

Assessment of the potential of sustainable fuels in transport

ANNEXES



RESEARCH FOR TRAN COMMITTEE

Assessment of the potential of sustainable fuels in transport

Abstract

This study provides the European Parliament's Committee on Transport and Tourism (TRAN) with an assessment of the potential of sustainable fuels to decarbonise the transport sector, and help the sector achieve the 2050 decarbonisation goals. It assesses their potential for use in maritime, aviation and road transport, considering their technology readiness, feedstock availability, sustainability of supply, resource and energy efficiency, and the most appropriate match-making between fuels and applications.

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LIST OF ABBREVIATIONS

AFIR	Alternative Fuels Infrastructure Regulation
ATJ	Alcohol-to-jet fuel
BECCS	Bioenergy with carbon capture and storage
BEV	Battery electric vehicle
BtL	Biomass-to-liquids
CAN	Climate Action Network
CAPEX	Capital expenditure
CBAM	Carbon Border Adjustment Mechanism
CCUS	Carbon capture, utilisation and storage
CCS	Carbon capture and storage
CH₄	Methane
CO	Carbon monoxide
CO₂	Carbon dioxide
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
CSRD	Corporate Sustainability Reporting Directive
DAC	Direct air capture
EC	European Commission
EEA	European Economic Area
EEB	European Environmental Bureau
EEDI	Energy Efficiency Design Index
EJ	Exajoule (1 x10 ¹⁸ joules)
ERSV	Electric road system vehicle
ETC	European Topic Centre

ETD	Energy Taxation Directive
ETS	Emissions Trading System
EU	European Union
EV	Electric vehicle
FAME	Fatty acid methyl esters
FCEV	Fuel cell electric vehicle
FSD	Financial Stability Board
FT	Fischer-Tropsch
GHG	Greenhouse gas
H₂	Hydrogen
HDV	Heavy-duty vehicle
HEFA	Hydroprocessed esters and fatty acids
HVO	Hydrotreated vegetable oil
ICAO	International Civil Aviation Organisation
ICMA	International Capital Market Association
IEA	International Energy Agency
IMO	International Maritime Organisation
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
LCF	Low-carbon fuel
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicle
Lge	Litre of gasoline equivalent
LNG	Liquified natural gas

LPO	Loan Programs Office
MeOH	Methanol
Mtoe	Million tonnes of oil equivalent
N₂	Nitrogen
N₂O	Nitrous oxide
NFRD	Non-Financial Reporting Directive
NGO	Non-governmental organisation
NH₃	Ammonia
O₂	Oxygen
OECD	Organisation for Economic Co-operation and Development
OEM	Original equipment manufacturer
OPEC	Organisation of the Petroleum Exporting Countries
PAC	Paris Agreement compatible
PBtL	Power and biomass-to-liquids
PHEV	Plug-in hybrid electric vehicle
PV	Photovoltaic
RCF	Recycled carbon fuel
RD&I	Research, development and innovation
RED	Renewable Energy Directive
RES	Renewable energy sources
RFNBO	Renewable fuel of non-biological origin
RRF	Recovery and Resilience Facility
SAF	Sustainable aviation fuels
SMEs	Small and medium-sized enterprises

SMR	Steam methane reforming
TCO	Total cost of ownership
TCFD	Task Force on Climate-Related Financial Disclosures
TEN-T	Trans-European Transport Network
TRAN	European Parliament Committee on Transport and Tourism
TRL	Technology readiness level
UCO	Used cooking oil

GLOSSARY OF TERMS

Bioeconomy	<i>The bioeconomy covers all sectors and systems that rely on biological resources (animals, plants, microorganisms and derived biomass, including organic waste), their functions and principles¹.</i>
Bioenergy	Biomass used in the production of energy ² .
Biomass	The biodegradable fraction of products, waste and residues from agriculture (including vegetal and animal substances), forestry and related industries, as well as the biodegradable fraction of industrial and municipal waste ³ .
Drop-in fuel	Fuels that can directly be used on board existing vehicles (aircrafts, ships, cars, trucks, etc.)
e-ammonia	Ammonia produced with renewable hydrogen.
e-methanol	Methanol produced with renewable hydrogen.
Hard-to-abate sector	Any sector for which the options to decarbonise are not straightforward, due to a lack of appropriate technology or lack of competitiveness, such as aviation and shipping.
Point source emissions	Emissions issued by single identifiable point sources, such as smokestacks from large factory installations.
PBtL	Power & biomass-to-liquids are fuels obtained from biomass (e.g. residual forestry waste or by-products) and hydrogen derived from renewable electricity.
PtL, e-liquids or liquid derivatives	Power-to-Liquids or liquid derivatives are all hydrogen-based derivatives produced via Fischer-Tropsch synthesis ⁴ or from methanol. They comprise e-kerosene, e-diesel and e-gasoline.
Renewable hydrogen	Hydrogen produced via electrolysis using renewable (mainly wind and photovoltaic, or hydropower)-based electricity.
Renewable hydrogen derivatives	Comprises all products and fuels produced with renewable hydrogen including e-ammonia, e-methanol, e-liquids (also called liquid derivatives), e-gases.

¹ ([European Commission, June 2022](#)).

² ([European Environment Agency, 2001](#)).

³ ([European Environment Agency, n.d.](#)).

⁴ The Fischer-Tropsch process is a catalytic chemical reaction in which carbon monoxide (CO) and hydrogen (H₂) in the syngas are converted into hydrocarbons of various molecular weights, see also ([National Energy Technology Laboratory, 2017](#)).

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ANNEX A - OVERVIEW OF THE DIFFERENT TRANSPORT FUELS

This Annex provides further information to the overview of transport fuels in Chapter 2 of the main report. It includes, for each fuel group discussed in Chapter 2, the identification of the main applications for their use. The Annex also provides information on life-cycle GHG emissions, land use and land use change risks, energy efficiency and primary energy needs and water requirements that underpin the summary assessments available in Chapter 2, including details on sources used for the analysis. The Annex also includes complementary information and relevant sources, with respect to Chapter 2, on costs, supply availability, infrastructure needs and concludes with considerations on the scalability of all these fuel options.

Fuels covered include:

- Biofuels,
- Renewable fuels of non-biological origin (RFNBO): hydrogen, synthetic hydrocarbons, including liquid and gaseous e-fuels, and e-ammonia⁵,
- Fossil fuel-based hydrogen,
- Recycled carbon fuels (RCF).

⁵ Options using nuclear rather than renewable electricity for their production are also briefly discussed in the RFNBOs section.

Annex A.1.1 - Identification of the main options/applications of biofuel production via biochemical pathways

Ethanol can be used in spark-ignition combustion engines for road transport vehicles. This can either be in fuel blends in an anhydrous form in petroleum gasoline, or as Ethyl Tertiary Butyl Ether or ETBE, or, if in hydrous form, in adapted flex-fuel vehicles.

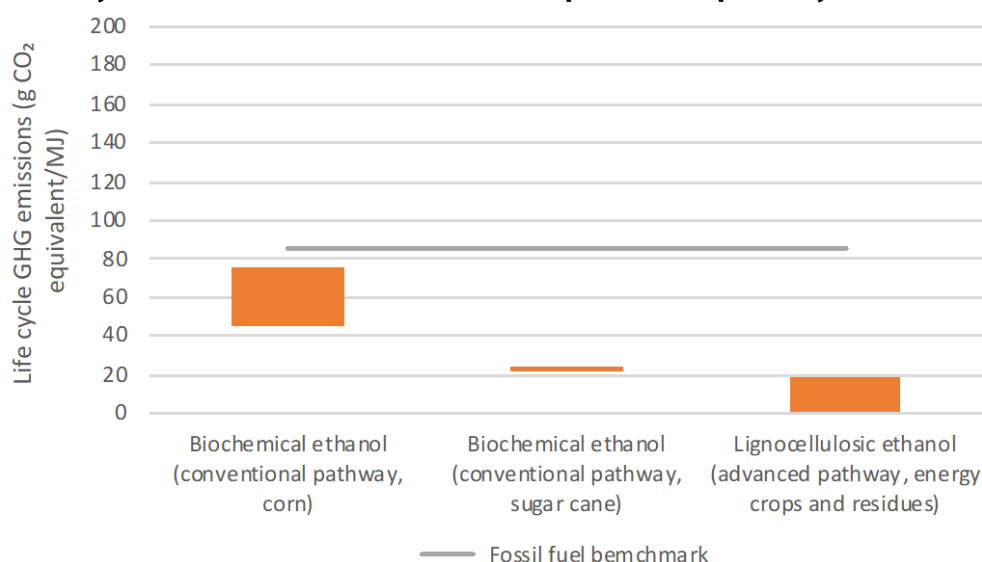
Maritime transport, aviation and heavy-duty road vehicles all largely make use of heavier petroleum distillates such as diesel. For biochemical pathways to play a role in these sectors, the products of biochemical fuel processes need to be reshaped into longer hydrocarbon molecules ([IEA Bioenergy, 2019](#)). This is what happens for alcohol-to-jet (ATJ) fuel processes.

Current and future prospects suggest quite a limited role for methane in the transport sector in the future, even if technologies enabling this development are already commercial ([Trinomics, 2022](#)). A primary use of biomethane in transport, especially in the near-term emergency related with the Russia-Ukraine war, is as a viable alternative to natural gas for compressed natural gas (CNG) and liquefied natural gas (LNG) fleets already on the road today.

Annex A.1.2 - Life-cycle GHG emissions of biofuel production via biochemical pathways

Depending on the feedstock and the location, the life-cycle GHG emissions of biofuels suitable for gasoline blending can vary greatly. Figure A-1 illustrates the ranges of life-cycle GHG emissions applicable to different biochemical biofuel production pathways. It differentiates between conventional feedstock and advanced feedstock⁶.

Figure A - 1 Life-cycle GHG emissions for biochemical production pathways



Note: minimum values of GHG emissions per MJ of fuels may be negative for lignocellulosic pathways, leading to carbon fixing in soils. Energy use and emission credits for by-products are also applied. Corn-based pathways refer to production in North America. Sugar cane-based pathways refer to production in Brazil.

Source: author's elaboration based on [ANL, 2022a](#) and [ANL, 2022b](#).

These figures include direct emissions from cultivation to production and estimations of land-use change effects. The latter relate to changes in carbon stocks on land, most notably through loss of above and below ground living biomass and soil organic carbon, which depend on direct or indirect changes in the way land is used (e.g. from cropland to pasture, or forest). Losses of soil carbon stocks lead to increases of GHG in the atmosphere ([Valin et al., 2015](#)). GHG emissions from land use change are assessed taking into account a complex set of factors, using models involving area changes of specific land types and emission factors for conversion of one land type to another.

The range of results included in Figure A-1 show that corn-based pathways have significantly higher life-cycle GHG emissions than sugar cane ethanol pathways, which rely heavily on the use of biomass residues (*sugar cane bagasse*) as a source of thermal energy and advanced pathways based on lignocellulosic feedstock. All of the biochemical processes considered have lower life-cycle emissions than the fossil fuel benchmark, close to 86 g CO₂e/MJ ([ANL, 2022a](#) and [ANL, 2022b](#))⁷. However, only the advanced conversion pathway approaches zero emissions. The corn-based pathway shown in the

⁶ This chapter considers zero net emissions for biogenic carbon. Whether this is the case, though, depends on the balance between carbon extraction from the atmosphere (during biomass growth) and addition (during combustion). This is subject to a time gap, and it can result in deviations from a net-zero balance, depending on the timing of absorption and addition. Additional effects relate to the impact on the biomass base of biomass extraction practices. Active management of forests (including higher wood harvesting than in forests that are not managed), for example, can lead to significantly higher CO₂ absorption than for unmanaged forests ([IRENA, 2019](#)).

⁷ The European baseline for this reduction is the average GHG intensity of the EU's fuel mix, referring to 2010, is 94 g CO₂/MJ ([European Commission, 2018](#)).

figure still produces over half of the GHG emissions of an equivalent quantity of fossil fuels. The sugar cane-based pathway of Figure A-1 leads to emissions that are close to one-quarter of the fossil fuel benchmark. This indicates that the compatibility of starch-based biochemical pathways that are not optimised for GHG emission abatement has a limited capacity to align with deep transport decarbonisation requirements.

Process improvements such as the integration of renewable hydrogen for fertiliser production or the sourcing of heat from low-carbon electricity rather than fossil fuels can reduce the life-cycle GHG emissions. They may open up opportunities for food and feed-based crops to be part of a future biofuel production mix in a way that enables them to better align with GHG requirements since hydrogen can enable higher efficiency of use of biogenic carbon, i.e. carbon derived from biomass resources ([DOE, 2022](#))⁸.

The two elements that typically contribute most to direct life-cycle GHG emissions (i.e. excluding those imputable to land use change, further discussed below) are the feedstock cultivation/harvesting process and the feedstock-to-fuel conversion process. For agricultural and forestry residues (advanced feedstock), the cultivation and collection emissions can be very low, due to their residual nature (allowing to piggyback on other activities that need biomass collection, such as pulp and paper production), but emissions and energy use for biomass conversion are significant. The cultivation/collection emissions of starch crops like corn are far greater (by a factor 10) than for residues. Dedicated lignocellulosic biomass is also paired with higher emissions than residues, due to the absence of piggybacking opportunities. Feedstock-to-fuel processing emissions are also significant for corn, but far less (in terms of share of total emissions) than for lignocellulosic pathways, for which estimates remain less GHG emission intensive overall ([Prussi et al., 2021](#)).

A number of pathways leading to the production of biomethane (only marginally considered in this analysis, due to competition with other end-uses and low demand in transport) offer the possibility to achieve low life-cycle GHG emissions. This is due to the opportunities that they offer to avoid emissions of CH₄ and N₂O, which are both GHG gases with global warming potentials significantly higher than CO₂ ([JEC, 2020](#)).

⁸ Combining hydrogen with biogenic carbon from CO₂ streams emitted in the atmosphere in conventional production pathways (thanks to processes similar to those discussed in the following sections for synthetic hydrocarbons and recycled carbon fuels) would allow to increase the amount of biogenic carbon that is converted into fuels. This increases the biofuel yield per unit of biogenic carbon available in the biomass feedstock, reducing land use and fertiliser requirements per unit of fuel produced (with positive implications for better sustainability), but it comes with higher energy costs for the additional conversions. Hydrogen and energy used for these processes should therefore be obtained from low-carbon energy pathways, to align with the need to reduce GHG emissions.

Annex A.1.3 - Land use and land-use change risks of biofuel production via biochemical pathways

Land use requirements for biochemical biofuel production result from the combination of biomass yields and process conversion efficiency. Biomass yields are higher for sugar cane and lignocellulosic energy crops than for starch-based biochemical pathways, while process conversion efficiency is lower for lignocellulosic feedstock (advanced process) than for corn, cereals and sugar crops (conventional process).

Impacts of emissions due to indirect land use change are estimated at 10-20 g CO₂e/MJ for food and feed crops (conventional feedstock: sugar cane or corn ethanol, respectively; values are also similar for alcohol to jet pathways, based on the same feedstocks) ([ICCT, 2021](#))⁹.

Indirect land use change emissions are generally estimated to be lower for lignocellulosic pathways if they rely on residues or energy crops grown in land areas that are not rich in soil carbon. They are significant, though, if energy crops compete directly for high quality land with conventional crops, as this can induce the displacement of land with high carbon stocks¹⁰. All pathways requiring cropland (including dedicated lignocellulosic crops) have far higher land use requirements than RFNBOs ([KiM, 2022](#)).

All pathways based on waste/residues (including those leading to production of biomethane) are paired with lower land use, but only to the extent to which their increase does not induce increased land use requirements, via product substitution, requiring increased supply of feedstocks needing cropland ([Malins, 2017](#)).

⁹ This is much lower than the 150 to 200 g CO₂e/MJ range estimated for some of the oleochemical pathways (in particular palm oil and residues like Palm Fatty Acid Distillate [PFAD], taking into account an induced demand for virgin oil). See the section on oleochemical pathways.

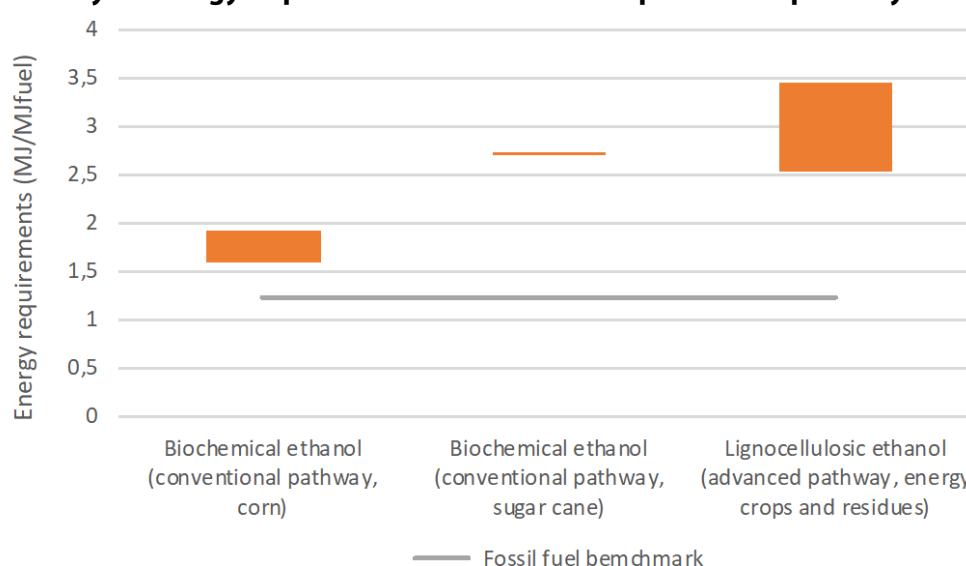
¹⁰ Reason for which all options that risk doing so are already excluded in legislation like the Renewable Energy Directive.

Annex A.1.4 - Energy efficiency of biofuel production via biochemical pathways

All biochemical pathways leading to ethanol are characterised by higher primary energy needs per MJ of fuel with respect to the 1.1 to 1.3 MJ/MJ range of fossil benchmarks (Figure A-2). Lignocellulosic (advanced) pathways require the most biomass inputs per every unit of energy contained in the fuel (a factor between 2.5 and 3.5), while values range between 1.6 and 1.9 for corn and are close to 2.7 for sugar cane (due to the inclusion of large amounts of lignocellulosic material, used on-site for process energy and co-production of electricity¹¹). Biogas production also requires high energy inputs, with MJ/MJ ratios estimated at values close to 2 ([JEC, 2020](#)).

Overall, this indicates a rather low energy efficiency of fuel production from biochemical pathways, on a MJ of biomass grown per MJ of fuel produced.

Figure A - 2 Life-cycle energy requirements for biochemical production pathways



Note: corn-based pathways refer to production in North America. Sugar cane-based pathways refer to production in Brazil. Contrary to the accounting practice adopted in the [GREET model](#) of the Argonne National Laboratory in the United States, on which the numbers in this figure are based, the energy contained in the fuel is also added here to the nominator if the MJ/MJ fuel ratio. This is because the biomasses entering the conversion process as feedstock contain energy that is then available in the final product. The same approach is followed for the fossil fuel benchmark, since the energy contained in the crude oil feedstock is necessary for the energy content of the fuels.

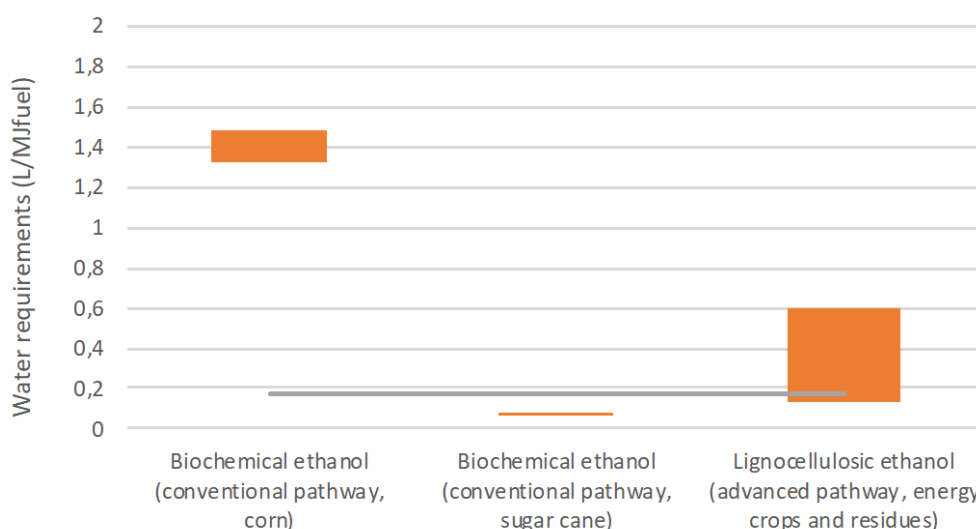
Source: authors' elaboration based on [ANL, 2022a](#) and [ANL, 2022b](#).

¹¹ Since there are not inherently higher energy needs to ferment sugar cane vs fermenting corn, it is worth noting that the primary energy per MJ of fuel for sugar cane could be far lower if the same amounts of lignocellulosic biomass were used as a feedstock for other processes and the heat and electricity that they generate were instead obtained from renewable energy such as solar electricity.

Annex A.1.5 - Water requirements of biofuel production via biochemical pathways

Freshwater requirements for biochemical biofuel production vary widely across pathways. The corn-based pathways of North America (most relevant today in terms of volumes produced globally) require far more freshwater over their life-cycle than the other feedstock options (Figure A-3) and fossil-based references (below 0.2 litres/MJ)¹². Lignocellulosic pathways require up to 0.6 litres/MJ, and the freshwater resource needs for sugar cane ethanol produced in Brazil (the most relevant producer globally for this pathway) are lower, compared with the fossil gasoline benchmark and corn-based pathways, due to higher water availability from rainfall. Values shown in Figure A-3 refer to specific pathways and are generally applicable to cases with high yields (and therefore not to cultivations on marginal land). Should the focus of biomass supply be on land with poorer fertility, water requirements are likely to increase. Water requirements are lowest in pathways that rely on waste feedstock as inputs. This is relevant not only for ethanol, but also for biogas.

Figure A - 3 Life-cycle water requirements for biochemical production pathways for ethanol and ATJ fuels



Note: corn-based pathways refer to production in North America. Sugar cane-based pathways refer to production in Brazil. Water requirements may vary significantly in regions with different degree of reliance on irrigation rather than water from rainfall and depend on region-specific characteristics (especially with respect to rainfall).

Source: elaboration developed for this analysis from [ANL, 2022a](#) and [ANL, 2022b](#).

¹² Water requirements are also significant for other cereal-based pathways, with regional differences across the globe, depending on rainfall.

Annex A.1.6 – Costs of biofuel production via biochemical pathways

Production costs for biochemical biofuels are the result of a balance between feedstock costs and conversion costs of feedstock into fuel (including capital and operating costs). Feedstock costs are lower for lignocellulosic biomass and higher for food and feed products, like cereals ([IEA, 2013](#), [IRENA, 2013](#) and [ICAO, 2018](#)). Conversion costs (i.e. the cost of processing feedstocks to obtain fuels) are higher for lignocellulosic pathways, in comparison with corn, cereals and sugar cane conversion (enzymatic hydrolysis is more complex than conventional fermentation).

Current technology maturity points to lower unit costs for conventional biochemical pathways based on corn, cereals and sugar cane (more mature and produced at a larger scale) than for lignocellulosic pathways (at a lower technology readiness level and scale). Costs are also higher for alcohol-to-jet fuels than they are for ethanol, due to higher energy inputs. Estimates vary with energy and other (e.g. fertiliser) prices. Production costs are also affected by aspects such as crop yields (with marginal land leading to lower yields, and therefore higher costs), the size and configuration of the production facility¹³, and the market value of potential co-products¹⁴.

Magnitudes for production costs (excluding cases of biomass production on marginal land, for which costs are higher due to low productivity, unless there are other revenue streams) were in the range of 15-18 USD/GJ (0.5-0.6 USD per litre of gasoline equivalent, Lge) for both US corn and Brazilian sugar cane ethanol before the recent surge in commodity prices ([IEA, 2018](#), [Irwin, 2021](#) and prices from [US Grains Council, 2019](#)). Accounting for a 70% increase in corn prices and 40% increase in sugar prices vs historical (pre-Covid) values and for a feedstock cost share of 60% for corn in the final production cost (before the price increase) for both corn and sugar cane-based pathways (in line with the information available in [IEA, 2013](#)), suggests that 2022 biofuel production costs are close to 21-26 USD/GJ for corn-based ethanol and to 18-22 USD/GJ for sugar cane-based pathways. This is also consistent with indications from ethanol prices ([US Grains Council, 2022](#)). Due to the maturity of the conversion technologies, future costs are likely to depend in a way that is far more significant on the evolution of commodity prices rather than technological developments. Other impacts on costs may come from the optimisation of biofuel plants for GHG emission reductions and the evolution of electricity prices.

Cost estimates are higher for alcohol to jet than conventional ethanol: 45-55 USD/GJ (1.6-1.8 USD/Lge) for conventional feedstock (corn and sugar cane) and 50-80 USD/GJ (1.7-2.7 USD/Lge) for advanced (lignocellulosic) feedstock ([ICAO, 2018](#) and [ICCT, 2019](#)). In addition, in this case, the values pre-date the recent surge in commodity and other prices. Accounting for the same feedstock cost increase considered above and a lower share of feedstock costs in total leads to cost estimate for current production close to 75 USD/GJ.

If biochemical pathways are reliant on lignocellulosic feedstock, more complex processing steps to obtain alcohol (via enzymatic hydrolysis) lead to higher cost estimates. These have been assessed in a similar range to thermochemical pathways, in the 30-55 USD/GJ range for the near term (before the increase in commodity prices), with potential to decrease to values as low as 30 USD/GJ, if not lower, with technology improvements and scale increases ([IEA, 2013](#), [Witcover, 2020](#)), despite slow progress against similar expectations in the early 2000s ([IEA, 2004](#)) and as long as feedstock prices remain at a level comparable with those observed before Covid. Like thermochemical pathways, these values are also likely to be higher due to the increase in commodity prices, even if the production cost gap is lower than in the case of food and feed crops (due to greater relevance of capital cost vs feedstock costs in

¹³ With costs subject to compromises between unit cost reduction from scale increases and the sparse nature of biomass resources, and opportunities such as waste heat recovery.

¹⁴ With a general tendency for reduced unit value for co-products as production scale increases.

the final biofuel production cost) and if lignocellulosic feedstock prices have not been subject to the same rate of change in the recent past. Considering a 20% increase and a 25% feedstock price (reflecting lower impacts on lignocellulosic feedstock prices of the commodity price increase, in line with historical trends), the share of total production cost (in line with [IEA, 2013](#)) points to an estimate of 2022 lignocellulosic biofuel production costs in the 31.5-58 USD/GJ range.

Production costs of biogas are lower than for ethanol. Estimates are in a range between 10 USD/GJ and 20 USD/GJ. There is only modest scope for cost reductions as the main production technologies are already mature ([IEA, 2020](#)). Additional costs are associated to the need to transport, store and distribute methane. In case of low usage rates of the assets or limited scope to share some of them with other end-uses, these costs could have major impacts on the competitiveness of biomethane as a transport fuel.

Annex A.1.7 - Supply and infrastructure availability for biofuel production via biochemical pathways

The costs of transport and distribution infrastructure for ethanol use can be contained if it can piggyback on existing gasoline infrastructure for petroleum fuels ([ITF, 2021](#)), but this opportunity is limited by the relatively high affinity of ethanol for water, which can potentially lead to greater water contamination of the fuel. Risks associated with water affinity of ethanol have impacts on the fuel distribution infrastructure required and associated costs. In particular, tank trucks may face issue of sediments from previous use contaminating the fuel, and of water leaks able to dissolve in the fuel, lowering its quality ([Trinomics, 2021](#)).

Similar to the case of vehicles, the use of some materials in the ethanol handling and storage equipment should be avoided (ethanol is a good solvent, and may degrade certain materials). Changes may be required concerning aluminium and rubber parts, truck tanks, storage tanks, or fuel dispensers. Hence, substantial costs may be needed along the entire chain¹⁵.

All sustainable fuels require high volumes of sales in case of standalone systems and fuel distribution (e.g. in the case of hydrous ethanol, currently only sold at the pump in Brazil) to minimise capital expenditure per unit of fuel delivered. These add to costs needed to adjust vehicle technologies (with flex fuel vehicles¹⁶ running on hydrous ethanol only marketed in Brazil). For drop-in jet fuels (for aviation) and shipping fuels, transport and distribution infrastructure costs can be minimised if fuels can be delivered to distribution facilities as blends, not if blending has to take place at the end of the distribution chain.

The provision of a fuelling infrastructure (including transport, storage and distribution) is a critical factor for biogas, since dedicated infrastructure for gaseous fuel distribution can face major difficulties to see unit cost reductions, especially with low frequencies of use or limited opportunities to share parts of the infrastructure with other end-uses. For these reasons, biogas is best used in the proximity of production, or, after purification, via injection in the existing gas grid. It is difficult to justify a growth of investments in the scale up of biogas distribution infrastructure in transport, given that this would need to piggyback on the infrastructure in use for methane, in a context where natural gas prices are on the rise and demand for natural gas vehicles is not picking up. Limited scope to reduce life-cycle GHG emissions from natural gas used in transport vehicles is an important hurdle for a significant scale up of biogas as a transport fuel, despite its attractiveness in niche applications. These include local transport vehicles, in particular fleets (as long as they are powered by engines that can run on methane), which may benefit from biogas availability in areas with biomethane production ([Trinomics, 2022](#)).

¹⁵ The consequences of a potential 100% use of ethanol will vary considerably depending on the characteristics of the existing equipment, and may possibly lead to completely replacing all equipment.

¹⁶ I.e. vehicles that can use ethanol or gasoline or a combination of the two, in internal combustion engines.

Annex A.1.8 – Scalability of biofuel production via biochemical pathways

To date, increased production of bioethanol has been primarily driven by policy action across several parts of the World, mainly Brazil, the United States and the EU, consisting mainly of mandates and rebates. Policy action led to significant increases in biochemical biofuel production, especially in the United States, with corn as the primary feedstock. By the year 2010, bioethanol production exceeded 100 billion litres, more than triple the amount of 2002 ([OECD/FAO, 2021](#)). The production increase in the United States over this period was more than fivefold.

Policies developed before 2007 were mainly focused on increasing biofuel supply and demand. Following measures paid growing attention to impacts of biofuels on food and feed prices, environmental concerns, including impacts of direct and indirect land use changes and biodiversity loss. Improved agricultural and smart farming practices may, in the future, open up opportunities for food and feed based (conventional) crops to be part of a future biofuel production mix in a way that enables them to align with sustainability requirements ([DOE, 2022](#)). However, historical developments to date, that saw conventional bioethanol (both for corn and sugar cane) deployed on a large-scale, point towards a misalignment between biochemical biofuel production from food and feed crops and sustainability requirements¹⁷. In particular, increasing demand of biofuels from food and feed crops (in conjunction with parallel pressure from the demand for agricultural products for food and feed purposes) is also paired with a set of market dynamics found to lead to cropland expansion globally, contributing to deforestation ([Searchinger, 2022](#)). Future increases in the use of land for biochemical biofuel production therefore requires a combination of different factors, contributing to a progressive, rather than a sudden process, to be sustainable. These factors include:

- an increased shift towards cellulosic feedstock ([ICL, 2021](#)), assuming good forest management practice are in place, and towards other waste-based feedstock;
- selective identification of options (e.g. harvesting practices) that do not result in removal of soil carbon stocks;
- the cultivation of crops in zones with sustainable agronomic practices in farming land and in land with natural constraints (unused, abandoned, and degraded land) ([Panoutsou et al., 2022](#));
- the exclusion of options whose use would release large quantities of carbon (irreplaceable within a reasonable time scale), in favour of options (e.g. managed forests and limited extraction of wood and energy) that can increase forest growth ([IRENA, 2019](#));
- clarity and in regulations to account for feedstock, agricultural and forestry practices that lead to land use change risks¹⁸, also in light of weaknesses in the link between increased demand for biomass resources and improved agricultural or forest management responses, (see [Giuntoli et al., 2019](#) for the forest case)¹⁹;
- and technological progress in the conversion processes ([IEA Bioenergy, 2019](#), [DOE, 2022](#)).

Due to the challenges associated with land use for energy production and the likely increases in value of material uses of biomass – for timber, fibre, and chemicals ([Material economics, 2021](#)), it will also be critical to prioritise the increase in sustainable bioenergy production in hard-to-abate sectors, like

¹⁷ The same is true for oleochemical pathways – see next section.

¹⁸ These include, for example, avoiding diverting to bioenergy the use of wood chips, saw dust, and black liquor already needed by competing activities, such as sawmills, leading to a net increase in demand for biomass. In agriculture, this includes the diversion of residues towards the bioenergy sector, inducing substitution for uses already in place (e.g. bedding, heat and power production) when it is not compensated by practices (such as increased reliance on renewable electricity production) freeing up sustainable biomass resources for biofuel production.

¹⁹ Asset (and job) stranding are additional and very relevant risks that may arise from misalignments between investment decisions and sustainability requirements.

aviation and maritime transport, rather than use these options for transport segments that can be more easily electrified.

Regarding biogas, a growing and large-scale role in transport in the future is unlikely ([Trinomics, 2022](#)), even if there are cases of biomethane plants producing fuels for the transport sector ([IEA, 2020](#)). Reasons for scepticism on a scale up of biogas in transport are the following:

- Available biomethane is likely to primarily serve the current major uses of natural gas, such as heating and cooking, especially in a context where there is a need to substitute fossil gas in existing end-use sectors (for energy supply security and decarbonisation reasons).
- Due to localised and limited feedstock supply, mostly relying on waste streams (unless very large quantities of bio-LNG are imported in the future), combined with cost minimisation imperatives, biogas is best used in the proximity of production, or, after purification, via injection in the existing gas grid.

Annex A.2.1 - Identification of the main options/applications of biofuel production via oleochemical and lipid pathways

Since oleochemical pathways lead to fuels that are similar to fossil diesel (in the case of FAME biodiesel) or are fully compatible for high blends with diesel or jet kerosene (in the case of HVO/HEFA), they are technically best suited for vehicle categories that are largely reliant on these fuels: heavy-duty road vehicles, aviation, and maritime transport. For the same reasons, oleochemical biofuels are also technically suitable for diesel cars.

In the case of maritime transport, oleochemical biofuels have better fuel quality than residual fuel oil, a low-grade fuel largely used in ships. Oleochemical biofuels have closer characteristics to marine diesel, but with lower sulphur content. Fuel quality can also be better than petroleum fuels for drop-in oleochemical biofuels (HVO/HEFA) used in aviation and road applications. The quality gap is largest for marine fuel, followed by aviation fuel, and narrowest for road fuel (because existing quality standards and specifications tend to get stricter moving from maritime to aviation and road fuels)²⁰.

²⁰ Better fuel quality has major implications for emissions of local air pollutants. In aviation, it is also important for non-CO₂ climate forcing effects.

Annex A.2.2 - Life-cycle GHG emissions of biofuel production via oleochemical and lipid pathways

Values from the [GREET model](#) of the Argonne National Laboratory in the United States, focused on oleochemical pathways using food and feed crops (vegetable oil) and including estimates of the effects of land use change, suggest a range of life-cycle emissions between 30 and 60 g CO₂e/MJ ([ANL, 2022b](#), [Cai et al., 2022](#))²¹. This should be compared with a benchmark close to 86 g CO₂e/MJ for petroleum fuels considered in the GREET model ([ANL, 2022a](#) and [ANL, 2022b](#)).

This indicates that, similarly to bioethanol from conventional feedstock, this pathway allows for a reduction in life-cycle GHG emissions in comparison with the fossil equivalent, without however offering the potential for a zero- or near-zero-emission solution. Uncertainties regarding the estimation of GHG emissions due to land use change ([Malins et al., 2020](#) and [Taheripour et al., 2021](#)) add a layer of uncertainty to this assessment, also calling for strict policy focus on the necessity to align biofuel production with sustainability requirements.

Used cooking oil (UCO) produces the lowest life-cycle GHG emissions (15 to 25 g CO₂e/MJ according to the review of [Prussi et al., 2021](#)), as long as its use does not lead to indirect land use change (which would be possible in case the reliance on UCO-based biofuels also triggers an increased demand for UCO substitutes, such as virgin vegetable oils for other uses or applications). Palm oil, because of its high indirect land-use change risk, is also subject to high life-cycle emissions ([ITF, 2021](#)).

As for biochemical biofuel production pathways, the feedstock cultivation/collection process and the feedstock-to-fuel production process are the two elements that contribute most to the life-cycle emissions²².

²¹ This is based on system boundaries that include energy flows needed for agricultural practices, feedstock collection and facilities converting lipid feedstocks into biofuels.

²² For example, closed pond for the palm oil mill effluent (POME) can capture 85% of methane emissions compared to an open pond, decreasing life-cycle emissions from 60 g CO₂e/MJ to 37.4 g CO₂/MJ ([Prussi et al., 2021](#)).

Annex A.2.3 - Land use and land-use change risks of biofuel production via oleochemical and lipid pathways

For UCO and other waste oils, such as corn-based oil (a by-product of corn crops cultivated for food), the cultivation and collection emissions are very low due to their waste and by-product nature, but effects related with indirect land use change, most relevant in case of significant scaling up of demand (leading to increased indirect demand for virgin oils), can change this²³.

Similar to biochemical pathways, land use requirements for oleochemical pathways based on crops are the result of the combined effect of biomass yields and process conversion. Emissions from the indirect land use change (ILUC) of feedstock production can be very significant, especially in cases where expansion of cropland leads to deforestation (as occurred in countries like Indonesia for the production of palm oil²⁴). The [ICCT \(2019\)](#) estimates ILUC emissions of 231 gCO₂e/MJ for palm oil feedstock used for HEFA production, based on results of the GLOBIOM model ([Valin et al., 2015](#)). These estimates are significantly higher than those resulting from GREET. Life-cycle emissions of HVO or HEFA including land use change effects also reach values over 200 g CO₂e/MJ in the work developed, for the assessment of life-cycle emissions for aviation fuels, by [Prussi et al., 2021](#)²⁵.

As discussed for biochemical pathways, all biofuels requiring cropland have far higher land use requirements than RFNBOs ([KiM, 2022](#)). All pathways based on waste are paired with lower land use, but only to the extent to which their increase does not induce increased land use requirements. Cultivation in zones with sustainable agronomic practices both in farming land and in land with natural constraints (unused, abandoned, and degraded land), and therefore with low indirect land use change risk, could help produce oleochemical with low environmental impact feedstocks and economic benefits to farmers ([Panoutsou, 2022](#)).

²³ For UCO, the risk of waste oil fraud from imported waste oils is also relevant. Due to the nature of used cooking oil, it is difficult to test and ensure it is a waste product.

²⁴ This occurred not only for increased demand as a biofuel production feedstock.

²⁵ The highest boundary includes life-cycle emissions due to indirect land use change, in the case of palm oil in particular (see next section "Land use and land use change risks"). [Prussi et al., 2021](#) also show that estimates of life-cycle emissions from waste products could be as low as 14 g CO₂e/MJ, without land use change effects.

Annex A.2.4 - Energy efficiency of biofuel production via oleochemical and lipid pathways

The feedstock-to-fuel processing energy requirements are generally low across all oleochemical pathways, with some differences depending on the technology used. The GREET assessments for total energy inputs per unit energy in the fuel, for HEFA pathways, ranges between 1.3 and 1.5 MJ/MJ²⁶. This is below the values characterising all biochemical pathways (see Annex A.1.4).

²⁶ Contrary to the accounting practice adopted in GREET, the energy contained in the fuel is added here to the nominator of the MJ/MJ fuel ratio, as in the case of Figure A.2. This is because the biomasses entering the conversion process as feedstock contain energy that is then available in the final product. The same approach is followed for the 1 to 1.3 ratio for fossil fuels.

Annex A.2.5 - Water requirements of biofuel production via oleochemical and lipid pathways

According to the analysis developed in the GREET model for oleochemical pathways based on food and feed crops (conventional) ([ANL, 2022b](#)), freshwater requirements per unit of energy contained in the biofuel are comparable with those of fossil fuels (below 0.2 L/MJ). This reflects that Rain pathways considered in GREET for oleochemical biofuels production are more reliant on rainfed crops, which have low additional water use (irrigated production would be paired with very high water requirements). Direct freshwater requirements for oleochemical pathway biofuels from waste oils are even lower, as their use is shared with the primary purposes for which waste oils have been produced (e.g. food use). Similar to GHG emissions due to indirect land use change, freshwater requirements increase, also for waste oils, when they induce increased demand for virgin oils.

Annex A.2.6 – Costs of biofuel production via oleochemical and lipid pathways

Oleochemical biofuel production costs are largely dependent on feedstock costs. Estimates pre-dating the price surges observed after the Russia/Ukraine war are in the range of 25-35 USD/GJ (0.8-1.2 USD/Lge) for pathways based on virgin vegetable oils ([IEA, 2013](#), [IRENA, 2013](#), [ICCT, 2019](#) and [ICAO, 2018](#)). Technological developments are unlikely to have significant impacts on cost reductions, as conversion technologies for oleochemical feedstock are mature. For the same reason, feedstock cost variations have significant impacts on the cost of production of oleochemical biofuels. Considering an 80% share of feedstock cost before the commodity price increase of 2022 (in line with [IEA, 2013](#), which shows that production costs of fuels from oleochemical pathway largely depend on the cost of the feedstock), along with a 60% increase of vegetable oil prices, indicates that production costs for oleochemical pathways reliant on vegetable oil as feedstock are closer to 50-55 USD/GJ.

Efficient supply chains for the availability and mobilisation of cheap feedstock, such as UCO, may help lower costs, but within the limits of its availability and supply potential²⁷. Due to the high contribution of feedstock costs to the total cost of HEFA production, it is also unlikely that production costs for oleochemical biofuels in general will decrease significantly in the future, unless there are large changes in vegetable oil prices ([ICCT, 2019](#)).

Like other biofuel pathways, this means that oleochemical biofuels can compete with petroleum-based alternatives only in cases where supply chains of waste oils are effectively streamlined or with increasing fossil fuel prices (e.g. as a result of carbon taxes or supply disruptions), even if some cost reductions are still possible from larger-scale conversion facilities²⁸.

²⁷ Waste oils have been estimated to be capable of covering up 10% of the aviation fuel demand of 2019 ([ICAO, 2018](#) and [World Economic Forum, 2020](#)). Aviation currently accounts for roughly 12% of all final energy use and direct GHG emissions in transport ([IEA, 2022](#)).

²⁸ The use of hydrotreating facilities already available in refineries is an interesting solution in this context, since it allows minimising capital costs. These same facilities can also be paired with low-carbon hydrogen to improve the life-cycle GHG emission profile of the fuels, without significant energy efficiency losses in case of replacements of hydrogen from steam methane reforming with renewable hydrogen from electrolysis.

Annex A.2.7 – Supply and infrastructure availability for biofuel production via oleochemical and lipid pathways

Regarding the transport, storage, and delivery infrastructure, replacing petroleum diesel with e.g., FAME biodiesel is feasible, but it requires equipment adaptations of the existing assets (with cost implications). This is due to the need to avoid the use of some materials in the handling and storage equipment because of the different chemical composition of FAME biodiesel ([Trinomics, 2021](#))²⁹. The consequences of a 100% use of FAME will vary considerably depending on the characteristics of the existing equipment, and may possibly lead to a complete replacement of all equipment.

HVO and HEFA technologies allow to bridge the infrastructure-related barriers discussed for FAME biodiesel, as they can be fully blended with petroleum diesel and jet fuels.

²⁹ There are several characteristics of the fuel that differentiate it from conventional diesel. Changes may concern piping, pump devices, meters, oil rail tank cars, and storage tanks (e.g. preventing material degradation requires epoxy coating in inner, or in cold countries, adding thermal insulation may be required). Hence, substantial costs may be needed along the entire chain.

Annex A.2.8 – Scalability of biofuel production via biochemical pathways

Similar to the case of bioethanol, increased production of oleochemical biofuels has been primarily driven by policy action, consisting mainly of mandates and rebates. The first wave of policies that led to an increase of biodiesel production includes, in particular, the European Directive on the promotion of the use of biofuels or other renewable fuels for transport ([European Commission, 2003](#)). The greater focus on diesel reflects a stronger reliance of the EU on this fuel, for road transport (due to adoption also in the passenger car segment). By the year 2010, 12 billion litres of biodiesel were produced in the EU, out of a global total of 20 billion litres, and up from roughly 2 billion litres in 2002 ([OECD/FAO, 2021](#)). The wave of bioenergy policies implemented globally after the year 2007 (as outlined in the section on biochemical pathways) led to an expansion of oleochemical biofuel production, mainly in the United States, Brazil and Indonesia, reaching almost 50 billion litres by now ([OECD/FAO, 2021](#), [IEA, 2021](#), [IEA, 2022c](#)).

Similar to the case of biochemical biofuel production pathways, significant European and global reliance on virgin vegetable oils as feedstock for biofuel production ([IEA, 2022c](#), [USDA, 2021](#), [T&E, 2021](#), [Cerulogy, 2022](#) and [Neste, 2022](#)) point towards a misalignment between this historical oleochemical biofuel production developments and sustainability requirements ([Searchinger, 2022](#)). This is mainly due to the severe effects of direct and indirect land use change, as discussed in the previous sections.

Looking forward, the extent to which sustainable feedstock will be available for processing in the new conversion facilities being built, especially in a context of an accelerated development, is unclear ([Trinomics, 2022](#)). Waste oils (in particular UCO) are the most relevant sustainable near-term supply). However, they are hampered by limited supply potential: waste oils have been estimated to be capable of covering up to 10% of the aviation fuel demand of 2019 ([ICAO, 2018](#) and [World Economic Forum, 2020](#), and aviation currently accounts for roughly 12% of all final energy use and direct GHG emissions in transport ([IEA, 2022](#)). UCO is also subject to risks of inducing indirect demand for virgin oils through substitution of the waste products with the oils and fraud, through the false description of biodiesel as sourced from UCO to illegally claim various national subsidies and tax breaks ([Michalopoulos, 2019](#) and [European Anti-Fraud Office, 2019](#)).

Indirect land use change effects limit the ability of oleochemical biofuels produced at scale³⁰ to align with sustainability requirements. This also increases pressure on food and feed prices ([Trinomics, 2022](#), [Cerulogy, 2017](#)).

As in the case of biochemical pathways, due to the challenges associated with land use for energy production, it will be critical to channel any increase in sustainable bioenergy production towards hard-to-abate sectors in priority, in particular aviation and maritime transport. This is because these have fewer other sustainable options compared to shorter-distance and lighter transport modes. This prioritisation is also aligned with greater reliance on diesel fuel and other middle distillates in these modes, offering stronger impacts (in terms of emission reductions for these sectors) for the same volumes of sustainable fuels than if these options were used for the (much larger) overall fuel demand, including for land transport.

³⁰ Biofuels from oleochemical feedstocks produced from the most sustainable agricultural practices are an exception, but they are likely to be available in limited volumes.

Annex A.3.1 - Identification of the main options/applications of biofuel production via thermochemical pathways

Thermochemical biofuels can be designed to be suitable as gasoline or diesel/middle distillate substitutes or as drop-in options. They are therefore technically suitable for a wide range of modes of transport, including cars and light vehicles (running on gasoline or diesel fuel), heavy-duty road vehicles (mainly using diesel), aviation (using jet fuel), and maritime transport (using diesel or heavy fuels).

As in the case of oleochemical pathways, thermochemical biofuels have better fuel quality than petroleum fuels (unless these are also upgraded). This is due to lower sulphur content and the characteristics of molecules characterising them.

As discussed in the section on biochemical biofuels, the use of biomethane in transport is possible, but also limited to scattered opportunities. These are due to the low reliance on natural gas as a transport fuel globally and to limited scope for growth, due to difficulties of natural gas – available in far larger volumes in comparison with biogas, and therefore crucial for a switch in infrastructure – to ensure deep emissions reductions in transport, on a life-cycle basis ([Cai et al., 2022](#)).

Annex A.3.2 - Life-cycle GHG emissions and energy efficiency of biofuel production via thermochemical pathways

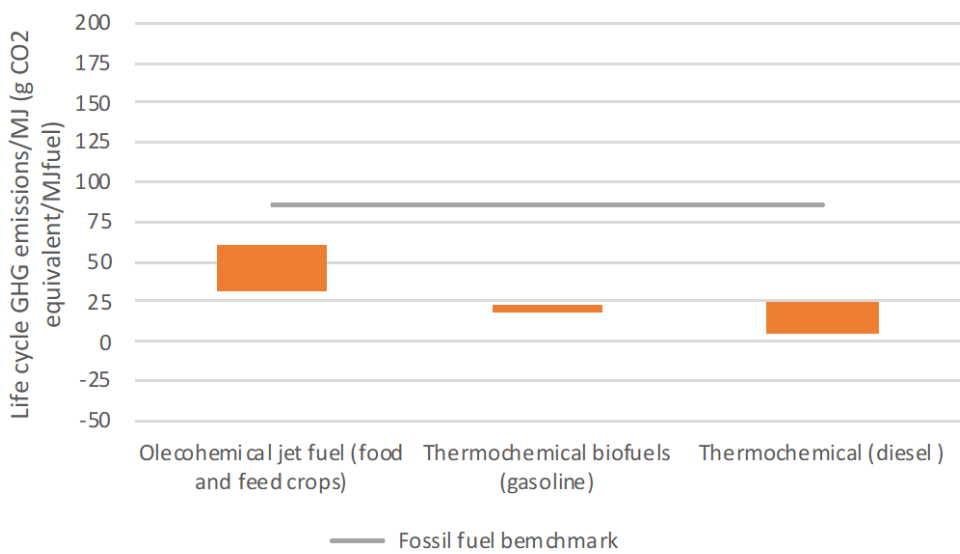
Thermochemical pathways for fuels that can be blended into gasoline and diesel fuel (similar considerations also apply to aviation fuels) are characterised by lower GHG emissions per MJ compared with petroleum-based fuels but also higher primary energy requirements per MJ of fuel (and therefore lower energy efficiency). They also have a greater reliance on biomass resources (Figure A-4 shows results based on the GREET model of the Argonne National Laboratory for these pathways).

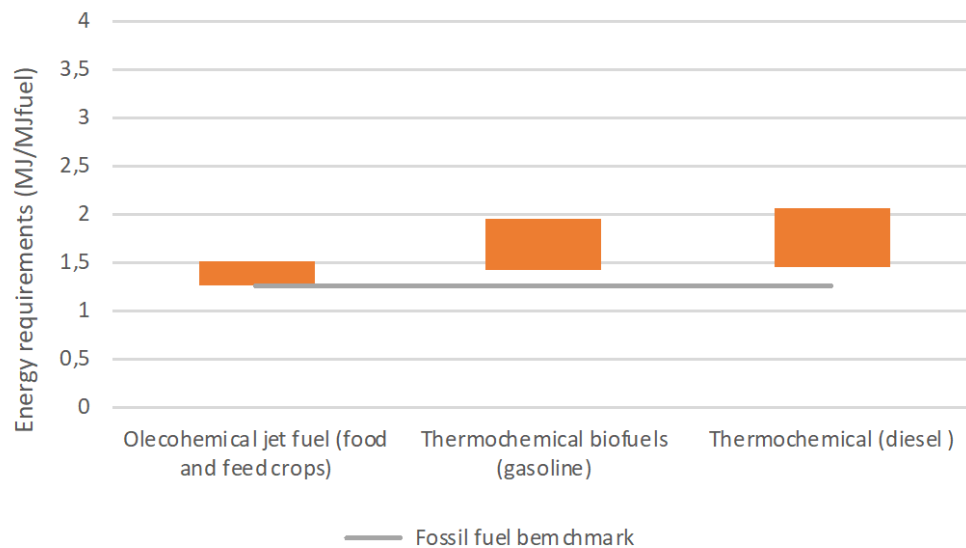
Life-cycle GHG emissions (excluding land use change) are comparable with those observed for lignocellulosic ethanol (due to the fact that primary energy and process feedstocks are similar). Energy efficiency is better than for lignocellulosic ethanol, but still poorer than any other biofuel production pathway considered, meaning that thermochemical biofuels still require large amount of primary biomass per unit of energy contained in the fuel.

While energy crops and residues lead to significant reductions in GHG emissions, the use of non-biogenic municipal solid waste as a feedstock through the Fischer-Tropsch (FT) process can result in emissions greater than 170 g CO₂e/MJ (ITF, 2021). The life-cycle emissions, in these cases, largely depend on the origin of the waste. Emissions are very high when the combustion of carbon is not offset by the carbon absorption of feedstock growth, as in cases where waste contains carbon of fossil origin. In contrast, if municipal solid waste is 100% biogenic, life-cycle emissions can be as low as 5 g CO₂e/MJ (Prussi et al., 2021).

The use of waste feedstocks (and the replacement of processes that would otherwise release GHG emissions in the atmosphere) are both crucial to enable low life-cycle GHG emissions for thermochemical biomethane. In the US and EU markets, waste-to-methane production from processes using wastewater sludge and animal manure as feedstocks present the biggest opportunities to reduce WTW GHG emissions over those petroleum fuels (Cai et al., 2022).

Figure A - 4 Life-cycle GHG emissions and energy requirements for petroleum-based fuels and thermochemical biofuel production pathways from lignocellulosic and waste feedstocks





Note: Contrary to the accounting practice adopted in GREET, the energy contained in the fuel is added here to the nominator of the MJ/MJ fuel ratio, in line with the practice adopted in Figure A-2. This is because the biomasses entering the conversion process as feedstock contain energy that is then available in the final product. The same approach is followed for the fossil fuel benchmark, since the energy contained in the crude oil feedstock is necessary for the energy content of the fuels.

Source: elaboration developed for this analysis from [ANL, 2022a](#) and [ANL, 2022b](#).

Annex A.3.3 - Land use and land-use change risks of biofuel production via thermochemical pathways

Indirect land use change effects are inherently low for waste-based pathways, while they depend on biomass yields, conversion efficiency, biomass input requirements and substitution effects with alternative land uses for energy crops. Current estimates for thermochemical biofuel pathways are similar, in this respect, to those developed for lignocellulosic biofuel pathways.

Overall, as discussed for biochemical and oleochemical pathways, all pathways requiring cropland (including dedicated lignocellulosic crops) have far higher land use requirements than RFNBOs ([KiM, 2022](#)). Waste-based biofuels are paired with lower land use, but only if their production increase does not induce indirect land use changes via product substitution and increased overall demand for feedstocks needing cropland in other sectors of the economy.

Annex A.3.4 - Water requirements of biofuel production via thermochemical pathways

Thermochemical biofuels are subject to lower water requirements per unit of energy contained in the fuel if they rely on pyrolysis and residues as feedstock (when both conditions apply, water requirements are lower than petroleum fuels) and higher (comparable with lignocellulosic biochemical conversion, and close to 0.6 L/MJ of fuel, i.e. more than three times higher than in the case of petroleum fuels) for energy crops and Fischer-Tropsch conversion ([ANL, 2022a](#)). Lower water requirements for waste-based pathways also apply to biomethane ([ANL, 2022a](#)).

Annex A.3.5 – Costs of biofuel production via thermochemical pathways

Thermochemical biofuels, and in particular fuels produced through a gasification/Fischer-Tropsch process, are subject to large upfront capital investments. Overall cost estimates (developed before the recent commodity price increase) are likely to range between 45 and 55 USD/GJ (1.5 to 1.8 USD/L) ([ICCT, 2019](#), [ICAO, 2018](#)), but more optimistic cost assessments, as low as 30 USD/GJ (1 USD/Lge), have also been reported ([IEA, 2013](#), [IRENA, 2013](#), [Hannula, 2016](#) and [ICAO, 2018](#)). This shows that there can be room for improvement if technological developments enable an increase in the level of technology readiness and other barriers, reducing capital cost³¹. Increases in prices of lignocellulosic feedstock may be relevant, especially in case of changes in primary demand due to substitution of fossil energy (namely gas) for space heating. However, impacts on production cost estimates are mitigated by the higher share of capital investments in comparison with other pathways. This suggests that the rate of increase vs estimates developed before the recent commodity price increase (affecting mainly operational costs) may be lower than for oleochemical and other food-based pathways. Whether or not this would be the case also depends on impacts of the changes in commodity prices on capital costs (e.g. due to increased demand for plant construction and changes in the cost of materials, like metals needed for the plant construction).

For biomethane, costs are estimated in the same range already discussed in Annex A.1.6, i.e. between 10 and 20 USD/GJ ([IEA, 2020](#)). These are net of incremental costs related to transport, storage, and distribution infrastructure (clearly benefiting from sharing with other end-uses to be minimised).

³¹ The share of CAPEX are estimated at approximately 60% of production costs for agriculture residue feedstocks and roughly 80% for municipal solid waste (assumed cheaper) ([ICCT, 2019](#)).

Annex A.3.6 – Supply and infrastructure availability for biofuel production via thermochemical pathways

Similar to HVO and HEFA technologies, thermochemical pathways can be produced as drop-in fuels, allowing to bridge infrastructure-related barriers, as they can be fully blended with petroleum fuels, despite important changes along the upstream value chain.

As discussed in Annex A.1.7 for biochemical biomethane, renewable natural gas would need to share infrastructure with natural gas of fossil origin or target specific fleets to reduce costs ([Trinomics, 2022](#)).

Annex A.3.7 – Scalability of biofuel production via thermochemical pathways

Thermochemical pathways have, as in the case of lignocellulosic biochemical conversion, the advantage to rely on primary biomasses other than food and feed crops. These biomasses have the clear advantage of a better sustainability profile, but only to the extent to which they can rely on wastes and residues, since direct competition for energy crops could still increase pressure on land use change, and therefore on deforestation ([Searchinger, 2022](#)) and other environmental and economic pressures ([PNAS, 2022](#)).

While the reliance on primary biomasses other than food and feed crops is clear, it is relevant to flag that there are processes benefiting from cost savings from the joint harvest of food and feed crops, with other forms of biomass, suitable for thermochemical (but also biochemical) conversion: a key example is sugar cane ethanol, which is paired with the collection of large amounts of lignocellulosic material (bagasse), generally used to produce energy for the conversion plant. Similar examples can apply to corn grain (used for biochemical ethanol production) and corn stover (which can be a feedstock for biochemical or thermochemical conversions of cellulosic feedstocks).

Similar to lignocellulosic biochemical pathways, future increases in thermochemical biofuel production require a combination of different factors: in addition to the reliance on cellulosic feedstocks ([ICL, 2021](#)) or biomass residues, these include the selective identification of options that do not result in the removal of soil carbon stocks, the exclusion of options whose combustion would release large quantities of carbon (irreplaceable within a reasonable time scale), regulatory requirements that exclude agricultural and forestry practices that lead to land use change risks, as well as technological progress in the conversion technology ([IEA Bioenergy, 2019](#), [DOE, 2022](#))³².

As already pointed out earlier for biochemical and oleochemical pathways, the challenges associated with land use for biofuel production call for a prioritisation of biofuels in sectors where they are more cost-effective options than competing decarbonisation options, such as direct electrification or the use of low-carbon hydrogen as an energy vector. This is primarily the case for aviation and maritime transport.

Regarding biomethane, a number of important hurdles limit its significant adoption as transport fuel. These include the need to share fuelling infrastructure with fossil natural gas, limited scope to reduce life-cycle GHG emissions from fossil natural gas used in transport vehicles, competing demand for methane in other end-uses, limited supply potential for renewable natural gas and biomethane ([Cai et al., 2022](#)) and a strong near-term need for the replacement of existing methane demand ([European Commission, 2022](#)).

Due to their capacity to significantly increased fuel yields from biogenic carbon sources, power and biomass-to-liquids (PBtL) fuels, blending biofuel production with renewable hydrogen or other low-carbon hydrogen pathways³³ can offer relevant contributions to ease these challenges. A brief summary of their key characteristics is summarised in Box A.1..

³² See the discussion developed for advanced biochemical pathways, reliant on the same type of feedstocks, for greater details on these points.

³³ The use of fossil hydrogen to integrate biogenic feedstocks would have detrimental impacts on life-cycle GHG emissions, unless life-cycle emissions from fossil hydrogen can be abated (see section 2.3.1 regarding this).

Box A.1 Power and biomass-to-liquids (PBtL) fuels

Power and biomass-to-liquids (PBtL) are fuels obtained from the combination of renewable hydrogen (from electrolysis) and biogenic feedstocks, derived from biomass and containing both carbon and hydrogen. They come with the advantage to significantly improve the fuel yield from biogenic carbon ([Hannula, 2016](#)).

Similar to thermochemical biofuels and other synthetic fuels, PBtL fuels can technically be designed to be suitable for a variety of fuel blends, including gasoline and diesel/middle distillates, and also as drop-in options.

PBtL produced with biogenic feedstocks and renewable hydrogen can have low life-cycle GHG emissions intensities, comparable or lower than thermochemical biofuel pathways that the addition of renewable hydrogen allows to complement.

The increase in the biofuel yield per unit of biogenic carbon available in the biomass feedstock enabled by PBtL pathways (applicable to biochemical or thermochemical biofuel production processes) reduces land use and fertiliser requirements per unit of fuel produced, with positive implications for better sustainability.

Benefits in terms of land use come with a cost of higher energy (in particular renewable electricity) requirements for the additional conversions required by PBtL fuels, in comparison with biochemical or thermochemical processes not integrating the addition of renewable hydrogen.

The same positive impacts observed for increase in the biofuel yield per unit of biogenic carbon can also lead to lower freshwater requirements, since water needs for renewable hydrogen tend to be lower than those needed to grow biomass, unless biomass growth can be mainly rainfed or is mainly sourced from waste. In such cases, PBtL may have comparable or higher water requirements than biochemical and thermochemical biofuels produced without the integration of renewable hydrogen.

If cost challenges related to renewable hydrogen production are overcome and technology readiness is increased, PBtL fuels can gain a commercial advantage over processes that are not enhanced by the integration of low-carbon hydrogen. PBtL costs have been estimated to be more competitive than the costs of thermochemical biofuels (based on biomass gasification) obtained without renewable hydrogen integration if renewable hydrogen costs fall below EUR 2.2 (USD 2.6) to EUR 2.8 (USD 3.3) per kg, depending on the process configuration ([Hannula, 2016](#)).

Annex A.4.1 - Identification of the main options/applications of renewable hydrogen production

Key applications are the use of hydrogen as a feedstock for chemical processes (as it is already the case today, especially in refining and fertiliser production). Possible applications are still as a feedstock/intermediate for the production of chemicals and fuels, as well as a reducing agent in steelmaking.

An important question in the use of hydrogen for transport is whether hydrogen could be used as a fuel in itself or whether it will mostly be an intermediary in the synthesis of hydrocarbons or ammonia. The direct use of hydrogen as a fuel in end-use applications has implications on infrastructure and storage needs in order to deliver the fuel to end-users, and on vehicle powertrain and fuel tank (e.g. fuel cell electric vehicle to be fitted with a hydrogen tank). Renewable hydrogen derivatives (e.g. liquid e- hydrocarbons) have different implications, addressed in the next section.

Powertrains enabling the direct use of hydrogen as a fuel include:

- adapted internal combustion engines and turbines, in which hydrogen is combusted (releasing energy and water);
- fuel cells, in which the hydrogen is transformed into electricity driving an electric motor and which releases water³⁴.

Hydrogen in transport can be used under liquid (LH₂) and compressed gaseous forms (CGH).

³⁴ While water vapour is mostly a GHG, the additional amount of water emitted from fuel combustion or via a fuel cell is tiny compared with the natural hydrological cycle and is therefore not having significant climate change impacts ([Lee, 2018](#)).

Annex A.4.2 - Life-cycle GHG emissions and energy efficiency of renewable hydrogen production

The main avenue of choice for the production of renewable hydrogen from pathways of non-biological origin is through the splitting of water into H_2 and O_2 . This process, called electrolysis, requires electricity as input, which must come from renewable sources in order for the hydrogen produced to qualify as an RFNBO. Hence, the scale-up of such a process implies the scale-up of renewable electricity generation capacities.

The top section of Figure A-5 summarises life-cycle GHG emissions from different forms of electrolytic hydrogen, benchmarking them against the cases of hydrogen production from fossil resources. Values at the top of the range refer to liquid hydrogen production (more energy intensive), while values at the bottom of the range refer to gaseous hydrogen³⁵.

Figure A-5 points to a significant capacity for renewable hydrogen (shown in orange) to cut life-cycle GHG emissions with respect to conventional fossil-based pathways and grid electricity³⁶. Figure A-5 points also to slightly poorer life-cycle GHG emission performances for hydrogen from nuclear electricity and from biomass³⁷, in comparison with renewable hydrogen.

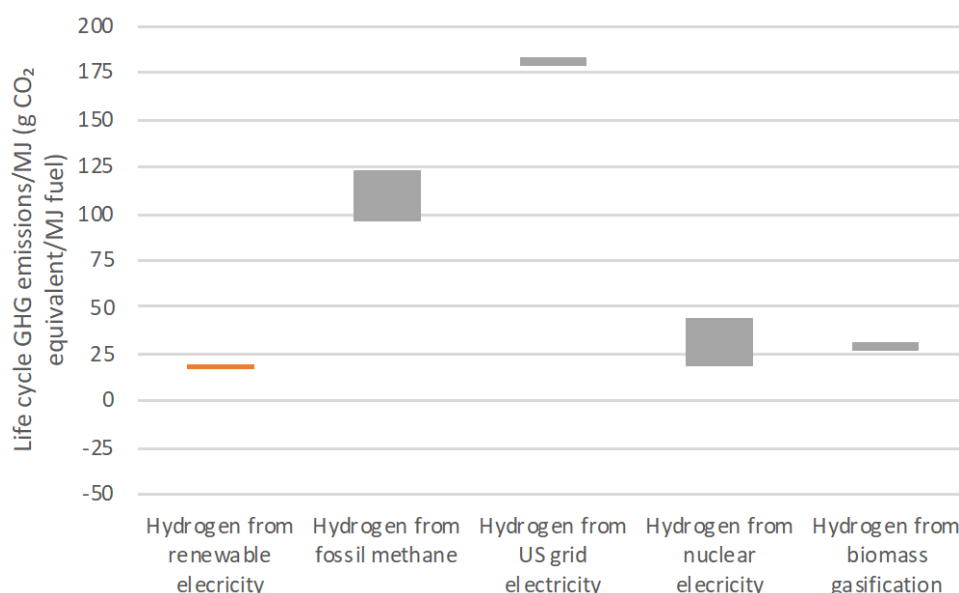
Regarding life-cycle GHG emissions of hydrogen, it is also important to flag that recent findings have shown that hydrogen leakage (e.g. due to the need for hydrogen venting to maintain it in stable conditions in storage tanks) can have significant drawbacks for the mitigation of climate impacts. This requires hydrogen emissions from transport, storage, and distribution facilities to be thoroughly controlled and limited, in order to align hydrogen (even if produced from renewable electricity) with climate policy goals³⁸. Recent estimates, in particular, have shown that there is strong timescale dependence when evaluating the climate change mitigation potential of clean hydrogen alternatives. In particular, if renewable hydrogen with emission rates due to leakage or venting close to 10% was used to fully replace fossil fuels, it would only cut climate impacts in half over the first two decades (which is far from the common perception that green hydrogen energy systems are climate neutral). Over a 100-year period, climate impacts could be reduced by around 80%. Lower levels of hydrogen leakage or venting (1%) enable deep reductions in climate impacts over all timescales ([Ocko and Hamburg, 2022](#)).

³⁵ The energy requirements shown in Figure A-5 values are similar to the 1.45 values identified in [FVV \(2022\)](#) for hydrogen production, to which [FVV \(2022\)](#) adds 0.15 MJ/MJ due to losses at the station and for compression.

³⁶ Results for grid electricity refer to the US (the focus of the GREET model used to produce the figure), which has a higher carbon intensity than the EU. Using the average carbon intensity of electricity production in the EU would still point to significantly higher GHG emissions per MJ, even if lower than in the US.

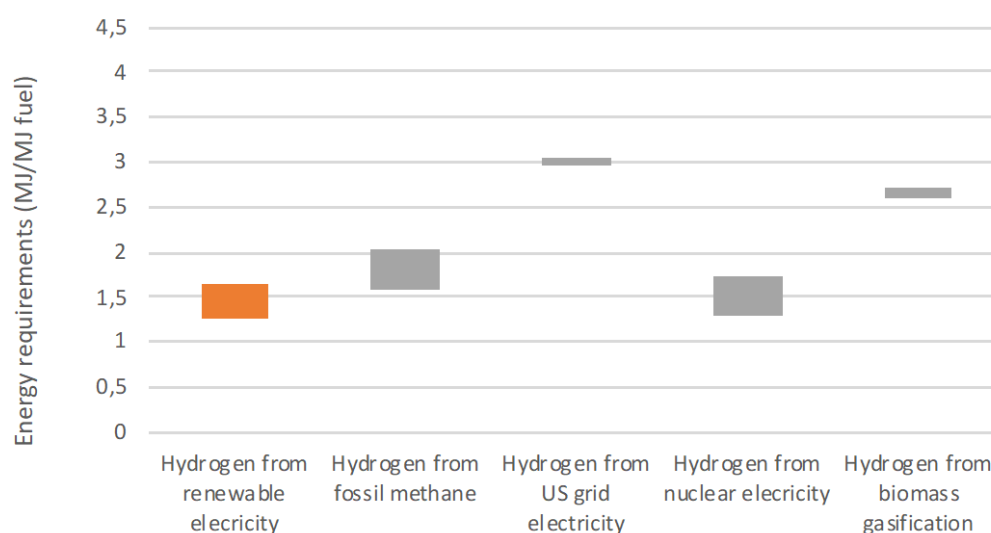
³⁷ In the case of hydrogen from biomass, GHG emissions per MJ are also higher than for advanced biofuels containing carbon. These results reflect a lower energy content in the hydrogen alone, if produced from biomass, than in the case of hydrocarbon production. This indicates that the production of hydrocarbons is a better use of biomass resources than the production of hydrogen alone.

³⁸ Regarding leakage, hydrogen's has an indirect global warming effect through mechanisms that extend the lifetime of methane and other greenhouse gases (GHG) in the atmosphere ([Fan et al., 2022](#), [Paulot et al., 2012](#), [Derwent et al., 2020](#), [Ocko and Hamburg, 2022](#)).

Figure A - 5 Life-cycle GHG emissions for renewable hydrogen production against other production pathways

Source: elaboration developed for this analysis from [ANL, 2022a](#) and [ANL, 2022b](#).

Figure A-6 shows the amounts of primary energy needed by these pathways.

Figure A - 6 Energy requirements for renewable hydrogen production against other production pathways

Notes: primary energy accounting for nuclear electricity does not consider heat losses (this also applies to the portion of nuclear in the US grid mix). Energy requirements are roughly three times larger for hydrogen from nuclear electricity if heat losses are accounted for. Energy and emissions for hydrogen from low-carbon electricity exclude amounts needed to build renewable energy production capacity, transport, distribution and storage infrastructure. Energy and emission values at the top of the ranges refer to liquid hydrogen, values at the bottom of the ranges to gaseous hydrogen production. Contrary to cases of biofuels and fossil fuels, and in this case in line with the accounting practice adopted in GREET, the energy contained in hydrogen is not added, for electrolytic production processes, to the nominator of the MJ/MJ fuel ratio. This is because the energy inputs required to provide energy to the fuel need to enter the process in the form of electricity and not as part of the feedstock (water), as water is also a product of the chemical conversion of hydrogen. For processes other than electrolytic production, the energy present in feedstocks other than water is included in the nominator of the MJ/MJ fuel ratio, as in previous instances. This is because the energy contained in the feedstock is necessary for the energy content of the hydrogen, in these cases.

Source: elaboration developed for this analysis from [ANL, 2022a](#) and [ANL, 2022b](#).

Figure A-6 underlines the important primary energy requirements needed to produce renewable hydrogen, showing also that they are comparable to those identified for fossil hydrogen and hydrogen from nuclear electricity (if accounted as primary energy³⁹), lower than for hydrogen from biomass and far lower than in cases where electricity is from the grid.

³⁹ If nuclear electricity is considered as primary energy, rather than heat: if heat is the primary energy for nuclear, as in conventions used for the energy balances of the International Energy Agency, total energy requirements for nuclear hydrogen are roughly three times higher.

Annex A.4.3 - Land use and land-use change risks of renewable hydrogen production

For renewable hydrogen (and by extension for other RFNBOs derived from renewable electricity), the land area considerations relate primarily to the land use requirements of the renewable power generation⁴⁰.

Available estimates indicate that, per MJ of fuel produced, land use requirements for renewable hydrogen production are far lower than for any crop-based biofuel (by a factor 80 to 200, with details depending on crops and conversion efficiencies). These land use requirements are however higher than for waste-based biofuels and for hydrogen from fossil energy with carbon capture and storage ([KiM, 2022](#)).

⁴⁰ It is estimated that land use requirements for conversion facilities as well as for Direct Air Capture (DAC) (in the case of the conversion of the renewable hydrogen into a hydrocarbon) are smaller in comparison with those for renewable power generation ([ICAO, 2022](#)). The overall land use area necessary for RFNBOs production is also estimated to be significantly smaller than for similar quantities of biofuel production ([T&E, 2017](#)).

Annex A.4.4 - Water requirements of renewable hydrogen production

Water requirements (in terms of volumes of water per unit energy of fuel produced) for renewable hydrogen production are comparable with water requirements for hydrogen production from fossil methane (close to 0.17 L/MJ of fuel) ([ANL, 2022a](#)). Water requirements are higher for hydrogen from nuclear electricity, due to the cooling needs of nuclear power plants. The same applies to hydrogen production from electricity originating from thermal power plants ([ANL, 2022a](#)).

The water requirements for renewable hydrogen production are 10 times higher than for petroleum fuels (gasoline and diesel fuel) and are comparable with biofuel production from waste feedstocks (biochemical and thermochemical pathways). They are higher than for Brazilian sugar cane ethanol production (which water requirements are mainly met by rain), and roughly a factor 10 smaller than for corn-based biofuels production in North America (which is reliant on significant irrigation requirements).

Annex A.4.5 - Costs of renewable hydrogen production

Production costs of renewable hydrogen largely depend on the costs of renewable electricity production. As in any other case, the weight of capital costs depends on the size of the production plant and the volumes of demand, with lower unit values for larger plants and significant demand. The weight of fuel costs depends on the ability to produce electricity from low-cost renewable sources, today only available in times of the day when there is overgeneration of solar or wind energy. This may be counterbalanced by the location of the renewable energy capacity with very high renewable solar and wind potential, which may lead in the future to imports of renewable electricity (via high voltage direct current cables, and eventually imports of hydrogen, via derivatives, as discussed later) being cheaper than domestic production ([IRENA, 2022a](#), [IEA, 2019](#)). Further considerations depend on the need (or not) to use energy for other processes (in particular for water desalination, if it is needed⁴¹).

For hydrogen obtained from electrolysis (in gaseous form), production costs are estimated between 25 and 50 USD/GJ (3 and 6 USD/kg, or 0.065 to 0.13 USD/kWh of hydrogen) if electricity costs are between 0.025 and 0.07 USD/kWh, adding to 0.04 to 0.06 USD/kWh of hydrogen of capital costs ([IEA, 2019](#))⁴². Costs could also be as low as 8 to 16 USD/GJ (1 to 2 USD/kg) if production takes place in very favourable conditions (i.e. with high capacity factors and therefore low capital costs – in the 0.01 to 0.02 USD/kWh range, and low electricity costs – in the 0.01 to 0.025 USD/kWh range) ([IRENA, 2022a](#))⁴³. Liquid hydrogen costs are higher, even in regions where electricity costs may be very low, due to the need for additional processing steps. According to [EnTEC, 2022](#), this leads to production costs for liquid hydrogen that are between 27 and 55 USD/GJ, depending on the renewable electricity production costs that are possible in different global regions.

⁴¹ In water-constrained locations, the extra transport and/or desalination of water can raise hydrogen production costs, but this is not thought to be a significant part of the cost (only up to 4%) ([IRENA, 2022b](#)).

⁴² Figure 12 in IEA report

⁴³ With a 1.4 MJ/MJ energy ratio for hydrogen production, all primary energy from electricity, 120 MJ/kg of hydrogen and 3.6 MJ/kWh, a hydrogen production cost of 1 USD/kg would need less than 0.02 USD/kWh for electricity (the 0.02 USD/kWh value excludes all capital costs for the electrolyzers). Figures can be found pages 33 and 37 in the IRENA report, and in the related footnotes.

Annex A.4.6 - Supply and infrastructure availability for renewable hydrogen production

The costs of transporting hydrogen by road (on-board trucks) are estimated in a range between 12 and 20 USD/GJ (1.5 and 2.5 USD/kg) (carrying liquid or pressurised gaseous hydrogen, considering transport volumes greater than 5 t/day). The costs of transporting hydrogen by dedicated pipelines (which require tens of tons in terms of volumes transported) are between 8 and 12 USD/GJ (1 and 1.5 USD/kg) ([IEA, 2019](#)). Transport in dedicated pipelines has a more attractive cost profile than hydrogen transport on trucks only on condition that there are significant volumes of transport (and therefore only in the presence of end users who need large volumes). For this reason, the expectation is that the most frequent solution will be that of hydrogen trucks, at least in the next decade.

A recent literature review ([ACER, 2021b](#)) that analysed in depth the option of repurposing natural gas infrastructure (the most relevant choice from a cost minimisation perspective) found that its successful transition is conditional on three main factors: (1) the existence of parallel pipelines in natural gas networks, (2) ensuring security of natural gas supply to consumers during the conversion period and (3) the existence of hydrogen market uptake in the area served by a pure hydrogen corridor.

These indications point to important risks (and therefore barriers) linked with gas infrastructure repurposes and hydrogen end-use in a multitude of applications. This leads to timing constraints (due to the need to substitute natural gas flows with renewable hydrogen flows while keeping customers' services, to ensure that industrial clusters can avoid high mothballing⁴⁴ costs) and adds to the challenges of converting a wide number of small end-use equipment and appliances, as mentioned above.

Additional challenges arise from path dependency for hydrogen transport and distribution infrastructure. This is due to the fact that while pipelines are the cheapest transport option for hydrogen, they are only cost effective where large-scale volumes are needed (in the absence of these, costs are lower for other forms of hydrogen transport and distribution such as transport of compressed or liquefied hydrogen tanks by trucks, but still higher, per unit volume, than what they could be with high volumes of hydrogen deliveries in pipelines). Transporting derivatives over long distances rather than hydrogen will also be a cheaper option.

Additional costs, estimated between 20 and 40 USD/GJ (2.5 and 5 USD/kg), also apply to cases where hydrogen is imported by sea ([IRENA, 2022b](#), [EnTEC, 2022](#))⁴⁵.

The distribution of hydrogen is also necessary to bring hydrogen to end users, possibly combining with the need in industrial facilities. Similar to transport, distribution can take place in two ways: by road, on-board of trucks, and by pipelines. The latter are much less relevant for small volumes of demand in widespread distribution sites, such as in the case of use in transport vehicles, due to high investment costs per unit of fuel delivered. Estimates of distribution costs are close to 12-15 USD/GJ (1.5-1.8 EUR/kg) for hydrogen trucks ([Yang and Ogden, 2008](#) and [IEA, 2019](#))⁴⁶. For hydrogen carried by truck, it is also worth noting that safety aspects limit transport capacity to 500 kg of hydrogen per truck

⁴⁴ Mothballing is the deactivation and preservation of equipment or a production facility for possible future use or sale.

⁴⁵ The estimates refer to the use of ammonia as an energy carrier or liquid organic hydrogen carriers (LOHC). For liquefied hydrogen, the estimated costs are higher: between 4 and 7.5 EUR/kg ([IRENA, 2022](#)). Estimates refer to transport distances of 10,000 km. Imports by sea would concern, if anything, hydrogen with lower production costs compared production closer to the area of demand, following the exploitation of more significant primary resources. Use of energy in situ, and export of finished products, would likely be cheaper. High voltage direct current cables are also a valid alternative to hydrogen transport, once differences in end-use efficiency are factored in ([Barnard, 2022](#)).

⁴⁶ Distribution cost estimates for California (a leading market for hydrogen in transport) are close to 1.5 EUR/kg for a number of refuelling stations close to 100 per urban area, and higher (1.8 EUR/kg) if the station number is lower ([Yang and Ogden, 2008](#), Figure 11). Higher volumes of hydrogen to be distributed may lead to lower unit costs ([IEA, 2019](#)), but this is an unlikely case in the context of the growth in demand over the next decade.

([Houssin et al., 2021](#)). This is over 30 times lower than the energy transported by a 60 000 litres tanker transporting liquid fuels, which implies considerable consequences in terms of increased pressure on truck traffic.

Centralised renewable hydrogen production (e.g. in large-scale renewable electricity & electrolyser plants) is subject to lower unit costs thanks to economies of scale, but it loses competitiveness due to the need for a hydrogen transport and distribution network. Decentralised production is subject to higher costs for the smaller electrolysers, but it can be more profitable if it allows to reduce the costs associated with the transport and distribution network. It is therefore possible to have decentralised production in smaller production units (electrolysers) leading to lower final costs (despite higher production costs). In these cases, however, the cost of hydrogen remains higher than in cases of centralized production and large-scale demand.

Hydrogen refuelling stations at 700 bar (currently in use in the global automotive market and for which standardisation is underway, in the case of heavy vehicles) have investment cost estimates of around USD 1-1.5 million for a capacity of 500 kg/day (equivalent to 2 000-3 000 USD per kg/day of distribution capacity) ([IEA, 2019](#))⁴⁷. This also includes storage costs. Costs increase proportionally for larger stations but are higher per kg of hydrogen distributed for smaller stations. The unit cost per kg of hydrogen also depends on the capacity utilisation rate of the filling station. Considering a value for capacity utilisation of 20% adds about 3 USD/GJ (0.4 USD/kg). Additional costs also derive from the energy necessary for the operation of the station (for the compression and cooling of hydrogen)⁴⁸.

Based on the data indicated above, the cost of renewable hydrogen for road transport vehicles is unlikely to be less than 60 USD/GJ (7 USD/kg), and probably closer to 75-83 USD/GJ (9-10 USD/kg). It could fall close 40 USD/GJ (5 USD/kg) if hydrogen is produced at very low costs (from very cheap electricity⁴⁹) and if it is widely used in other sectors (as this could cut transport, storage and distribution costs per unit energy contained in the fuel).

Costs of hydrogen as a fuel delivered to aviation and shipping may be lower (where it may be possible to avoid distribution costs and to leverage synergies with industrial clusters and the so-called *hydrogen valleys*), but still likely to be above 50-66 USD/GJ (6-8 USD/kg) at least for a decade. Costs could fall to USD 35/GJ (USD 4/kg) if hydrogen is produced from abundant primary renewable energy resources available at very low costs (e.g. in cases where they would otherwise be stranded, due to high costs of access to demand markets) and if it is widely used in other sectors (as this is crucial to share transport and storage costs)⁵⁰.

For reference, in 2019, in a market where public policies significantly promote hydrogen for transportation such as California, and with no specific constraints for producing hydrogen in low-emission processes, the price of hydrogen at the pump was close to 16 USD/kg, with larger capacity stations capable of offering it at 13 USD/kg ([CAFCP, 2022](#)).

⁴⁷ Estimates are around two-thirds for 350 bar stations, but the latter have essentially been used only for the bus market, and are not in line with vehicle manufacturers' expectations.

⁴⁸ Estimates developed for the EU for hydrogen refueling are at 3.8 EUR/kg, adding to 3 EUR/kg for distribution by pipeline and 1 to 6 EUR/kg for transport ([Blanco et al., 2018](#)).

⁴⁹ This may be the case with abundant overgeneration of renewable electricity, in global regions highly endowed with renewable energy – namely wind and solar – resources, if renewable electricity is largely used for the production of hydrogen. It would be less likely for nuclear electricity and even less likely for grid electricity, unless this occurs in a context with very high production shares of renewable electricity.

⁵⁰ Authors' own assessment.

Annex A.4.7 - Scalability of renewable hydrogen production

One of the reasons for a growing interest in renewable hydrogen is its scalability potential, grounded on the large availability of water (including sea water) on the planet and the idea that renewable electricity could be widely available.

Key barriers to the scalability of renewable hydrogen relate to:

- the high requirements of renewable electricity needed to produce hydrogen;
- the resources (e.g. the materials needed for the installations generating electricity and the electrolyzers) required to produce and convert all this energy;
- the fact that the supply chains needed to produce these resources (including critical materials) are not yet established at the scale that is necessary for a rapid deployment⁵¹;
- the high energy requirements to liquefy renewable hydrogen, and to maintain cryogenic conditions to store, transport and distribute LH2;

Limiting factors applied to renewable electricity generation also include public acceptance ([Rand and Hoen, 2017](#), [Jarvis, 2021](#), [Motavalli, 2021](#), [Jarvis, 2022](#)).

One aspect of particular importance for an accelerated development of renewable hydrogen (and its derivatives) lies in the large renewable electricity requirement that it implies. This is especially relevant in a context where there are more energy efficient uses of renewable energy, capable to indirectly displace more GHG emissions and fossil energy than what would happen if renewable electricity is used for renewable hydrogen production and use (see Box 1 in section 3.2.2). Key examples of effective use of renewable electricity include electric vehicles for all land transport options and heat pumps for residential heating, thanks to their high energy efficiency. These examples add to the direct use of renewables to displace fossil methane used for marginal electricity generation. The combination of these limitations underlines the need for additionality, temporal and geographical correlation criteria for renewable electricity used for hydrogen, RFNBOs and RCFs, in line with a recent proposal by the European Commission ([European Commission, 2023](#))⁵².

⁵¹ Reducing European and global reliance on fossil energy requires a major acceleration in the scaling up of these supply and value chains. However, this comes with important geopolitical implications ([IRENA, 2019](#), [IEA, 2021](#) and [IRENA, 2022](#)).

⁵² In order to account hydrogen and RFNBOs as fully renewable, the methodology setting out detailed rules for the production of RFNBOs proposed by the Commission requires renewable electricity ([European Commission, 2023](#)) to be generated from new capacity (principle of additionality) or take place at times where it supports the integration of renewable power generation into the electricity system (temporal correlation) or in bidding zones where renewable electricity already represents the dominant share and adding additional renewable electricity generation capacity would not be necessary or possible (geographical correlation).

Annex A.5.1 - Identification of the main options / applications of renewable e-hydrocarbons production

The **hydrocarbons** obtained from synthesis processes have different chemical compositions. Similar to the thermochemical biofuels discussed earlier and the recycled carbon fuels discussed below, their chemical composition can be designed to align with a variety of common fuels, such as gasoline or diesel-type fuels, including as drop-in options. Renewable e-hydrocarbons are therefore technically suitable for a wide range of transport modes: light- and heavy-duty road vehicles (gasoline and diesel fuels), aircraft (jet fuel) and ships (diesel fuels). Their fuel quality can be designed to be comparable to, if not better than, petroleum fuels.

Methanol is of interest for use as a transport fuel due to its liquid form under ambient conditions, avoiding the need for pressurisation or refrigeration (which is needed for hydrogen, ammonia or methane). Its volumetric energy density is approximately half that of diesel and gasoline, but two times greater than liquid hydrogen, and three times greater than compressed hydrogen ([IRENA, 2021](#)). Lower toxicity and spill behaviour risks with respect to ammonia ([ORNL, 2021](#)) add to greater ease of handling in making e-methanol one of the options currently being taken under significant consideration as a low-carbon **maritime fuel**, in cases where direct electrification has limited scope (long distances)⁵³.

⁵³ The interest in methanol in maritime transport is justified by limited availability of renewable carbon for low-carbon fuels, calling for a prioritisation in modes – namely shipping and aviation over long distances – where there is far less scope for direct electrification with respect to inland transport. Contrary to maritime transport, aviation also requires fuels that can remain liquid at very low temperatures. Methanol does not qualify for this.

Annex A.5.2 - Life-cycle GHG emissions of renewable e-hydrocarbons production

To ensure that GHG emission abatement stemming from e-hydrocarbons can be effectively maximised and so that they qualify as RFNBOs, the primary electricity needed for electrolysis and the primary energy required for direct air capture or – initially – other sources of concentrated carbon, need to be renewable-based.

The life-cycle GHG emissions of other synthetic hydrocarbons largely depends on the way the hydrogen (H) and carbon monoxide (CO) needed for their synthesis are obtained. Similar to the case of recycled carbon fuels (RCFs), failing to rely on low-carbon forms of primary energy would quickly make e-hydrocarbon production counter-productive from a GHG emission abatement perspective. This is due to the important primary energy needs to synthesize them compared to the production of fossil hydrocarbons and, beyond an initial transitional phase, to the need for circularity for what concerns direct emissions generated from the combustion of the fuels⁵⁴.

Importantly, the updated proposal of the European Commission regarding the methodology to assess the life-cycle emissions of RFNBOs and RCFs and the threshold of emission reductions or RCFs to meet sustainability requirements⁵⁵ points to the necessity of a capacity to abate emissions that is at least 70% below the European fossil fuel benchmark of 94 g CO₂e/MJ ([European Commission, 2023](#)). This will place (correctly) a significant focus on the need to rely on renewable electricity for RFNBO production. In the European proposal, this is also paired with a parallel updated proposal regarding the need for additionality for this renewable electricity capacity⁵⁶ ([European Commission, 2023](#)). The latter is grounded in the risk of increasing – indirectly – fossil fuel use in electricity generation if renewable electricity is not paired with energy efficient end-uses, as discussed in greater detail in the section on scalability).

Additional constraints come from the need to mitigate hydrogen leakage, given its indirect climate forcing effects.

⁵⁴ For synthetic fuels to achieve life-cycle emissions that are lower than for petroleum fuels (85-90 g CO₂/MJ), the emissions from the electricity generation mix should be lower than approximately 200 g CO₂/kWh ([ANL, 2022a](#)).

⁵⁵ The delegated act establishes a minimum threshold for GHG emissions savings of RCFs and specifies a methodology for assessing greenhouse gas emissions savings from RFNBOs for transport and from RCFs.

⁵⁶ This is addressed in the delegated act establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin.

Annex A.5.3. - Land use and land use change risks and energy efficiency of renewable e hydrocarbons production

Renewable e-hydrocarbons which require DAC need extremely large masses of air to be processed: 1.6 tonnes of air for every kg of CO₂ captured and over 2400 m³ of air per m³ of CO₂ captured⁵⁷. This leads to a total of over 4 tonnes of air to be processed to produce one litre of diesel-like fuel. This means that, to process an amount of air containing the carbon needed to produce one litre of fuel, a fan of 1 m of diameter would need to operate for almost 5 minutes with a uniform air flow moving at 50 km/h through it⁵⁸.

The above considerations point to surface requirements for the process of direct air capture of carbon that are relevant. Nevertheless, and most importantly, available estimates indicate that, per MJ of fuel produced, renewable e-hydrocarbons reliant on DAC needs require far less land than for any crop-based biofuel – by a factor 40 to 100, with details depending on crops and conversion efficiencies⁵⁹. Land requirements for renewable e-methanol are roughly half of those of non-alcoholic renewable e-hydrocarbons (but 20% higher than for renewable e-ammonia) (KiM, 2022)⁶⁰. Land use requirements for renewable e-hydrocarbons are also slightly higher than for waste-based biofuels and for hydrogen from fossil energy with carbon capture and storage.

⁵⁷ This is due to the low volume of CO₂ in the air (air is mainly composed of nitrogen and oxygen, with CO₂ accounting for 410 ppm (0.04%) - . there are 0.018 g CO₂/mol of air).

⁵⁸ Similar calculations, with different examples, are developed in Cebon (2022).

⁵⁹ Land requirements are lower in a transitional phase, reliant on point sources of non-renewable carbon.

⁶⁰ Tables 4.2 & 4.6

Annex A.5.4 - Energy efficiency of renewable e-hydrocarbons production

Estimates of primary energy needs for the production of renewable e-hydrocarbons range between 2 and 2.5 MJ of fuel per MJ of primary energy input if the fuels are produced with DAC, including 1.6 to 1.9 MJ/MJ of low-carbon electricity and 0.4 to 0.6 MJ/MJ of thermal energy (recovered from heat pumps or sourced from waste heat, if available) ⁶¹.

This shows also that producing the e-hydrocarbons from concentrated CO₂ sources is less energy intensive. An energy gain of roughly in line with the 0.4 to 0.6 MJ/MJ of fuel referenced above is in line with the recent assessment by [Soler et al. \(2022\)](#).

Available analyses show also that methanation (leading to methane as e-hydrocarbon product) is more energy efficient than other conversions (0.1 MJ/MJ lower than methanol and 0.2 to 0.5 MJ/MJ lower than other liquid e-hydrocarbons) ([IRENA, 2021](#), [Jarvis and Samsatli, 2018](#), [Peters et al., 2022](#), [Soler et al., 2022](#)). This is consistent with the fact that methanation does not require additional energy inputs after electrolysis and DAC ([Jarvis and Samsatli, 2018](#)). Methanol synthesis is also more energy efficient than Fischer-Tropsch synthesis (which is one of the processes used to produce non-alcoholic synthetic hydrocarbons) ([IRENA, 2021](#), [Jarvis and Samsatli, 2018](#), [Peters et al., 2022](#), [Soler et al., 2022](#)).

⁶¹ Values derived from [ANL \(2022a\)](#) and [ANL\(2022b\)](#), [Deutz and Bardow \(2021\)](#), considering a direct air capture process with dedicated heat pumps, for the production of molecules of C₁₂H₂₆. Values compatible with these ranges are also indicated in [Peters et al.\(2022\)](#) and [Soler et al. \(2022\)](#).

Annex A.5.5 - Water requirements of renewable e-hydrocarbons production

Water is essential to produce the hydrogen required for RFNBOs. However, the mass of hydrogen per MJ of energy contained in the final fuel is 60% to 33% lower for e-hydrocarbons than for hydrogen itself when used as a fuel (since the energy content in e-hydrocarbons also comes from their carbon content).

Water is also needed for DAC processes. According to [Keith et al., \(2018\)](#), a DAC plant operating at ambient conditions of 20°C and 64% relative humidity requires 4.7 kg of water per kg of CO₂ captured.

Combining water requirements for DAC and hydrogen from electrolysis leads to an estimate of 0.4 L/MJ of e-fuel⁶², more than double the value reported for hydrogen, higher than for rainfed biofuels (if water resulting from rain is not accounted), but well below those water requirements of irrigated crops in biofuel production.

⁶² This is based on 0.17 kg of water/MJ for hydrogen (i.e. 20.4 kg of water/kg of hydrogen, with 120 MJ/kg of heating value), 4.7 kg of water/kg of CO₂, 0.27 kg of carbon (kg C)/kg CO₂ (leading to 17.2 kg of water/kg C), 0.86 kg C/kg of C_nH_{2n} hydrocarbon (based on atomic mass ratios), 0.14 kg of hydrogen per kg of C_nH_{2n} hydrocarbon and roughly 44 MJ/kg of heating value for C_nH_{2n} hydrocarbons.

Annex A.5.6 – Costs of renewable e-hydrocarbons production

The cost of renewable e-hydrocarbons largely depends on the cost of the primary electricity needed to produce hydrogen and to capture CO₂ from the air. To a lower extent, it also depends on the cost of capital needed for the facilities that convert the key building blocks (H₂ and CO) into fuel. Given the relevance of energy costs in the final cost estimates, the energy efficiency of processes such as CO₂ reduction into CO, methanation, methanol synthesis and Fischer-Tropsch synthesis also have implications on final production costs.

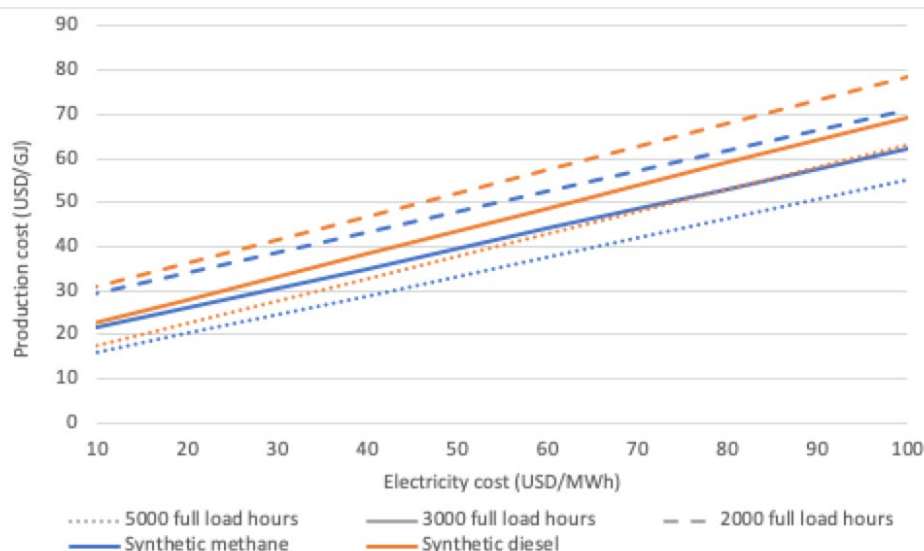
Production cost advantages for renewable e-methane and e-methanol (their production processes being more energy efficient than Fischer-Tropsch), though, need to be balanced with increased costs for transport, storage and distribution, as these fuels require new infrastructure and engines if used for transport purposes.

[IRENA, 2021](#) gives near-term cost estimates for renewable e-methanol in a range of 60 to 120 USD/GJ. An assessment developed in [EnTEC, 2022](#) suggests cost estimates in a similar range (between 55 and 100 USD/GJ) for imported e-methanol (delivery at the border of Europe). For renewable e-methane, the cost suggested by [EnTEC, 2022](#) is roughly 4-5 USD/GJ lower than for e-methanol, and, for renewable e-diesel production, up to 4-5 USD/GJ higher than for e-methanol. [IEA, 2019](#) also points to a similar gap (roughly 7 USD/GJ) between renewable e-methane and e-diesel. Near-term cost values estimated for renewable e-diesel by [EnTEC, 2022](#) and [IRENA, 2021](#) are also similar to those of renewable e-kerosene assessed in [ICCT, 2022](#) (70 to 100 USD/GJ). The values in this range are compatible with costs between 600 and 1 000 USD/t for DAC and 3 to 6 USD/kg for hydrogen production from renewable electricity and electrolysis.

Lower costs are achievable in the longer term and also possible in a transitional phase if DAC can be replaced by concentrated carbon sources (as shown by [Soler et al., 2022](#)).

Estimates from the Mærsk Mc-Kinney Møller Center for methanol from point source CO₂, range between 41 and 55 USD/GJ in 2030 and 22 to 32 in USD/GJ 2050 ([Mærsk Mc-Kinney Møller Center, 2021](#)). Due to the timeframes indicated, these factor in low electricity costs and other process optimisations. These values are more optimistic compared with the range estimated by [Concawe](#), between 45 and 70 USD/GJ, for e-methanol, considering CO₂ from point source in 2030 and DAC in 2050, for production located in Europe ([Soler et al., 2022](#)). They are also more optimistic than the costs assessed by Concawe for production taking place in the Middle East and North Africa, ranging between 45 and 50 USD/GJ ([Soler et al., 2022](#)).

Long term values by [ICCT, 2022](#) and [IEA, 2019](#) range between 30 to 60 USD/GJ. Similar ranges (47 to 64 USD/GJ in 2030 and 25 to 35 USD/GJ in 2050) are also projected for renewable methanol from DAC by the Mærsk Mc-Kinney Møller Center, focusing on shipping). This indicates clearly that cutting e-fuels costs requires to reduce electricity costs to make both DAC and hydrogen production cheap enough. With respect to the near-term assessments, DAC and hydrogen production costs would need to halve to achieve the longer-term costs suggested ([Mærsk Mc-Kinney Møller Center, 2021](#)). Estimates in this range are also shown in Figure A-7 (focusing on values by [IEA, 2019](#) for renewable e-diesel and e-methane).

Figure A - 7 Production costs of renewable e-diesel and e-methane

Note: blue lines refer to renewable e-methane, orange lines refer to renewable e-diesel. Variations in capacity factors of electrolyzers (reflected in different values in load hours) are shown with different line patterns.

Source: adapted from [IEA, 2019](#).

In addition, [EnTEC, 2022](#) estimates that approximately 2.7 USD/GJ should be added to renewable e-methane and USD 2.2/GJ for e-methanol costs, if they are traded (at scale) across global regions, compared with 1.6 USD/GJ for e-diesel. Values with a similar magnitude are also considered by Concawe for fuels transported from the Middle East and North Africa to Europe ([Soler et al., 2022](#)). Costs are higher for longer distances, but cost differentials based on distance are just a fraction of the total cost gap between renewable e-methane/e-methanol and e-diesel. Should the trade of fuels not currently taking place at scale (or blending not be easily feasible), the unit cost of the infrastructure needed to handle and transport them could grow significantly.

Annex A.5.7 – Supply and infrastructure availability for renewable e-hydrocarbons production

Supply and infrastructure challenges are specific to the type of renewable e-hydrocarbon considered and to the end-use envisaged for it. They are therefore discussed separately for drop-in liquid non-alcoholic e-hydrocarbons, e-methanol and e-methane below.

Drop-in liquid renewable e-hydrocarbons

A key advantage of liquid non-alcoholic e-hydrocarbons (diesel- or gasoline-like) is the possibility to produce them as drop-in options. This allows to bridge infrastructure-related barriers, with cost cuts and lower stranded asset risks, as these fuels can be fully blended with petroleum fuels.

The trade-offs of such drop-in fuels relate to higher primary energy needs for production and lower energy efficiency at end-use, compared to the use of renewable hydrogen as a fuel or to direct electrification, together with the other challenges discussed previously (e.g. relative to DAC, to technology scale-up, etc.).

Methanol in shipping

Methanol as a fuel is frequently considered by the industry to be a feasible option to replace oil-based marine fuels ([IRENA, 2021](#), [Maersk, 2022](#)). This is because methanol is liquid and can be stored in regular, non-pressurised tanks. This avoids the need for expensive cryogenic equipment (which is instead necessary for LNG and liquid hydrogen). Methanol is also already widely handled globally as the world's most commonly shipped chemical commodity, but is hardly used as a fuel today, irrespective of the transport mode.

However, the need for more than twice the space compared to diesel-like fuels and heavy fuel oil (due to its lower energy density) is an important drawback for methanol, affecting both onshore and shipping infrastructure. Another challenge comes from the fact that methanol requires engines capable to use it (also including in dual- or multi-fuel configurations). A progressive shift to ships capable to use methanol as a fuel would be therefore necessary. This exposes investments in new fuel distribution infrastructure, necessary for methanol to be widely adopted as a shipping fuel, to relevant risks. These risks require adequate mitigation strategies: a key example in this respect is the coordination of initiatives to develop green corridors ([Global Maritime Forum, 2021](#)).

A number of other challenges are shared with other e-hydrocarbons: they relate to the volumes of air to be processed in DAC facilities, size and cost of DAC installations, the large-scale renewable electricity installations required to feed renewable hydrogen and energy to e-methanol synthesis processes (including the material requirements necessary to build them), and the necessity to reduce costs of renewable e-methanol production technologies through scale increases and technological advances.

E-methane

E-methane also requires dedicated infrastructure to be available to refuel vehicles and faces far greater barriers than other RFNBOs, in particular as renewable e-methanol and liquid e-hydrocarbons. The reason is that e-methane is less economical to handle due to its need for cooling, pressurisation and systems capable to minimise leaks and slippage from vehicle tanks (issues that methane shares with other gaseous fuels, in particular hydrogen)⁶³. This is to be considered in combination with the fact that methane is not widely used as a transport fuel today.

⁶³ Methane may leak to the atmosphere at extraction sites, from pipelines, from LNG tanks as boil-off or when using it as a fuel due to slippage of partly unburned fuel from the vehicle. Any methane leaks are particularly detrimental for the climate as methane is a potent GHG, irrespective of its origin.

Challenges related with DAC, hydrogen production, renewable electricity generation and fuel synthesis in large-scale facilities, as well as the need to reduce technological costs and reach higher technology readiness across the value chain are also shared with other renewable e-hydrocarbons.

Annex A.5.8 – Scalability of renewable e-hydrocarbons production

Similar to renewable hydrogen, one of the reasons for a growing interest in renewable e-hydrocarbons is their scalability potential. This is grounded on the large availability of water (including sea water) on the planet and the universal availability of atmospheric CO₂. One additional reason is the possibility to use e-hydrocarbons as direct substitutes to their fossil equivalents, thanks to properties that can be tailored to make them fully compatible with existing vehicles.

Key barriers to the scalability of renewable e-hydrocarbons primarily relate to the production of renewable electricity but also to the fuels' synthetisation processes (including: sites with abundant renewable resource, material requirements for renewable electricity generation and electrolyzers and their supply chains⁶⁴, DAC costs and surface/size requirements).

This implies an accelerated development of renewable electricity. The latter is especially relevant in a context where there are more energy efficient uses of renewable energy, capable to displace more GHG emissions and fossil energy than if renewable electricity is used for e-hydrocarbons production.

Limiting factors applied to renewable electricity generation also include public acceptance, through the opposition by residents to proposed developments in their local area ([Rand and Hoen, 2017](#), [Jarvis, 2021](#), [Motavalli, 2021](#), [Jarvis, 2022](#)).

The combination of these limitations underlines the need for strict additionality, temporal and geographical correlation criteria for renewable electricity used for RFNBOs ([European Commission, 2023](#))⁶⁵.

⁶⁴ Reducing European and global reliance on fossil energy requires a major acceleration in the scaling up of these supply and value chains. However, this comes with important geopolitical implications ([IRENA, 2019](#), [IEA, 2021](#) and [IRENA, 2022](#)).

⁶⁵ In order to account hydrogen and RFNBOs as fully renewable, the methodology setting out detailed rules for the production of RFNBOs proposed by the Commission requires renewable electricity to be generated from new capacity (principle of additionality) or to take place at times where it supports the integration of renewable power generation into the electricity system (temporal correlation) or in bidding zones where renewable electricity already represents the dominant share and adding additional renewable electricity generation capacity would not be necessary or possible (geographical correlation).

Annex A.6.1 – Identification of the main options/applications of renewable e-ammonia production

Burning pure ammonia in a compression ignition engine is challenging (it requires high compression ratios to ignite the fuel) but feasible, especially in cases where ammonia ignition is facilitated by the use of a pilot fuel ([ITF, 2020](#)). Using ammonia in fuel cells is also an option, but demonstration of high efficiency and durable fuel cell systems operating on ammonia is still at low levels of technology readiness ([European Commission, 2022](#)).

Despite the fact that renewable e-ammonia raises more health and safety considerations than competing RFNBO alternatives, especially for its spill behaviour ([Kass et al., 2021](#)), it is increasingly considered as one of the options that could help to decarbonise maritime transport ([IEA, 2019](#), [ITF, 2020](#), [Englert et al., 2021](#)). The use of ammonia as a shipping fuel is also currently at an early stage of technological maturity ([ITF, 2020](#)).

Limited consideration of ammonia as a fuel option for other modes (road and aviation) is due to the safety and environmental hazards of spills taking place in closed environments (e.g. aircraft) or on land, with the above-mentioned associated toxicity threats and the need for the fuel to be handled by professionally trained operators.

Annex A.6.2 - Life-cycle GHG emissions of renewable e-ammonia production

As a carbon-free molecule, no CO₂ is released upon combustion of ammonia and any CO₂ emissions would arise only at fuel production and transportation stages. Ammonia combustion produces mostly nitrogen (N₂) and water (H₂O), the molecules from which ammonia was built, which do not constitute threats to global warming ([Kobayashi et al., 2019](#)). However, combusting ammonia in an engine (unless this is subject to effective after treatment of exhaust gases and other leakage minimisation processes) may also lead to the formation of nitrous oxide (N₂O), which has a global warming potential 298 times larger than CO₂⁶⁶ and other air pollutants, consisting of nitrogen oxides (NO_x), with risks of substantial alterations to the global nitrogen cycle ([Wolfram et al., 2022](#)).

As in the case of hydrogen synthesis, the GHG emission intensity of the different production steps of synthetic ammonia are crucial to determine its life-cycle GHG emissions. Renewable e-ammonia production, which relies on renewable electricity for hydrogen and nitrogen production, associated to the [Haber-Bosch process](#), can lead to major GHG emission abatements (80%⁶⁷ to 90%) vs. hydrogen production from steam methane reforming⁶⁸ ([Liu et al., 2020](#)).

Annex A.6.3 - Land use and land use change risks of renewable e-ammonia production

Available estimates indicate that, per MJ of fuel produced, land use requirements for renewable e-ammonia are roughly 25% higher than for renewable hydrogen, 20% lower than for renewable e-methanol, 40% of those needed for renewable e-hydrocarbons and far lower than any crop-based biofuel – by a factor 50 to 150 depending on crops and conversion efficiencies ([KiM, 2022](#)). Land use requirements are higher than for waste-based biofuels and hydrogen from fossil energy with carbon capture and storage ([KiM, 2022](#)).

⁶⁶ [IPCC Fourth Assessment Report](#), 100-year time horizon.

⁶⁷ Translating into production emissions of about 28 g CO₂/MJ.

⁶⁸ With the use of natural gas as a feedstock, electricity to power the Haber-Bosch process derived mostly from coal and natural gas, and without carbon capture and storage.

Annex A.6.4 - Energy efficiency of renewable e-ammonia production

Assessments of energy efficiency of renewable e-ammonia point to ratios of energy inputs to energy contained in the fuel in the 1.8 MJ/MJ (i.e. a 55% efficiency) to 2.4 MJ/MJ range (i.e. a 42% energy efficiency) ([IRENA, 2022](#) and [Bicer et al., 2016](#))⁶⁹. These values are comparable with those considered for renewable e-hydrocarbons and higher than the 1.5 MJ/MJ (i.e. a 67% energy efficiency) characterising a conventional production pathway using natural gas to produce hydrogen ([IRENA, 2022](#)) or the 1.2-1.3 MJ/MJ of renewable hydrogen production ([ANL, 2022a](#) and [2022b](#)).

Similarly to e-hydrocarbons synthesis via electrolysis, the high ratio of energy inputs per unit output in the fuel (about half the input energy being lost throughout the production process) highlights how crucial reliance on decarbonised electricity is. If electricity inputs do not have an extremely low emission profile, life-cycle GHG emissions would very quickly exceed those of a production pathway based on natural gas.

⁶⁹ [IRENA, 2022](#) also reports that process improvements from high-temperature electrolysis have the potential to increase the energy efficiency of renewable ammonia production to 62-72%.

Annex A.6.5 – Costs of renewable e-ammonia production

Renewable e-ammonia is the cheapest RFNBO to produce, except for renewable hydrogen ([Mærsk Mc-Kinney Møller Center, 2021](#)). As in the case of other e-liquids, the cost of renewable e-ammonia depends largely on the cost of hydrogen production through electrolysis ([IRENA, 2022](#) and [IEA, 2019](#)). The other steps of e-ammonia production (nitrogen purification and the Haber-Bosch process) are only a small fraction of the total cost. Estimates by Concawe range between 45 and 65 USD/GJ for European production, in a 2030 timeframe ([Soler et al., 2022](#)). IRENA's near-term cost estimates for renewable e-ammonia range between 40 and 75 USD/GJ.

Potential cost reductions largely depend on decreases in the price of renewable electricity. Additional savings can result from reductions in the cost of electrolyzers. These could come from technology learning with large-scale deployment. Efficiency gains and the optimisation of storage and operational hours can also contribute to reducing production costs ([IRENA, 2022](#)). Projected values integrating such improvements are in the range of 30 to 50 USD/GJ by 2030 and even 15 to 30 USD/GJ by 2050 ([IRENA, 2022](#))⁷⁰. [Concawe](#) indicates a range between 35 and 55 USD/GJ for ammonia, in 2050, considering production in Europe and/or the Middle East and North Africa ([Soler et al., 2022](#)). The latter is at the bottom of the range, including transport. This integrates the consideration that transporting e-ammonia by ship has clear cost advantages vs. transporting liquefied hydrogen (approximately a third of the cost) ([ENTEC, 2022](#)).

Existing transport infrastructure for fossil-based ammonia can be used for e-ammonia, reducing transportation costs, but this is only relevant in cases where this infrastructure already exists (which may be interesting cases to start piloting ammonia use as a fuel in maritime transport). Similar to the case of methanol, not yet used as a fuel in shipping nor in other energy end-uses, substantial investments (including in infrastructure, in particular distribution infrastructure) are necessary for renewable e-ammonia to make a significant contribution to the decarbonisation of the transport sector ([IRENA, 2022](#)).

⁷⁰ These ranges are similar to long-term projections assessed in [IEA, 2019](#): 15 USD/GJ with electricity at 20 USD/MWh, and 50 USD/GJ with electricity at 80 USD/MWh. Values at the low-end of these ranges (30 to 43 USD/GJ in 2030 and 15 to 23 USD/GJ in 2050) are also projected by the Mærsk Mc-Kinney Møller Center ([Mærsk Mc-Kinney Møller Center, 2021](#)).

Annex A.6.6 - Supply and infrastructure availability for renewable e-ammonia production

The use of ammonia as a fuel poses significant safety and environmental risks that need to be addressed. Beyond toxicity hazards, ammonia requires the development of adapted engines (including for the prevention of N₂O release to the atmosphere⁷¹) ([Mærsk Mc-Kinney Møller Center, 2021](#)). Similar to methanol, key technical challenges also include the need for more than twice the space of diesel-like fuels and heavy fuel oil due to lower energy density, affecting both onshore and shipping infrastructure.

Regarding infrastructure deployment prospects, ammonia faces challenges that are similar (but probably stronger, due to safety and an acceptability profile that is likely more challenging) to those of methanol. Like methanol, ammonia is already traded globally as a feedstock for industrial purposes. However, volumes transported currently are just a fraction of what would be required if ammonia was widely used as a fuel (even if only in the maritime sector). A shift to ammonia-powered ships would only take place as engines are replaced over time (also with the possibility to refurbish existing ships).

Increased investments are a necessity in a scenario that sees wide adoption of ammonia as a shipping fuel. Coordinated action is therefore crucial to manage risks, which is being done for example by green maritime corridor initiatives (as for methanol) ([Global Maritime Forum, 2021](#)).

⁷¹ N₂O is an extremely potent GHG; see sub-section "Life-cycle GHG emissions".

Annex A.6.7 - Scalability of renewable e-ammonia production

Ammonia is made from nitrogen. This is available in far larger quantities in the air and cheaper to obtain than the CO₂ that is needed for renewable e-hydrocarbons. Ammonia also requires hydrogen and energy (namely renewable electricity), like renewable e-hydrocarbons. The key barriers to the scalability of renewable e-hydrocarbons, due to this aspect, also apply to renewable e-ammonia. This includes consideration of the resources required for producing cheap renewable electricity and the supply chains needed to enable this.

The need to prioritise energy efficient uses of renewable energy, discussed in Sections 2.3.1 and 2.3.2 for hydrogen and e-hydrocarbons, respectively, also apply to ammonia. So does the need for pairing renewable electricity to produce RFNBOs with additionality, and with temporal and geographical correlation requirements ([European Commission, 2023](#)).

Annex A.7.1 - Identification of the main options/applications of fossil-based hydrogen production

Hydrogen from fossil energy, without the abatement of GHG emissions, accounts for almost all current global demand, almost fully focused on use as chemical feedstock for fertiliser, refining and methanol production (70 Mt). An additional amount of 45 Mt was estimated, globally and in the same timeframe, for use in industry, without prior separation from other gases ([IEA, 2019](#))⁷².

The applications for hydrogen from fossil resources are the same identified for renewable hydrogen. They include use as a reducing agent in steelmaking (one of the emerging areas of interest for industrial decarbonisation) and the direct utilisation as an energy vector/fuel. They may also include use as a feedstock/intermediate for the production of chemicals and fuels.

Devices enabling the direct use of hydrogen as energy vector include those reliant on combustion (including internal combustion engines and turbines, if adapted) and fuel cells. Technically, these devices could be used on road transport vehicles, aircraft and maritime vessels. Barriers to these applications relate to the complexity of on-board storage, due to the need for compression and/or liquefaction to increase volumetric energy density.

⁷² Page 17, 2d paragraph (for 70 Mt) and footnote 1 (for 45 Mt).

Annex A.7.2 - Life-cycle GHG emissions and energy efficiency of fossil-based hydrogen production

Hydrogen production processes based on steam reforming of fossil methane releases large amounts of GHG and requires far more fossil energy compared with the direct use of the petroleum fuels (Figures A-5 and A-6, while the benchmark for petroleum fuels is 86 g CO₂e/MJ⁷³ and 1.1 to 1.3 MJ/MJ). Similarly, and always due to energy losses during the methane reforming process, emissions per MJ of energy contained in hydrogen from steam methane reforming, without CCS, are 30% higher than the direct combustion of methane.

The higher emissions of fossil hydrogen are exacerbated by energy losses associated with transport, compression or liquefaction and storage of hydrogen. Low-carbon hydrogen production is, therefore, a strict condition to achieve meaningful reductions in GHG emissions.

The pairing of steam methane reforming with the capture and storage (CCS) can improve the life-cycle emission profile of fossil hydrogen. If coupled with CCS, hydrogen production from fossil methane could theoretically sequester more than 90% of the CO₂ emissions occurring from hydrogen production by fossil fuel reformation ([Romano et al., 2022](#))⁷⁴. Indeed, rates of CO₂ sequestration in the 70% to 90% range are also reported according to the [IEA \(2019\)](#). The 70% estimate is also used in the context of the European Renewable Energy Directive (European Commission, 2018) to define a sustainability threshold for renewable hydrogen production ([Romano et al., 2022](#)). The Commission proposal of July 2021 extends this threshold to RFNBOs and RCFs, proposing to count these to meet its transport target (revised into a greenhouse gas intensity reduction metric, rather than a volumetric share) if its GHG emissions savings meet this requirement ([European Commission, 2021](#)).

Due to energy losses, a 70% cut in emissions vs hydrogen production from steam methane reforming without CCS scales down to less than 60% if compared with methane combustion. Additionally, achieving this level of abatement requires extremely successful efforts to abate upstream methane emissions and the use of decarbonised electricity to supply parts of the process ([Howarth and Jacobson, 2021](#), [Romano et al., 2022](#), [Howarth and Jacobson, 2022](#)).

Current industry practices only capture lower levels of CO₂, estimated between values ranging between 30-40% ([Howarth and Jacobson, 2021](#)) and 55% (ICCT, 2022) if compared with steam methane reforming without carbon capture. The lower-end of these values are close to the emissions that would be obtained from direct combustion of methane (Howarth and Jacobson, 2021), while the higher end leads to limited emission reductions on a life-cycle basis.

Using methane only as feedstock, and renewable electricity for energy inputs in methane reforming processes with CCS is estimated to improve savings vs hydrogen from steam methane reforming (unabated) to a range between 47% and 66%, and 37% to 47% vs direct methane combustion ([Howarth and Jacobson, 2021](#), [Romano et al., 2022](#), [Howarth and Jacobson, 2022](#)). Further reductions require cuts of upstream emissions from methane extraction. This, combined with the fact that most CCS is used in combination with enhanced oil recovery (which provides the incremental revenues used for the

⁷³ The source for this benchmark is the GREET model ([ANL, 2022a](#) and [2022b](#)). The fossil fuel benchmark used in European legislation is 94 g CO₂e/MJ ([European Commission, 2018](#)).

⁷⁴ The capture rate could technically even be close to 100% if hydrogen is produced from the combination of water electrolysis for oxygen production (and hydrogen as a by-product) and power generation from methane through a process that uses CO₂ as the working fluid (the Allam cycle) and CO₂ sequestration ([Collins, 2021](#)). More generally, all technologies enabling increased CO₂ storage rates (in particular auto thermal reforming vs. steam methane reforming) come with energy penalties. Optimizing process to increase CO₂ sequestration is therefore associated with increased energy needs, and these need to be met by low-carbon sources to ensure that the overall balance can be low-carbon.

operation of the facilities, with emission penalties), questions the effectiveness of fossil hydrogen with carbon capture in meeting the requirements needed for sustainable transport fuels.

The energy requirements of hydrogen production from steam methane reforming with CCS are close to 1.7 MJ/MJ⁷⁵. Energy needs are higher than in the case of hydrogen production from steam methane reforming without CCS due to the requirements related with carbon capture. For hydrogen production from methane reforming with CCS, carbon sequestration also requires to co-locate hydrogen production and the availability of geological reservoirs allowing CO₂ storage⁷⁶.

Methane pyrolysis is a process that also relies on fossil natural gas to produce hydrogen, allowing to abate life-cycle emissions because it leads to the production of solid carbon as a by-product ([IEA, 2021](#)).

Hydrogen production from methane pyrolysis requires relatively high temperatures (> 800°C) to split methane into gaseous hydrogen and solid carbon (e.g. carbon black, graphite) ([IEA, 2021](#)). Similar to the case of hydrogen from methane reforming with CCS, these temperatures need to be reached using renewable or other forms of low-carbon electricity to power electrical heaters to minimise GHG emissions. Actual life-cycle emission abatement for hydrogen produced from methane pyrolysis is therefore dependent on the primary form of energy used for this purpose.

Methane pyrolysis uses three to five times less electricity than electrolysis and has an overall energy conversion efficiency (considering methane and electricity, combined, to produce hydrogen) of 40-45% ([IEA, 2021](#)). However, due to methane inputs (not needed for electrolytic hydrogen), total primary energy requirements for hydrogen production from methane pyrolysis are still between 2.2 and 2.5 higher than the energy contained in the hydrogen (without considering further losses due to transport, storage, distribution and end-use). These values are comparable with the range of 2.2 to 2.6 MJ/MJ of gaseous hydrogen from the electrolysis of low-carbon electricity ([ANL, 2022a](#))⁷⁷.

⁷⁵ The MJ/MJ ratio used here is assessed including the energy contained in the feedstock at the numerator, in line with what has been done for fossil fuels, biofuels and all other options where the energy contained in the feedstock is also found in the fuel.

⁷⁶ Carbon capture technology must also be financially viable and effectively store carbon in a secure way for centuries.

⁷⁷ While lower needs for electricity in the production of hydrogen from methane pyrolysis means also that higher carbon intensity of electricity would lead to lower overall GHG emissions in comparison with electrolytic hydrogen, it does not take away the need to rely on low carbon electricity mixes to ensure effective GHG emission reduction.

Annex A.7.3 - Land use and land use change risks of fossil-based hydrogen production

Due to the low land use requirement per MJ of fossil fuels and the complementary role of renewable electricity (which has larger land use requirements) for the production of low-carbon fossil-based hydrogen, overall land use requirements are lower than for renewable hydrogen. Since renewable hydrogen already has lower land use requirements than most other fuels – with the sole exception of waste-based options ([KiM, 2022](#)), land use change risks due to the production of low-carbon fossil-based hydrogen are low.

Annex A.7.4 - Water requirements of fossil-based hydrogen production

Water requirements for pathways based on fossil methane are higher than in the case of conventional hydrogen production from steam methane reforming without CCS, since these are largely imputable to methane extraction. Water requirements increase for processes requiring additional electricity production, like pyrolysis and carbon capture, and depend on the source of electricity considered, with higher requirements for pathways requiring cooling of thermal processes.

Annex A.7.5 - Other sustainability considerations for fossil-based hydrogen production

Methane pyrolysis faces the challenge of producing 3 kg of carbon black per every kg of hydrogen. This could be used, initially, in rubber, tyres, printers and plastics. However, a significant scale up of hydrogen production from methane pyrolysis could lead to oversupply of carbon black, given that demand for carbon in 2020 being 16 Mt, which corresponds to hydrogen production from pyrolysis of 5 Mt of hydrogen ([IEA, 2021](#)), less than 10% than the current demand in pure form. This means that that carbon black production could far exceed demand for it, if hydrogen production from methane pyrolysis (currently at lower technology readiness than others) is scaled up. This does not only limit the scope for additional revenue streams from the sale of carbon black, but it also risks generating a significant waste stream, which requires proper handling.

Annex A.7.6 - Costs of fossil-based hydrogen production

Capital costs for fossil-based low-carbon hydrogen production pathways (based on estimates developed for large-scale hydrogen production from steam methane reforming with CCS) have been estimated at 4.2 USD/GJ or 0.5 USD/kg ([IEA, 2019](#)). Operational costs have been estimated at 3.3 USD/GJ, or 0.5 USD/kg). Additional costs are needed for methane, a crucial feedstock for these pathways.

Accounting for a 1.6 MJ/MJ of hydrogen ratio (optimistic vs. the range in Figure A-6) indicates that a methane price similar to the historical values of 20 USD/MWh would add roughly 8.9 USD/GJ (1.1 USD/kg) for the production of hydrogen. The energy cost of hydrogen grows to 35 USD/GJ (4.2 USD/kg) for a natural gas price of 80 USD/MWh, close to the market average in Europe from late 2021 to mid-2022, and to 68 USD/GJ (or 8 USD/kg) for a natural gas price of 150 USD/MWh (i.e. the one attained in July 2022).

The total production cost in centralised facilities would then range from the 16.3 USD/GJ (1.9 USD/kg) of a gas price of 20 USD/MWh (as in times prior to the Russia-Ukraine conflict) to 43 USD/GJ (5.1 USD/kg) with gas at 80 USD/MWh and 74 USD/GJ (8.9 USD/kg) with the gas prices of July 2022.

Annex A.7.7 - Supply and infrastructure availability for fossil-based hydrogen production

The observations made in the section on renewable hydrogen are also relevant here. Hydrogen production costs exclude additional costs for transport, storage and distribution of hydrogen as a fuel and/or hydrogen trade. These additional steps, necessary for hydrogen end-use in transport, would likely add 35 USD/GJ (3.5 USD/kg) to 40 USD/GJ (5 USD/kg) for road transport vehicles. Incremental costs due to hydrogen transport and distribution could be lower, possibly 15 to 25 USD/GJ (2-3 USD/kg) for shipping and aviation. This assumes that these modes could be better placed to leverage the centralized facilities developed for industrial purposes (chemical plants, fertilisers), in the proximity of airports and ports and in the context of the so-called *hydrogen valleys*⁷⁸.

⁷⁸ References regarding costs are cited in the section on electrolytic hydrogen (Annex A.4.5).

Annex A.7.8 – Scalability of fossil-based hydrogen production

One of the key advantages of low-carbon hydrogen production from fossil resources (with carbon capture and storage) is the possibility to leverage existing extraction facilities to capitalise on the large scale production scale of these resources, even if they remain options that are not going to be indefinitely available. This same feature is also one that could help handling risks of asset stranding (i.e. the loss of economic value of assets related with fossil resources, in a context of declining demand). Limiting factors arise from the need for extremely successful efforts to abate upstream methane emissions (a development not observed to date), the necessity to ensure that there is a possibility to co-locate production facilities with sites allowing for the geological storage of CO₂ and low-cost renewable energy.

The need for extremely successful efforts to abate upstream methane emissions is not only a requirement for hydrogen from methane reforming with CCS, but also for methane pyrolysis, given that upstream methane emissions are a shared challenge for all hydrogen production pathways based on fossil methane. For methane pyrolysis, further challenges are paired with the risk to oversupply the market with solid carbon, increasing costs due to the need to handle waste (since there is no scope for combustion of solid carbon of fossil origin, if GHG emissions shall be avoided) rather than leading to opportunities to sell by-products.

As discussed in the section on electrolytic hydrogen, further limitations for hydrogen as an energy vector for transport vehicles come from the importance to minimise energy losses occurring across the whole supply chain. Low life-cycle energy efficiency is exposing hydrogen and its derivatives to the risk of being outcompeted by options (especially direct electrification) whose profile comes with better life-cycle energy efficiency and lower costs, for the same service delivered. These, along with lower costs and risk profile for the deployment of electric vehicle charging infrastructure, limit the extent to which the use of hydrogen and its derivatives (rather than batteries and electricity, or petroleum-based hydrocarbons complemented by emission offsetting technologies) will be scaled up in transport. Such limitation is not only for electrolytic hydrogen pathways, but also for low-carbon fossil-based pathways.

Annex A.8.1 – Identification of the main options / applications of recycled carbon fuels production

Similar to thermochemical biofuels, recycled carbon fuels can technically be designed to be suitable for a variety of fuels, including gasoline and diesel/middle distillates, and also as drop-in options. Like other thermochemical synthetic fuels, they can therefore be technically suitable for a wide range of modes of transport, including cars and light vehicles (using gasoline or diesel), heavy-duty road vehicles (using diesel), aviation (using jet fuel) and maritime transport (using diesel or heavy fuel oil). As for other synthetic fuels, their fuel quality can be designed to be comparable to, if not better than, petroleum-based fuels.

Annex A.8.2 – Life-cycle GHG emissions of recycled carbon fuels production

The life-cycle GHG emission abatement potential of RCFs largely depends on the origin of the feedstocks required and the GHG emissions associated with its alternative disposal (i.e. the emissions that would occur if the feedstock is not used to produce the RCFs).

A recently updated proposal by the European Commission on the methodology for assessing GHG emissions savings from RFNBOs and RCFs used in transport clarifies credits should not be granted for capturing CO₂ which has already been taken into account under other provisions of law ([European Commission, 2023](#)). This excludes, in principle, emissions from fuel combustion falling within the scope of the EU ETS and other regulated sectors, but it allows for a temporary (until 2040) inclusion of concentrated sources of CO₂ (including from fossil origin) within the scope of what is viable for both RFNBOs and RCFs.

To ensure that GHG emission abatement can be effectively maximised, RCFs production will need to replace alternative uses of waste streams that are significantly more GHG intensive. To do so, it will also need to rely on low-carbon forms of energy. Failing to substitute waste disposal processes that are more GHG emission intensive or to rely on low-carbon forms of primary energy means that RCF production would quickly be counterproductive from a GHG emission abatement perspective, since it would risk to increase net emissions.

The recent proposal of the European Commission regarding the methodology to assess life-cycle emissions of RFNBOs and RCFs addressed this aspect effectively, requiring, for RCFs, a capacity to abate emissions that is at least 70% below the European fossil fuel benchmark of 94 g CO₂e/MJ⁷⁹ ([European Commission, 2023](#)). The parallel European proposal on the additionality of renewable electricity production ([European Commission, 2023](#)) also helps mitigating the risk of increasing – indirectly – fossil fuel use in electricity generation by prioritising the direct use of electricity for end-uses that are more energy efficient.

A government assessment on the LCA performance available from the United Kingdom sounds sceptical on significant opportunities where RCFs can demonstrate GHG savings capable to meet the regulatory sustainability thresholds. The diversion of waste feedstocks from heat generating applications, according to the document, is likely to lead to more GHG savings compared with diverting feedstocks from waste to electricity plants ([DfT, 2022](#)).

⁷⁹ The same percent reduction is required in the Renewable Energy Directive for RFNBOs ([European Union, 2018](#)).

Annex A.8.3 – Land use and land use change risks of recycled carbon fuels production

Due to their reliance on liquid and solid waste streams as feedstocks, it is reasonable to expect that land use requirements of RCFs are on the low-end of the range observed for other fuels, along the lines of findings that have shown low land use impacts for waste-based fuel production pathways.

Annex A.8.4 – Energy efficiency of recycled carbon fuels production

The government assessment developed in the United Kingdom for RCFs, already mentioned in the life-cycle GHG emission section, points to low conversion efficiency of feedstocks into RCF ([DfT, 2022](#)). This is in line with other cases reliant on conversion processes like gasification, pyrolysis and liquefaction, such as thermochemical biofuels.

Annex A.8.5 – Costs of recycled carbon fuels production

A key advantage of RCFs, in comparison with e-hydrocarbons is the possibility to rely on concentrated sources of carbon. A key limitation, this time shared with e-hydrocarbons and adding to the lower GHG emission abatement capacity, is the necessity to convert the feedstocks into syngas, and then to recombine building blocks into fuels. Existing indications on costs point towards the need for reductions to achieve competitiveness, due to the advanced fuel technologies required ([DfT, 2022](#)). Due to the reliance on concentrated carbon streams, it is also reasonable to consider that limitations in scale can limit the scope to reduce capital costs.

Annex A.8.6 – Supply and infrastructure availability for recycled carbon fuels production

Similar to thermochemical biofuel technologies, RCFs can be produced as drop-in fuels, allowing to bridge infrastructure-related barriers, as they can be fully blended with petroleum-based hydrocarbons and methanol. In the case of methanol (mainly considered as an option for maritime transport), they face the same infrastructure-related and mode-specific barriers already discussed for e-methanol from renewable electricity (Annex A.5.7). The reason for this is that methanol would require the development of a dedicated transport, storage and distribution infrastructure.

Annex A.8.7 – Scalability of recycled carbon fuels production

RCFs are subject to inherent limitations of RCFs in terms of GHG emission abatement per MJ of fuel. This is combined with processes with sizable energy efficiency losses for their production (similar to those characterising thermochemical biofuel production, but without the same GHG emission abatement advantages). It comes also with the large energy losses occurring for fuel combustion. These characteristics clearly limit the scope of use of RCFs as part of a long-term decarbonisation and energy efficiency strategy, likely confining them to marginal cases. Demand for RCFs that could demonstrate a compelling GHG emission abatement capacity is likely to be stronger in modes where more direct electrification faces major technical barriers, such as shipping and aviation.

Limitations for the use of RCFs also come from the limited scale of flows of carbon that can be recovered from waste processing.

ANNEX B

This annex contains details of the four major scenario groups considered in Section 3.1, which provide projections of energy demand and supply for the transport sector in 2050.

Scenario Group 1: EU 2050 Long Term Strategy

General context of the scenarios

The European Commission developed a series of scenarios in support of the development of the long-term strategy for EU GHG emissions reduction in accordance with the Paris Agreement ([European Commission, 2018](#)). Two of these scenarios, the 1.5TECH and 1.5LIFE scenarios, which are considered below, achieve substantial emissions reduction, reaching net-zero GHG emissions by 2050 and thus pursuing efforts to achieve a 1.5°C temperature change.

The 1.5TECH scenario aims to increase the contribution of the technology options that include electrification, use of hydrogen and e-fuels, and also relies on the deployment of biomass associated with significant amounts of carbon capture and storage (BECCS) in order to reach net-zero emissions in 2050. The 1.5LIFE scenario relies less on the technology options of 1.5TECH but assumes a drive by EU business and consumption patterns towards a more circular economy. Similarly, the increase in climate awareness of EU citizens translates in lifestyle changes and consumer choices, which include food diets resulting in lower GHG emissions, the sharing economy in transport, limiting growth in air transport demand, and more rational use of energy demand for heating and cooling. While the inland navigation sector, covering inland waterways and national maritime, is an integral part of all scenarios, an additional variant, 1.5LIFEMar, was used to treat EU international shipping separately.

Main assumptions (relating to sustainable fuels)

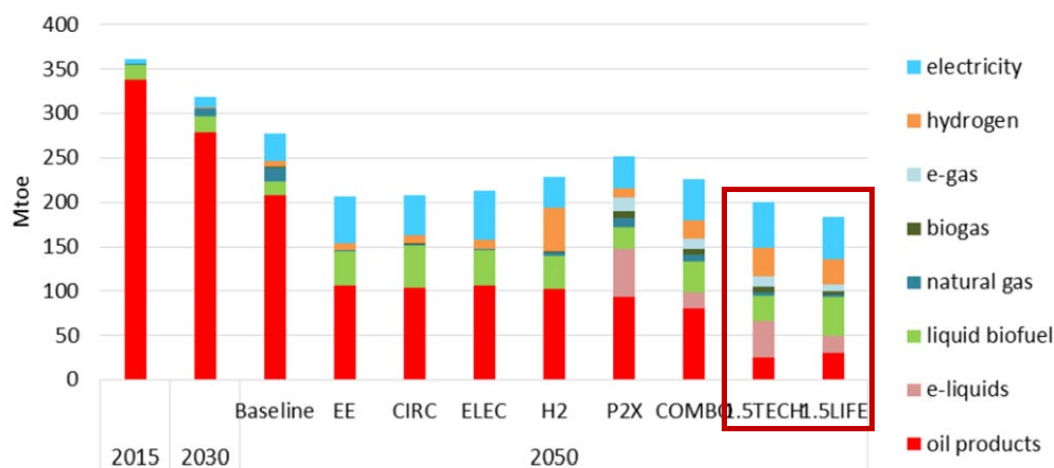
Both the 1.5TECH and 1.5LIFE scenarios assume significant improvements in transport energy efficiency and electrification for all transport modes (but to a very limited degree for aviation and maritime), as well as increased modal shift. Advanced biofuels and E-fuels are deployed for all transport modes but with priority for HDVs, aviation and maritime.

Results in terms of final energy demand

For heavy-duty vehicles (HDVs), there is a high uptake of low carbon fuels, in particular of e-fuels and biofuels. In both the 1.5TECH and 1.5LIFE scenarios, bio-kerosene (25% and 45% of the fuel mix, respectively) and e-liquids (34% and 10% of the fuel mix, respectively) represent the main alternatives for reducing the carbon intensity of air transport fuels. Electricity remains a niche market for this sector by 2050. In the 1.5LIFE scenario, the significant uptake of liquid biofuels and e-liquids in aviation is coupled with a reduction in energy demand relative to 2015 (5% decrease by 2050), driven by the lower growth in transport activity and energy efficiency improvements. Energy efficiency is projected to provide a significant contribution to the achievement of emissions reductions from maritime transport by 2050, with a 33% reduction in emissions relative to 2015 in the 1.5LIFEMar scenario achieved through propulsion, propeller and hull coating technologies, and through speed reduction. The 1.5LIFEMar scenario would mean a significant uptake (54%) of liquid biofuels in the EU international maritime fuel mix by 2050, implying a 27.5 Mtoe (1.2 EJ) liquid biofuels demand by 2050 for this subsector.

Figure B-1 shows the full range of scenarios considered in the [European Commission \(2018\)](#) report. The 1.5TECH and 1.5LIFE scenarios considered here are highlighted by a red box.

Figure B - 1 Fuels consumed in the transport sector in 2050 in scenarios developed for the EU's 2050 Long Term Strategy



Source: [European Commission, 2018](#)

Scenario Group 2: IPCC 1.5

General context of the scenarios

The IPCC reviewed over 200 mitigation pathways that either kept surface temperature increases below a given threshold (1.5°C or 2°C) throughout the 21st century, or returned to a value below 1.5°C above pre-industrial levels at some point before 2100 after temporarily exceeding that level earlier ([IPCC, 2018](#)). The Below 1.5°C pathways are considered here. This work was on a global basis and no breakdown for the EU is provided. Hence, here we focus on relative changes rather than absolute figures for comparison with the other scenarios considered which are European (EU27 & UK) based.

The IPCC pathways are based on global integrated assessment models (IAMs) that represent key societal systems and their interactions, like the energy system, agriculture and land use, and the economy, and these are compared with sector-specific studies. Pathways limiting peak warming to below 1.5°C throughout the entire 21st century have a 50–66% likelihood. No pathways were available that achieve a greater than 66% probability of limiting warming below 1.5°C during the entire 21st century. Only nine of the 200 mitigation pathways considered limit peak warming to below 1.5°C throughout the entire 21st century. Consequently, 44 other pathways with a low amount of overshoot (where a warming of 1.5°C is exceeded at some point during the 21st century and which are termed 1.5°C-low-OS or 1.5DS-L pathways) were also considered here.

Main assumptions (with relevance to sustainable fuels)

In the IPCC Below 1.5°C and 1.5°C with low overshoot pathways considered here, there are marked demand reductions, a strong upscaling of renewables, and use of sustainable biomass. Electricity covers a markedly larger share of global final energy demand in transport sector by mid-century.

Results in terms of final energy demand

For the IPCC pathways considered here, global transport final energy demand in 2050 declines by around 16% compared with the 2370 Mtoe (99.2 EJ) of demand in 2010. This reflects increases in activity outside Europe. Around 25% of the final global transport final energy consumption is electrified in 2050 (corresponding to ~20 EJ). Biofuels constitute around an eighth of global transport final energy

consumption (~10 EJ) in 2050, and roughly double in terms of primary biomass supply, given conversion losses.

Scenario Group 3: CAN Europe

General context of the scenario

The Climate Action Network (CAN) Europe and the European Environmental Bureau (EEB) jointly elaborated a single Paris Agreement Compatible (PAC) scenario ([CAN Europe/EEB, 2020](#)), along with their member organisations and external experts. This is a European-wide energy scenario that is aligned with the Paris Agreement's objective to limit global warming to 1.5°C degree.

Main assumptions (with relevance to sustainable fuels)

The PAC scenario assumes total transport final energy demand will be halved between 2015 and 2040 through efficiency gains, through electrification, technical improvements, modal shift and behavioural changes. An overall reduction in final energy demand from the aviation sector of 26% in 2040 compared to the 2015 baseline will stem mostly from price incentives (including a EUR150/t carbon price by 2040).

Non-fossil gases and fuels are based on hydrogen that is exclusively produced with renewable electricity, which is converted into renewable ammonia, synthetic methane and liquid synthetic fuels. For private cars, the PAC scenario assumes a fully electrified fleet by 2040. Road freight is covered primarily by electrification (either through batteries, highways with overhead catenary lines or switching traffic to rail) and by renewable hydrogen for heavy-duty vehicles. Shipping is covered by electricity for short-distance, a mix of electricity and renewable hydrogen for mid-distance (intra-EU), and a mix of renewable hydrogen and ammonia for long-distance. Aviation is mostly covered by liquid synthetic fuels and marginally by second-generation biofuels, until the progressive development of electric aircraft post-2040.

Results in terms of final energy demand

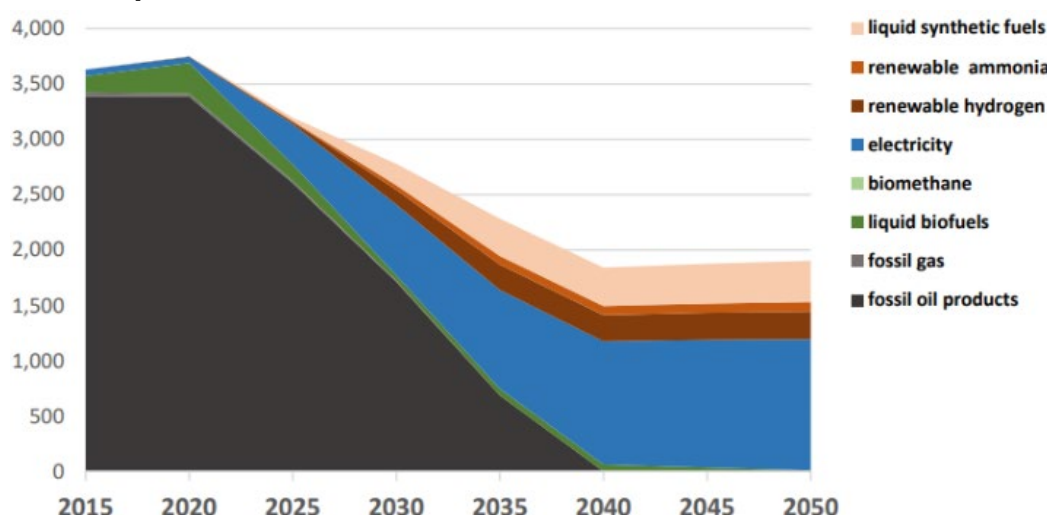
Transport will move from a 90% fossil-based to a 100% renewable energy mix in the next 20 years. Direct use of electricity will represent around two thirds of the transport final energy mix while biofuels demand will be halved by 2040, moved to second-generation biofuels and strictly dedicated to aviation.

In the transport sector, renewable hydrogen is scaled up to cover 131 TWh (0.5 EJ) of demand in 2030 (5% of transport's final energy demand) and 250 TWh (0.9 EJ) in 2050 (13% of final energy demand). It is mainly used to substitute fossil oil products in heavy freight where electric drivetrains are not fully deployed, and in fuel cells in mid-distance shipping. In parallel, renewable hydrogen is converted to renewable ammonia for long-distance shipping (maximum of 86 TWh or 0.3 EJ in 2050, 4% of the transport sector's final energy demand).

For aviation, liquid synthetic fuels are regarded as the only short-term renewable alternative besides liquid biofuels to phase out the fossil oil product kerosene. Aeroplanes become the most important consumer of renewable gases and fuels with 192 TWh (0.7 EJ) of liquid synthetic fuels consumed in 2030 (7% of transport's final energy demand), rising to 374 TWh (1.3 EJ, 20% of demand) in 2050, while electric aircraft are progressively used to substitute for the use of biofuels.

Figure B-2 shows the final total energy demand for the transport sector in the CAN Europe/EEB PAC scenario.

Figure B - 2 Final total annual energy demand (TWh) for the EU27+UK transport sector in the CAN Europe/EEB PAC scenario



Source: [CAN Europe/EEB 2020](#)

Scenario Group 4: Concawe Low Carbon Fuels

General context of the study / scenario

Concawe (a research group of European fuel manufacturers)⁸⁰ assessed different potential scenarios for the EU refining industry to contribute to EU climate targets ([Concawe, 2021](#)). With a wide focus on road, aviation and maritime sectors, three potential demand scenarios (covering the EU27 and UK) show the total volume of low carbon fuels (LCFs) that could be required to contribute to climate neutrality in EU transport by 2050. **The Concawe HIGH scenario** considers a high demand for low carbon fuels (LCF) in all transport modes. It assumes that the passenger car segment is not fully electrified by 2050, i.e. there is a mixed fleet with internal combustion engines still present, where LCF replace passenger car fossil fuel demand by 2050. **The Concawe MEDIUM scenario** considers that demand LCF will come first from light and heavy-duty transport and then progressively penetrate the aviation and maritime sectors. By 2050, the passenger car segment is fully electrified and LCF is used in heavy-duty road as well as aviation and maritime. **The Concawe LOW scenario** considers a more aggressive penetration of alternative powertrains in both the light and heavy-duty road segments such that there is no remaining demand for liquid fuels in road transport by 2050, with all production of LCF used in the aviation and maritime sectors. All three Concawe scenarios are European-wide energy scenarios that are aligned with the Paris Agreement's objective to limit global warming to 1.5°C degree.

The Concawe High scenario is discussed further below.

Main assumptions (with relevance to sustainable fuels)

The HIGH scenario, with high demand for LCFs in all transport modes, is the most challenging scenario considered by Concawe. It assumes that LCFs penetrate the road transport sector first, growing in aviation and maritime beyond 2035. This scenario is deemed an end-point one, assuming that the passenger car segment is not fully electrified and a mixed fleet with internal combustion engines is still present, and in which LCFs ramp up, progressively replacing the fossil fuel demand by 2050. The 2050 total final energy demand for road transport in the Concawe HIGH scenario is the same as defined in the [European Commission \(2018\)](#) 2050 baseline scenario (1.5TECH, discussed above). Other key

⁸⁰ ([Concawe, n.d.](#)).

assumptions in the HIGH scenario include: lignocellulosic-based technologies being ready for deployment in 2025 and moving almost immediately to mass deployment across Europe; specification changes for gasoline beyond E10 to allow higher bio-blends; and e-fuels from renewable electricity scale-up from early 2025. Because of uncertainty about the availability of feedstock for HVO production, domestic European HVO capacity is limited to 10 Mtoe (0.4 EJ) in 2030. This is close to the global production value in 2021.

Results in terms of fuel demand for the Concawe HIGH scenario

Production of biofuels and e-fuels will reach ~30 Mtoe (1.3 EJ) by 2030, which is a ~70% GHG intensity reduction on average when compared against a pure fossil reference for 2030. By 2050, all remaining fossil fuels used in road transport are replaced by biofuels/e-fuels. The total amount of LCFs required for road transport is ~90 Mtoe (3.8 EJ). Up to ~70 Mtoe (2.9 EJ) additional biofuels/e-fuels may be required in 2050 for aviation and maritime, representing 70% of the liquid fuel demand for these sectors.

Figure B-3 shows the projected volumes of LCFs and fossil fuels for all transport modes in the Concawe HIGH scenario.

Figure B - 3 Projected volumes of LCFs and fossil fuels for the Concawe HIGH scenario (high demand for LCF in all transport modes)

VOLUME					
Mtoe	2030	2035	2040	2050	
Road					
Fossil	192	140	73	0	
LCF	31	34	62	93	
1G	16	12	9	7	
Advanced	14	16	32	40	
efuels	1	6	21	46	
Aviation & Maritime					
Fossil	111	98	74	31	
LCF	3.3	12.7	34.7	66.5	
Advanced	3	9	19	35	
efuels	0	3	16	32	
Total LCF	34	47	97	159	
1G	16	12	9	7	
Advanced	16.8	25	51	75	
efuels	1	9	37	78	
Remaining fossil	303	238	146	31	

Source: [Concawe, 2021](#)

This study provides the European Parliament's Committee on Transport and Tourism (TRAN) with an assessment of the potential of sustainable fuels to decarbonise the transport sector, and help the sector achieve the 2050 decarbonisation goals. It assesses their potential for use in maritime, aviation and road transport, considering their technology readiness, feedstock availability, sustainability of supply, resource and energy efficiency, and the most appropriate match-making between fuels and applications.
