility—cost and environmental impact

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Keywords: power-to-fuels, e-fuels, CO_2-fuels, carbon capture and utilization, techno-economic analysis, climate impact, LCA

Supplementary material for this article is available online

Abstract

Electrofuels, fuels produced from electricity, water, and carbon or nitrogen, are of interest as substitutes for fossil fuels in all energy and chemical sectors. This paper focuses on electrofuels for transportation, where some can be used in existing vehicle/vessel/aircraft fleets and fueling infrastructure. The aim of this study is to review publications on electrofuels and summarize costs and environmental performance. A special case, denoted as bio-electrofuels, involves hydrogen supplementing existing biomethane production (e.g. anaerobic digestion) to generate additional or different fuels. We use costs, identified in the literature, to calculate harmonized production costs for a range of electrofuels and bio-electrofuels. Results from the harmonized calculations show that bio-electrofuels generally have lower costs than electrofuels produced using captured carbon. Lowest costs are found for liquefied bio-electro-methane, bio-electro-methanol, and bio-electro-dimethyl ether. The highest cost is for electro-jet fuel. All analyzed fuels have the potential for long-term production costs in the range 90–160 € MWh^{-1}. Dominant factors impacting production costs are electrolyzer and electricity costs, the latter connected to capacity factors (CFs) and cost for hydrogen storage. Electrofuel production costs also depend on regional conditions for renewable electricity generation, which are analyzed in sensitivity analyses using corresponding CFs in four European regions. Results show a production cost range for electro-methanol of 76–118 € MWh^{-1} depending on scenario and region assuming an electrolyzer CAPEX of 300–450 € $kW_{elec}{}^{-1}$ and CFs of 45%–65%. Lowest production costs are found in regions with good conditions for renewable electricity, such as Ireland and western Spain. The choice of system boundary has a large impact on the environmental assessments. The literature is not consistent regarding the environmental impact from different CO_2 sources. The literature, however, points to the fact that renewable energy sources are required to achieve low global warming impact over the electrofuel life cycle.

1. Introduction

There is widespread recognition that anthropogenic greenhouse gas (GHG) emissions need to be reduced to avoid severe global climate change [1]. Transportation, primarily road, rail, air and marine, was responsible for approximately 27% of global GHG emissions associated with energy use in 2019 [2]. The transport sector can also contribute to local health and environmental problems from emitted particulate matter, NO_x, and other substances [3]. The GHG emissions can be decreased by reducing the demand for energy, the emission intensity of that energy, or both. This paper focuses on the feasibility of reducing GHG emissions through the emission intensity of transport-related energy by using electrofuels, i.e. liquid or gaseous hydrogen-containing fuels produced by combining energy from electricity, hydrogen from water (via electrolysis), and carbon, or possibly nitrogen [4, 5]. Capturing carbon to produce electrofuels typically comes with a cost. There is, however, a special case in which externally provided hydrogen reacts with surplus CO or CO_2 produced within a biofuel production process (e.g. biomass gasification reactor or anaerobic digestion) giving products that we call bio-electrofuels in this article. Depending on production technology, the resulting electrofuels and bio-electrofuels can be either liquid or gaseous, including electro-methane, electro-methanol, electro-gasoline, electro-diesel, and electro-ammonia. For brevity, the electrofuel terms in this paper hereafter are denoted e-fuels, e-methanol, bio-e-fuels, bio-e-methanol, and so on.

E-fuels are of interest for all transport modes; many hydrocarbon e-fuels could be used in existing vehicles and may not require significant investments in new distribution and fuelling infrastructure. They are of special interest in sectors such as long-distance aviation and deep-sea shipping, where electrification opportunities are limited because liquid fuels with high energy density are difficult to substitute. E-fuels could also contribute to balancing intermittent electricity production by providing a use for excess or very low-cost electricity. E-fuel production also generates marketable by-products such as high-purity oxygen and heat. However, according to the literature, the combined efficiency of energy conversion and utilization is a challenge compared to options that use electricity directly, see e.g. [6–9].

The concept of e-fuels has, during the last 5–10 years, gained increased attention from different industries such as the automotive, fuel producers, and energy utility companies. Many scientific papers, analyzing different aspects of e-fuels, have been published describing technical implementation of the production processes, production costs, and environmental performance. There is no paper, to our knowledge, that compares the production costs of bio-e-fuels to e-fuels, neither any paper analyzing production costs of e-fuels based on modelled electricity price scenarios for 2050.

The aim of this study is to review publications on e-fuels and bio-e-fuels to summarize current knowledge on production costs and environmental performance, calculate harmonized production costs for a range of bio-e-fuel and e-fuel options, as well as assess future production costs depending on different electrolyzer CAPEX and different capacity factors (CFs), with corresponding modelled electricity prices and hydrogen storage costs.

Baseline values from the ranges of component costs, found in the literature, are used to estimate the harmonized production costs over near-term (approx. 5–10 years) and long-term (approx. 20–30 years) horizons. The sensitivity of the long-term production costs is then analyzed using electricity price scenarios, corresponding to different CFs, for year 2050, from four European regions.

For perspectives on e-fuels from different parts of the transport sector we refer to a sister article entitled ‘Review of electrofuel feasibility: Prospects for road, ocean and air transport’ [10].

2. Literature search

A literature search was made using Scopus. There is a wide range of terms for e-fuels in the literature, where we have focused on six groups of search terms: (a) electrofuels and similar, (b) power-to-x and similar, (c) power-fuels, (d), sun-fuels, (e) CO_2-fuels, and (f) hydrogen-fuels, where the chosen terms appeared in the title, abstract or keywords (see search string A below and exact string for each search term group in figure S1). We added *AND NOT *cigar** to exclude all publications focusing on e-liquids for e-cigarettes. For the term power-fuels we added *AND NOT ‘power fuel cell*’* to avoid publications focusing on the development of fuel cells. Also, the acronyms PTX, PTL, or PTG were found in almost 100 000 publications and therefore we added *AND (methane OR methanol OR gasoline OR diesel OR ammonia OR kerosene OR fuel*)* to the search string. Other terms for aviation fuels, e.g. *electro-jet**, generated thousands of publications on other types of jet-challenges such as ‘equatorial electrojet’, ‘auroral electrojet’, ‘water-jet’, and ‘jet-printing’. From testing different *AND NOT*-terms it was found that electrofuels for aviation were typically covered by the term kerosene prefaced by ‘e-’ or ‘electro’, and therefore we excluded electro-jet from the Scopus searches. The number of publications per year, between 1960 and 2020, using the six groups of search terms, is illustrated in figure S1 in supplementary material.

The search term group PTX, PTG, PTL, or terms prefaced by ‘power-to-’, are the most common nomenclature in the literature, including 5911 publications between 1960 and 2020 with a steady increase since the late 90s where the annual publication rate between 1960 and 1996 was approximately 0–10 compared to over 600 during 2020 (figure S1). Terms prefaced by ‘e-’ or ‘electro’, in total 3457 publications (approximately 200 during 2020) are frequently used in the literature, showing similar growth since 1995. The search term ‘powerfuels’, ‘CO_2-fuels’, and ‘hydrogen fuels’ resulted in 635, 70, and 127 publications, respectively. All groups of terms show increasing trends except ‘sun-fuels’ (39 publications), and from scanning the abstracts of the group ‘sun-fuels’ we found them irrelevant for this study. It should be noted that the same publication can appear in more than one search term group.

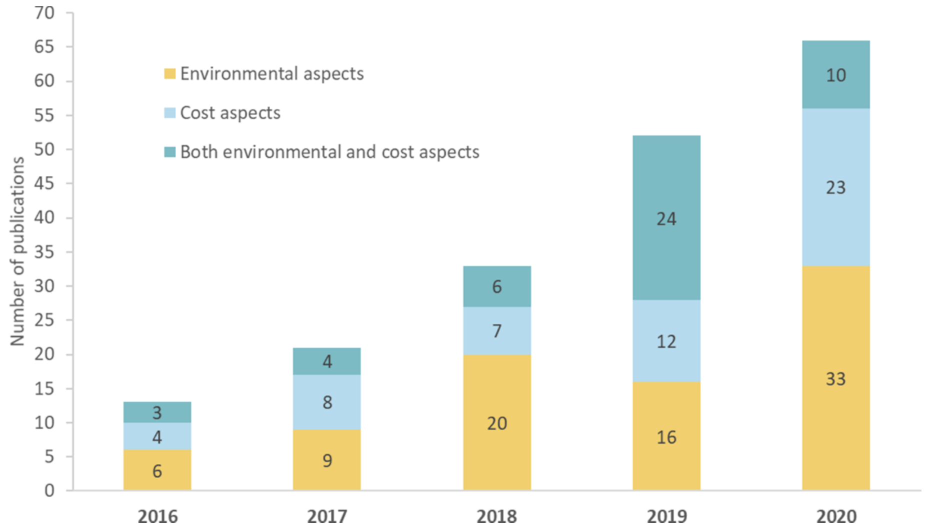


Figure 1. Number of publications per year analyzing e-fuels focusing on only environmental or cost aspects, or a combination of both, found in Scopus using our search strings presented in text. In total 185 publications.

To identify relevant publications for this study, we combined the search term groups with constraints to exclude publications not analyzing fuels produced from carbon or nitrogen. After exploring different options where either relevant publications were excluded or irrelevant publications were included, we ended up constraining the electrofuel-group with *AND (carbon OR nitrogen)* and the remaining search groups with *AND ('carbon recycling' OR 'carbon conversion' OR 'carbon capture' OR 'carbon capture and utilization' OR 'carbon capture and utilisation' OR ccu OR 'direct air capture')*, see search string A, below. This search string was then combined with an additional string focusing on either environmental aspects (AB) or cost aspects (AC), as follows:

A= *(electrofuel* OR efuel* OR 'e-fuel*' OR 'electro-fuel*' OR 'e-gas' OR 'e-methane' OR 'e-methanol' OR 'e-gasoline' OR 'e-diesel' OR 'e-kerosene' OR 'e-ammonia' OR 'e-liquid' OR 'electro-methane' OR 'electro-methanol' OR 'electro-gasoline' OR 'electro-diesel' OR 'electro-kerosene' OR 'electro-ammonia' OR 'electro-liquid*' OR electromethane OR electromethanol OR electrogasoline OR electrodiesel OR electrokerosene OR electroammonia OR electroliquid* AND (carbon OR nitrogen)) OR (powerfuel* OR 'power-fuel*' OR ((ptx OR ptl OR ptg OR 'power-to-*') AND (methane OR methanol OR gasoline OR diesel OR kerosene OR ammonia OR fuel* OR liquid*)) OR 'CO_2-fuel*' OR 'CO_2-derived fuel*' OR 'CO_2-based fuel*' OR 'hydrogen-based synthetic fuel*' OR 'hydrogen-based fuel*' AND ('carbon recycling' OR 'carbon conversion' OR 'carbon capture' OR 'carbon capture and utilization' OR 'carbon capture and utilisation' OR ccu OR 'direct air capture')) AND NOT *cigar* AND NOT 'power fuel cell*'*
B= AND ('environmental impact*' OR 'climate impact*' OR LCA OR 'Life cycle assessment*' OR 'CO_2 emission*' OR 'carbon dioxide emission*' OR 'carbon emission*' OR 'GHG emission*' OR 'greenhouse gas emission*')
C= *AND (cost* OR 'techno-econom*')*

The search string A resulted in 936 publications between the earliest found (1938) until 2020. Searches including environmental aspects (AB) or cost aspects (AC) resulted in 196 and 159 publications, respectively, between the earliest found 2001 and 1998, respectively, until 2020. Search string ABC resulted in 64 publications mentioning both aspects, meaning that 645 publications in search A, (i.e. A + ABC − AB − AC) and every publication before 1998 mentioned neither environmental nor cost aspects, as defined in our search strings, in title, abstract, or keywords.

Interest in analyzing environmental and/or cost aspects of e-fuels has steadily increased over the years, especially after 2016. For that reason, but also since an earlier literature review included publications up to March 2016 [6], we have chosen to review publications from 2016 through 2020. Results for this Scopus search, covering the combined case (ABC), the environmental aspects only (AB minus ABC) or costs only (AC minus ABC), in total 185 publications 2016–2020, are shown in figure 1 and listed in table S1 in supplementary material.

For this study, relevant publications have been added through 'snowballing' (i.e. identify additional relevant publications from reading publications' reference lists), thereby including also reports, theses, and policy documents, see table S2 in supplementary material. Additional searches were made when looking for specific data. Our results are compared to results from a few 2021–2022 publications found after finishing the literature review.

A geographical distribution in e-fuel research, indicated by first author's affiliation, indicate that Germany (60 publications) had the largest research interest in e-fuels between 2016 and 2020, followed by Italy (20 publications) and then China, the USA, and the UK, each having 13–18 publications, see figure S2 in supplementary material.

The review results, and how we analyze the information found, are described in sections 3–5.

3. Production cost aspects

E-fuels are produced by storing electrical energy, as chemical energy, in the form of gaseous or liquid fuels. This key factor differentiates them from biofuels [5]. In this study, we distinguish between biofuels, bio-e-fuels, and e-fuels through our assumptions on carbon capture. We assume e-fuels are formed from electrolytic hydrogen (i.e. hydrogen produced from electricity) and carbon (or nitrogen), where the carbon is captured from a point source or from the air. The carbon capture (yellow box in figure 2) comes with a monetary cost. Bio-e-fuels are defined here as fuels generated by adding electrolytic hydrogen to a biomass-based conversion process (such as anaerobic digestion or biomass gasification) to increase the production yields by utilizing CO_2 or CO (green boxes in figure 2). On this basis, there is no need for carbon capture for bio-e-fuels. The concept bio-e-fuels is further described in section 3.4.

Biofuels (biomass-derived fuels produced without using electrolytic hydrogen) and refined biofuels where hydrogen is used to form biofuels of higher qualities (e.g. hydrotreated vegetable oil, HVO, and hydrothermal liquefaction, HTL [11]) are excluded from this study.

The carbon used to form e-fuels (yellow box in figure 2) is captured from industrial emissions (fossil or biogenic point sources) or air. Examples of biogenic point sources are biomass combustion processes, pulp and paper facilities, or CO_2 from fermentation when producing ethanol. Nitrogen can be separated from air.

By chemically combining the carbon (or nitrogen) with hydrogen, a variety of fuels can be produced, as illustrated in figure 2. The most important components and pathways to produce these fuels are described below.

3.1. Hydrogen production

E-fuels get their name from the large amounts of electricity used in their production. Electricity is used in an electrochemical process called electrolysis where water molecules are split into hydrogen and oxygen. To keep the resulting gases apart, the reacting compartments are separated by an electrolyte, which is also used to classify the main technologies: alkaline electrolysis (AEL), polymer electrolyte membrane electrolysis (PEMEL), and solid oxide electrolysis (SOEL). Table 1 provides an overview of the available costs and efficiency ranges in the analyzed literature, which vary significantly. The low and high values of the ranges for CAPEX represent the most optimistic data provided by the authors of the reviewed papers, but should not necessarily be compared across as not all authors assess all technologies. Brynolf *et al* [6] provide a detailed discussion of the causes of the wide ranges of cost assumptions. In general, the efficiency of electrolysis has a high impact on the total fuel production efficiency because of the large amounts of hydrogen required in the synthesis.

3.2. Carbon and nitrogen sources

As shown in figure 2, e-fuels can be produced within a range of pathways using carbon (CO or CO_2) or nitrogen sources. Of the reviewed literature, 14 papers [27–40] refer to e-fuels produced when hydrogen is added into a biofuel production facility to increase the carbon-to-hydrogen ratio (here named bio-e-fuels), the remaining studies refer to e-fuels made using CO_2 captured from point sources (fossil or biogenic) or air.

Table 2 shows the reported costs for capturing CO_2 and nitrogen. Carbon can be sourced by capture from CO_2 point sources such as ethanol production, bioenergy power plants, cement production, or other industrial processes. Capture technologies include absorption, membrane filtering, cryogenic capture, or oxy-combustion. Direct air capture (DAC) involves removing CO_2 from air (air-sourced carbon). This method is challenging because of the low CO_2 concentrations in ambient air but has gained interest especially in combination with carbon storage as a method for achieving negative emissions by offsetting past and future CO_2 emissions [41].

While carbon-based e-fuels are the most investigated, ammonia has also been considered as a hydrogen carrier or as a fuel itself. E-ammonia has the advantage of not generating any CO_2 when used and can therefore be attractive if CO_2 is restricted in exhaust emissions. Pure gases, such as N_2, can be separated from air by first cooling it until it liquefies, then selectively distilling the components at their various boiling

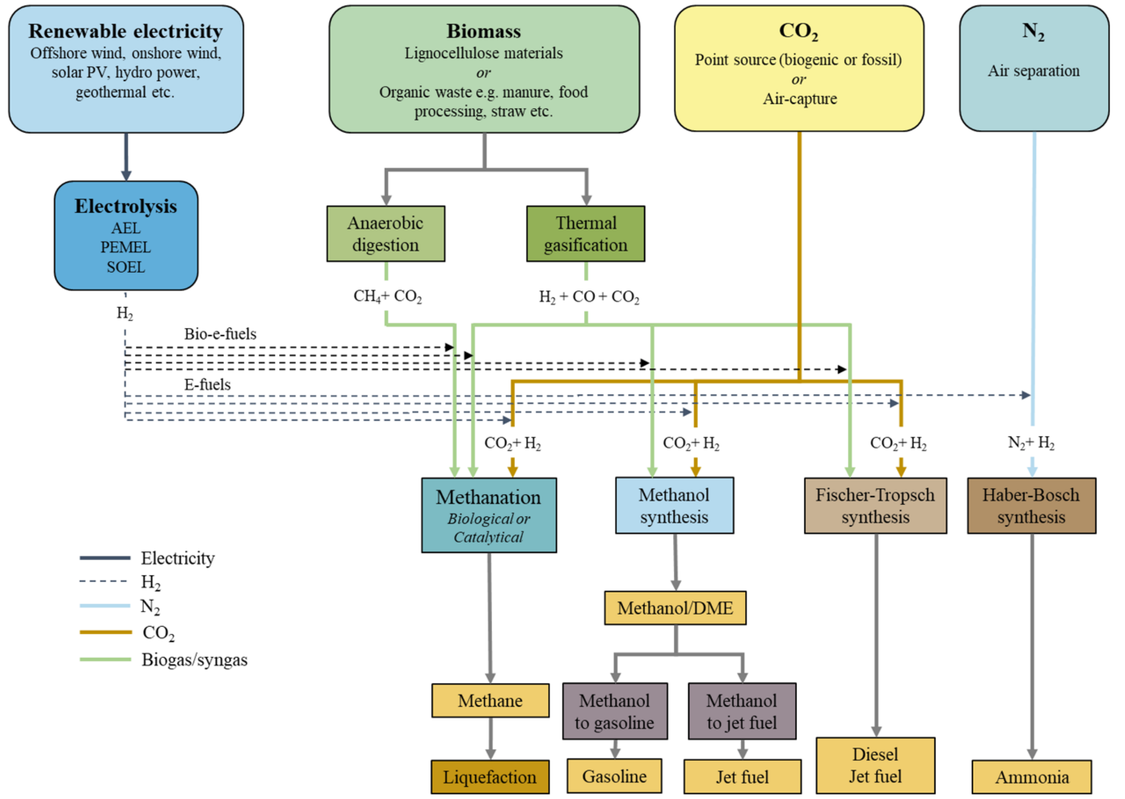


Figure 2. Production pathways, including feedstocks and fuels produced, for the main fuel options in this study. All carbon-based fuels can be produced either as e-fuels or bio-e-fuels. E-fuels are formed from H_2 and CO_2 or N_2. Note that both energy flows and material flows are illustrated, i.e. electricity and biomass (energy inputs), CO_2, N_2 and biomass (material inputs) and hydrocarbons, methanol, and ammonia (energy carrier outputs). Read more on the special case bio-e-fuels in section 3.4. Acronyms used: PV, photovoltaic solar panels; AEL, alkaline electrolysis; PEMEL, polymer electrolyte membrane electrolysis; SOEL, solid oxide electrolysis; DME, dimethyl ether.

Table 1. Near- (approx. 5–10 years) and long-term (approx. 20–30 years) electrolysis cost (€$_{2019}$ kW$_{el}{}^{-1}$) and efficiency values used in our base analysis, the range of values in the literature are shown in parentheses. Only the central values in the reviewed literature were selected from each publication to build on the knowledge from the reviewed studies, rather than 'redo' their work. Acronyms used: CAPEX, capital expenditures; OPEX, operational expenditures.

		Near-term	References	Long-term	References
AEL	CAPEX (€ kW$_{el}{}^{-1}$)	800 (400–1300)	[6, 12–20]	470 (380–560)	[14, 16, 17]
	OPEX (% of CAPEX) incl. stack replacement[a]	2%–9%	[6, 12, 14, 17]	2%–5%	[12, 14, 17]
	Efficiency (LHV basis)	67% (63%–71%)	[6, 12, 14, 17]	68% (66%–70%)	[14, 17]
PEMEL	CAPEX (€ kW$_{el}{}^{-1}$)	1040 (500–2400)	[6, 12, 14, 15, 17, 20–23]	545 (400–950)	[14, 17, 21–25]
	OPEX (% of CAPEX) incl. stack replacement[a]	2%–11%	[6, 12, 14, 17, 22–24]	2%–5%	[12, 14, 17, 22–24]
	Efficiency (LHV)	64% (58%–69%)	[6, 12, 14, 17]	68% (62%–71%)	[14, 17, 24]
SOEL	CAPEX (€ kW$_{el}{}^{-1}$)[b]	1280 (450–4250)	[6, 12, 15, 17, 22, 23]	380 (300–450)	[12, 17, 22, 23, 26–28]
	OPEX (% of CAPEX) incl. stack replacement[a]	2%–3%	[6, 12, 17, 22]	2%–3%	[12, 17, 22]
	Efficiency (LHV)	78% (76%–81%)	[6, 12, 17, 22]	79% (75%–83%)	[17, 22]

[a] Brynolf *et al* [6] do not include the stack replacement in the OPEX, but specifies it separately. For this reason, we recalculated the OPEX for this source to include the stack replacement.

[b] Although data provided in this table reflect what is presented in the reviewed papers, it is a bit surprising that lower end of the range for CAPEX near-term SOEL is lower than for PEM. However, estimates for cost reductions are differently optimistic between studies and this study presenting SOEL CAPEX by 2030 being 450 € kW$_{el}{}^{-1}$ was published in 2018 [22].

Table 2. Carbon and nitrogen production costs in €$_{2019}$/t$_{CO2/N2}$ calculated from CAPEX identified in the literature at an interest rate of 5%, with lifetimes of 25, 20, and 30 years and OPEX of 4%, 5%, and 2% of CAPEX for point-source carbon capture (fossil and biogenic), air-source carbon capture and nitrogen capture, respectively. The cost for electricity is excluded when calculating these values, but included in fuel production cost. Values shown for near-term (approx. 5–10 years) and long-term (approx. 20–30 years) horizons are base values used in this article while values in parentheses are the range in the reviewed literature. Only the central values in the reviewed literature were selected from each publication. The base values represent the authors expert judgement based on the literature review.

	Near-term[a]	References	Long-term[a]	References
Point-source carbon[b]	50 (20–260)	[6, 17, 42–51]	25 (10–100)	[17, 25, 27, 52–55]
Air-sourced carbon[c]	300 (25–778)	[17, 23, 41, 43, 51]	90 (15–105)	[17, 22, 23, 41, 43, 53]
Nitrogen capture	9 (8–10)	[17]	7 (5–14)	[17, 24]

[a] Both near- and long-term costs are uncertain, however, as can be seen in figure 4 the contribution from this cost factor to the e-fuel production cost is relatively small and therefore the uncertainties are less critical in this study.

[b] Carbon point sources are of both biogenic and fossil origin, with high concentration sources typically having capturing costs in the lower end of the ranges.

[c] Costs for direct air capture are very uncertain since currently no large-scale units are commercially in operation. As an example of recalculations made, Fasihi *et al* [41] present CAPEX for DAC of 189 €/t$_{CO2}$ for 2030, which assuming 20 year life time, 5% interest rate, 5% OPEX, become 25 €/t$_{CO2}$ of captured CO_2, i.e. the most optimistic value for near-term DAC.

temperatures. The low distillation temperature can be achieved by using an air separation unit (ASU), based on a refrigeration cycle, or more lately by using expansion turbines for cooling. Another option is pressure swing adsorption (PSA) that provides separation of oxygen or nitrogen from air without liquefaction. The principal disadvantage of the PSA cycle is the risk of high gas losses resulting from the pressure release. In this study we have assumed that nitrogen is captured using the ASU process, also generating potential by-products such as oxygen and sometimes argon.

Costs for carbon capture and nitrogen capture are presented in various ways in the literature, as CAPEX, final production costs or avoided CO_2 costs. For uniformity, the identified costs are all converted to production costs, including the annuitized CAPEX and OPEX. Table 2 lists the base values used in our harmonized calculations in section 4 and the range of values found in our literature review.

3.3. E-fuel synthesis

Hydrogen and carbon can, in our study, be combined to give a variety of fuel products using three technologies: methanation, methanol synthesis, and Fischer–Tropsch (FT) synthesis. In addition, hydrogen can be combined with nitrogen to produce ammonia in the Haber–Bosch synthesis.

Methanation can be achieved using catalysts (catalytic methanation) or using methanogenic microorganisms (biological methanation). Biological methanation can be implemented as an additional process in biogas plants and has relatively low operational temperature, while catalytic methanation operates at high temperatures and is highly exothermic. The excess heat can be used for other purposes, such as for district heating networks or as heat source for high-temperature electrolysis, which can increase overall efficiency of a plant [56]. A general description of the e-methane production technologies is given by deBucy [57].

Methanol synthesis is similar to catalytic methanation, where CO_2 and CO in syngas are combined with H_2 to generate methanol. The reaction is exothermic and operates at high temperatures and pressures. The resulting methanol can be further reacted to give dimethyl ether (DME), gasoline, diesel, or jet fuel [6, 29, 58]. The raw methanol produced includes approximately 10% water which is removed by distillation.

FT synthesis is a series of reactions in which CO and H_2 react to form hydrocarbons. The reactions occur at high temperatures and pressures. A reverse water-gas shift reaction usually precedes the FT synthesis to achieve the optimal H_2/CO stoichiometry. The resulting FT liquids are a mix of paraffins, olefins, and alcohols and the reaction is not particularly selective [32]. Depending on the mix and the length of the upgrading process, the resulting products would usually be gasoline, diesel, jet fuel, and high-quality lubricants, while according to [17] alcohols can be another product.

Ammonia synthesis by the Haber–Bosch process uses a catalyst under high temperature and pressure. As with the other syntheses, it is exothermic and normally designed to operate under continuous production. However, if future ammonia synthesis can operate dynamically, flexible operation may make economic sense as a means to utilize hydrogen from intermittent renewable electricity [24] avoiding costly hydrogen storage.

Among the reviewed literature, some papers describe the process efficiency of the fuel synthesis, while others focus on the overall efficiency of the e-fuel plants. In table 3 we have reported the former. The lifetime of the units varies between 15 and 30 years, depending on type of synthesis, while the OPEX are 9%–11% for FT synthesis and 3%–5% for the other syntheses. Table 3 presents an overview of the fuel synthesis costs and process efficiencies. The process efficiencies are considered to be the same in the near- and long-term. Sub-section 4.1 describes the overall efficiencies identified in the studied literature.

Table 3. CAPEX and efficiencies for e-fuel syntheses. Values shown for near-term (approx. 5–10 years) and long-term (approx. 20–30 years) horizons are base values used in this article while values in parentheses are the range identified in the reviewed literature. Only the central values in the reviewed literature have been selected from each publication. The base values represent the authors expert judgement based on the literature review. The CAPEX per kW_{fuel} depends on the size of the facility; the near-term numbers reflect small scale plants below 50 MW, the long-term numbers reflect larger plants.

		Near-term	References	Long-term	References
Hydrogen to methane	CAPEX (€$_{2019}$ $kW_{fuel}{}^{-1}$)	450 (125–1350)	[6, 22]	250 (75–700)	[8, 23, 59]
	Process efficiency	70%–83%	[6, 23, 28, 29, 60]	70%–83%	[23, 28, 29, 60]
Hydrogen to methanol	CAPEX (€$_{2019}$ $kW_{fuel}{}^{-1}$)	700 (300–1200)	[6, 58]	300 (200–650)	[8, 27, 58, 59]
	Process efficiency	69%–89%	[6, 29, 59]	69%–89%	[29, 59]
Hydrogen to DME	CAPEX (€$_{2019}$ $kW_{fuel}{}^{-1}$)	700 (300–1200)	[6, 58]	300 (200–650)	[8, 27, 58, 59]
	Process efficiency	69%–89%	[6, 29, 59]	69%–89%	[29, 59]
Methanol to gasoline (MTG)	CAPEX (€$_{2019}$ $kW_{fuel}{}^{-1}$)	600	[6]	300 (250–370)	[29, 59]
	Process efficiency	86%	[29]	86%	[29]
Methanol to jet fuel (MTJ)	CAPEX (€$_{2019}$ $kW_{fuel}{}^{-1}$)	1000[a]	*Author's estimation*	500 (370–900)	[28, 59]
	Process efficiency	74%	*Author's estimation*	74%	*Author's estimation*
Hydrogen to Fischer–Tropsch	CAPEX (€$_{2019}$ $kW_{fuel}{}^{-1}$)	1600 (400–2100)	[6, 17, 22, 32, 58]	750 (300–1030)	[8, 17, 25, 58, 59]
	Process efficiency	59%–78%	[22, 59]	59%–78%	[22, 59]
Hydrogen to ammonia[b]	CAPEX (€$_{2019}$ $kW_{fuel}{}^{-1}$)	1300 (1300–2200)	[17]	800 (580–1100)	[17, 24, 59]
	Process efficiency	61%–79%	[59, 61]	61%–79%	[59, 61]

[a] Although one can expect the two processes MTG and MTJ to be similar, there is currently very little information in the literature. The MTJ process is still in test and demonstration scale and therefore near-term (as well as long-term) costs, and efficiencies, are very uncertain. For simplicity we have assumed a near-term investment cost double that of the long-term cost found in literature, following similar trend as the other fuel options.

[b] The estimated CAPEX for ammonia in this table is without the air separation unit.

3.4. Bio-e-fuel synthesis

Bioenergy sources such as animal manure, organic waste from food processing, straw, and other energy crops are suitable feedstocks for different anaerobic processes such as digestion or fermentation. Anaerobic digestion plants can convert biodegradable organic material into biogas which is composed primarily of methane (CH_4) and CO_2. Lignocellulosic feedstocks, such as wood chips, wood pellets, straw, tops and branches or even biogas plant residues, are considered suitable for thermal gasification or other deconstructive processes. In gasification, the solid biomass is endothermically converted into a synthetic gas (syngas) in the presence of an oxidizing agent such as oxygen or steam. Syngas is a mixture of H_2, CO, CO_2, CH_4, water, and light hydrocarbons that can be synthesized into other fuels. Korberg *et al* [28] and Hannula [29] are recommended for more information on gasification and anaerobic digestion, respectively.

In both gasification into syngas and anaerobic digestion, biofuels are produced through a reaction between hydrogen and carbon (CO or CO_2). The produced fuels do not utilize all the carbon content in the biomass, with the excess carbon generally being released as biogenic CO_2. To utilize this excess biogenic carbon, it is possible to insert additional hydrogen into the production process (e.g. to the syngas or to the biogas, see figure 2) which will generate additional fuel without the need for carbon capture. We denote this special case of a hybrid between biofuels and e-fuels as bio-e-fuels, see figure 3.

Bio-e-fuel production costs include those for gasification/anaerobic digestion, biomass feedstock/biogas substrate, electrolyzer, electricity, fuel synthesis and eventual liquefaction. Costs are spread over the entire volume of fuel produced. In the literature, gasifier CAPEX is in the range of 1100–1700 €$_{2019}$ $kW_{syngas}{}^{-1}$ for the near-term [17, 29] and 350–1300 €$_{2019}$ $kW_{syngas}{}^{-1}$ for the long-term [17, 27, 28, 59] while anaerobic digestion plant costs are 200–235 € $kWh_{biogas}{}^{-1}$ [17] in the near-term and 160–205 € $kWh_{biogas}{}^{-1}$ in the long-term [17, 28] depending on the type of biomass used, with lower costs for manure-based feedstocks and higher costs for straw or industrial waste feedstocks. We assume CAPEX for gasification (including gas cleaning) of 1250 and 1150 € $MW_{dry\ biomass}{}^{-1}$ as well as CAPEX for biogas plants of 1900 and 1650 € $MW_{biogas}{}^{-1}$ for near-term and long-term, respectively. The costs for biomass feedstock are assumed to be 7 and 1.2 € GJ^{-1} for solid biomass and biogas substrate, respectively, for both near- and long-term. Conversion efficiencies are assumed 77% in near-term and 83% in long term for the gasifier. Data for our base case calculations are summarized in table 7.

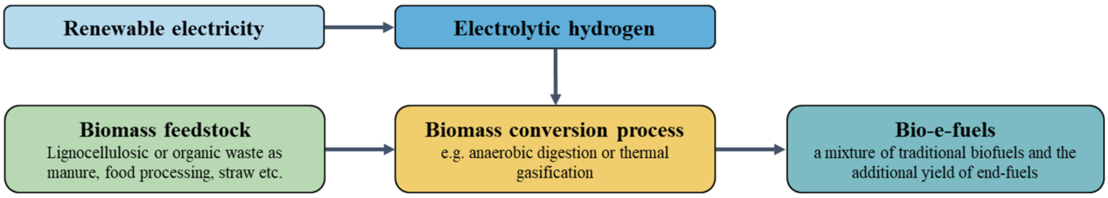


Figure 3. Bio-e-fuels are generated by adding electrolytic hydrogen to a biomass-based conversion process (such as anaerobic digestion or biomass gasification) to increase the production yields by utilizing the excess CO_2 or CO generated in the biomass conversion process. This will generate additional fuel without the need for carbon capture. Production cost for bio-e-fuels is built up by summing costs for electricity, biomass feedstock, and annuitized CAPEX for electrolyzer and the gasifier or anaerobic digester. Costs are spread over the entire volume of fuel produced.

Table 4. Hydrogen storage costs (€$_{2019}$ kWh^{-1}) in the near- (approx. 5–10 years) and long-term (approx. 20–30 years).

	Near-term	References	Long-term	References
Cavern storage	2–3	[17]	0.8–1.5	[17, 25, 62]
Steel tank, including compressors, installation and manhours	45–57	[17]	21–27	[17]
Steel tank, without compressors or manhours			7.6	[28]
Steel tank, other	16	[63]	20	[27]

Table 5. Cost of liquefaction prior to use in transport sector (€$_{2019}$ kWh^{-1}) for near- (approx. 5–10 years) and long-term (approx. 20–30 years) horizons.

Liquefaction[a]	Near-term (€$_{2019}$ kWh^{-1})	Long-term (€$_{2019}$ kWh^{-1})	Electricity consumption (kWh$_{el}$ kWh$_{fuel}$$^{-1}$)	References
Methane	0.37 (0.30–0.45)	0.31 (0.28–0.35)	0.06–0.11	[14, 23]
Hydrogen	0.30 (0.21–0.44)	0.17	0.28	[14]

[a] The OPEX are estimated as 8–12 € kW^{-1} for methane liquefaction and 25 € kW^{-1} for hydrogen liquefaction.

3.5. Hydrogen storage

A challenge for renewable e-fuel production is the desire for continuous operation of the synthesis process while using the available low-cost renewable electricity which is typically from variable, intermittent sources. Depending on the operating profile of the e-fuel production plant, a hydrogen storage may be needed. Hydrogen storage can be in underground caverns or in steel tanks, with the latter potentially more suitable for e-fuel production due to its versatility and widespread availability, but at a higher cost. Table 4 lists hydrogen storage costs identified in the literature review. In our base case calculations we assume that fuels will be produced without hydrogen storage (figures 4 and 5) whereas we in the sensitivity analyses assume a mix of both cavern and steel tank storage, see section 4.3.

3.6. Other costs and components

Depending on the type of e-fuel, additional fuel processing may be needed after fuel synthesis. For use in road transportation vehicles, gaseous fuels (methane and hydrogen) require compression or liquefaction for improved volumetric density and storage. Liquefied methane (LNG) is already used in the transport sector. The independent expert in assurance and risk management, DNV, reports that, in 2019, there were 175 marine vessels operating on LNG globally and over 200 on order for 2020–2021 [64]. LNG is also used in heavy-duty vehicles [65] and is a possible fuel for aircraft [66]. Liquefied hydrogen has been suggested for heavy road vehicles [67], shipping [68], and aviation [66]. DME and ammonia are also liquefiable but require only a modest temperature and pressure change for liquefaction. Table 5 summarizes the costs of liquefaction and compression in the surveyed literature.

The production of e-fuels requires purified water, for which Brynolf *et al* [6] suggest a cost of 1 € m^{-3}, while Albrecht and Nguyen [25] suggest 2.05 € m^{-3}. Further details on water requirements are given in section 5.2.

3.7. Potential by-product revenues

Production of e-fuels generates by-products that could bring revenue streams, potentially leading to improved business models for the fuel producers. The primary by-products are excess heat from electrolysis and fuel synthesis and O_2 from electrolysis, but also fuel gases and naphtha could be by-products from the

Table 6. Potential revenues from e-fuel by-products based on current market prices found in the literature.

By-products	Current market price	Reference	Notes
Low temperature district heat	30–40 € $\mathrm{MWh_{heat}}^{-1}$	[25, 29]	Sorknaes *et al* [26] find 8–13 € MWh^{-1} as a modelling result, based on the replacement ability with other heat sources.
High temperature industrial process heat	25–34 € $\mathrm{MWh_{heat}}^{-1}$	[13, 50]	Low and high pressure steam.
Oxygen	23.7–87 € t^{-1}	[13, 25, 42, 50, 70]	
Fuel gas	36 € MWh^{-1}	[29]	A by-product of methanol to gasoline process.
LPG equivalent	43 € MWh^{-1}	[29]	A by-product of methanol to gasoline process.
Naphtha	30.6 € MWh^{-1}	[32]	A by-product of FT synthesis.

synthesis processes. The production of N_2 from air separation generates by-products such as O_2, argon, and other noble gases that can help the economics of e-ammonia production. Different electrolysis types generate different amount of excess heat at various temperatures that can be adjusted to fit potential district heating temperature levels. However, the waste heat can also be used within the process to maximize the synergies and efficiency of e-fuel production if SOEL is used [61]. It may also be possible to gain revenues from the ancillary services by the participation of electrolysis units in the frequency regulation and load balancing required for reliable operation of the electric grid [69], but this may also imply reduced operational hours and predictability. Table 6 presents an overview of potential revenues from such by-products. In this study, revenues are not included in the harmonized fuel production costs but as an illustration of the effect a revenue can have, the potential cost reduction of being able to sell high-purity oxygen is shown in figure 4.

4. Total conversion efficiencies and production costs

A summary of the literature regarding the total conversion efficiencies from electricity to e-fuels, or bio-e-fuels, is presented in section 4.1. Since insights from Brynolf *et al* [6] reveal that there is a wide diversity of assumptions and approaches among different studies, resulting in a broad range of e-fuel production cost estimates, we have chosen to not summarize all production costs found in the literature review. Instead, we utilize the near-term and long-term component costs, identified in section 3, to calculate production costs in a transparent and harmonized way (section 4.2). How the production costs are affected by changing assumptions on critical factors as electrolyzer CAPEX and the price of electricity, which depends on hours per year the facility is in operation, i.e. the CF, are analyzed in sensitivity analyses (section 4.3).

4.1. Total efficiencies for e-fuel production plants

In some of the reviewed papers the authors present the overall plant efficiency rather than process-level efficiency. This overall efficiency refers to the total outputs divided by the total inputs. The inputs may include hydrogen, or the electricity used to power electrolysis, while the output refers to the energy content in the final fuel. Overall, the system efficiencies vary significantly among the reviewed papers, influenced by the choice of technologies and the efficiency assumed by the authors for the key component: electrolysis. The overall efficiency will also depend on the state of the energy carrier or fuel especially for fuels that are gaseous at standard temperature and pressure as additional energy is needed for compression and liquefaction.

For FT e-fuels, Schmidt *et al* [58] suggest that with existing technology, overall efficiencies can reach 39%–47%, which is in line with the estimate by Michailos *et al* [70], but in the future these may increase to 53% [16]. The Danish Energy Agency [17] reports that the overall efficiency of FT plants today is 37%, which could increase to 55% by 2050, while Helgeson and Peter [14] estimate a maximum efficiency of 51% by 2050. Albrecht *et al* [50] and Albrecht & Nguyen [25] find future electricity-to-fuel efficiencies of 49%–51% for both e-fuel and bio-e-fuel plants. Hillestad *et al* [32] presents higher system efficiencies (65%) in a bio-e-fuel plant based on FT synthesis, which are similar to the benchmark values presented by Blanco *et al* [22] in combination with high-temperature electrolysis, at 63%–64%.

For bio-e-methanol, Hannula [29] suggests a current potential of 57%–58% efficiency starting from biomass and electricity. Utilizing SOEL, Zhang and Desideri [46] find efficiencies of 71%–72% while Zhang *et al* [47] report 68%–69%. The Danish Energy Agency [17] estimates overall efficiencies of 58% in 2020 and 65% in 2050.

For bio-e-methane, Hannula [29] estimate that production through the biomass gasification and hydrogenation pathway could reach a system efficiency of 58%–59%, while Helgeson and Peter [14] find that bio-e-methane produced through methanation coupled with electrolysis may reach 54% efficiency by 2050. Koysoumpa *et al* [33] estimated that e-methane plants can have system efficiencies between 58% and 63%. McKenna *et al* [71] estimates a maximum efficiency of 68%. Korberg *et al* [28] find that bio-e-methane generated by methanation, adding hydrogen to biogas production facilities to reduce the CO_2 yield, can achieve 82% efficiency.

4.2. Calculated production costs utilizing reviewed component costs

To compare the production costs of different e-fuel options in a harmonized way, the baseline near-term and long-term costs of key components, presented in section 3, are used, along with other cost assumptions, presented in table 7. Revenues from by-products will have a benefit on the cost aspects. In this study potential revenues from by-products are not included when calculating the production cost. However, to illustrate the potential impact of such revenues, figure 4 includes an assumption that oxygen by-product can be sold for 50 €/tO_2. The main reason for not including potential by-product revenues in the calculation of production cost is that the future market for by-products, e.g. oxygen and heat, is very uncertain particularly with large-scale e-fuel production.

The costs for fuel infrastructure are also omitted in this cost analysis. Infrastructure costs are presented and discussed in the sister paper 'Review of electrofuel feasibility: Prospects for road, ocean, and air transport' [10].

There are of course a range of fuel options we have excluded in this cost analysis. The review of papers considering cost and environmental impacts did not turn out including results for exactly the same fuels and therefore some fuels included in the environmental section is not included in the cost assessment. The fuel option e-OME (electro-oxymethylene dimethyl ether) is an example of this. However, in Kramer *et al* it is shown that e-OME is having the highest production cost among the assessed e-fuel options (140–370 € MWh^{-1}), which is slightly higher than FT-diesel (120–310 € MWh^{-1}) [8].

Figure 4 shows the harmonized production costs for e-methanol and liquid hydrogen built up by the different component costs using our base values (long-term) from the literature review, see table 7. The main reason for including liquid hydrogen is that electrolytic hydrogen is utilized for all e-fuel options (grey and light blue parts of the bars) but costs are, in figure 4, added for liquefaction when used as a fuel itself.

The cost for electrolyzer and electricity are dominant factors in both the case of e-methanol and electrolytic hydrogen whereas the costs for methanol synthesis and carbon capture are minor and the cost for water negligible. Approximately 1.2 energy units of hydrogen are required to produce 1 unit of e-methanol which increases demand for electricity in the e-methanol case. For the hydrogen case, the liquefaction process needs electricity, around 0.28 $kWh_{electricity}/kWh_{hydrogen}$. The two different reasons for increased electricity demand are in the same size of order leading to a total cost for electricity of 83.1 and 83.7 for e-methanol and liquefied hydrogen, respectively. The cost for electricity constitutes 70% of the total production cost for e-methanol and 80% of the total production cost for liquefied hydrogen. The beige part of the bars, below the black line, in figure 4, illustrates potential revenue from selling excess oxygen. For both the e-methanol case and the hydrogen case, the revenue is 5% of the total production cost.

Different fuels involve different degrees of complexity to distribute, for example the cost for a hydrogen fueling infrastructure is greater than for liquid fuels (not requiring cooling or compressing). The infrastructure cost for all fuel options, further, depends on different factors such as distribution distance and type of end-user. The fuel infrastructure costs are presented and discussed in the sister paper 'Review of electrofuel feasibility: Prospects for road, ocean, and air transport' [10].

In figure 5, production costs for a range of bio-e-fuels, e-fuels and electrolytic hydrogen are presented and compared with a range of 0.2–0.7 € $liter^{-1}$ for the production cost of fossil gasoline/diesel, corresponding to an oil price range of \$30–\$100/barrel [72].

Near-term production costs (figure 5) are in the range of approximately 110–230 € MWh^{-1}, with the lowest cost for liquefied bio-e-methane from biogas (similar to bio-e-methanol, bio-e-DME, and liquefied bio-e-methane from syngas), and highest for e-kerosene through the methanol-to-jet process. All analyzed fuel options have the potential to have a production cost between 90 and 160 € MWh^{-1} in the long-term. From figure 5 it can also be seen that bio-e-fuels have lower production costs than their e-fuel versions. Although hydrogen is used to produce all types of e-fuels and bio-e-fuels it can be noted that it is not obvious that the costs for hydrogen are lower than the e-fuels and bio-e-fuels when including costs for liquefaction or compression. The reason that bio-e-methane, co-produced with anaerobic digested biogas, is marginally cheaper than compressed hydrogen is because production costs are spread over the entire volume of fuel produced, i.e. for the bio-e-methane case, the inclusion of the energy in biogas. That is, although

Table 7. Assumptions used to calculate harmonized production costs of different e-fuels and bio-e-fuels in the near- (approx. 5–10 years) and long-term (approx. 20–30 years). Data origin from the ranges found in the literature review, presented and discussed in section 3, tables 1–6. Costs represent €2019.

Electrolysis	Unit	Near-term	Long-term
CAPEX electrolyzer (near-term: an average of AEL and PEMEL, long-term: an average of AEL, PEMEL and SOEL)	€ kW_{el}^{-1}	900	500
OPEX (including replacement of the stack)	Share of CAPEX	0.04	0.04
Conversion efficiency	$H_{2,LHV}$/electricity input	65%	74%
Demand for water (assuming 2X stoichiometric demand)	Ton MWh_{H2}^{-1}	0.54	0.54
Cost for deionized water	€/ton_{water}	1	1
Bio-e-fuel processes[a]	Unit	Near-term	Long-term
CAPEX gasification (including gas cleaning)	€ $MW_{dry\ biomass}^{-1}$	1250	1150
Conversion efficiency	$GJ_{Syngas}/GJ_{Input\ biomass}$	77%	83%
Biomass feedstock	€ $GJ_{biomass}^{-1}$	7	7
CAPEX biogas plant (anaerobic digestion)	€ MW_{biogas}^{-1}	1900	1650
Biogas substrate feedstock	€ $GJ_{biogas\ substrate}^{-1}$	1.2	1.2
Fuel synthesis	Unit	Near-term	Long-term
CAPEX synthesis reactor and conversion efficiency in parentheses			
Hydrogen to methane	€ MW_{CH4}^{-1}	450 (83%)	250 (83%)
Hydrogen to methanol	€ MW_{MeOH}^{-1}	700 (84%)	300 (84%)
Hydrogen to DME	€ MW_{DME}^{-1}	700 (81%)	300 (81%)
Methanol to gasoline	€ $MW_{Gasoline}^{-1}$	600 (88%)	300 (88%)
Methanol to jet fuel[b]	€ $MW_{Jet\text{-}fuel}^{-1}$	1000 (74%)	500 (74%)
Hydrogen to Fischer–Tropsch liquids[c]	€ $MW_{fuel\ liquids}^{-1}$	1600 (66%)	750 (66%)
Ammonia synthesis (including ASU)	€ MW_{NH3}^{-1}	1400 (79%)	850 (79%)
OPEX	Share of CAPEX	0.04	0.04
Other[d]	Unit	Near-term	Long-term
Cost for CO_2 capture (point source)[e]	€ ton_{CO2}^{-1}	50	25
Electricity price[f]	€ MWh_{el}^{-1}	50	50
Hydrogen liquefaction	€ kW_{fuel}^{-1}	0.30	0.17
Other investments (e.g. costs for installation and unexpected costs)	Factor multiplied to CAPEX	1.5	1.5
Capacity factor for electrolyzers (in base case assumed to operate without H_2 storage)	Share of max capacity	0.70	0.70
Interest rate		0.05	0.05
System life time	Years	25	25

[a] Bio-e-fuels production costs are built up by costs for gasification/anaerobic digestion, biomass feedstock/biogas substrate, electrolyzer, electricity, fuel synthesis and eventual liquefaction.

[b] Although one can expect the two processes MTG and MTJ to be similar, there is currently very little information in the literature. The MTJ process is still in test and demonstration scale and therefore near-term (as well as long-term) costs, and efficiencies, are very uncertain.

[c] We assume a production efficiency from H_2 to FT liquids of 73%, and that 90% of this output can be a commercialized fuel after upgrading (of any type). For simplicity reasons we assume all commercial FT liquids being diesel and jet fuels (and thereby disregard from that a certain share of the commercial FT products are gasoline, feedstock for chemicals and other products).

[d] We do not include cost for carbon transport or storage, essentially assuming that carbon is captured close to the e-fuel production site and the rate of capture exactly matches the demand. This is a simplifying assumption that deserves further scrutiny in future assessments.

[e] Cost for CO_2 capture is very uncertain, but from figure 4 it can be seen that the contribution from this cost factor to the production cost is relatively small and therefore the uncertainties are less critical.

[f] Future electricity prices are uncertain and depend on different factors such as the future demand for electricity, the share of variable renewable power sources, potential phase out of nuclear power, the integration with other energy sectors. From running the eNODE model under different scenarios (see section 4.3) we find that all studied regions show an average electricity price of approximately 50 € MWh^{-1} by both 2030 and 2050, which we have assumed in our base case calculations. The effect of different electricity prices is explored in our sensitivity analyses.

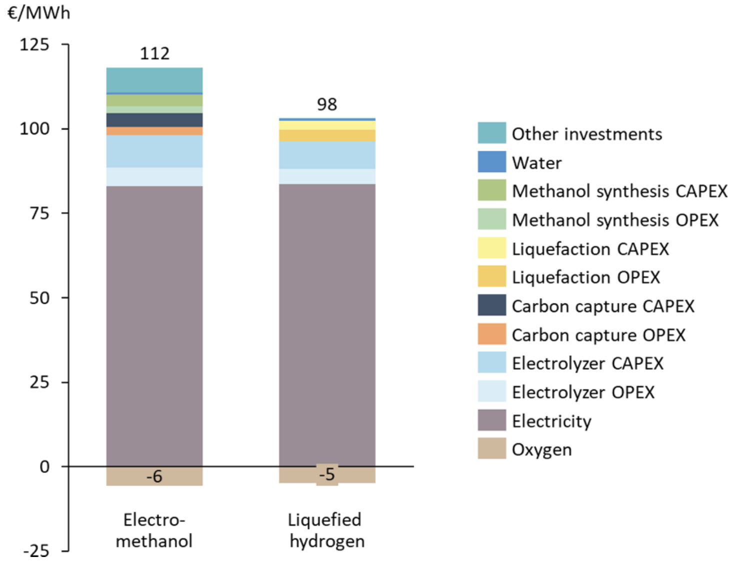


Figure 4. Production costs for e-methanol and liquefied electrolytic hydrogen showing the different component costs, using base values (long-term) from the literature review. All data used in the calculations are presented in table 7. In this study, revenues are not included in the harmonized fuel production costs but as an illustration of the effect a revenue can have, the potential cost reduction of being able to sell high-purity oxygen at 50 €/tO_2 is shown. Acronyms used: CAPEX capital expenditures, OPEX operational expenditures.

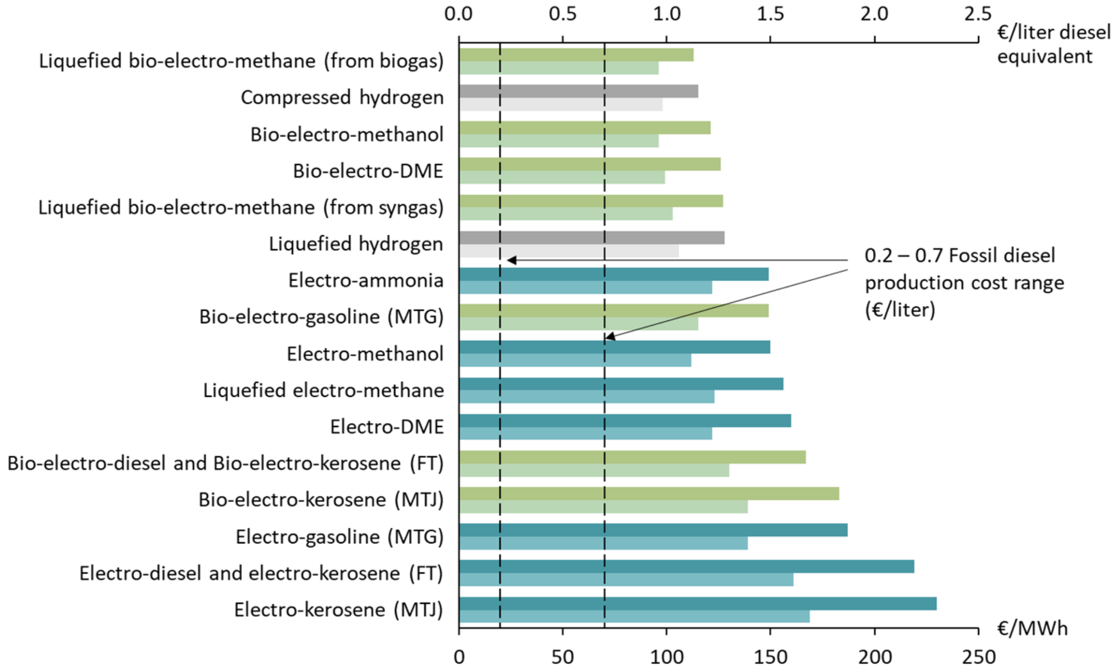


Figure 5. Production costs for electrolytic hydrogen, bio-e-fuels, and e-fuels using base values from the literature review (see table 7). Costs include factors presented in figure 4 except for the potential revenues. The near-term costs, approx. 5–10 years in future, are the dark-colored bars and long-term costs, approx. 20–30 years in future, are the light-colored bars. The black dotted lines show production costs of fossil gasoline/diesel/kerosene for an oil price of $30–$100/barrel [69]. Acronyms used: DME, dimethyl ether; MTG, methanol-to-gasoline; MTJ, methanol-to-jet; FT, Fischer–Tropsch.

bio-e-methane requires investment in synthesis process and carbon capture (not needed for the liquefied hydrogen case), the cost for feedstock is lower than the price of electricity, and much more electricity is needed for the 'stand-alone' hydrogen production, than for producing the lower volumes of electrolytic hydrogen needed for the bio-e-methane production.

All e-fuels and bio-e-fuels have higher production costs than fossil gasoline/diesel/kerosene, assuming an oil price of $30–$100/barrel [72].

4.3. Sensitivity analyses

The two largest cost factors that impact e-fuel production costs are the electricity price and the electrolyzer CAPEX, as presented in figure 4 and concluded by e.g. [6, 8, 9]. Both these cost factors are uncertain, and it is, therefore, of interest to explore how varying these would impact the total cost. We have used the long-term results for liquefied electrolytic hydrogen and e-methanol to exemplify the impacts on the total production costs. All e-fuels and bio-e-fuels are of course impacted by the cost of producing electrolytic hydrogen, i.e. the electricity price and the cost for electrolyzer.

Electricity prices vary with time and between regions, depending on the supply and demand of electricity and transmission capacity, see e.g. Europe's power market Nordpool spot [73]. If the production of hydrogen takes place with a constant production flow over time, an average yearly electricity price allows an estimate of the average e-fuel production cost for a year. The electrolyzers are then running close to all hours of the year and only stop for maintenance. However, one can also choose to run the electrolyzers at certain hours of the year, e.g. choosing hours with low electricity price. This would, however, require an over-investment in electrolyzer capacity and investments in hydrogen storage to meet the demand for hydrogen. An average electricity price over the whole year is then no longer relevant to use for the calculation of e-fuel production cost, since such a price would be too high. Therefore, when assuming an electricity price for the estimations of production cost, it is important to understand at what CF the facility is operated (i.e. the ratio between the actual output of unit versus what it is capable of producing at maximum output) and if there is a need for hydrogen storage to enable stable fuel production while only intermittently using electricity for electrolysis.

Furthermore, the electricity prices in the future may vary more than today, both in the near-term, but especially in the long-term perspective, as more fluctuating renewable electricity sources, such as wind and solar power, provide a larger share of electricity generation. We will most likely have more hours with lower, and more hours with higher, electricity prices than today. Therefore, using current yearly average electricity prices to estimate future production costs is not an appropriate assumption.

In these sensitivity analyses, we have instead used output in terms of electricity prices from a European energy systems model called eNODE that generates future electricity price-scenarios for different regions. eNODE is a cost minimization model designed to analyze the transformation of the European electricity system when reaching climate targets. It includes investment decisions in new electricity generation capacities to meet an exogenously given electricity demand under the constraints of European climate targets. The eNODE model can also invest in transmission and storage technologies to balance the integration of more variable renewable electricity (VRE). The model has an hourly time resolution and a geographical resolution where Europe is divided into 22 regions (see for example [74] for a more detailed description of the model). In the model run used for this study, we have included a hydrogen demand of 1000 TWh per year in the industry and transport sectors in Europe (referred to as the Reference (Ref) scenario). The acceptance for VRE and the total electricity demand will to a large extent impact the shape of the electricity price profile, therefore we have also run the model with a scenario assuming low acceptance for building new VRE and a hydrogen demand of 2500 TWh per year in Europe (referred to as the Low VRE scenario). The eNODE model includes two types of hydrogen storage (a) a large scale line rock cavern based on a storage CAPEX of 0.011 M€ MWh^{-1}, 100% efficiency, no OPEX and a system life time of 40 years, and (b) a small scale steel storage based on a storage CAPEX of 0.022 M€ MWh^{-1}, 90% efficiency, 0.004 M€ MWh^{-1} in OPEX, and a system life time of 40 years [62].

In the sensitivity analysis we calculate the total cost of producing e-fuels using modelled electricity prices for 2050, when reaching zero CO_2 emissions from the European electricity system, for four selected regions in Europe that have different electricity system configurations. The selected regions are Hungary-Croatia-Slovenia, Ireland, western Spain, and southern Sweden. These regions have different conditions for wind, solar and hydro power which affect electricity prices as seen in figure 6. Southern Sweden (electricity price area SE3 and SE4) has access to rather large amounts of reservoir hydro power from northern Sweden and good wind conditions; Ireland has good wind conditions; western Spain has favorable solar conditions; and Hungary-Croatia-Slovenia has relatively poor conditions for wind, hydro, and solar generation. The number of hours with low electricity prices might result in new loads starting to use electricity not included in the modelling. However, to be able to utilize hours with very low electricity prices, for example to produce hydrogen and fulfilling a relatively constant hydrogen demand throughout the year, the investment costs for electrolyzer overcapacity additional hydrogen storage need to be taken into account.

For each CF, we have optimized the size of the hydrogen storage and which hours to operate to reach a total hydrogen and e-methanol cost that is as low as possible for each CF. The hydrogen storage is sized by the model, for each CF run, to balance hydrogen demand and production, generating a cost for hydrogen storage (€ $\mathrm{MWh_{H2}}^{-1}$) that is unique for each country and each CF.

Figure 6(a) shows the modelled electricity prices per hour for year 2050 for the two scenarios (Ref and Low VRE) and figure 6(b) shows the same electricity prices sorted from lowest to highest hours. To find

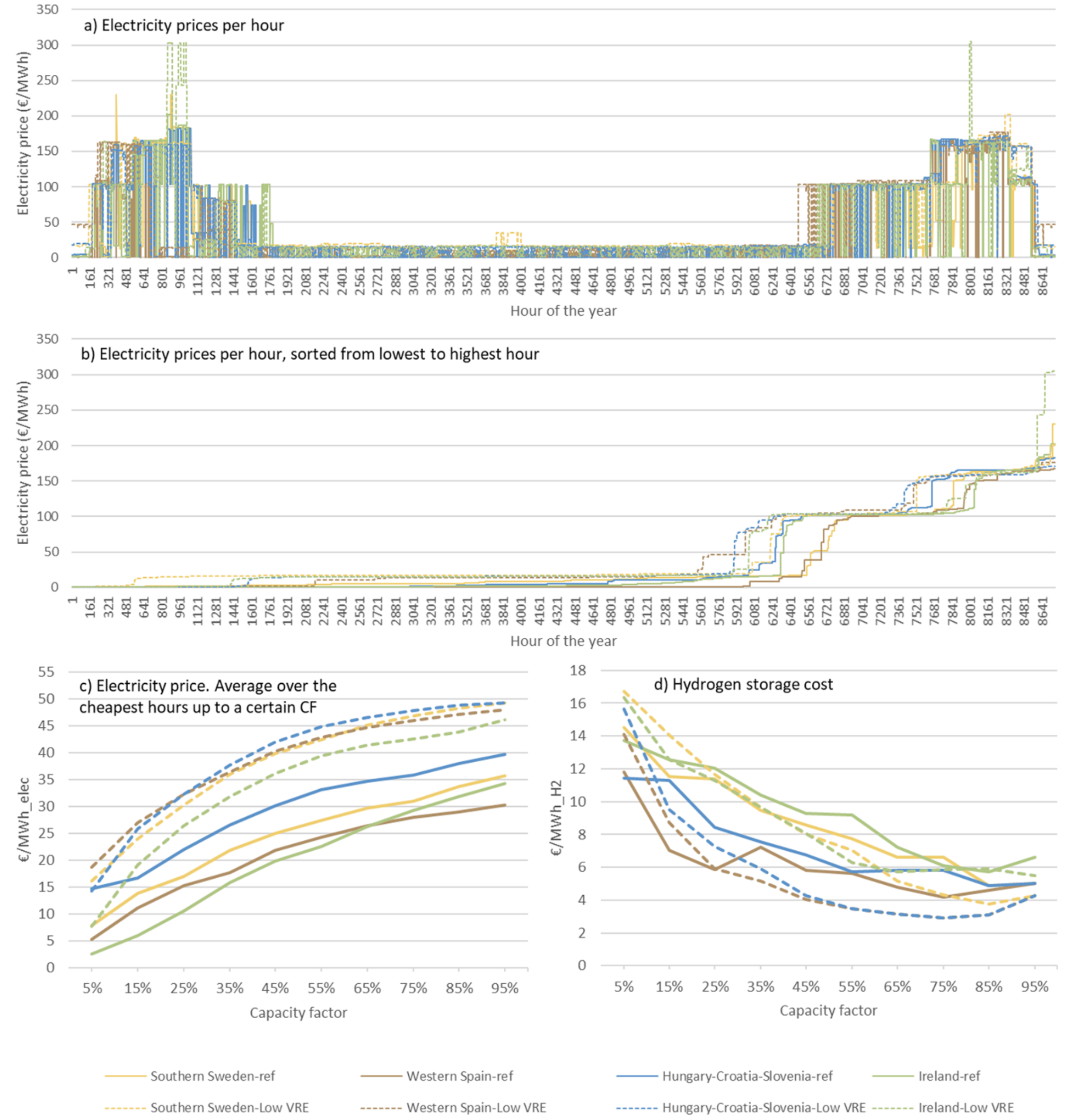


Figure 6. Modelled electricity prices, and corresponding hydrogen storage costs for different capacity factors (CFs), for 2050 for two scenarios (Ref and Low VRE) for four regions in Europe, where (a) shows the electricity price per hour in chronological order, (b) the same electricity prices sorted from lowest to highest hours, (c) average prices over the cheapest hours up to a certain CF, and (d) the generated hydrogen storage costs per CF, using the European energy systems model eNODE, see text for assumptions.

which average electricity price, and hydrogen storage cost, to match with each CF, the model has been systematically run constrained to only operate the electrolyzers the amount of hours corresponding to CFs 5%, 15%, 25%, up to CF95%. The optimal average electricity price for each CF, for each European region, are presented in figure 6(c) with corresponding hydrogen storage costs presented in figure 6(d).

As an example, utilizing the results in figure 6(c), for southern Sweden, we find that operating the electrolyzers at CF 55% and 85% can be done at average electricity prices of 27 € MWh^{-1} (Ref), and 43 € MWh^{-1} (Low VRE) as well as 34 € MWh^{-1} (Ref), and 48 € MWh^{-1} (Low VRE), respectively. Corresponding hydrogen storage costs are then 7.8 € $\mathrm{MWh_{H2}}^{-1}$ (Ref, CF55%) and 7.0 € $\mathrm{MWh_{H2}}^{-1}$ (Low VRE, CF55%) as well as 4.9 € $\mathrm{MWh_{H2}}^{-1}$ (Ref, CF 85%), and 3.8 € $\mathrm{MWh_{H2}}^{-1}$ (Low VRE, CF 85%), see figure 6(d). There is a large difference in electricity prices between summertime and wintertime in all regions, as seen in figure 6(a), with close to zero electricity prices during summertime and higher prices, with some hours over 150 € MWh^{-1}, during wintertime.

In addition, to the electricity price, producers of e-fuels will likely need to pay a grid fee. In Sweden, the grid fee varies depending on location of the production unit and the price scheme from the grid utility company. It is common to pay both a fixed amount for the maximum power used by the production unit and a fee per energy unit [75]. For example, an e-fuel production unit placed in Sweden, using maximum 20 MW of power and 140 GWh year^{-1} (i.e. running 80% of the year at maximum capacity) might pay a grid fee of about 8.4 €$_{2020}$ MWh^{-1}. However, this number will vary between countries, within countries, with production unit sizes, number of hours that the unit is running per year, maximum power used, etc. In a future electricity system, it might even be the case that a production facility can (instead of paying a grid fee) get paid by the grid company for helping to balance the grid by running the unit when there is a surplus of electricity and for not running when there is a shortage of electricity or having grid fee exemptions in these hours. Therefore, it will be difficult to estimate grid fees in a future scenario, and we have chosen not to include a grid fee in the calculation of the electricity price, presented in figures 6 and 7.

In figure 7, we have used the electricity prices in figure 6(c), and hydrogen storage costs in figure 6(d), to estimate the production cost of liquefied electrolytic hydrogen and e-methanol for CFs 5%, 15%, 25% up to 95%. Figure 7 also shows the results assuming different electrolyzer CAPEX presenting the total production cost in each cell of the matrices, for the cases Ref and Low VRE for the regions Hungary-Croatia-Slovenia, Ireland, western Spain and southern Sweden.

Results presented in figure 7 show production costs of liquefied electrolytic hydrogen, for case Ref, in 2050, in the ranges of 80–87 € MWh^{-1}, 66–72 € MWh^{-1}, 58–64 € MWh^{-1}, 66–72 € MWh^{-1}, for Hungary-Croatia-Slovenia, Ireland, western Spain, and southern Sweden, respectively, assuming electrolyzer CAPEX of 300–450 € kW^{-1} combined with CFs of 45%–65% (figures 7(a), (e), (i) and (m)). Results for the Low VRE case, for the same combination of electrolyzer CAPEX and CFs, are slightly higher as 97–104 € MWh^{-1}, 91–98 € MWh^{-1}, 87–93 € MWh^{-1}, and 90–96 € MWh^{-1} for Hungary-Croatia-Slovenia, Ireland, western Spain, and southern Sweden, respectively (figures 7(c), (g), (k) and (o)). For the same combination of electrolyzer CAPEX and CFs, the production cost ranges for e-methanol in Hungary-Croatia-Slovenia, Ireland, western Spain, and southern Sweden are 91–100 € MWh^{-1}, 78–86 € MWh^{-1}, 76–86 € MWh^{-1}, and 84–94 € MWh^{-1}, respectively for the Ref case (figures 7(b), (f), (j) and (n)), and 107–117 € MWh^{-1}, 102–112 € MWh^{-1}, 104–114 € MWh^{-1}, and 107–118 € MWh^{-1}, in the Low VRE case, (figures 7(d), (h), (l) and (p)).

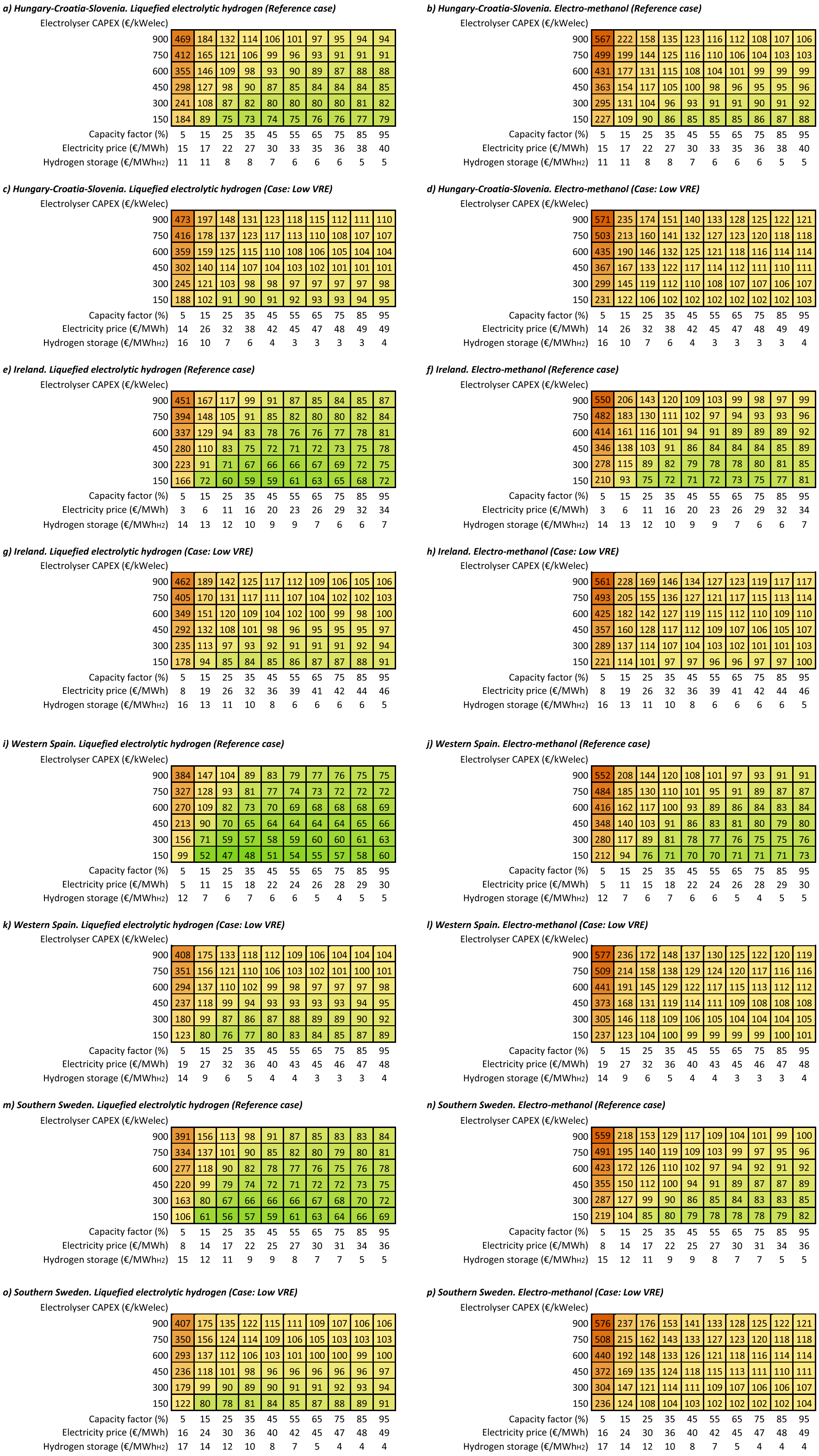
The production costs are generally much lower, for all regions, in the Ref case compared to the Low VRE case, which first and foremost is because of when assuming a limited acceptance for building solar and wind power as in the Low VRE case, the electricity system needs to invest in more expensive generation technologies which gives slightly higher average electricity prices. The two regions Ireland and western Spain generally show lower production costs compared to the regions Hungary-Croatia-Slovenia and southern Sweden. This regionally differences depend on that Ireland and western Spain are expected to have more access to cheap VRE systems, compared to the two other regions.

For each of the 16 charts, the lowest production costs can generally be found in the interval of CFs 35%–85%. This shows that even if low electricity prices can be utilized when running the production at low CF as e.g. 35% of full capacity, the cost for storing hydrogen will make the total production cost about the same as running it on 85% of full capacity. For CFs lower than 35% the CAPEX for electrolyzers and hydrogen storage dominate and increases the cost per MWh of fuels produced (i.e. when the fixed costs are distributed over a low amount of produced fuel units, the production cost per unit increases). For CFs higher than 85% the cost for electricity (utilizing higher average electricity prices) takes a large share of the production cost and slightly increases the cost per MWh of fuels.

5. Environmental impacts of utilization of e-fuels in the transport sector

Costs vary depending on technology as do material requirements, energy demand, and emissions to the environment. These aspects in return impact the results of environmental assessments of for example different e-fuel production pathways. Different materials have different environmental impacts, such as different emission levels of GHG emissions, and so called ‘up-stream emissions’ from electricity used or metal mining operations. Different types of environmental assessments focus on different issues. Section 5 summarizes and reviews the current knowledge of environmental impacts from e-fuels and presents the main influencing factors to the results. In total 41 of the reviewed publications include relevant information on environmental impacts and are assessed in this section of the review, out of which 17 are life cycle assessment studies or reviews of life cycle assessment studies [19, 52, 76–86]. The first sub-sections (sections 5.1–5.5) focus on carbon-based e-fuels, as they are the primary investigated production pathways, and in section 5.6 environmental impacts of e-ammonia are outlined.

The system boundary and included technologies can vary between assessments because they investigate different research questions and systems, or to simplify the assessment model. The scope of an environmental assessment, therefore, becomes essential to interpret the results. Figure 8 illustrates the life cycle of e-fuel production, and the dotted lines show system boundaries in the reviewed literature. Several of



a) Hungary-Croatia-Slovenia. Liquefied electrolytic hydrogen (Reference case)

Electrolyser CAPEX (€/kWelec)										
900	469	184	132	114	106	101	97	95	94	94
750	412	165	121	106	99	96	93	91	91	91
600	355	146	109	98	93	90	89	87	88	88
450	298	127	98	90	87	85	84	84	84	85
300	241	108	87	82	80	80	80	80	81	82
150	184	89	75	73	74	75	76	76	77	79
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	15	17	22	27	30	33	35	36	38	40
Hydrogen storage (€/MWh$_{H_2}$)	11	11	8	8	7	6	6	6	5	5

b) Hungary-Croatia-Slovenia. Electro-methanol (Reference case)

Electrolyser CAPEX (€/kWelec)										
900	567	222	158	135	123	116	112	108	107	106
750	499	199	144	125	116	110	106	104	103	103
600	431	177	131	115	108	104	101	99	99	99
450	363	154	117	105	100	98	96	95	95	96
300	295	131	104	96	93	91	91	90	91	92
150	227	109	90	86	85	85	85	86	87	88
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	15	17	22	27	30	33	35	36	38	40
Hydrogen storage (€/MWh$_{H_2}$)	11	11	8	8	7	6	6	6	5	5

c) Hungary-Croatia-Slovenia. Liquefied electrolytic hydrogen (Case: Low VRE)

Electrolyser CAPEX (€/kWelec)										
900	473	197	148	131	123	118	115	112	111	110
750	416	178	137	123	117	113	110	108	107	107
600	359	159	125	115	110	108	106	105	104	104
450	302	140	114	107	104	103	102	101	101	101
300	245	121	103	98	98	97	97	97	97	98
150	188	102	91	90	91	92	93	93	94	95
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	14	26	32	38	42	45	47	48	49	49
Hydrogen storage (€/MWh$_{H_2}$)	16	10	7	6	4	3	3	3	3	4

d) Hungary-Croatia-Slovenia. Electro-methanol (Case: Low VRE)

Electrolyser CAPEX (€/kWelec)										
900	571	235	174	151	140	133	128	125	122	121
750	503	213	160	141	132	127	123	120	118	118
600	435	190	146	132	125	121	118	116	114	114
450	367	167	133	122	117	114	112	111	110	111
300	299	145	119	112	110	108	107	107	106	107
150	231	122	106	102	102	102	102	102	102	103
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	14	26	32	38	42	45	47	48	49	49
Hydrogen storage (€/MWh$_{H_2}$)	16	10	7	6	4	3	3	3	3	4

e) Ireland. Liquefied electrolytic hydrogen (Reference case)

Electrolyser CAPEX (€/kWelec)										
900	451	167	117	99	91	87	85	84	85	87
750	394	148	105	91	85	82	80	80	82	84
600	337	129	94	83	78	76	76	77	78	81
450	280	110	83	75	72	71	72	73	75	78
300	223	91	71	67	66	66	67	69	72	75
150	166	72	60	59	59	61	63	65	68	72
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	3	6	11	16	20	23	26	29	32	34
Hydrogen storage (€/MWh$_{H_2}$)	14	13	12	10	9	9	7	6	6	7

f) Ireland. Electro-methanol (Reference case)

Electrolyser CAPEX (€/kWelec)										
900	550	206	143	120	109	103	99	98	97	99
750	482	183	130	111	102	97	94	93	93	96
600	414	161	116	101	94	91	89	89	89	92
450	346	138	103	91	86	84	84	84	85	89
300	278	115	89	82	79	78	78	80	81	85
150	210	93	75	72	71	72	73	75	77	81
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	3	6	11	16	20	23	26	29	32	34
Hydrogen storage (€/MWh$_{H_2}$)	14	13	12	10	9	9	7	6	6	7

g) Ireland. Liquefied electrolytic hydrogen (Case: Low VRE)

Electrolyser CAPEX (€/kWelec)										
900	462	189	142	125	117	112	109	106	105	106
750	405	170	131	117	111	107	104	102	102	103
600	349	151	120	109	104	102	100	99	98	100
450	292	132	108	101	98	96	95	95	95	97
300	235	113	97	93	92	91	91	91	92	94
150	178	94	85	84	85	86	87	87	88	91
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	8	19	26	32	36	39	41	42	44	46
Hydrogen storage (€/MWh$_{H_2}$)	16	13	11	10	8	6	6	6	6	5

h) Ireland. Electro-methanol (Case: Low VRE)

Electrolyser CAPEX (€/kWelec)										
900	561	228	169	146	134	127	123	119	117	117
750	493	205	155	136	127	121	117	115	113	114
600	425	182	142	127	119	115	112	110	109	110
450	357	160	128	117	112	109	107	106	105	107
300	289	137	114	107	104	103	102	101	101	103
150	221	114	101	97	97	96	96	97	97	100
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	8	19	26	32	36	39	41	42	44	46
Hydrogen storage (€/MWh$_{H_2}$)	16	13	11	10	8	6	6	6	6	5

i) Western Spain. Liquefied electrolytic hydrogen (Reference case)

Electrolyser CAPEX (€/kWelec)										
900	384	147	104	89	83	79	77	76	75	75
750	327	128	93	81	77	74	73	72	72	72
600	270	109	82	73	70	69	68	68	68	69
450	213	90	70	65	64	64	64	64	65	66
300	156	71	59	57	58	59	60	60	61	63
150	99	52	47	48	51	54	55	57	58	60
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	5	11	15	18	22	24	26	28	29	30
Hydrogen storage (€/MWh$_{H_2}$)	12	7	6	7	6	6	5	4	5	5

j) Western Spain. Electro-methanol (Reference case)

Electrolyser CAPEX (€/kWelec)										
900	552	208	144	120	108	101	97	93	91	91
750	484	185	130	110	101	95	91	89	87	87
600	416	162	117	100	93	89	86	84	83	84
450	348	140	103	91	86	83	81	80	79	80
300	280	117	89	81	78	77	76	75	75	76
150	212	94	76	71	70	70	71	71	71	73
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	5	11	15	18	22	24	26	28	29	30
Hydrogen storage (€/MWh$_{H_2}$)	12	7	6	7	6	6	5	4	5	5

k) Western Spain. Liquefied electrolytic hydrogen (Case: Low VRE)

Electrolyser CAPEX (€/kWelec)										
900	408	175	133	118	112	109	106	104	104	104
750	351	156	121	110	106	103	102	101	100	101
600	294	137	110	102	99	98	97	97	97	98
450	237	118	99	94	93	93	93	93	94	95
300	180	99	87	86	87	88	89	89	90	92
150	123	80	76	77	80	83	84	85	87	89
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	19	27	32	36	40	43	45	46	47	48
Hydrogen storage (€/MWh$_{H_2}$)	14	9	6	5	4	4	3	3	3	4

l) Western Spain. Electro-methanol (Case: Low VRE)

Electrolyser CAPEX (€/kWelec)										
900	577	236	172	148	137	130	125	122	120	119
750	509	214	158	138	129	124	120	117	116	116
600	441	191	145	129	122	117	115	113	112	112
450	373	168	131	119	114	111	109	108	108	108
300	305	146	118	109	106	105	104	104	104	105
150	237	123	104	100	99	99	99	99	100	101
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	19	27	32	36	40	43	45	46	47	48
Hydrogen storage (€/MWh$_{H_2}$)	14	9	6	5	4	4	3	3	3	4

m) Southern Sweden. Liquefied electrolytic hydrogen (Reference case)

Electrolyser CAPEX (€/kWelec)										
900	391	156	113	98	91	87	85	83	83	84
750	334	137	101	90	85	82	80	79	80	81
600	277	118	90	82	78	77	76	75	76	78
450	220	99	79	74	72	71	72	72	73	75
300	163	80	67	66	66	66	67	68	70	72
150	106	61	56	57	59	61	63	64	66	69
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	8	14	17	22	25	27	30	31	34	36
Hydrogen storage (€/MWh$_{H_2}$)	15	12	11	9	9	8	7	7	5	5

n) Southern Sweden. Electro-methanol (Reference case)

Electrolyser CAPEX (€/kWelec)										
900	559	218	153	129	117	109	104	101	99	100
750	491	195	140	119	109	103	99	97	95	96
600	423	172	126	110	102	97	94	92	91	92
450	355	150	112	100	94	91	89	87	87	89
300	287	127	99	90	86	85	84	83	83	85
150	219	104	85	80	79	78	78	78	79	82
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	8	14	17	22	25	27	30	31	34	36
Hydrogen storage (€/MWh$_{H_2}$)	15	12	11	9	9	8	7	7	5	5

o) Southern Sweden. Liquefied electrolytic hydrogen (Case: Low VRE)

Electrolyser CAPEX (€/kWelec)										
900	407	175	135	122	115	111	109	107	106	106
750	350	156	124	114	109	106	105	103	103	103
600	293	137	112	106	103	101	100	100	99	100
450	236	118	101	98	96	96	96	96	96	97
300	179	99	90	89	90	91	91	92	93	94
150	122	80	78	81	84	85	87	88	89	91
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	16	24	30	36	40	42	45	47	48	49
Hydrogen storage (€/MWh$_{H_2}$)	17	14	12	10	8	7	5	4	4	4

p) Southern Sweden. Electro-methanol (Case: Low VRE)

Electrolyser CAPEX (€/kWelec)										
900	576	237	176	153	141	133	128	125	122	121
750	508	215	162	143	133	127	123	120	118	118
600	440	192	148	133	126	121	118	116	114	114
450	372	169	135	124	118	115	113	111	110	111
300	304	147	121	114	111	109	107	106	106	107
150	236	124	108	104	103	102	102	102	102	104
Capacity factor (%)	5	15	25	35	45	55	65	75	85	95
Electricity price (€/MWh)	16	24	30	36	40	42	45	47	48	49
Hydrogen storage (€/MWh$_{H_2}$)	17	14	12	10	8	7	5	4	4	4

Figure 7. Production costs (€ MWh^{-1}) for liquefied electrolytic hydrogen and e-methanol assuming data from the long-term (approx. 20–30 years) horizon, analyzed for different electrolyzer CAPEX combined with different capacity factors, with its corresponding electricity price and hydrogen storage cost, identified in figures 6(c) and (d), for the cases Ref and Low VRE, for the four regions Hungary-Croatia-Slovenia (a)–(d), Ireland (e)–(h), western Spain (i)–(l), and southern Sweden (m)–(p). All other assumptions are listed in table 7. The colors illustrate the relative production cost where, the lower the cost the darker the green, and the higher the cost the darker the red.

the reviewed papers assumed that the usage of the e-fuels would replace conventional fossil fuels and therefore only investigated the cradle-to-gate life cycle [13, 49, 76, 77, 79, 82, 85, 87–89] as the rest of the technology used would be identical. This corresponds to system boundary options A–D in figure 8. Other

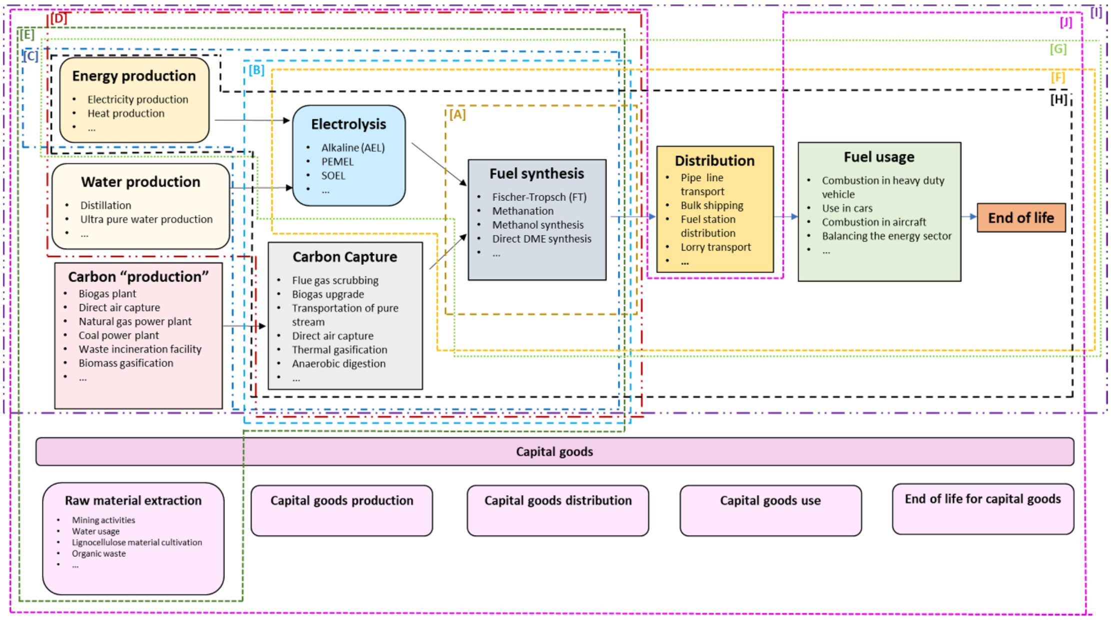


Figure 8. Simplified illustration of e-fuel life cycle. Dotted lines mark system boundaries used in reviewed environmental assessments ((A) [90], (B) [49, 82, 85, 87, 89, 91], (C) [76, 88, 89]: (however this only applies for one of the cases in [76]), ((D) [79], (E) [82], (F) [13], (G) [80, 87], (H) [19, 52, 83, 84], (I) [78], (J) [81, 85]). Within each box different production alternatives for the same process step in the life cycle are listed. The type of production process used depends on the scope of the assessment and the fuel produced. Acronyms used: PEMEL: polymer electrolyte membrane electrolyzers; SOEL: solid oxide electrolyzers.

studies do not use a quantitative approach and report qualitative results of the environmental performance of producing and using e-fuels [25, 43, 48, 58, 90].

In total 13 environmental impacts have been investigated in the reviewed publications. The environmental impacts covered in most papers include climate change/GHG emissions, water requirements, and health aspects.

5.1. Climate change

The most investigated environmental impact is climate change/global warming, which was considered in all reviewed environmental assessments. Most papers present emissions from electricity production [77, 82, 86] and/or carbon supply (carbon source and capture process) as the primary contributor [52, 78, 79, 81, 89]. The exception is studies which have assumed the contribution of electricity production and carbon supply to be zero due to methodology related arguments [43, 76, 79, 86, 87, 92, 93], and where heating is provided by natural gas [13, 85, 88]. In figure 9, the range of results for GHG emissions found in the reviewed literature is illustrated. The scope and systems investigated varies and no direct comparison of the reported GHG emissions can be made due to this. However, each paper gives insight to the specific investigated system.

Based on the reviewed studies, e-fuels appears to generally offer emission reductions if produced from low-carbon renewable electricity, but if the electricity is produced using fossil energy sources, GHG emissions can become higher compared to fossil fuels [52, 79, 81–83, 88, 89, 94, 95]. An energy grid mix with a high degree of renewables might be sufficient to achieve CO_2 reductions, but how much of the energy which is required to come from low-carbon electricity varies between assessments [30, 53, 81, 82, 84, 88, 89]. Some studies integrate heat produced in the electrolyzer with the fuel production to minimize the energy requirements [88]. This appears to lower the emissions.

Different methodological choices in addition to the choice of electricity source can cause a significant variation in the carbon footprint of e-fuels [13, 95]. Including for example, which parts of the technical system that are included (e.g. cradle-to-gate or full life cycle), which CO_2 flows that are modelled (all or only CO_2 flows of fossil origin), if the CO_2-input is considered with environmental burden (a co-product or main product) or without (e.g. a waste or by-product from another process), if indirect effects, such as land use changes, are included or not.

Two main ways of modelling GHG flows were identified in the literature. In the first way, established by e.g. the global CO_2 initiative publishing guidelines for techno-economic assessments and life cycle assessment for e-fuels and other forms of CO_2 utilization [96], all emissions and feedstocks were traced upstream in the supply chain and the impact calculated based on the overall sum of flows to and from the e-fuel production

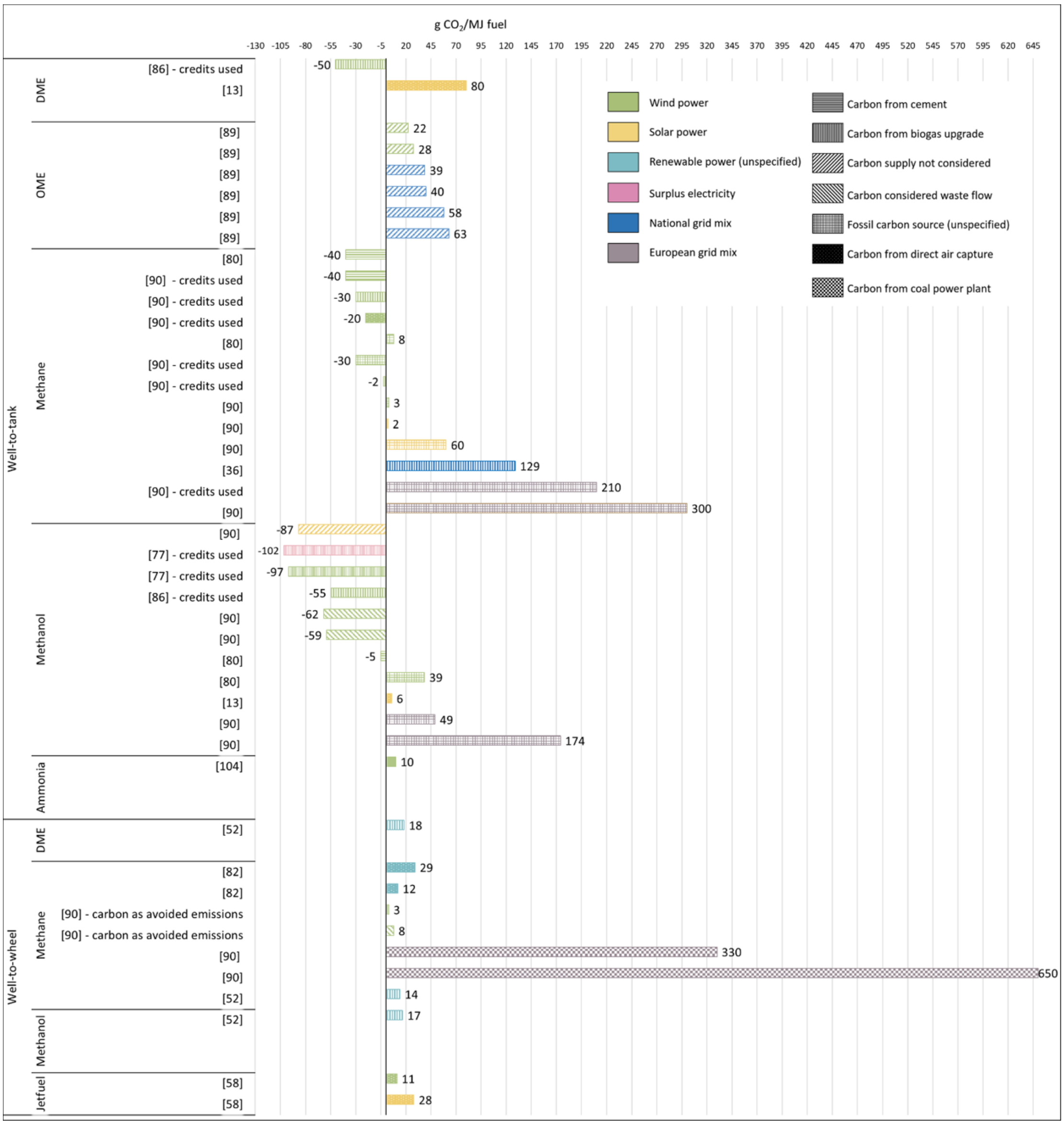


Figure 9. Summary of GHG emissions from the production of e-fuels identified in the reviewed assessments separated between well-to-tank and well-to-wheel studies. The results are not directly comparable as the methods for calculating the environmental impact from environmental streams varies. Note that the first jet fuel pathway represent methanol to jet and the second a pathway using FT. The list includes results from articles presenting values in emissions kg^{-1}, emissions km^{-1}, or emissions MJ^{-1} which have been converted to the same unit using lower heating value (LHV) of 22.5 MJ kg^{-1} for ammonia conversion, 20.1 MJ kg^{-1} for methanol, 28.8 MJ kg^{-1} for DME, and 50 MJ kg^{-1} for methane. The presented results in $gCO_2\ MJ_{fuel}{}^{-1}$ can be converted into $kgCO_2\ MWh_{fuel}{}^{-1}$ and gCO_2 $liter^{-1}$ diesel equivalent, if multiplied with 3.6 or 36, respectively. For details, see table S3 in supplementary material.

processes and the surrounding environment, see for example [80]. By using this method, it is possible to treat all CO_2 flows equally independent on origin. Negative when removed from the atmosphere (e.g. by DAC or biomass growth) and positive when emitted to the atmosphere at the combustion phase. In the second way, only CO_2 flows of fossil origin is considered while all CO_2 from non-fossil origin is treated as having zero climate impact and disregarded, see for example [50]. The choice of carbon capture technology in the fuel production, the assumed system boundary, and how emissions of CO_2 are treated in the calculations explain why some studies present negative impacts from the e-fuel technology (figure 9).

As the captured CO_2 emissions are released when the e-fuels are used, these results should be viewed as comparative results. When the CO_2 supply is viewed as a by-product/waste where the environmental burden/cost has already been allocated to a main product [76] the environmental assessments show low climate change effects, but when DAC is used to supply the carbon the impact on the climate is higher due to the additional electricity needed to capture the CO_2 (recall that also renewable electricity emits GHG over its life cycle) [79]. Some studies are available which perform sensitivity analysis on the choice of carbon source

[78, 79]. The type of climate impacts included also varies between papers, with some including indirect land use changes leading to secondary effects, indirect emissions etc.

In some studies, negative GHG emissions are presented. This is done through two methods: (a) GHG emissions have been removed from the atmosphere through some form of capture process, e.g. DAC or biomass cultivation, and not yet been released back to the atmosphere. For example, cradle-to-gate assessment does not include combustion of fuels and therefore can have negative results. (b) Some studies investigate the system changes of an action, such as introduction of e-fuels, where the e-fuel are being credited benefits from replacing a product on the market. That is, if emissions which should have been released to the atmosphere from existing fuels, no longer is emitted, they are subtracted from the process associated with e-fuel production. By doing this, a system change is shown where market mechanisms are included. This approach is called crediting and results where this approach was used are in figure 9 marked as 'credits used'.

Most studies investigate the environmental impacts from e-methanol [13, 27, 43, 52, 59, 60, 79, 85, 89, 97] and e-methane [39, 48, 52, 59, 60, 77, 79, 80, 85, 98]. The assessments investigate a range of research questions related to the fuels and, as shown in figure 9, the absolute results between the assessments varies. The reviewed assessments mainly assess direct effects from GHG emissions to air and no assessment including indirect effects on climate from NO_x or PM emissions have been identified. There are currently few environmental assessments looking at FT liquids, but in Artz *et al* [89] two studies were harmonized and the results indicate that the source for heat supply is of importance to reach low global warming impact for this type of e-fuels as well as utilizing renewable electricity. Only some studies have been found which compare the climate change impact from different e-fuels [13, 52, 83]. In Bongartz *et al* [52], methane, methanol, DME and electrolytic hydrogen is compared under similar assumptions and hydrogen was found to have the lowest climate impact. Of the carbon-based fuels methane (CH_4) performed the best. This was due to the less required CO_2 feedstock per H unit and that the methane production facility required no additional electricity for the fuel production in comparison to other e-fuels. The studies did not consider leakage of CH_4 in fuel production.

Only one of the assessments looks at future propulsion technologies, i.e. in Koj *et al* [80] SNG ICE vehicles are compared to electric and fuel cell options for road applications. The results indicate that BEVs perform better in most categories investigated. The assessment includes vehicle production, but it is unclear how carbon sources were treated in the assessment and hydrogen infrastructure needs further assessment.

Although some synthesis processes are exothermic, the reviewed literature indicate operation of the full plant still requires supply of additional energy (except for e-methane, excluding the liquefaction step). The literature shows that the choice of heat sources to supply energy for the fuel synthesis processes appear to have a significant impact on the climate performance of the life cycle. The literature, further, points to the fact that renewable energy sources are required to achieve low global warming impact over the e-fuel life cycle. The literature is, however, not consistent regarding the environmental impact from different CO_2 sources. There is a shortage of assessments focusing on the environmental impact from different CO_2 sources and the methodology for the assessments varies, however in the results presented in figure 9 all pathways which include CO_2 from non-fossil origin in combination with electricity of low carbon intensity show low global warming impact. There is a need for additional studies assessing the environmental impact from different CO_2 sources for different scenarios.

Further investigation of oxygen utilization is also needed.

5.2. Water requirements

Fresh water is a scarce resource and increased water use can be critical in some regions. Water is one of the consumables in the e-fuel life cycle, required in the electrolyzer as well as in some carbon capture processes [19, 77] and fuel synthesis related purposes [76, 78]. No scientific paper has been found which directly assesses and compares water consumption from e-fuel production with water consumption of other fuels. However, the material in- and outflows of some studies show that the water consumption in e-fuels production is mainly driven by the electrolyzer, and in some of the reviewed papers water consumption in the electrolyzer is quantified. The type of electrolyzer will influence the water demand of the fuel production. In a review paper on hydrogen production Bhandari *et al* [99] conclude that alkaline electrolyzers consume around 10–12 l of water per kg H_2 and PEM around 18 l, but in the papers reviewed here most studies assume stoichiometric consumption at around 9 l of water per kg H_2 (see table S4 in supplementary material) and the assumed consumption varies from 8.85 l to 16.68 l between papers. Some papers fully exclude water consumption in their analysis [52, 76, 78, 88], and [77] does not present the figures used.

In Schmidt [100] stoichiometric estimates are used to investigate the water demand for e-jet fuel production (FT) and a water demand of 1.3–1.4 l per liter of e-jet fuel is established. This is in the study compared to estimates of water requirement for bio jet fuel available in other literature, and the e-fuel was found beneficial. However, this was only presented in a report rather than a peer reviewed study and no full material flow analysis or similar were conducted. A quantitative analysis would be needed to further investigate this claim. To better understand the size of water demand to produce e-fuels, a comparison to other fuel options, e.g. biofuels, would be valuable.

5.3. Land use

Winther-Mortensen *et al* [101] have estimated that transforming the global energy sector from fossil fuels to e-fuels would be technical achievable but would require 1.1%–13% of the Earth's land surface, which is lower than a fully biomass-based system. Schmidt [100] have published a report that addresses land use in e-fuel production. It is an assessment which primarily includes land used for facilities such as electricity production. The land utilization appears to be lower than the land requirements for biogenic fuels. However, no direct quantitative assessment of the full land surface requirement has been found and further investigations, which include for example land use connected to carbon capture, is needed. Besides the area of land required, also type of land should be included in future assessments.

5.4. Health aspects

Health aspects are investigated in life cycle assessments mainly by looking at emissions to the environment which have damaging properties to humans. When assessing how e-fuels impacts health, two main types of health impacts are quantified: impacts from particulate matter causing for example respiratory issues in humans, and human health impacts caused by toxic emissions. No study was identified which states that assessing these impacts is the primary goal of the study.

The reviewed articles, which address particulate matter impacts, point out combustion occurrences as the primary sources of particulate emissions. The main contribution to particulate emissions globally is combustion processes, and the characteristics of these processes affect the number of particulate emissions released. The same energy carriers (molecules) have similar emission profile regardless of the fuel production pathway, but the e-fuel production pathways produce fuels which lack contaminants such as sulfur. The high purity of the fuel leads to cleaner combustion profiles compared to fossil fuels' production pathways, avoiding for example SO_X formation. Some new types of energy carriers with new chemical structures could also be possible, such as oxymethylene dimethyl ether (OME). As shown by Deutz *et al* [78], the combustion characteristics of OME, which differ from conventional fuels, can impact the number of particulate emissions over the life cycle. They study OME used as a drop-in fuel in diesel, compared to diesel, used in lightweight vehicles and their results show that OME could reduce the emissions of NO_x and soot by 43% and 75%, respectively. The life cycle results are, however, dependent on the electricity source when producing the OME. Thermal power stations, which burn a fuel to produce electricity, e.g. coal power plants, can increase NO_x [78] and other particles emissions over the fuel's entire life cycle, depending on the combustion characteristics, and the electricity demand in the electrolysis process. Health impacts related to human toxicity found in the literature are primarily linked to cancer and non-cancer effects. Several studies suggest metal emissions (such as hexavalent chromium and heavy-metals), connected to electricity production, are the primary source of toxic impacts from the e-fuel life cycle [76, 84, 91]. However, no analysis was found which primarily assess toxicity, and the scope of the presented data is thereby restricted. The reviewed studies do not include data on metal emissions throughout the full life cycle, and differences in metal content between different fuels are not addressed. Therefore, these results are uncertain. Further studies are thereby required to determine whether there are impacts of e-fuels on human health.

There are some further assessments, in the literature, focusing on specific health related issues. In a paper by Matzen and Demirel [85], several emissions which can impact human health associated with e-methanol and DME were quantified. DME production has formaldehyde as a by-product, which is a known carcinogen, and they found emissions of formaldehyde, during DME fuel production, to be the most significant health-related emissions, in this fuel's life cycle. The results are compared to biogenic and conventional fossil alternatives, and the e-fuels appear beneficial to, or in parity with, fossil alternatives for almost all emission types, including VOC and SO_x. However, the VOC and SO_x results are not further analyzed nor connected to impacts on health, or the environment, and no cause for these results are presented.

5.5. Other environmental impacts

Acidification and eutrophication have been assessed in a few papers, e.g. by [36, 76], but mainly as a secondary result linked to the use of materials etc. The impacts appear to be driven by material requirements, and the scope of the papers have primarily been limited to emissions from the direct production and use of the fuels rather than materials required in those processes. However, acidification impacts from e-methanol appear to be lower than from natural gas-based methanol and biogenic methanol. The main influencing factors appear to be chemicals used in the CO_2 capture process, such as monoethanolamine, cleaning of water if ultraclean is required in the process, and emissions from the electricity production [76]. The results of Vo *et al* [36] indicate that unless renewable electricity is used for the fuel production, emissions from the electricity production would be the main source contributing to acidification. The reviewed assessments did not include any assessments focusing on noise pollution, social aspects, or other aspects, apart from those mentioned in this paper.

5.6. The environment and e-ammonia

As e-ammonia is produced using hydrogen and nitrogen (not carbon), the environmental impact from using e-ammonia differs from the other e-fuels included in this assessment. The literature search found no articles with detailed analysis of the environmental impacts from using e-ammonia in transport.

Life cycle assessments for ammonia up until production (not including fuel usage) are available and a few are highlighted here to give an indication of the main climate change related emissions sources. Chisalita *et al* [102] compared different ammonia production pathways and found that e-ammonia could lower several types of environmental impacts compared to conventional ammonia, but this depends directly on the electricity source used in the electrolyzer. A similar analysis focusing on GHG emissions was performed by Liu *et al* [103]. Use-phase impacts of e-ammonia differ significantly from other e-fuels, as there is a potential for ammonia slip, NO_x emissions, CO emissions, N_2O emissions, and hydrocarbon emissions (depending on pilot fuel use) [104]. Assessments of the environmental impacts of e-ammonia compared to other fuels are lacking and are needed particularly for marine applications when e-ammonia might be an attractive future fuel [105].

6. Discussion

We have reviewed publications on e-fuels and summarized current knowledge for some of the key aspects, including production costs and environmental performance. As a comparison to our results, we have identified some recent papers published during 2021, i.e. after finishing our literature review that also have analyzed the literature on environmental performance and/or cost of e-fuels. In Garcia-Garcia *et al* [106] environmental assessments of methanol, methane, DME, dimethyl carbonate, propane, propene, and other light hydrocarbons were reviewed. The results of climate impact mirrors that of our study, and much of the literature is the same for both studies. However, here we provide a more in-depth analysis over the current state-of-art for other impact categories. In Ueckerdt *et al* [107] both costs and climate mitigation potential are discussed and analyzed. They conclude that prioritizing between different applications of e-fuels should take precedence for policy makers, as future unavailability, due to production bottlenecks or similar, could lead to fossil-fuel lock in effects. Isaacs *et al* [108] quantify the economic and life cycle environmental characteristics of four e-fuel technology pathways that rely on the FT synthesis. Their results indicate that a hybrid power- and biomass-to-liquid pathway is the most environmentally and economically promising option for e-fuel production, and as in our study the results highly depend on assumptions on component costs and electricity emission intensity.

Examples of other studies also identifying bio-e-fuels having advantages over e-fuels are, e.g. [109], who found the production costs of bio-e-fuels, starting from biomass gasification to have the lowest costs among the synthetic fuels, due to the simplicity of the process and high conversion rate. Also Lester *et al* [59] found that bio-e-fuels have better potential to substitute fossil fuels due to low production costs and low biomass consumption compared to e-fuels and biofuels.

6.1. System boundaries and guidelines

In this study, as also shown in Brynolf *et al* [6], the large range of e-fuel cost estimates, and other assumptions, in the literature would benefit from being more harmonized. Even if guidelines for techno-economic assessments [110] and life cycle assessments [111, 112] of e-fuels have been published there are still a broad range of different system boundaries assumed in the reviewed studies. In 2020 a guideline was published by Müller *et al* [111] outlining general principles for assessment of products from carbon capture utilization in regards to techno-economic assessments and life cycle assessments. It includes principles on setting the system boundaries for the analysis as well as the choice of functional unit. Principles around how to allocate burdens/costs between different end-products, produced from the same processes (i.e. solving for multifunctionality), is also discussed, but no principles are proposed. The choice of system boundary for the assessment has a big impact on both the production cost estimate, efficiency as well as environmental performance. This review clarifies several dimensions of how system boundaries might vary not only over cradle-to-grave, but also to which extent production of capital goods are considered in the different included steps within the system boundaries.

As the reviewed papers aim to answer a broad spectrum of research questions, a variety of assumptions and system boundaries is expected and necessary to an extent, however, this restricts the comparability of the results between papers. The high variety of method choices in assessments of e-fuels have been analyzed and discussed in several papers [89, 95, 106, 113]. A common conclusion for these earlier reviews is the need for a coherent assessment method for comparable results. This is for example important for policy purposes while for research purposes there are also the need for using specific data related to the investigated research question. However, development in e-fuels moves fast. Since assumptions on future costs and environmental performance, on technologies still in development, are very uncertain, guidelines may also risk becoming obsolete, suggesting outdated technologies. Guidelines as well as recommended data should therefore be treated with care.

6.2. Type of carbon and electricity

E-fuels are discussed from different perspectives, for a lot of different applications, in the reviewed literature: as utilization of waste streams of carbon, as utilization of excess electricity, as potential renewable transport fuels, and as a way to store renewable electricity to name the most common. The perspective has a great impact on the choices made both in the economic and environmental assessment. Examples of this are studies assuming the contribution of electricity production and carbon supply to be zero due to methodology related arguments [43, 76, 79, 86, 87, 92, 93].

We have shown that e-fuel carbon intensity when considering the full life cycle is dependent on the energy source and carbon source for carbon-based e-fuels. This result is consistent with other studies, a recent being the review by Ueckerdt *et al* [107], where the carbon mitigation effects of using e-fuels were discussed in detail. As in this study they conclude fully renewable energy systems are required to achieve low GHG emissions. Regarding the type of carbon, in the IEA global hydrogen review [114] it is concluded that to ensure the CO_2 neutrality of the produced fuel in the long term, CO_2 supplies should be captured at bioenergy conversion plants or directly from the atmosphere. Mylan *et al* [115] point out that biogenic and atmospheric CO_2 are the most interesting sources, but the utilization of fossil CO_2 makes sense in given situations. If CO_2 is captured from persistent fossil point sources, the climate benefit can be equal to or even better than direct atmospheric CO_2 capture. However, this is not the case if the e-fuel production prolongs the lifespan of the point sources by, for example, increasing their profitability or causing technology lock-in effects. Production of e-fuel from unsustainable sources could potentially cause feedback effects such as societal dependency on the e-fuels from these sources where a move to other fuels would have climate benefits. Comparing e-fuels with other drive-line options is central to establishing its environmental and societal impacts. A continued discussion, about the impact from using different types of carbon and electricity, is therefore required to advance the methods evaluating environmental performance of e-fuels.

6.3. Negative emissions

The results on climate effect from using e-fuels vary, in the literature, from being in parity with, or more damaging than, fossil fuels, to negative emissions (i.e. beneficial for the climate). Results showing negative emissions from using e-fuels are rare, no case have been found in this review indicating true negative emissions to the atmosphere. Negative results were found in cradle-to-gate studies, where the fuel was not used/combusted, and in studies where the e-fuel has been credited benefits from replacing a product on a market. These results are thereby directly tied to the comparison made in the study, either by comparing fuel production pathways rather than fuel usage, or by assessing a specific marginal change which might differ for different scenarios. As shown and discussed by Tanzer and Ramírez [116], absolute negative emissions can only occur if carbon is extracted from the environment and then stored over a long or indefinite period of time without returning to the atmosphere. As carbon-based e-fuels, used in the transport sector, release the carbon back to the atmosphere when combusted in vehicle engines, results showing negative emissions should be viewed with caution and the circumstances for the assessed case critically reviewed.

6.4. Fuel infrastructure

An important argument for using e-fuels is the possibility to utilize existing infrastructure or at least only limited modification of existing infrastructure. There is a need for studies comparing the technical feasibility, cost, and environmental performance of fuel distribution infrastructure for different types of fuels targeted for different transport modes to determine when such benefits outweighs the benefits of a larger system change, see [117] for an example.

From the review it is evident that there are limited amount of studies considering fuel distribution infrastructure, with cradle-to-grave system boundaries, neither for the cost nor the environmental performance. For the cost of e-fuels the literature indicate that fuel distribution infrastructure might have a significant impact on different e-fuel options (see our attempt to address the infrastructure aspects in [10]). Some results indicate that health impacts might be affected by inclusion of capital goods such as infrastructure, but in general the impact of fuel infrastructure appears to be lower for environmental concerns, than for cost aspects, but as this is rarely included in assessments no definite conclusion can be drawn. To reduce the uncertainties around contributions to the cost and environmental impact from the fuel infrastructure, including this in future e-fuel assessments would be valuable.

6.5. Demand for land and water

Many papers in this review perform simplified environmental assessments, focusing on climate impact. Land and water issues are discussed only in a few papers, although these aspects could be direct limiting factors for e-fuels in some regions. The few land use estimates available indicate that the required land for e-fuel production may be considerable depending on production scenario. Water scarcity is a pressing environmental resource in several regions. As no full analysis has been identified we cannot exclude this to be a potential environmental concern. The literature points to the fact that water requirements for e-fuel production may be significant in regions where water is a scares resource and water scarcity may correlate to regions with great solar and wind potential, making further analysis of these issues relevant for future studies.

6.6. E-fuel supply potential

The literature presents a wide range of estimated e-fuel supply potential. In the lower range Christensen and Petrenko [118] estimate e-fuel production potential in a European context for different levels of production subsidies, and find that in the most favorable policy scenario, i.e. a subsidy of 1.50 €/liter diesel equivalent, around 400 million liters of e-fuels could be produced in 2030, representing approximately 0.15% of total EU road transport fuel demand. A higher supply potential is estimated by Mesfun *et al* [119], showing that depending on carbon and fossil fuel price, 0.15–15 million tonnes per year of captured CO_2 can be used in the synthesis of e-fuels, displacing up to 11% of current fossil fuel use in transportation. In a Swedish context, the supply potential of recoverable biogenic CO_2 point sources that could be utilized for e-fuels production amount to 30 million tons of CO_2 per year, meaning the if all that recoverable biogenic CO_2 were used to produce e-fuels, the yield would correspond to twice the current demand for transportation fuels in Sweden [60]. Böhm *et al* [120] assume a technology costs decrease by 12%–15% for each doubling of cumulative capacity and find overall cost reductions of more than 75% from up-scaling to multi-MW plants which could lead to a global e-fuel production capacity of 4530 GW.

The supply potential can thus be estimated from different perspectives such as cost-competitiveness or from the size of available CO_2-sources. The global supply potential of CO_2 point sources which will remain in a future world, aiming for meeting climate targets, is unknown. Industrial processes that generate capturable concentrations of CO_2 could, e.g. be pulp and paper industries, waste treatment facilities, power and heat generation facilities, and biofuel production facilities. At least in forest rich countries, as Sweden, there seem to be sufficient supply potential of CO_2 from biomass-based sources [60]. CO_2 can in regions lacking by-product streams, from biomass processes, be captured from air, however, at a higher cost. The actual global supply potential of e-fuels is currently very uncertain and depends on aspects as access to CO_2, renewable electricity, and the cost-competitiveness of the produced e-fuels. Uncertainties on the future availability of e-fuels are also connected to concerns that e-fuels may contribute to fossil-fuel dependence lock-in [107].

6.7. E-fuel production in remote locations

Recently, an interest has arisen for producing e-fuels in sunny or windy countries with plenty of unused land (e.g. Sahara, Australia, Patagonia) where renewable electricity could be generated at low cost [114, 121]. E-fuels produced in such countries can be distributed to fuel demanding markets as Europe and USA. Some demonstration projects plan for advance up to commercial scale in such regions, e.g. the Haru Oni project in Chile, plan a production capacity, in 2026, of 550 million liters of e-fuels per year, with an electrolyzer capacity of 2 GW, and the Helios Green Fuels project in Saudi Arabia, based on an electrolyzer capacity of 1.5–2.0 GW, plan for an annual production of 1.2 Mton e-ammonia [114]. Schorn *et al* [121] conclude that e-methanol, including the costs for distribution to Europe, can be available at a similar cost as the market price of fossil methanol, around 400 €/ton, if renewable or process- related CO_2 is available at costs of 100 €/ton or below in the hydrogen-producing country.

Although the e-fuel production cost has potential to be even lower than the lowest costs shown in figure 7, in regions with exceptionally good conditions for renewable energy, there are several uncertainties that need to be solved if e-fuel production was concentrated in such remote locations. These uncertainties are for example, access to cheap CO_2 sources, water supply and other environmental impacts, security of supply, and costs for storing and transporting different types of e-fuels.

6.8. Future electricity prices and electrolyzers' life time

Our results on future electricity prices show relatively low prices for a large fraction of the year in all assessed European regions, also for scenarios assuming a very high demand for hydrogen (case LowVRE) that to some extent can represent a society utilizing low electricity prices. However, in the future, new innovative ways of utilizing very low electricity prices, without costly investments in storages or overcapacity in the production facility, may be developed, leading to that less hours with near zero cost electricity may be available in future than what is shown in this study.

Our results, showing relatively high production costs for very low CFs, are apart from the electricity price and cost for hydrogen storage also connected to assumptions on the electrolyzers' life time. We have assumed a life time of 25 years regardless of how many hours per year the electrolyzer is in operation. If operating the electrolyzer on very low CF will prolong the electrolyzer's life time (longer than 25 years), our production costs for very low CFs are overestimated.

6.9. Regulations and policies

Reflections on different types of regulations and policies are discussed in the literature. Mesfun *et al* [119] investigate the impact of carbon policy and fossil fuel prices on the economic and engineering potential of power-to-gas and power-to-liquid systems as storage for intermittent renewable electricity. Results indicate that large-scale deployment of these technologies, for producing e-fuels from excess intermittent electricity, is feasible, particularly when incentivized by carbon prices. Perner and Bothe [122] claim that the power-to-x industry needs to be built up in both producing and importing countries and point at that, with increasing e-fuel maturity, policies should move from more technology-specific policies towards a more generic approach to provide opportunities for all carbon-neutral technologies, including e-fuels. They further suggest that existing standards for biofuels, that monitor and certify fuels to guarantee that sustainability and social standards are met, should be adjusted to cover e-fuels.

Our results show a wide gap between the production cost of fossil diesel/gasoline/jet-fuel and the production costs for all types of e-fuels. This gap would need to be narrowed by policies/regulations for e-fuels to compete in the market.

7. Conclusions

From the analyses made in this study we can draw the following conclusions:

- Production costs in near-term (5–10 years) can be expected to lie in the range of approximately 110–230 € MWh^{-1} (1.1–2.3 €/liter diesel eq), where the lowest costs are shown for liquefied bio-e-methane from biogas, bio-e-methanol, bio-e-DME, and liquefied bio-e-methane from syngas. Highest production cost, among the assessed fuel options, is shown for e-kerosene through the methanol-to-jet process.
- All analyzed fuel options have the long-term (20–30 years) potential to achieve a production cost between 90 and 160 € MWh^{-1} (0.9–1.6 €/liter diesel eq).
- Production costs for bio-e-fuels can be expected to be lower than their e-fuel versions.
- E-fuel production costs are connected to the conditions for VRE systems such as wind, and solar generation in a region. Production costs are lower in regions such as Ireland (good wind conditions), and western Spain (good solar conditions), compared to the two other assessed regions southern Sweden and Hungary-Croatia-Slovenia. In Ireland and western Spain the production costs of e-methanol, in 2050, might be in the range of 76–86 € MWh^{-1}, asssuming an electrolyzer CAPEX of 300–450 € $kW_{elec}{}^{-1}$ combined with CFs of 45%–65%. For the same combination of electrolyzer CAPEX and CFs, the production costs of e-methanol, in 2050, might be in the range of 84–100 € MWh^{-1} in the regions southern Sweden and Hungary-Croatia-Slovenia.
- The production costs are generally much lower, for all regions, in the reference scenario (Ref case) compared to the scenario assuming low acceptance for building new variable renewable energy systems combined with a high demand for hydrogen (Low VRE case), which first and foremost is because when assuming a limited acceptance for building solar and wind power, the electricity system needs to invest in more expensive generation technologies which gives slightly higher average electricity prices.
- To achieve low global warming impact over the life cycle of e-fuels, renewable energy sources are required. The literature is, however, not consistent regarding the environmental impact from different CO_2 sources.

- The choice of system boundary for the assessment has a large impact on the production cost estimates, efficiency as well as environmental performance of e-fuels.
- Further analyses of the impact of e-fuels on health, land use, water demand, and noise pollution are required to fully understand their environmental impact.

Data availability statement

All data that support the findings of this study are included within the article (and any supplementary files).

Acknowledgments

The authors want to acknowledge funding from Ford's University Research Program as well as from the Swedish Energy Agency within the industrial and academic collaboration project 'Future Alternative Transportation Fuels'. The authors gratefully acknowledge financial support from the Swedish Energy Agency and the Swedish Knowledge Centre for Renewable Transportation Fuels (f3) [project carried out within the collaborative research program Renewable transportation fuels and systems program (Samverkansprogrammet Förnybara drivmedel och system) 'Project No. P48357-1']. The project RE-INVEST 'Renewable Energy Investment Strategies' (Grant No. 6154-00022B) funded by the Innovation Fund Denmark and EP2Gas (Grant No. 64017-0011) funded by Energy Technology Development and Demonstration Programme Denmark are also acknowledged. Finally, the authors want to thank Karna Dahal, Postdoctoral Researcher at University of Eastern Finland as well as professor Karin Andersson, at Maritime Environmental Sciences, Chalmers, for fruitful discussions.

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